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INTEGRATED RESOURCE PLANNING IN INDIANA:
Building Reliable and Economic Energy Efficiency for the Next Generation

Report to the
Indiana Utility Regulatory Commission

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I. EXECUTIVE SUMMARY

The public commends the Commission on instituting this docket. Integrated resource planning represents promise for the future -- promise of lower-cost capacity, environmental compatibility, and economic and energy efficiency. In promulgating the rules that will evolve from this docket, the Commission should be careful to draw a map that will exhibit a vision for the future and will boldly and confidently set the course for Indiana utilities to follow.

The premise behind integrated resource planning is hardly revolutionary. Indeed, finding a set of options most likely to provide reliable service at the lowest cost is both predictable and commendable economic behavior. Thus, when looking to meet future capacity needs, utilities should choose resources with the lowest cost first, then draw on progressively more expensive options until demand is satisfied. Petition of SIGECO, Cause No. 38738 (October 25, 2989) at 5. Such an approach is simply good business--for utilities and their ratepayers. Requiring it through integrated resources planning is simply good government.

This is a particularly propitious time for Indiana to embark on integrated resource planning (IRP), for three reasons. First, the erosion of the large reserve margins of the 1980s has raised the prospect of considerable new capacity needs over the next decade. Ensuring that these needs are met at the lowest costs, whether by utility construction, purchases, or demand-side management (DSM), should be a high priority for all concerned.

Second, significant progress in IRP and DSM planning has been achieved by other states with more urgent capacity needs and higher energy costs. That experience is now sufficient for Indiana to build upon in crafting its own energy future.

Third, the passage of the Clean Air Act Amendments will present Indiana with many difficult decisions in the next five to ten years. The new Clean Air Act provides complex incentives for reducing certain emissions, and raises the possibility that other emissions (especially air toxics) may be regulated in the near future. Options for responding to the acid rain section of the Amendments include end-use conservation (for which there are specific incentives), fuel-switching, co-firing, scrubbing, purchasing allowances, and plant derating and retirement. Many of these options will increase marginal costs of supply or create permanent or temporary needs for replacement capacity. Other choices will arise in complying with the toxics and smog provisions.

Environmental costs and benefits of different resource options should be explicitly considered in resource selection. Environmental controls--even expensive controls such as SO_2 scrubbers--reduce but do not eliminate all of the environmental costs of electric power generation. These remaining environmental impacts (externalities) continue to impose costs on society, even if they do not show up in the direct monetary costs utilities incur when they choose resources. Therefore, the Public recommends that the IURC adopt the position of monetizing these externalities and incorporating them into the cost/benefit analyses used to determine least-cost options. These environmental costs can be monetized by valuing them at the costs of the additional controls which will be required to offset the extra emissions.

Quantifying these externalities allows IURC to capture more fully the benefits to Indiana ratepayers of integrated resource planning. These externalities are accounted for in the societal test. Using this test for the development of demand-side management programs within a least-cost planning framework will reflect the true value of efficiency programs to the utility, its customers, and Indiana. Once a portfolio of demand-side management programs has been designed, equity problems between customer classes and between program participants and non-participants can be handled through cost recovery mechanisms and by balancing the mix of programs. This assures that bills, not rates, are minimized when selecting cost-effective demand-side management programs.

DSM often seems to be the centerpiece of IRP, perhaps because DSM is traditionally so under-developed, compared to supply-side options. Indiana utilities have a considerable amount of work to do on DSM planning, to catch up to their supply-side capabilities. Among the imperatives for DSM program design are:

- comprehensive design of programs, including comprehensiveness in the range of measures included, the range of delivery mechanisms, the bundling of measures within programs, and the range of customers included;

- the design of programs by customer type and market sector, rather than by end use or technology;

- the avoidance of cream-skimming, i.e., the capture of modest low-cost savings in a building or application, while ignoring more expensive but cost-effective potential;

- the capture of transient efficiency opportunities, which will be lost if not realized when they become available;

- the building of capability, both in the utility and in the community, for delivering efficiency services;

- achieving high penetration and participation rates, by paying as much of the incremental costs of efficiency as are necessary to ensure customer participation;

- using large-scale programs early, to capture transient opportunities, to develop capability and to defer resources; and

- scheduling the deployment of all cost-effective DSM options prior to the commitment of new supply resources.

Indiana's utilities should expect to spend at least 4% of their revenues on DSM, and reducing energy and peak load by at least 1% annually, before they add new supply.

To facilitate this commitment to DSM, the IURC should establish mechanisms for utilities with comprehensive end-use efficiency programs to

- be assured of recovery of their expenditures, particularly those expended between rate-case test years;

- recover their expenditures in a manner which will not unnecessarily increase shareholder risks, utility administrative costs (e.g., by filing of frequent base rate cases), or adverse or inequitable rate effects;
- recover the earnings lost due to utility-sponsored efficiency improvements; and
- as necessary, earn a performance-based bonus for energy efficiency achievements.

The computation of lost earnings and of incentives will require high-quality measurement and verification programs for DSM. The same is true for maintaining the quality of program delivery, refining program design, and integrating projections of DSM with demand forecasts and supply planning. Measurement and verification should thus be designed into the DSM effort from the beginning.

The review of DSM program design, of measurement and verification plans, of incentive programs, of DSM achievements and of related cost recovery will be facilitated by the collaboration of the utilities with traditionally adverse parties representing various groups of ratepayers, environmental interests, and the public as a whole.

Resource bidding may be an important part of integrated least-cost planning. On the supply side, solicitation of supply from non-utility generators is likely to be beneficial. The utility's weighting of price and non-price factors should be fully (and where possible, quantitatively) documented, explained, and reviewed by the IURC. The IURC should have a strong rule in reviewing bidding structures, evaluation rules, and proposed contracts, but responsibility for implementing supply solicitations should remain with the utilities.

In principle, demand-side resources could also be obtained by bidding, in the same process as supply-side bidding, or in a parallel process. Indeed, a few states have started to explore this option, although responses have been modest compared to the supply-side bidding response. A number of problems arise with demand-side bidding, including "cream-skimming," lost opportunities, a failure to bundle energy services, and a loss of information.

Ultimately the IURC will draw Indiana's map for energy planning into the 21st century. Integrated resource planning, if properly implemented will assure that the route taken will best benefit the state of Indiana and its ratepayers. It is therefore imperative that the IURC chart a course in this proceeding which is thorough in all aspects and progressive where necessary.

II. INTEGRATED RESOURCE PLANNING PROCESS AND METHODOLOGY

This docket is a singular opportunity to launch Indiana utilities and the Indiana Utility Regulatory Commission into integrated least-cost planning. Such planning should fully integrate demand-side resources (load management and, primarily, energy efficiency) with traditional utility supply-side resources and resources available from independent power producers. It will also incorporate risk and the environmental costs of electricity generation so as to yield a resource plan with the lowest overall cost to ratepayers and to Indiana.

This docket is, in part, a response to the Commission's recognition of the need for comprehensive planning, as evidenced by SIGECO's application to construct a combustion turbine facility (Cause No. 38738). In its Order of Oct. 28, 1989, the Commission stressed the need for extended, regular long-term planning so that potential least-cost options would be available when needed, rather than being foreclosed because they were not immediately available (see second page of the Commission's Notice of Proposed Rulemaking). Integrated resource planning (IRP) is not an abstract concept for Indiana; it is a very timely and urgent issue, if the IURC and the utilities are to have all resource options available to meet future ratepayer needs.

1. IRP Objectives

The basic objective of IRP should be the minimization of total costs of providing energy services to Indiana ratepayers, or equivalently, of maximizing the total net benefit of those services. This objective must be elaborated to clarify that service reliability is a benefit (or the lack of it is a cost), and that risk and service risks are costs (or reductions in risk are benefits). As for any other utility activity, IRP should be implemented in an equitable manner.

a. Reliable Service

Reliable service is important to ratepayers. However, the amount of reliability which is cost-effective for various classes is not obvious. In addition, utility analysis of reliability levels is often limited to supply-level reliability, ignoring the effect of transmission and distribution outages on the reliability of service to the customer.

Loss-of-load probability (LOLP) or a related concept (e.g., loss-of-energy probability (LOEP)) should remain the criterion for supply resource planning under IRP. Utilities should be required to review the effect of different resource options on the reserve margin required to achieve their target LOLP; large and/or unreliable generating units require larger reserve margins to provide the same system LOLP.

Utilities should also be required to review the costs and benefits of current LOLP criteria. To the extent that significant additional costs would be incurred to provide benefits of special value to particular customers, it may be appropriate to charge those customers for the added reliability or to use dispersed generation to selectively increase reliability to critical facilities. Utility resource planning often overlooks the reliability advantages of smaller, more dispersed supply sources.

Furthermore, utilities should be required to report on the relative cost-effectiveness for improving reliability (as measured in customers interrupted annually, or kWh of lost sales) of investments in generation, transmission, and distribution. Investments in distribution reliability can sometimes achieve greater increments in reliability than equivalent investments in the bulk supply system. Cost-effectiveness evaluation of DSM programs should reflect the reliability benefits of such resources, including their small size, geographical dispersion, inherent tendency to follow load, and their reduction of demands on the transmission and distribution system.

Reliability is often approached as a static, deterministic issue, when it actually is dynamic and affected by many uncertainties, including load growth, future availability of power purchases, and future availability of existing and new generators. DSM evaluation should credit efficiency resources with the flexibility provided by their small increments, rapid response times, and tendency to follow load growth, all of which can contribute to maintaining reliability under difficult circumstances.

b. Environmental Externalities

Reducing impacts on the environment from power plant operation creates many benefits. Tangible benefits can include health care and material cost savings, reduced risk of catastrophic events such as the destruction of the ozone layer and global warming, reduction in potable water use, and less risk to the utility of subjection to future environmental taxes or retrofit requirements. Less tangible but equally important benefits include improved visibility, water quality and other human aesthetic qualities, and alleviation of the environmental stresses on terrestrial and aquatic ecosystems.

While many of these benefits are difficult to assess for a variety of reasons, our society has indicated a high willingness to pay to reduce costs associated with environmental degradation and the risk of a catastrophic event. It is therefore prudent for the Indiana utilities to consider the benefits of avoiding these environmental effects and to anticipate future environmental taxes or other costs in resource decisions.

Ottinger (1990) summarizes the status of states' actions regarding incorporation of externalities (as of the spring of this year). According to Ottinger, incorporation has been ordered in 21 jurisdictions including 19 states, the Northwest Power Planning Council and the Bonneville Power Administration.[1] Orders requiring the incorporation of externalities were pending or under consideration in another 10 states.

In this chapter, we discuss incorporating environmental effects in utility planning, provide a working definition of externalities, and discuss the major issues regarding the inclusion of externalities in utility planning. Based on the analysis outlined in this chapter, recommendations for incorporating externalities into utility planning in Indiana are presented.

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[1] Since this review, Illinois has ordered the utilities to incorporated externalities into their resource plans.

i. Definition and Scope of Externalities Analysis

We use the term "externality" to refer to any cost or benefit that is not reflected in the price paid by a utility or its customers for energy-related goods or services. Only environmental externalities are considered in this chapter, although other important economic and social externalities also exist. Environmental externalities include: emissions of air pollutants that contribute to ozone or acid rain, or have direct health impacts; emissions of greenhouse gases; consumption of water in cooling systems and the thermal and chemical impact on receiving water bodies; land use; and other potentially important effects including EMF from power lines.

Energy production and consumption, like most human activities, produce a range of external environmental effects. Some of these effects are well-understood, predictable effects, such as the amount of land required by a facility. Other effects are strongly supported by empirical evidence, such as ambient pollution effects on human health. Some represent risks, which may be well-understood, both as to probability and effect, or may be highly uncertain. For example, the designers of a dam may know that there is a one-in-a-million chance of the dam's failing and killing 2,000 people. Similarly, the number of people who will be killed in grade-crossing accidents involving coal trains is unknown, but the probability distribution may be highly predictable. Still other consequences are not fully understood in a technical sense, such as the effect of trace gas emissions on global warming and the effect of global warming on human and ecological systems. Finally, the net effects may be difficult to determine: the construction of a water reservoir may provide recreational benefits and habitat for waterfowl, but destroy other recreational opportunities, flood wetlands and disrupt the habitat of other ecosystems.

The complexity and results of an analysis of externalities are influenced by geographic scope. Some analyses of externalities are specifically designed to evaluate only those effects that occur in a specific service area or state. For example, the Massachusetts Department of Public Utilities has determined that externalities of electric power sources must be considered regardless of where they occur, while Vermont will include only costs that have some connection to state residents. This type of limitation may simplify the assessment process, by excluding some impacts, or complicate the process, by requiring the identification of the location of each externality. For example, if oil spills were to be included in Vermont's analysis if they occurred in only New England waters, it would be necessary to determine the port through which marginal supplies of oil were imported.

Geographic scope also affects the evaluation of specific externalities in other ways. For instance, emissions of the ozone precursors NO_x and VOCs have varying effects depending on the population density, current ambient air quality and climate in the immediate area and areas downwind of the emissions source. On the other hand, emissions of CO_2 have global effects regardless of the source of the emissions.

The scope of an externality analysis may also be affected by decisions to exclude classes of effects, or to limit the method of valuation. For example, an analysis that valued all effects at market prices (e.g., an otter at the price of its pelt, a human life at the present value of lost wages, wilderness at the income it generates in tourism) would miss some important aspects of many effects, but would be somewhat simpler to perform than a study that attempted to determine a total social value for each affected system.

One reasonable approach to limiting scope is to identify in advance the marginal sources of energy and related products and services. For example, if we can trace the marginal source of residual oil for utility boilers in New England (e.g., Venezuelan oil, refined in the Caribbean, and imported by tanker), then we can largely ignore the externalities produced by other supplies (e.g., new wells in the Rocky Mountains or enhanced oil recovery in Alberta.) Similarly, if we know that the marginal source of transmission capacity is an upgrade of an existing line, rather than a new line on a new right-of-way, then we can limit our analysis to identifying the externalities from the pipeline upgrade. The identification of fuel source, transportation method, technologies employed and their related externalities may not be easy. Indeed, the externality values we are estimating may ultimately influence the choice of new power supply technology and fuel options.

Once the marginal sources have been identified, the scope of an externalities evaluation can be further narrowed by initially concentrating on the most important effects, to the extent these are known. The choice of externalities to be included in utility planning and the scope of the evaluation can be determined largely independently of the method of estimating the value of reducing the externalities.

ii. Externalities in Indiana

Indiana's electric utilities are major contributors to the state's air pollutant emissions. In 1988, sixteen electric power plants numbered among Indiana's twenty leading sources of emissions of sulfur dioxide. Vigo County, portions of Lake and Marion counties, and the cities of Richmond and Michigan City have been designated as non-attainment areas for SO_2. State law limits SO_2 emissions from coal combustion facilities, which provide most of Indiana's electricity supply, to 6 lb/MMBtu.[2] However, nine counties in addition to the ones containing non-attainment regions follow more strict SO_2 emissions limits because of the size of the facilities in these counties.

Indiana does not independently set emissions limits for oxides of nitrogen (NO_x), which cause acid rain, form tropospheric ozone and smog, and contribute to the greenhouse effect by conversion to nitrous oxide (N_2O). Several of Indiana's electric power plants accounted for approximately 73% of the state's NO_x emissions in 1988. The proposed Clean Air Bill designates the Gary-Lake County area as a severe ozone non-attainment area, which is one category below the highest classification of extreme. In addition, the regions of Indiana bordering Cincinnati and Louisville, Kentucky constitute moderate ozone non-attainment areas, while Evansville, Indianapolis and South Bend-Mishawaka are marginal non-attainment areas.

Ten counties do not meet the federal ambient air quality standards for total suspended particulates, which impair visibility and have effects on the human respiratory system. The Indiana Department of Environmental Management monitors particulate matter under 10 microns in

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[2]Because of their ages, nearly all plants in the state are exempt from the emissions limits of the New Source Performance Standards.

diameter (PM10), which are largely byproducts of SO_2 and NO_x emissions that are more damaging to human health than larger particulate matter. Several electric power plants made significant contributions to the state's PM10 emissions, and a few are located in particulate non-attainment areas.

iii. Incorporating Environmental Effects

Environmental and other external effects of power plant construction and operation should be reflected in resource planning in three ways. First, for effects that will be mitigated, Indiana utilities should include reasonable estimates of the cost of mitigation. For example, the costs of complying with the proposed Clean Air Bill can be estimated and should be included in utility planning now to reflect the costs imposed by the bill on existing and new resource options. Second, for residual effects that will be internalized through taxes and fees, the Indiana utilities should include estimates of those internalized costs. Such a tax might be required for carbon released from fossil fuel combustion. Third, for the residual effects that remain after mitigation efforts and will not be internalized, the Indiana utilities should include estimates of the social cost of these effects. The costs in the third category are truly externalities and are discussed in detail in the following sections. The costs in the first two categories are simply projections of future internalized costs, and should be treated in the same manner as fuel price or other forecasts, as illustrated below.

(1) Internal Cost Effects of Acid Rain Legislation

The proposed Clean Air Act would internalize a number of costs, either by requiring reduction of emissions at the plant or by imposing tradable allowances. The most dramatic and immediate effect is the requirement of significant SO_2 emission reductions by 1995 from 37 generating units at 15 Indiana power plants. These reductions will generally require the addition of a scrubber or conversion to low-sulphur coal.

Starting in 2000, all of Indiana's coal units will have to purchase SO2 allowances for emissions above a base level, which will generally be their emissions level in 1985.[3] If the units produce less than their allowed level, they will be able to sell the extra allowances to other utilities or independent power producers. Low-NO_x burners, which are not very expensive, will be required on tangentially-fired and dry bottom wall-fired (coal) boilers. NO_x control requirements for wet bottom wall-fired boilers, cyclones and all other types of utility boilers will be established by EPA, but they are unlikely to be much more expensive than the low-NO_x burners.

This legislation will increase the value of DSM for Indiana utilities. First, the 1995 requirements will tend to increase avoided costs. If the plants are switched to low-sulfur coal, Indiana utilities' fuel costs, and hence their avoided costs, will be higher than currently projected,

[3] The base period may be 1985-87 for some units as outlined in Title IV, Sec. 402 of the Clean Air Act Amendments of 1990 (April 3, 1990 draft). We have not yet reviewed the details of the latest version of the legislation.

starting in 1995.[4] If scrubbers are installed, capacity and availability will likely be reduced, requiring the use of more expensive replacement fuels. Scrubbers also increase non-fuel variable O&M.

Second, the SO_2 emission trading program will increase the avoided costs of the Indiana utilities. Starting in about 2000, every ton of SO_2 emitted by power plants in Indiana will require the utility to buy one allowance, if it is over its baseline emission level, or sell one less allowance, if the utility is under the baseline emission level. More energy generated by the coal units leads to more allowances used for a given fuel type and set of emission controls. A coal unit that just met the proposed 1995 emission requirements would emit 1.2 lb of SO_2 per MMBtu, while an oil plant (burning 0.9% S #6 oil) would emit about 1 lb of SO_2 per MMBtu. At 10,000 BTU/kWh, 1 MWh would require 10 MMBtu; for a typical unit, that would produce about 10 lb of SO_2. If an allowance is worth $1,500/ton SO_2 (the price set forth in Title IV, Sec. 403(a), April 3, 1990 draft), the additional cost of 200 MWh of generation, which produces about 1 ton of SO_2, would be $1,500, or $7.50/MWh.

The value of each allowance will depend on the details of the final legislation; on the demand for allowances, which is a function of new coal and oil-fired power plant construction, retirements and repowerings, and usage of existing units; and on the supply of allowances a function of the cost of low-sulfur fuels and of emission control technologies. For the Administration bill, ICF (1989) estimated that allowances would trade for $651-$711/ton SO_2 in 2000, $527-$650 in 2005, and $575-$800 in 2010, all in 1988 dollars. The current legislation provides for the EPA to offer a small number of allowances each year at $1500 in 1990 dollars. Thus, the value of an allowance might be $600-$1,500/ton SO_2, and each MWh of marginal fossil generation might cost $3.00 to $7.50 in emissions allowances, in 1990 dollars. These values, or improved estimates as they become available, should be incorporated in Indiana utilities' tests for evaluating DSM measures.

(2) Anticipation of a Carbon Tax

The Intergovernmental Panel on Climate Change (IPCC) has determined that the buildup of carbon dioxide and other greenhouse gases in the earth's atmosphere will cause the phenomenon known as the greenhouse effect. Less certain is the feedback effects that will result from the greenhouse effect in terms of cloud cover and the ability of the oceans to absorb the excess CO_2, and therefore slow the rate of global warming. Yet given the potentially catastrophic impact of global warming on climate and global food supply, and the scientific near-consensus that the greenhouse effect will occur, several nations and some U.S. states are initiating measures for incremental reductions in greenhouse gas emissions through carbon taxes or CO_2 emissions caps.

The international community is pressuring the United States to reduce and/or stabilize CO_2 emissions. Whether the U.S. will respond with a carbon tax or use other methods of reducing CO_2 emissions is unclear at this time. Indiana will be called upon to reduce its share of CO_2 emissions,

[4]The prices for low-sulfur coal are likely to rise, although the magnitude of the increase will depend on the response of utilities to the legislation.

and the uncertainty of how it will be required to do so should be incorporated into the comparison of non-fossil options like DSM to fossil-fired supply options.

iv. The Non-zero Value of Reducing Externalities

The value of reducing externalities is greater than zero in Indiana. Reducing externalities beyond regulated emissions levels reduces tangible and intangible costs, as discussed in the first paragraph of the Introduction.

A DSM measure that causes a net reduction in NO_x and VOC emissions in an area that is in non-attainment for ozone may reduce the ambient level of ozone in that area. This will in turn reduce ozone-related health and material costs to residents, and eventually will reduce the need for expensive controls on new sources of NO_x and VOCs emissions within the air basin. This value is realized regardless of the source of reductions (within the air basin), and regardless of whether the source is currently in or out of compliance with its individual emissions allowances for these pollutants.

Even if the emissions reductions required by the proposed Clean Air Act are such that ambient air quality targets will eventually be reached, the DSM measure adopted today will result in at least 10 years of health and environmental benefits before the ambient targets are realized. In addition, if air quality does not reach the ambient air level targets considered to be safe for humans, a goal that has been largely elusive to environmental policy makers to date, then the DSM measure extends these benefits beyond the scheduled emissions reductions.

The DSM measure also has lasting benefits beyond compliance with ambient air quality standards to the extent it reduces the need for expensive controls on new sources of air pollutant emissions. For example, if enough DSM or other clean resources are utilized so that operating coal plants could use low NO_x burners for NO_x control in Indiana in the future rather than installing expensive selective catalytic reduction (SCR) on small gas turbines, then the DSM has effectively avoided the difference in cost per pound of NO_x emissions between SCR and a low NO_x burner. Since Indiana's economy and energy use can be expected to grow in the future in all sectors, this is an important benefit of DSM and other non-polluting resources. This is also true for areas that meet federal standards for air quality, since prevention of significant deterioration rules also require expensive control equipment on new sources of emissions. One point of clarification: the direct future costs of control equipment on new plants should be included in the direct avoided cost of the plant. However, the residual emissions of an additional plant will contribute to the degradation of ambient air quality in the air basin, which may again require the use of the expensive control measures to maintain ambient levels.

DSM measures may have health and environmental benefits beyond permitted federal ambient air levels. Ambient air limit regulations assume that there is a threshold below which no effects are observed, or the risk of an individual developing effects is acceptably low. However, these rules may not consider the cumulative effects of these pollutants. Further, there is evidence that some pollutants, such as NO_x, might be carcinogenic at a level that is unlikely to have a threshold tolerance.

The value of reducing externalities can be estimated for near-term use in utility regulation by the prudent use of at least one explicit monetization method, implied valuation or the avoided marginal cost of abatement. This method is appropriate for decisions concerning virtually all utility demand- and supply-side resource choices including decisions concerning DSM, comparison of utility and non-utility generation facilities, and evaluation of off-system power purchases.

So far in this chapter, we have asserted that the value of reducing externalities is greater than zero, but have not attempted to estimate this value. Indeed, some have argued that we do not need to estimate a dollar value for reducing externalities in order to include them in utility planning. The fact is that utility planners monetize, or place a dollar value on, externalities no matter what method they use to include them. The next section discusses the basis for explicit monetization of externalities for utility planning.

v. Methods of Incorporating Externalities

In this section we briefly discuss the application, strengths and weaknesses of four methods of including externalities in utility planning, which have been adopted or considered by other state utility commissions. The first approach, rating and weighting, was an attempt to include externalities into utility planning on a qualitative basis. It was proposed in Massachusetts (and elsewhere) but was found to suffer from several important drawbacks summarized below. This method has not, to our knowledge, been adopted for utility planning. The second method, development of a percent adder, estimates the externality benefits of DSM as a percentage of the direct costs of the avoided resource option. This method is also simple to apply for DSM evaluation, but it suffers from unnecessarily and arbitrarily relating the externality benefits of DSM to the direct costs of the supply-side option.

In the third method, use of a utility avoided cost adder, a cents/kWh externality adder is used for the evaluation of DSM measures. This method is simple to use to evaluate the environmental benefits of DSM and avoids several drawbacks of less quantitative methods. In the fourth method, monetization, the value of reducing each externality (for instance $/lb emitted) is determined by the regulator, and the value of reducing the total externalities of a specific resource option (in cents/kWh) is based on these values. Explicit monetization is the most flexible method of valuing externalities in that it can be used to evaluate the environmental effects of any resource options including DSM measures, QFs, utility generation and power purchases.

(1) Rating and Weighting

Rating and weighting is a complicated and often completely subjective determination of the relative value of reducing specific externalities. The important externalities of a resource option are identified and weighted relative to one another. For instance, acid rain is assigned 10 points, ozone formation is assigned 15 points, and global warming is assigned 5 points. The subjective determination of the relative values of reducing particular externalities, such as the value of reducing ozone relative to global warming, is probably the greatest, but certainly not the only, weakness in this method. For each resource option, externalities are rated on a numerical scale (say 1-5 points) depending on the perceived severity of the externality. Then the rating of each externality is multiplied by its weight, and this product is summed to create a score for the resource option.

Since this score is compared to price in utility resource decisions, this is a very complicated and unreproducible method of quantifying externalities. Further, it relies on the subjective judgement of the utilities about environmental matters in virtually every element; in the relative weights, the total weight of the externality category in relation to price, the rating scale and the individual ratings assigned to particular projects. Some utilities have in fact adopted the rating and weighting method of incorporating externalities <u>because</u> it allows them the flexibility to determine the effect that externalities will have on their resource options and to understate the importance of their emissions. If there were no other method of estimating the value of reducing externalities, this method might be better than assigning them a zero value. However, the explicit monetization methods are better costing tools in that they are more reviewable, consistent across utilities, and based on objective measures of the direct costs externalities place on society or the value of reducing externalities as implied through regulations and air quality targets.

(2) Percent Adder

Percent adders are used in a few states to evaluate the cost-effectiveness of DSM measures. The percentage adder is calculated as a percentage of the direct avoided cost, is expressed as cents/kWh, and is added to the direct avoided cost of the utility. This type of adder was a positive first step in including externalities in DSM decisions, but it unnecessarily relates the value of the avoided externalities to the direct costs of the avoided supply-side option. This method is used by the Northwest Power Planning Council, and in Wisconsin and Vermont to recognize the environmental and/or planning risk reduction benefits of DSM. The two methods discussed below have replaced the percentage adder in knowledgeable externality discussion.

(3) Cents/kWh Adder

If the Commission is interested in the near term in including externalities into decisions concerning only DSM, then an appropriate and much simpler version of explicit monetization is the use of a cents/kWh adder to the avoided costs. In this method an estimate of the value of reducing the externalities that would be avoided by the adoption of a DSM program is developed and added to the direct avoided cost of the utility, and used to evaluate the cost-effectiveness of DSM measures. A version of this method was adopted by the New York Public Service Commission.

A cents/kWh adder can be estimated using the monetization methods discussed below. If used properly, this method retains the objectivity and consistency across utilities of explicit monetization without the complexity involved in Indiana's developing independent estimates of the value of reducing externalities. One drawback is a lack of refinement necessary to compare supply options to one another.

(4) Monetization

With this method, individual externalities are identified and a unit value is estimated for each externality. For air emissions, the value is expressed in $/lb emitted. For oil spills the value might be expressed in $/gal oil spilled. For water use the value might be expressed as $/gal throughput, $/MMBtu of thermal impact on the receiving water body, or $/lb of chemical pollutant discharged in the receiving water body, or all three. Other externalities can be similarly categorized. The total externalities of resource options, expressed in cents/kWh, can then be calculated and compared. Monetization has been adopted in Massachusetts, California and New York and is currently being proposed in Nevada and Vermont.[5]

In general, there are three basic methods for estimating an explicit value for reducing externalities:

1. Estimating the relative physical, chemical, or toxicological potency of various pollutants;

2. Direct estimation of the environmental effects of a pollutant, and the valuation of each of those effects; and

3. Determination of the implied societal value of reducing the pollutant, from the maximum cost society has committed (or appears about to commit) to pay for reductions of this pollutant.

In the first approach, relative potency, the relative values of specific externalities are estimated. These relative values can then be translated into cost (monetized) by estimating the value of one of the externalities, and relating the other related externalities to it. Relative potency can be used to estimate the relative values of reducing emissions of the greenhouse gases.

Direct assessment and valuation, the second approach, attempts to identify all quantifiable effects of an externality to society. In general, each effect must be quantified, and a unit cost must be established. This procedure is generally treated as if it were a technical exercise, but the definition of relevant externalities, selection of important effects, choice of quantification measures and techniques, and determination of unit cost are often highly judgmental and subjective. Direct costs are currently being estimated by several researchers including the Pace University Energy Project (Ottinger et al., 1990), the U.S. Department of Energy, and the New York utilities.

The third approach, marginal cost of control, relies on the costs of required or anticipated regulations or control measures to estimate a societal value of reducing emissions of particular externalities. For example, the proposed Clean Air Bill, once adopted, gives us specific information about what society is willing to pay, on a national basis, to reduce SO_2, NO_x, VOC and toxic air emissions. Similarly, other federal or state regulations provide estimates of the value of reducing externalities at the margin. This rationale is also referred to as implied valuation, shadow pricing or revealed preference. Alternatively, the marginal costs of control are the direct pollution-control

[5] New york estimated a cent/kWh externality adder, from which the New York utilities in some cases backed out the $/lb of emissions for various externalities.

costs that can be avoided by an exogenous reduction in emissions, as with the adoption of DSM. There is increasing use of the cost of abatement to determine the value of reducing externalities, specifically in California, New York and Massachusetts. Appendix B provides additional description of the rational, strengths and weaknesses of this method.

In the direct estimation and implied valuation approaches, the value of reducing each externality is explicitly monetized. Typically, values are expressed in such terms as \$/pound of pollutant emitted, or \$/unit of the externality. For instance, the combined value of all of the air emissions of a power source would be:

$$\$/\text{kWh (Total)} = \text{Sum (lbs/kWh x \$/lb)}$$

vi. Why Monetize Externalities?

There are several reasons why estimating a dollar value of reducing externalities is particularly useful for including externalities in utility planning in Indiana.

1. Externalities are already assigned values, or monetized, in utility planning. Since power supply decisions necessarily consider the capital and operating costs of supply options, the assumptions made about other non-price factors, such as the inclusion (or exclusion) of external effects, always imply a value for those non-price effects.

2. If externalities are not considered in utility planning, the externalities are implicitly (or explicitly) valued at zero. Clearly, the emissions from a utility plant in Indianapolis contribute to ambient air quality there and elsewhere, and an emissions reduction from such a plant has positive value. Reductions of externalities in other jurisdictions have positive value also.

3. Some states have included externalities through the adoption of a generic price adder for externalities to account for the environmental benefits of DSM measures. Even though adders are not disaggregated into individual externalities, they do provide a rough monetary estimate of the total value of reducing the environmental (and other external) costs of supply-side options when compared to DSM measures.

4. The Massachusetts Department of Public Utilities, the New York Public Service Commission and the California Energy Commission have explicitly valued several externalities including major air emissions and, in the case of New York, water and land use externalities. In some cases the values chosen are placeholding values, but they clearly support specific non-zero values for these externalities. The inclusion of externalities has thus been established in regulatory decision-making in these and other jurisdictions.

5. Estimates developed through monetization are based on estimates of the direct costs of the externality on human health and the environment, are measures of our society's willingness to pay for reducing externalities such as the costs of regulations, or are estimates of the direct pollution-control costs avoided by an exogenous reduction in emissions. Therefore,

they are independent of the price of supply options or, generally, individual utility regulations.

6. Explicit monetization can be locally or regionally consistent, as appropriate for the externalities under consideration. The societal value of reducing a regionally or globally important externality is largely independent of the source of that externality, while the location of a source with an externality causing local effects will be much more important.

7. Explicit monetization is reviewable and reproducible. Unlike other methods proposed for incorporating externalities in utility supply planning, such as ranking or rating and weighting, the estimated externality values from monetization largely replace the subjective judgement of the utilities with objective analysis and reasoning, and can be refined in an iterative process through information provided by the utilities and other interested parties.

8. Explicit monetization can be consistent across utility options. A simplistic adder is useful to reflect the environmental benefits of energy conservation. However, for an analysis between supply options, explicit monetization can be used to compare an option that is cheap but relatively polluting and an option that is cleaner but possibly more expensive. A pound of SO_2 emissions reduced through the use of scrubbers or lower sulfur fuel is as valuable as that reduced through conservation or any other means. The cleaner supply options should be credited with that benefit, all else being equal.

9. Explicit valuation encourages individual plant innovation to improve efficiency, reduce emissions and reduce other externalities beyond required levels. Adders, or other methods of including externalities do not have this advantage.

Credible estimates of the value of reducing environmental impacts have been developed and are useful for evaluating externalities in Indiana.

vii. Including Externalities in Resource Planning in Indiana

Indiana would not be the first, nor by any means the only, state to consider environmental effects in its resource planning. The vigorous debate that has occurred in other states and at national and international conferences has caused the development of a framework in which to think about the value of reducing externalities and how they can and should be incorporated into resource planning. It is prudent for Indiana to consider the environmental effects of its resource options to anticipate future costs.

Of the methods discussed above for including externalities in utility planning, the Commission should consider two methods, the cents/kWh adder and explicit monetization.

The simplest method of including externalities in resource planning in Indiana would be a single externalities adder, expressed in cents/kWh, consistent across utilities, to reflect the environmental benefits of DSM over supply-side resources for the DSM measure life. The advantage of this method is simplicity in utility use, and the disadvantage is its inability to distinguish between differences in supply-side options that have different externalities. The value of this adder could be determined through one of the monetization methods. This externality adder would escalate with inflation over time, and be added to the utilities' direct avoided cost for the evaluation of the cost-effectiveness of DSM measures in Indiana.

Alternatively, a slightly more sophisticated approach would be to adopt "dual" cents/kWh adders, which would attempt to reflect more closely the externalities backed out by a DSM measure over its life. In the earlier years when the DSM measure backs down existing (and relatively dirty) generation capacity, the first externality adder would be relatively high to reflect the high emissions from existing sources. The second externality adder would be used once the control equipment required by the Clean Air Act is in place and new supply capacity is delayed or avoided. This adder would be lower than the first to reflect the lower externalities now displaced by the DSM measure. For instance, a DSM program started in 1991 might reduce generation from a mix of existing marginal resources including some unscrubbed coal plants, which have high externalities, until 1995, and then reduce a different marginal mix including fewer unscrubbed coal plants and perhaps avoid the construction of a new combustion turbine and have lower externalities thereafter. Dual adders can more closely reflect the environmental benefits of a DSM measure, would also be simple to use in utility planning, and can be estimated from the monetization methods.

Indiana could also adopt explicit monetization of externalities for the evaluation of DSM measures and for the comparison of utility and non-utility supply-side resource options. To use this method, the Commission could adapt the methods adopted in other states for application in Indiana. Essentially, the important externalities should be identified, and individual unit values for reducing these externalities should be developed from the marginal cost of control. The utilities would then apply these values to the emissions or other externalities from their resource options to determine option-specific externalities. In this case, the externalities of DSM measures should also be calculated, although within the accuracy of this analysis, zero appears to be the best estimate for the externalities of DSM.[6]

In order to use a cents/kWh adder or explicit monetization, the important externalities of electricity generating sources in Indiana must be identified, and the value of reducing these externalities must be estimated. We can get a good idea of the important externalities and their value by using the methods and estimates developed in other states. These calculations are made in tables 1-5, and are explained below.

Previous analyses of externalities of electricity generation show that the most important externalities are the air emissions SO_2, NO_x, VOC, CO, PM10, and CO_2. Therefore, initially for Indiana we will concentrate on valuing these emissions. Other air emissions, such as heavy metals, water impacts from cooling water systems, and land impacts should also be included if significant. Table 1 lists the air emissions from existing power plants in Indiana for 1988.[7]

[6]Some concern has been expressed about the effect of DSM measures on CFC release and indoor air quality. These are serious concerns, but the effects can largely be internalized through proper program design. For instance, a refrigerator rebate program should be coupled with an old refrigerator retirement and CFC disposal program.

[7]For sources of VOCs that were less than the emissions from the top 102 sources, emissions are estimated from generic emissions source factors developed by the California Energy Commission, as indicated.

Table 2 provides a summary of generic externality values of a selection of existing and new power plants in Indiana according to different valuation methods.[8] This table indicates that the externalities of an existing unscrubbed coal plant are in the range 2.7-8.9 cents/kWh, an existing scrubbed plant has somewhat lower externalities at 1.5-6.5 cents/kWh and the current Indiana system average externalities are in the range 2.5-8.3 cents/kWh.[9] For new power plants, the externalities of a combustion turbine are in the range 1.1-6.0 cents/kWh, a combined cycle are in the range 0.5-3.4 cents/kWh, and an atmospheric fluidized bed coal plant are in the range 0.7-3.8 cents/kWh.

The methods used by the three states are similar in some ways. Each uses the cost of control to estimate the value of reducing externalities, including the cost of the SO_2 reductions required under the Clean Air Act for SO_2, and the cost of the best available control technology for NO_x and PM10. For CO and VOCs, California and Massachusetts also used the marginal cost of the controls required to reduce these emissions.[10] Also, each use estimates of the costs of tree planting to estimate the value of reducing CO_2 emissions. Each of these assumptions would be applicable to Indiana, and Indiana-specific unit values for these air emissions would be in the ranges presented.

There are two primary differences between the high estimates generated by the Massachusetts method and the low estimates generated from the New York method (other than the emissions New York did not value). One major difference is the value placed on reducing emissions of the greenhouse gas CO_2. The unit value adopted by the Massachusetts DPU of \$22/ton CO_2 is based on conservative estimates of the cost of planting trees for carbon reduction in the U.S. The California unit value for CO_2 of \$7.09/ton CO_2 is based on a more optimistic estimate of the cost of tree-planting in urban settings to reduce the energy required for cooling. The New York unit value of about \$2/ton CO_2 adopted by the New York PSC was 1/10th that proposed by the New York State Energy Office, which was developed as the average cost of tree-planting and CO_2 scrubbing, and is a place-holding value. The Massachusetts estimate is a reasonable estimate of the cost of CO_2 reduction through tree-planting. However, given the uncertainty of federal and global policy concerning global warming the other states have chosen lower estimates of the value of reducing CO_2 to include in utility planning at this time.

The second major difference is that Massachusetts and California basically, and correctly, used the <u>marginal</u> cost of control to determine the value of reducing the externalities, while New York again took a very conservative position of using the average cost of a number of control measures. There is no basis for using the average cost to determine either the implied value of reducing the externalities or the avoided control costs realized through an exogenous reduction in emissions, as discussed above. Since New York was the first state to explicitly adopt explicit

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[8]Tables 3-5 provide the supporting calculations for this summary table. "New" refers to power plant technologies which may be used in the future in Indiana.

[9]The externality values indicated by the 15% adder would indicate that the environmental effects of the existing system are lower than the environmental effects of new plants. This is clearly a nonsensical result.

[10]New York did not place a value on these emissions.

monetization of externalities, the use of the average cost of control (rather than the higher, and probably at that time less politically acceptable marginal cost of control) was a moderate first estimate.

Therefore, the Massachusetts and California methods of estimating the externalities of power supply options give reasonable estimates of the value of reducing the externalities from similar plants in Indiana. The externality values implied by the New York method are probably understated for Indiana because they rely on the average cost of control.[11] The Indiana-specific externality values could be somewhat lower than that implied by the Massachusetts and California methods if a lower CO_2 value is assumed.

If the Commission were to adopt a single externality adder, a very moderate adder would be 1-2 cents/kWh. A 2.0 cent/kWh adder is below most of the estimated externalities for existing plants presented in Table 2, and is below all of the estimates of externalities of the new units except those generated using the New York method. It is roughly equal to 15% of the avoided costs of the new units as prescribed by Wisconsin.

If the Commission were to adopt dual adders, very moderate adders would be 3-4 cents/kWh for the near term and 1-2 cents/kWh after the year 2000 based on the analysis described above.

Finally, we urge the Commission to move toward full monetization of the important externalities in Indiana to evaluate all resource options. The externalities that are particularly important in Indiana include the air emissions SO_2, NO_x, VOCs, PM10, CO, and possibly air toxics, cooling water use, and any important externalities subsequently identified by the Commission. This analysis could be performed in the format presented in Tables 3-5, where the emissions of an existing or new resource are multiplied by Indiana-specific unit values in order to come up with the externalities (in cents/kWh) of each resource option.

c. Rates vs. Revenue Requirements

Least-cost planning should seek to minimize customer bills and total resource costs, not average rates. So long as the level of service is equivalent, the customers are better off with lower total costs; they should be indifferent between higher and lower rate levels, as long as their bills are lower. "Bills," in this sense, should include not just the electric bill, but all other costs affected by the utility's DSM program, including participants costs for DSM measures, gas bills, water bills, and the costs of meeting environmental quality goals.

Demand-side management (DSM) programs that raise rates by an average of 5 percent while reducing kilowatt-hour sales by 10 percent will reduce customer bills by 5.5%. A residential customer would clearly be better off paying 8.4 cents/kWh for 9,000 kWh/year (or $756) than paying 8 cents for 10,000 kWh (or $800). So long as the customer's house is as comfortable and

[11] It should be noted that New York also adopted additional placeholding values for water and land-use effects (not valued here) of 0.4 cents/kWh, which were added to the total externalities of supply-side options.

as well lit, the $44 savings is the only important difference between the two outcomes. Similarly, an industrial customer comparing costs for a new plant in Indiana with one in Ohio would prefer to pay 5 cents/kWh for using 6 GWH/year (or $300,000) in an efficient plant in Indiana, rather than 4.5 cents/kWh for using 8 GWH/year (or $360,000) in a standard-efficiency plant in Ohio. Thus, both new and existing customers will be better off with a cost-effective DSM program than without one.

Of course, care must be taken to extend energy-saving opportunities to all customers to minimize if not eliminate the number of non-participants. In addition, customer expenditures on DSM measures need to be included in the cost-minimizing equation to ensure that all costs of energy saving are counted.

This is not to say that rates are irrelevant. On the other hand, utilities and regulators must be sensitive to the incidence of rate impacts on different customer groups. Customers with highly elastic demands (e.g., industrials that can shift operations to other plants or cogenerate) may uneconomically bypass the utility system if their rates rise because of demand reductions by other customers. Customers without these options (e.g., residentials) will just suffer from higher rates. Fortunately, these potential adverse rate impacts of least-cost demand-side investment can be easily mitigated, either by targeting DSM services to vulnerable customers, or by ensuring that the rate effects of DSM are borne by customer groups that can participate in the program.

2. Integration of Supply-Side and Demand-Side Resources

As the Commission's Issue Statement recognizes, supply-side and demand-side resources cannot be evaluated in isolation from one another. To facilitate the effective integration of resources, the IURC should move the state's utilities toward:

- Rate design that sends accurate price signals to customers on the true marginal costs of their decisions to consume or conserve electricity;

- An unbiased and consistent economic approach for comparing resource costs and performance;

- Developing and maintaining adequate capability to deploy all viable resource options, both supply and demand-side sources;

- Analytical calibration and synchronization of demand-side resource planning with demand forecasting; and

- Identifying institutional impediments to systematic resource integration and proposing remedies for overcoming them.

a. The Economic Screening Test

In screening supply resources and DSM measures and programs, the utility should rely primarily on the societal or all-ratepayers test to compare benefits and costs. The societal test includes all costs and benefits to any portion of "society." The breadth of interests to be included in "society" must be determined, and may vary with the type of cost under consideration. Under the societal test, DSM benefits are not confined to the utility's avoided supply costs.[12] They also include all savings unrelated to electricity savings, such as reduced maintenance expenses, or the marginal value of other fuels or regulated utilities affected by the program (e.g., water, gas). Accurate resource comparisons using the societal test also include unpriced environmental externalities.[13] The social costs of DSM include the direct costs to the utility and to participants; administrative and monitoring costs; any increase in other energy and utility costs; and any quantifiable externalities.

The all-ratepayers test is a close cousin of the societal perspective, in that it counts all costs that are internalized in market prices to affected ratepayers.[14] Costs and benefits that fall on portions of society outside the set of ratepayers are ignored, as are all externalities not expected to show up as direct costs to ratepayers in another form.

Only the societal or all-ratepayers test will consistently reflect the true value of efficiency programs to the utility, its customers, and Indiana. Any measure that passes the societal/all-ratepayer screening -- i.e., is cheaper than supply -- is worth pursuing. Least-cost planning requires that the utility attempt to realize the potential of all such measures, since failing to do so would unnecessarily lead to higher total costs.

b. The Role of Other Tests

The other tests often proposed for evaluating DSM investments are the utility revenue requirements test, the participants test, and the non-participants test.

The utility test reflects the incremental costs the utility would incur to obtain different resources on ratepayers' behalf. It varies from the all-ratepayer test since it excludes costs that participants bear and includes incentives paid to the participants. Since the costs that flow through utility rates are not all the costs of DSM (or more generally providing energy services to

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[12]Avoidable supply costs include fuel and variable O&M from existing generation; capital and operating costs of new, life-extended or reactivated units; purchases; transmission investments, operating costs, and wheeling charges; distribution investments and operating costs; line losses; and margins on off-system sales.

[13]The costs of control required for avoidable supply should be included in the all-ratepayers test, as should any cost for fees paid because of emissions. Externalities for which the utility does not have to pay should be included in the societal test.

[14]Again, the scope may have to be defined for some costs. "Ratepayers" might include only the ratepayers of the particular electric utility, but the IURC would probably want to include costs and benefits to ratepayers of other Indiana electric utilities, and of Indiana gas and water utilities. As a practical matter, it may be easier to include out-of-state ratepayers of affiliated utilities (as through holding companies).

consumers), the utility cost should not be used to determine whether actions are cost-effective. However, the utility test has both general and specific roles in fine-tuning program design.

In a general sense, the utility test is useful in identifying program designs that minimize revenue requirements. All other things (especially total benefits) being equal, lower utility costs are usually preferable to higher costs. "Free riders" (participants who would have taken an action in the absence of the utility incentive) have little effect on the all-ratepayers test, but can be very important to the utility test. This treatment of free riders helps utilities focus attention on those efficiency savings that are unlikely to occur without their demand-side investment.

The non-participants' test (also called the no-loser's test or the rate impact measure) computes the effect of the proposed program on the bills of other ratepayers. The non-participants' test is not very meaningful on a measure-by-measure or program-by-program basis. The non-participants' test is a measure of equity, of the effect on other customers of the operation of a particular utility DSM program or measure. However, individual measures and programs cannot really be considered equitable or inequitable in isolation. Rather, the costs and benefits of the entire portfolio of conservation programs either produce an equitable outcome, or do not. The effect on equity of each program will depend on the cost recovery from that program,[15] whether the participants in this program are already participating in other programs, and how the bills of members of various classes and sub-classes are affected by the program.

Once an entire portfolio is designed, it is relevant to ask whether the effects are equitable overall. If there are equity problems, they can be addressed by changing cost recovery patterns, by increasing the penetration of programs to groups that would otherwise face higher bills, and possibly by changing the timing of program implementation.

Some utilities have mistakenly decided that lost billing revenues from conservation constitute real costs. While such lost revenues may pose strong financial disincentives for utility investment, they are *transfers* among groups of ratepayers and not true costs.

The non-participants' test is a misleading indicator for least-cost planning. The no-losers test leads utilities to reject energy efficiency savings whenever utility prices exceed utility marginal costs -- no matter what the cost of the efficiency resources.[16] Virtually every regulatory authority that has seriously examined the no-losers test has recognized its fallacies and rejected it as a threshold measure of resource cost-effectiveness.[17]

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[15]For example, the equity effects will depend on how the costs are recovered from various rate classes.

[16]For an analysis of this and other fallacies of the no-losers test, see my May 1988 testimony in Massachusetts DPU Docket No. 86-36, Investigation Into the Pricing and Ratemaking Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities, on behalf of Energy Federation, Inc. Also see my paper, "Lost Revenues and Other Issues in Demand-Side Resource Evaluation: An Economic Reappraisal," with Paul Chernick, 1988 Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy, Pacific Grove, CA, September, 1988.

[17]See Wisconsin PSC, Findings of Fact, Conclusions of Law and Order in Docket 05-EP-4, 5 August 1986, at pp. 8-9. Wisconsin re-affirmed its rejection of the no-losers test in its fifth Advance Plan decision in April 1989 in Docket 05-EP-5. Vermont utilities are prohibited from using the no-losers test to reject efficiency investments in the PSB's

The participant test is usually a conventional cost-benefit analysis, from the perspective of a hypothetical customer, generally with a discount rate similar to that of the utility. The costs are limited to the participant contribution to the program or measure cost, and the benefits are the reduction in bills to the participant.[18] The participant test can be useful for gauging the need for, and possible effects of, utility financial incentives to customers designed to overcome market barriers to efficiency investment. The utility can use the participant test to help determine the size of incentives needed to achieve specific payback periods for different types of measures.

Great care must be exercised in interpreting the participant test, especially if it is to be used to fine-tune the optimal incentive levels for DSM programs. The fact that a program appears to be very cost-effective for participants does not imply that a large percentage of customers will actually participate. A wide range of market barriers causes customers to neglect many measures that appear to be highly cost-effective, even in the absence of utility incentives. Hence, a favorable result on the participant test does not imply that the program design will actually be attractive to potential participants.

As utilities gain experience with DSM program design, they will be able to assess the attractiveness of alternative program design, based on tests that more accurately reflect the actual concerns of customers. To gain an understanding of how incentives influence participation, utilities should start by offering full funding of incremental efficiency costs to establish the upper limits on achievable participation.[19] Once these upper limits are established, utilities will be in a position to "back into" optimal incentive levels without sacrificing cost-effective participation. Taking the opposite approach -- trying to determine optimal incentives by starting too low -- runs the risk of delaying capability building and under-estimating the size of efficiency resources.

c. Non-cost Criteria

It is generally recognized that effective planning requires recognition of factors other than expected direct costs under base-case conditions. Environmental externalities are discussed in Section 1.b, above. Other externalities, such as oil import vulnerability, and employment effects are

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Recommended Decision in Docket 5270, pp. III 85-88. The Washington D.C. Commission rejected the no-losers test as a primary screen on demand-side investments in its March 1988 order in D.C. PSC F.C. 834 (Phase II). So did the Idaho Commission in Order No. 22299, Case No. U-1500-165 (Jan. 27, 1989); the Connecticut DPUC in its June 11, 1986 decision in Docket 85-10-22 at pp. 35-86; the Nevada Commission in its October 1986 decisions in Docket 86-701 regarding the resource planning of Sierra Pacific Power; and the New York PSC in its 26 July 1988 decision in Opinion No. 88-20 in Case 29409, pp. 23-49. The Massachusetts Department of Public Utilities firmly rejected the no-losers test in its Decision and Order in DPU 85-266-A/85-271-A, 26 June 1986, pp. 147-48. It reaffirmed this policy in subsequent orders, including DPU-86-36-E, November, 1988.

[18] A conceptually distinct aggregate participant test would include the participants' collective share of the portion of the DSM measure cost recovered through rates and their share of the system cost savings due to DSM. Since any one participant's rates are not significantly affected by his/her own decision to participate in the DSM program, these aggregate costs and benefits are not relevant to assessing the desirability of a program.

[19] For some market segments, experience from other utilities may indicate that some participant cost share is feasible without significantly decreasing response.

also sometimes included in the analysis. These externalities are often extremely difficult to quantify and value; they may be incorporated as non-price factors. This section will discuss factors, such as risk mitigation and planning flexibility, which affect the variability of direct costs and the utility's ability to moderate both costs and their variability.

Numerous non-cost factors are often suggested for incorporation into the resource selection process. These include:

- flexibility factors:
  - option scale (small additions being preferable to large additions),
  - options for accelerating or delaying the in-service date of the option,
- operational benefits:
  - dispatchability,
  - maintenance flexbility,
  - tendency to follow load,
  - location within service territory,
- diversity factors:
  - different fuel sources and pricing terms than the utility's major supplies,
  - limited vulnerability to regulatory, institutional, or weather conditions that would increase demand or decrease utility supplies (e.g., environmental regulations, coal supply strikes or lock-outs, coal-pile freeze-ups at times of high heating loads),
- probability of successful completion:
  - technology maturity,
  - sponsor/vendor experience,
  - design and development status,
  - site availability,
  - licensing status,
  - environmental and land-use compatibility,

- probability of successful operation:
    - technology maturity,
    - sponsor/vendor experience, and
    - financial security (capitalization, debt coverage, etc.).

Certain of these non-cost criteria belong in resource evaluations, since ignoring them may lead to suboptimal results. If these factors are incorporated into formal scoring systems, the points given to each category, and to each possible value within the category, should be somehow related to the cost advantage which would provide a similar number of points. This may be a simple analysis. For example, the value of a certain license might be determined by estimating the probability of denial, the length of time required for the denial, and the cost of short-term replacement power until an economical long-term replacement can be secured.

It may also be useful to perform separate cost-effectiveness evaluations with the entire proposed evaluation system, and with only monetized criteria, in order to isolate the effects of non-cost criteria on resource selection. The IURC should understand the extent to which each factor drives the utility's decisions.

d. Integration and Evaluation Methodology

Comparison of resources should be consistent with the least-cost planning objective of demand-side investment. Accordingly, screening should be based on the utility's full avoided costs. Failure to consider full avoided costs will screen out cost-effective options whose savings cost less than utility supply. All of the costs and benefits of supply resources should be compared to one another including:

- providing capacity,
- providing economical energy for local use or off-system sales,
- reducing (or increasing) reserve margins,
- increasing (or reducing) transmission requirements, and
- increasing (or reducing) fuel and technology diversity.

In comparing demand-side resources to supply-side resources, the utility should also reflect:

- the tendency of DSM to reduce loads at the times of highest energy costs,
- the reduction in capacity and reserves,

- the reduction in marginal line losses, which tends to be highest at the times when DSM is most effective,

- the reduction in transmission and distribution requirements, and

- the reduction in planning risk.

The purpose of IRP is to maximize net benefits -- not to maximize the benefit-cost (B/C) ratio. It is easy to see why maximizing the B/C ratio will not minimize total costs and is thus inconsistent with least-cost planning. The program B/C ratio is an average over all measures and participants. A utility can always increase an already-high B/C ratio -- say 2 -- by taking out measures with B/C ratios of under 2. This would leave only measures with higher B/C ratios (e.g., those with a B/C ratio of 6.) But every measure with a B/C ratio above 1.0 excluded from the program would still have been cost-effective.[20] A utility following this approach would have to compensate for these forgone savings with more expensive supply. Utilities do not appear to constrain supply options to keep B/C ratio limits above arbitrary levels, and they should similarly not constrain DSM.

A third area in which supply-side and demand-side resources should be treated comparably is in capability building. If a utility identifies a resource, whether supply or demand-side, that is potentially cost-effective at some point in the planning horizon, the utility should act to ensure the resource will be available if needed. On the supply side, the utility would learn more about the technology, identify sites, assess licensing problems, determine lead times for design, licensing and construction, and seek bids from suppliers. On the demand side, the utility would also have to build capability to deliver the resource. Utilities are usually quite active in building capability to deliver supply-side resources; they should also demonstrate they are building capability to realize all cost-effective demand-side resources.

Fourth, the integration process should ensure that transient resource opportunities are not lost due to utility inaction. Transient options appear on the supply side, such as opportunities to install cogeneration at new industrial or commercial facilities, to obtain capacity in a jointly-owned plant or a pipeline expansion, or to place underground cables when roadways are being rebuilt. Transient opportunities are more common on the demand side, occurring whenever new buildings are built or renovated, factories revamped or expanded, or equipment replaced. Utility plans should provide for the capture of the maximum feasible amount of cost-effective transient resources. This demands immediate analysis, since the transient resources will be lost forever if they are not utilized as they arise.

Fifth, long-range DSM plans must be integrated with long-range resource planning. Utilities should time DSM acquisitions so they can influence supply planning. This does not mean efficiency acquisitions should commence at the time new capacity is needed to come on line since by then it would be too late.

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[20]We are not suggesting that utilities strive for program B/C ratios of 1.0. Individual measures should each be cost-effective, i.e., incremental B/C ratios should equal or exceed unity to be included in programs and specific customer applications.

Suppose a new combined cycle plant is needed in 10 years. This indicates that the utility should pursue energy-efficiency resources available for less than the cost of new combined cycle generation. Exactly when such acquisition should begin depends on how long it will take to acquire enough efficiency savings to displace energy to be provided by the new plant. This depends on the maximum savings achievable per year. If the maximum annual rate of savings is 10% of achievable potential, then full-scale acquisition should begin now.

Nor is it appropriate for utilities to conclude that efficiency resources are not "needed" now because new generating capacity is not planned. On the supply side, energy-cost reductions are routinely used to justify investments in increased efficiency, reduced fuel costs (e.g., new rail spurs), and increased availability of low-energy-cost plants. Similarly, energy-efficiency resources are "needed" if they will substitute for more expensive generating fuel, will allow for profitable off-system sales of energy or baseload power, or will displace supply investments designed to reduce fuel costs.

Demand-side programs are worth pursuing now if their avoided energy and capacity costs exceed their implementation costs. This does not mean that utilities should dismiss all programs whose costs exceed benefits when measured from today's perspective. Programs that do not appear cost-effective today may be worth acquiring when avoided costs increase as utility load grows and supply costs increase. Utilities should run programs that promise to be cost-effective in the future in capability-building mode, as discussed earlier. These programs are equivalent to utility expenditures to preserve supply alternatives as viable resource options.

Integration requires that utilities play equal roles in the acquisition of supply, load management and conservation resources. Many utilities have different approaches for these three resources. They are generally willing to install and operate most supply and load-control measures directly, but are content to leave efficiency investments to their customers. Information is often the only extra ingredient these utilities add to the operation of market forces when it comes to efficiency investment. This difference in approach prevents the integration of efficiency into the utility's resource portfolio.

3. Risk and Uncertainty

All four methods for analyzing uncertainty that are listed in the Commission's Issue Statement -- scenario analysis, sensitivity analysis, portfolio analysis and probability analysis -- are useful (and overlapping) tools. These approaches are discussed at greater length by Hirst and Schweitzer, *Uncertainty in Long-Term Resource Planning for Electric Utilities*, Oak Ridge National Laboratory, ORNL/CON-272, December 1988. None of the methods is entirely satisfactory in itself. The IURC should gradually move the Indiana utilities toward clearly and fully considering the comparative advantages of resource plans in terms of relative risk and flexibility.

The most economical plan under base-case conditions may not produce the lowest expected costs over the range of uncertainties. The plan with the lowest expected costs may have a wider range of costs (over time and over uncertainties) than some alternative with higher expected costs. Risk and uncertainty should thus examine both the difference between base-case and expected costs, and between expected costs and variability in costs.

Adding diversity to and increasing the number of power sources serving Indiana utility customers tends to lower the amount of reserve capacity needed to maintain given reliability objectives. Similarly, demand-side resources, particularly energy-efficiency investments, can be uniquely advantageous to the utility system due to their small size, their ability to be expanded and contracted quickly as circumstances change (a function of short lead time), and their natural tendency to vary with loads. DSM programs can be reduced because they consist of many small projects, and because the reduction in the program scope does not reduce the effectiveness of the projects already completed. Large generation projects, in contrast, must be either continued or terminated as a unit; a half-completed 800 MW DSM program will provide about 400 MW, while a half-completed 800 MW coal plant will provide nothing. DSM program scale tends to vary naturally with load growth, as the amount of new construction and new equipment tends to rise in times of high growth, and fall in times of low growth. Installed DSM measures will also tend to produce greater savings in extreme weather or high levels of economic activity than in mild weather and recessions.

While difficult to model, these benefits are gaining increasing recognition by utility planners and regulators. The Northwest Power Planning Council has estimated that the short lead time and the load-following characteristics of conservation confers an expected cost advantage about 10%, compared to 600 MW coal plants. The Vermont Public Service Board has also adopted a 10-percent comparative risk discount factor for utility demand-side resource costs. (Decision in Docket 5270, April 16, 1990, Appendix IV-B).

a. Analytical Approaches

Scenario analysis generally assumes that the future is known, and determines optimal plans for various known futures. This approach does not provide estimates of cost of uncertainty, the value of planning flexibility, or the ability to make mid-course corrections. Scenario analysis generally (but not necessarily) assumes smooth cost and growth trajectories. This form of analysis is not useful for modelling the effects of surprises, such as changes in capital costs, construction schedules, fuel prices, load growth, plant availability or environmental regulations.

Sensitivity analysis examines one plan under several futures. It tends to have the same limitations as scenario analysis. Simply putting probabilities on the alternative futures and selecting the plan with the lowest expected cost does not adequately reflect the flexibility of alternative plans.

Portfolio analysis examines the robustness of a set of resource strategies in alternative futures. This approach is particularly interesting, in that it can isolate the effect of a single variable (e.g., unit size, construction schedule) on the range of costs encountered under uncertainty. The realism and usefulness of this technique is greatly enhanced by allowing for reoptimization of the supply plan over time, as each alternative future unfolds.[21]

[21] The issue statement suggests that the resource plans should reflect "different regulatory and corporate goals." This does not seem to be appropriate. IURC should prescribe the regulatory and corporate goal of minimizing social cost.

Probability analysis refers to the weighting of the future outcomes by the probability of the events that would cause those outcomes. Hence, it is a framework for reducing the range of outcomes in portfolio analysis to a single value, reflecting the expected outcome. If future choices are reflected following resolution of current uncertainties, this technique converges on a decision analysis approach.

The distinctions between these approaches is often semantic; in practice, various utility analyses could be classified in more than one of these categories, and each application would require additional description to distinguish it from very different applications in the same category. The important features of a comprehensive risk model would include:

- the ability to model many strategies;
- the recognition that forecasts are almost always wrong, and that all forecasted values will change;
- the recognition that changes in actual values (e.g., reduced load growth) will tend to result in changed forecasts (e.g., lower forecasts of future loads), which may or may not be more accurate than current forecasts;
- rapid changes in actual values (e.g., fuel costs) and in forecasts;
- adaptation of future plans to reflect actual values and changed forecasts;
- the costs of over-building, under-building and changing schedules of plants under construction;
- uncertainties in average and individual plant construction costs, construction schedules, reliability, and operating costs;
- uncertainties in fuel prices and load growth;
- the possibility for multiple and repeated surprises and changed forecasts;
- the correlation of DSM program magnitude with load growth; and
- the ability to report both expected costs and the variability of costs.

These objectives could, in principle, be achieved in a decision-analysis framework, such as that used in the MIDAS program. As a practical matter, the large number of uncertainties and future choices may overwhelm the analytical ability of decision-analysis programs. The alternative is the Monte Carlo approach, in which the future value of each uncertain variable (including future forecasts) is selected from a probability distribution, and the resource plan is then updated. In this manner, the simulation walks through one future. The next run selects alternative values of the variables, and determines the corresponding planning responses and the final cost outcomes. Capturing the range of future outcomes may require several hundred runs.

Either the decision-analysis or Monte-Carlo analyses can be run with several resource planning rules. Standard units can be set at various sizes, requiring various lead times, and so on. DSM can be excluded, or modelled as retrofits, transient opportunities, or a mix of resources.

b. Capability Building

DSM investments are sometimes thought of as more risky than supply investments due to the greater familiarity of utilities with the supply side and the larger scale of individual supply options. This may be true for Indiana utilities in the very short term: the results of a decision next week to build a 100 MW combustion turbine are likely to be more predictable than the results of a decision to achieve 100 MW of DSM savings over the next two years. However, as the utilities improve their ability to deploy DSM resources, they will tend to resolve the uncertainties. While we cannot currently be sure which DSM approaches will be most productive in Indiana, we can be fairly sure that a very flexible, low-risk economical option can be developed.

The Northwest Power Planning Council explains that capability-building programs "provide essential experience for turning efficiency potential into real resource options before they are actually needed." The Council offers the following definition of capability-building investment:

> *Capability-building programs* are implemented in the absence of data on measured costs and savings, as a means of verifying working assumptions and predictions. Capability-building programs tend to be considerably more costly, per unit of electricity saved, than the resource acquisition programs they may eventually lead to. Because the initial development and demonstration costs are high, electricity savings will appear much more expensive than when programs are taken to the acquisition stage. The Hood River Conservation Project is an example of a capability building project.[22]

Demand-side capability-building efforts are comparable to development activities associated with supply-side options. Capability building is directly analogous to the pre-operation expenditures that utilities incur in the pursuit of promising supply-side resources. Demand-side programs require start-up and testing equivalent to the environmental, engineering, feasibility and design studies that routinely precede ground-breaking for utility supply resources. Utilities routinely invest in supply research and development projects which will in themselves produce no benefits at all for ratepayers, in the hope that the technology developed by the projects will be applicable for the utility. Utility DSM capability-building will at least produce some tangible direct benefits, although they may not be cost-effective until the resulting programs are fully implemented.

Building capability to acquire any resource takes time. This is especially true for resources with which utilities lack experience and understanding. Electricity surpluses have afforded many utilities a window of opportunity to develop the capability to deliver efficiency resources. Unfortunately, this window is closing rapidly. To take advantage of this window for meeting future resource needs, capability-building must begin now.

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[22]"Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," 1987, at p. 4-8.

To reduce future risks, utilities should identify all programs that appear to be cost-effective either immediately or later in the planning period, when avoided costs rise. As expeditiously as possible, they should be testing all currently cost-effective programs with large-scale efforts; as soon as feasible, they should implement all clearly cost-effective programs.[23] Finally, the utilities should identify all programs that would be cost-effective over their planning horizons, and determine when they will have to start implementing test programs to ramp them up to full capability by the time they are needed.[24]

In determining how and when capability-building investment campaign should proceed, utilities needs to make the following determinations for each potential efficiency option:

(1) what information the utility needs about potential efficiency programs in order to determine their cost-effectiveness as resources, including their available magnitudes, costs and performance;

(2) what steps are necessary to generate this information to decide on the likely cost-effectiveness of these resources;

(3) how long it will take to develop enough information to determine whether each efficiency resource appears likely to be cost-effective at any time in the planning horizon; and

(4) what steps to follow, and how long they would take, to deliver the resource, once the decision establishes that it is cost-effective to deploy.

By working backward from the time that the programs are expected to become cost-effective, the utility should develop explicit schedules and budgets for capability-building investment in all market segments.

The utilities will need DSM delivery capability prior to the date at which they need capacity. There are several reasons for acquiring early DSM-delivery capability. First, for transient opportunities (e.g., new construction, rehabilitation, renovation, expansion, routine equipment and appliance replacement, and industrial process modifications), all cost-effective opportunities should be captured as they occur. A building constructed in 1994 will not be rebuilt in 1999, if the utility then decides that it needs the capacity and energy benefits of the efficient building.

Second, many DSM programs will be less expensive than operating existing marginal power supplies, including line losses and T&D requirements. By implementing DSM prior to the need for new capacity, the utility can reduce costs long before it avoids generating capacity.

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[23] A special effort should be made to scale up lost-opportunity programs quickly, since their potential savings are not deferrable.

[24] "Need," in this context, refers to the sum of capacity and energy savings, including line losses, T&D savings, risk reduction and externalities.

Third, the utilities must convince themselves and the Commission that its DSM programs will produce real savings before they can avoid capacity additions. For example, a utility expecting to add a combustion turbine in 1999 would have to decide in 1996 whether to order the equipment and pursue licensing.[25] Thus, by 1996, the utility would have to have run enough large-scale programs to demonstrate that significant demand reductions would be achievable by 1999. To allow time for implementation, evaluation and review, the utility would have to start those programs immediately.

Hence, if Indiana utilities are to minimize risks and costs to ratepayers they will have to build real DSM delivery capability rapidly.

4. Demand Forecasting

It is important to recall that all demand forecasts will be wrong. Forecasts are important primarily as starting points for risk analysis and for the detail on end uses that can be developed through them.

a. Documentation Requirement

To be useful for public reviews of the need for new resources, the forecasts must be well documented. For the special needs of DSM planning, the utilities should be required to report the assumed efficiency trends, mix of end uses, and mix of load from new and existing buildings. Economic modelling of this sort is always crude, so the emphasis should be on clarity and reasonableness, rather than an illusory precision.

b. Prescribing Methodologies

(1) End-use vs. Econometric Models

As least-cost planning evolves, utility demand forecasting is seen increasingly as an exercise for establishing a baseline against which demand-side programs are evaluated and implemented, rather than a deterministic projection of future demand. End-use modeling is often recommended as necessary for least-cost planning so that the effects of demand-side programs can be calibrated to and deducted from the load forecast. An end-use perspective is also essential for screening and designing demand-side programs, since DSM measures cannot be specified without knowledge of the loads to be modified or reduced. To be useful for planning, and to allow verification from field data, the results should be as end-use specific as possible.

On the other hand, end-use modelling requires vast amounts of new data that may take years for utilities to develop. Thus, it may not be worth the expenses and delay associated with

[25]The lead time may be longer if turbine manufacturers are operating at or near capacity. The lead time for compressed air energy storage or combined-cycle units would be longer.

wholesale conversion from econometric to end-use methods. Furthermore, many inputs to energy usage decisions are economic (e.g., prices, income, level of economic activity) and the relationships between these inputs and the amount of electricity used must often be estimated econometrically.

Moreover, short-term load changes (in the range of 6 months to 3 years) are more heavily influenced by the economic factors than by changes in installed equipment. Thus, end-use models have not performed as well as econometric models in short-term predictions.

A mix of the two approaches may be the best solution for the near-term requirements of integrated planning. Econometric models should be recommended for short-term forecasts and to drive portions of the long-term forecasts. End-use forecasting should be used wherever feasible; long-run econometric forecasts should be divided up by end use and efficiency to the extent feasible.

(2) Uniform Economic Inputs

California requires all of its utilities to use the same forecasting methodology and the same basic inputs. This is only important if the forecasts are to be compared to one another, or if the IURC thinks that a state agency forecast or utility consensus is much more likely to be reasonable than the individual utility forecasts. Given the inherent uncertainties in load forecasting, it is not clear that standardization will be helpful.

The IURC should expect to review economic inputs, especially fuel prices, as those are used in evaluation of alternative resources. Some utilities (e.g., NEES and PEPCo) have used fuel price forecasts that are much lower than virtually all published forecasts, resulting in lower assessments of cost-effective DSM.

(3) Sensitivity

Sensitivity analyses help to estimate the range of plausible growth rates and identify the most important variables. Identification of important variables will allow the utility and the IURC to concentrate efforts on reducing critical uncertainties, preparing responses to changes in those variables, and designing DSM and supply programs that will vary in the right direction as those most important variables change.

5. Reporting Requirements

a. Required Data

Regulators and utility planners have put into place explicit standards for various aspects of integrated utility planning in Wisconsin (Advance Plan 5), Vermont (Docket 5270), the Pacific Northwest (1986 Northwest Power Plan), and Massachusetts (DPU Docket 86-36). Commissions in Maryland (Case 8063 Phase II) and the District of Columbia (Formal Case 834 Phase II) have also made considerable progress in developing reporting standards for integrated resource planning. The following information may be appropriate for utilities to file along with their integrated plans:

(1) Comprehensive database of customer peak and energy usage by end-use;

(2) Schedule of long-run avoided costs, with and without environmental externalities, with supporting assumptions about capital costs and escalation rates;

(3) Catalog of costs, magnitudes, and performance of available supply- and demand-side resources. The supply side should cover new utility generating plants, life-extension for existing plants, power purchases, and power offered by IPPs. The demand side should include, for each market sector, the most successful program designs (including covered measures, where a list is feasible) identified from national experience.

(4) Details of program designs, projections, assumptions, and target markets for DSM programs. Many important details are often missing from such submissions, particularly the fraction of efficiency measure costs covered by utility program incentives, the rationale for the specific incentive levels, and the exact proportion of target populations that utilities expect to reach with their programs.

Determining reporting requirements at the outset can avoid unnecessary controversy and confusion later. It is probably more important to specify clearly the questions the filing is to answer (e.g., "for each cost-effective measure or program not currently scheduled for implementation, explain why such option is not included in the IRP."), rather than to lay out specific formats.

b. Time Horizons

The time horizon should be long enough to reflect the lead-times and economic lives of major utility generating options, ranging from 15 to 30 years. Forecasts of loads, fuel prices and generation capacity costs are progressively unreliable as time goes by. Hence, few plans are specified for more than 20 years, an adequate IRP time horizon. However, the evaluation of the benefits of an option should be extrapolated to the lifetime of the option.

c. Specifying IRP Goals and Objectives

The utility's IRP goals and objectives need not be specified in the IRP. The utility's goal should be to carry out the IURC's requirements. The IURC should establish goals and objectives. The basic goal is the minimization of costs. Other objectives should include the reduction of risk, the provision of reliable service, the capture of transient opportunities, the building of capability and the development of comprehensive programs.

To the extent that utilities establish proxies for an IURC goal or objective (e.g., restate "Reduce fuel price risk" as "Increase gas use," or "Maintain reliable service" as "Maintain 20% reserve"), the utilities should identify and justify those proxies.

In addition to specifying basic IRP goals and objectives, the IURC may need to establish operational guidelines for the utilities, such as mandating that the utilities pay as large a share of the cost of DSM as is required to overcome market barriers.

d. Frequency of IRP Filings

Biennial IRPs seem to be the national standard, although a few states require filings only every three or five years. In choosing filing schedules, the Commission needs to strike a balance between comprehensiveness and timeliness. Filings more often than biennially would require constant preparation and review, while intervals of more than three years would allow IRPs to become seriously out of date between filings.

e. Short-term Action Plans

Short-term plans are very important, and conceptually distinct from the less frequent long-term plans. Annual action plans would cover actions for the next 2-3 years for DSM, purchases, sales, refurbishments, construction status, pollution control projects (especially with Clean Air Act Amendments) and research projects. While the long-term potential for DSM programs would be identified and scheduled in the long-range plan, the short-term plan would provide budgets, hiring plans, penetration and participation goals, marketing plans and a host of other details that are only meaningful and necessary to specify for the next few years.

The roles of short-term action plans increase in proportion to the length of time between long-term filings.

f. DSM Pre-approval

Given the uncertainties utilities perceive regarding the effect of DSM programs on their costs, revenues and earnings, and the internal resistance to DSM, pre-approval should be an option for the utility, to reduce risk. To the extent that the IURC can review and approve program design, the utility's risks are reduced, the IURC and the parties will be better informed, and the program will likely be improved.

Pre-approval may require considerable commitment of analytical resources by the IURC and other parties. Commission pre-approval can also add a cumbersome and time-consuming layer to selecting resources. The review is apt to be faster, easier and more productive in the context of collaborative program design between the utility and traditional critics. The IURC review of collaboratively-designed programs can be less extensive than for utility-design programs; remaining differences between the parties will be highlighted and clarified, simplifying the IURC's task.

In any case, preapproval can be effective for only those items specified in the program plan that is actually approved. Utilities must remain responsible for the implementation of the program, as they remain responsible for the construction and operation of power plants even after they receive certification. To the extent that the utility makes implementation decisions on its own (e.g., selects contractors, revises or fails to revise delivery mechanisms to reflect new information), it must take responsibility for the prudence of those actions. The pre-approval can also cover only information known at the time of the approval; the utility must retain responsibility for accelerating, decelerating, modifying, to terminating programs as conditions change. Pre-approval should not be viewed as shifting responsibility for DSM development and management from the utility to the Commission.

Pre-approval of DSM programs and cost recovery may be appropriate at this early stage in the evolution of least-cost planning. Once utilities are more familiar with DSM planning, more capable of quality program design, and more comfortable with the likelihood of cost recovery for DSM, pre-approval may be no more necessary for DSM than for T&D system operations.

III. DEMAND-SIDE MANAGEMENT

1. Ratebasing vs. Expensing

The ratebasing of DSM investments, in itself, does not provide much of an incentive for utility investment in DSM. Utilities generally prefer to expense expenditures, and prefer to depreciate ratebase as quickly as possible.

Ratebasing of DSM does have certain benefits for utilities. First, it allows them to recover costs incurred between rate-case test years. Expenses in those periosds are generally lost, while most of the capitalized costs can be included in rates in the next case. This may be an important consideration for utilities expecting to file rate cases only infrequently. The same benefit may be achieved by allowing utilities to defer conservation program costs, possibly with an AFUDC-like interest credit, until the next rate case. The details of the deferral (e.g., the allowance of an interest credit, the start and end dates for the credit calculation, the rate used in the credit calculation, and the amortization of the balance between rate cases) will determine the implicit incentive for DSM expenditures. More favorable treatment may be justified for utilities with aggressive programs.

Second, ratebasing allows the costs of DSM programs to be collected from ratepayers at roughly the same time that they are receiving the benefits of the programs. Expensing DSM investments in 1991 that will reduce electric bills for ten or twenty years results in a sharp mismatch of costs and benefits. With expensing, custmer bills could rise in the first few years, to produce reductions in later years. This may be both inequitable and unnecessarily disruptive.

The depreciation or amortization period should usually be the same as the investment lifetime, as is true for supply. However, different treatment may be justified for administrative convenience, to moderate rates (including rate effects of non-DSM expenditures), and to assuage utility concern with regulatory risk.[26] In particular, it may be advantageous to expense or to rapidly amortize Indiana electric utility DSM expenditures over the next few years, so that the costs are out of the way prior to the effects of the Clean Air Act. This issue can be resolved on a case-by-case basis for each utility.

Eligibility for ratebasing of DSM expenditures should be defined to mimic the comparable rules governing supply options. In general, all pre-operation expenditures for supply (including design, planning, start-up, testing) can be capitalized, except for overall ongoing planning costs. Hence, DSM program design, evaluation, and implementation should all be eligible for ratebase treatment. For accounting reasons, the IURC may want to distinguish between formal DSM ratebase items, which are owned by the utility and depreciated, and utility investments in customer-

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[26] Utilities often express concern that DSM cost recovery will be allowed over an extended period, only to be denied by a subsequent Commission, depriving the utilty of much of the value of its investment. This is probably not a real threat. Experience with cancelled plants over the last 10-15 years suggests that deferral of cost recovery is not particularly risky. Once cost recovery policy for a particular cost item has been established, PUCs do not often change their minds. If this is true for cancelled plants, which offer no continuing benefits, it should be even more true for DSM, which does provide continuing benefits.

owned equipment, which can be capitalized and amortized in a fashion which exactly mirrors ratebasing.[27]

2. DSM Incentives Beyond Rate Base Treatment

a. Introduction to DSM Incentives

This section discusses utility recovery of the costs of DSM expenditures. It then discusses alternatives for dealing with the sales-erosion problem. Finally, it presents alternatives for rewarding utilities for investing in cost-effective demand-side resources. The three issues are closely related. Moreover, their relative importance to utilities varies widely. Some utilities are only concerned about their exposure to cost disallowances of DSM expenditures; others care about revenue losses exclusively; still others insist on receiving shareholder incentives.

At least three financial factors tend to make comprehensive demand-side investment much less attractive than conventional supply to investor-owned utilities. In decreasing order of importance, these deterrents to integrated resource strategies are:

1. Raising efficiency lowers short-run profit.

2. Uncertainties about the dependability and predictability of cost recovery for demand-side investments, and especially the potential application of prudence and "used and useful" tests may discourage DSM investment.[28]

3. DSM requires the expenditure of utility funds.

4. Demand-side expenditures do not offer the investor return of capital-intensive supply investments.

For every kWh of sales lost to more efficient use, the utility loses its sales margin. This margin is the difference between tariff price set by regulators and any short-run variable costs not flowed through to ratepayers. The more effective a utility's demand-side efficiency investment, the more it loses. This is precisely the wrong signal to send a utility that is supposed to be reducing ratepayer costs with efficiency improvements.

Adjustments to test-year sales in the utility's previous rate case will not fully correct this problem. Even if a rate case reflects the expected savings from efficiency programs, the utility has no incentive to realize the sales losses accounted for in the efficiency-adjusted test year. Once costs are assigned to classes and then structured through rate design, the tail-block price fixes how much revenue a utility will collect on each additional kWh or kW sale. Each sale the utility can effectively retain from intended efficiency savings contributes to earnings.

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[27]The Massachusetts DPU has made this distinction.

[28]The predictability of cost recovery (i.e., that the costs <u>will</u> be recovered) is separate from the mechanism for cost recovery (i.e., <u>when</u> the cost will be recovered).

In addition to the direct pressure exerted by the potential margin, lost revenues also tend to accelerate the need for utilities to file rate cases. Many utilities appear to be averse to general rate cases, which may occupy a large fraction of senior management time for many months.

To remove this perverse disincentive, regulators in a growing number of states, including New York, Vermont, and Massachusetts have begun to eliminate penalties for sales losses attributable to utility DSM programs. The systems differ in many respects, but the general approach is quite simple. Using a methodology reviewed and approved by the regulators, the utility estimates kWh and kW sales losses in each rate class, multiplies those sales losses by the net revenue per unit in the rate's tail block, and recovers the resulting lost revenues over time.

In any such performance-based system, the details of the methods, data requirements and assumptions must be negotiated. In particular, the precise approach for measuring demand-side performance should be settled in advance. A projection of lost revenues can be collected during the period the measures are being installed, but reliable estimates of the revenue losses will generally be available several months following that period. Thus, some reconciliation mechanism is usually included in the process. Actual cost recovery may flow through an adjustment clause, or be deferred with an AFUDC-like credit until the next rate case.

The IURC can take two types of actions to reduce utility reluctance to invest in DSM. The first type reduces the uncertainty in the recovery of costs by clearly defining the role of the prudence and used-and-useful tests for DSM. In particular, these definitions must reflect the experimental nature for some DSM programs, especially in the process of building capability. Almost by definition, capability-building efforts require utilities to make mistakes. The IURC should clarify, as did the Vermont PSB in Docket 5270, that prudently implemented programs which were prudently believed to be likely to lead to cost-effective full-scale programs will be considered used-and-useful until their costs are fully recovered.[29] The prudence standard for program design and implementation should also be clearly defined to be limited to the level of case applied in continuing programs of comparable scale, as in distribution maintenance. Finally, the IURC should reassure utilities that any supply-side plant that becomes or remains excess due to DSM will not cease to be used-and-useful.

The second type of action simplifies DSM program cost recovery. For most costs, the public interest is served by encouraging utilities to avoid cost increases; regulatory lag tends to impose this type of discipline. For DSM, the public interest is frequently served best by rapidly increasing expenditures, often at times when the utility would have not otherwise chosen to file a rate case. It is therefore appropriate to make DSM cost recovery easier than recovery of other costs. This may be accomplished by flowing some DSM costs through an existing fuel adjustment mechanism, by creating a new adjustment mechanism, or (most simply) by allowing the deferral of DSM costs with a capitalized return, until the next rate case. Establishing a preapproval program

[29]The Vermont PSB also clearly established that the results of collaborative design efforts between utilities and their traditional critics would carry a presumption of prudence.

for DSM program design may also be helpful.[30] Of course, utilities must continue to be responsible for implementing their programs prudently, including modifying them if new information reveals that the pre-approved design is not suitable.

Explicit incentives for utility performance in DSM may be justified, to overcome certain barriers to enthusiastic utility participation in DSM implementation. These barriers include staff biases against DSM (from decades of promoting electric energy use), perceived risks related to higher unit prices, reduced competitiveness and future regulatory uncertainty. Regardless of whether these concerns are valid, utility (i.e., shareholder) incentives may be beneficial to ratepayers, to the extent that they accelerate utility DSM programs.[31]

Incentives should be designed with the following objectives in mind:

- Only superior performance should be rewarded. Mediocre performance does not justify an incentive, and sub-standard performance should be penalized. Minimum performance levels (roughly 40-50% of projected program performance) have been adopted by the Massachusetts DPU for Massachusetts Electric, Western Massachusetts Electric, and Boston Gas; and by the New York PSC for Orange and Rockland Utilities. The incentive should increase linearly from the threshold level, to a maximum significantly higher than the expected program results.

- Utilities should be rewarded for performance, not projections. Incentives should reflect the actual number and size of installations and actual energy savings, to the extent feasible. This will generally require a "true-up" mechanism. To limit utility risk, the true-up should become final at some previously determined date, which may be 1-5 years from the end of the installation period. The exact period should be determined by the nature of the program, and the inherent lag in the evaluation process. For example, new-construction programs will require longer evaluation periods than will retrofits, since the effect is not observable until after the design, construction, and occupancy processes are complete.

- Utilities should not be rewarded for doing what they do in the normal course of business. Sales promotions, time-of-use rate design, interruptible load programs and direct load control are long-standing utility programs that impose no new risks and should encounter little internal opposition; no incentives should be offered for such programs. Incentives are probably also not justified for DSM bidding, since the utility is not responsible for the cost or quality of the program design or execution.

[30]In practice, the review of DSM program design in adversarial proceedings has been difficult. The best and most aggressive DSM program designs have been developed in collaborative processes between the utilities and their traditional critics. Those programs have generally been easier for regulators to review and approve, since at least some of the most interested parties have already had a chance to participate in program design, and to publicly dissent, if necessary.

[31]This discussion assumes that direct program costs and lost revenues will be recovered, and does not include such recovery as "incentives." In fact, more favorable and less risky collection of these costs, as compared to other utility costs, may reduce the need for explicit incentives.

- Utilities should be rewarded for maximizing total benefits, which involves both the total number of kWh (and KW) saved, and the reduction in social costs per kWh saved. Thus, all the lifetime costs and benefits should be reflected in the incentive computation.

- Superior performance should allow utilities to increase their earnings by a large enough margin to warrant management attention and to overcome internal resistance. An increase in after-tax return on equity (ROE) on the order of about 1% should be sufficient for this purpose. The IURC may want to determine the exact incentive level on a case-by-case basis, considering the history of each particular utility and its progress over time.

The previous discussion covers positive incentives, the carrots which reward utilities for pursuing DSM. In addition, the IURC should put the utilities on notice that inaction on IRP and DSM may result in some negative incentives, the sticks that penalize utilities for sub-standard performance. Negative incentives can be directly coupled to the positive incentives; if superior performance on DSM can earn a utility a 1% increase in ROE, perhaps a lack of action should cost up to 1% on ROE.[32]

The IURC should also warn the utilities that failure to pursue DSM could result in general rate disallowances, as for the costs of power supply and T&D which would not have been necessary with DSM, or of proposed supply projects. If the utilities have not fully developed DSM, the IURC may not be able to determine that new supply facilities are needed.

b. Higher Rate of Return for DSM

This is not a useful approach, for two reasons. First, any reasonable increment in return on a small investment may not be large enough to attract management attention, or overcome internal resistance. Second, this approach rewards the utility for spending money, not for achieving savings of kWh or total costs. Better program designs may save more kWh with less investment, so that improving the program reduces the utility incentive.

c. Decoupling Revenues from Sales

The explicit computation of lost revenues is only one way of removing the efficiency disincentive created by lost revenues. Another alternative is the straightforward uncoupling of sales from profits. California's Electric Rate Adjustment Mechanism (ERAM) has done this since the early 1980s by recovering or refunding variations from test-year revenue projections. While other

[32]The Massachusetts DPU has assessed ROE penalties of 0.5% to 1%, and the DCPSC has penalized a utility by 0.15%, for inadequate DSM activity. The California PUC has imposed similar penalties for inadequate efforts to promote cogeneration. Both Massachusetts and Vermont have refused cost recovery for improperly designed IRP and DSM programs.

uncoupling arrangements have been proposed,[33] ERAM is the best known. The NYPSC has recently approved a similar arrangement for Orange and Rockland Utilities.

California's ERAM mechanism is attractive in many ways. It reduces utility incentive to increase sales through inter-fuel competition, promotion of extra end-uses and amenities, discouraging efficiency improvements, or attracting development. Most of these effects are desirable, but not all. The California PUC considered dismantling ERAM, due to the perception that the utilities had lost the incentive to resist bypass.

ERAM also corrects for all other factors that change sales, including weather and economic conditions. This is largely an unintended effect, some of which is desirable. For example, a hot summer will raise sales, which under traditional regulation would be retained by the utility. Under ERAM, some of the extra revenues are flowed back to the ratepayers in the next year, fairly quickly moderating the financial effect. Unfortunately, in a recession, ERAM operates to increase rates to make up in the utility's revenue shortfall. The midst of a recession is probably a bad time to raise rates.[34]

For a jurisdiction like California, with a future test year, tracking of a variety of costs, and regularly scheduled rate cases, ERAM is a fairly simple and straightforward incremental addition. In most jurisdictions, moving to ERAM would be a very big step for regulators, utilities and other parties. At least two problems arise in Indiana.

First, Indiana uses an historic test year, so ERAM is very difficult to apply. Simply put, the California PUC establishes in a 1990 rate case a revenue level it actually expects to be achieved and to be sufficient for 1991. The IURC (and many other regulators) establishes in a 1990 rate case a revenue level it has no expectation of seeing in 1991, and which is not likely to be adequate for the utility; both some costs, and the sales levels from which unit rates are calculated, are based on test year (e.g., 1989) levels, and are generally understated. This historic test year method has clearly operated reasonably for setting rates, producing outcomes utilities and consumer advocates find reasonable.[35] However, it produces no target of the functioning of the ERAM; in addition to the test-year revenue level, used in setting rates, the IURC would have to project a rate-year revenue level.

Second, ERAM requires either frequent rate cases, to reset the target revenue level, or continuing adjustments, either flowed through in current rates or capitalized to the next rate case. In traditional ratemaking, increasing sales tend to balance inflation; if no major investment is added to rate base, rates may remain adequate for many years. California uses triennial rate cases, with interim adjustments for a wide range of expenses and investments. These amount to almost

[33]See, for example, P. Chernick, "Revenue Stability Target Ratemaking," 1983, and D. Moskovitz and R. Parker, "How to Change the Focus of Regulation so as to Reconcile the Private Interest with the Public Goals of Least-Cost Electric Planning" (Presented to the Sixth NARUC Biennial Regulatory Information Conference, September 1988).

[34]The recovery could be spread over several years to reduce the short-term burden on ratepayers.

[35]This statement is only true to the extent either side in any rate-setting hearing is ever satisfied with the outcome. It does not appear that either utilities or other parties are significantly better off with future rather than historical test years.

continuous ratecase updates. Given the tendency for complexity in California regulation, the ratemaking complications of ERAM do not impose any remarkable burden. Indiana would have to revamp its ratesetting methodologies to allow for continuous updates or retroactive ratesetting, or the utilities would have to file annual rate cases.

The high price of the ERAM has had limited benefits for DSM. Even with ERAM in place, once the PUC relaxed pressure for conservation investment, the California utilities gradually reduced their commitment to DSM until a group of consumer and environmental activists raised the issue. As part of the agreement to accelerate DSM investment, the utilities still insisted on explicit incentives.

Despite its long-term potential, ERAM would require too far-reaching a revision of Indiana ratemaking to be feasible at this time. The resources of the IURC, the utilities and the other parties would be better spent on making IRP and DSM successful and productive. The issue can be revisited later.

d. Split-savings

Splitting <u>net</u> savings between ratepayers and shareholders is a reasonable structure for incentives, as discussed above. However, the utility cannot be paid only for a portion of the <u>gross</u> savings, as are some third-party contractors. If the utility must cover its direct costs, plus lost revenues, plus a compensation for risk, in a portion of the bill savings, it will invest in only measures that are much less expensive than supply. DSM measures that are only 20-30% less expensive than supply will not be funded.

As discussed above, incentives should be given for only extraordinary efforts and efficiency investments, as opposed to traditional utility functions such as providing information, load management, rate design or sales promotion.

3. DSM Cost Allocation

In general, DSM costs should be recovered from participating rate classes, for equity reasons. Customers who cannot participate in the programs may reasonably resent paying for them. Exceptions should be entertained where necessary, as to avoid unacceptable rate effects in small classes.

A disproportionate share of quick and cost-effective energy-saving opportunities is in the commercial sector. Accordingly, even if care is taken to extend DSM programs as widely as possible (e.g., to small businesses and to low-income households), commercial customers are likely to reap a large share of the benefit of utility DSM expenditures. As discussed above, the shifts in cost responsibility due to electricity savings from conservation programs may dominate direct program costs in determining rate impacts. For this reason, it may become necessary to concentrate the rate effects of commercial DSM in the commercial sector to protect some ratepayers from bearing an unfair share of the direct costs, lost revenues and incentive costs of DSM programs.

The sharing of costs between participants and the utility's ratepayers as a whole involves very different principles than the inter-class allocations of the utility's share of the costs. The participant's share of the cost will affect the efficiency, as well as the equity, of the DSM program.

The utility should start by identifying an efficient mechanism for delivering services in each market. Given that mechanism, and the nature of the market barriers in each market, a funding level must be identified that will achieve essentially all of the achievable potential by the time it is cost-effective, and will not significantly increase the costs of program delivery. Utilities should not arbitrarily refuse to pay for the bulk of the cost of efficiency improvements, and even for the full incremental cost, if that is the most effective and efficient means of securing those improvements.

To the extent that some program costs are recovered from participants, the participants should be given the option of having the recovery flow through their bills. This may be very important for some customers (such as government agencies) which would have to secure numerous and complicated approvals to put up cash or to sign a loan agreement. It may also be important for customers with cash constraints, and may overcome a psychological barrier even for those customers who are not cash-constrained.

4. DSM Screening

The assertion in the Statement of Issues that "screening is necessary to reduce the number of resource options that will be thoroughly evaluated" is problematic. Programs should not be designed by evaluating hundreds of potential measures or technologies, and then grouping the successful measures into programs. Recent experience has demonstrated that the proper approach to DSM program design is driven by market sectors.

A market-oriented DSM design process starts with a segment of the market and designs a program to achieve all cost-effective conservation within that market. The cost-effectiveness of the resulting program is also determined at the level of the entire package. This can be thought of as a "top-down" design process, as opposed to the conventional "bottom-up" process of enumerating and evaluating each technology (or end-use or measure) individually.

Market segments should be defined to facilitate determination of the type of delivery mechanisms that would be appropriate; that is, small customers as opposed to large ones, lost opportunities as opposed to discretionary programs, and customer-driven choices as opposed to those usually made by contractors. For the residential class, useful segments might include:

- heating retrofits,
- water-heating retrofits (possibly including heat pumps),
- new-appliance efficiency, including choice and water-heater installation measures (wraps, pipe insulation, end-use reductions),
- new-building efficiency, and
- lighting, probably broken into direct retrofit, demonstration programs, and retail market shifting.

Many of these markets would have separate requirements and investment strategies, depending on the strength and configuration of market barriers impeding different customers' investment in cost-effective efficiency options. Thus, the utilities should offer different incentives and assistance for owner-occupied and rental housing, and for low-income and other customers, since the barriers differ among these groups.

For commercial, institutional, and governmental customers, there may be similar differences in requirements for delivery mechanisms and incentive levels for large and small customers, and for business and non-profit customers. Appropriate segments might include:

- comprehensive retrofit, including lighting, HVAC, building shell, window treatments, refrigeration, and motors (e.g., elevators);
- new construction, renovation and rehabilitation; and
- routine equipment replacement (e.g., chillers).

For industrial customers, the categories would be similar to those for commercial customers. However, the "new construction" category should probably also include major equipment and process changes (analogous to the commercial rehab, but not necessarily affecting the spatial layout). In addition, the retrofit program must allow for customer-originated improvements in equipment and processes.

Depending on how the segments are defined (e.g., whether the low-income residential retrofit market is counted as a subset of the residential retrofit, or as a separate market), this approach would focus on roughly one or two dozen packages, rather than many dozens of technologies and measures.

Thus, the only screening necessary is that based on the utility's avoided cost. Once general program concepts are sketched out, eligible measures can be identified and grouped into the program categories. For programs driven by site-specific analysis, such large Commercial and Industrial, and probably residential spaceheating retrofit, the cost-benefit analyses will be conducted for the specific site. In those programs, lists of measures are usually intended only to stimulate the analysis team. For prescribed programs (non-heating residential retrofit, new residential construction, appliance rebates, residential lighting, small commercial retrofit), the individual measures are screened for cost-effectiveness (assuming the existence of the program), which eliminates the need to include any joint costs (administration, advertising, participant contact, monitoring, evaluation, travel time, etc.). Once the cost-effective measures are screened into the program, the entire program can be screened, with the joint costs included.

It is important, as discussed in Section I.2.d, above, that all avoided costs be included in both screening phases.

a. Technological Maturity

DSM measures that are not technologically mature may not be suitable for full-scale implementation in the short term. However, lack of technological maturity is not an excuse for ignoring a promising DSM option in the long term. The lack of technological maturity may result from market barriers, which the utility can help overcome. Relatively small utility orders of the most efficient refrigerators, now in pilot production, might allow that production to be scaled up and cost brought down, so that the technology would become available for full-scale implementation. Whenever maturity issues impede DSM measure application, the utility should enquire into the nature of the problem, and into the utility's potential role in resolving the problem.[36]

Utilities similarly attempt to push technology on the supply side, acting individually, in consortia, or through EPRI to develop compressed air energy storage, fuel cells, coal gasificiation, coal cleaning, emission controls and other technologies.

b. Consistency with Planning Objectives

Since the objective of IRP is to minimize costs, the costs and benefits of an option must be reviewed to determine whether it is consistent. Establishing a set of planning objectives, other than the fundamental objectives of reducing total costs, maintaining reliability, and providing an equitable distribution of costs and benefits, can create problems.

For example, many utilities apply a set of load-shape objectives, and use those to screen out some DSM options. In the EPRI DSMRank spreadsheet, the utility would enter weights for each of a dozen load-shape effects, such as peak clipping, valley filing, load shifting, strategic conservation, strategic load growth and flexible load shape for both summer and winter seasons.[37] These weights are generally arbitrary (and undocumented), since they are not expressed in physical units (e.g., kW) or monetary terms. DSMRank then multiplies those weights times rough measures (assigned values of O, 1, or 2) of each option's contribution to achieving those effects. This approach assumes that the desirability of a load-shape change can be determined without any knowledge of the cost of the change, and only a rough approximation of the benefit.

Depending on the cost and benefit of each option for a particular utility, any of the load-shape changes may be desirable or undesirable from an all-ratepayer/societal perspective. If a valley-filling measure is inexpensive to implement, displaces expensive alternatives (e.g., fossil fuels in some industrial processes), and can be terminated before new baseload capacity is required or existing baseload capacity becomes valuable for resale, it may be very beneficial. If the measure is expensive, has limited benefits, and will increase system costs in the long term, it may be very undesirable. The concept of "valley-filling", and all the other DSMrank concepts, are not particularly useful in screening programs or measures.

Load-shape objectives should not have any explicit role in screening measures for least-cost planning. To the extent that program designers know certain kinds of load changes are particularly valuable, they can concentrate on identifying measures that achieve those types of

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[36]The Indiana utilities might best achieve these results through joint programs, or through division of responsibility and sharing of results. One utility might be responsible for testing, and creating a market for state-of-the-art refrigerators, another for windows, and third for lighting controls, and so on.

[37]These terms are EPRI's. The significance of the term "strategic" is unclear.

changes. The IURC may also wish to impose stricter standards for the justification of promotional programs (e.g., valley filling and load growth) than for conservation. However, for screening on measures and programs, only the costs and benefits of each option are relevant.[38]

c. DSM Prioritization

Priorities in DSM development include capability building and capturing transient opportunities. To assure capability building is comprehensive, utilities should build some capability in each significant market sector. This will also tend to increase the equity of the program, since it will be available to the widest range of customers. Capability building is discussed at some length in Section I.3.b.

Transient opportunities, or lost-opportunity resources, are defined by the Northwest Power Planning Council as those "which, because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use." (Northwest Power Planning Council, 1986 Northwest Conservation and Electric Power Plan, Vol. 1, p. Glossary-3). On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or physical barriers to their later acquisition. ("Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," at 7).

Opportunities to secure inexpensive efficiency savings occur when new residential and commercial buildings are designed and constructed. Similar one-time opportunities also arise when households and businesses add or replace appliances and equipment. Once foregone, these "resources" must be replaced in the future either with alternative supply or more costly conservation (e.g., as retrofits to the newly built facilities). In the case of new equipment such as appliances, all efficiency potential may be lost until the end of its useful life. (*Id.* at 9).

Transient opportunities represent rapidly vanishing resources because builders, businesses, and consumers are making essentially irreversible choices on a daily basis. The window of opportunity for influencing these decisions is quite short. For new commercial construction, this window may be a matter of weeks or months; for appliances, a utility's opportunity to acquire cost-effective savings may be limited to hours or at most days. The consequences of these decisions can last anywhere from a decade to a century.

Moreover, lost-opportunity resources are the most flexible demand-side resources available to utilities. They tend to correlate with demand growth since rapid demand tends to correspond to construction booms and facility expansion. Unlike any other option available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.

Utilities should concentrate on capturing lost opportunities that arise in the marketplace due to inaction by customers or those acting on customers' behalf. Utilities should also make every

[38]The benefits per annual kWh saved from a conservation measure will depend on the shape of the load effects, as well as the number of years the measure will persist.

effort to avoid creating lost-opportunities by their own incomplete action -- for example, efficiency programs that capture only the easiest and cheapest savings potential.

The priority status of capability-building and transient opportunities has been widely recognized. The Northwest Power Planning Council first urged the Bonneville Power Administration and the region's utilities and regulators to pursue capability-building strategies and lost-opportunities in its 1983 Plan. Its 1986 plan reaffirmed this recommendation, in spite of a large capacity surplus. (1986 Northwest Plan, *op. cit.,* at 9-28 through 9-30). In Vermont, the Public Service Board and the utilities it regulates are making capability-building and lost-opportunity resources their top priorities.[39] The Idaho Public Utilities Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan" and a "Capability-building Plan." (See Order No. 22299, Case No. U-1500-165, January 27, 1989). The Wisconsin PSC also declared that utilities should not let such valuable yet transitory efficiency opportunities escape:

> The importance of improving the energy efficiency of commercial buildings as soon as possible must be emphasized. These buildings represent long-term investments (up to 70 years) which will significantly affect the use of energy once they are constructed. Retrofitting to achieve energy efficiency, as experience has shown, is usually expensive, if possible at all. Therefore the commission is not willing to allow these 'lost opportunities' for energy efficiency to continue unabated." (Fifth Advance Plan Order, *op. cit.*, at 33-34)

New England Electric and Northeast Utilities have adopted this same perspective in their demand-side programs, which they developed under unprecedented collaborative design processes spearheaded by the Conservation Law Foundation.[40] Utilities in Massachusetts and Vermont are re-orienting their current demand-side strategies toward capability-building and lost-opportunity resources.

5. DSM Measurement and Verification

Measurement and verification (often referred to as "monitoring and evaluation," which is easily confused with the economic evaluation of measures and programs, or the evaluation of the overall program design) are absolutely vital to integration of DSM into utility planning. When a utility builds a power plant, it makes provisions for determining whether the plant is fully operational (e.g., by defining an "acceptance run" or defining "commercial operation" in terms of consecutive hours at a specified load level); for determining the cost of the plant; and for monitoring heat rate, emissions, generation, availability, equivalent availability, forced outage rates, operating costs and so on. If these data were not available for operating plants (for example, for atmospheric fluidized bed coal plants), utilities would have great difficulty in determining the economics of new generation options, or even the cost-effectiveness of maintaining existing units.

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[39] PSB Docket 5270, Vol. III, at 58-59, 92-102.

[40] See "Power by Design: A New Approach to Investing in Energy Efficiency," submitted to the Massachusetts DPU by CLF on behalf of NEES, September, 1989; CL&P Conservation and Load Management Program Plans, Filed in response to DPUC Order No. 3, Docket No. 87-07-01.

Similarly, utilities must determine how well their DSM programs are functioning. M&V is important in determining whether programs, measures and incremental program enhancements are cost-effective; for ensuring that the services are delivered effectively and efficiently; for improving program design and delivery; and for determining the effect of the current and projected program effort on loads, costs and supply requirements.

These reviews should cover process, progress, quality, and impact. Process evaluation determines whether the delivery mechanisms are functioning smoothly, whether decision-making processes are clear and appropriate, and whether the participants in the process (customers, contractors, trade allies and utility staff) understand their roles and are comfortable with the program. Progress verification determines the number of units (buildings, square feet, etc.) treated or affected by the program, the number of units (e.g., lamps, water-heater wraps) installed, the number of customers in the program (waiting for service, in treatment, and treated), the amount of money spent, and the number of rebates delivered. Quality assurance includes a technical review of the work actually performed (e.g., was the right type of pipe insulation installed on the right pipes, and was it taped properly), as well as the choice of measures (e.g., was the installation of 34W tubes and electro-magnetic ballasts the best option, or should this customer have received T8 lamps, dimmable ballasts, and reflectors). Impact measurement estimates the actual effect of DSM on kWh sales, load shapes and customer costs.

The techniques appropriate for these applications differ, although they all will rely to some extent on review of program records. Process evaluation will tend to use visits to participant, utility, and contractor facilities while services are being provided; interviews; and review of printed materials used in marketing and carrying out the program. Progress evaluation will require visits to previously treated sites and some interviews with participating customers to determine what was actually done. Quality assurance will require more detailed inspection of work, and of the decision to implement (or not implement) particular measures. Impact evaluation is the most complex, usually requiring a mix of billing record analysis,[41] end-use metering, specialized customer metering (to determine load shape effects), and some combination of direct observation and interviews to determine use patterns (e.g., how many hours a day are these lights on, and does anyone turn them off during lunch hour).

All of these processes will rely heavily on sampling. Not every participant will be interviewed for process evaluation, receive an on-site inspection for progress verification and quality assurance, or be metered for impact measurement. All reported installations must be added up for progress verification, but only a small fraction need to be verified. Similarly, in some programs, all participating customer bills may be reviewed for sales reductions, but only a small percentage will require end-use metering or detailed statistical analysis.

Any sampling effort can be pursued at a wide range of statistical accuracies, depending on the size of the sample. The optimal size of the sample is determined by the tradeoff between the

[41]These analyses are typically both time series, comparing the consumption of treated customers to their pre-treatment energy usage, and cross sections, comparing treated customers to control customers. For some programs, especially those that change entire markets, control groups may be difficult to identify in the utility's service territory; the best control group may be customers of a nearby utility without a comparable program.

cost of the data and its value in affecting decisions.[42] The appropriate balance between precision and cost will differ with program type, stage of development, and measurement purpose.

For example, if preliminary analysis suggests that the benefit/cost ratio of typical installations in a program is quite high (e.g., 3:1), additional expense to refine the impact analysis may not be very useful. The effort might be better directed to determining the cost-effectiveness of marginal applications (e.g., in a commercial chilling equipment replacement program, the cost-effectiveness questions may focus on smaller customers, or low-load-factor and off-peak applications), or to ensuring that the baseline efficiency implied by the impact analysis is reflected in the base load forecast. If a program appears to be uneconomic due to high levels of free ridership (e.g., customers who would have taken the action without utility intervention), the load forecast should reflect that market-driven efficiency improvement.

Preliminary analyses may also identify the critical issues in program cost-effectiveness, design and impact. For one program or measure, the critical variable may be free ridership; for another, average energy savings; for another, the load shape of savings; and so on. Additional impact analysis should be targeted to resolve the most important issues, rather than achieving fixed sample sizes or levels of statistical confidence.

Measurement and verification is a vital part of DSM implementation, and should be planned into programs from their inception. However, the M&V function should not be allowed to interfere with the development and delivery of programs. More M&V is always possible, especially on the impact issues; the costs of higher accuracy include both direct financial expenditures for data collection and analysis, and the delay due to the collection and analysis efforts. DSM implementation should proceed with the best available data, especially in capturing transient opportunities and building capability.

6. DSM Program Evaluation Criteria

A number of criteria need to be considered in evaluating the quality of the utilities' DSM plans. This is distinct from the evaluation of programs to be included in the plans. In addition to those listed by the IURC in the Statement of Issues, other important evaluation criteria include the quality of the utility's effort to build and maintain delivery capability and the extent to which the utility pursues lost-opportunity resources.

a. Comprehensiveness

In addition to the meanings listed in the Statement of Issues, utilities should aim for comprehensive penetration and participation, and the comprehensive utilization of the potential efficiency resource (i.e., avoid cream-skimming).

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[42] There will also be affects from the mere existence of the M&V program. Quality assurance may also be useful in encouraging high-quality work by contractors who know they will be reviewed. Similarly, process review may encourage more cooperative attitudes on the part of staff and contractors, and progress review will encourage honesty on the part of all reporting parties.

"Comprehensiveness" implies achieving all cost-effective efficiency improvements, for each customer involved in a program and addressing all customers and all market segments. The Vermont PSB's Decision in Docket 5270 provides the following definition:

> Utility demand-side investments should be comprehensive in terms of the customer audiences they target, the end-uses and technologies they treat, and the technical and financial assistance they provide. Comprehensive strategies for reducing or eliminating market obstacles to least-cost efficiency savings typically include the following elements: (1) aggressive, individualized marketing to secure customer interest and participation; (2) flexible financial incentives to shoulder part or all of the direct customer costs of the measures; (3) technical assistance and quality control to guide equipment selection, installation, and operation; and (4) careful integration with the market infrastructure, including trade allies, equipment suppliers, building codes and lenders. Together, these steps lower the customer's efficiency markup by squarely addressing the factors that contribute to it. (Vol. III, at 44)

DSM analyses often examine individual measures, or small bundles, rather than the total opportunities for improving the efficiency of a customer. The comprehensive approach delivers all the efficiency services that are economical as a package; the single cost of getting an installer to the house is spread across a large number of measures, and no potential cost-effective savings are left "on the table."

For example, residential water-heater control programs are often completely isolated from other water-heating measures, let alone measures for other end-uses. Before a utility installs a time clock on an electric water heater, it should determine whether that control is more beneficial than alternatives, such as converting the customer to a gas water heater, installing a water-heating heat pump, or improving efficiency. While an installer is on the premises, the utility should ensure that the water heater and pipes are wrapped, and that efficient showerheads and faucet aerators are installed. With little additional cost, the same installer can screw in a few compact fluorescent light bulbs.[43]

Utilities should invest in as much savings from customers as they can for less than the avoided costs of supplying power. Comprehensive investment strategies will obtain the optimum amount of least-cost efficiency resources.

Comprehensive purchases of efficiency savings is a markedly different proposition from selling or marketing conservation measures. As the Vermont PSB found, the latter tends to concentrate on individual technologies. It often leads utilities to fragmented and passive efforts to convince customers to adopt individual measures that marketing research indicates they are most likely to want and accept. Another frequent error is to seek only the least expensive DSM savings. Such a strategy may tend to overlook more costly savings that are still less expensive than utility avoided costs. Both alternatives, while intuitively attractive at face value, could well lead utilities to acquire more than the least-cost quantity of supply resources. The Vermont PSB observed:

[43]To further reduce costs, the same installer can install toilet dams for the water utility and minor heating conservation measures for the gas utility, allowing the fixed cost of the visit to be split three ways.

> The distinction between selling efficiency as a customer service and buying efficiency from end-users as a utility resource is more than a matter of semantics. The purchasing paradigm motivates utilities to pursue all cost-effective efficiency potential once each customer is contacted. The efficiency resource must, in essence, be viewed as a power plant which is engineered directly by the utility and whose full costs must be paid if it is cheaper than other means of satisfying the utility's service obligation. The measures and technologies themselves are merely tools for maximizing the productive yield from utility investments in those efficiency resources. (*Vermont PSB Docket 5270,* Vol. III, at 42-43).

Treating each customer as a potential electricity resource has important implications for DSM program design and implementation. One implication is that utilities should assess and access efficiency potential customer by customer, not end-use by end-use. Otherwise, utilities would have to re-visit their customers many times over to tap all available cost-effective efficiency savings. In the end, less of the efficiency resource would be recovered at higher costs than if the utility extracted all the efficiency potential one customer at a time.

Addressing technologies and end-uses comprehensively among customers avoids two common mistakes in utility efficiency programs: failing to account for interactions between technologies and end-uses; and "cream-skimming" -- neglecting measures that would be cost-effective at the time other measures are installed, but whose savings would not justify the administrative, diagnostic, and other overhead costs of a "re-retrofit" later. Absolute potential savings from remaining measures generally decrease as more measures are applied to an end use. However, unit costs of saved energy are likely to be significantly higher if individual measures are engineered, delivered, and installed singly and administered under separate programs.

In addition to their efficiency benefits, comprehensive strategies are necessary to overcome market barriers to customer efficiency investment. Addressing market barriers individually might be appropriate if market barriers operated in isolation. Unfortunately, this is typically not the case for groups of customers. It is the *multiplicity* of strong and *mutually reinforcing* market barriers that explains the pervasiveness of the payback gap among utility customers. Individual customers may decline particular cost-effective efficiency measures for one reason or another; but chances are that a variety of barriers explains why any given group of consumers does not tap economically feasible efficiency potential. Short of customizing a different program for every customer, utilities need to design programs that address the full array of obstacles preventing least-cost customer efficiency investments. (See Vermont PSB 5270 at 45).

Low-income households offer a classic example of how market barriers can interact to retard efficiency investment. Low-income households have virtually no access to capital on any terms. Residents are often renters, and thus have little motivation to invest in efficiency even if they had the means. Even if they had access to enough capital to finance efficiency investments and the incentive to invest it, poor people are unlikely to take any avoidable risks with their scarce capital. Finally, low-income people may be limited in their ability to obtain and act on the information needed to choose among efficiency options, including technical data on expected costs and savings, information on equipment choice and design, and evaluation of contractors and suppliers. Loans, information programs and rebates are likely to fail as incentives for these customers. Only comprehensive direct delivery of services (information, financing, procurement, contractor management) is likely to achieve the cost-effective efficiency potential.

b. Program Costs

Program costs are often thought of as a parameter to be minimized. However, national experience indicates strongly that small program costs imply small program efforts, and hence small program effects. Instead of attempting to minimize program costs, utilities should be endeavoring to identify and achieve all cost-effective DSM opportunities. Utilities should also be using the dollars they spend as effectively as possible.

The economic potential for efficiency savings in a utility service area depends on the costs and performance of different technologies for providing energy services to its customers, and the extent to which customers will adopt them. As discussed, there is strong evidence that market barriers prevent customers from investing in efficiency measures unless they are extremely profitable. In determining how much Indiana utilities might cost-effectively spend on DSM, it is informative to review the commitments and plans of specific utilities which have taken DSM seriously as a resource.

Most of the utilities with aggressive conservation plans are located in New England, California or Wisconsin. The plans of New England and Wisconsin utilities are shown in Table 6a. The most interesting columns in Table 6a are columns [4], [6], [8], and [9]. Column [4] expresses each utility's conservation expenditures as a percentage of its projected revenues at the program midpoint. This figure ranges between 1.8% for United Illuminating (UI) and 6.4% for the program proposed for Central Vermont Public Service (CVPS), with an average of 3.6%.

Column [6] expresses the total energy saved in the last year of the program as a percentage of projected sales for that year. UI saves 1.2% of its projected MWh sales at the end of its three-year program. The plan proposed for CVPS saves 14.3% of sales after ten years; overall the plans average 5.5% in savings from projected sales.

Note that because the savings in the last year of the program include the effects of all the conservation measures installed in the course of the program, longer programs will tend to show more impressive results.

Similarly, column [8] shows the MW saved in the last year of each utility's conservation program, expressed as a percentage of projected peak load for that year. The percentages range from 1.6% for Wisconsin Electric (WEPCo) to 18.3% for New England Electric (NEES).[44] WEPCo's figure is low because it represents the results of only a two-year program. Savings are equivalent to about 0.5% to 1.2% of sales per program year.

The ongoing efforts of the major California utilities are summarized in Table 7, which summarizes projected 1990-91 conservation expenditures and savings. The utility expenditures and savings were taken from the January 1990 Report of the Statewide Collaborative Program, An Energy Blueprint for California. Utility revenues and sales are from the Energy Information Administration's Financial Statistics of Selected Electric Utilities, 1987.

[44] NEES filed more aggressive programs in Massachusetts in October 1990.

The table gives figures for Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). The first column represents each utility's spending on conservation programs in 1990 and 1991 in nominal dollars.

Column [2] expresses annual conservation expenditures as a percentage of 1987 ultimate consumer revenues. Column [3] lists the incremental MWh saved in each year. Column [4] expresses those savings as a percentage of 1987 ultimate consumer sales.[45]

Not covered in this table is the extremely ambitious efficiency investment campaign recently announced by the Sacramento Municipal Utility District (SMUD). According to the July 1990 plan, SMUD intends to build the equivalent of a 600 MW power plant through efficiency investments over the next ten years.[46]

These summaries indicate that utilities making a concerted effort to tap all cost-effective DSM potential have identified demand-side resources sufficient to reduce annual anticipated sales growth by about 1%. To obtain such savings, these utilities are spending in the range of 3% to 5% of their annual operating revenues on conservation and load management programs.

Based on this national experience, it seems likely that Indiana utilities will find that gradually ramping up DSM spending to 3 to 5% of annual revenues will be cost-effective. The ramp-up rate will be constrained by the time required for building capability; in addition, the full-scale retrofit programs currently pursued by some other utilities may not be cost-effective in Indiana until the market for baseload energy becomes tighter. On the other hand, the low electric rates in Indiana suggest that Indiana customers have less efficient equipment than do those in New England and California, so DSM potential may be greater here. Those same low rates also result in a fixed share of annual revenues (e.g., 4%) being a smaller absolute expenditure for an Indiana utility than for a coastal utility with high rates.

c. Program Design and Implementation

The quality of program design and implementation is as important as the total DSM budget. While utilities are unlikely to achieve a large fraction of the cost-effective DSM potential without spending significant amounts of money, they are also unlikely to achieve much unless the money is well spent. Specifically, DSM programs should be designed to overcome the market barriers that create the opportunity and need for utility DSM investment. They should be comprehensive, increase both the internal capability of the utility and the general capability of the region to implement DSM, and capture lost opportunities.

[45] Both PG&E and SDG&E have both gas and electricity conservation programs. The Blueprint provided PG&E expenditures specifically for electricity conservation. SDG&E expenditures appeared to only include only the costs of the electricity conservation program, and no gas conservation costs, but this was less clear than for PG&E.

[46] SMUD 1990, p. 1.

Reviewing design and implementation is not easy. The task is simplified somewhat by collaborations between utilities, consumer advocates, environmental advocates, and energy advocates. These collaboratives have been successful in New England, and are now underway in New York State and Maryland.

(1) Identifying and Overcoming Market Barriers

Some efforts to promote cost-effective efficiency investments have concentrated on pricing signals, such as combining rate design and rebates to approximate marginal cost. However, market barriers weaken price signals and leave a large potential for cost-effective utility investment in demand-side resources. The NARUC handbook sums up this relationship as follows:

> The short-payback requirements for efficiency investments usually result from different combinations of these factors [market barriers]. But the multitude of dynamics involved explains why the payback gap is not just found for particular end uses or particular customer groups, but is so universal. It also explains why consumer investment[s] in efficiency and load management are not governed solely or even mainly by an economically efficient response to prevailing prices. For these reasons, the redesign of utility rates alone, or any other strategy limited to the correction of prices only, is insufficient to mobilize the bulk of demand-side resources. Direct intervention is needed to strengthen market mechanisms and remove institutional and market barriers. (page II.15).

Customers may have many rational reasons for neglecting efficiency measures that are cost-effective for the utility. An aversion to capital-intensive electricity substitutes may be perfectly valid, especially since efficiency is paid for so much differently from electricity. The simplest reason that efficiency is so regularly passed over in favor of "business as usual" is that, as an investment, it is not available on the same pricing terms as electricity or fossil fuels already being purchased by customers. If it were -- either through market innovation, utility market intervention, or both -- even short-payback customers would be much more likely to choose efficiency whenever it was priced below electricity. However, purchasing efficiency generally requires greater customer time and effort, and exposes the customer to more risk, than does purchasing electricity.

Other factors which compound the costs and dilute the benefits of efficiency measures to utility customers:[47]

1. *Limited access to relatively high-priced capital* can constrain payback periods to durations far shorter than the useful lives of the investments;

2. *Split incentives* between decision-makers (e.g., landlords, plumbers, architects, HVAC contractors) and bill-payers (e.g., tenants, or customers dependent on various professionals for specifying, purchasing, or designing their equipment) diminish the benefits the decision-making party receives from efficiency investments by conferring them on the bill-payer, while often leaving the decisionmaker with extra costs and/or risks;

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[47]See Vermont PSB 5270, Vol. II at pp. 54-57; Vol. III at 24-27. The NARUC handbook lists these and other market barriers at II-12 through II-14.

3. *Real and apparent risks* of various forms impede individual efficiency investments, particularly the illiquidity of conservation investments (financial risk); uncertainty over market valuation of efficiency (market risk); fear of "lemon" technologies, equipment, or installation (technological risk); the risk of additional time and effort requirements for resolving disputes and evaluating the quality of the installation; the possibility of regrets and recriminations; and

4. *Limited experience, access and information* regarding efficiency technology means suppliers and installers can create high search and evaluation costs, in terms of a customer's own time, effort and inconvenience.

Different market barriers require different program designs or features to overcome them. Limited access to capital obviously constrains efficiency investment, either because the customer is in no position to obtain capital to fund such commitments, or because the customer is unwilling to deplete his/her financial reserves to finance all economically justifiable efficiency investment.[48] Where capital can be borrowed to finance desired efficiency investments, borrowing terms are often far shorter than the life of the efficiency investment. The short amortization schedule pushes debt-service costs above the cashflow savings of the efficiency investment, creating cashflow problems.

For some customers, capital problems can be overcome by market-rate loans for energy efficiency. However, experience indicates that energy efficiency loan programs tend to have only limited success, for a number of reasons, including:

- the difficulty of many customers in obtaining loans under normal banking rules, due to lack of credit or collateral;

- the difficulty of many institutional and governmental customers in getting authorization to borrow money;[49]

- customer uncertainty as to whether bill reductions will balance the debt repayment;

- customer concern that the increased resale value of the building will not cover the outstanding debt; and

- most importantly, the failure to reduce the other market barriers.

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[48]Lenders often fail to appreciate the value of efficiency, either as an increase in their security value in the building, or as an improvement in the borrower's ability to repay other debts. This market barrier is partially an institutional problem, and partially a further consequence of inadequate information.

[49]They may also have problems getting approval to spend operating funds (appropriated for utility bills) on capital improvements (reducing utility bills), and may have to go through very complex bidding arrangements for even minor capital improvements. Combined with serious split incentives (government building managers and their department may not get to keep any of the reduction in utility costs for other purposes), these barriers make governmental and institutional facilities very difficult to motivate with conventional incentives.

The inadequacy of loan programs to produce all cost-effective efficiency savings is obvious, given the fact that most customers can afford much higher efficiency than they actually buy in end uses such as refrigerators and lighting, where incremental capital requirements are small.

Split incentives are notoriously difficult to overcome. Many property owners do not pay the utility bills of the buildings they lease. Many building occupants do not own the buildings for which they pay utility bills. Making investments to lower the operating costs of tenants is rarely a high priority for landlords, just as spending money to raise property values (and therefore rents) is not terribly attractive to renters.

Equally serious institutional impediments retard efficiency investments at other stages of the real estate market. Developers do not pay to operate the appliances, heating and cooling systems, or lighting in the homes and offices they build. Quite often they see their objective as minimizing the completion costs of their buildings. Engineers and architects may incur higher uncompensated time requirements to design more efficient buildings or specify more efficient equipment; if an unusual design encounters problems (whether related to the efficiency measures or not), the designer may be subject to greater liability than if standard designs were followed. Similar concerns arise for plumbers (who select most replacement water heaters), lighting designers and electrical contractors (who collectively are responsible for most lighting design choices, other than those determined by architects) and HVAC contractors (who select most replacement heating and cooling equipment).

These split-incentive situations may require that the utility pay the entire incremental cost of the DSM measure (as in the tenant/landlord split), or all of the incremental design costs (as in the designer/owner splits). Many utilities provide independent efficiency design services. The utility may also need to provide some certification procedure (to bless the non-standard designs and improve marketing prospects for participating designers and builders) and some training.

Energy efficiency investments expose individual consumers to a variety of real risks. Any retrofit project (for efficiency or for other purposes) can have higher-than-expected costs, or operate less effectively than expected. Unusual designs may not always work quite right, especially when they are first put into service. For each customer, this risk is not diversifiable; even if the chance of a major problem is only 1:100, the customer may risk financial disaster by investing in efficiency. For example, if 100 residential customers are offered the opportunity to invest $3000 apiece in ground-coupled heat pumps, with a 99% probability of bill savings worth $6,000 in present value and a 1% probability of no savings (and thus a $3000 net loss), they might all decide that the risk of being the unlucky one was an unacceptable risk. The utility can reduce this risk through *diversification* in its demand-side resource portfolio. If the utility invests in all 100 heat pumps, and one saves no energy, the utility's net benefit is not significantly reduced.

Utilities can also reduce risk by providing various design, procurement, delivery, review and maintenance services to ensure that equipment is properly selected, installed and used. However, the assumption and diversification of risky investments by the utility is probably the most effective tool for reducing the risk-related barriers to efficiency investments.

Lack of information about efficiency options can create significant market barriers to efficiency investments, where acquiring and critically evaluating information on the costs and performance of competing efficiency options is expensive in time and money. That effort can be prohibitive for new technologies for all but the largest and most sophisticated end-users. Consumers often have a difficult time finding high-efficiency equipment they can examine and see in operation. Seeing a photograph of a light bulb in a catalog tells the potential purchaser little about whether it will fit in his/her fixtures, how it will look, whether it will hum, and how the light it emits will look. Only seeing, handling and turning on the bulb (and ultimately taking it home) will answer these questions. This leads to a vicious circle, in which suppliers tend not to carry more expensive, high-efficiency equipment if customers do not ask for it, and customers do not order the equipment because it is not available.[50]

If left to their own devices, consumers not only need to understand individual technologies; they need to know how measures interact. Energy savings from combining some measures (e.g., lighting efficiency and cooling systems) are less than the sum of their individual energy savings, but one measure may reduce the cost of another (e.g. lighting efficiency improvements may allow for the downsizing of chillers). More importantly, customers need to be able to select and to supervise providers, designers, and installers. Unless they know someone who has undertaken a similar project, the choice of providers may be formidable.

Loans and rebates are apt to be of very little value in inducing customers to undertake efficiency measures they do not understand, to purchase products they cannot find, or to seek out specialists whose work they cannot assess. Utilities will be able to overcome these barriers only with strong measures, including direct delivery of services, creation of markets for efficient products, and building the capability of local business to deliver efficiency equipment and services.

Providing customers with more information about efficiency opportunities is necessary but not sufficient for fully realizing economical efficiency potential. Utility experience confirms that *reinforcing information* with aggressive marketing, financial incentives and installation assistance yields increased savings at lower program costs. This point is well illustrated by the utility experience with the Residential Conservation Service (RCS). Throughout the U.S., utilities spent millions of dollars on programs to provide energy audits to their customers between 1981 and 1986. But relatively few utilities did much to help customers *act* on this information. Consequently, few customers participated in the audit programs, and even fewer participants installed the costly but ultimately cost-effective measures recommended by the audits. Costs were high and savings were low in a program that most observers agree yielded disappointing results.[51]

At the opposite extreme of the RCS program was Bonneville Power Administration's Hood River Conservation Project. This program sought to establish the outer limits of cost-effectiveness by deliberately installing as many measures as possible in as many homes as possible, including

[50] Special orders also tend to be more expensive; once the efficient equipment is stocked normally, its price is likely to fall, and customers are more likely to accept it.

[51] See Update of the Evaluation of the Residential Conservation Service Program, Centaur Associates, September 1986.

those previously treated under previous utility weatherization programs. The result was 90% participation and large savings.[52]

To summarize, overcoming market barriers will require careful program design. For many market sectors, utilities should offer direct design and/or installation services. For example, a residential heating retrofit program should provide for an audit, selection of cost-effective measures, and installation with as little demand on customer time as possible. To the extent that the utility designs, arranges, finances, oversees and warranties the work, the customer avoids most of the hassle factors that complicate any major home improvement. This is particularly important for residential and small commercial customers, and may also be significant for larger customers in some segments.

In other cases, the utility may need to change the way that products and services are priced and delivered in its service territory. Offering incentives to appliance dealers, heating contractors, plumbers (for water-heater replacement), and lighting dealers may be more effective than offering rebates to customers. For lighting, the utility may need to get compact fluorescents into homes through direct delivery or discount mail order (so that customers gain some experience with them) and also get them onto store shelves (so that customers can buy them). Information, loans and rebates may be appropriate as part of some programs, but they are often only part of the best solution, and are sometimes totally inappropriate.

(2) Building Capability

In order to be effective, DSM programs must increase the capabilities of the utilities, which includes in-house understanding and adoption of:

- new and rapidly advancing technologies;
- marketing methods, incentive structures and program delivery for different types of customers and efficiency measures;
- reliable measurement and evaluation techniques; and
- management strategies that accommodate rapid feedback to allow mid-course correction.

Most of all, it is essential that utilities improve the efficiency-delivering ability of the existing market infrastructure: the vendors, installers, engineers and architects who need familiarity and confidence with energy-efficient equipment to specify and supply it. This transformation of the market infrastructure is critical to overcome a number of the barriers to efficiency investment, including perceptions of risk, lack of information, split incentives and the non-financial cost of time and hassle in locating non-standard equipment.

[52]See "Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," 1987, pp. 15-20.

Utility demand-side programs can create the necessary demand for efficient products. For example, Low-E windows were available only on special order in the Pacific Northwest and Connecticut prior to large-scale utility programs. Now they have become a stock item in these areas. Similarly, the regional availability of energy-saving electronic ballasts and triphosphor lamps tends to coincide with aggressive utility lighting programs.

d. Economic Assessment

The terms of economic assessment of DSM should be prescribed by the IURC. Utilities should not be using different tests for screening measures and programs from those prescribed by the IURC, which should be maximization of total net benefits under the societal/all-ratepayers test. Any decision not to pursue any apparently cost-effective measure or program should be fully documented.

Any willful refusal to comply with the IURC's IRP rules should be dealt with firmly.

IV. RESOURCE BIDDING

1. Role of Resource Bidding

a. Supply vs. All-Source Bidding

Resource bidding may be an important part of integrated least-cost planning. Supply bidding has become well established in a number of states. In principle, demand-side resources could also be obtained in the same process as supply-side bidding, or in a parallel process. Indeed, a few states have started to explore this option, although responses have been modest compared to the supply-side bidding response. Typically, an energy service company (ESCO) will submit a bid to provide a particular number of MW and MWh from a group of customers, for a specified rate per kW and/or per kWh. Alternatively, a large customer may provide a similar bid for its own facilities. A number of problems arise with demand-side bidding, including cream-skimming, lost opportunities, failure to bundle and loss of information.[53] Cream-skimming, in this sense, refers to the implementation of only the lowest-cost measures, in cents/kWh or $/kW, rather than all cost-effective DSM.

Figure 1 depicts the promise of competitive acquisition of demand-side resources and highlights potential pitfalls of relying exclusively on DSM bidding. The same market forces that help create ratepayer benefits act to retard them. While the utility pays the bidder for the savings (Q1) achievable at the bid price (PB), the optimal level of DSM investment would produce greater total savings (Q2). In short, the more competitive the ESCO's bid, the lower the bid price, the greater the difference between the DSM which is cost-effective for the utility and for the ESCO, and the greater the tendency toward cream-skimming.

The competitive nature of the bidding process creates the inherent tendency for cream-skimming. To win, bidders must compete on price (i.e., offer a low fraction of utility avoided costs, CS). Profit maximization prevents successful bidders from pursuing efficiency potential beyond Q1. Any additional investment on their part would lose money, since the CE curve is above PB beyond that point. Without competitive pressures to reduce bid prices, a bidder could theoretically offer to acquire the full Q2 amount of demand savings at a price of CS. At that point, society is better off; however, all ratepayer benefits would be handed over to the DSM bidders (areas A, B, and E beneath the CS line and above the CE curve).

Limited experience bears out some of the charges against DSM bidding. In a rare side-by-side comparison of performance contracting with direct utility investment, Hicks reports that DSM bidding yielded less savings at higher costs.[54] Goldman and Wolcott found that lighting

[53] The following discussion is adapted from Chernick, Plunkett, and Wallach entitled *Demand-Side Bidding: Is It Economically Viable*, Seventh NARUC Biennial Regulatory Information Conference, Columbus, OH, September 1990.

[54] Hicks, Elizabeth, "Third Party Contracting Versus Customer Programs for Industrial/Commercial Customers," Proceedings on Energy Program Evaluation: Conservation and Resource Management. Chicago: August 1989.

retrofits, often the easiest and cheapest savings, account for 60-75% of third-party energy savings. This lends credence to the accusation of cream-skiming.[55]

Cream skimming becomes a serious problem if it pre-empts otherwise cost-effective demand-side resources. This results if demand from Q1 to Q2 is met with new supply because the opportunity is lost to install efficiency measures costing more than PB, yet which are still less expensive than avoided system costs (CS). The utility may be able to pick up where the bidder left off at Q1. Changing horses mid-stream in this way may be infeasible or inefficient in practice. If the former, the loss to ratepayers and society is the area E. If the latter, then the loss would be somewhat less than area E, as discussed below. Unfortunately, the bidding system tends to maximize lost opportunities: as competitive forces drive down PB, the amount of foregone demand savings increases.

The extent of lost opportunities depends on the cost of coming back for Q2 - Q1. If a utility can revisit the facility for the same cost as installing it originally, then this loss can be minimized or avoided entirely. Another solution might be to induce the performance contractor to undertake the additional measures at its own cost, while preserving the competitive incentive.

On the other hand, it is becoming increasingly clear that substantial economies can be realized from bundling measures in comprehensive investment. Nowhere are such advantages more prevalent than in new construction. The Vermont Public Service Board characterized the advantages by distinguishing between a utility investment strategy that targeted each end-use and measure individually across all customers, and an investment done building by building across all possible end-uses and measures in each building. The piecemeal approach would lead to multiple programs for each customer, raising costs and reducing savings. Such diseconomies resemble the traditional case against having more than one utility control the distribution of retail power. Just as two sets of poles and wire would needlessly raise cost, so would having multiple programs repeatedly treat customers' efficiency potential. We could represent the added costs of follow-up treatment with two separate supply curves for energy efficiency which would sum to a new, steeper supply curve in Figure 1.

Consequently, opportunities may be lost by demand-side bidding even if a utility program exists to provide demand savings from Q1 to Q2. The utility's optimal strategy during one site visit is to install all measures with incremental costs less than the marginal supply cost. An ESCO, on the other hand, will install only those measures with costs less than or equal to the fixed payment to the bidder during that visit. Thus, for the utility to pick up where an ESCO leaves off and attain the optimal level of investment, it will have to undertake effort that either duplicates work already done during the initial visit or could have been done at a lower incremental cost during the original site visit. Such activities include customer identification and marketing, travel, diagnosis, preparing specifications, installation management and possibly monitoring, measurement and evaluation. The need for additional time, thought and effort by the customer should not be ignored in figuring added costs for a second site visit.

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[55] Goldman, C.A. and D.R. Wolcott, "Demand-Side Bidding: Assessing Current Experience," Proceedings of the ACEEE 1990 Summer Study on Energy Efficiency in Buildings. September 1990.

This additional fixed cost burden translates into a utility efficiency supply curve that is shifted to the left of CE in Figure 1. As a result, investing in efficiency measures up to CS will no longer yield savings of Q2; the intersection of the efficiency curve with CS will now lie to the left of Q2. Thus, the opportunity to acquire the full Q2 of demand savings will have been lost and the difference will have to be covered with new supply.

In addition, even if the repeat visit appears to be cost-effective to the utility, the customer may be unwilling to accept further disruption of his/her home life or business. Thus, the sheer number of visits may contribute to the loss of opportunities.

While it is difficult to represent in Figure 1, the loss of information may be a serious cost of demand-side bidding. One of the greatest needs in DSM at this time is additional information about customer interaction, delivery mechanisms, marketing, frequency of measure applicability, and so on. The competitive environment of demand-side bidding transforms the public good of information to a valuable private commodity. The ESCOs will resist sharing their information and skills with the utility, let alone one another.

There may be some specialized roles for demand-side bidding. For example, the Wisconsin PSC has used competition from other DSM providers to inspire greater dedication to DSM on the part of Madison Gas & Electric. Several utilities have programs in which large customers can design and "bid in" site-specific combinations of measures that may not be covered by specific utility programs. This approach is especially likely to be useful for industrial process end-uses. Some form of bidding or public review may also be useful if the utility is not receptive to including DSM options from particular vendors. Electric utilities may not be open to purchasing DSM services from traditional rivals or threats, such as solar water heater manufacturers, gas utilities, and cogeneration developers. However, DSM generally appears to be more appropriately pursued as a utility function, with contractors bidding to provide services which are largely specified by the utility.

b. Relating Demand-Side Criteria to Supply-Side Criteria

Whether in a bidding process or otherwise, the comparison of demand and supply projects should be as transparent and reviewable as is feasible.

c. IRP as Prerequisite to Bidding

In principle, IRP should be a prerequisite to *any* new supply. It is not clear that this is more true for bidding than for utility construction, or for negotiated purchases without bidding. In any case, the IURC certainly should not encourage utilities who are leary of bidding to stall on IRP (and hence on DSM) to avoid bidding.

While IRP should proceed as quickly as possible, fully-developed IRP is not an absolute prerequisite to competitive bidding. Over a dozen utilities, including Virginia Power, Central Maine Power, Boston Edison, Puget Sound Power & Light, and Orange & Rockland Utilities (NY State), have implemented successful bid solicitations without their utility commissions having accepted integrated least-cost plans. It will take considerable time to draft and impose statewide IRP guidelines, for utilities to develop their first IRPs, and for the Commission to review them. This time can be used to develop bidding mechanisms for obtaining cost-effective resources from IPPs.

2. Bidding and the IURC

Experience with other utilities indicates that the IURC should carefully control the bidding process. Utility bidding proposals tend to be arbitrary and are often biased against QFs or against certain categories of QFs. Depending on the utility, those biases may be against unfamiliar or small plants, which require utility staff to deal with generation sources unlike the utility's own plant; against large plants, which would significantly reduce the utility's need to build its own plants; in favor of exotic, unlikely or limited options;[56] against technologies which could be used to reduce purchases from the utility (especially small packaged cogeneration); or any of a number of other concerns.

The weighting and evaluation of non-price factors, the length of time over which the contract is evaluated, and the avoided costs used by the utility, can all reduce the amount of viable QF capacity, or distort choices among QF alternatives.

However, it may not be appropriate for the IURC to help draft bid solicitations or select the award group. Rather, the Commission's role might be to issue guidelines for utility bidding, covering the types of costs to be included, the economic evaluation to be used, and the transparency of non-price factor ratings. The IURC would then approve the bid package prior to issuance, and review and approve the resulting contracts. While the Commission would not be responsible for actively certifying consistency among the bid package, the winning bids, and the utility's IRP, it would adjudicate complaints from the UCC, potential bidders, and other parties on these issues. It may also be appropriate for the Commission to review Indiana utility activities with bid solicitation at some future point to monitor compliance with Commission guidelines and recommend improvements.

3. Avoided-Cost Ratemaking

This is a complicated issue, with many tradeoffs. Limiting utility cost-recovery for their own new resources to their avoided cost projections has some advantages. These cost recovery limits give utilities incentives to build and operate their plants efficiently.[57] This approach also

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[56]For example, Boston Edison has a history of selecting such QFs as those fired by such exotic fuels (by New England standards) as peat, anthracite culm or petroleum coke, or large unsited coal-fired cogenerators, which are unlikely to find environmentally acceptable sites or steam hosts. In at least one case, BECo cancelled a contract just as the QF obtained its critical permits and was prepared to start construction. As a result, few of the QFs which BECo has selected have reached operation, what has been completed is not likely to be replicated, and most of its projected QF additions are unlikely to enter service.

[57]Operations would tend to be efficient in reducing O&M costs, reducing fuel cost, reducing heat rates, and increasing availability.

discourages the utility from understating generation-level avoided costs, since these will be applied to QFs, to DSM, and to the utility's own projects.[58]

Avoided-cost ratemaking also has several disadvantages. The prospect of being constrained to a regulated return if a project is successful,[59] but being limited to avoided cost if the project is problematic, can make utilities reluctant supply builders of last resort. What capacity they do build is likely to be low-risk conventional peaking capacity. Ratepayers would lose the opportunity of having a utility seeking out innovative, possibly risky, but ultimately cost-effective generation options to reduce ratepayer costs. The utilities, like the QF developers, will be concerned with maximizing their profits, not with minimizing ratepayer costs.

To reduce the cost of under-collecting for new generation, a utility operating under avoided-cost ratemaking may overestimate avoided costs. This will increase the likelihood that someone else will agree to provide new power supplies, and will also reduce the utility's risk if it is the builder. While the higher avoided costs will help QF developers, the utility may find other ways to discourage QF develpment, so as to capture the high avoided-cost rates for itself. Avoided-cost ratemaking may require greater scrutiny of the utility's behavior in cost forecasting, in its dealings with QFs, and in its decisions regarding the maintenance of existing resources, which will affect the need for new resources.[60]

Other options exist, such as the use of a formula for sharing net costs or savings between shareholders and ratepayers. A sharing formula might recognize that utilities, unlike IPPs, cannot declare *force majeure* and disappear in the event of unforeseen problems, but must continue to provide service. However, it would still possess (in mitigated form) all of the disadvantages discussed above. The cost caps included in the Certificates of Need issued by the IURC operate in part like avoided-cost ratemaking, although the utility may be able to shift costs between initial construction, interim additions, and O&M to stay under the cap.[61]

Avoided-cost ratemaking represents a potentially radical change in planning and ratemaking in Indiana. The IURC might better expend the effort necessary to effectuate this change in implementing DSM programs and integrated planning. Once those elements are in place, and there has been greater experience with the cost caps, the IURC might want to revisit avoided-cost ratemaking.

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[58]Note that avoided cost for DSM will tend to include several cost items (e.g., losses, T&D, reserves, etc.) that are not included in supply-level avoided costs.

[59]This requirement may be relaxed in theory, but utilities often express doubt that they would be allowed to keep high returns if their avoided-cost projects were very successful.

[60]This is true regardless of whether the utility is trying to avoid building (and thus may be willing to make non-cost-effective ratebased investments in maintaining existing capacity) or to increase avoided costs for the capacity it is expecting to build (which might discourage cost-effective expenditures in O&M, life extension, and operating efficiency).

[61]The incentives imposed by the caps are complex. For example, cost-effective incremental investments in operating efficiency may be discouraged by the cost caps, since construction cost is capped, but not heat rate, O&M, or forced outage rate.

4. Type of Bidding Process

a. Second-price Auctions

Utility supply bidding programs generally use either a first-price auction, in which each winning bidder receives his bid price, or a second-price option, in which each winning bidder receives the price bidding by the lowest-cost losing bidder.[62] In either case, the winners are generally determined as the group that can provide power least expensively, up to some quantity the utility has established.

For any given set of bids, first-price auctions are less expensive for ratepayers. This approach is used by most of the utilities with bidding systems.

Second-price auctions, have the advantage of eliciting from each bidder a true minimum bid. Since the amount paid to winners is independent of their own bids, each bidder need merely determine the minimum price at which it will accept a contract. In the first-price auction, each bidder must trade off the minimum bid (with a higher probability of success) with a higher bid (with a a higher payoff if the bid is successful). Hence, bids will be lower for the second-price auction than for the first-price auction, so it is not clear whether total contract costs will be greater with the first-price or the second-price approach. In addition, the bids of the losing bidders will define a supply curve for additional supply, and the lowest-cost suppliers (with the highest probability of remaining financially viable) will be selected, rather than the best estimators of the market-clearing price. California has adopted the second-price auction, primarily due to the selection of low-cost providers, and the resulting improved probability of success.

b. Open and Closed Ranking Systems

Non-price attributes such as fuel source and diversity, environmental impact, dispatchability and location can be important to the utility and its customers and deserve strong consideration in bid evaluation. Open ranking systems, in which the weighting given to these criteria is specified in advance, have several advantages in considering these factors. First, the utility's ability to favor particular projects, including its own, is reduced. Second, open ranking increases the perception of fairness. Thrid, open ranking may encourage more bidders, since they can assess their probability of success before the expensive bid preparation process. Fourth, the bidders will tend to be those most able to meet the priorities of the IURC and utilities, as laid out in the ranking rules. Fifth, open ranking assists bidders in developing their proposals and in selecting tradeoffs (as between price, front-loading, and coverage ratios) that maximize the attractiveness of the bid to the utility. Sixth, open bidding is easier for the IURC to monitor and review.

The major advantage of closed bidding is the additional flexibility it gives the utility in selecting projects and sets of projects that best meet its needs. While most of the important

[62]Where externalities and non-price factors are included, these benefits are generally netted out of the bid price. To allow for comparisons between proposals with different start and end dates, the bids are often stated as a percentage of avoided costs.

considerations can be specified in advance in an open bidding system, other issues may arise in optimization of the project mix. For example, all of the winning bidders may be dependent on the completion of a single gas piepline or the interpretation of a single air-quality rule; all of the low bidders may expect to enter service one year after the utility expects to need capacity. While the bidding system may have adequately discounted each individual contract for its timing or uncertainty, the ranking rules may not be valid if all new supply shares the same disadvantage. In this situation, an inflexible open bidding system might require the utility to accept a set of bidders who are collectively a poor mix.

The IURC might best establish an open bidding system, with an explicit allowance for utility changes in the award group, to reflect system optimization and interaction between projects. The IURC should carefully review any departures from the bidding system, as it should carefully review the bidding system itself.

5. Allocation of Risks

It may be premature for the Commission to establish limits on the proportion of resource needs satisfied through power from IPPs and energy-service companies. We would explore whether this question could be taken up at some future time, especially if non-utility resources come to comprise a large portion of the resource plan of any Indiana utility. Utilities may be able to address this through the scoring system used in their bid selection criteria.

a. Project Viability

The issues raised here by the Commission are quite real. Projects the utility counts on that do not enter service, or are seriously delayed, can impose significant additional costs. Indicators of success, such as completion or commitments for design, financing, siting, and licensing; developer experience; and technological maturity can help the utility identify projects with high non-completion risks. The project developer is more likely to be aware of completion risks than is the utility; performance bonds or similar damage provisions will tend to encourage bidders to assess the probability of success for their projects. To encourage prompt admissions of serious difficulties, the portion of the deposit refunded should decline as the interval between contract award and project in-service date passes. These deposits should not be thought of as insurance against non-performance, for which they are apt to be too small, but as an incentive for realism on the part of developers.[63] A combination of the approaches noted by the Commission would thus be appropriate.

The weight given in bidding to indicators of success and to probability of success should be carefully reasoned and justified, if possible with quantitative analyses. Similarly, the size of any credits for large surety deposits should be tied to reasonable estimates of the benefits they provide.

[63]It is important to recall that when a utility undertakes construction of a new plant, the ratepayers receive no bond against the utility's failure to complete the plant, or to do so on time. Any additional costs to provide replacement power are generally borne by the ratepayers.

b. Front-loading and Ratepayer Risk

There is some risk to ratepayers that projects will enter service, only operate for a few years, receive payments above avoided cost in that period, and then become inoperable or uneconomic to operate. The same risk occurs for utility power plants; cost recovery for baseload plants is generally more front-loaded than are QF contracts. However, utilities do not shut down power plants simply because they cost more to operate than the utility expected when the plant was first planned. Thus, while the problem is not unique to non-utility power supply, the IURC should take reasonable steps to limit the risk.

Two basic approaches exist for limiting such risk. The first is analytical. Utilities can quantify the extent of frontloading and the finacial viability of the QF project with an appropriate fiancing modeling package, such as The Power Analyst. By modelling the QF's cash flow, the utility can determine whether reasonable future risks (such as increased fuel costs, a major capital requirement, or short-term availability problems) would render the plant uneconomical to operate late in its life. If this is the case, the utility should insist that the project's rates be redesigned, so that the rates are likely to continue covering the projects costs throughout the contract period.[64] This may require reducing rates in the short term; the effect of these changes on coverage ratios can also be studied with the Power Analyst or a similar tool. Rates can also be tied to fuel prices, producing the same expected cost, but with less financial default risk.

Attachment A is an application of The Power Analyst to modelling project viability.

The second approach is financial. The utility may require heavily front-loaded projects to maintain bonding, a letter of credit or similar assurance that the project will operate until its breakeven point, the time at which the present value of avoided costs equals the present value of contract payments. Bonding requirements should not exceed the difference between contract payments and projected avoided costs for the number of billing units for which the utility has actually paid as of a given date. The financial assurance need not cover potential future payments, and should not be expected to cover the difference between the contract price and actual avoided cost, which would not be known at the time the QF and its financial backer negotiated an agreement. Of course, in the event that avoided costs are much less than expected, utility plants may not be cost-effective, either. Even ensuring the coverage of 100% of the difference between contract payments and projected avoided costs is probably excessive, since this would provide much better insurance for non-utility plants than for utility plants. The IURC could either limit the required assurance to a fraction of the differential between rates and avoided costs, or make such assurance a voluntary factor, included in the ranking scheme with a weight that is appropriately derived and documented.

[64] Or at least until the front-loading has been paid off and the plant has become a net benefit to ratepayers.

c. Limits on Non-utility Generation

No general limits on non-utility generation appear to be appropriate. The utility should be realistic in assessing project probabilities of success. In addition, the utility should have contingency plans, for utility or non-utility supplies, and a diverse portfolio.

6. Measuring the Competitiveness of Bidding

The major competitiveness concern is the potential for self-dealing between utilities and utility affiliates. This is easily resolved by regulatory requirements. No affiliates of the purchasing utility should be allowed to bid. No bidders should be affiliates of utilities to whom the purchasing utility (or any affiliate) is offering capacity or other services.

As discussed above, there are reasonable concerns that particular utilities will tend to bias their competitive bidding in favor of particular types of generators.

7. Bidding and DSM Incentives

As discussed in Section III.1.a, most DSM should be obtained directly through the utility, rather than through bidding. DSM obtained through bidding should not be eligible for incentives; the utility has done nothing to earn an incentive. If incentives actually cause utilities to prefer their own DSM to DSM obtained through bidding, and they design and operate comprehensive, efficient programs, the failure to use third-party DSM services should not be missed. DSM obtained through bidding should be eligible for lost-revenue recovery.

It is unlikely that DSM incentives will create a significant utility bias against supply. Existing utility biases against DSM are quite strong, and most utilities have powerful internal advocates for power plant construction.

TABLE 1: 1988 POLLUTANT EMISSIONS FROM INDIANA UTILITIES

					Emissions (TPY)					Emissions (lb/kWh)				
Plant	Type	Generating Capacity (MW)	Heat Rate (Btu/kWh)	Net Generation (kWh)	SO2	NOx	CO	PM10	VOCs	SO2	NOx	CO	PM10	VOCs
IMPC Breed	Coal CSC [7]	496	10,168	1,675,507,000	50,168	11,989	194	944		0.0599	0.0143	0.0002	0.0011	
IMPC Rockport [5]	Coal CSC	1,300	10,180	5,945,955,000	22,098	12,809	1,116	624		0.0074	0.0043	0.0004	0.0002	
IMPC Tanners Creek	Coal CSC	1,100	10,049	3,974,945,000	53,924	21,465	452	915		0.0271	0.0108	0.0002	0.0005	
IP&L C.C. Perry (Section K) [4]	Coal CSC	35	29,003	NA	15,549	3,040	194	717						
IP&L Elmer W. Stout	Coal CSC	845	10,557	2,315,677,000	43,153	8,527	344	11,244		0.0373	0.0074	0.0003	0.0097	
	Oil CTU	75	19,757	1,749,000										
	Diesel IC	3	NA	123,000										
IP&L H.T. Pritchard [4]	Coal CSC	367	[2]	689,286,000	14,915	3,708	194	847		0.0433	0.0108	0.0006	0.0025	
	Diesel IC	3	NA	121,000										
IP&L Petersburg	Coal CSC	1,190	10,223	9,579,248,000	96,157	30,335	1,335	3,335		0.0201	0.0063	0.0003	0.0007	
	Diesel IC	8	NA	409,000										
NIPSC Bailly [5]	Coal CSC	650	11,046	2,832,499,000	73,882	23,369	383	624		0.0522	0.0165	0.0003	0.0004	
	Gas CTU	34	19,881	560,000										
NIPSC Dean H. Mitchell	Coal CSC	616	10,728	2,499,840,000	11,634	10,868	405	2,614		0.0093	0.0087	0.0003	0.0021	
	Gas CTU	52	35,204	873,000										
NIPSC Michigan City	Coal CSC	661	10,584	2,941,936,000	68,030	24,425	422	1,259		0.0462	0.0166	0.0003	0.0009	
NIPSC R.M. Schafer [4],[5]	Coal CSC	582	11,152	4,939,319,000	30,359	26,509	194	624		0.0123	0.0107	0.0001	0.0003	
	Gas CTU	155	18,471	5,180,000										
PSI Cayuga	Coal CSC	995	10,392	4,250,873,000	91,536	22,207	661	1,511		0.0431	0.0104	0.0003	0.0007	
	Oil IC	11	NA	714,950										
PSI Edwardsport [4],[5]	Coal CSC	165	[1]	147,308,550	4,577	1,062	194	624		0.0621	0.0144	0.0026	0.0085	
PSI Gibson	Coal CSC	2,991	9,935	14,080,533,000	265,982	68,565	2,154	1,524	251	0.0378	0.0097	0.0003	0.0002	0.00004
PSI Robert A. Gallagher [5]	Coal CSC	560	10,717	1,874,384,850	44,360	9,339	270	624		0.0473	0.0100	0.0003	0.0007	
PSI Wabash River [5]	Coal CSC	753	11,110	2,230,236,960	48,130	12,063	346	624		0.0432	0.0108	0.0003	0.0006	
	Oil IC	8	NA	273,900										
SIG&E Brown	Coal CSC	531	10,683	2,249,038,000	6,676	5,135	313	971		0.0059	0.0046	0.0003	0.0009	
SIG&E F.B. Culley	Coal CSC	415	10,858	2,242,359,000	63,093	11,549	329	624		0.0563	0.0103	0.0003	0.0006	
Hoosier Energy Merom	Coal	980	NA	4,172,042,000	21,293	10,836	646	5,174		0.0102	0.0052	0.0003	0.0025	
Hoosier Energy Frank E. Ratts [4]	Coal	233	NA	1,011,913,000	26,513	4,856	194	945		0.0524	0.0096	0.0004	0.0019	
Logansport Municipal [3],[4],[5]	Coal CSC	53	NA	96,065,020	2,068	850	194	624		0.0431	0.0177	0.0040	0.0130	
Richmond P&L Whitewater Valley [4],[5]	Coal/Oil	93	11,432	NA	12,050	3,890	194	624						
TOTAL [6]				69,758,969,230	1,038,548	320,466	10,332	36,275						
TOTAL SYSTEM AVERAGE LBS/KWH										0.0298	0.0092	0.0003	0.0010	

Notes:

[1] PSI heat rate for entire system = 10,186 Btu/kWh

[2] IP&L heat rate for entire system = 10,521 Btu/kWh

[3] Logansport's NOx emissions are less than 850 TPY (less than .2% of the state total).

[4] The CO emissions for these plants are less than 194 TPY (less than .1% of the state total).

[5] The PM10 emissions for these plants are less than 624 TPY (less than .2% of the state total).

[6] Emissions from plants without a listed net generation are not included in the total figures.

[7] CSC stands for conventional steam cycle coal–fired generation.

Sources:

EIS/PS Emissions Ranking Report Point Sources. February 1990, pp. 1, 15, 23–4, 39, 49.

Electrical World, "Directory of Electric Utilities." McGraw–Hill, New York: 1986.

FERC Form No. 1, pp. 402–410, December 1988.

TABLE 2: SUMMARY OF THE EXTERNALITIES OF INDIANA POWER PLANTS
Expressed in cents/kWh generated

Valuation Method	Existing Power Plants			New Power Plants		
	Existing unscrubbed Coal Plant	Existing scrubbed plant	1988 Indiana system average	CTU #2 oil .3% S	CC Firm gas	AFBC .5% S
[1] 15% adder	0.3	0.3	0.3	1.9	1.1	1.5
[2] Massachusetts DPU unit values	8.9	6.5	8.3	6.0	3.4	3.8
[3] New York PSC unit values	2.8	1.5	2.5	1.1	0.5	0.7
[4] CEC out-of-state unit values	4.4	2.8	4.0	2.3	1.3	1.4
Plausible Range	2.7–8.9	1.5–6.5	2.5–8.3	1.1–6.0	0.5–3.4	0.7–3.8

[1] Indiana short-run avoided cost is estimated to be 2 cents/kWh. For the new units, avoided costs were taken from the NEPOOL Generation Task Force (1989).
[2],[3],[4] Tables 2,3,4.

TABLE 3: EXTERNALITIES OF INDIANA POWER PLANTS BASED ON THE MASSACHUSETTS DPU UNIT EXTERNALITY VALUES

		Emissions (lb/kWh)					
		Existing Power Plants			New Power Plants		
Externality	Unit Value ($/lb)	Existing unscrubbed coal plant	Existing scrubbed coal plant	1988 Indiana system average	CTU #2 oil .3% S	CC firm gas	AFBC .5% S
SO2	0.75	0.04	0.01	0.03	0.004	0	0.006
NOx	3.25	0.01	0.01	0.01	0.007	0.004	0.002
VOCs	2.65	0.00003	0.00003	0.00003	0.0005	0.0001	0.00003
CO	0.43	0.0003	0.0001	0.0003	0.002	0.001	0.0002
PM10	2.00	0.002	0.0003	0.001	0.0005	0.0001	0.002
CO2	0.011	2.11	2.19	2.16	2.84	1.88	2.09
Heat rate (Btu/kWh)		10,100	10,500	10,329	13,600	9,000	10,000
Externalities (cents/kWh)		8.9	6.5	8.3	6.0	3.4	3.8

Sources:

Emissions from existing units: Table 1 except for CO2 and VOC emissions (Chernick and Caverhill, 1990).

Emissions from new units: Chernick, P. and E. Caverhill, "Comparison of Total Costs of Supply Options for 89-239." May 1990.
(original data from California Energy Commission's recommendations for generic power plant emission factors).

Unit values: Massachusetts DPU decision in Docket 89-239. August 31, 1990. Unit values are exptrddrf as $ per pound of pollutant emitted.

TABLE 4: EXTERNALITIES OF INDIANA POWER PLANTS BASED ON NEW YORK PUBLIC SERVICE COMMISSION UNIT EXTERNALITY VALUES

		Emissions (lb/kWh)					
		Existing Power Plants			New Power Plants		
Externality	Unit Value ($/lb)	Existing unscrubbed coal plant	Existing scrubbed coal plant	1988 Indiana system average	CTU #2 oil .3% S	CC firm gas	AFBC .5% S
SO2	0.41	0.04	0.01	0.03	0.004	0	0.006
NOx	0.89	0.01	0.01	0.01	0.007	0.004	0.002
VOCs	0	0.00003	0.00003	0.00003	0.0005	0.0001	0.00003
CO	0	0.0003	0.0001	0.0003	0.002	0.001	0.0002
PM10	0.16	0.002	0.0003	0.001	0.0005	0.0001	0.002
CO2	0.001	2.11	2.19	2.16	2.84	1.88	2.09
Heat rate (Btu/kWh)		10,100	10,500	10,329	13,600	9,000	10,000
Externalities (cents/kWh)		2.8	1.5	2.5	1.1	0.5	0.7

Sources:
Emissions from existing units: Table 1 except for CO2 and VOC emissions (Chernick and Caverhill, 1990).
Emissions from new units: Chernick, P. and E. Caverhill, "Comparison of Total Costs of Supply Options for 89-239." May 1990. (original data from California Energy Commission's recommendations for generic power plant emission factors).
Unit values: New York State DPS, "Consideration of Environmental Externalities in Competitive Bidding Program to Acquire Future Electric Capacity Needs of Niagara Mohawk Power Corporation." Unit values are expressed as $ per pound of pollutant emitted.

TABLE 5: EXTERNALITIES OF INDIANA POWER PLANTS BASED ON THE CALIFORNIA ENERGY COMMISSION UNIT EXTERNALITY VALUES (OUT-OF-STATE)

		Emissions (lb/kWh)					
		Existing Power Plants			New Power Plants		
Externality	Unit Value ($/lb)	Existing unscrubbed coal plant	Existing scrubbed coal plant	1988 Indiana system average	CTU #2 oil .3% S	CC firm gas	AFBC .5% S
SO2	0.54	0.04	0.01	0.03	0.004	0	0.006
NOx	1.46	0.01	0.01	0.01	0.007	0.004	0.002
VOCs	0.16	0.00003	0.00003	0.00003	0.0005	0.0001	0.00003
CO	0.01	0.0003	0.0001	0.0003	0.002	0.001	0.0002
PM10	0.43	0.002	0.0003	0.001	0.0005	0.0001	0.002
CO2	0.0035	2.11	2.19	2.16	2.84	1.88	2.09
Heat rate (Btu/kWh)		10,100	10,500	10,329	13,600	9,000	10,000
Externalities (cents/kWh)		4.4	2.8	4.0	2.3	1.3	1.4

Sources:

Emissions from existing units: Table 1 except for CO2 and VOC emissions (Chernick and Caverhill, 1990).

Emissions from new units: Chernick, P. and E. Caverhill, "Comparison of Total Costs of Supply Options for 89-239." May 1990. (original data from California Energy Commission's recommendations for generic power plant emission factors).

Unit values: California Energy Commission Docket 88-ER-8. October 10, 1990. Units values are expressed as $ per pound of pollutant emitted.

Table 6a: Summary of Conservation Expenditures and Savings for Selected Electric Utilities

Utility	Total DSM expenditures [1]	Program life, yrs [2]	Average Annual cost [3]	Prog cost as % of projected revenues at prog. midpoint [4]	Annual MWh saved at end of prog. [5]	MWh saved as % of projected sales at end of prog [6]	Total MW saved at end of program [7]	MW savings as % of projected pk load in last yr of prog [8]	Program capacity factor [9]
[a]: BECo	$213,800,000	5	$42,760,000	3.3%	526,801	3.7%	117	3.9%	51%
[b]: CL&P	$624,915,000	10	$62,491,500	2.5%	1,741,170	6.8%	466	8.9%	43%
[c]: COM/Electric	$69,000,000	5	$13,800,000	3.3%	246,936	4.8%	46	4.4%	61%
[d]: EUA	$60,000,000	5	$12,000,000	4.6%	183,172	4.3%	53	5.9%	39%
[e]: NEES	$1,546,255,000	20	$77,312,750	4.0%	2,285,000	6.5%	1162	18.3%	22%
[f]: WEPCo	$113,836,000	2	$56,918,000	4.3%	304,800	1.3%	74	1.6%	47%
[g]: WMECo	$117,742,000	10	$11,774,200	2.7%	306,755	6.5%	43	5.2%	82%

Notes:
EUA's plan only includes costs and savings from the C/I sectors, as their residential programs had not yet been reviewed and approved.
[1][a]: data from Boston Edison's "The Power of Service Excellence: Energy Conservation for the '90's" (3/90).
[1][b]: data from Northeast Utilities' "Status of Private Power Producers and Conservation & Load Management," (4/90).
[1][c]: data from COM/Electric's "Mass. State Collaborative Phase II Detail Plans" (10/89).
[1][d]: data from Eastern Utilities' "Plan for the 90's: Results from Phase II of the Collaborative Planning Process", (2/90).
[1][e]: data from the New England Electric System's "Conservation and Load Management Annual Report" (5/90).
[1][f]: data from Wisconsin PSC docket #6630-UR-103, WEPCo exhibit TJG-2, p. 3, 11, 40.
[1][g]: data from Western Mass Electric's " Conservation and Load Management Program Plan for the 1990's" (9/89) and "Conservation and Load Management Program Update" (1/90).
[2]: The duration of the program described in each utility's DSM plan, though it is likely that most programs will be run for a longer period of time.
[3]: [1]/[2]
[4]: see Table 6b for source of revenue projections.
[5]: sources same as for [1].
[6]: see Table 6b for source of sales projections.
[7]: sources same as for [1].
[8]: See Table 6b for source of each utility's peak load projection.
[9]: [5] / ([7] * 8760)

Table 6b: Background Assumptions for Table 6a.

Utility	Prog. length [1]	'88 Sales revenues [2]	Revenues projected to 90 [3]	'90 $? [4]	Revenues projected for prog midpoint [5]	'88 Sales, MWh [6]	Sales projected for '90 [7]	Sales projected for prog end [8]	Peak load forecast for last yr of prog. (MW) [9]
[a]: BECo	5	$1,072,002,516	$1,206,320,829	y	$1,280,157,315	12,496,672	13,001,538	14,354,748	3,016
[b]: CL&P	10	$1,621,621,143	$1,824,804,824	n	$2,451,229,505	20,076,014	20,887,085	25,461,240	5,244
[c]: COM/Electric	5	$354,596,712	$399,026,489	y	$423,450,102	4,512,961	4,695,285	5,183,974	1,053
[d]: EUA	5	$219,642,491	$247,162,957	y	$262,291,307	3,725,256	3,875,756	4,279,148	900
[e]: NEES	20	$1,424,000,000	$1,602,422,415	y	$1,953,343,983	22,641,000	23,555,696	35,002,526	6,335
[f]: WEPCo	2	$1,181,447,183	$1,329,478,545	n	$1,329,478,545	21,547,582	22,418,104	23,323,796	4,507
[g]: WMECo	10	$290,414,985	$326,803,007	n	$438,988,961	3,731,682	3,882,442	4,732,675	824

Notes:

[1]: length of DSM program, as described in each utility's DSM plan.

[2]: ultimate consumer revenues for '88, from 1990 Energy Information Administration (EIA) "Selected Statistics for Electric Utilities", except for NEES figure, which is from NEES' annual 1989 Annual Report, p. 19; note that NEES figure includes off-system sales.

[3]: adjust '88 revenues for '90 : [2] * (((1+growth_rate) * (1 + rate_increase)) ^ 2); growth rate = 2%, rate increase = 4%.

[4]: are the utility's DSM budget figures in 1990$ (y) or do they include inflation (n)? [4][a],[b],[c],[g],[i]: personal communication with utility representative; [4][d],[e],[f],[h]: financial assumptions given in utility's report.

[5]: utility revenues, adjusted for program midpoint; if DSM budget is in real 1990$, then [5] is also in 1990$ but includes a sales growth rate of 2%; if the budget was given in nominal dollars, then [5] includes an adjustment for inflation (4%) as well as for growth (2%).

[6]: utility's 1988 ultimate consumer sales, also from EIA '90, except for [6][f] (NEES), which is from Table III-B-1, same source as [10][f]; note that this figure includes off-system sales.

[7]: [6] adjusted for 1990, assuming 2% growth rate; [6] * ((1+.02)^2).

[8]: [7], adjusted for program end, assuming 2% growth rate; [7] * ((1+.02)^[1]).

[i]: UI's budget figure was given in nominal dollars, assuming 4.5% inflation.

[9][a]: from BECo's "Long Range Intergrated Resource Plan, 1990-2014", vol II (5/90) p. 11.

[9][b]: from Northeast Utilities "Long Range Forecast of Electrical Loads and Power Facilities Requirements in Massachusetts," (1/88) vol.1, Table IV-1; the table only forecasts peak load through 1997, [10][b] represents the 1997 peak load of 5040 MW * (1.02)^2.

[9][c]: from Com/Electric's "Long Range Forecast of Electric Power Needs and Requirements..." (1/89), vol 1, Table E-11.

[9][d]: from EUA's "Long Range Forecast of Electric Power Needs and Requirements, 1989-98" (5/89), Table II-A1.

[9][e]: from NEES' "Supplement to Long Range Forecast 3," vol 2 (1/90), Table II-B-3.

[9][f]: from WEPCo's "Integrated Resource Plan in Support of the Concord Generating Station", (5/89), Table 2-1.

[9][g]: Ibid.; 1997 forecast of 800 MW was increased by (1.01)^2 to reflect growth.

Table 7: Summary of Projected 1990-91 Conservation Expenditures and Savings for Major California Utilities

Utility	Program Expenditures [1]	% of '87 revenues [2]	Incremental MWh saved/yr [3]	% of '87 sales [4]
PG&E				
1990	$106,770,000	2.2%	452,400	0.7%
1991	$118,410,000	2.4%	529,900	0.8%
SCE				
1990	$68,000,000	1.3%	922,800	1.5%
1991	$69,900,000	1.3%	922,800	1.5%
SDG&E				
1990	$13,056,000	1.0%	59,900	0.5%
1991	$21,642,000	1.7%	90,600	0.8%

Notes:
[1]: All utility figures from Report of the Statewide Collaborative Process, January 1990; program expenditures are in nominal dollars.
[2]: Utilities' 1987 annual ultimate consumer revenues from the Energy Information Administration's Financial Statistics of Selected Electric Utilities, 1987 (published in 1989).
[4]: Utilities' 1987 annual ultimate consumer sales from the Energy Information Administration's Financial Statistics of Selected Electric Utilities, 1987 (published in 1989).

CE: Utility and bidder efficiency cost curve

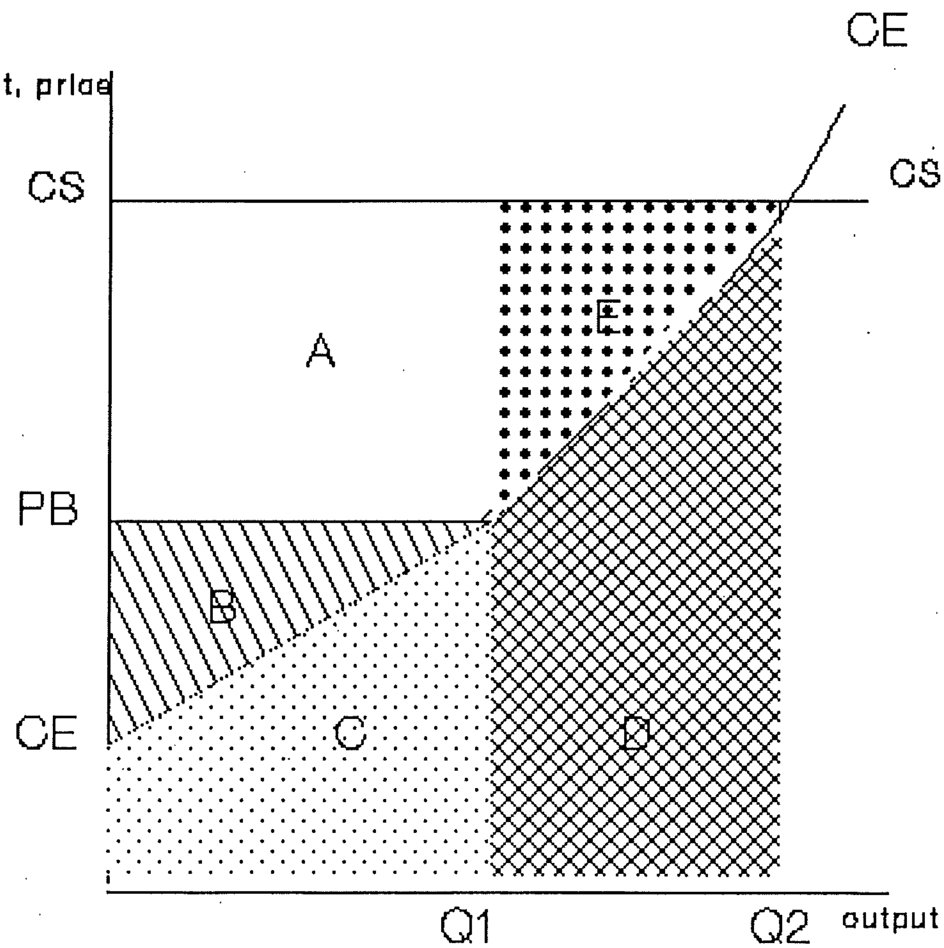

Figure 1