COST/BENEFIT ANALYSIS OF DEMAND-SIDE MANAGEMENT PROGRAMS

Virginia State Corporation Commission
Staff Report
Case No. PUE900070

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COST/BENEFIT ANALYSIS OF DEMAND-SIDE MANAGEMENT PROGRAMS

I. INTRODUCTION

This report presents the results of a Virginia State Corporation Commission Staff investigation of cost/benefit methodologies for the evaluation of electric and natural gas utility demand-side management programs. The analytical techniques used to determine the economic costs and benefits of demand-side programs are critical to the development and implementation of effective programs. Commission policy regarding utility demand-side programs should assure that programs are evaluated with rigorous techniques that identify explicitly the economic costs and benefits associated with proposed demand-side management programs. This report identifies the cost/benefit techniques in common use by utilities today, discusses their advantages and disadvantages, and makes recommendations regarding the use of such tests in Virginia.

The Staff's investigation of cost/benefit techniques is an outgrowth of a recent comprehensive review of Commission policy regarding utility demand-side management programs. This review was initiated on January 7, 1991 with the establishment of Case No. PUE900070. The Commission recognized the need in that proceeding to establish policy regarding cost/benefit techniques for demand-side programs. It directed its Staff on March 27, 1992 to establish a working group to consider appropriate cost/benefit methodologies for demand-side programs and to file a report with recommendations to the Commission. This document is the Staff's report.

The Staff's report reflects many of the ideas discussed by the Task Force on Cost/Benefit Methodologies (Task Force) organized by the Staff in response to the Commission's order. The Task Force met periodically from June through September of 1992. The discussions that ensued were successful in identifying the issues involved in the development and use of the various cost/benefit methodologies and in clarifying the points of view of the various participants. The participants in the Task Force are listed in Appendix 1. While the Task Force was instrumental in the development of the Staff report, the report is a Staff document and not meant to represent a consensus of the Task Force.

This report is organized as follows. Section II provides an overview of current demand-side management programs of utilities in Virginia as well as Commission policy regarding such programs. Section III identifies the key concepts and issues associated with demand-side management programs that influence the choice and application of cost/benefit tests. Section IV identifies the tests that were reviewed by the Staff and discusses their use and advantages and disadvantages. The next two sections of the report address the numerous policy and technical issues that are associated with the use of cost/benefit tests. The last section offers conclusions and recommendations for the Commission's consideration.

II. BACKGROUND

The role of demand-side management (DSM) in utility resource planning continues to expand in Virginia. A comparison of the current long-term resource plans of electric utilities to their plans of just a few years ago reveals important differences in both scope and content. The number of demand-side programs offered, the variety of the offerings, and the effect of these programs on customer demand have grown rapidly in recent years.

Natural gas utilities in Virginia are also increasing their demand-side management activities. While resource planning for natural gas utilities has received much less attention than such planning for electric utilities, natural gas resource planning will play an increasingly important role in the future.

An overview of the demand-side management programs offered by major utilities in Virginia is provided as background in this section of the report. Also provided as background information is a summary of recent changes in State Corporation Commission policy regarding utility conservation and load management programs. The Commission recognizes the opportunities offered by demand-side planning and has revised policy to further encourage cost effective programs. A Commission statement on cost/benefit techniques, if adopted, will complement these policy revisions and provide much needed guidance for utilities developing DSM programs.

Overview of Demand-Side Management Programs

Electric Utilities

The demand-side management programs of Virginia's electric utilities are continuously evolving. Electric utilities in the state, in general, have expanded DSM budgets over the last five years and spent considerable time and effort in exploring the demand-side options available to them. The demand-side plans of Virginia's electric utilities represent a mixture of old and new programs designed to meet a variety of conservation and load management goals. Selected projections of peak demand and energy reductions for the major investor-owned electric utilities operating in the state are provided in Tables 1 and 2 below. These projections were taken from each Company's 1992 Ten Year Resource Plan filed with this Commission on July 31, 1992. New forecasts will be out shortly, however, that may change these numbers significantly.

TABLE 1
ESTIMATED REDUCTION IN PEAK DEMAND
(MW)

	1992	2000
Appalachian Power*		
Summer	--	125
Winter	10	188
Delmarva Power		
Summer	184	333
Winter	6	79
Potomac Edison		
Summer	132	215
Winter	147	239
Virginia Power		
Summer	235	735
Winter	397	542

Note: Appalachian Power's projections represent estimates of the aggregate impact of expanded DSM programs being considered for implementation.

TABLE 2
ESTIMATED REDUCTION IN ENERGY
(GWH)

	1992	2000
Appalachian Power*	--	503
Delmarva Power	11	135
Potomac Edison	300	621
Virginia Power	140	30

Note: Appalachian Power's projections represent estimates of the aggregate impact of expanded DSM programs being considered for implementation.

Slowing the growth in system peak demand remains a top DSM goal for most electric utilities in the state. Virginia Power estimates that it is currently reducing its winter peak by 397 MW (3.2%) and its summer peak by 235 MW (1.8%). The Company is summer peaking and expects to continue to focus DSM efforts on reducing its summer peak demand. Summer peak reductions are expected to increase to 735 MW or 4.4% of unadjusted peak load by the year 2000.

Delmarva Power is also planning on significant reductions in summer peak demand as a result of its DSM efforts. Delmarva currently estimates a summer peak reduction of 184 MW in 1992. Peak reductions are estimated to increase to 333 MW by the year 2000. While these expected peak reductions are smaller than those for Virginia Power on an absolute basis, they represent larger reductions as a percentage of unadjusted peak demand. Delmarva's estimated summer peak reductions are 7.7% of unadjusted peak demand in 1992 and 11.6% of peak demand in the year 2000.

The 1992 demand-side management plans of Appalachian Power and Potomac Edison show greater peak reductions in the winter than in the summer. Appalachian Power expects winter peak reductions to increase from only 10 MW in 1992 to 188 MW or 2.7% of unadjusted peak demand in the year 2000. Potomac Edison is currently reducing winter peak demand by an estimated 147 MW or 6.5%. By the end of the decade this percentage is expected to increase to 8.6%.

Projections of annual GWH energy reductions due to DSM programs vary significantly from utility to utility in Virginia. Potomac Edison is reducing energy sales by an estimated 300 GWH or 2.4% of sales in 1992. This figure increases to an estimated 621 GWH or 4.2% of unadjusted sales by the year 2000. The projections of GWH savings of other major Virginia electric utilities tend to be much lower. With the exception of Virginia Power, the electric utilities in Virginia expect to increase energy savings due to DSM programs throughout the next ten years. A number of Virginia Power's DSM programs are expected to result in large increases in energy sales so that the overall effect of its programs after the year 2000 is an increase in energy sales.

The electric utilities in Virginia will call upon a wide variety of conservation and load management programs in order to achieve these projected load modifications. Virginia Power's 1992 demand-side management plan, for example, identifies 22 programs available to residential, commercial, and industrial customers. American Electric Power, parent company of Appalachian Power, recently investigated 189 specific DSM measures. Forty-four of these programs passed various screening tests and are under consideration for implementation in its various service territories. Potomac Edison, a subsidiary of the Allegheny Power System, also completed a comprehensive review of its demand-side alternatives in 1992. The Company offers DSM programs in the residential, commercial, and industrial sectors and now expects to realize significant peak savings in the areas of thermal treatment of new and existing structures, energy efficient lighting, and HVAC efficiency.

Finally, a brief mention should be made of the demand-side management efforts of the electric cooperatives serving the state. There are thirteen retail electric cooperatives and one electric generating and transmission (G&T) cooperative serving Virginia. Many of the cooperatives in the state have had a load management program for a number of years. Load management has included the control of line voltage and water heater control. Most of the retail cooperatives also offer residential energy audits and information programs regarding conservation measures. Time-of-use and interruptible rates are also available from many retail cooperatives and are considered part of their DSM effort.

Natural Gas Utilities

The demand-side management programs of Virginia's natural gas utilities are typically not as extensive as the programs offered by electric utilities. Many gas utilities in the state do, however, offer customer information and technical assistance programs, interruptible rates, and cooperative advertising programs.

A variety of information designed to promote conservation and the use of energy efficient equipment is provided by gas utilities. Among the topics typically covered are the need for periodic inspections and maintenance of furnaces, weatherstripping and caulking, proper setting of water heater controls, and appliance efficiency. Cooperative advertising with local heating appliance dealers and contractors is undertaken to promote both the conservation of gas as well as increased gas usage. Technical assistance is also offered, normally to large industrial users. Finally, interruptible rates for commercial and industrial customers are offered by most of the natural gas utilities in the state.

Commission Policy Regarding DSM Programs

On March 27, 1992, the Commission issued a final order in Case No. PUE900070, revising Commission policy regarding electric and gas utility conservation and load management programs. The order represented an attempt to establish a new regulatory framework to encourage the development of cost effective conservation and load management programs by electric and natural gas utilities operating in the state.

The Commission's final order in Case No. PUE900070 made key findings in the following areas:

1) Promotional Allowances - Restrictions on utility promotional allowances were modified to permit promotional allowance programs designed to achieve energy conservation, load reduction, or improved energy efficiency.

2) Formal Review of CLM Programs - Formal review and approval of utilities' conservation and load management programs are now required. The Commission allowed utilities the option of either approval on a program by program basis or periodic review of the entire demand-side package.

3) Cost/Benefit Analysis - The Commission Staff was directed to organize a working group to develop recommendations regarding the appropriate cost/benefit test(s) to be used in the evaluation of conservation and load management programs.

4) Demand-side Bidding - Virginia Power was directed to develop an experimental demand-side bidding program.

5) Consumer Information - The Commission Staff was directed to review the information available to consumers about conservation and identify possible methods of distribution in order to reach the largest number of consumers interested in energy efficiency and conservation.

The Commission rejected arguments for policy change in several other areas. Chief among these were arguments to incorporate environmental externalities into the cost/benefit calculation for demand-side programs and to revise ratemaking treatment for CLM program costs. In the case of environmental externalities, the Commission concluded that it did not have the statutory authority to include environmental externalities in the ratemaking process. The Commission also argued that the incorporation of environmental externalities should be dealt with from a broader perspective than utility ratemaking. The United States Congress and the Virginia General Assembly were identified as more appropriate bodies to provide such perspective.

The Commission rejected various proposals to modify ratemaking treatment of conservation and load management expenditures. In particular, proposals for automatic adjustment clauses were explicitly rejected. As for the argument that utilities should be compensated for "lost revenues" that may occur with the implementation of DSM programs, the Commission noted that there was a pending proceeding to revisit utility rate case rules. It stated that if rules for a more forward looking test year were adopted, then problems associated with decreasing revenues from aggressive conservation programs may be alleviated.

The Commission's March 27, 1992 order is in some respects a first step at sorting through the many regulatory issues that arise with increasing levels of demand-side program activity. Many other issues will develop as more programs are implemented and operating experience is realized. The development of a Commission policy on the use of cost/benefit tests in evaluating demand-side programs is an extremely important next step in policy development. The Commission's policy in these areas will have a major impact on the types of DSM programs that are implemented in the state and the success of those programs.

III. DSM Program Evaluation - Concepts and Issues

Utility demand side management programs are developed for many different reasons. In most cases, particularly in Virginia, DSM programs are initiated by the utility. While specific reasons vary, these programs are implemented because the sponsoring utility believes the program will contribute to the achievement of corporate goals. Thus, DSM programs become an important tool for the utility in implementing corporate strategy.

Reasons for implementing DSM programs, however, extend far beyond their contribution to the achievement of utility corporate objectives. Demand-side management programs are a tool of public policy. Demand-side programs are a means for public utility commissions or state legislative bodies to promote energy efficiency and to influence energy markets to better promote the public interest. It is this public policy aspect of demand-side management that has created much of the interest and controversy in the topic.

Bef(re proceeding to specifics of DSM cost/benefit tests, it will be useful to provide a brief overview of the load objectives of utilities in implementing DSM programs as well as the public policy issues associated with such programs.

Utility Demand-side Prcgram Objectives

Demand-side planning encompasses any activity related to the design and assessment of utility programs to influence customer use of electricity or natural gas. Among the strategic objectives that can be promoted through the use of demand-side management are lowering costs to the customer, reducing construction requirements, improving environmental quality, increasing customer value, and improving regulatory relations. These strategic goals imply a variety of operational objectives, including those for modifying load shapes.

Different utilities will pursue different load shape objectives, depending on individual system characteristics and corporate strategy. Demand-side programs can reduce peak loads, shift load from peak to non-peak hours, build off-peak load, or contribute to a general reduction of sales throughout the day. DSM programs can also contribute to a general increase in sales and greater market share. Although many programs do not fit neatly into any one particular category, the following six categories of demand-side management programs can be identified.[1]

1) **Peak Clipping** - Peak clipping is a reduction of system peak loads, normally using direct load control. This effect can reduce a utility's need to operate its most expensive capacity and postpone the need for certain future capacity additions.

2) **Valley Filling** - Valley filling involves building off-peak loads. A security lighting program offered to residential customers is an example of a valley filling program. This effect can reduce a utility's average fuel costs and spread capacity fixed costs over a larger base of energy sales.

3) **Load Shifting** - Load shifting involves shifting load from on-peak to off-peak hours, which can essentially produce the combined effects of peak clipping and valley filling. Examples of such programs are time-of-use rates and thermal energy storage systems.

4) **Strategic Conservation** - Strategic conservation involves a reduction in sales as well as a change in the pattern of use. A program to encourage the replacement of incandescent lights with compact fluorescent is an example of a strategic conservation program.

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1 This categorization is based on that used in a number of EPRI reports in the 1980s. See, for example, EPRI EM-4815-SR.

5) **Strategic Load Growth** - Strategic load growth results in a general increase in sales beyond the valley filling described earlier. This may involve increased market share of loads that could be served by competing fuels, for example when heat pumps are promoted to replace gas furnaces.

6) **Flexible Load Shape** - A flexible load shape can reduce cost of service by tailoring price and quality of service to meet individual customer needs. An air conditioner cycle control program, for example, would contribute to a more flexible load shape.

The existence of fundamentally different types of objectives, and thus DSM programs, has implications for the choice and use of cost/benefit methodologies. An ideal cost/benefit technique would provide a meaningful quantification of costs and benefits for a variety of DSM programs. However, in practice, a cost/benefit methodology that provides useful information when applied to a conservation program may not provide meaningful information when applied to a DSM program that is meant to promote sales. It is important in such situations to be aware of the limitations of various tests and to be able to properly interpret their results.

Public Policy Issues

The advantages of demand-side management to public utilities are now widely acknowledged. The number of demand-side management programs both under development and actually implemented in the country continues to accelerate. The uncertainty and apprehension associated with earlier DSM efforts is slowly giving way to greater confidence as experience is gained and savings verified.

A recognition by utilities of the potential benefits to be gained through the implementation of demand-side management programs, however, is only one factor explaining the surging interest in such programs. Another major factor is the advantages offered by demand-side programs from a regulatory and public policy perspective. Demand-side programs are tools that can be used to promote a variety of public goals. The public policy aspects of demand-side programs should be fully recognized when considering cost/benefit techniques for the evaluation of such programs.

A utility evaluating a DSM program does not conduct the same type of analysis that a private firm would perform in evaluating capital investment decisions. The regulated nature of a utility requires that it conduct an analysis that is broader than what is typically performed in the private sector. The cost/benefit analysis framework promotes such an analysis.

A broader framework often includes an analysis of costs and benefits to parties other than the utility. The impact of a program on utility ratepayers and customers participating in a program, for example, are perspectives that are typically sought. Environmental and employment benefits and costs associated with DSM programs are also considered in some calculations.

The issue of an appropriate cost/benefit test for DSM programs must be evaluated in a public policy context. While some of the issues surrounding cost/benefit methodologies are of a technical nature, certain key issues require policy judgment. Many of the most important issues discussed by the Task Force were policy issues related to the use of various cost/benefit tests as opposed to more technical issues related to the development of appropriate tests. The Staff believes that these related policy issues are an important part of its work and will devote considerable time to discussing them in Section VI of this report.

IV. COST/BENEFIT TESTS AND DSM PROGRAM EVALUATION

The growth in demand-side activities over the last decade has been accompanied by increased efforts to develop rigorous techniques for program evaluation. Cost/benefit techniques have been developed for the evaluation of demand-side programs and successfully applied by utilities throughout the country. The results of such evaluations have been very useful in clarifying issues before regulatory bodies and in identifying how the impact of specific programs will differ among those groups having a stake in a proceeding.

In this section of the report is a discussion of general cost/benefit analysis techniques and the specific application of cost/benefit techniques to demand-side programs. The more widely used cost/benefit tests for evaluating demand-side programs are identified and examined. The Staff's conclusions regarding the appropriateness of various tests and their strengths and weaknesses are also presented.

The Cost/Benefit Analysis Framework

Cost/benefit analysis is an approach to systematically and quantitatively compare alternatives based on the relative costs and benefits associated with each alternative. Once established, a cost/benefit framework allows the analyst to not only compare various options but to systematically revise data and assumptions and develop alternative scenarios. Such a framework facilitates decisionmaking by requiring explicit quantification of costs and benefits. Although many of the techniques involved in cost/benefit analysis are also applied in the private sector analysis of projects, cost/benefit analysis is normally associated with decisions made in the public sector or that have a strong public policy or regulatory aspect.

While the details vary from application to application, in general cost/benefit analysis involves the following elements:[2]

1) Determining the role of cont/benefit analysis in the decisionmaking process. For example, who will use the analysis being conducted and how will they use it?

2) Determining the social goals that provide a basis for evaluation of proposed alternatives. Costs and benefits can be identified and measured only relative to specific criteria or objectives.

3) Correctly identifying the benefits and costs of each proposed alternative and measuring each. This involves determining the value of costs and benefits at the time they occur and for the stakeholders affected.

4) Combining all of the benefits and costs in order to determine an overall measure of an alternative's net benefits. This can involve aggregating benefits and costs that occur in different time periods, aggregating benefits and costs that accrue to different groups of people, and/or aggregating benefits and costs that would occur in different possible future circumstances.

5) Reaching a conclusion. This involves selecting appropriate criteria for choosing among alternatives on the basis of total benefits and costs.

As outlined in this framework, cost/benefit analysis is a tool to provide information and analysis to decisionmakers. Decisionmakers must combine this information and analysis with other considerations in making a decision. The ultimate goal is the formulation and adoption of improved public policy.

From an economist's perspective, cost/benefit analysis is grounded in the theory of welfare economics. Two assumptions underlie this theoretical framework: 1) social welfare depends on

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[2]There exists an extensive literature on cost/benefit analysis. See, for example, E.J. Mishan, Cost-Benefit Analysis, 1976.

the individual welfare of the members of the society, and 2) an individual's welfare is best judged by that individual. The concept of Pareto optimality is used to evaluate increases in individual and, thus, social welfare. While Pareto optimality can be expressed in several ways, in general, when option A is compared to option B, if at least one individual believes his welfare is greater under option A, and no individual believes his welfare is less, then one can conclude that option A makes a greater contribution to social welfare than option B. The choice of option A is a Pareto improvement.

In practice, most policy issues do not involve an opportunity for Pareto optimal choices. Real world problems typically involve winners and losers. However, the theoretical construct of Pareto optimality is useful when discussing choices that benefit one group of individuals at the expense of others.

<u>Cost/Benefit Analysis of Demand-Side Management Programs</u>

Cost/benefit analysis can be successfully applied to utility demand-side programs. The emphasis on quantification and the public policy perspective inherent in the approach are particularly suitable for demand-side program analysis. However, successful application of the technique requires careful thought and attention to detail. The effects of even the simplest of demand side programs on a utility's customers and operating system can be complex. The assumptions and techniques used in conducting the technical analysis required of a DSM program evaluation are often controversial and frequently challenged.

The tendency when evaluating electric utility demand-side programs is to draw analogies with the cost/benefit analysis conducted on the supply side. While there are similarities there are also important differences. The operating characteristics, system impacts, and availability of demand-side resources are often very different from supply-side resources. More importantly, however, is the fact that unlike supply side resources, demand side resources are not typically owned by the utility. Ownership of resources by the customer requires special attention to the needs of the customer and a measure of costs and benefits to customers as well as to the utility. These characteristics of demand-side programs have resulted in a special group of cost/benefit tests for program evaluation.

Standard Tests

A set of cost/benefit analysis techniques unique to demand-side programs are now widely used throughout the United States. While specific items included in these tests will vary from application to application, the intent of the set of tests is to provide estimates of the costs and benefits of a particular program from a number of different perspectives. This presentation of costs and benefits from a set of perspectives has now become standard practice in many jurisdictions in the country.

The standard practice that has emerged had its genesis in California. The California Public Utility Commission and the California Energy Commission issued their "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management

Programs" in 1983. This document identified costs and benefits from the perspective of key stakeholders that would be affected by a particular DSM program and provided equations for the quantification of such costs and benefits. The "Standard Practice Manual" was revised in December 1987.

There are now a number of other sources that identify cost/benefit equations for the evaluation of demand side programs. The Electric Power Research Institute (EPRI), for example, has formulated a set of tests for electric utilities that are similar to those tests defined by the California Standard Manual. Software is also available that facilitates the application of cost/benefit tests. One such commercial program is DSManager, which is an EPRI sponsored product.

__Staff Review of Cost/Benefit Tests__

The efforts of the Staff and the Task Force were directed toward reviewing the cost/benefit tests that have evolved as standard practice. While other evaluation techniques exist, the set of tests identified in the California Standard Practice Manual and more recently by EPRI and others were considered "state of the art". These tests offer a sufficient variety of perspectives and level of details to be responsive to the Commission's directive in this proceeding.

The Staff also has surveyed other state public utility commissions to gather information on the cost/benefit analysis techniques used elsewhere. A summary of the survey results is provided as Appendix 2. The results of the survey indicate that the California Standard Manual type tests are the predominant set of tests used elsewhere.

Cost/benefit tests as measured from five different perspectives are summarized below. Although these perspectives are equally applicable to the analysis of natural gas demand-side programs, the discussion will focus on electric utilities. The cost/benefit tests identified are those presented in the 1987 California Standard Practice Manual. The summary of the various tests and the discussion of advantages and disadvantages are based largely on information included in the California Manual. The equations used in the California manual are provided in Appendix 3. Information on cost/benefit analysis from various EPRI documents is also used. While definitions included within tests will vary somewhat depending on the source, the perspectives offered are very similar.

Participant Test

The Participant's Test is a measure of the quantifiable benefits and costs of a program from the perspective of the participating customer. The test is an indicator of the attractiveness of a program to a customer and thus provides information useful in estimating likely participation rates.

The benefits of participation in a demand-side program include any reductions in a customer's utility bill, incentives paid by the utility or third party, and any federal, state or local tax credit received. Among the costs to a program participant are all expenses incurred as a result of participating in a program plus any increases in the customer's utility bill. Expenses include the cost of any equipment or materials purchased, operation and maintenance costs, and any removal costs.

The Participant Test typically only includes direct and quantifiable benefits and costs. Discomfort, changes in the value of service, and the value of a customer's time in arranging for installation of a DSM device are some of the factors that are more difficult to quantify and are often not included in the participant test.

Utility Cost Test

The Utility Cost Test measures the net costs of a demand-side management program based on the costs incurred by the utility and excluding costs incurred by the participant. This test is also called the utility revenue requirements test since it measures the change in revenue requirements.

The benefits included in the Utility Cost Test are the avoided supply costs for periods when there is a load reduction. This includes reductions in the costs of transmission, distribution, generation and capacity. Payments received from customers as a result of any charges the utility may have for participating in a DSM program are also considered benefits to the utility.

Costs under the Utility Cost Test include program costs incurred by the utility, incentives paid to customers, and increased supply costs for periods in which load is increased.

Ratepayer Impact Measure Test

The Ratepayer Impact Measure (RIM) test measures the differences between the change in total revenues paid to a utility and the change in total costs to a utility resulting from the DSM program. As revenues and total costs change, rate levels change. This test is also called the Non-Participant test and the No Losers test.

The benefits calculated in the RIM test are the savings from avoided supply costs and any revenue gains. Avoided costs include reductions in transmission, distribution, generation, and capacity costs for periods in which load has been reduced.

The costs in the RIM test include the program costs incurred by the utility, any incentives paid to the participant, decreased revenues for periods in which load has been reduced, and increased supply costs for any period in which load has been increased. Utility program costs include development and start up costs, administration and promotional costs, and the costs of equipment, installation, and monitoring and evaluation.

Total Resource Cost Test

The Total Resource Cost (TRC) test measures the cost of a program as a resource option from the point of view of the utility and its ratepayers as a whole. Since the utility and its ratepayers are taken as a whole, transfer payments between the two groups are ignored. The test also represents the combination of the effects of a program on customers participating as well as those not participating in a program. The TRC test is also known as the All Ratepayers test.

The benefits calculated in the Total Resource Cost test are the avoided supply costs for periods when there is a load reduction. Any net avoided participant costs or tax credits are also considered to be benefits.

The costs in this test are the program costs paid by both the utility and participants and any increase in supply cost for periods in which load is increased. All equipment costs, installation, operation and maintenance costs, cost of removal, and administration costs are included in this test.

Societal Test

The Societal Test goes beyond the Total Resource Cost test in that it attempts to quantify the change in total resource costs to society as a whole rather than to just the utility and its ratepayers. The Societal Test uses essentially the same variables as the TRC test but they are defined from a broader societal point of view. It is considered a variant of the TRC test in the California manual.

The Societal Test attempts to incorporate the costs and benefits of power generated that are not captured by the market system. Such "external" factors include environmental, health, and safety impacts; local economic effects; and oil import issues. The Societal Test may also use a broader measure of marginal cost and a societal discount rate.

The Societal Test will receive very limited discussion in this report. The Commission made it clear when it directed its Staff to organize a working group to develop recommendations on appropriate cost/benefit methodologies that the effort should not include the question of how to quantify environmental externalities. It is the quantification of environmental costs that, in practice, distinguishes the Societal Test from the Total Resource Cost test. While the Societal Test was brought up on occasion during Task Force meetings, this test was never considered an alternative for recommendation to the Commission.

V. APPLICATION OF COST/BENEFIT TESTS

A set of cost/benefit tests are applied to demand-side programs because there exists a need to measure costs and benefits from multiple perspectives. In essence, each test provides only part of the total information potentially available regarding the impact of a particular demand-side program. When the total set of tests is applied, a more complete picture emerges.

The challenge for Virginia's utilities in evaluating DSM programs is to interpret the results of each test and make a decision regarding whether or not to pursue implementation of the program. This decision must be made within the context of Commission goals and regulatory policy regarding demand-side management programs. When considering approval of demand-side programs, the Commission will be examining the results of the same tests, along with other information about the program, in making a determination of whether or not a proposed program is in the public interest.

A solid understanding of the purpose and applicability of each test and the ways the tests are used in conjunction with one another are needed in order to interpret test results. While each test provides useful information, not all tests provide meaningful information for all types of DSM programs. Furthermore, each test has strengths and weaknesses that should be recognized by program evaluators. This section of the report provides an overview of how the various tests are applied in DSM program evaluation. A summary of the limitations of each of the tests is also provided.

DSM Cost/Benefit Tests in Practice

Many of the utilities in Virginia, particularly the investor-owned electric utilities, are familiar with the DSM cost/benefit tests identified earlier and currently evaluate potential conservation and load management programs from several different perspectives. Several of the utilities in the state have essentially adopted the California Standard Practice Manual tests and present the results of those tests in resource planning filings or applications for approval of demand-side programs in Virginia. Appalachian Power (AEP), Potomac Edison (APS), and Washington Gas Light are examples of utilities in Virginia that use a set of tests based on the California Standard Manual. Other utilities use one or more of the tests, sometimes under different names, but do not evaluate programs from all of the various perspectives. A few of the utilities in the state do not have significant demand-side programs and have not developed any formal procedures for evaluation.

While procedures vary, a common approach among utilities that use the DSM tests in integrated resource planning is to apply the set of tests in a multiple step process. The first step is to develop a list of potential DSM options. A set of these programs is then evaluated using a Total Resource Cost test to determine cost effectiveness. The programs that pass the TRC test are then subjected to a RIM test to determine their effect on rates. The Participant Test and the Utility Cost Test are applied as needed during the process to estimate costs and benefits from the perspective of program participants and the utility.

In some instances, a demand-side program will pass a cost/benefit test from each of the perspectives. In many situations, however, the program will be cost effective from one perspective but not from another. For example, many conservation programs pass the Total Resource Cost test but do not pass the Ratepayer Impact Measure test. Those programs that raise rates are often evaluated further to see if changes in program design can be made to mitigate rate increases. Although some programs can be modified, decisions regarding tradeoffs between higher rates and the benefits of resource efficiency shown in the Total Resource Cost test are frequently required.

Limitations of Individual Tests

There is no one cost/benefit test that provides all the information that a public utility commission or a utility needs to evaluate the likely economic impact of a particular demand-side management program. The best results are obtained when the various tests are used in combination, rather than in isolation, because each test has some limitations in the information it provides. The strengths and weaknesses of the various tests are outlined below.

Participant Test

The Participant Test is fairly narrow in scope. Its purpose is simply to estimate costs and benefits for those customers that decide to participate in a DSM program. Thus, the Participant Test provides an estimate of the attractiveness of a program to those customers. This information is useful for estimating program penetration rates and for determining the levels of incentives, if any, necessary to induce program participation. While the Participant Test in conjunction with other tests can be used to evaluate DSM options as alternatives to supply side options, the Participant Test standing alone cannot.

A major drawback of the Participant Test is that it does not traditionally pick up the non-quantifiable or indirect benefits and costs considered by a customer in making the decision to participate. Customer behavior and attitudes regarding a particular DSM program are difficult to predict. Many factors beyond the monetary factors included in a typical Participant Test analysis are considered by a potential program participant.

Utility Cost Test

The Utility Cost Test is a measure of the change in total costs to the utility due to the implementation of a DSM program. Total costs to the utility are equivalent to revenue requirements so the Utility Cost Test is a good measure of the change in total utility bills due to the program. The test is also directly comparable to supply side tests, since supply side tests typically attempt to measure the change in a utility's costs due to a supply-side resource. Another advantage from a technical perspective is that complexities involving rates and rate design are reduced since the test treats revenue shifts between participating and non-participating customers as transfer payments. The test focuses solely on the difference between the utility's avoided costs and the utility's cost to implement the program.

The Utility Cost test, like the Participant test, offers a limited view. It does not provide certain information that a decisionmaker would likely want before making a decision on implementing a certain program. Participants' cost, for example, are not included. More importantly, however, the test ignores the issue of cross subsidy between participants and non-participants in a program. Some demand-side programs will cause non-participant rates to rise, information which may be of great importance in analyzing the program. Finally, the utility cost test cannot be used to evaluate a load building program, thus its applicability is limited somewhat.

Ratepayer Impact Measure Test

The Ratepayer Impact Measure (RIM) test is a measure of the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from the DSM program. If a change in revenues is larger or smaller than the change in total costs, then rate levels will change because of the program. The RIM Test essentially evaluates a DSM program based on the direction and magnitude of associated rate changes.

The major advantage of the RIM test is that it offers a measure of the impact of a DSM program on customers who do not participate in the program. The non-participant perspective is necessary because all ratepayers may be affected by the actions that some ratepayers take. For many DSM programs, revenues lost from DSM programs have to be made up by ratepayers. In these situations, those customers not participating in the program are only affected to the extent that the program causes rates to rise.

As was the case with the participant and utility tests, the non-participant test offers a limited perspective. The test is, in fact, similar to the Utility Cost Test. If there are no revenue changes due to a program, the Utility Cost Test and the Ratepayer Impact Measure test yield the same results.

The disadvantage most frequently associated with the RIM Test is that it is very difficult for true conservation programs to pass the test. From a technical standpoint, the test is also particularly sensitive to projections of marginal costs and rates.

Total Resource Cost Test

The goal of the Total Resource Cost test is to measure the net cost of a DSM program as a resource option based on the total costs of the program including the participants' and the utility's costs. The major advantage of the Total Resource Cost test is its scope. The test is essentially a measure of the change in the average cost of energy *services* across all customers. The cost of energy services to customers differs from the cost of energy by the inclusion of customer equipment and operating costs. Since this test treats utility incentives paid to participants and revenue shifts as transfer payments, the test results are unaffected by the uncertainties of projected average rates.

The major weakness of the test is that it ignores the issue of cross subsidies between program participants and non-participants. Therefore, DSM programs that pass the Total Resource Cost test could produce unacceptable impacts upon non-participants.

Limitations of All The Tests

The evaluation of DSM programs can benefit greatly from the rigorous application of cost/benefit analysis techniques such as those outlined in this report. It should be recognized, however, that in addition to the weaknesses specific to individual tests discussed above, there are a number of limitations that are characteristic of all the tests. The appropriate use of cost/benefit tests for DSM programs requires a good understanding of what the tests can and cannot do.

1 The tests do not incorporate factors that are unquantifiable. Decisions made by consumers as well as utilities reflect a variety of factors. Many of these factors are very subjective and are simply unquantifiable. Although ingenious methods have been developed for quantifying some of these factors, key factors influencing decisions will still be missed.

2 The tests require a great deal of data. The development of such data can be time consuming and costly. In many cases, appropriate data do not exist.

3 * Tremendous uncertainty is associated with many of the assumptions and data used in the tests. Much of this uncertainty is due simply to the nature of demand-side planning. It is almost impossible to predict with any accuracy, for example, the number of customers likely to participate in a particular program over a typical 20 year planning horizon. The rapid evolution in

demand-side programs adds to the uncertainty. In many situations cost and benefit data must be developed for DSM programs and technologies for which the utility has little or no operating experience.

4 The tests are static. There is no iteration between the various tests that takes into account the effect of a change in one test on another.

5 The tests require aggregating costs and benefits over different groups of people and discounting of cash flows over time. Both of these techniques are open to criticism.

6 Finally, the tests ignore such issues as the ability of the firm to finance and staff the program and the assessment of legal and regulatory issues.

<u>Conclusions Regarding Multi-Perspective Cost/Benefit Analysis</u>

A multi-perspective approach to cost/benefit analysis of DSM programs has emerged as a result of a greater awareness and interest in pursuing energy efficiency. In order to take advantage of unexploited opportunities to promote efficiency, it proved necessary to consider cost effectiveness from a broader perspective than just the utility or its ratepayers. With the development of the Total Resource Cost test and the related Societal test, the cost/benefit analysis frameworks for a broader perspective were established. The establishment of integrated resource planning requirements and the adoption of the TRC Test as the primary measure of cost effectiveness have been important means by which most public utility commissions have attempted to promote greater energy efficiency.

The Staff believes that a multi-perspective approach to cost/benefit analysis is appropriate. Each test provides valid information about the proposed program. The information provided through the entire set of tests provides as full a picture as possible and is needed by the Commission in making its determination of whether a program is in the public interest.

While the Staff is not proposing any particular set of equations to be used in determining costs and benefits from multiple perspectives, the California Standard Practice Manual can serve as a good starting point for those utilities developing programs. There should be room for flexibility in developing cost/benefit numbers for particular programs for each utility. It is not the adherence to a strict set of equations that is important, but rather the commitment of a utility to measure costs and benefits from the four perspectives identified in the California Standard Practice Manual and to implement each test as rigorously as possible.

A number of technical and policy issues need to be addressed within this multi-perspective cost/benefit analysis framework. Much of the time of the CLM Task Force was spent discussing technical and policy issues associated with the application of the various tests. The resolution of these issues are very important in developing guidelines for how the tests should be used in practical applications in Virginia. These technical and policy issues are discussed in the next section of this report.

VI. TECHNICAL AND POLICY ISSUES

It is difficult to separate the technical issues that emerge in the development of DSM cost/benefit analysis with the policy issues that accompany the application of such tests. The term technical in this usage is meant to refer to aspects of the tests that are more mechanical in nature and for which certain techniques or procedures can be considered clearly superior to others. By contrast, policy issues are more subjective. The resolution of policy issues requires not so much technical competence but rather judgment and leadership on the part of the Commission.

The issues identified in this section of the report have been identified by the Task Force as key technical and policy issues to be addressed in the application of cost/benefit tests to DSM programs. A number of the ideas introduced earlier in the report will be elaborated in this discussion of issues. The discussion is meant to provide the information the Commission needs to interpret, apply and balance the perspectives offered by the various tests. Although the issues cannot be neatly categorized, the presentation of issues will begin with more technically oriented issues and end with policy issues.

Assumptions and Data

The results of any cost/benefit test are no better than the assumptions and data used in its development. In practice, the assumptions and data are as influential as the particular test chosen in the evaluation of cost effectiveness of a DSM program. Because of their critical importance, the Staff recommends guidelines be adopted for data input and modeling assumptions.

A set of guidelines was developed by the Task Force. These guidelines are meant to provide direction to electric and natural gas utilities in developing applications for approval of demand-side management programs. While utilities would be expected to be in general compliance with these guidelines, the Staff envisions that a departure from strict adherence to the guidelines would be considered for small utilities or those in unusual circumstances. The guidelines are as follows:

1) The assumptions used in developing projected input data and the models used in the integrated resource planning process should be identified and well-documented. Utility specific data should be used whenever possible (eg., unit performance data, end-use load research data, market research data, etc.). In cases where utility specific data are not available, the assumptions must be clearly defined.

2) Historic data, if available, should be assessed in developing projected data. Significant departures from historic trends should be explained.

3) Each projected data series should represent the company's most current forecast.

4) Computer modeling techniques should be used in the development of an integrated resource plan.

5) Estimates of the capital and O&M (operation and maintenance) costs of supply-side options should include realistic projections of the costs of compliance with all promulgated environmental regulations or enacted legislation from which environmental regulations will be promulgated.

6) Each assumption and/or projected data series should be consistent with all other assumptions and/or projections. Consistency of data should be maintained between all models used within the integrated resource planning process.

7) Alternative projections to determine sensitivity to input assumptions should be developed. These alternative projections should be used to perform cost/benefit analysis.

While disagreements regarding input assumptions and data will not be eliminated, the above guidelines would establish basic "ground rules" for data development.

Item 5 is particularly noteworthy because of the increasingly important role of environmental considerations in resource planning. The Commission made clear in its March 27, 1992 Order in this case that the Task Force need not consider the issue of quantifying environmental externalities in its deliberations. It is often difficult to clearly distinguish, however, between those environmental costs that are internal and should be quantified in an evaluation and those that are, in fact, external.

The Task Force received guidance on this issue from one of its members, Elizabeth Haskell, Virginia's Secretary of Natural Resources. Secretary Haskell arranged a presentation by members of four of the environmental agencies that report to her. The presentation included an overview of relevant Federal and State environmental laws and a discussion of how the "best available control technology" standard should influence a utility's planning.

The Staff agrees with Secretary Haskell's recommendation that all environmental costs related to any State or Federal laws that have already been enacted should be considered internal, and thus quantified, for a cost/benefit evaluation. The magnitude of these costs, however, will often be uncertain. Regulations associated with some enacted legislation have not yet been developed. The best available control technology can also change. The newly formed Virginia Department of Environmental

Quality will be available to provide utilities with information on legislative and technological changes that would affect the development of environmental cost estimates to be used in avoided cost calculations.

Since there is considerable uncertainty associated with the costs of compliance with environmental regulations, sensitivity analysis may be particularly useful in this area. Uncertainty over environmental compliance costs has added to the risk associated with supply-side options. Different assumptions for environmental regulations could result in very different electric utility expansion plans as well as planned demand-side programs. While the uncertainties and risks associated with DSM programs have been reduced in recent years through research and direct operating experience, the risks associated with supply-side options have increased due to greater uncertainty regarding environmental cost compliance.

Applicability of Tests

The set of tests used to evaluate DSM programs should be able to effectively evaluate all types of programs. This would include fuel switching and load building programs as well as conservation and more traditional load management programs. While the multi-perspective approach to cost/benefit analysis can accommodate most types of DSM programs, difficulties sometimes develop when evaluating fuel switching and true load building programs.

If costs and benefits are defined broadly enough, fuel switching programs should be handled adequately through the set of tests identified in this report. If, for example, an electric utility were proposing a program that had a significant impact on the consumption of natural gas, that impact would be estimated and would be picked up in the estimated costs and benefits included in the various tests. This problem will be discussed in the next section.

Load building programs present challenges for several reasons. First, load building is often viewed as a competitive threat. Load building programs offered by electric utilities, for example, are seen by natural gas utilities as attempts to gain heating market share at their expense. Second, load building programs are typically denounced by environmental and conservation groups because of the associated pollution and consumption of resources. Finally, true load building programs can be difficult to evaluate because of difficulties in quantifying the benefits associated with such programs. The value of the service that is being provided as a result of a load building program does not fit neatly into the cost/benefit tests that are typically used for evaluation.

As a practical matter, most load building programs do not pass the Total Resource Cost test. This is because such programs consume resources without offsetting quantifiable benefits. The result is that the TRC test is considered by some to give meaningless results when applied to load building programs.

The difficulty that load building programs have in passing the TRC test is not a major impediment to the application of a multi-perspective set of tests. It is simply another example of the need to know what benefits and costs are included in each test and how to apply them.

While there is a temptation to make judgments concerning the applicability of various tests to particular types of programs, it is a temptation that should be resisted. The danger is that one may begin to select a cost/benefit test based on the type of program to be evaluated. Test determination on the basis of program type would likely lead to a predetermined result since the ability to pass a particular test depends on the type of program being evaluated. A more appropriate approach is to subject all the programs to a set of tests. The results of each test can then be evaluated and weighed before making a final decision on the merits of the program.

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<u>Incorporating Alternative Energy Supplier Effects</u>

The cost/benefit tests discussed in this report identify the perspectives of key stakeholders that are likely to be affected by DSM programs. These stakeholders include the utility initiating the program, the utility's customers likely to participate in the program, and the utility's customers that are not likely to participate in the program. For many DSM programs, these three groups represent the major parties affected by the program. However, for those DSM programs that have a significant impact on a customer's choice of fuels, there is another group of stakeholders. This group is the alternative energy suppliers that may be affected by the implementation of a DSM program. How to treat alternative energy suppliers is one of the more controversial aspects of developing a cost/benefit analysis framework.

A number of issues arise when considering the inclusion of alternative energy suppliers into the cost/benefit analysis framework recommended in this report. The threshold question is whether one utility in evaluating its DSM programs should be required to consider the effect of its programs on alternative energy suppliers. Should a utility's responsibility in evaluating DSM programs extend beyond its stockholders and customers to also include evaluating the effect of its program on alternative energy suppliers? If such an evaluation is the responsibility of the utility, the question then becomes how can the evaluation be best performed.

The opinions on this topic expressed by utilities represented on the Task Force were divided. Electric utilities tended to argue that little, if any, consideration should be given to the effect of a DSM program on alternative energy suppliers. While some electric utilities acknowledged that in principle such an impact should be considered, the practical problem of developing reliable estimates of such an impact was considered formidable. Natural gas utilities, on the other hand, were more receptive to the idea of incorporating the impacts of DSM programs on alternative energy suppliers. Washington Gas Light, for example, argued that such effects should be included and that the effects could be easily factored into the evaluation through marginal/avoided cost estimates and filed tariffs. The Staff would note, however, that past efforts to determine marginal or avoided costs often have been far from straightforward.

Theoretically, the Staff believes that the assessment of the effects of proposed DSM programs on alternative energy providers may be appropriate in certain instances, particularly where such effects are associated with programs that are promotional in nature. However, the Staff believes that it may be impractical to consider the impact of a DSM program on alternative energy suppliers and that the burden of such an analysis may actually discourage utilities from pursuing programs that may otherwise be viable. In many cases, the development of rigorous data to quantify the effect of a program on alternative energy suppliers will be impossible. While rates and avoided cost data for utilities are often available, the detailed data necessary to estimate program impacts may not be. For some DSM programs, potential alternative fuel impacts would be so minimal or speculative that any analysis would not be very useful. In other cases, however, the necessary data could be obtained and estimates made.

The consideration of the effects of programs on alternative energy suppliers may be inconsistent with current planning activities, line extension policies or certain cost/benefit methodologies. For example:

- Utilities do not typically consider the impact of supply-side options on alternative energy suppliers. The consideration of the impact of DSM programs on alternate fuels is tantamount to suggesting that a gas fired unit is superior to a coal unit because it enhances the revenue of a natural gas utility; or a power purchase from another utility is a better option because it benefits the selling utility's customers. In short, the threshold question becomes: should a utility's resource plan give consideration to the effect that it has on other regulated utilities or unregulated competitive energy suppliers?

- Line extension policies included in utility tariffs have not historically included consideration of the impact of such an extension on a competing utility. These policies typically consider the feasibility of the extension from the limited perspective of the utility making the extension. An expansion of the extension criteria to include the effects on alternate energy providers may raise questions regarding a utility's obligation to provide service. It would certainly complicate the economic analyses inherent within a line extension policy.

- The consideration of DSM impacts on alternate fuels is, to a certain extent, inconsistent with the Utility Cost and the Total Resource Cost tests which do not consider revenue impacts associated with a DSM program to be either a benefit or a cost. A requirement that the effects of DSM programs on alternative suppliers be included could result in a situation where a utility must consider the lost revenues of a competing utility while ignoring its own lost revenues in the application of either of the above cost/benefit tests.

The consideration of DSM effects on alternate fuel suppliers may also raise issues of discrimination. For example, a DSM program may be determined inappropriate in an electric utility's service area where gas service is available but appropriate where gas service is not available. Should all of the electric utility's customers be offered the same services?

While there are a number of problems associated with the consideration of the impact of DSM programs on alternate fuels, there are certain instances where such a consideration may be appropriate. Examples include programs that rely primarily on fuel displacement to achieve their goals, such as the promotion of add-on heat pumps or gas air-conditioners. For these types of activities, the utility's own program operation assumptions would necessarily imply certain quantifiable impacts on alternative energy suppliers.

The Commission's rules governing promotional allowances require the consideration of the impact of promotional allowances on alternative energy suppliers. Any utility proposing a promotional allowance program that is likely to have a significant effect on the sales levels of an alternative energy supplier must consider the effect of the program on that supplier and demonstrate that the program serves the overall public interest. The Staff believes that it is appropriate to expand consideration of alternative energy supplier impacts to include any DSM program that increases sales of a sponsoring utility and is expected to have a significant impact on competing fuels. Such consideration, however, should not be mandated for all DSM programs. For example, an electric utility should not be required to consider the impact on alternative fuel suppliers of a program that promotes electric vehicles because such impacts would likely be insignificant.

Depending on the nature of a DSM program, the consideration of alternative energy supplier impacts may be detrimental to competition between energy suppliers. Competition often serves to encourage both utilities and unregulated energy suppliers to reduce costs and to operate more efficiently. In the case of activities that increase sales, a requirement that the effects on alternate fuels be considered may serve to curb unfair anticompetitive practices. For other DSM programs, such a requirement may artificially protect uncompetitive alternate fuel services.

While alternative energy suppliers could include a number of industries, the two industries that will be most affected by any Commission policy are the electric and natural gas industries. There is strong competition between these two industries in many parts of Virginia. As a practical matter, any DSM program proposed by a utility in one of these industries that has a significant negative impact on a utility in the other will likely be opposed in proceedings before the Commission. Since electric utility DSM programs are currently much more common than DSM programs of natural gas companies, such intervention will typically be a situation of a natural gas utility opposing the implementation of an electric utility DSM program. In such circumstances, the Commission will probably be asked to consider the effects of the program on both industries in making a determination of whether the program is in the public interest.

If DSM effects on alternative energy suppliers are to be considered, there should be some mechanism to require utilities to release non-proprietary data outside of a rate case. For many utilities the evaluation of DSM programs is an ongoing process. There may be a need for specific data from other utilities throughout the year as programs are reviewed and circumstances change. It may be possible to develop some mechanism whereby utilities could send out requests for data from other utilities outside of a formal Commission proceeding. Utilities would be required to respond to such "informal interrogatories" just as they would formal interrogatories.

In summary, the Staff recommends that the Commission's policy regarding the consideration of DSM effects on alternate fuels should be flexible. A sponsoring utility should consider such effects when evaluating programs that increase sales and if the impacts can be quantified with a reasonable degree of certainty.

Fuel Switching

The fuel switching issue is closely related to the issue of determining the impact of a DSM program on alternative fuel suppliers. It is discussed separately because it can be a very controversial issue. While the issue has received less attention in Virginia than in a number of other states, the potential for significant fuel switching certainly exists among Virginia utilities.

A fuel switching program is any program that is meant to encourage consumers to change the fuel they consume. A marketing program by an electric utility to encourage natural gas customers to switch to electricity would be considered a fuel switching program. Of particular interest to regulacory policymakers are fuel switching programs to encourage conservation and more efficient use of resources. An electric utility that encourages the substitution of natural gas for electricity to reduce its load is using fuel switching as a demand-side management program. A program to replace old electric water heaters with natural gas water heaters is an example of such a program. The circumstances under which these types of programs should be promoted raise controversial policy issues.

Fuel switching programs present additional complexities in the application of cost/benefit tests. The issues previously discussed concerning determining the impact on alternative fuel providers would certainly apply. In addition, fuel switching programs can raise difficult cost allocation problems. Normal cost allocation dilemmas are compounded when considering the costs and benefits of both an electric and a natural gas utility and their respective customers. However, while the analysis may be much more difficult, the multi-test framework outlined in this report can accommodate fuel switching programs.

__State Versus Regional Perspectives and Jurisdictional Issues__

The Commission has responsibilities to develop policies that promote the welfare of the citizens of Virginia. At the same time, many of the Commission's policies will have effects that extend beyond the borders of the state. Commission policies that influence utility planning, in particular, will often have regional implications. Generation and transmission planning are perhaps the two most obvious areas of planning where public utility commission policies have direct regional implications. Public utility commission policy regarding DSM programs can also have regional influences, particularly those policies that affect environmental quality. The issue that arises in such circumstances is how the Commission should balance the interests of Virginia utilities and consumers with the interests of the region in those situations where the various interests may conflict.

In Staff's opinion, the development of specific demand-side management policy addressing the state versus regional interest issue is unworkable. A policy statement that would give real guidance could only be developed in response to a specific situation. While the interests of Virginia utilities and customers are paramount, the Commission does currently consider the regional implications of its decisions affecting utility planning. However, no general policy statement has been developed nor is one needed.

Similar issues arise when considering the applicability of cost/benefit tests to multi-state utilities. One problem that emerges is the possibility of different public utility commissions requiring different tests. Another potential problem could occur if one regulatory commission required the inclusion of certain input data while another would not allow the use of that same data. However, although these potential problems can complicate utility planning, there does not appear to be a need to adopt specific policy to address them at this time.

__Verification of DSM Program Impacts__

If DSM programs are to win the full support of utilities and regulators, they must produce measurable results. As DSM programs grow in size and cost, the evaluation of such programs to determine their effects and cost-effectiveness becomes increasingly important. The Commission needs to recognize the importance of verification of program savings and assure that its policy promotes a comprehensive utility evaluation of DSM programs.

Sophisticated techniques for evaluating DSM programs are now being developed. These techniques are being applied to a wide variety of programs throughout the country. The measurement of the operation and performance of programs is becoming increasingly precise as techniques evolve and experience is gained. Objective measurements are replacing the anecdotal evidence and personal impressions often relied upon in the past.

While a discussion of the details of DSM program evaluation is beyond the scope of this report, in general there are two types of evaluations performed on DSM programs. Impact evaluations focus on the effects of the program. They provide quantitative documentation on program costs and benefits. Included in such evaluations are measurements of program participation, program costs, performance of program technology, and changes in energy and load as a result of the program. Process evaluations examine program operations to identify how well the program is implemented and to suggest ways to improve program implementation. Such evaluations focus on program goals and activities and often are based on interviews with utility program staff, participants, and trade allies. Both types of program evaluations are needed and should be conducted by utilities implementing new DSM programs.

Three general methods of analysis are used in conducting impact evaluations. The most straight forward approach is direct measurement. Direct measurements are used to calculate changes in energy use by comparing measurements at different times. Direct measurements include customer billing, whole building metering, and end-use metering. A second approach is engineering modeling. Engineering models use physical models, such as simulations of buildings, to analyze energy use. These models rely on a variety of input data including weather data, facility and equipment inventories, and operating patterns. A third widely used technique is statistical modeling. Statistical modeling typically uses billing data, market-segment information, and demographic and economic variables to measure changes resulting from a program.

Commission policy should require utilities to conduct the analysis necessary to develop reliable estimates of the impact of DSM programs. One of the major hurdles facing DSM program developers is the skepticism that exists among many people that the projected net benefits of many DSM programs are overstated. Unless methods are in place to systematically measure operation and performance such skepticism is justified.

Utilities should measure the performance of DSM programs with the same competence and diligence with which they measure the performance of power plants. Where possible, multiple methods of measurement should be employed and the results compared. The persistence of benefits over the long term is particularly important. However, just as procedures for monitoring power plants evolved over time, it will take time for truly effective measurement and monitoring programs to be developed. Fortunately, a great deal of effort is now under way to improve measurement and monitoring techniques by utilities.

Ratepayer Impact Measure Test Versus Total Resource Cost Test

Two cost/benefit tests, the Ratepayer Impact Measure (RIM) test and the Total Resource Cost (TRC) test, warrant particular attention in a discussion of DSM policy issues. Policy decisions regarding the validity and appropriate use of these tests will be extremely influential in determining the nature and scope of utility DSM programs in Virginia. The clash of opinions between advocates of these two tests brings into focus a number of the more controversial issues surrounding utility planning in the 1990s.

The RIM test focuses on changes in overall utility rates and rates to non-participants due to the implementation of a DSM program. A program fails the RIM test if it results in higher utility rates. Advocates of the RIM test believe that such a test is needed to assure that markets are not tampered with needlessly and to protect non-participants from the higher rates that can result from many DSM programs. RIM test proponents argue that reliance on the RIM test promotes both efficiency in energy usage as well as equitable treatment between parties that may be affected by a utility DSM program. Utility prices are considered to send important signals to consumers and to be extremely important to well functioning energy markets.

Advocates of the Total Resource Cost test argue that it offers a broader measure of cost effectiveness. The TRC test is considered to be a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its rate payers as a whole. A demand-side program is cost effective under the TRC test if it can provide an energy service at a cost lower than the cost for the utility to provide similar service under the existing set of resources.

In many cases, a DSM program will be cost effective under one test but not another. Conservation programs, for example, will often pass a TRC test but fail a RIM test. In these situations the natural question that arises is which test should be the primary test of cost effectiveness.

A number of public utility commissions have issued orders in recent years addressing cost-effectiveness tests for DSM programs. The trend among commissions that have addressed the issue has been to mandate the TRC test as a primary test of cost effectiveness and to relegate the RIM test to a secondary role. The use of a RIM test to screen DSM programs has been expressly prohibited in several states.

A key aspect of the theoretical debate is whether the RIM test is a test of economic efficiency or simply a test of equity. Advocates of the TRC test typically argue that the RIM test is primarily a test for equity and suggest that the TRC and RIM tests be applied sequentially. In this approach, programs are screened for cost effectiveness based on the TRC test. The RIM test is then applied to determine the rate implications of the proposed program. While the design of a program could be influenced by the results of the RIM test, the cost effectiveness or economic efficiency of the program would be determined by the TRC test. The RIM test used in this way would provide an idea of the rate impact and the amount of subsidy involved in the program.

Advocates of the RIM test argue that the test is first and foremost a test of economic efficiency. The strongest supporters of the RIM test argue that any DSM program that increases energy prices will result in an overuse of that option and will be inefficient relative to a program that prices DSM so that energy prices do not change. The RIM test is thus considered to have advantages based on both efficiency and equity grounds.

It is also argued that there are practical limits on rate increases due to DSM programs. If rates rise significantly, customers that have other options will simply leave the utility system which could result in further rate increases for the remaining customers. Large industrial companies have voiced such concerns through their trade association the Electricity Consumers Resource Council (ELCON).

Fundamental philosophical differences also lie at the heart of much of the debate between the RIM and TRC tests. Advocates of the TRC test tend to believe that there are tremendous opportunities for efficient conservation to be exploited and that there are large economic costs to environmental hazards. The existence of such opportunities suggest that energy markets have failed and that institutional changes are needed to realize the savings that are possible. Regulatory changes to encourage the promotion of DSM programs by utilities are one such vehicle of institutional change.

Advocates of the RIM test are often more skeptical of the estimates of very large savings available from unexploited opportunities for conservation. It can be very difficult and costly to develop reliable estimates of conservation potential.

Although credible estimates do exist, many such studies have been methodologically flawed and discredited. While there are undoubtedly market imperfections, many economists and other advocates of the RIM test do not see enough market failure to justify the type of energy market intervention that is taking place in many states today. Advocates of this position are reluctant to move away from market mechanisms and the discipline that is imposed by the RIM test.

The Staff's position in the TRC versus RIM test debate is a practical one. Both tests provide valuable information and each should be applied when evaluating DSM programs. One test should not be considered primary while the other is considered secondary. Neither should one single test be used to screen programs from further consideration for implementation. The result of a TRC test is needed by utilities and the Commission in order to evaluate the broadest impact of the program. The result of a RIM test is equally important for both efficiency and equity reasons. Final decisions regarding the implementation of DSM programs must be subjective decisions that reflect all the information about a particular program and that balance the concerns of the parties likely to be affected by the program.

<u>Other Issues</u>

The Staff considers the issues discussed above to be the key issues to be addressed in developing Commission policy regarding cost/benefit analysis of demand-side programs. However, in addition to these issues, a variety of related topics were discussed by the Task Force. These discussions were very useful in identifying the concerns and perspectives of the various Task Force participants and in placing cost/benefit analysis in context.

Application of Tests

An issue that arose fairly early in Task Force discussions concerned whether the cost/benefit tests that were developed should be applied to individual programs or to groups of programs. There are many situations, for example, where a program considered in isolation may fail a particular cost/benefit test, but in combination with one or more other programs may pass. The same question could be asked of a utility's entire package of programs. Virginia Power, for example, has implemented a number of programs that do not pass the RIM test but its policy is to assure that its entire package of programs, taken as a whole, passes the RIM test.

In Staff's opinion, this issue will have to be addressed on a case by case basis. Circumstances could certainly arise whereby the Commission may consider it in the public interest to approve a group of programs which consist of individual programs that do not pass key cost/benefit tests. There are also circumstances where individual programs, as well as groups of programs, will be rejected even if they do pass key cost/benefit tests. In situations where several programs are being presented to the Commission, it is important that the utility be able to present test results for each individual program and for various combinations of programs if the results are dependent. It should be stressed that cost/benefit test results are but one of many factors considered by the Commission when reviewing DSM programs.

Experimental and Pilot Programs

The utility practice of developing experimental and pilot DSM programs prior to full scale program implementation should receive the full support of the Commission. Several experimental and/or pilot DSM programs are in place now in Virginia and are enabling utilities to collect the data necessary to estimate the cost effectiveness of full scale programs. The Commission likely will see many applications for approval of pilot programs in upcoming years as utilities intensify efforts to evaluate DSM options.

Pilot or experimental programs must be carefully structured to enable acquisition of the data necessary for a complete program evaluation. Since cost effectiveness is unknown, such programs need to be limited in scope. The number of program participants, program budgets, and the period of time that the program is offered should all be restricted to a scale appropriate for data collection purposes. Utility applications should clearly delineate the purpose of the pilot program, the data to be collected, and how the data will be evaluated.

The Staff recommends that utility applications for pilot and experimental programs that meet these requirements be treated differently from applications to approve permanent, full scale programs. While such applications should address the anticipated benefits and costs of the proposed program and provide any cost effectiveness analysis that has been conducted, a quantitative application of the cost/benefit tests outlined in this report should not be required. Indeed, the chief purpose of pilot and experimental programs is to collect the data necessary to conduct a detailed evaluation of the program.

There are also advantages to simply not requiring Commission approval for certain experimental or pilot DSM programs. Utility pilot DSM programs that have rates associated with them or that involve promotional allowances should require Commission approval. However, if a pilot or experimental program is limited in scope and meets the other requirements outlined above, the Staff sees little need for a formal Commission approval process.

Utilities With Limited Presence in Virginia

The electric and natural gas utilities that serve Virginia vary considerably in size and presence in the Commonwealth. The state's largest utility, Virginia Power, is one of the larger utilities in the country and has the vast majority of its sales in Virginia. Several other utilities, while being a part of fairly large systems, serve relatively small parts of the state. Potomac Edison and Delmarva Power are examples of utilities in this situation. Still others, a number of electric cooperatives and natural gas utilities for example, operate solely in Virginia but are simply small systems.

The question that emerges when considering the different sizes and situations of utilities in the state is whether different policies should apply to small utilities or those utilities with limited presence in the state. Smaller utilities may not have the resources or expertise to conduct sophisticated analysis of DSM programs. Those utilities with limited presence in the state may have the resources but not the incentive to develop programs in Virginia if the policy in this state requires them to comply with procedures that are very different from those in other states in which they operate.

The Staff believes that any policy adopted regarding DSM programs should recognize the difficulties that small utilities may have in complying with Commission requirements. Complying with the Staff's proposed guidelines for data and assumptions, for example, may be unduly costly for some small utilities. Commission policy should be flexible enough to accommodate the legitimate concerns of small utilities. The Commission's policy should encourage the development of cost effective DSM programs by small utilities rather than discourage such programs through onerous regulatory requirements.

VII. CONCLUSIONS AND RECOMMENDATIONS

The Staff believes that a multi-perspective approach to determining the costs and benefits of demand-side management programs is needed in order to evaluate the full impact of a DSM program on a utility and its customers. Estimates of costs and benefits from many different perspectives will be needed by the Commission in making its determination of whether a particular DSM program or set of programs is in the public interest.

The Commission in its deliberations must balance the interests of parties that will be affected by any proposed program. The results of the various tests provide the quantitative information needed to strike an appropriate balance. With this information, the Commission can better address the efficiency and equity issues that emerge when considering DSM proposals. It should be clear that efficiency and equity issues will emerge in just about any DSM proposal that comes before the Commission. The discussion of these issues can only be improved by the requirement of quantitative cost/benefit tests from multiple perspectives as proposed in this report.

The Staff proposes that quantitative cost/benefit analysis from at least four perspectives should accompany all applications for approval of DSM programs before this Commission. These four perspectives are 1) program participant, 2) program non-participant, 3) utility, and 4) all ratepayers. While these four perspectives correspond to the perspectives identified in the California Standard Practice Manual and other publications, the Staff is not endorsing a specific set of equations to be used in any particular set of cost/benefit tests. A utility should have leeway to develop equations that are most appropriate for its particular system. The Staff does recommend, however, that for administrative reasons, departures from the California Manual equations be clearly documented in any application for DSM program approval.

The cost/benefit tests discussed in this report are most appropriately applied collectively rather than individually. Each test provides information that collectively contribute to a broad understanding of the impact of a particular DSM program. No one test, however, provides all the information needed to evaluate a program. It is inappropriate, therefore, to accept or reject a DSM program on the result primarily of only one test.

The Staff recommends that utilities not screen DSM programs on the basis of whether or not they pass any one particular cost/benefit test. The practice, for example, of screening programs based solely on the results of a RIM test may inappropriately be eliminating programs that are very cost effective from other measures. Likewise, the Staff considers the practice of picking a "primary" cost effectiveness test and relegating another or others to a secondary status is also inappropriate. This approach is practiced in a number of states where the Total Resource Cost test is considered the primary measure of cost effectiveness and the results of a RIM test are considered of secondary importance.

<u>Data Development</u>

The data used in conducting a cost/benefit analysis should receive as much scrutiny as the methodology employed. In order to promote the development of rigorous data, the Staff is proposing the following set of minimum guidelines for data input and modeling assumptions.

Guidelines for Data Development and Modeling Assumptions

1) The assumptions used in developing projected input data and the models used in the integrated resource planning process should be identified and well-documented. Utility specific data should be used whenever possible (eg., unit performance data, end-use load research data, market research data, etc.). In cases where utility specific data are not available, the assumptions must be clearly defined.

2) Historic data, if available, should be assessed in developing projected data. Significant departures from historic trends should be explained.

3) Each projected data series should represent the Company's most current forecast.

4) Computer modelling techniques should be used in the development of an integrated resource plan.

5) Estimates of the capital and O&M (operation and maintenance) costs of supply-side options should include realistic projections of the costs of compliance with all promulgated environmental regulations or enacted legislation from which environmental regulations will be promulgated.

6) Each assumption and/or projected data series should be consistent with all other assumptions and/or projections. Consistency of data should be maintained between all models used within the integrated resource planning process.

7) Alternative projections to determine sensitivity to input assumptions should be developed. These alternative projections should be used to perform cost/benefit analysis.

Note: These guidelines are meant to provide direction to electric and natural gas utilities in developing applications for approval of demand-side management programs. The degree of sophistication expected in the analysis may be modified due to the size and circumstances of the applicant.

These guidelines will certainly not eliminate disputes regarding the assumptions and data used in preparing cost/benefit tests. However, they will assure that certain minimum standards for data development are met and that all participants in a proceeding have a basic understanding of how key data were developed.

<u>Incorporating Alternative Energy Suppliers Effects</u>

Current Commission policy requires a utility to consider the effect of proposed promotional allowance programs on alternative energy suppliers if the program is likely to have a significant effect on the sales of such suppliers. The Staff proposes that this consideration of the effect of DSM programs be extended to include any program that results in the increased sales of a sponsoring utility whether or not such a program involves a promotional allowance. Where possible, such analysis should be quantified and included directly in the set of cost/benefit equations developed for program evaluation. However, for many such programs, it may not be possible to quantify the effects on alternative energy suppliers with a reasonable degree of certainty. In these cases, an evaluation of the impact on alternative fuel suppliers should not be required.

<u>Verification of DSM Program Impacts</u>

Commission policy should require utilities to conduct the analysis necessary to develop reliable estimates of the impact of DSM programs and to verify the load impacts of programs that are in place. While the Staff is not recommending specific policy changes to promote the verification of DSM program impacts, it does recommend that the Commission emphasize the importance of verification of DSM program savings and load impacts in any order related to this proceeding.

Virginia utilities should be encouraged to develop state of the art techniques to verify the savings and load impacts associated with DSM programs. These techniques should measure long-term as well as short-term effects. Careful measurement needs to be emphasized during a utility's experimental and pilot program phases of program development as well as after programs are in place. Measurement and verification of program savings should also be a key consideration in dealings with third party providers of demand-side services. Any demand-side bidding program, for example, should be structured to encourage bids from organizations that emphasize rigorous measurement and verification of program impacts.

Other Policy Issues

A number of other policy issues have been addressed in this report and in Task Force discussions. The Staff's conclusions and recommendations in these remaining areas are brief.

With regard to the multi-jurisdictional and state versus regional interest issues, the Staff concludes that the development of policies specific to DSM in these areas is not needed. The problems that arise due to individual state regulation of multi-jurisdictional utilities are certainly not unique to demand-side planning. Similar issues arise in a number of other areas of utility regulation. Specific problems that arise in these areas are best handled on a case by case basis rather than through broad policy statements.

The Staff also is not recommending the adoption of policy regarding the issue of the application of tests to individual programs versus groups of programs. The most appropriate methodology will differ depending upon circumstances and is best determined on a case by case basis.

With regard to experimental and pilot programs, the Staff is proposing that the only utility pilot or experimental programs that should be subject to mandatory Commission approval are those that involve promotional allowances or that have associated rates. If a program is truly an experiment or a pilot, there should be limits on the program budget, number of participants, and program duration. Limited experimental or pilot programs need to be encouraged and, with the exception of those involving rates or promotional allowances, should not be subject to formal Commission approval.

Those pilot or experimental DSM programs that are subject to approval need to be carefully structured and fully explained in applications with the Commission. However, while such applications should address the anticipated costs and benefits of the proposed programs, a lack of data may prevent the calculation of costs and benefits from the various perspectives outlined in this report and should not be mandatory.

Finally, any demand-side management policy that is adopted by the Commission should recognize the differences in size and circumstances between the utilities in the state. Policy should be flexible enough to promote the development and implementation of rigorous cost/benefit methodologies by all of Virginia's utilities. Compliance with new demand-side management policy may be burdensome for utilities that are small or have limited operations in the state. In such circumstances, utilities should be granted exemptions, on showing of good cause, from unduly burdensome requirements under any new policy adopted.

Concluding Remarks

The Staff is indebted to the members of the Task Force that devoted time and effort toward assuring a comprehensive review of the issues related to evaluating DSM programs. Although there were many areas of disagreement in our discussions, the Staff believes that this report is representative of the general conclusions of the Task Force. The report was sent to Task Force members prior to filing to provide an opportunity for commenting on the Staff's recommendations. The written comments of each Task Force member are attached as Appendix 4, which is bound separately. The final report was modified to include a number of the comments of Task Force participants.

The development of Commission guidelines for the evaluation of DSM programs will be a major step toward the realization of cost effective energy usage in the Commonwealth. There will remain, however, a great deal of controversy concerning many of the DSM proposals that come before the Commission. As pointed out in this report, there are no perfect cost/benefit tests and many assumptions are necessary for the calculation of each test. While the quantification of a DSM evaluation using cost/benefit tests will help frame the issues involved, the Commission's judgment as to what avenue best promotes the public interest often will be the final determinant.

APPENDIX 2

APPENDIX 2

SURVEY OF STATE COMMISSIONS: DSM COST/BENEFIT METHODOLOGIES

Alabama

The Alabama PSC has not formally designated any one measure for use in evaluating DSM programs. The only regulated electric, Alabama Power, currently is using the non-participants test in evaluating DSM programs. In a recent order, the Commission encouraged the utility and staff to work together in choosing an appropriate methodology but nothing has been formalized at this time.

Arizona

The Arizona Commission requires that utilities perform the total societal cost test for evaluation of DSM programs.

California

The total resource cost (TRC) test is used as a primary screen but information from the other tests described in the California Standard Practice manual is used to adjust funding levels and incentives.

Delaware

A Commission order in Delaware requires that the total resource cost test be the primary measure used for program selection and analysis. The utilities may use other measures in addition to TRC for their own analysis or to prioritize programs.

District of Columbia

The D.C. Commission requires utilities to use the all ratepayers test (also known as the total resource cost test or TRC). The Commission has ruled against fuel-switching so the analysis considers only the host utility's fuel. This test has been used since the 1990 plans were filed. PEPCO was using the No-Losers Test (also called RIM) before the Commission required the All Ratepayers test.

Florida

The Commission has directed utilities to look at RIM, TRC with societal factors (societal cost test) and the participants test. Although they perform multiple tests, utilities generally only ask for approval for programs that pass the RIM test and, by law, the Commission cannot propose programs for the utilities. Thus, utilities are not pursuing a lot of true conservation programs. Florida has been using these methodologies for about 12 years. There has been more criticism lately about the types of programs being chosen by utilities.

Georgia

According to a Commission rule published in January 1992, a screening test, either the societal cost test or the utility cost test, must be completed for each DSM measure. If the measure passes either test, it is eligible for inclusion in the utility's plan. The utility must assess the impact of using other energy sources or technologies. Also, the utility should quantify, where possible, external costs and effects (environmental and others). If a measure fails the screening test, it is eliminated from consideration. If the utility decides to eliminate a measure, it must be explained or justified by the utility. The same screening test is done on a program basis (which may include one or more measures). At the program level, the program's administrative costs are included.

Idaho

The Commission has not formally specified any measures that must be used. In a recent major conservation order, the Commission did, however, indicate that using the no-losers test (or RIM) alone was not acceptable. For the most part, utilities are using the TRC test and the utility cost test.

Iowa

The Commission requires utilities to use the TRC with environmental externalities. Utilities may present the results of the utility cost test, RIM, and the participants test to the Commission.

Maine

The Commission has established a Rule defining the standards for measurement; the primary or principle test is the all ratepayers test (or TRC). If there is a significant rate impact (>1% change in revenue requirement) then the RIM or societal test may be looked at. According to Maine's Rule, "a utility shall give priority to programs with the greatest net present value under the all ratepayers test. For those cost effective programs which fail the rate impact test, a utility shall give priority to programs that are most widely available to the largest number of participants, and that distribute benefits to as many customer classes as possible." Maine also has a DSM incentive that rewards the utility for minimizing the rate impact of DSM programs.

Maryland

The Maryland Commission requires the TRC test. Utilities may consider information provided by other cost/benefit tests in prioritizing programs or to ensure that plenty of customers have the opportunity to participate in DSM programs. Evaluation is done on a measure level <u>and</u> on a program level.

Missouri

A Rule was recently proposed for electrics addressing many issues of integrated resource planning. Gas companies will be considered at a later date. The DSM analysis will look at the individual end use measures first, then the DSM programs (which may combine measures). The test used for both is called the probable environmental benefits test, a variation of the utility benefits test. The environmental factors are taken into account through a risk assessment which considers the likelihood of new regulations being imposed as well as the expected costs of meeting those regulations; thus, they will treat environmental costs using uncertainty or risk analysis instead of trying to actually quantify external costs. At the specific measure level, utility marketing and delivery costs are excluded as well as some customer rebates. Costs and benefits are levelized over the life of the measure. At the program level, the present value of the costs and benefits is used. The biggest point of contention in developing this rule has been the issue of inter-fuel competition.

Nebraska

Only public power and rural electric coops; no need to address the issue of cost/benefit tests.

New Jersey

The New Jersey Board of Public Utilities adopted a rule within the last year addressing cost/benefit analysis. Utilities are required to offer certain "core" programs. Other programs must pass at least the TRC (primary measure). Utilities may use other measures for their own information. New Jersey does require electric utilities to add 2¢/kwh for environmental externalities (and something comparable for gas companies).

New York

The New York Commission has been using TRC as a reference test or threshold since the mid 1980s. The other tests defined in the California Standard Practice Manual may also be used to evaluate the effectiveness of the program. The utilities were encouraged to pursue the most cost-effective programs first in the early years and were provided incentives to do so.

North Carolina

Instead of requiring a particular test, North Carolina requires that no one test can eliminate a program; this was specifically aimed at the sole use of the RIM test. The utilities are expected to look at the results of several tests in evaluating each program. The N.C. Commission is also concerned about utilities subjecting their entire package of programs to the RIM test but it has not formally addressed this problem.

Ohio

Ohio's administrative rules governing integrated resource planning and DSM program evaluation were put in place in 1989. For conservation programs, utilities must use TRC. For load building programs, utilities use RIM. They may also use RIM to evaluate the rate impact of a conservation program but not as a screening tool. To ensure that enough conservation programs are included in the utilities' plans, the Commission staff has at times recommended programs to the utilities that have been successful in other states. The utilities must, at the minimum, perform an evaluation of the recommended program.

Pennsylvania

The Commission requires that utilities use the TRC test, the utility cost test, the participants test and the non-participants test for analysis. However, the TRC test is used as the primary screen.

Rhode Island

The Commission requires the use of the total resource cost test.

Tennessee

The Tennessee PSC only regulates one small electric company and is not doing much with DSM program evaluation at present.

Washington

The Commission has not formally suggested a particular method of evaluating DSM programs but has spoken disapprovingly of the RIM test. The utilities are primarily using the TRC test.

Wisconsin

Wisconsin utilities have had some form of integrated resource planning for almost 15 years. Recently, the Wisconsin PSC began requiring the use of the revenue requirements perspective (or utility cost test) as a primary cost/benefit test and the TRC test as a secondary test in evaluating DSM program costs and benefits. The PSC issued this requirement to prevent utilities from relying on the RIM test as the sole measure of DSM costs and benefits.

Wyoming

The Commission currently has no rules addressing economic measures that utilities must use. However, the staff has told the utilities informally that it wants to see the results of several economic tests.

ECONOMIC TESTS USED TO EVALUATE DSM PROGRAMS

	Survey data from NARUC Annual Report on Utility and Carrier Regulation, 12/31/90. (This information has not been corrected for inaccuracies.)		Tests REQUIRED by state commissions (if different than survey results at left); updates based on phone contact in July and August 1992.	
	PRIMARY ECONOMIC TEST	OTHER ECONOMIC TESTS	PRIMARY ECONOMIC TEST	OTHER ECONOMIC TESTS
ALABAMA PSC	6	4,5	6; NOT FORMALLY ADOPTED	
ALASKA PUC				
ARIZONA CC	3			
ARKANSAS PSC				
CALIFORNIA PUC			1	3,4,5,6
COLORADO PUC				
CONNECTICUT DPUC	4			
DELAWARE PSC	PENDING BEFORE COMM.		1	
DC PSC	1			
FLORIDA PSC	UNDER REVIEW; 3,4,5,6		3,5,6	
GEORGIA PSC	UTILS. USE 1,4,5,6; PSC NOT FORMALLY ADOPTED		3,4	
HAWAII PUC				
IDAHO PUC	NONE SPECIFIED; USE 1,5	4		
ILLINOIS CC				
INDIANA URC	NONE RULED OUT; USE 1,4			
IOWA UB	3	4,5,6		
KANSAS SCC	NOT ADDRESSED BY COMM.			
KENTUCKY PSC	1			
LOUISIANA PSC				
MAINE PUC	1	3 FOR PRGS W/RATE IMPACT >1%		
MARYLAND PSC	1,3,4,5,6		1	
MASSACHUSETTS DPU	3			
MICHIGAN PSC	4	3,5,6		
MINNESOTA PUC				
MISSISSIPPI PSC	6	1		

KEY – ECONOMIC EVALUATION METHODS

1 – TOTAL RESOURCE COSTS
2 – TOTAL TECHNICAL COSTS
3 – TOTAL SOCIETAL COSTS
4 – UTILITY COST TEST
5 – PARTICIPANTS TEST
6 – NON-PARTICIPANTS TEST

App. 2
Sch. 1
(Cont'd)

ECONOMIC TESTS USED TO EVALUATE DSM PROGRAMS

	Survey data from NARUC Annual Report on Utility and Carrier Regulation, 12/31/90. (This information has not been corrected for inaccuracies.)		Tests REQUIRED by state commissions (if different than survey results at left); updates based on phone contact in July and August 1992.	
	PRIMARY ECONOMIC TEST	OTHER ECONOMIC TESTS	PRIMARY ECONOMIC TEST	OTHER ECONOMIC TESTS
MISSOURI PSC	1,4		PROBABLE ENVIR. BENEFITS	4
MONTANA PSC	BASED ON AVOIDED COSTS			
NEBRASKA PSC				
NEVADA PSC				
NEW HAMPSHIRE PUC	1	4		
NEW JERSEY BPU	1,3,5,6; NO FORMAL IRP		1	
NEW MEXICO PSC				
NEW YORK PSC	3,4,6		1	
NORTH CAROLINA UC	4,5,6	4,5,6	NONE REQUIRED BY COMM.	
NORTH DAKOTA PSC	4			
OHIO PUC	1,6 FOR LOAD-BUILDING ONLY			
OKLAHOMA CC	4			
OREGON PUC	3			
PENNSYLVANIA PUC	1,4,5,6			
RHODE ISLAND PUC	1			
SOUTH CAROLINA PSC				
SOUTH DAKOTA PUC	4,5, POSITIVE NET BENEFIT			
TENNESSEE PSC				
TEXAS PUC				
UTAH PSC				
VERMONT PSB				
VIRGINIA SCC	6	1,4,5	UNDER CONSIDERATION	
WASHINGTON UTC	4	1,6	NONE REQUIRED BY COMM.	
WEST VIRGINIA PSC				
WISCONSIN PSC			4	1
WYOMING PSC				

KEY - ECONOMIC EVALUATION METHODS

1 = TOTAL RESOURCE COSTS	4 = UTILITY COST TEST
2 = TOTAL TECHNICAL COSTS	5 = PARTICIPANTS TEST
3 = TOTAL SOCIETAL COSTS	6 = NON-PARTICIPANTS TEST

APPENDIX 3

APPENDIX 3

FORMULAS FOR COST/BENEFIT TESTS
CALIFORNIA STANDARD PRACTICE MANUAL

Participant Test

The following are the formulas for discounted payback, the net present value (NPV_p) and the benefit-cost ratio (BCR_p) for the Participant Test.

$NPV_p = B_p - C_p$

$NPV_{avp} = (B_p - C_p)/P$

$BCR_p = B_p/C_p$

$DP_p = \text{Min } j \text{ such that } B_j \geq C_j$

where:

NPV_p = Net present value to all participants

NPV_{avp} = Net present value to the average participant

BCR_p = Benefit-cost ratio to participants

DP_p = Discounted payback in years

B_p = Benefit to participants

C_p = Costs to participants

B_j = Cumulative benefits to participants in year j

C_j = Cumulative costs to participants in year j

P = Number of program participants

J = First year in which cumulative benefits are ≥ cumulative costs.

The Benefit (B_p) and Cost (C_p) terms are further defined as follows:

$$B_p = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1 + d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_p = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1 + d)^{t-1}}$$

where:

BR_t = Bill reductions in year t

BI_t = Bill increases in year t

TC_t = Tax credits in year t

INC_t = Incentives paid to the participant by the sponsoring utility in year t

PC_t = Participant costs in year t to include:
- o Initial capital costs, including sales tax
- o Ongoing operation and maintenance costs
- o Removal costs, less salvage value
- o Value of the customer's time in arranging for installation, if significant

PAC_{at} = Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)

AB_{at} = Avoided bill from alternate fuel in year t

The first summation in the B_p equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for B_p.

Note that in most cases, the customer bill impact terms (BR_t, BI_t, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BR_t formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times (K_{it}-1)) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times (K_{it}-1)) + OBI_t$$

where

ΔEG_{it} = Reduction in gross energy use in costing period i in year t

ΔDG_{it} = Reduction in gross billing demand in costing period i in year t

$AC:E_{it}$ = Rate charged for energy in costing period i in year t

$AC:D_{it}$ = Rate charged for demand in costing period i in year t

K_{it} = 1 when EG_{it} or DG_{it} is positive (a reduction) in costing period i in year t, and zero otherwise

OBR_t = Other bill reductions or avoided bill payments (e.g. customer charges, standby rates).

OBI_t = Other bill increases (i.e. customer charges, standby rates).

RIM Test

The formulas for the lifecycle revenue impact (LRI_{RIM}), net present value (NPV_{RIM}), benefit-cost ratio (BCR_{RIM}), the first-year revenue impacts and annual revenue impacts are presented below:

$$LRI_{RIM} = (C_{RIM} - B_{RIM}) / E$$

$$FRI_{RIM} = (C_{RIM} - B_{RIM}) / E \qquad \text{for } t = 1$$

$$ARI_{RIM_t} = FRI_{RIM} \qquad \text{for } t = 1$$

$$= (C_{RIMt} - B_{RIMt})/E_t \qquad \text{for } t=2,\ldots,N$$

$$NPV_{RIM} = B_{RIM} - C_{RIM}$$

$$BCR_{RIM} = B_{RIM}/C_{RIM}$$

where:

LRI_{RIM} = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program).

FRI_{RIM} = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARI_{RIM} = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts <u>does not</u> equal the LRI_{RIM}.)

NPV_{RIM} = Net present value levels

BCR_{RIM} = Benefit-cost ratio for rate levels

B_{RIM} = Benefits to rate levels or customer bills

C_{RIM} = Costs to rate levels or customer bills

E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers.

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + UC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

where:

UAC_t = Utility avoided supply costs in year t

UIC_t = Utility increased supply costs in year t

RG_t = Revenue gain from increased sales in year t

RL_t = Revenue loss from reduced sales in year t

UC_t = Utility program costs in year t

E_t = System sales in kWh, kW or therms in year t or first year customers

UAC_{at} = Utility avoided supply costs for the alternate fuel in year t

RL_{at} = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B_{RIM} and C_{RIM} equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

Utility Cost Test

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

$$NPV_{UC} = B_{UC} - C_{UC}$$

$$BCR_{UC} = B_{UC} / C_{UC}$$

$$LC_{UC} = LCUC / IMP$$

where:

NPV_{UC}	=	Net present value of utility costs
BCR_{UC}	=	Benefit-cost ratio of utility costs
LC_{UC}	=	Levelized cost per unit of utility cost of the resource
B_{UC}	=	Benefits of the program
C_{UC}	=	Costs of the program
LCUC	=	Total utility costs used for levelizing

$$B_{UC} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

VIC - Utility increased supply costs.
INC - incentives paid to part.

$$LCUC = \sum_{t=1}^{N} \frac{UC_t + INC_t}{(1+d)^{t-1}}$$

(All variables are defined in previous equations.)

The first summation in the B_{UC} equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UAC_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

UAC_{at} = (Use UAC_t formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it}-1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times (K_{it}-1))$$

where:

(Only terms not previously defined are included here.)

ΔEN_{it} = Reduction in net energy use in costing period i in year t

ΔDN_{it} = Reduction in net demand in costing period i in year t

$MC{:}E_{it}$ = Marginal cost of energy in costing period i in year t

$MC{:}D_{it}$ = Marginal cost of demand in costing period in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

RG_t = BI_t* (net-to-gross ratio)
RL_t = BR_t* (net-to-gross ratio)
RL_{at} = AB_{at}*(net-to-gross ratio)

TRC Test

The formulas for the net present value (NPV_{TRC}), the benefit-cost ratio (BCR_{TRC}) and levelized costs are presented below:

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

$$BCR_{TRC} = B_{TRC} / C_{TRC}$$

$$LC_{TRC} = LCRC / IMP$$

where:

NPV_{TRC} = Net present value of total costs of the resource

BCR_{TRC} = Benefit-cost ratio of total costs of the resource

LC_{TRC} = Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)

B_{TRC} = Benefits of the program

C_{TRC} = Costs of the program

LCRC = Total resource costs used for levelizing

IMP = Total discounted load impacts of the program

The B_{TRC}, C_{TRC}, LCRC, and IMP terms are further defined as follows:

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{UC_t + PC_t - TC_t}{(1+d)^{t-1}}$$

UC - utility costs
PC - partic. costs
UIC - utility increased supply costs
UAC - utility avoided cost
TC - tax credits
PAC - participant avoided costs

$$IMP = \frac{\sum_{t=1}^{N}\left[\left(\sum_{i=1}^{I} \Delta EN_{it}\right) \text{ or } \left(\Delta DN_{it} \text{ where } i = \text{peak period}\right)\right]}{(1+d)^{t-1}}$$

(All terms have been defined previously.)

The first summation in the B_{TRC} equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.