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Determinants and Impacts of Demand-side Management Program Investment of Electric Utilities

Philipp Degens

Portland State University

DETERMINANTS AND IMPACTS OF DEMAND-SIDE MANAGEMENT PROGRAM INVESTMENT OF ELECTRIC UTILITIES

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PHILIPP DEGENS

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COMMITTEE APPROVALS: [redacted]

Kuan-Pin Lin, Chair

[redacted]

Thomas Potiowsky

[redacted]

Giles Burgess

[redacted]

Andrew M. Fraser

[redacted]

James Strathman
Representative of the office of Graduate Studies

DOCTORAL PROGRAM APPROVAL: [redacted]

Beatrice T. Oshika, Director
Systems Science Ph.D. Program

****

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ABSTRACT

An abstract of the dissertation of Philipp Degens for the Doctor of Philosophy in Systems Science: Economics presented April 30, 1996.

Title: Determinants and Impacts of Demand-Side Management Program Investment of Electric Utilities

From the late seventies through the early 1990's electric utilities were facing many different forces that caused them to invest into demand-side management programs (DSM). Roots of the growth of DSM can be found in the high inflation and energy price shocks of the late seventies and early eighties, spiraling building costs of generation, safety and environmental concerns, increased costs of new capacity with possible exhaustion of scale economies, unexpected high elasticity in the demand for electricity, and public utility commissions that sought alternatives to the resulting high rate increases.

This study develops and estimates four equations that look at the more aggregate utility level impacts of DSM. The goal of two equations is to determine what factors influence utility investments in DSM and if stock market investment in utilities is affected by DSM. Two additional equations are developed to determine system level impacts of DSM on cost of and quantity demanded of electricity. To estimate these models four

years of annual data were collected for 81 utilities spanning 1990-1993. These utilities have sold over 60% of all the electricity in the US and were responsible for over 80% the national spending in DSM.

The DSM investment model indicated that of the major variance in DSM investment is due to the utility's regulatory environment. Both an above average regulatory climate and least-cost planning requirements had major impacts on the level of DSM investment. The cost of equity capital equation revealed that DSM expenditures had a positive impact on the valuation of utility's stock. Cost and quantity equations were estimated both individually and simultaneously. DSM expenditures seemed to have a negative impact on both average cost and quantity demanded. Although these relationships were statistically significant, the impacts were quite small.

To summarize; the regulatory environment seems to have the strongest impact on the level of DSM investment; DSM spending was associated with an increased stock valuation; as expected DSM investments were found to have a negative relationship with quantity demanded; and finally DSM investment appeared to reduce the average cost.

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I. Introduction

Demand-side management (DSM) can be considered a utility management strategy that allows a utility to more effectively use its plant and equipment while allowing more efficient energy use by a customer. This is accomplished through a set of programs and policies designed to affect a customer's consumption levels or timing of a customer's electricity demand. This contrasts with a supply-side strategy, where increased electricity demand will be met by adding generation, transmission, and distribution facilities. In changing the electric power demand levels, DSM programs and policies are targeted to promote conservation, reduce waste, and increase the use of more efficient motors, tools, and appliances. These programs affect the timing of electricity demand by seeking to smooth fluctuations in demand, so the bulk of electricity provided to consumers can be generated from more efficient base load plants rather than more expensive peak load plants. This smoothing of demand also reduces excess capacity in generating plants and transmission and distribution facilities required to meet peak demands.

DSM includes a wide variety of policies and programs, and has not been perfectly defined. However, it can be separated into two major categories: load management and conservation (Gellings and Talukdar, 1986). Load management strategies shift the period in which electricity is required. This does not necessarily reduce the volume of electricity consumed, in part, it may even increase it. It does result in the more efficient use of plant and equipment, causing a reduction in the total cost of providing the service. Programs targeted only at conserving of existing loads do not move electrical demand from one time to another. Rather they remove the demand entirely[1].

Following the oil price shocks of the 1970's the conservation of energy resources has become an area of greater interest to the general public. Consequently, energy conservation has come about through government mandates[2] and rational economic choices by consumers and producers. In the electric industry, resource conservation also became critically important during this time. Environmental regulation put many electric utilities under tighter constraints when building generation, transmission, and distribution facilities. The threat of further regulation, added costs from proposed "carbon" taxes, and internalization of the costs of other externalities continued to increase the financial risk in the construction of generation, transmission, and distribution facilities.

The rampant inflation and changes in safety requirements for nuclear power plants and environmental regulations for coal-fired thermal plants during the seventies and early eighties also caused power plant construction costs to escalate unexpectedly. These rising construction costs combined with concurrent hikes in fuel costs, led to rate increases. Electricity demand proved to be more elastic than expected. Utility forecasts

[1] For a more detailed description of load management and conservation programs, see Appendix 2.
[2] The Public Utilities Regulatory Act of 1978 mandate that state regulators adopt marginal cost pricing to encourage economic conservation.

of demand for electricity often proved to be overestimated, at times leading to excess power generation coming on line.

Faced with the choice of rate increases caused by excess capacity, many public utility commissions (PUCs) denied requests for rate increases in an effort to protect customers from price shocks. However, rates did increase to protect the utilities from financial insolvency. In many cases, PUCs allowed price increases to occur in conjunction with automatic fuel adjustment clauses. Some construction work in progress (CWIP) was also allowed into the rate base, easing the utilities' cash-flow difficulties. The inclusion of CWIP in the rate base went against the previous regulatory practices of allowing "used and useful" items into the rate base. However, some PUCs did not allow unfinished power plants into the rate base, and continued this policy even after the projects were completed, deeming the investments to have been imprudently incurred. Thus, major capital investments, previously considered fairly risk-free, lead to financial instability for many electric utilities. Regardless of the methods used to reduce price shocks, electric utilities' operating environment changed dramatically, putting many companies in financial straits.

During this time utilities also began to face increased competition. Price increases made alternative fuels more attractive, causing many customers to switch fuels. In addition, the Public Utilities Regulatory Act of 1978 (PURPA) increased opportunities for non-utility generators to compete with electric utilities. Facilities qualifying under PURPA were allowed access to the existing electric system, and utilities were forced to purchase electricity generated by these non-utility generators at the utilities' marginal costs. In cases where marginal costs exceeded average costs, these power purchases would tend to increases prices as utility prices are based on average costs.

PURPA also created incentives for existing customers to self- or cogenerate electricity. Surplus power could be sold to the utility, while back-up power would be available from the utility. This tended to either erode the customer base or to provide added leverage to larger industrial and commercial customers negotiating electricity rates. Coupled with consumer advocacy of conservation, these trends increased the electric utilities' interest and activities in what has become known as demand-side management.

DSM programs can be utilized for a variety of strategic purposes. Conservation and load management programs can be used to defer investments in new plant. This capital minimization strategy reduces present capital costs and concomitant risks associated with added capacity. Such risks include insufficient demand for the new capacity, cost escalation due to compliance with emerging environmental standards, higher inflation rates that increase capital costs, or prudency reviews that prevent investments from being allowed into the rate base and thus earning a rate of return because a PUC has deemed investments to have been imprudently incurred. DSM programs that aim at deferring capital investments typically target "peak clipping" and load shifting; reducing peak demand or shifting it to off-peak periods, hence reducing the need for added capacity.

DSM programs were also developed to increase revenues. This is done by building new, off-peak loads by offering lower rates during those periods. Revenues can be increased through programs that promote strategic load growth. This often takes the form of promoting new electro-technologies, such as electric cars or electric arc furnaces in steel mills, or by increasing the overall market penetration of certain appliances and equipment. Some programs use DSM to bolster sales retention and increases in market share. These programs are designed to entice existing customer loads from switching to competing fuels or offer incentives to customers that choose electricity as their fuel for new equipment.

DSM programs were believed to be very flexible in their implementation and goals (Hirst, 1989a). Many utilities invested in these programs to counter one or more adverse condition encountered in the new environment. DSM programs were promoted by many PUCs as least-cost alternatives to new construction and therefore a way to keep rates low. PUCs encouraged the implementation of DSM programs through a variety of incentives, such as higher rates of return or allowing DSM investments into the rate base. In many states PUCs did bring about least-cost planning (Mitchell, 1989, 1992) which forced utilities to at least consider DSM as a potential resource along with conventional generation. Some PUCs actually decoupled electricity sales from the rate of return to prevent discouraging utility investments in DSM programs.

Currently much of the rationale behind these strategies has either diminished in strength, disappeared or become secondary to other forces shaping the electric industry. The industry is most influenced by the appearance of low-cost, flexible electricity generation in the form of gas-fired combustion turbines, deregulation, competition at all customer levels (retail wheeling), industry consolidation through mergers, non-utility power generation, increased system interconnectivity, and increased wholesale interchanges.[3] This has led to an decline in utility interest in pursuing DSM.

Part of this decline in interest in DSM has also been caused by its success. In many cases, the most cost-effective DSM investments have already been made. Many of these have been realized through state and federal government mandates requiring more efficient appliances, lighting, HVAC equipment, and motors. For example, product efficiency labels were required by the Energy Policy and Conservation Act of 1975. Major home appliance energy efficiency standards were mandated through the National Appliance Energy Conservation Act of 1987. Most of these standards took effect in 1990, with refrigerator and freezer standards coming into force in 1993. Further legislation, establishing lighting and plumbing efficiency standards, came into being with the New Energy Act of 1992. This act furthered the introduction of various

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[3] For discussions of the issues facing the electric power industry today see Stevenson and Penn (1995), Hempling (1995), Berg and Tschirhart (1995), Hirsch (1991), and Joskow (1989).

other efficiency standards, such as increased energy-efficient building codes and more efficient commercial electrical equipment.

Electric utilities promoted many of these moves towards increased standards. EPA's "Green lights" program could not have happened without electric utilities developing the initial markets for these energy-efficient products. In addition, many utility programs led the way towards adoption of these new standards and other market transformations. Such programs geared towards market transformations include the Model Conservation Standards for new commercial and residential construction adopted by many states, the "Golden Carrot" energy-efficient refrigerator, and the increased availability of compact fluorescent bulbs. With standards achieving higher efficiency levels the marginal cost of a "negawatt" [4] increases, since it is easier and cheaper to develop technology that increases efficiencies at the lower levels (e.g. going from 60 % efficiency to 70% efficiency) than to capture the last few remaining percentage points in efficiency (e.g. going from a 97% efficiency to 99% efficiency).

Another factor now impacting DSM investment is technological change. DSM has always been touted as a flexible resource that can be acquired in piecemeal fashion without an extensive planning horizon. With the future electricity demand unknown and base load power plant construction requiring 10 to 15 years of planning, design, and construction before completion, DSM often proves to be a much more appealing investment. Further, developments in combustion turbine technology (in efficiency,

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[4] A kWh of energy savings.

reliability, and size) have allowed theses units to become base-load units (Hirsch, 1991). The combustion turbines can be constructed and sited easily and be used to provide incremental 100 MW loads within a year or two.[5] This fact, coupled with fairly stable gas prices, causes DSM to compete with a technology that is also flexible.

DSM has been pronounced dead many times. However, tactics such as the Association for DSM Professionals changing its name to the Association of Energy Service Professionals in 1995, indicates of how that the status of DSM in the electric utility industry is declining. "Regulator driven" DSM is expected to disappear, while "customer driven" DSM is expected to flourish, with utilities offering DSM as a service for their customers.[6] In this way, customers who benefit from the services pay for them, explicitly, removing issues of cross-subsidization from customers not receiving the services. DSM is presently being repackaged as a value-added service strategy that will become part of a utility's competitive strategy (Shick and Hamilton, 1996). It is also expected that more informational interconnectivity will allow many DSM options, such as TOU rates, smart homes, utility control of appliances etc., to become increasingly cost-effective to implement.

DSM investment has risen slowly since the early eighties, rising from more than $860 million in 1982[7] to $2.9 billion in 1993.[8] More recently these expenditures, in comparison to new capital investments, have gone from 3% of investment in new plant

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[5] Electric Utility Week, February 26, 1996, pp. 16.
[6] Quad Report, vol. 3 no. 7, August, 1995, pp. 1 and Shick and Hamilton (1996).
[7] Cogan and Williams (1983).
[8] EIA Form 861 (1993).

and equipment in 1990 to almost 10% of new investment in electric plant in 1993. As a percentage of total generation, expected savings have risen during this four-year period from 0.6% to 1.5%. Projected demand savings have increased from approximately 17,000 MW in 1990 to 23,000 MW in 1993. Savings produced by these demand programs can be expected to reduce consumption from 2.5% (Prete, 1992) to 3% by the year 2000 and to 6% by the 2010 (Faruqui, Seiden, and Braithwait, 1990). By the turn of the century DSM programs are projected to reduce peak loads representing 73% of new capacity (Prete, 1992).

Even though factors thought to spur the growth of utility DSM investment have waned, the impacts of past and current DSM programs are still present. DSM continues to be a flexible resource in which investments fluctuate depending on electricity's costs of supply and price. Many of the factors which led to DSM investment may arise again. Inflation may reappear increasing capital costs, and energy costs will not necessarily remain stable over time. Industry behavior may cause regulatory pressures to increase, especially in the face of rising rates. A major factor driving industry restructuring are anticipated lower prices. With regulators seeking to provide rate payers with lower prices, deregulation is considered positive. However, if prices increase, it is possible regulation will reappear. DSM would likely follow programs, especially regulator-driven DSM.

Much research has been conducted that models the DSM impacts at the customer and end use level.[9] In many traditional electric industry models, however little has been done in incorporating the DSM investment impacts into the models' frameworks. At a more aggregate level, few models have been developed. None have been estimated to determine DSM impacts. A few studies (Keelin and Gellings, 1986)(Faruqui, Seiden, and Braithwaite 1990)(Hirst, 1991) have been conducted on the national impacts. These have primarily used simulation models. None have directly estimated DSM impacts at the utility system level or the national levels.

Integrating DSM investments into models at the utility system level proves useful because the decisions by a single economic agent can be more thoroughly analyzed. If a sufficient number of utilities are analyzed, better forecasts of national level impacts can be made. As part of this study, four models were estimated. The first models DSM investments for factors influencing utility DSM investment levels. Aggregate DSM impacts at utility system levels were estimated using a pair of simultaneous equations that model cost of and demanded for electricity. A final model was estimated to determine how the market values DSM investments. This was accomplished by estimating a simple model for factors influencing equity capital costs, with DSM being one of the factors.

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[9] DSM program impacts have been studied in numerous evaluations carried out by individual utilities. The results of many of these evaluations have been presented in the proceedings of the ACEEE Summer Session, the Energy Program Evaluation Conference, and the National DSM Conference. Numerous other studies have been sponsored by the Electric Power Research Institute.

These models were estimated using four years of data from 81 utility holding companies. In 1990, these utilities sold 60.7% of the electricity in the United States, and 78.6% of the electricity sold by investor-owned utilities. That same year they represented 83.5% of total nationwide DSM expenditures, and 92% of DSM expenditures of all investor-owned utilities.

Analysis of DSM investment by the investor-owned utilities indicated that program expenditures were heavily influenced by the regulatory environment. This suggested that regulatory incentives play a large role in the decision to invest in DSM. Least-cost planning requirements also were positively associated with DSM investments. The estimated model revealed a positive, but not strong, correlation between DSM and capacity constraints.

DSM impacts on costs and on quantities demanded revealed a negative relationship. In both cases, the relationship was statistically significant. However, DSM's actual impact on price and quantity was insignificant. When solely examining energy savings, DSM investments did not appear cost-effective unless the persistence of that impact was assumed to last 20 or more years. As DSM investments defer capital investments, the cost-effectiveness of DSM can not be measured solely by the energy savings. Though DSM is only associated with minute decreases in cost this must be seen in a positive light. Despite utility spending on DSM and the accompanying revenue losses, the model does not indicate that DSM investments raise costs of electricity, that in turn will lead to rate increases.

A variety of factors may have led to these low impacts. Government energy-efficiency legislation and program spillover[10] may have increased the efficiency of customers, even though the utilities serving them had not invested heavily in DSM. Further, many DSM programs are load management programs that shift consumption, and possibly even causing an overall increase in energy used.[11] Other programs are geared towards strategic load growth or load retention. Even if a new or retained load is energy-efficient, the net result remains an increase in electricity consumption.

Impacts of DSM investments on capital costs were not only positive and statistically significant, but had a fairly large impact on the value of the utility's stock. This large impact on market valuation may be due to the DSM variable acting as a proxy for other variables. Possibly, utilities investing in DSM are considered more innovative and customer services oriented. As the market puts a premium on DSM investment during regulation, this favorable valuation of DSM may remain as the industry restructures.

This study indicates that the substantial financial investments in DSM make it possible to measure the DSM impacts at system levels. The study also indicates that

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[10] Spillover can appear in a variety of guises. For example customers who obtain program-sponsored appliances move to another utility's service territory. One utility's advertisements affect an adjacent utility's customers' purchasing habits. Energy-efficiency practices cultivated by a commercial or industrial customer are transferred to another site.

[11] Energy storage equipment uses more kWh at lower off-peak rates to store heat or cold.

even though much of DSM investment appears to be influenced heavily by regulation, DSM services may continue to flourish following industry deregulation.

II. Literature Review

For some time, a great many detailed studies have been available on the impacts and cost-effectiveness of individual DSM programs. A fairly large industry has developed to plan and implement evaluations of specific programs. The detail and breadth of many of these evaluations arose largely due to PUC's basing shareholder incentives on the measured impacts of these programs (Fels and Keating, 1993). With industry restructuring on the horizon, this area of research has declined. An obvious sign of this shift was the cessation of the industry newsletter, Evaluation Exchange, in 1995.

DSM evaluation was primarily done on the program level, while less research was concerned with the system-level DSM impacts. Some studies have been carried out on individual nation-wide programs, such as the Residential Conservation Service (Clinton et al, 1986) and the Low-Income Weatherization Service (Brown et al, 1993). Early studies on overall DSM impacts collected DSM expenditure and savings data using surveys of utilities. In 1982, estimated DSM spending in 1982 was $860 million for 120 surveyed utilities (Cogan and Williams, 1983). As these data represented DSM spending for the majority of the largest private and public power producers in the country, the figures in the above sum should be fairly close to the total. Expenditures were expected to yield construction cost savings of two dollars for every dollar spent on DSM. An updated study for 1985 and found little, if any increase in DSM spending (Cogan and Williams, 1985).

The Electric Power Research Institute (EPRI) has funded numerous studies on all facets of DSM. EPRI sponsored the first study of overall DSM impacts on the electricity industry in 1986 (Keelin and Gellings, 1986), which was followed by a more comprehensive update in 1990 (Faruqui, Seiden and Braithwait, 1990). Both studies forecast national DSM impacts. The earlier study primarily used engineering estimates to project national impacts. The second study was more comprehensive, and incorporated real world results of DSM programs and end use simulation models to project DSM impacts. Another EPRI study (Blevins and Miller, 1993) only provided estimated savings and expenditures for the utilities surveyed. In many cases, the utilities did not report either savings or expenditures. On average, the surveyed utilities reported annual funding levels of $730 million from 1991 to 1993. Trends within DSM spending indicate a shifting of funds from conservation to load management programs (Prete et al, 1992).

A more comprehensive estimate of total DSM impacts has been available from the Energy Information Agency (EIA), which has collected total utility DSM expenditure and savings data from all public and private electric utilities since 1990. According to this data, total industry DSM expenditures have grown from around $1.2 billion in 1990 to $2.9 billion in 1993 (Table 1). This is approximately 3% of new plant investment in 1990, and has grown to about 10% of new plant investment in 1993. As a percentage of total expenditures, DSM spending doubled during this time period, growing from just under 0.9% in 1990 to 1.9% in 1993. Expected savings during this time period more than doubled, going from 17 million MWh in 1990 to over 41 million MWh in 1993. Demand savings increased from around 17,000 MW in 1990 to 23,000 MW in 1993. Reductions in peak load were larger than those of savings because many of the programs were geared towards peak clipping (Prete et al, 1992).

Table II.1

EIA Reported and Projected DSM Expenditures and Savings for all Utilities

	1990	**1991**	**1992**	**1993**	**2000**
DSM (millions)	$1,201	$1,750	$2,396	$2,888	$3,394
MWh Savings (thousands)	17,060	23,432	30,029	41,007	78,444
Savings as % of total Generated	0.6%	0.8%	1.1%	1.4%	2.5%
Number of Utilities	379	458	1,008	1,143	NA

DSM investments are expected to reduce total electricity demand, over that required in their absence. The reduction in total national electricity consumption was projected to be 1.1% in 1990, 3% in 2000, and 6% in 2010 (Faruqui, Seiden, and Braithwait 1990). Another study (Hirst, 1991) projected even greater impacts if DSM programs were implemented more aggressively. EIA future forecasts have estimated that DSM programs will result in peak load reductions representing 73% of new capacity.

II.1. Demand-Side Management Investment

DSM expenditures remain quite variable. Some utilities do not have DSM programs while others spend as much as 8% of their total annual expenditures on DSM. No single simple reason explains why utilities invest in DSM. For the electric utility industry, DSM program objectives "are shaped by a utility's reserve margin, fuel mix, expected demand growth, regulatory climate and other exogenous factors" (Cogan and Williams, 1987).

The reasons for DSM program investments can be separated into two main groupings: programs embarked upon to achieve profits and those that utilities undertake to fulfill governmental legislation or PUC regulations. In the case of government legislation the reason for DSM investment is quite straightforward. Utilities have had to implement DSM programs that were mandated by the federal and state governments. One of the largest nationwide DSM programs, the "Residential Conservation Service (RCS)," was brought about by the National Energy Conservation and Policy Act of 1978. It lasted until 1989. This legislation required utilities to offer home energy audits at little cost to residential customers. During a single 3 year period of the program's existence, over 3 million audits were performed nationwide at the cost of $360 million (Clinton et al, 1986). PURPA nudged many utilities into accepting innovative rates and some states have indirectly created DSM programs by mandating least-cost planning. Least-cost planning incorporates both supply-side and demand-side alternatives to meet projected demand. Thus, utilities affected by these regulation, must consider DSM programs in their resource acquisition planning process. If deemed cost-effective under the least-cost plan, DSM programs may be implemented. Furthermore, PUCs have been known to order additional DSM program expenditures (Canine, 1990).

Unmandated DSM investments undertaken for a profit motive can be separated into five categories:

1. Addition of revenues.
2. Prevention of revenue losses.
3. Risk reductions.
4. Public relations.
5. PUC profit incentives.

Revenues can be increased through a variety of programs including innovative rates that promote new, off-peak consumption, marginal cost pricing such as TOU rates, or growth in general consumption, such as declining block rates can be structured to promote additional sales. These rates correspond with microeconomic theories of monopoly behavior, and are explained in the rubric of second- and third-degree price discrimination (Mansfield, 1970), (Scherer, 1970). The success of these programs on increasing revenues depends on the customer classes involved and their respective elasticity of demand. To succeed in increasing revenues, the new rates have to be mandatory or they must attract sales that would not have occurred otherwise. Price rebates during off-peak periods or times of excess reserve capacity have to be targeted toward new sales if the utility seeks to realize an increase in revenues.

Programs that sponsor strategic load growth can also be seen as profitable. Many of these programs prevent fuel switching, thus retaining market shares. In addition, as yet unserved markets are developed through new electro-technologies such as electric cars, or electric arc furnaces in steel production. Strategic load growth programs can increase the market penetration of certain electric equipment, such as programs promoting the installation of air conditioning equipment. Energy-efficient space heating equipment programs for utilities with a summer peak load or increasing the penetration of space cooling equipment for winter peaking utilities can take advantage of excess system capacity and be profitable. The long-run aspects of these programs are also a consideration, as installation of the equipment will provide the utility a steady revenue stream over the lifetime of the equipment.

Sales losses can occur either through the customer bypassing the utility's electric system or through entirely leaving the service area. Bypass can take the form of self-generation or cogeneration, fuel switching, or non-utility installation of energy conservation measures. This is predominantly a problem for a utility when, large electricity purchasers threaten to do any of the above, because a large revenue loss will increase costs for customers remaining in the system (Hyman, 1986). Under the threat of system bypass, DSM programs or lower rates may be offered to customers to decrease their electric power costs and retain them in the system. As long as the cost of DSM programs or lowered rates remain above service costs, the utility and other rate payers benefit because revenue losses and rate increases will not be as great as they would have been had the large customer been allowed to bypass the system. The higher elasticity of demand of many larger customers causing lower rates or conservation programs, results in the DSM programs being a form of third-degree price discrimination.

Whereas utility bypass was once seen as a threat primarily coming from larger customers (Plummer, 1990), it may soon be possible to associate this risk with all customer classes. Retail wheeling is a very possible reality (Stevenson and Penn, 1995). This will allow competition at all customer levels, while electricity services are offered from a variety of suppliers. Such competition will place high-cost utilities under pressure. To survive they may have to incur severe financial losses by writing off high-cost generation. Bundling DSM with electric services is seen as a method of remaining competitive at higher prices as DSM services adds value that justifies higher prices.

The risk reduction for capital investments is another reason for investments in DSM. Although this a profit motive, this occurs because of failures in the country's the regulatory system. During the 1980's, the growth of demand has often failed to keep in step with industry projections. Often electric plant was built for demand that did not materialize. This caused reserve capacity margins to grow in many utilities, resulting in higher fixed costs for the electricity sold. To meet these higher fixed cost, utilities filed for rate increases. Often these rate increases were politically unpalatable, due to their size and denied by PUCs. At the same time, many PUCs did not allow the added capacity into the rate base through a new process of prudency hearings. This caused many utilities to change their capital investment procedures (Hirsch, 1991). Such prudence reviews have led to smaller construction projects with less costs uncertainties (Lyon, 1991). To meet future demand growth, DSM programs were favored, as they promoted peak clipping, load shifting, and conservation. Lower cost DSM investments would be made instead of building new power plants requiring long lead times that were based on dubious predictions of future demand and had a high risk of having all or part of the project's capital expenditures lost due to prudency hearings.

Another risk associated with power plant construction are the environmental externalities that are associated with production, transmission, and distribution. The electric utility industry emits one-third of the nation's CO_2, the majority of its SO_2, and one-third of its NO_x. (Hirst, 1991). With the Clean Air Act of 1969 and the National Environmental Policy Act of 1970 began an era of environmental control programs in the United States that forced utilities to incorporate environmental costs into their system planning processes. New Source Performance Standards were periodically updated using the "best available control technology," that allowed emissions to be reduced over time. These policies, combined with additional regulations on water pollution and solid waste controls, caused environmental control systems to account for one-fourth to one-third of the total costs of new coal-fired power plants (Rubin, 1989). Further, increases in electricity generation costs can be expected as more stringent emission standards are enacted. Several state governments and PUCs have already started to incorporate the costs of these externalities in rate hearings (Cohen et al, 1990). Evidence has been found that older capacity is used more intensely (Stanton, 1993), that indicates that the industry is postponing the use and construction of new capacity. To comply with the new standards, if they are passed, will put new and even existing generation at risk of higher costs.

The potential health risks of electromagnetic fields around transmission lines are also facing higher scrutiny. Possible negative impacts raise the specter of increased transmission costs. This, together with other environmental regulations, should make DSM investments more attractive as they defer the construction of new generation and transmission and distribution systems (Hirst, 1991).

The reductions of capital and environmental risks are an important facets of DSM that now have competition from supply-side alternatives. Developments in combustion turbine technology and world-wide competition have allowed the prices of gas-fired combined-cycle plants to decrease 30% to 40% over the last 4 years.[12] Cost

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[12] Electric Utility Week Feb. 26, 1996 pp. 11.

savings have notably occurred in construction times where the building schedules for such plants have fallen to eighteen months. New advancements in coal-fired power plants have also reduced risks associated with these plants. Developments in coal gasification and fluidized bed technologies have also reduced these plants' installed costs by 15% to 20% within the same 4 year period. For this coal fired technology construction times have also been cut by half, to about three years. Technological improvements have decreased the viable sizes of these coal plants. These shorter lead times and the ability for smaller increments in capacity to be installed have reduced the magnitude of capital risks. In addition, using gas-fired or newer coal burning technologies has reduced the environmental risks for these generating plants.

DSM investments are also a form of public relations. DSM programs that are pursued for such reasons often promote conservation and efficient energy by use of advertising, energy audits, demonstration projects, or small scale retrofit and measure installation programs. Some programs, such as low-income weatherization have a dual purpose of promoting community goodwill for the utility and while decreasing the number of unpaid bills. These programs are usually relatively inexpensive and their reductions in electricity demand are quite small. With the arrival of competition brought about by industry restructuring, DSM programs can also be seen as a way to promote and differentiate one utility from other energy providers. This can enhance the utility's competitiveness (Flynn, 1992).

Since utility profits are regulated by the PUCs, regulatory incentives and disincentives can impact a utility's decision to invest in specific inputs. At the moment, many DSM proponents hold the view that "each kWh a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings" while "each kWh saved or replaced with an energy-efficiency measure, no matter how little the efficiency measure costs, reduces utility profits" (Moskowitz, 1989). This is certainly true for pure conservation programs that only reduce existing loads, thereby reducing utility revenues. Unless the lost revenue is recouped through a rate increase, there are no incentives for conservation investment. In certain states, attempts have been made to change the incentive to produce electricity rather than conserve electricity. California's Electric Revenue Adjustment Mechanism (ERAM), the state of Washington's larger rate of return on DSM investments, and other DSM incentive plans that have been developed in New York, Massachusetts, and Pennsylvania indicate PUCs trying to foster investments into DSM programs. Greater acceptance levels can occur with the recovery of DSM program costs, adjustments for the associated revenue losses, and increases in rates of return in these investments countering perceived risks involved with DSM investments (Reid and Chamberlain, 1990).

With expected increases in competition, most of the regulatory efforts are suspended. Once competition begins, "customer-driven" DSM services may be all that will remain of previous DSM programs. Once the customers are able to change energy service providers, it will no longer be cost-effective for utilities to invest in DSM services that have long-term pay-backs. Capacity and energy savings derived from a customer receiving these services will be shifted if the customer moves to a new electricity service provider.

DSM Investments occur for reasons that are dependent on a plethora of utility characteristics, regulatory environments, and characteristics of customers served. Utility investments in production inputs have been modeled by using the framework of a profit maximization model (Averech and Johnson, 1962), (Baumol and Klevorick, 1970). Other models of utility investments in supply-side resources, such as transmission and generation facilities, were developed by Baughman, Joskow, and Kamat (1979). Here the inputs are explained by the characteristics of the firm and its customer base. These models provide an appropriate framework for understanding the DSM investment levels and the factors driving them. These models incorporate a variety of utility characteristics, such as total sales, sales by customer class, total number of customers by customer class, and service area. A model of this type will provide information on what type of utility characteristics are likely to influence the level of DSM investment.

II.2. Cost of Equity Capital

Various models for capital costs have been developed over time. These include separate models for the cost of debt capital (Berndt, 1979), (Archer, 1981), (Dubin and

Navarro, 1982), (Prager, 1989) and the cost of equity capital (Trout, 1979), (Archer, 1981), (Dubin and Navarro 1982), (Gapenski, 1989), (Fanara and Gorman, 1986). For the most part, these models have been developed to determine if and how regulation impacts electric utilities' capital costs.

The cost of equity models use the market-to-book (M/B) ratio as a dependent variable. This ratio quantifies the relationship between the price that a utility's common stock commands on the market and the book value of its assets. Financial and managerial factors found to have a strong positive relationship with the M/B ratio include the actual rate of return, the expected rate of return, and the dividend pay-out ratio (Dubin and Navarro, 1982). A negative relationship to the M/B ratio was connected to debt financing and nuclear power plant construction (Gapenski, 1989). The cost of debt capital has been found to have a negative relationship with the percentage of total costs paid in taxes and for fuel (Dubin and Navarro). Prager (1989) showed that a large variety of utility characteristics can play an important role in determining the cost of capital.

II.3. Electricity Demand and Price

Impacts on electricity demand and price have been studied extensively over the years. Electricity demand is actually driven by the services it offers, such as light, heat, or powering motors. Therefore, it is a derived demand and is associated with a capital good, such as a light bulb, electric appliance, or motor that provides the desired service. Electricity consumption can be modeled using the following equation:

$$\mathbf{Quantity = f(R, A)}$$

where A is the vector of the stocks of electricity using equipment and R is the vector of the utilization rates of each type of equipment. Lacking exact data on equipment stocks one can create a reduced form equation:

$$\mathbf{Quantity = f(P_e, P_g, Y, Z)}$$

where quantity is a function of P_e,, the price of electricity, P_g, the price of competing fuels, income, Y, and the vector of other variables, Z. Unless the supply of electricity is perfectly elastic, the identification problem (Pindyck and Rubenfeld, 1991) arises. The identification problem "is essentially one of inferring characteristics of demand alone from market data that reflect the combined influences of both supply and demand behavior" (Bohi, 1984). To deal with this problem a cost function can be modeled separately with the equation:

$$\mathbf{Cost = f(Quantity, P_l, P_f, P_k, W)}$$

where the cost of electricity is determined by the quantity demanded, the vector of fuel prices P_f, the price of labor P_l, the cost of capital P_k, and a vector of other factors W. These two equations can be linked with a linear constraint:

$$\mathbf{P_e * Quantity = Cost + Return\ on\ Investment}$$

Using this constraint, the cost and demand models can be estimated simultaneously.

Bohi (1984) identifies a number of other issues involved in developing of energy demand models: the aggregation level, measurement issues, functional form, and estimation techniques. Given the detailed data available on electricity production and consumption, numerous studies have been performed at different levels of aggregation. Bohi (1981) has argued that aggregating demand at the utility level is inappropriate, as the basis for demand would differ greatly between commercial, industrial, and residential customers. Residential customers are motivated by utility maximization, while industrial and commercial customers are assumed to maximize profits or minimize costs. Beginning with the classic article by Houthakker (1951), most studies model electricity demand for specific rate classes, consumers, or firms. Bohi has shown that models operating at detailed levels of aggregation perform better than those at greater levels of aggregation (Bohi, 1981).

Developments in demand's functional form have occurred over a long period of time. Linear or log-linear formats were specified in the earlier models of demand. This changed in the seventies with the advent of the translog model (Jorgenson, 1986) (Griffin, 1992). The translog model offers a more flexible functional form which does not restrict the models' elasticities. However, translog estimations are static and thus are unable to capture the temporal properties of demand. Translog model estimation also generates a large number of parameters. To effectively estimate the model only a small number of explanatory variables can be included, which places restrictive assumptions on the model.

Measurement issues are also of interest. Electricity consumption is influenced by variables such as income, area of home, appliance stocks, etc., that should be included in the model. Frequently, these variables are correlated with each other, making it difficult to estimate their separate influences. An issue continuously discussed is the choice for the price variable (Taylor, 1977). If the marginal price is considered to be the most appropriate, rate schedules that include items such as block pricing, fixed charges, demand charges, and seasonal and time-of-use rates make its calculation quite difficult. When customers are aggregated over multiple rate schedules, the determination of the marginal price becomes even more complex. The relative merits of including the marginal price are still not established (Taylor, 1977) and one study (Shin, 1985) indicates that customers respond to average cost.

Electricity demand and supply studies have been repeatedly enumerated and described in reviews by Taylor (1975), Cowing (1978), Hartman (1979), Bohi (1981, 1984), Jorgenson (1986), Berndt (1991), and Griffin (1992). A few of these studies simultaneously estimate price and demand (Halvorsen, 1977, 1978) (Chern, 1978). Using the marginal price instead of the average price is one of the methods employed to remove the simultaneity (Berndt, 1991). Estimating the marginal price accurately when aggregating over rate classes, utilities, or over a span of time when seasonal and TOU rates are present proves quite problematic. With larger customers where demand charges apply, actual marginal prices depend on energy prices and demand charges. Interruptible service rates are even more difficult to model.

State, regional, and national level models comprised most of the early demand studies. This has changed as more micro-level data have become available allowing studies to focus on industry, firm, and household level data. Hourly demand and demand of specific end uses have also been researched. The leap from regional to micro-level studies has largely avoided the demand at the utility level. One of the few published studies performed at this level was undertaken by Lyman (1978).

The elasticities estimated through these models have varied significantly. Short-run residential price elasticities have ranged from -0.03 to -0.54, while long-run elasticities have overlapped slightly, ranging from -0.45 to -2.2 (Bohi, 1981, 1984). Estimated income elasticities have ranged across more unrealistic levels: -0.32 to 2.0 in the short-run and 0.12 to 2.2 in the long-run. Commercial and industrial studies have estimated similar ranges for short and long-run price elasticities. With income elasticities, commercial short-run elasticities have ranged from 0.1 to 0.72 while long-run elasticities have naturally been higher, ranging from 0.8 to 1.32. Industrial studies have shown output elasticities ranging from 0.08 to 0.87 in the short-run to 0.51 to 0.73 in the long-run. The ranges of these estimates are quite great and vary by estimation technique, aggregation level, and data quality. It is possible the elasticities are changing over time as tastes change, the electro-technologies grow, and inter-fuel competition increases.

DSM investments have been repeatedly studied within a demand model framework. Numerous billing, load shape, and end use metering studies have been performed at many utilities. Early studies of program impacts began in the seventies (Berry et al, 1981). These and later studies have typically been specified as:

$$\text{Quantity} = k\,(\text{DSM, Price, Customer, Weather})$$

where the quantity of electricity (hourly, daily, monthly, etc.) is a function of customer characteristics, electricity price, weather, and DSM investment. In earlier studies (Hirst et al, 1982), (Hirst, White, and Goeltz, 1984),the DSM variable used in the estimation was represented by a dummy variable for participation. Eventually, studies used expected savings (Train, 1985) or measure costs (Horowitz and Degens, 1987) to replace the dummy variable, thus allowing the estimation of, respectively, the realization rate of expected savings and the marginal cost of energy savings. Evaluation methods became more and more refined, and methods used came to depend on the type of measures installed, level of savings, and type of participating customers (Sonnenblick and Eto, 1995).

The cost of electricity has been repeatedly studied at the firm and plant level. Typically, the cost function is estimated by itself and not simultaneously with demand. The reasoning behind this is that in a regulated market the output price is set by the regulatory authority. Therefore, the quantity demanded is exogenous to the cost. With output a function of the regulated price, the output level no longer is under the utility's control. With output fixed, cost minimization becomes a profit maximizing firm's objective from the viewpoint of a regulated utility (Jorgenson, 1986). Most recent electric industry studies specify the cost function as a translog cost function. An early article by Christensen and Greene (1976) that used the translog cost function to examined the economies of scale in the electric industry. Other studies have researched the effects of fuel adjustment clauses (Gollop and Karlson, 1978) and the cost implications of vertical integration (Henderson, 1986). These models assumed the utilities in the sample were fairly homogenous, and that most of the variance in cost is explained by input prices. The nature of the translog cost function may have precluded more explanatory variables from being included in these models. If more explanatory variables were included, the number of parameter estimates would grow exponentially, making the model more difficult to estimate.

Simpler price models have been estimated for the electric industry. These do not use the translog functional form and could also be used to model costs. Halvorsen

(1975) estimated a log-linear model of electricity's marginal price as part of a simultaneous model. In a later study by Chern (1978), aggregate industrial prices and demand were estimated in a pooled model for 15 industries. A study by Primeaux and Mann (1986) estimated a set of linear price equations that represented the different rate schedules of the three main customer classes. The research was done primarily to determine if the regulator selection process impacted rates. A one-equation linear model of price at the utility level was estimated by Tolley and Bodmer (1990). This model, though simple, explained much of the variance in rates ($R^2 = 0.64$), and indicated that a variety of utility characteristics and regulatory environments influenced the average price. Berndt, Doane, and Epstein (1995) effectively expanded this study, showing again that many factors associated with state and local government regulation have large impacts on the average electricity price.

III. Methodology

III.1. Investments in DSM

Many studies have been written about the research on various facets of DSM. However, a model has not yet been developed to explain DSM investments. Given the substantial investments made in DSM and the variety of reasons for these investments it is of general interest to develop such an investment model. This is especially true with the advent of industry restructuring and ensuing competition. If DSM investments respond to customer demand, demand will remain despite deregulated competition. If DSM expenditures are partially associated with specific utility characteristics present in a competitive environment, again it is probable that some DSM investments will continue after competition comes about. However, if DSM is mainly associated with the industry's regulatory climate, deregulation may cause a decrease in utility-funded DSM programs.

Simple models explaining investment levels in infrastructure, operations and maintenance expenses have been estimated by Joskow, Baughman, and Kamat (1978). These models can easily be used as a framework to explain DSM investments. They incorporate a set of financial/managerial, operating, and customer characteristic variables. Given that many DSM programs are mandated by regulators, a DSM investment model should also incorporate regulatory variables. The general specification of such a model would be:

$$DSM = f(\text{Financial, Managerial, Operating, Customer, Regulatory})$$

DSM expenditures can be expected to be caused by a large variety of variables. The prices and costs of electricity is expected to play a large role in determining DSM investment levels and should be positively associated with DSM investment for two main reasons. First, high electricity costs will translate to higher rates, therefore resulting in greater pressure for lower rates from interest groups. Second, higher costs will also increase the number of cost-effective DSM opportunities available to a utility.

The cost of installing new capacity also influences DSM spending. The actual perceived cost of new capacity cannot be observed as it consists of more than the installed cost. Rather, it is interconnected with the capital and associated environmental risks. A variety of potential proxy variables exist for the need of new capacity and the concomitant costs and risks thereof. Large levels of CWIP as a percentage of the total electric plant, load factor or changes in the load factor, changes in peak load, or changes in capacity can indicate a need for new capacity investments. Also, a low load factor indicates the utility has excess capacity and would be less likely to invest in DSM that would reduce total amounts of electricity sold. Wholesale power sales might be a suitable proxy for excess capacity. Available capacity, especially at peak periods, can spur an utility to market power produced from its remaining idle capacity to other utilities.

The source of electricity may also impact the DSM investment levels. DSM activity probably will be positively correlated with power purchases and hydroelectric power generation. Electricity purchased from other companies is not an energy source that will expand the rate base, and the utility cannot obtain capital returns from it. It is assumed the utility will strive to replace this type of energy through DSM programs, for which it may earn monetary incentives.[13] Utilities with a greater share of hydroelectric power generation can be expected to have large DSM investments. Hydropower is a low-cost source of electricity with little potential for expansion. Additions to generating capacity produce higher-cost electricity. Expanding capacity would subject the consumers of hydropower dependent utilities to much larger relative rate increases than customers of utilities that already use more expensive power. This potential consumer suffering would increase the pressure on PUCs to find an alternative to building additional capacity.

Nuclear energy sources can also be positively correlated to DSM investments as DSM marketing could increase a utility's image as a steward of the environment. Difficulties that utilities have encountered with nuclear reactors have created the need to find and invest in non-nuclear energy sources. The age of a utility's capital stock can

[13] Certain conditions may make purchasing power more desirable than DSM investments. Utilities that are not allowed to earn a return on the DSM investment, are not allowed to recoup lost revenues, or have new power plants coming into service in the near future may be more inclined to purchase power.

also be positively correlated, because the older the stock, the greater the probability that aging plants will be phased out and newer, more expensive ones phased in. To reduce the investment in newer, more expensive plants, utilities should be willing to invest in DSM programs. A combined electric and a gas utility would be expected to be associated with higher DSM investment levels. A dual-fuel monopoly would allow the electric utility to remain impartial to fuel switching as a form of DSM. Fuel switching would not be associated with net lost revenues as sacrificed kWh sales would mean increased gas sales.

Weather can lead utilities in areas with extreme weather conditions to favor DSM. Extreme weather conditions bringing about higher summer or winter peaks and a consequent rise in excess capacity, increase utilities' incentive to undertake DSM investments. DSM programs in these seasonally peaking utilities could garner additional savings as individual customer loads among residential customers would be fairly large, allowing cost-effective installation of energy saving measures.

The density of a utility's service territory could play a role in DSM investments, though there are plausible reasons to assume that the relationship could be positive or negative. A lower density could cause many DSM options to be uneconomical due to the greater costs of providing services to a customer base that is further apart, thus reducing overall DSM investment levels. On the other hand, DSM programs could reduce the need for adding to transmission and distribution systems which could be quite costly in a service territory with greater population density. Greater industrial sales are expected to have a negative impact on DSM spending as industrial customers have been known to lobby against DSM, claiming they are subsidizing it and therefore paying higher than necessary prices (Clarkson, 1992).

Residential customer characteristics may also influence the DSM investment levels. Many utilities offer DSM programs to low-income customers. Greater numbers of low income customers may increase the level of DSM spending. On the other hand, low-income consumers lack access to the credit necessary to finance energy efficiency measures and have been found to have higher discount rates (Howarth and Anderson, 1993). Lower incomes therefore may reduce DSM program participation and spending if programs require participants to finance some portion of the energy efficiency service. Residential customer appliance stocks should also play a role in demand for DSM. Greater appliance stocks should increase the potential savings available to the average customer. As potential savings increase so will the demand for DSM services that will target these savings.

A utility's regulatory climate remains an important factor in determining investment. A PUC may have ordered the DSM investment in the first place. A variety of investment and research firms evaluate and rank regulatory agencies. These rankings in the past have been typically based on six criteria (Dubin and Navarro, 1982):

1. Allowed rate of return.
2. Average regulatory lag and use of interim rates.

3. Whether a historical or future test year is used.
4. If CWIP is allowed in the rate base, or if AFUDC[14] is allowed.
5. If tax credits and accelerated depreciation are "flowed through" or "normalized."
6. The presence of an automatic fuel adjustment clause.

It is hypothesized that the less favorable a utility's environment ranks the more a utility will invest in DSM. For a greater investment in DSM allows investments in more expensive generation alternatives to be delayed until a return on such capital investment will be more profitable. Further, a utility may consider such investments as a way to placate a PUC's least-cost planning demands with the hope of being granted a greater rate of return.

The presence of least-cost planning requirements and more stringent environmental standards are further variables that come under the rubric of a regulatory environment. State regulations pertaining to emissions and waste disposal, often higher than the federal standards, positively impact DSM programs as the costs of additional and existing generating capacity rise relative to DSM alternatives. However, some stricter state standards, such as building codes and appliance energy use standards, can make many DSM programs redundant or eliminate their cost-effectiveness.

[14] Allowance for funds used during construction.

III.2. Impact of DSM: Cost of Equity Capital

As a corporate strategy, DSM investment is not rewarded by increases or decreases in price or demand, but in the value of the company's stock. Testing the market's acceptance of DSM programs as this kind of corporate strategy is of great interest with the advent of industry restructuring. If the market does not value DSM during regulation, a decline in utility offered DSM services can be expected after deregulation.

The cost of equity capital or utility's stock price have been studied through numerous models that can easily be adapted to observe impacts of DSM expenditures. The simple models estimated by Trout (1979) and Dubin and Navarro (1982) can be reestimated with a term for DSM investment included. The adjusted model can be specified as:

Market-to-Book Rate = *g* (DSM, Financial, Managerial, Operating, Regulatory)

where the market-to-book rate is the dependent variable. The market-to-book (M/B) ratio quantifies the relationship between the utilities' common stock price and the book value of the assets. Variables associated with a strong positive relationship to the M/B ratio are: the actual rate of return, the expected rate of return, and the dividend pay-out ratio (Dubin and Navarro, 1982). Negative relationships have been detected in utilities with high levels of debt, taxes, or fuel costs, or those constructing nuclear power plants.

Earlier studies found a negative relationship between the regulatory environment and the cost of capital. In the case of the M/B ratio, an improved regulatory environment increased the M/B rate and, in the case of debt capital, a favorable regulatory environment was associated with a reduction in the rated bond yield. The only study (Gapenski, 1989) to analyze data from the 1980s found the regulatory environment to have little or no impact on equity capital costs. The regulatory environment has typically been entered into the models as a dummy variable or as a qualitative ranking.

Circumstances have changed within the electric utility industry since these studies have been performed. DSM programs and investments have become a multi-billion dollar industry and non-utility generation investment has exceeded that of utilities. Further, the arrival of retail wheeling has almost become a reality. With these changed circumstances, it cannot be expected that variables determining the cost of capital will remain fixed.

How DSM investments will affect stock values is unknown. It is possible that the market will view them as a successful strategy that minimizes capital expenditures while effectively retaining existing market shares and increasing sales to growing markets. On the other hand, DSM programs may be viewed as a losing strategy that wastes utility funds and results in revenue losses that will result in lower stock values.

Finally, DSM expenditures may be so small and unimportant that impacts on stock values will be negligible.

Additional variables that may have an impact on the stock values are those associated with increased capital investments, such as CWIP or the age of plant. CWIP was expected to have a negative relationship with the M/B ratio. The greater the amount of this presently unproductive expenditure, the less the market will value the utility. New construction is associated with capital investment risks, given factors such as new environmental rules, inflation, and lack of demand. In addition with industry restructuring, some new construction will become "stranded investments," no longer entitled to be included in the rate base where they can earn a rate of return. Plant age is expected to increase the utility's stock price since greater age will indicate less money invested in more expensive new capacity and possibly more efficient use of existing capacity.

Another variable that will be entered into the model is the cost of debt capital. A higher interest rate on short or long-term debt should be associated with higher stock prices as borrowing costs will be higher. The plant age, load factors, changes in peak loads, prices of electricity, and makeup of customers are also important variables that should be considered when developing the model. The age of plant should have a positive effect as investments in additional plant are being kept low. Average annual load factor should be associated with a higher stock price because more efficient use of existing plant should be associated with higher actual returns on investment and earnings per share, thus increasing stock prices. However, very high load factors may indicate that insufficient generation is available to meet customer demand and will require new construction that, in turn, could be associated with lower stock prices. Increases in peak load will eventually lead to additional capacity or long-term purchases being required. Again, capital expenditures on new plant is expected to reduce the M/B ratio. For utilities with a low load factor this growth in peak load make use of excess capacity. Increases in peak load may be associated with overall load growth (peak and off-peak) that in turn may improve the load factor of the utility with a positive impact on stock prices. The price of electricity is becoming an important factor on the eve of deregulation. It is expected that utilities with lower prices will have lower costs and, therefore, will be able to compete successfully when retail wheeling becomes a reality. These utilities will have their stocks bid upward in anticipation of competition. Distributions of customers should impact stock prices as each class has different costs associated with the services it requires. The share of industrial sales should have a positive impact as they are less expensive to serve and have higher, steadier loads. However, competition may change this. Larger customers with larger loads will have more to gain from switching suppliers for even marginal changes in price. In most scenarios for restructuring the industry, industrial customers first benefit from retail wheeling, while the commercial and residential classes remain captive markets for electric utilities.

DSM expenditures will also enter into the model. DSM does not have a predicted sign. A negative sign would indicate that DSM investment depresses the utility's stock value, while a positive sign would indicate the market puts a positive value on DSM investments.

III.3. Impact of DSM: Demand for Electricity

The factors influencing electricity demand have been studied comprehensively since the fifties. Economists have found the greatest interest in the short-run and long-run, price and income elasticities and cross-price elasticities of competing fuels. This focus is understandable given that this information is necessary in planning electric plant and equipment investments. With the development of DSM programs, another factor was introduced influencing electricity demand. Much energy demand modeling work has been incorporated into the evaluation of DSM programs. However, these studies are primarily involved with studying specific program impacts and use micro-level data disaggregated to the customer level or even to equipment levels. Aggregate models of DSM impacts have not yet been estimated. Detailed aggregated simulation models have been used to estimate DSM impacts (Keelin and Gellings, 1986), (Faruqui, Seiden, and Braithwait, 1990), but actual estimation has not yet been done at a more aggregate level.

DSM expenditures in 1993 were close to 10% of new electric plant investments. DSM spending has increased from 1990 through 1993, rising from under 1% to 1.5% of total expenditures for investor-owned utilities. At some utilities, DSM represents over 8% of total annual expenditures. In California, DSM was expected to satisfy 60% of the state's growth in electricity requirements for the nineties (Prete, 1992). The overall cost of these programs is substantial and is expected to achieve moderate growth levels, despite the oncoming industry restructuring. Therefore, it is timely to look at the more aggregate impacts of DSM on demand.

A simple model of DSM's affect on electricity demand can be estimated at utility levels. The general specification of the model would be:

$$\text{Quantity} = k\,(\text{DSM, Price, Fuel, Customer, Weather})$$

This is the same general model used in countless DSM evaluations. The only difference lies in the level of aggregation. DSM evaluations use customer or end use level data, while the proposed model can be estimated at the system level. The DSM variable that utilities consistently report is the level of DSM spending. There is no expected sign for DSM investment. This is due to differing impacts of load management and conservation. In theory, a predominance of conservation in DSM investments will cause the estimated coefficient to be negative. If load management programs comprise the main type of DSM investment and are structured to shift loads to off-peak periods, the coefficient should be positive.

The level of aggregation to the utility level was partially determined by, as with most studies, the availability of data. Since 1989 the Energy Information Agency has collected data on utility expenditures on DSM. The data for the years 1990 through 1993 has been published and is presently available thus allowing for one consistent source of reported DSM data. Four years of DSM expenditure data were therefore available for all investor and publicly owned electric utilities[15].

The expected price elasticity will be negative, ranging from -0.45 to -2.0, which approximate the values found in previous residential, commercial, and industrial electricity demand studies. The estimated price elasticity will represent a weighted average price elasticity as demand of all customer classes is aggregated to represent utility system level demand. Aggregating to the system level does not allow the marginal price to be estimated for the average customer, thus the average price is used. Even with disaggregation to the customer class level, it is doubtful that a meaningful marginal price estimate could be estimated. Since the beginning of the 1980s, the rate structures of many utilities have become more complex. A variety of rates have been negotiated for commercial and industrial clients. These new rates vary from customer to customer, depending on their ability to switch fuels or become cogenerators, their levels of peak demand, or even their financial stability. Utility rates also vary widely in

[15] Even though utility expenditures are reported from a consistent source, expenditures may not be completely comparable. Companies just beginning DSM programs may have all of their expenditures in planning and administration costs without actual investments in programs. Reported DSM expenditures should be viewed more as an index of past and present DSM investments.

the residential and commercial sectors, where they may change seasonally, be flat, have increasing or decreasing block rate structures or have fixed charges.

Positive cross-price elasticities should be expected given the variety of competing fuels. As the price of these fuels rises, customers are expected to increase their electricity demand by partially substituting electricity for now more expensive, competing fuels. Due to supply constraints placed on gas, many electricity customers may prefer gas but cannot obtain the service. Consequently gas' cross-price elasticity will be biased downwards.

Income elasticities have been estimated in many previous studies, but, when aggregation takes place over customer classes the results are not be comparable. Nonetheless, the estimated income elasticity is expected to be positive and within the range of those estimated by previous models. This ranges from 0.2 to 2.2 (Bohi, 1981, 1984), (Taylor, 1975).

Electricity demand will naturally be dependent on the population levels and commercial and industrial activity levels in the utility's service territory. The number of residential accounts should provide a good estimate of populations and should have a positive sign. The number of commercial and industrial accounts, however, may not prove a good proxy for energy consumption because in many cases only a few accounts will be responsible for most of the electricity consumption. Thus, employment in these two sectors will be used as a measure of the sector's activity, with an expected positive relationship to electricity demand. General industrial employment may prove to be an inexact measure of industrial demand for electricity due to the differing levels of intensity of electricity use and substitutability for electricity in industrial processes. Industrial employment may provide a more exact measure in certain SIC groups that use electricity more intensively than others.

Climate extremes should increase energy demand due to increased heating or cooling loads within buildings of all customer classes. Given greater levels of electric space heating, a greater consumption of electricity is to be expected. Appliance stocks may also vary because many states now have more stringent appliance and building codes than those of the federal government. These more stringent codes will affect appliance and building stocks, resulting in less electricity consumption for states where they apply.

III.3. Impact of DSM: Cost of Electricity

There is also interest in estimating the DSM's impacts on the production of electricity, or specifically on its cost. The proposed cost equation will be a simple, one-equation model similar to those used to estimate price of electricity used by Halvorsen (1975), Tolley and Bodmer (1990), and Berndt, Doane, and Epstein (1995).[16] This equation takes the following form:

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[16] This specification was used rather than a neoclassical translog cost specification that is typically seen in electric utility cost studies. A large number of factors, other than

$$\text{Cost} = j\,(\text{DSM, Quantity Financial, Managerial, Operating, Regulatory})$$

where the dependent variable cost, is the average cost of producing one kWh. This is a relatively simple model that can incorporate many of the variables affecting the cost of electricity. Quantity is expected to decrease average costs due to economies of scale. The DSM's variables expected parameter is anticipated to be negative. A negative correlation is expected because the entire point of investing in DSM is to reduce the cost of electricity. DSM was not promoted as a method of saving electricity at any cost, but was intended as a least-cost alternative. Utilities are investing in DSM to prevent having to invest in more expensive capacity expansion. Nevertheless, it is possible that DSM increases costs if non-cost-effective investments are made. Also, DSM programs that primarily target conservation may, in the short-run, increase costs as conservation results in immediate revenue losses. In the long-run, conservation defers investments in electric plant resulting in lower costs. In the short-run, quantities sold are reduced, resulting is higher costs.

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input prices, were expected to influence DSM impacts on costs. A translog model specification that includes numerous non-price variables will tend to have an extraordinary number of coefficients and substantially reduce the degrees of freedom of the regression model. This study includes electric utilities with different power generation technologies. A translog specification typically assumes similar technologies. The neoclassical model assumes that the industry is at its long-run equilibrium. With the market restructuring and the large number of mergers within the industry this assumption is in question.

A large number of operating, financial, and managerial characteristics should play a role in determining the average cost of electricity. As with most prior price and cost equations, variables representing capital, labor, and fuel costs will be included. Naturally, increases in the costs of these items are expected to lead to increases in average costs. Financial variables, such as the utility's bond rating, interest rates on long-term debt, and tax payments can be expected to increase the electricity's average cost. Without competitive pressures, utilities may add unnecessary staff, thus increasing costs. For some utilities, taxes account for three-quarters of the variation in price (Thompson, 1985).

Operating factors, such as capacity under construction, make up of generating resources, line losses, density of the service territory, and age of the electric plant are also expected affect average costs. Construction work in progress (CWIP) should have a positive impact, either through its inclusion in the rate base or its negative impact on cash flow. Hydroelectric power is an inexpensive form of power generation and a larger share of electricity generated from this source should be associated with a decrease in cost. Electricity generation with nuclear power should increase the cost of electricity. Though initially deemed an inexpensive form of energy, nuclear energy has proven quite expensive due to high construction costs, unexpectedly low plant utilization rates and other reasons. Higher line losses are naturally associated with increased costs. A larger service territory requires more transmission lines per customer. However, as a service territory becomes more dense, additional costs are incurred in laying underground transmission lines. With older plant, much of the capital expenses have been depreciated. Thus, lower costs can be charged. Older generating plant may also be less expensive to operate, even if the embedded costs are the same as in new plant. Older power plants and transmission and distribution facilities may not require the same environmental or safety standards as new plant.

For a utility also supplying gas, administrative costs can most likely be kept lower due to synergistic effects such as combined customer records and billing procedures. The more industrial sales are a percentage of total sales, the greater expected electricity cost reductions. Industrial customers are less expensive to serve than residential and commercial customers. On average, industrial customers consume large amounts electricity reducing average fixed costs, and many of them consume high-voltage electricity, which is less expensive to supply. The less the population density of the service territory, the more expensive it is for a utility to supply electricity to its customers, and the greater the expanse, the more transmission and distribution system costs relative to its customer base.

An unfriendly regulatory climate is expected to lower the probability that PUCs will grant rate increases. This has a dampening effect on cost as utilities will make even more attempts to minimize costs. Though various federal laws already establish permitted emissions and wastes levels, state governments may make these levels even more restrictive. With one-fourth to one-third of the total cost for a new coal plant going into environmental control systems, these more restrictive regulations can substantially affect costs (Rubin 1989). Some states now are moving towards requiring utilities to internalize environmental externalities within the utilities' cost structure, adding to the cost of electricity.

III.5. Scope of Analysis

The EIA has collected DSM investment data since 1989, though these have only been available since 1990. The four years of EIA data available (1990-1993) were analyzed in this study. DSM investment data were available from other sources,[17] but were not used in favor of staying with a single consistent data set. Also, the EIA surveys all major utilities making it possible to assume that utilities without reported DSM investment actually had little or no DSM expenditures.

The EIA collects a large volume of annual data on the financial and operating characteristics of private and public utilities. Fairly detailed information available for, approximately[18] 180 largest investor-owned utilities is part of this data. At the end on 1989, these utilities represented 99% of investor-owned utility sales and just under 79% of total electricity revenues from sales to ultimate consumers in the United States.

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[17] When this study was initially conceived, the analysis period was expected to be the 1980's. During that period DSM investments were inconsistently reported by utilities. DSM expenditures from the decade were obtained from a variety of surveys (Cogan and Williams, 1985,1987) (Nadel, 1991). In 1991, I also collected this expenditure data by surveying utilities and PUCs around the country. Collection methodologies between sources often caused expenditure figures for the same utilities to significantly differ.
[18] This is an approximate number as the number reported each year will vary slightly due to mergers and fluctuations in utility sizes.

Investor-owned utilities produce the bulk of the electricity used in the United States and the majority of these have financial statistics published by the EIA. Using this group of utilities to estimate the models described above, would give a clear indication of the DSM determinants and impacts in the United States. It would be difficult to include in this study municipal, federal, or other types of non-profit generators or electricity distributors. The Federal Energy and Regulatory Commission (FERC) reporting guidelines differ between investor-owned utilities and the non-profit utilities. This causes some variables to be reported by investor-owned utilities but not by the non-profits. In addition, the non-profits are not regulated by the state PUCs but by elected boards. Finally, the profit motive, which supposedly spurs the investor-owned utilities into DSM program investments to reduce electricity prices and increase stock values, is missing from non-profit firms.

Not all of the reported utilities can be analyzed as separate economic decision makers. Many utilities are operating units of holding companies and, therefore, do not operate independently. Also, some reported utilities are actually partially owned by other utilities. This is true for a number of the nuclear power plants in the Northeast, such as Connecticut Yankee or Maine Yankee, where up to nine utilities own varying shares in the plants. Even if only partial, ownership of other utilities will impact the operations and investment decisions of a particular utility. Analysis of individual economic agents requires investments and expenditures be aggregated to the holding company levels. In cases where partial ownership of a utility was evident, all variables were weighted by the percentage owned.[19] This weighting was performed for each of the 900 EIA reported variables.

Aggregating to the holding company level was particularly important because other utility data were obtained from Value Line, an investment publication which reports at the holding company level. Value Line was the source for a variety of financial data and items such as load factor, peak load, capacity, rate of return, dividend pay-out ratio, and average age of plant. Value Line also reported on merger activities and bankruptcies. Utilities were dropped if they had merged with another utility during the 4 year analysis period, as merger year data might be inconsistent, with some variables representing the utility before and others after the merger. El Paso Electric was excluded from the analysis because of its bankruptcy, which was thought to impact most of its operations and investment decisions. Other utilities were omitted if they were not reported in Value Line or Moody's Utilities.[20] A few utilities were removed from the sample due to significant foreign operations or because most of their business activities were outside the electric utility industry. Texas-New Mexico Power was not included in the final sample because it did not have generating facilities. The final sample of holding companies with complete data for the four-year study period included 81 companies. These 81 actually represent 119 utility operating companies reported by the EIA.

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[19] A simple example of this would be a generating company owned equally by two electric utilities. If 30 MWh was sold by an operating company, the owners would each be associated with 50% of the power produced.

[20] Moody's Utilities was used as a source to determine ownership shares.

Table III.1

Utility Sample Attrition

Sample	Utilities
Utilities reported on by EIA 1984-1993	190
Utilities dropped	72
Companies used in analysis	119
Number of holding companies in analysis	81

Models estimated using the final sample of electric holding companies should provide a good indication of overall DSM impacts. In 1990, these electric utilities sold most of the electricity in the United States representing 60.7% of all electricity sold and 78.6% of electricity sold by investor-owned utilities. In the same year, the utilities represented 83.5% of total nationally-reported DSM expenditures and 92% of DSM expenditures reported by all investor-owned utilities.

Typically, customer characteristics are not available for most utilities except for sales to specific customer classes. Reported population or service area sizes are only available for a portion of the sample. What is known, however, are total sales to end users by state. This breakdown was available for 1993 from data published in EIA's Form 861. Total electric sales by state allow each utility's share of state electric sales to be calculated. The utility's share of total state electric sales is assumed to approximate service to the equivalent portion of the state's population and businesses. This assumption means a utility selling 50% of a state's electricity consumption will provide services to 50% of its population and will deliver electricity to companies with 50% of the business activity.

This assumption allows various state and regional level demographic data to be used to estimate utility customer characteristics. State and regional level variables include income, employment, weather variables, types of industrial activity, the regulatory environment, energy prices, and appliance stocks. A complete listing of variables and their sources is supplied in Appendix 1.

Many utilities do not operate within a single state. For utilities operating in two or more states, customer demographic variables are calculated using the weighted average of each variable. The weight used is the percentage of total sales to end users sold in each state seen as a percentage of total utility sales to end users.

The final data set used in the analysis contained information on 81 electric utilities over a four-year period. Variables available were detailed information on the companies' financial and operating characteristics, approximated demographic data on each utility's customer base, information on the regulatory environment of each utility, weather variables, and prices of competing fuels.

IV. Empirical Estimation

IV.1. Model Summary

Four equations were estimated as part of this analysis. These models are specified as:

1. DSM $= f$ (Financial, Managerial, Operating, Customer, Regulatory)

2. M/B Ratio $= g$ (DSM, Financial, Managerial, Operating, Regulatory)

3. Cost $= j$ (DSM, Quantity Financial, Managerial, Operating, Regulatory)

4. Quantity $= k$ (DSM, Price, Fuel, Customer, Weather)

Factors influencing DSM investments were incorporated in the first equation. The second equation estimated DSM impacts on the a utility's cost of equity capital, or stock price. The third equation estimated the average cost of producing electricity to determine how DSM influenced the average cost of producing electricity. The fourth equation was used to estimate DSM investments impacts on electricity demand. Variables used in the final models are shown on Table IV.1. They are separated into firm financial/managerial and operating characteristics, customer and demographic characteristics, and regulatory environment characteristics.

Table IV.1

Variables Used to Estimate Model

Variable Name	Variable Description	Source
Financial and Managerial		
ROR	Rate of return on investment.	Value Line
PCTAX	Taxes as a percentage of total expenditures.	FERC Form 1
PCCWIP	CWIP as a percent of total electric plant investment.	FERC Form 1
WAGES	Natural log of the average utility wage.	FERC Form 1
PCGASREV	Total gas operation revenues as a percent of total utility revenues.	FERC Form 1
DIVIDEND	Dividend pay-out ratio.	Value Line
EQDBRAT	The equity- debt ratio.	Value Line
MBRATIO	Market-to-book ratio, the market share price divided by the book value per share.	Value Line
Operational		
PCIND	Percentage of total sales to industrial customers.	FERC Form 1
PCDSM	DSM percentage share of total expenditures.	EIA Form 861 and FERC Form 1
PRICE	Average price of electricity.	FERC Form 1
PCPURCH	Percent of total power (purchased and generated) that was purchased.	FERC Form 1

Variable Name	Variable Description	Source
LOAD	The annual load factor (ratio of average load divided by peak load).[21]	Value Line
COOLDD	Annual cooling degree-days.	BLS
DENSITY	Pole miles per residential customer.	FERC Form 1
QUANTITY	Total quantity electricity sold to final consumers divided by number of residential customers.	FERC Form 1
INVKWH	The investment in plant per kWh generated or purchased.	FERC Form 1
PCNUKE	Percent of generated and purchased power that is generated by nuclear power plants.	FERC Form 1
FUELKWH	Fuel costs per kWh generated.	FERC Form 1
PLANT	Average age of utility plant.	Value Line
PCRESALE	Total electricity resales as a percent of total electricity sold.	FERC Form 1
Customer		
PCINC	Per capita income.	BEA REIS
RESKWH	Average MWh consumption per residential customer.	FERC Form 1
GAS	Price of natural gas.	Gas Facts Yearbook
PCMFG	Manufacturing as a percentage of total employment.	BEA REIS

[21] This was derived by computing the average annual hourly kWh demanded (total kWh sold divided by 8,760, the number of hours in the year). This was divided by the maximum hourly kWh demanded during the peak period (usually one specific hour).

Variable Name	Variable Description	Source
Regulatory		
PCPAPER	Percentage of all employment income from the pulp and paper industry	BEA REIS
PCPMETAL	Percentage of all employment income from the primary metals industry.	BEA REIS
LCUP	Dummy variable indicating least-cost planning required within the firm's service territory. 1 = Required 0 = Not required	Mitchell (1989, 1992)
REGOOD	Dummy Variable indicating the regulatory environment is rated above average. 1 = Above average 0 = Average or below average	Value Line

IV.2. DSM Investment Equation

Large levels of investor-owned utility DSM investment were hypothesized to be caused by specific firm, customer, service territory, and regulatory characteristics. Simple models have been developed explaining investment levels in infrastructure and operations and maintenance expenses. Such a model has been adapted to explain DSM investments. The estimated DSM investment model has the general specification:

DSM = f(Financial, Managerial, Operating, Customer, Regulatory)

Data were available on total DSM expenditures for 81 utilities over a four-year period of 1990 through 1991. Supplemental information on utility characteristics, service area demographics, and regulatory climate were collected. These data allowed for a set of cross-section time-series models to be estimated.

Variable scaling and normalization proved important as the utilities analyzed ranged from just under 1 million MWh sales to 119 million MWh sales. The equation's DSM variable was expressed as a percentage of total expenditures. All explanatory variables were either included in the equation as averages, ratios, or dummy variables. The explanatory variables included in the final model are shown in Table IV.2 along with the expected sign of the estimated parameter.

Table IV.2

DSM Investment Model Variables

Variable Name	Expected Sign	Variable Description
PCDSM	Dependent Variable	DSM as percent of total expenditures
PCIND	-	Percentage of total sales to industrial customers
RESKWH	+	Average MWh consumption per residential customer
PCINC	?	Per capita income

Variable Name	Expected Sign	Variable Description
PCPURCH	+	Percent of total power (purchased and generated) that was purchased
LOAD	+	The annual load factor (ratio of average load divided by peak load)
ROR	+	Rate of return on investment
LCUP	+	Dummy variable indicating least-cost planning required within the firm's service territory 1 = Required, 0 = Not required
REGOOD	-	Dummy Variable indicating the regulatory environment is rated above average 1 = above average, 0 = below average or average

In addition, three dummy variables, Y91, Y92, and Y93, give the model the form of a fixed-effects cross-section time-series model. Given cross-section time-series data, it is possible the actual parameters differed between each times-series and/or cross-section. With 81 different cross-sections with only four time-series observations each, it was not considered viable to estimate varying coefficients for each utility. Varying coefficients were tested for across years[22] (Table IV.3). The resulting F-test

[22] Two equations were estimated: a restricted model including 8 explanatory variables and the intercept, and an unrestricted model that included annual interaction terms for 8 explanatory variables and different intercepts for each year. The F statistic of 0.92 was not statistically significant and was calculated as:
$((ESS_R - ESS_{UR})/q)/(ESS_{UR}/(N\text{-}k)= ((437\text{-}402)/27)/(402/(324\text{-}36)$
Where ESS_{UR} was the error sum of squares of the unrestricted model with varying coefficients, and ESS_R was the error sum of squares of the model where the parameters

rejected the hypothesis that all coefficients varied across all years. Yearly dummy variables were included in the model because specifying different intercepts for each year were found to be statistically significant when compared to the restricted model. The calculated F statistic was 4.2, which is significant at the 1% level.[23]

In regression estimation, other statistical problems can occur which may result in biasing the parameter estimates, their variances, or the efficiency of the estimate. Two problems typically looked for with cross-section time-series models are autocorrelation and heteroscedasticity. Autocorrelation arises when error terms are correlated with one another. The presence of autocorrelation does not bias the coefficient estimated using OLS. However, inefficient variances of the parameter estimates typically result. Testing and correcting for autocorrelation is not really applicable for the data set being analyzed. The data have only four years of data for each firm. Testing for autocorrelation for each cross-sections' four-year time period would have dubious results. In addition, correction for even the simplest first-order autocorrelation model would result in the loss of one-quarter of the observations, leading to a serious reduction in the efficiency of the estimation.

Heteroscedasticity arises when the variance of the error term is not constant across sample observations. Heteroscedasticity does not bias the parameters' estimates. However, heteroscedasticity can result in inefficient estimators.

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did not vary over the years. The number of restrictions placed on the model number was q, k was the number of parameters in the unrestricted model and N was the number of observations.

[23] Hypothesis test inputs are reported in Appendix 3.

The presence of heteroscedasticity was tested for using the Breusch-Pagan test[24] (Breusch and Pagan, 1979). All explanatory variables were included in the regression used to estimate the test statistic as no particular regression variable was suspected of causing the heteroscedasticity. The calculated test statistic was 128, which at 8 degrees of freedom leads to rejection of the null hypothesis of homoscedasticity.

Detecting heteroscedasticity with these tests is straightforward; correction for heteroscedasticity is not. Correcting for heteroscedasticity requires making certain assumptions about the functional form of the heteroscedasticity. As ordinary least squares (OLS) offers unbiased estimates of the parameters, the method developed by White (1980) was used to calculate a heteroscedasticity-consistent variance-covariance matrix (HCV).[25] This method is extremely useful as it allows us to make appropriate

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[24] The Breusch-Pagan test estimates the test statistic through a two-stage procedure. The equation:

$$\mathbf{Y} = \alpha + \beta\mathbf{Z} + \varepsilon$$

that is suspected of having heteroscedasticity is estimated using OLS, where the dependent variable Y is a function of intercept α and the vector of explanatory variables Z. The error term is ε. The estimated error term is squared and divided by the asymptotic variance of the error term and the regression:

$$\frac{\hat{\varepsilon}^2}{\sigma^2} = \mathbf{a} + \mathbf{bZ} + \mathbf{e}$$

is estimated. Where the estimated error term squared $\hat{\varepsilon}^2$ is divided by the asymptotic variance of the error term σ^2 defined as the mean of the squared residuals. The test statistic is half of the regression (explained) sum of squares. This test statistic is distributed asymptotically as a chi-squared distribution with degrees of freedom equal to the number of variables in Z. This is a general test for the presence of heteroscedasticity and does not require any prior knowledge of the functional form that the heteroscedasticity takes.

[25] White's HCV is calculated by constructing the diagonal matrix G where the diagonal terms are the squared residual terms from the original OLS regression. The HCV matrix is then estimated by computing the GLS variance-covariance matrix (X'X)$^{-}$

statistical inferences based on the result of the OLS without specifying the form of heteroscedasticity. The parameters' standard errors and t statistics were reestimated for the model using the HCV(Table IV.4).

Table VI.3

DSM Investment Equation Hypothesis Testing

What Was tested	Test and Test Statistic	Result
Varying slopes and intercepts for each year	F-test F statistic = 0.92	Not statistically significant
Varying slopes for each year with one intercept	F-test F statistic = 0.85	Not statistically significant
Varying intercepts for each year	F-test F statistic = 3.88	Statistically significant Fixed-effects model specified
Heteroscedasticity	Breusch-Pagan Test Chi-squared statistic = 128	Presence of Heteroscedasticity detected. White's HCV estimated

[1] $X'GX(X'X)^{-1}$, where the X matrix consists of all the explanatory variables. The square roots of the diagonal terms of this matrix are the HCV standard errors associated with each coefficient.

Table IV.4

Parameter Estimates of the DSM Investment Equation

(N = 324 R^2 = 0.41 log-likelihood -502.04)

Variable	Parameter Estimate	Standard Error	t Statistic
INTERCEPT	-4.328526	1.137	-3.806
Y91	-0.051772	0.1280	-0.4046
Y92	0.496565	0.1734	2.864
Y93	0.429587	0.1864	2.304
PCIND	-0.015344	0.005964	-2.573
RESKWH	0.113888	0.03009	3.784
PCINC	0.118443	0.02684	4.413
PCPURCH	0.007154	0.005477	1.306
LOAD	0.021909	0.01162	1.885
ROR	0.054400	0.02732	1.991
LCUP	0.960189	0.1913	5.018
REGOOD	1.187852	0.2741	4.334

The regression equations overall performance proved satisfactory because most of the explanatory variables have parameter estimates with the correct sign and are also statistically significant. The sign of the parameter estimates were, for the most part, as expected, with the exception of the income, PCINC, and the regulatory climate, REGOOD. The estimated R^2 of 0.41 does indicate that much of the variation in DSM spending remains to be explained.

Utility characteristic variables included in the model were the rate of return, ROR, load factor, LOAD, and percentage of total power purchased, PPURCH. The estimated rate of return parameter (0.05), was small and positive. This indicated financially healthier utilities tended to invest more in DSM. It is possible that the direction of causality was the reverse, since firms investing in DSM may be allowed a higher rate of return. The actual absolute impact was quite small given a one-point increase in the rate of return increased the DSM share of total expenditures by just 0.02. The positive relationship between the annual load factor, LOAD, and DSM indicates that DSM investments were possibly being used to defer capacity. A lower load factor indicates excess capacity during off-peak periods, but as the load factor becomes higher, the reserve margin shrinks, thus producing the need for more capacity. DSM investments that shift load and conserve electricity tend to lower the overall load factor and the need for additional capacity investments. The purchased power parameter estimate (0.007) was positive, indicating that utilities may have been trying to replace purchased power through investment in DSM "negawatts." However, the parameter was not statistically different from zero, and the impact of the estimated coefficient was quite small, as the model predicts that a utility purchasing 100% of its electricity would only increase DSM's share of total expenditures by 0.7.

The percent of electricity sold to industrial customers, PCIND, had the expected negative sign (-0.015). A negative parameter was expected because industrial customers have used their market power to lobby for less DSM. Another interpretation could be that utilities tend to target industrial customers less in DSM programs and, therefore, utilities with greater industrial sales have, in general, less DSM expenditures.[26] Again, the absolute impact of the industrial customers' share of consumption was quite small, as the regression predicted that a utility with only industrial customers would decrease DSM's share of total expenditures by 1.5 points.

The average residential consumption, RESKWH, had the hypothesized positive impact on DSM expenditures (0.11). This positive relationship was assumed because larger per-customer consumption should be associated with more end uses per customer. With more end uses more appliances and equipment are available to target and more areas exist for potential energy savings. Higher consumption levels also allow DSM program implementation to become more cost-effective if there are fixed costs to providing DSM services. The estimated coefficient indicates that a utility with average annual residential customers consuming 15,000 kWh versus one with residential consumption of only 5,000 kWh per year will have a one-point higher DSM share of total expenditures.

[26] Lower DSM investments in industrial customers could be due less market imperfections that prevent industrial customers from investing in DSM. Industrial customers will have better access to capital than residential customers and have a profit incentive to invest in energy-efficient processes and equipment.

In the case of income, PCINC, utilities in areas with higher per capita incomes were associated with greater DSM expenditures. It had been hypothesized that larger number of low-income customers would bring about greater levels of DSM investment. A lower per capita income would be associated with a greater number of low-income customers. However, the parameter estimate (0.12), was positive and indicated that for every thousand dollar increase in average per capita income DSM's share of total expenditures increased by one-tenth of one-point. The positive correlation could have been because people with higher incomes demand more DSM. People with higher incomes could have more to gain from DSM programs due to greater appliance stocks, or lower discount rates will increase their propensity to invest in energy-efficiency measures. If DSM was viewed as a competing good to electricity of higher quality, it is possible DSM demand increases with income, simply because these people will be willing to pay more for higher quality sources of electricity.

The two regulatory variables, LCUP and REGOOD, had a considerable impact on DSM investments. The model predicted that a utility operating within states with least-cost planning and above average regulatory environment were likely to increase DSM expenditures by over 2 % of total expenditures. Given that DSM shares of total utility expenditures averaged 1.41% for the four-year analysis period, this is a considerable impact. The least-cost planning variable was obtained from two studies done by Mitchell (1989, 1992). The studies classified the state of least-cost planning in each state for the years 1989 and 1991. States were classified into five categories, no progress in LCUP, if LCUP was under consideration, if LCUP was under development, if LCUP was in implementations, and whether LCUP was being practiced. During 1989 seven states had LCUP that was in practice which increased to 14 in 1991.

Results for these two years were extended to the adjoining years. The variable was a one if least-cost planning had been implemented in states making up over 50% of a utility's service territory and zero otherwise. Least-cost planning compels utilities to consider DSM and supply-side resources when developing resource plans. It is, however, the potential pro-DSM regulatory climate and not just the integration of DSM into resource plans that causes the relationship between LCUP and DSM to be positive. The parameter estimate of 0.96 indicated that least-cost planning requirements would increase DSM's share of total expenditures by the same amount.

The regulatory climate variable REGOOD was obtained from Value Line. Value Line classified the regulatory climate of utilities as average, above average, and below average. This qualitative rating was converted into a binary variable that was one in an above average regulatory environment and zero otherwise. It was expected that a "PUC driven " DSM would be associated with states with below average regulatory climates. Also, it was assumed that PUCs coercing utilities into implementing DSM programs would receive a below average regulatory climate rating. This proved not to be the case, as the parameter estimate (1.2) was positive and statistically different from zero. The model predicted that utilities operating in an above average regulatory climate would increase DSM's share of total spending by 1.2 points. Perhaps in a good regulatory environment the PUC will structure the incentives to invest in DSM in such a ways as to make such an investment profitable. In monetary terms a 1.2% of total expenditures of the average utility would represent approximately $14.5 million.

The model showed an apparent shift in DSM spending in 1992 and 1993 relative to 1990 and 1991. This is seen from the yearly dummy variable coefficients where in the two later years the average utility increased its DSM share of total expenditures by respectively 0.5 and 0.43 of a percentage point.

An important result of the model was to show that the regulatory environment played a very significant role in DSM spending. Given this result, one can expect reductions in the levels of DSM spending with the onset of industry restructuring and deregulation. Industry restructuring will not necessarily mean the end of regulator driven DSM. After industry restructuring, PUCs may still regulate transmission and distribution companies and require them to offer DSM services perhaps financing this by assessing a line charge.

Many other explanatory variables were considered for inclusion in the model.[27] All of these variables proved not to have a statistically significant impact on the level of DSM expenditures. The one variable that was expected to have a strong relationship with DSM spending levels was price. It had been expected that higher prices would result in the PUC placing greater pressure on the utility to invest in DSM. Also, higher

[27] Included in these variables were regional dummy variables and a variable for the number of states in which the utility operated. Statistically insignificant coefficients were estimated for all of these variables.

prices should result in larger numbers of DSM opportunities becoming cost-effective. However, the average price and price of each customer class all appeared not to be correlated with DSM investments.

IV.3. Cost of Equity Capital Equation

DSM investment was hypothesized to have an impact on the value of the utility's stock. Successful and unsuccessful corporate strategies should be rewarded (penalized) by an increase (decrease) in the value of their stock. Earlier studies have investigated the effect of the regulatory climate on the cost of equity capital. The way in which the market values DSM, as a corporate strategy, is of more interest now that the industry is restructuring. The simple equation that was estimated is quite similar to those used in earlier studies and is specified as:

$$\text{M/B Ratio} = g\,(\text{DSM, Financial, Managerial, Operating, Regulatory})$$

where M/B ratio was the market-to-book ratio, defined as the stock market price per share divided by the book value per share. This ratio quantified the relationship between a utility's common stock price and the book value of the assets.[28] Utilities that

[28] The book value is an accounting term, calculated as the sum of all assets minus the sum of all debts, liabilities, and preferred share prices.

pursue a corporate strategy favored by the market can expect the M/B ratio to rise as the stock price is bid up relative to the book value. Variables included in the model are presented in Table IV.5

Table IV.5

Cost of Equity Capital Equation Variables

Variable Name	Expected Sign	Variable Label
MBRATIO	Dependent Variable	Market-to-book ratio, the market share price divided by the book value per share.
PLANT	+	Average age of utility plant
EQDBRAT	-	The equity- debt ratio
PCIND	?	Percentage of industrial sales
ROR	+	Rate of return
REGOOD	+	Dummy variable indicating the regulatory environment is rated above average
LCUP	?	Dummy variable indicating least-cost planning required within the firm's service territory
DIVIDEND	+	Dividend pay-out ratio
PCDSM	-	DSM as a percentage of total expenses
PCCWIP	-	CWIP as percent of total utility plant and equipment
PCRESALE	+	Percent of total sales that are to other utilities

The tests performed on the model are shown in Table VI.6. F-tests indicated that slope parameters and the intercept varied in a statistically significant fashion for all of the four years. The same was true for a regressions that either specified that slopes varied or intercepts varied over all four years. However, after a fixed-effects model was specified, a F-test indicated that there was not statistical grounds for specifying different slope parameters in addition to the varying intercepts since the F statistic was 1.01.

The Breusch-Pagan test indicated that heteroscedasticity was present. As in the DSM investment equations above, instead of correcting for heteroscedasticity, HCV standard errors and t statistics were calculated and presented with the parameter estimates on Table VI.7.

Table VI.6

Cost of Equity Capital Model Hypothesis Testing

What Was tested	**Test and Test Statistic**	**Result**
Varying slopes and intercepts for each year	F-test F statistic = 5.17	Statistically significant
Varying slopes for each year with one intercept	F-test F statistic = 5.6	Statistically significant
Varying intercepts for each year	F-test F statistic = 42.3	Statistically significant
Varying intercepts for each year *vs.* varying slopes and intercepts for each year	F-test F statistic =1.01	Not statistically significant Fixed-effects model specified
Heteroscedasticity	Breusch-Pagan Test Chi-squared statistic = 40.5	Presence of Heteroscedasticity detected. White's HCV estimated

Table IV.7

Parameter Estimates of the Cost of Equity Equation Error and t Statistic

(N= 324 R^2= 0.88 log-likelihood = -1,383)

Variable	Parameter Estimate	Standard Error	t Statistic
INTERCEPT	4.011668	8.709	0.460
Y91	8.098673	2.536	3.194
Y92	22.569784	2.624	8.601
Y93	32.480163	3.068	10.59
PLANT	1.234811	0.9181	1.345
EQDBRAT	1.217913	0.1508	8.078
PCIND	0.277331	0.08997	3.083
ROR	3.114928	0.5784	5.386
REGOOD	5.165617	3.486	1.482
LCUP	-8.930453	2.896	-3.084
DIVIDEND	1.829703	0.4530	4.039
PCDSM	1.909826	0.9304	2.053
PCCWIP	-0.435635	0.09706	-4.488
PCRESALE	-0.136690	0.07167	-1.907

The overall regression results were quite fruitful in that the explanatory variables included in the regression explain 64% of the variance and had, for the most part, parameter estimates that were significantly different from zero. The parameters estimated in the equation also had the expected signs. The annual intercepts, Y91, Y92, and Y93, captured much of the steady rise that utility stocks were experiencing over this four-year period.[29]

Variables that had a very significant impact on the M/B ratio were the rate of return, ROR, and the dividend pay-out ratio, DIVIDEND. A one-point increase in the rate of return, ROR was predicted by the model to cause a 3.1 point increase in the M/B ratio.[30] The dividend pay-out ratio, DIVIDEND, had less of an impact as a one pint increase in the dividend pay-out ratio was associated with a 1.8 point increase in the M/B ratio. Increased stock prices should be associated with utilities that have greater earnings and provide greater annual income to their stockholders.

For every point the equity-debt ratio, EQDBRAT, increased the M/B ratio was expected to increase by 1.2 points. This indicated that more leveraged utilities tended to have a lower M/B ratio. This in turn showed that the market penalized the use of debt financing.

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[29] Average utility stock prices increased a total of 36% over the four-year time period whereas the intercepts account for an average rise of 26%.
[30] The average utility stock had a mean MB ratio of 1.45 during the analysis period. Therefore, a 3.11 point increase in the MB ratio is the equivalent of 2% increase in valuation.

The market appeared to favor utilities that do not invest heavily in new construction. Practically a half a point decrease (-0.43) in the M/B ratio was associated with each percentage point increase in PCCWIP, which is CWIP's share of the total utility plant investment. That the market put higher valuation on utilities that deferred capital expenditures was also revealed with the parameter estimate of the average age of plant, PLANT. This parameter estimate indicated that for year increase in mean age of plant the M/B ration increase by 1.2 points. Part of this impact on M/B ration is also due to the fact that as plant ages it depreciates and lowers the book value of the firm. If stock value decreases at a lower rate than the asset value due to depreciation the M/B ratio will increase.

That DSM defers new construction might be an explanation for the finding that DSM expenditures were treated favorably by the market. In the case of the DSM variable, PCDSM, a one percent increase in DSM's share of total expenditures were associated with a 1.9 point increase in the M/B ratio. That DSM had such a strong impact of the M/B ration was an important finding. This statistically significant parameter estimate indicated that the market puts considerable value on a corporate strategy that incorporated DSM programs and services. It was possible that DSM acted as a proxy for other variables such as utility innovation or the level of customer services the utility offers. If it was DSM investment that brings about the higher stock values then it is possible that after the electric industry is deregulated that DSM services will still be offered by utilities because it is a good corporate strategy.

Utilities that have a large industrial customer base could be expected to have higher stock prices since industrial customers will have lower administrative costs associated with them and provide large and stable loads. Also, many industrial customers have large 24 hour electricity loads that utilize the utilities off-peak, excess capacity. This is expected to change after retail wheeling comes into existence. At that time, industrial customers should have a greater tendency to switch from one supplier to the next, for small marginal changes in price. The industrial customer share of sales, PCIND, had a positive, statistically significant parameter estimate (0.28), that indicated that the market bid up the share price of utilities with a larger industrial customer base. A ten point increase in the market share of industrial customers was associated with a 2.8 point increase in the M/B ratio.

The regulatory environment variable, REGOOD, had a parameter estimate of 5.17. This indicated that utilities operating in an above average regulatory environment had a M/B ratio that was 5.17 points higher than a comparable utility operating in average or below average regulatory environments. This result was not statistically different from zero. The least-cost planning dummy variable, LCUP, had an estimated coefficient of -8.9. This indicated that utilities operating in states that required least-cost planning suffered from decreased stock prices. That the M/B ratio decreased by nearly 9 points with least-cost planning is a good indication that the market does not put much stock in mandated least-cost planning.

Comparisons between this and earlier studies may not be appropriate as the electric industry has changed considerably since the time of the earlier studies. One indication of this is that earlier models incorporated far fewer explanatory variables yet had similar explanatory power (Dubin and Navarro, 1982). That more variables were correlated with the M/B ratio was possibly a sign that factors influencing an electric utility's stock price have become more complex now than in the past. Another, reason for this difference was that only a cross-sectional data was analyzed in the earlier study. This would tend to reduce much of the variance in stock values since they fluctuate over time.

One area in which results are not quite comparable is the impact of regulatory environment. In earlier studies that took place in the seventies a good regulatory environment was positively correlated with cost of capital. However later studies carried out in the eighties indicated that this regulatory power over the utilities cost of capital had waned. The equation estimated above indicated that regulatory environment still has an impact on the utilities' cost of equity capital.

IV.4. Electricity Demand Equation

Since the early eighties, utilities have been investing large sums of money into DSM. DSM has been promoted as a way to meet existing and growing customer demand in electricity without investing in potentially costly generating plant, transmission, and distribution facilities. Though small as a percentage of total expenditures, DSM investments have become quite sizable, with over $2 billion spent in 1993. The effects of DSM on electricity demand was investigated by estimating a simple demand model. The estimated DSM investment model has the general specification:

$$\text{Quantity} = k\,(\text{DSM, Price, Fuel, Customer, Weather})$$

where the quantity of electricity demanded was a function of DSM investment, price of electricity, Price, customer characteristics, Customer, prices of competing fuels, Fuel, and weather conditions, Weather, that influence electricity consumption[31]. As DSM programs will affect a wide variety of customer classes, demand for electricity was analyzed at the utility level. The dependent variable, quantity, was entered into the equation as the natural logarithm of the total MWh sold to all customer classes divided by the number of residential customers. This is to approximate a population -weighted consumption and make the utilities more comparable. All other variables that were not percentages were also entered into the equation as natural logarithms.

[31] These are weather conditions that influence, such end uses as electric space heating. space cooling or lighting.

Table IV.8

Demand for Electricity Equation Variables

Variable Name	Expected Sign	Variable Label
QUANTITY	Dependent Variable	Natural log of total MWhs sold to final consumers divided by the number of residential customers.
PCDSM	?	DSM percentage share of total expenditures
PRICE	-	Natural log of the average price of electricity
GAS	+	Natural log of the price of natural gas
PCMFG	+	Manufacturing as a percentage of total employment
PCINC	+	Natural log of the average per capita income
COOLDD	+	Natural log of the annual cooling degree-days
DENSITY	-	Natural log of Pole miles per residential customer
PCPAPER	+	Percentage of all employment income from the pulp and paper industry
PCPMETAL	+	Percentage of all employment income from the primary metals industry

The estimated equation went through a number of tests similar to those described in the DSM investment model section above (Table VI.9). The possibility that coefficients varied over the years for all variables was tested with an F-test. The resulting F statistic of 0.69 did not indicate that the slopes and intercepts were different for each year. Additional F-tests were performed to determine if only slopes differed, or if only intercepts differed between years. The F-tests revealed that slopes did not appear to vary between years and that specifying a fixed-effects model with separate annual intercepts was appropriate since the intercepts were statistically different from zero.

Using the Breusch-Pagan test again resulted in the detection of heteroscedasticity. The heteroscedasticity was not corrected for, but HCV standard errors and t-tests were calculated.

Table VI.9

Demand for Electricity Model Hypothesis testing

What Was tested	Test and Test Statistic	Result
Varying slopes and intercepts for each year	F-test F statistic = 0.69	Not statistically significant
Varying slopes for each year with one intercept	F-test F statistic =0.75	Not statistically significant
Varying intercepts for each year	F-test F statistic = 3.7	Statistically significant Fixed-effects model used
Heteroscedasticity	Breusch-Pagan Test Chi-squared statistic = 139	Presence of heteroscedasticity detected. White's HCV estimated

Table IV.10

Parameter Estimates of the Demand for Electricity Equation

(N= 324 R^2 = 0.73 log-likelihood = 136.6)

Variable	Parameter Estimate	Standard Error	t Statistic
CONSTANT	-3.821700	1.464000	-2.611
Y91	-0.019376	0.025790	-0.7512
Y92	0.070512	0.026360	2.675
Y93	0.032548	0.026490	1.229
PRICE	-0.634480	0.050450	-12.580
PCDSM	-0.030450	0.008292	-3.672
GAS	0.052589	0.055690	0.9443
PCMFG	1.036900	0.277900	3.731
PCINC	0.371980	0.147000	2.530
COOLDD	0.231960	0.019980	11.610
DENSITY	-0.028309	0.009531	-2.970
PCPAPER	2.502300	1.829000	1.368
PCPMETAL	4.393700	1.106000	3.973

This equation for the demand for electricity performed quite well. All of the variables had the expected sign and most of the explanatory variables had parameter estimates that were statistically different from zero. Close to 70% of the variance in the quantity demand is explained by the few variables included in the equation. What was particularly heartening was that for the price of electricity, PRICE, the estimated own-price elasticity was -.63, which was within the ranges estimated by earlier studies (Bohi 1981, 1984). The price elasticity should be interpreted as the weighted average for all customer classes. The estimated coefficient for per capita income, PCINC, was 0.37. This estimated income elasticity was also within the ranges of earlier studies. Again, a direct correspondence with the values estimated for one customer class was not possible. For this study, the demand of all customer classes is aggregated and therefore the price elasticity is a weighted average for all the customer classes. The estimated cross-price elasticity of the gas price, GAS, was 0.05, and had the expected positive sign. However, the estimated parameter was quite small and not statistically different from zero. This would seem to argue that inter-fuel competition between gas and electricity will not be greatly affected by marginal changes in the price of gas.

That the estimated elasticities had the correct sign and approximated those estimated in other studies in magnitude bolsters the results of this equation. The equation was estimated, primarily, to determine the impact of DSM investment. The parameter estimate of the DSM variable, PCDSM, was -0.03. The coefficient was statistically significant and indicated that DSM expenditures were associated with reductions in electricity demand. However, DSM's impact on the demand for electricity was quite small as a one-point increase in DSM's share of total expenditures was only associated with a 0.03% decrease in electricity consumption.

The investment cost for each kWh saved can be estimated for the average utility. The average utility had $1.2 billion annual expenditures during the analysis period. A 1% share of total expenditure was equal to $12 million. This level of DSM expenditures was associated with a 0.03% decrease in total electricity demand. As the average utility produced approximately 21.4 million MWh of electricity this was a decrease of 6,850 MWh for every $12 million dollar spent on DSM. This represented DSM expenditures of approximately $1,750 per MWh reduction or $1.75 per kWh reduction. The relatively modest amount of energy savings that were associated with DSM spending may be cost-effective under certain fairly restrictive assumptions.[32]

Other factors that may have obscured the effects of DSM are spillover, load growth and service retention strategies, or federal and state energy efficiency standards. Spillover refers to many programs sponsored by utilities having impacts that are not just confined to their service territories. Utility advertising that promotes energy-efficient products and energy use practices will also be seen and heard by customers of

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[32]Cost per kWh saved or "negawatt" are presented in the table below, using simple pay-back calculations that assume the electricity cost escalation and the utility discount rates are the same and only the DSM investment lifetime varies.

Simple Pay-back Calculations On DSM Investments

DSM Investment Life	Cost Per "negawatt"
10	$0.175
15	$0.116
20	$0.087
30	$0.058

adjacent utilities. Other direct spillover effects would come through population movements. A person may have received an energy-efficient refrigerator while being the customer at one utility. After changing jobs and place of residence the person becomes a customer of a different utility and has transferred the DSM savings embodied in the refrigerator to the new utility.

A utility with programs incorporating strategic load growth, off-peak load growth, and service retention strategies will have more electricity demanded from it relative to a utility without DSM programs. Strategic load growth strategies seek to promote electro-technologies and increase electricity's market share in specific end uses. Programs promoting energy-efficient air-conditioners to first-time buyers will only lead to increased demand for electricity. Off-peak load growth would be fostered through lower rates. Many programs promoting hot water or cold storage have been implemented using these rates. Programs that target load retention will cause the utility to lose less load relative to utilities that are not promoting such programs. Programs that target new purchases of electric water heaters will retain the water heating loads of customers that would have otherwise switched to gas.

Energy-efficiency standards will result in greater impacts on electricity demand of utilities that are situated in areas of higher growth. This is because increased customers and income will be associated with greater levels of new construction and purchases of new electricity appliances and equipment. New appliances and new buildings will also be more energy-efficient.

DSM should not be judged only by its energy impacts. DSM investments defer other investments in generation capacity. These impacts cannot be known since generation never built is never reported. However, DSM impacts the long-run construction of power plants and investments in transmission and distribution facilities is an area of further research.

The level of manufacturing activity, PCMFG, in the service territory had the expected positive sign. The estimated parameter of 1.03 indicated that for every one-point increase manufacturing has in the share of total employment there an associated 1% increase in electricity consumption. The type of industrial activity also played a measurable role in electricity demand. Both the paper and pulp industry, PCPAPER, (2.5) and primary metals industry, PCPMETAL, (4.4) as measured by the share in total employment income, had the expected positive parameter signs. These two industries are highly energy intensive (Kahane and Squitieri, 1987), and greater levels of industrial activity in theses areas are expected to increase electricity demand. However, in the case the of the paper industry the parameter was not statistically different from zero. For the paper industry ,a one-point increase in the share of total employment income resulted in an increase in electricity demand of 2.5%. The primary metals industry had an even stronger relationship, as electricity demand to increased by 4.4% for each one-point increase in the share of employment income.

The cooling degree-day variable,[33] COOLDD, with the parameter estimate 0.23, was associated with greater levels of electricity consumption. Weather conditions were expected to influence the demand for electricity with cooling degree-days giving an indication of the cooling requirements in any given year. The estimated coefficient indicated that a utility with a service territory in a warmer climate with cooling degree-days 4% greater than average will be associated with almost a 1% increase in annual demand.

A service territory density variable, DENSITY, was constructed by dividing the number of residential customers by the number of miles of transmission lines. Demand for electricity was expected to be negatively related to the density inter-fuel competition may increase with greater density given that gas service will be less available to customers in rural areas. Another possible reason for the negative relationship could be that there are less industrial and commercial customers in rural areas, which will also bring down the demand for electricity. The parameter estimate of -0.03 did conform with this hypothesis and though the parameter was statistically different from zero the actual impact was quite small.

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[33] Cooling degree-days are a unit measuring the extent that the outdoor mean daily temperature falls above the base (in this case, 65 degrees). The cooling days were population weighted by state, and weighted further by utility sales in each state.

IV.5. Electricity Average Cost Equation

DSM has been promoted as a least-cost alternative to adding capacity in both generation plant and transmission and distribution facilities. On the assumption that DSM investment is a lower-cost alternative to other investments in other factors of production, one should expect that utilities that are investing in DSM resources would have lower costs associated with production of electricity. To determine the magnitude of DSM's impact on cost an average cost equation was estimated with the general form:

$$\text{Cost} \quad = \quad j\,(\text{DSM, Quantity, Financial, Managerial, Operating, Regulatory})$$

As DSM investment is affected by a variety of factors, a more general form of the cost function is specified. The dependent variable, average cost, was calculated by dividing the total reported electric utility expenditures by the total number of kWh sold to final customers and on the wholesale market. This variable and is entered into the equation as a natural logarithm.

The tests that were performed on the model are shown in Table VI.7. F-tests indicated that slope parameters and the intercept did not vary in a statistically significant fashion in for all of the four years. The Breusch-Pagan test indicated that heteroscedasticity was present. As with the earlier models instead of correcting for heteroscedasticity HCV standard errors were calculated, as were t-tests based on them.

Table IV.11

Average Cost of Electricity Equation Variables

Variable Name	Expected Sign	Variable Label
AVGCOST	Dependent Variable	Natural log of the average kWh cost
QUANTITY	-	Natural log of the total quantity electricity sold to final consumers divided by number of residential customers
PCPURCH	+	Purchased power as percent of total electricity sold.
PCDSM	-	DSM as percent of total expenditures.
INVKWH	+	Natural log of the investment in plant per kWh generated or purchased.
PCNUKE	+	Percent of generated and purchased power that is generated by nuclear power plants.
FUELKWH	+	Natural log of the fuel costs per kWh generated.
PCTAX	+	Taxes as a percentage of total expenditures.
PCCWIP	+	CWIP as a percent of total electric plant investment.
PLANT	-	Natural log of the average age of utility plant.
RESKWH	-	Natural log of the average annual consumption of a residential customer.
WAGES	+	Natural log of the average utility wage.
PCGASREV	-	Total gas operation revenues as a percent of total utility revenues.
PCRESALE	-	Total electricity resales as a percent of total electricity sold.

Table VI.12

Demand for Electricity Model Hypothesis Testing

What Was tested	Test and Test Statistic	Result
Varying slopes and intercepts for each year	F-test F statistic = 0.69	Not statistically significant
Varying slopes for each year	F-test F statistic = 0.72	Not statistically significant
Varying intercepts for each year	F-test F statistic = 0.74	Not statistically significant
Heteroscedasticity	Breusch-Pagan Test Chi-squared statistic = 40.5	Presence of Heteroscedasticity detected. White's HCV estimated

Table IV.13

Parameter Estimates of the Average Cost of Electricity Equation

(N= 324 R^2= 0.88 log-likelihood 304.3)

Variable	Parameter Estimate	Standard Error	t Statistic
INTERCEPT	-2.443700	0.320400	-7.627000
QUANTITY	-0.311190	0.024410	-12.750000
PCPURCH	0.308000	0.041060	7.501000
PCDSM	-0.003209	0.003301	-0.972100
INVKWH	0.124550	0.027550	4.520000
PCNUKE	0.004000	0.000445	8.986000
FUELKWH	0.354650	0.023940	14.810000
PCTAX	0.003910	0.001338	2.922000
PCCWIP	0.248160	0.087630	2.832000
PLANT	-0.176880	0.028050	-6.307000
RESKWH	-0.197410	0.030950	-6.379000
WAGES	0.023626	0.024180	0.977300
PCGASREV	-0.153350	0.050010	-3.066000
PCRESALE	-0.270120	0.048620	-5.555000

The overall model predicts average cost of each kWh sold very well with an R^2 of 0.88. Also, the estimated coefficients had in all cases the expected sign. The DSM parameter estimate of -.003, had expected negative sign indicating that as DSM's share of total expenditures rose the cost of electricity production went down. The parameter estimate is unfortunately not statistically different from zero. However, as a point estimate the parameter is the best available indicator of the impact of DSM and as such predicts a only a very minor decrease in average costs. A one-point increase in DSM's share of total expenditures was predicted to reduce average cost by three thousandth of one percent. Even if DSM expenditures became quite substantial the absolute impact on the average costs of production would be quite small[34].

That DSM expenditure impacts on average cost were negative rather than positive offered some support for the argument DSM investments are least-cost alternatives to supply-side investments. From the demand equation estimated above, DSM investments resulted in reductions in quantity demanded. All other things being equal, a reduction in demand would be associated with a increase in average cost and not a decrease. It seems that in spite of the DSM induced reductions in demand that would tend to increase average costs, DSM expenditures were concurrently associated with reductions in average costs.

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[34] DSM expenditures averaged 1.4% of total annual expenditures. This was the equivalent of $1.8 billion (1990$) that was associated with a 0.003% reduction in cost or the equivalent of approximately $6 million (1990$).

The regression results are actually supportive of DSM since DSM impacts on cost appeared to be negative or in the worst case negligible. This indicated that utilities could use DSM as a customer service or as a tool to support market growth or market retention without great concern that it will lead to increases in cost and rate increases.

Three variables that describe the output levels of a utility were included in the model as explanatory variables. The total quantity sold to final consumers, weighted by the number of residential customers, QUANTITY, was -0.3 and had the expected negative sign indicating that as quantity sold increased the average cost per kWh decreased. A ten percent increase in quantity demanded was associated with a decrease in price of about 3%. It was assumed that the average residential demand, RESKWH, would also be negatively correlated since many of the costs of transmission and distribution and administration are associated with the residential customer class. This variable proved to be highly significant and did not have problems of multicollinearity with the variable, QUANTITY. The estimated coefficient indicated that a ten percent increase in residential demand would cause a 2% decrease in average cost. The other electricity output variable was, PCRESALE, which was the percent of total electricity sold that was sold on the wholesale market. A negative relationship was assumed since wholesale power sales will make use of excess generating capacity and reduce average costs and also many of the costs associated with selling to the final consumers are not present. The parameter estimate of -0.27 indicated that a three point increase in resales was associated with close to a 1% decrease in average cost.

Inputs into the production of electricity were also included in the cost model. Capital is represented by, INVKWH, the ratio of total plant investment to electricity generated and purchased. The parameter estimate of 0.12, had a positive sign indicating that when the capital input per kWh went up by one point the average costs went up by a bit more than one-tenth of that. Fuel costs, FUELKWH were entered in the equation as the average dollar cost of fuel per megawatt hour generated. The estimated coefficient was 0.36 indicating that a 10% increase in fuel prices would be associated with an increase in electricity prices of 3.6%. With a parameter estimate of 0.023 for WAGES, the changes in the average cost of labor (wages, pension, and benefits), had little impact on average cost. If labor costs increased by 10% average costs would only be expected to increase by 0.24%.

The sources of electricity were also found to affect the average cost. Utilities that generated all of the electricity demanded appeared to have lower costs of electricity production than those that purchased some portion of the electricity sold. The parameter estimate for purchased power, PCPURCH, of 0.31 indicated that is power purchases increased their share of total power sold by ten points, the associated increase in average costs was 3.1%.[35] One of the reasons for this higher price for purchased power may be due to a short-run purchases that have a premium price associated with them. Another reason is that purchased power will already have profit embedded in its cost. The share of total electricity generated by nuclear power was

[35] There may be some question as to the direction of the causal relationship if utilities with higher power costs are more prone to purchasing power to reduce their costs.

expected to increase costs. The estimated parameter for the variable PCNUKE was 0.004 and indicated that nuclear power was positively correlated with the average cost. The impact of nuclear power appeared to be quite small since regression predicted a 0.4% increase in average cost if 100% of the electricity were generated at nuclear power plants.

Financial and operating characteristics of utilities also influenced the average cost of electricity. Taxes as share of total expenditures, PCTAX, with an estimated coefficient of 0.004 was positively associated with cost. The total impact was quite small since a one-point increase in taxes' share was predicted to cause a four thousandths of a percent increase in average cost. New construction had a potentially large impact the average cost since the variable PCCWIP, the ratio of CWIP to total plant investment, had a parameter estimate of 0.24. CWIP represents presently unproductive capital investments which add to the cost of operations. These costs can be from a variety of sources such as increased debt payments[36], and inclusion of CWIP costs in the general costs. The regression results estimated that a utility where CWIP represented 4% of the total electric plant average costs would increase by 1%.

Negative relationships with average cost are estimated for the age of plant, PLANT

[36]Long-term debt payments will increase to finance construction costs and short term debt payments may increase due to cash-flow problems that result from cash-flow problems from incurring the long-term debt.

(-0.18), and dual fuel utilities, PCGASREV. The regression results for the variable PLANT, indicated that utilities with older plants have lower costs. This could be due to a variety of factors. The most probable reason for this negative impact was that capital investments of older plants had a greater percentage of their value amortized and the capital investments in the plant no longer entered into the rate base resulting in lower costs. The presence of older plant possibly was also an indication of better operations and maintenance procedures that allow the utility to operate plant longer than other utilities. Putting off the plant retirement in turn allows the utility to put of construction in replacement plants and thus reduce costs. Increased plant age could also indicate that the utility optimized the running of the plants in such a way that load factor is increased again pushing investment in new construction into the future and reducing overall capital costs. Another factor was that older plant may be actually cheaper to run than newer facilities. Older plants may have been grandfathered the right to burn certain cheaper fuels, such as higher sulfur coal, or were not required to comply with certain environmental protection requirements.

Dual fuel utilities also appeared to have a cost advantage over those that supply only electricity. The variable, PCGASREV, was the percent of total utility revenue is the result of gas operations and had a parameter estimate of -0.15. The estimated equation predicted that a utility that obtained 10% of its revenue came from gas operations would have average electricity costs that were 1.5% lower than a utility that obtained 100% of its revenue from electricity sales. This should be expected since gas and electric operations will share many costs thus lowering overall average costs to both electric and gas services. An area where high savings can be expected is the administration, where billing and meter reading can be combined, and many administrative tasks overlap.

IV.6. Simultaneous Estimation of Demand and Cost

Discussed earlier was the possibility that cost and quantity are both simultaneously determined. Due to the simultaneous nature of the quantity, average cost and price the assumption that the dependent variables are fixed in repeated sample is violated. This causes the OLS estimators to be biased. To correct for possible bias the following set of simultaneous equations were estimated:

Cost $= j$ (DSM, Quantity Financial, Managerial, Operating, Regulatory)

Quantity $= k$ (DSM, Price, Fuel, Customer, Weather)

Price $= r$ (Cost, Return on Investment)

Where the first two equations are described in the cost equation and demand equation sections above. The third equation was described previously as an equality [37] that connected the cost and demand equations together. It was however, specified as an equation above because the demand being modeled is the demand of final consumers, the price that is entering the equation is the average price that they are faced with while the average cost of kWh sold applies to kWh sold to final consumers and kWh resold to other utilities. The costs associated with kWh sold to final consumers and kWh sold to the wholesale market could not be separated. Average sales to other utilities

[37] $\mathbf{P_e * Quantity = Cost + Return\ on\ Investment}$

comprised an average of 17% of utility sales during the analysis period. Costs associated with these sales were therefore quite substantial and had to be taken into account when estimating the average costs. The price equation was included in the model to connect the average cost and demand equations.

A specification test developed by Hausman (Hausman, 1978) is one method to detect the presence of simultaneity.[38] The Hausman test was performed on each of the equations. In respect to the tests performed on the cost and quantity equations the residuals that were entered into the test equations had parameter estimates that were statistically different from zero, while the cost residual entered into the price equation was not statistically significant.[39] The tests indicated that average price was simultaneous with quantity and quantity was simultaneous with average cost.[40]

To correct for simultaneity a variety of methods have been developed. The method used below is the full information maximum likelihood method (FIML). It

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[38] The test relies on the fact that the endogenous terms are correlated with the error terms. It is a two stage procedure. The first stage estimates the reduced form equations for the price, quantity and cost variables. The residuals of these regressions are then entered into the appropriate single equation and the equations are estimated individually. Evidence of simultaneity results in estimation statistically significant coefficients for the residuals.

[39] For the quantity equation the price residual had a t statistic of 4.8. For the cost equation the quantity variable had a t statistic of 2.2. In the price equation the cost residual had a t statistic of 0.16.

[40] A likelihood ratio test was also performed by calculating the test statistic $-2^*(L_R - L_{UR})$. L_R is the log-likelihood of the restricted model and L_{UR} is the log-likelihood of the unrestricted model. The statistic is distributed in a chi squared with degrees of freedom equal to the number of restrictions. This was calculated as -2(763-(136+304+323))=54. Since the chi squared distribution at 1% significance level and with 2 degrees of freedom is 9.21 the likelihood ratio test indicated that that there were statistically significant differences between the restricted and unrestricted model.

should also be noted when estimating systems of equations simultaneously the parameters become more sensitive to specification error.[41] This is because specification error in one equation can now affect the parameter estimates of all equations. The three equations were then estimated simultaneously, after specifying PRICE, COST and QUANTITY as endogenous variables. The results of the regression are shown on Table IV.12.

[41] Pindyck and Rubenfeld, 1991.

Table IV.12

Price and Quantity Model Full Information Maximum Likelihood

(Demand $R^2 = 0.71$, Cost $R^2 = 0.86$, Price $R^2 = 0.89$ log-likelihood = 736)

Variable	Parameter Estimate	Asymptotic Standard Error	Asymptotic "T" Ratio
DEMAND			
INTERCEPT	-4.589499	1.11818	-4.10
Y91	-0.031724	0.02277	-1.39
Y92	0.066024	0.02649	2.49
Y93	-0.00226246	0.02807	-0.08
PRICE	-0.529159	0.06433	-8.23
PCINC	0.528366	0.11011	4.80
PCDSM	-0.028933	0.0084108	-3.44
PCPAPER	2.571696	1.11153	2.31
PCPMETAL	5.285998	1.46055	3.62
PCMFG	0.953801	0.36484	2.61
COOLDD	0.225914	0.02837	7.96
GAS	-0.155696	0.06865	-2.27
DENSITY	-0.041138	0.01295	-3.18

Table IV.12 (Continued)

Price and Quantity Model Full Information Maximum Likelihood

(Demand $R^2 = 0.71$, Cost $R^2 = 0.86$, Price $R^2 = 0.89$)

Variable	Parameter Estimate	Asymptotic Standard Error	Asymptotic "T' Ratio
COST			
INTERCEPT	-1.967013	0.30372	-6.48
QUANTITY	-0.457192	0.06365	-7.18
PCPURCH	0.247021	0.04702	5.25
PCDSM	-0.010453	0.0050595	-2.07
INVKWH	0.126946	0.02958	4.29
PCNUKE	0.00373310	0.0004410	8.46
FUELKWH	0.324953	0.02070	15.70
PCTAX	0.00288182	0.0012720	2.27
PCCWIP	0.237657	0.12637	1.88
PLANT	-0.145528	0.02440	-5.96
RESKWH	-0.157962	0.03501	-4.51
WAGES	0.017129	0.01811	0.95
PCGASREV	-0.072485	0.05163	-1.40
PCRESALE	-0.078066	0.08416	-0.93
PRICE			
INTERCEPT	0.345067	0.08436	4.09
COST	0.886778	0.02233	39.72
ROI[42]	0.090960	0.01224	7.43

[42] Average income per kWh sold.

In general the results of the FIML were similar to those that were estimated for the equations separately. Given that FIML method simultaneously estimated the set of equations and corrects for bias introduced due to simultaneity, the results of the FIML estimation were the preferred results. The signs and the relative magnitudes of the estimated coefficients were for the most part the same. Discussion of the FIML results therefore primarily targeted those estimates where the results differed significantly.

In the demand equation the impact of DSM expenditures, PCDSM, is still as weak as before with a parameter estimate of -0.03. The estimated price and income elasticities, respectively -.053, and 0.52, changed slightly though were still within the ranges found in earlier studies. One parameter value that changed significantly was the price of gas, GAS. The cross-price elasticity of gas was estimated at -0.15 that was negative and statistically different from zero. This coefficient indicated that an increase in the price of natural gas would bring about a decrease in demand for electricity. This result is not reasonable since a rise in price of a competing fuel should be associated with a reduction in the demand for electricity.

The cost equation did not have any variables that changed the direction of their impact. The most significant change was that the estimated PCDSM coefficient, -.01, became statistically significant and had increased its impact by a factor of three. The impact was still extremely small relative to the total spending on DSM and average cost of producing electricity.[43] Two other variables that had their changed parameter estimates with the FIML estimation were the dual fuel utility variable, PCGASREV, and the utility's wholesale activity variable, PCRESALE. The dual fuel utility coefficient, -0.07, was no longer statistically different from zero and the actual impact on average cost was much smaller. With the new coefficient a utility that obtained 10% of its revenues from gas would only experience a 0.7% reduction in the average cost of electricity compared to the 1.6% reduction measured in the single equation regression. The large reductions to average costs that had been associated greater levels of wholesale activity were also no longer estimated with the simultaneous model. The estimated coefficient for the share of resales was -0.08 compared to the -0.27 estimated in the single equation regression and was not statistically different from zeros. This indicated that increased bulk power sales did not lead to substantial decreases in average costs. Possibly bulk power sales are made at the short-run marginal cost and primarily cover only variable and not fixed costs.

The price equation performed quite well as was expected. Average costs and average income were assumed to be the primary components of the average price paid by retail customers. The parameter estimate of average cost, COST, was 0.89 and highly significant indicating that every one percent increase in cost led to a 0.89% increase in rate. The return on income parameter, ROI, was 0.09 and indicated that a

[43] Even increasing the associated reduction in average cost savings by a factor of 3 would only result in average total annual cost savings of approximately $18 million (1990$) compared to $1.8 billion (1990$) in average annual total DSM spending for the sample (see footnote 30).

1% increase in the investment income led to a 0.1% increase in price paid by final consumers.

V. Conclusion

The results of this study indicated that it was possible to measure the DSM system level impacts. During the period analyzed DSM investments constituted a large enough share of total expenditures and investments of investor owned utilities as to allow their impacts to be measurable. If future DSM spending on programs continues at its present rate, this type of an evaluation can be useful in providing national DSM impacts. Even with immanent industry restructuring, there are a sufficient number of plausible scenarios that include continued spending on DSM.

The estimated DSM investment model indicated that the utility's regulatory environment had a major impact on the variances in DSM investment. An above average regulatory climate and least-cost planning requirements were found to have large impacts on the level of DSM investment. As a favorable regulatory climate was associated with higher DSM spending, it was reasonable to assume that profit incentives, such as increases in the rates of return, allowing DSM investments into the rate base, or allowing utilities to recoup lost revenues were a PUC's methods for promoting DSM. The argument that PUC profit incentives promoted DSM investments was bolstered by the rate of return being positively correlated with DSM investments. Higher rates of return may have been due to the PUC profit incentives.

Another important regulatory factor proved to be PUC-mandated least-cost planning requirements. Utilities must consider DSM as a viable alternative to supply-side electricity generation to meet future electricity demand when using least-cost planning. In theory, this should allow DSM resources to be placed on a level playing field with supply-side resources. Forcing a utility to consider DSM in its resource planning raises the probability that DSM will be included in the mix of utility resource investments.

Some indications exist that capacity-constrained utilities invested more in DSM than did others. The model also indicated that power purchases were possibly substituted with DSM resources. Higher incomes and greater residential consumption of electricity were also associated with increased DSM spending. The positive relationship with income could indicate that the income elasticity for the demand for DSM is such that demand for DSM services rises with income. Greater DSM investments also occurred when average residential electricity consumption is higher. With greater electricity consumption, customers may have a greater demand for services to reduce energy expenditures that will increase demand for DSM programs. Also greater consumption will increase the average customer energy savings potential that will also increase the ability for a utility to offer cost-effective to DSM services.

The estimated DSM investment model explained 40% of the variance in DSM expenditures. Many other variables were entered into the equation, but were not found to be correlated with DSM expenditures. However, many of these variables, such as those used to represent capacity constraints, may have been too general. Further, using only dummy variables to describe the regulatory environment grossly simplifies the relationships between the utilities and one or more PUCs. A model using more detailed information should improve the estimation. The estimated model indicates areas, such as the regulatory environment and utility capacity requirements, where more research may be useful.

The direction of DSM impacts on average costs and quantities demanded were not unexpected. A negative correlation between DSM investments and quantity actually provided "negawatt" cost estimates, that under certain assumptions were in the vicinity of actual prices of electricity. However, estimated reductions in demand were only a fraction of the reported expected energy savings.

It is possible that the demand equation regression underestimated the impact of DSM investments. DSM programs have spillover effects into other utilities' service territories. DSM program participants may move the energy-efficient equipment sponsored through the program into the service territories of other utilities. Utility programs that bring about market transformations also have a spillover effects as it is not only the market in their service territory that is being transformed. Many DSM programs also result in net load growth. By targeting load retention, utilities investing in DSM prevent reductions in quantity demanded relative to utilities that do not pursue such a strategy. Therefore, the reported energy savings will be masked when energy savings are associated with new and retained loads.

The estimated average cost equation did verify that DSM's impacts on average costs was relatively small and negative. To put this impact in perspective it should be considered that short-run average cost impacts of energy conservation programs resulting in lost sales give an upward push to average costs. Even with these reductions in demand, DSM impacts on average costs were negative. This indicates that, on average over the four-year period, DSM has tended to reduce costs relative to utilities not instituting DSM programs. It is possible that even within the this study's time frame, DSM has deferred capacity and thereby lowered capital costs.

The estimated cost of equity capital equation results were quite surprising. Initially, DSM's theorized impact on the M/B ratio was without an expected sign and potentially could not have been correlated with the utilities' stock prices. DSM expenditures were found to have a positive, statistically significant, and substantial impact on the cost of equity capital. The model predicted that spending 5% of total expenditures on DSM would be associated with a 10 point increase in the M/B ratio. This represents an utility stock valuation, approximately 7% greater than that predicted if the utility had not made DSM investments. Part of this increase could be due to DSM deferring investments in capacity, as utilities with older plant and equipment, and less current new construction were also associated with higher stock prices. Part of DSM's impact may also be due to its acting as a proxy for other factors, such as improved customer relations and services or better operations and maintenance procedures, which should be associated with higher stock prices.

The DSM investment model indicated that a large factor influencing DSM spending levels was the regulatory environment. As the industry restructures and becomes more competitive, less regulatory involvement could mean reductions in DSM investments. The demand, cost, and equity capital models all indicate that utilities may continue offering DSM services after the industry's restructuring. DSM investments were not associated with large reductions in demand, which is an anathema for utilities. DSM was also associated with decreases, not increases, in average costs. If DSM programs were really not cost-effective by not deferring expensive capacity and purchasing "negawatts" at inflated prices, an increase in electricity costs should have been measured.

The cost of capital equation produced results that present DSM's future in a favorable light. DSM spending is associated with reduced capital costs. Thus, DSM investments may continue after the electric industry restructures because these investments can decrease the cost of equity capital. As the market places a premium on DSM investments during regulation, this favorable valuation of DSM may remain after the industry restructures.

It appears that regulator "driven" DSM constitutes a large part of DSM investment. If regulators and other interested parties do not wish DSM to decline after the industry restructures, provisions for DSM funding must be made, either through line charges, taxes, or other forms of funding. The findings also have implications for DSM practitioners in that the large and possibly excessive savings attributed to DSM are not in evidence. These savings may have been masked by programs that expand demand or retain loads. These types of programs will increase net demand regardless of how energy-efficient the new and retained load is. Savings from energy efficiency should not be equated with reductions in total load.

The study shows that utilities investing in DSM may be following an appropriate corporate strategy that rewards its shareholders. The estimated demand equation did not predict large revenue losses while the average cost equation associated DSM investments with a small decrease in average costs. Given these small impacts DSM has on both electricity cost and electricity demand, DSM investments could be pursued as a method to increase stock prices. In the future, DSM services may be used as a way to differentiate one utility from its competitors.

The years 1990 through 1993 were the years used for this analysis. However, the future of DSM is no longer what it was then. Industry wide restructuring is seen by many as the death knell of utility financed DSM. Retail wheeling will enable customers to choose and change electricity service providers. Without captive customers electric utilities will have no incentive to invest in demand-side programs. These DSM investments will be at risk if a customer were to change electricity providers. This does not mean that DSM services will not be offered by utilities. If utilities were to charge the customer receiving the DSM services directly for this service DSM would be less risky. Retail-level competition may in fact put electricity service providers under greater pressure to provide quality DSM services that customers are willing to pay for.

Retail wheeling will bring about greater price competition between energy service providers. This will eventually cause the profit margin in selling electricity to narrow. Energy services that include DSM will be used by utilities to compete for customers and to develop areas business with greater profitability. Retail wheeling may also cause the consumer to change their patterns of energy use if TOU pricing is adopted. The consumer will obtain the correct price signal from which to determine their consumption. These signals may induce the consumer to invest in energy efficient appliances, energy efficient homes or home improvements, or obtain DSM services from the energy provider.

Another possible scenario that includes DSM programs is a continuation and expansion of federal and state government funded DSM programs. PUCs could mandate or provide incentives for local distribution companies to provide DSM services if these services are not offered by actual electricity service providers. Such programs could be financed using a transmission charge.[44]

From the models estimated in this analysis, it seems inevitable that factors influencing DSM investment patterns will change in the future. Industry restructuring will include deregulation, tending to reduce DSM spending, since regulatory factors were found to influence investments in DSM. However, DSM was not found to induce large revenue losses or increase costs. These results, combined with the finding that DSM spending may increase stock prices, indicates that utility DSM spending will probably continue in some form or another in the deregulated future.

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[44] Line charges, billed as "distribution benefits charges", are promoted to fund energy efficiency, renewable energy sources and assistance to low-income customers. They exist in 3 states and are being proposed in 8 others (E News, January/February 1996, pp. 2).

VI. Future Research

This study reveals several important areas of further research. One of these is the impact of DSM on utility investments on new capacity investments. DSM investments were made, in part, to defer investments in the construction additional electric plant. Investigations into actual impacts would be of interest for planning further DSM investments. Separating DSM's impacts on capacity between generating capacity and transmission and distribution facilities would also be of use. This type of analysis can only be conducted at the utility level, as this is where decisions to add capacity are made. In most cases, DSM investments will not defer load in the year the investments are incurred, rather in some later year. When additional years of consumption, investment, and expenditures are available, research on DSM's impacts on deferred capacity can be undertaken.

Estimating DSM investment impacts at the customer class level would allow for better specification of demand equations. DSM impacts may also vary depending on the customer class. Disaggregating DSM investments to the level where specific types of expenditures can be groups will enable the impacts of conservation and load management programs to be measured separately. This will remove some of the ambiguity in the expected direction of DSM impacts, as conservation programs are expected to reduce demand, while load management programs will primarily shift electricity demand to another period.

DSM interactions with national and local legislation on energy efficiency remain to be measured. The National Appliance Energy Conservation Act 1987 and the New Energy Act of 1992 should have substantial impacts on energy consumption over time. How DSM programs change in the wake of industry restructuring remains another rich area for future research.

Appendix 1: Data Sources

Variables Used to Estimate Model

Variable Name	Variable Description	Source
Financial and Managerial		
ROR	Rate of return on investment	Value Line
PCTAX	Taxes as a percentage of total expenditures. Sum of total local, state, federal, and other taxes divided by total electric utility expenditures.	FERC Form 1
PCCWIP	CWIP as a percent of total electric plant investment. Total CWIP divided by total electric plant.	FERC Form 1
WAGES	Average utility wage. The sum of total wages, benefits, and pensions divided sum of full-time employees and half of the part-time employees.	FERC Form 1
PCGASREV	Total gas operation revenues as a percent of total utility revenues. Total gas revenue divided by total utility revenue.	FERC Form 1
DIVIDEND	Dividend pay-out ratio	Value Line
EQDBRAT	The equity-debt ratio. The mean of end of year and beginning of year total proprietary capital minus the mean value of end of year and beginning of year preferred stock divided by end of year and beginning of year long term debt.	FERC Form 1

Variable Name	Variable Description	Source
MBRATIO	Market-to-book ratio, the market share price divided by the book value per share. Annual earning per share multiplied by the average annual price earning ration divided by the book value per share.	Value Line
Operational		
PCIND	Percentage of total sales to industrial customers. Total MWh sold to industrial customers divided by total MWh sold to final consumers and for resale.	FERC Form 1
PCDSM	DSM percentage share of total expenditures. Total DSM expenditures divided by total electric company operating expenses.	EIA Form 861 and FERC Form 1
PRICE	Average price of electricity. Total revenues from final consumers divided by the total kWh sales to final consumers.	FERC Form 1
PCPURCH	Percent of total power (purchased and generated) that was purchased. Total power purchased divided by sum of total power purchased and generated.	FERC Form 1
LOAD	The annual load factor (ratio of average load divided by peak load)	Value Line
COOLDD	Annual cooling degree-days.	BLS

Variable Name	Variable Description	Source
DENSITY	Pole miles per residential customer. Total pole miles divided by the total residential customers. Available for 1990 and 1991. Value from 1991 used for 1992 and 1993.	FERC Form 1
QUANTITY	Total quantity electricity sold to final consumers divided by number of residential customers	FERC Form 1
INVKWH	Investment in plant per kWh generated or purchased. Total electric plant divided by total kWh sold to final consumers and for resale.	FERC Form 1
PCNUKE	Percent of generated and purchased power that is generated by nuclear power plants. Total electricity generated through electric power divided by sum of total generated and purchased.	FERC Form 1
FUELKWH	Fuel costs per kWh generated. Total fuel costs divided by kWh generated.	FERC Form 1
PLANT	Average age of utility plant by holding company.	Value Line
PCRESALE	Total electricity resales as a percent of total electricity sold to final consumers and for resale.	FERC Form 1
Customer		
PCINC	Per capita income by state and year.	BEA REIS
RESKWH	Average MWh consumption per residential customer. Total MWh sold to residential customers divided by number of residential customer.	FERC Form 1

Variable Name	Variable Description	Source
GAS	Price of natural gas by state and year.	Gas Facts Yearbook
PCMFG	Manufacturing as a percentage of total employment by state and year.	BEA REIS
PCPAPER	Percentage of all employment income from the pulp and paper industry by state and year.	BEA REIS
PCPMETAL	Percentage of all employment income from the primary metal by state and year..	BEA REIS
Regulatory		
LCUP	Dummy variable indicating least-cost planning required within the firm's service territory by state for 1989 and 1992. 1 = Required 0 = Not required	Mitchell (1989, 1992)
REGOOD	Dummy Variable indicating the regulatory environment is rated above average by state and year. 1 = Above average 0 = Average or below average	Value Line

Data Sources

1. Financial Statistics of Investor-Owned Electric Utilities (1989-1993).

   Data on electric utility financial and operating variables, contained on FERC Form 1, were obtained from the EIA. This included a total of 900 variables or approximately 45% of the data contained on the form. Practically all of the data contained in the annual EIA publication, Financial Statistics of Selected Investor-Owned Electric Utilities, for the years 1989-1993 was included in this database. Included in this data were the distribution of hydropower, nuclear, steam, and other power generation, fuel costs, total costs of power purchases and sales, residential, commercial, and industrial consumption, revenue by type of customer class, electricity sold by customer class, labor costs, construction work in progress (CWIP), taxes paid, environmental protection investment and costs, and rate of return.

2. Value Line (1988-1994)

   Electric utility financial characteristics such as book value per share, dividend pay-out percentage, percentage of AFUDC in profits, rate of return, price earning ratio, average earnings, regulatory environment, plant age, load factor, capacity, merger activity.

3. Moody's Public Utilities (1985).

   Electric utility merger activity, ownership percentages, and bond ratings.

4. EIA Form 861 (1990-1993)

   This data provided information on annual DSM expenditures and expected savings. The distribution of sales by state was also available for the year 1993. The 1993 distribution was used to represent that of the previous three years.

5. Regional Economic Information System (1989-1993)

   The Bureau of Economic Analysis maintains this database which is available on the Internet. This database contains wage and employment data at the state level for the year 1969 through 1993. Employment and wage data is available at the two digit SIC code level.

6. United States Commerce Department Web Site

Regional annual temperature data was obtained from the Commerce Department Web Site. This was for each of the 9 regions and had annual data. An average was used for 1993.

7. Gas Facts Yearbook (1989-1993), American Gas Association

Gas prices by state.

8. Bureau of Labor Statistics Web Site

Producer and regional CPIs and Weather data were obtained from this Web site.

9. Mitchell (1989, 1992) and Chamberlin, Fry, and Braithwait (1988)

Least-cost planning by state.

10. Housing Characteristics 1990, Energy Information Agency (1992)

Electric heat penetration rate.

11. Statistical Yearbook of the Electric Utility Industry, ,(annual), Edison Electric Institute

Total electric sales by state.

Appendix II: A Definition of Demand-Side Management

DSM ranges over a large set of policies and programs and has not been perfectly defined. The set of strategies pursued through these programs is shown on Figure 1. In general DSM can be separated into two major categories; load-management and conservation. These are discussed separately below.

Load-management

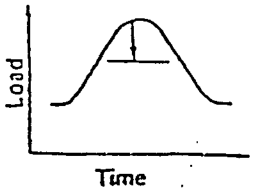
The typical electric utility does not generate a constant amount of electricity. Demand varies by time of day to time of year (Figure 2, 3, and 4). Most utilities in the south are summer peaking due to cooling demands while areas such as the Pacific Northwest are winter peaking due to large heating loads. Utilities must by law meet demand and for this reason will have excess generating capacity and an under used distribution and transmission system so as to be able to meet the peak demands on the system. As a peak period progresses more and more of the available capacity is used. The additional power that is generated is more costly since less efficient plant and equipment will be brought into use. Due to the practice of average cost pricing the consumer does not obtain the correct price signal, which is the marginal cost of production. Therefore at peak periods customers are paying below marginal costs and during off-peak periods the price is above the actual marginal cost.

Large differences between peak and off-peak periods will generally lead to higher than needed rates due to the excess capacity. Thus it will be in the utility's and consumers' favor to shift the demand for electricity that occur during the peak period into that of the off-peak or reduce it completely. Load-management is commonly separated into three strategies: peak clipping, valley filling, and load shifting, where a flexible load program is a subset of peak clipping. Another strategy is strategic load growth. The latter can include both conservation and load-management (Gellings and Talukdar, 1986). Utility sponsored programs which have been developed to induce these types of shifts in demand behavior are varied and many have only seen limited use. The load-management strategies can be separated into five different types of programs:

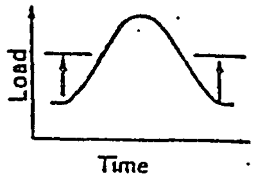
1. Time of use (TOU) rates (seasonal rates, time of day, coincident demand, demand charges).
2. Direct load control.
3. Control of customer appliances.
4. Energy storage.
5. Fuel switching.

TOU rates, in effect, are treating electricity demanded over a daily period and over seasonal periods as different products for which a different price is charged in each period due to differences in generation, distribution, and transmission costs. In

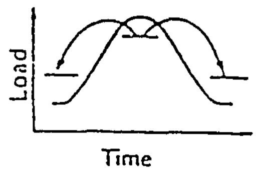
PEAK CLIPPING, or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of customers' appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.



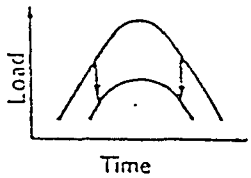
VALLEY FILLING is the second classic form of load management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.



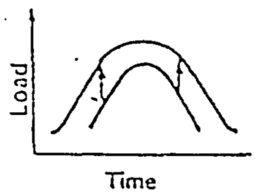
LOAD SHIFTING is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shifts. In this case, the load shift from storage devices involves displacing what would have been conventional appliances served by electricity.



STRATEGIC CONSERVATION is the load shape change that results from utility-stimulated programs directed at end use consumption. Not normally considered load management, the change reflects a modification of the load shape involving a reduction in sales as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.



STRATEGIC LOAD GROWTH is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are, or can be, served by competing fuels, as well as area development. In the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the U.S. industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.



FLEXIBLE LOAD SHAPE is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible — if customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.

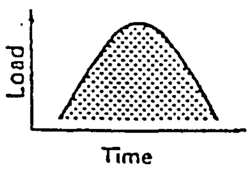


Figure 1
Demand-Side Management Strategies
(Gellings and Chamberlin, 1988)

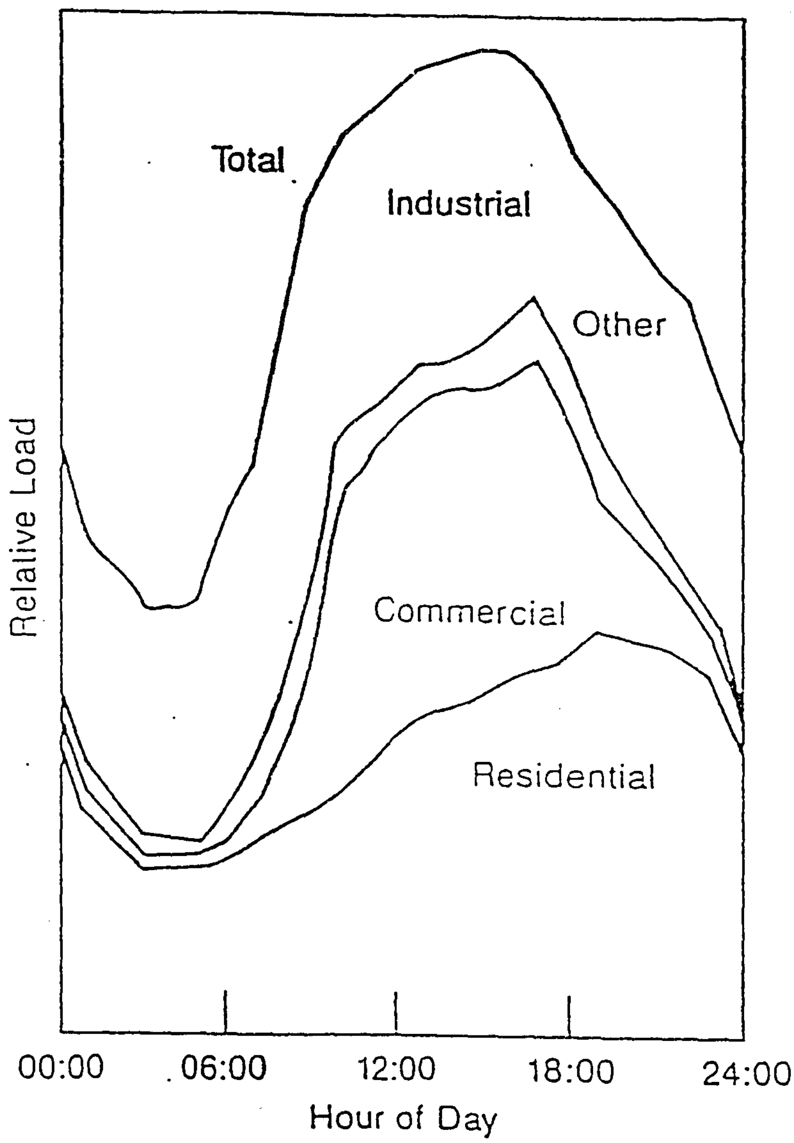


Figure 2
Typical Summer Daily Load Curve
(Gellings and Talukdar, 1986)

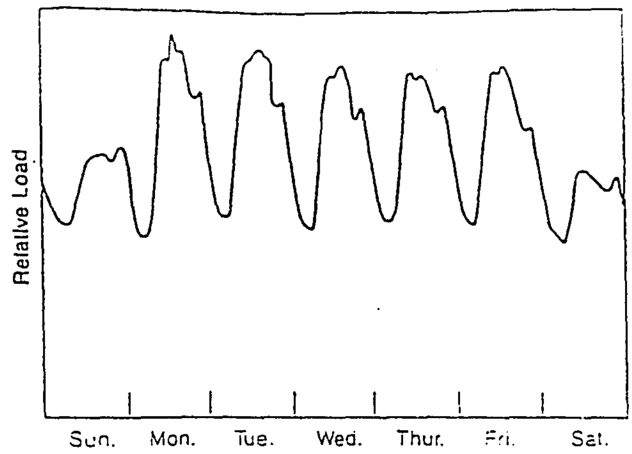


Figure 3
Typical Weekly Load Curve Margins for US Utilities
(Gellings and Talukdar, 1986)

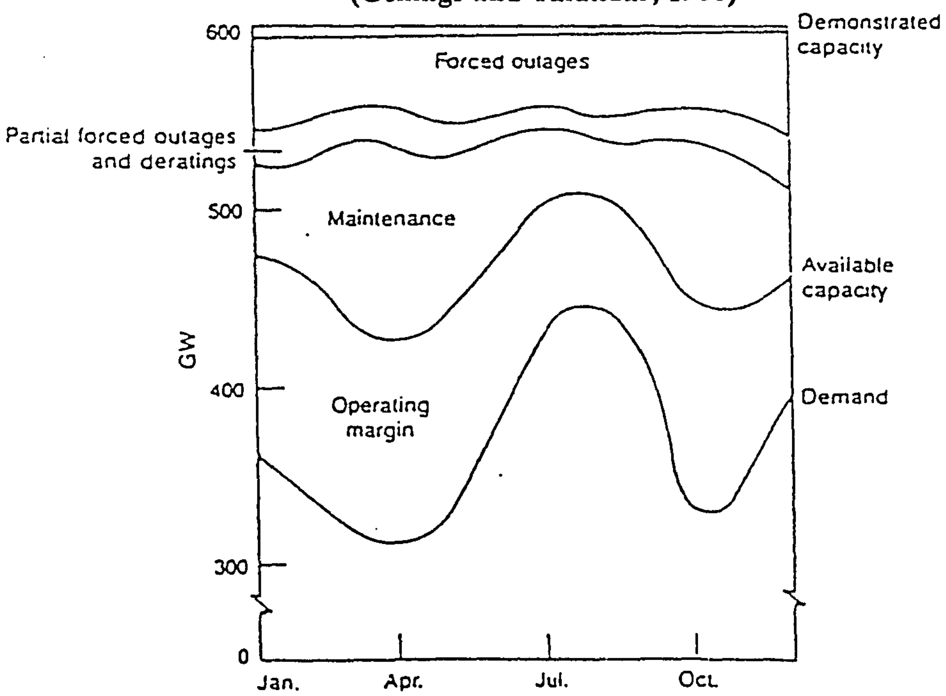


Figure 4
Monthly Peak Demand: Capacity and Operating Margins for US Utilities
(Gellings and Talukdar, 1986)

theory TOU rates would be more efficient rates to charge since they would better reflect the marginal cost of the electricity demanded. In practice they have seen only limited use in the United States while in France and later in England their use has become more widespread.

In the United States the rate structure prior to the 1980's was one in which declining block rates were prevalent. Increasing block rates and TOU rates were viewed as ways to constrict the demand for electricity, which would not have been in the utility's interest. Prior to the eighties, typical utility strategy to meet future demand had been the construction of more generation. The passing of the Public Utilities Regulation and Policy Act of 1978 encouraged the implementation of decreasing block and TOU rates, mainly in the form of a seasonal rate structure. There has been limited experiments in TOU pricing for most customer classes but actual implementation of such rates has only been used for selected larger industrial customers. At present metering costs for smaller customers have not been conducive to adopting utility-wide TOU pricing. One could predict with the lowering of cost of automatic metering devices, through either the projected fiber optic networks or small radio controlled meters, that real time pricing will become a reality by the end of the decade. This event would reduce the need for utility DSM programs since consumers would be obtaining the correct price signals and then be able to adjust their consumption accordingly.

Demand charges have been in use since the creation of the electric industry in the United States Their implementation is a two part tariff, usually referred to as the Hopkinson electricity tariff, where actual consumption of kWh and maximum instantaneous demand in kW are priced separately. Demand charges are based on the instantaneous demand in kW and have the desired effect of reflecting marginal costs associated with capacity usage. This is under the assumption the customer peak demand is coincident with system peak demand (Bonbright et al, 1988). At present demand charges apply mainly to industrial customers and to larger commercial users. Their peak kW demand is calculated either actual measurements of the customer demand or using customer class averages.

The additional four load-management program types have only seen limited use, though in many areas they should prove to be a cost effective alternative to additional generation. Direct load control applies mainly to industrial clients who have facilities to generate their own electricity. A peak clipping strategy that is employed is to contract with large customers the right not to supply them with electricity during the peak period. By offering them lower electric rates in exchange for lowering the quality of service utilities can achieve these service curtailments. These interruptable rates would be set through a bargaining process to be less than the normal rate, though how much less would depend on the lead time needed to notify the customer of service interruption, the total number of hours interruptions are allowable, and other factors. In a survey of utilities in 1985 over 75% of the sampled utilities had interruptible rates (Cogan and Williams, 1987). In theory programs allowing customers to buy power at a lower than normal reliability could be extended to the commercial and residential classes but as yet little has been done in this area.

Some programs result in the utility having direct control of customer appliances such as air conditioning systems, hot water heaters, or boilers. Again customers are offered power at a lower rate in exchange for losing some control over their appliances. In many cases the programs are designed not to interfere greatly with the workings of the appliances. In the case of hot water heaters homes are targeted in which little hot water is used during the day. The water heater is turned off by the utility during peak periods and then turned back on before the client returns home. With air-conditioning units the utility would use its control to let only a certain fraction of the units under its control cycle on for the same fraction of an hour. This would not necessarily reduce total consumption of electricity, but would remove the possibility of all units cycling on at the same time; causing a micro-peak. Also, in the case of a potential black or brown out the appliances under direct control could be turned off reducing this potential problem. By 1990 these types of programs have been planned to increase the number of controlled appliances from the estimated 2.5 million in 1985 to a total of 7 million (Limaye and Rabl, 1988).

DSM energy storage can be thought of as storing heat or cold at the place of usage and not being related to pumped storage. In the case of heating, heat is generated during an off-peak period and stored in a solid storage such as bricks or a boiler. During the peak hours this stored energy is used to heat or produce hot water. In the case of cooling, ice or cooled water are created in the off-peak period and used to cool a facility during the peak period. Obviously more electricity is consumed using this type of alternative and decreased rates must be used to encourage the installation of such facilities.

Fuel switching is generally not a preferred alternative to many utilities. In the case of an all electric utility, electric sales will suffer if customers switch from electricity to gas, oil or biomass. Where the electric reduction will only appear at peak periods a fuel switching program could be a cost effective alternative to supplying electricity from peaking facilities or having to add additional capacity. Some utilities have instituted programs which foster use of dual fuel appliances where electricity is the primary fuel and the secondary fuel is only used during peak periods. A possible problem that could arise from having customers switch from electricity to gas, is that gas supply problems could be created or aggravated.

Conservation

Two program types which do not fall into the category of load-management are:

1. Conservation
2. Efficient Load Growth

When added demand on the system is forecast, a utility should be indifferent between adding new generation and instituting conservation programs which would make the added demand unnecessary if they are granted an equal return on their investment. This would be true if prices were allowed to change reflecting the loss in revenue resulting from the reduction in sales brought on by conservation programs. At present most such programs are looked upon as variable costs. Only slowly are PUCs allowing for conservation investments to go into the rate base and recompensing the utilities for their revenue shortfall. In the advent of retail wheeling investments in such programs will become more problematic since many of these investments will be viewed as stranded costs. These DSM investments are typically owned by the customer and not the utility. With customers being able to switch service providers, any investments made for this customer will not benefit the sponsoring utility.

Existing conservation programs have targeted most customer classes and have a variable amount of direct utility involvement in conservation activities. The least direct involvement is the use of advertising by the utility to promote conservation and provide conservation information to consumers. A more direct form of utility promotion is the provision of utility sponsored energy audits with a varying degree of utility subsidization. Further programs offer installation of energy reducing features either through reduced interest loans or utility sponsored energy efficient appliance rebates. Another variant is buying electricity consumption reductions due to conservation activities from customers directly or from firms which provide conservation measures to customers. Other programs involve different types of utility and industry partnerships where incentives are paid to dealers to promote and stock items, manufacturers to design and produce efficient/"smart" appliances/equipment, or construct buildings that are energy efficient or "smart".

Recently the market transformation has become the goal of many utilities programs. Programs with the goal of transforming the market seek to make fundamental changes in the demand for energy efficiency services and energy efficient products. Successful programs can be phased out without causing the demand for the programs products and services to disappear. These programs are geared to change the buying habits of consumers, the stocking practices of dealers, and the product development and design practices of manufacturers. Programs such as these have made compact fluorescent light bulbs, high efficiency heat pumps and gas furnaces, motors, and appliances more available. It is only after the markets for these products have been developed and consumer acceptance is high that government legislation of efficiency standards becomes possible. This in turn makes the program impacts permanent. A clear example of this was the development of the energy efficient building codes that are now in place in Oregon and Washington. Utility programs that sponsored changes in building practices transformed the residential new construction market in such a way that code changes could be passed without great resistance from the home building industry.

Strategic load growth can fall into both conservation and load shaping strategies. This strategy targets energy use in new or renovated buildings and facilities, the replacement of old appliances, and new markets involving electro-technologies. Programs encouraging energy efficient designs and the placement of energy efficient appliances by architects, construction companies, appliance dealers and manufacturers, and contractors can fall into this category and can culminate in reduced future energy use and the targeting load impacts of new or changed demands. Often times the goal of these programs is to reduce fuel switching and retain market share in certain lucrative areas or to develop a toehold in potential new markets. Many heatpump and water heater programs are geared to retain market share of an important part of a utilities load. Air conditioner programs are often times used to boost the penetration rate of not only energy efficient air conditioners but the air conditioners in general.

Appendix III: Hypothesis Tests

DSM Investment Equation

1. Regression with 8 explanatory variables, interaction terms for each of the three years (24 variables), and different intercepts for each year (4 variables).
ESS = 402 N = 324
2. Regression with 8 explanatory variables, interaction terms for each of the three years (24 variables), and one intercept.
ESS = 408 N = 324
3. Regression with 8 explanatory variables and different intercepts for each year (4 variables).
ESS = 420 N = 324
4. Regression with 8 explanatory variables one intercept.
ESS = 437 N = 324

	F statistic
1. Regression 4 tested against Regression 1	0.92
2. Regression 4 tested against Regression 2	0.85
3. Regression 4 tested against Regression 3	3.89

Cost of Equity Capital Equation

1. Regression with 10 explanatory variables, interaction terms for each of the three years (30 variables), and different intercepts for each year (4 variables).
ESS = 87,426 N = 324
2. Regression with 10 explanatory variables, interaction terms for each of the three years (30 variables), and one intercept.
ESS = 87,763 N = 324
3. Regression with 10 explanatory variables and different intercepts for each year (4 variables).
ESS = 96,874 N = 324
4. Regression with 10 explanatory variables one intercept.
ESS = 140,729 N = 324

	F statistic
1. Regression 4 tested against Regression 1	5.17
2. Regression 4 tested against Regression 2	5.63
3. Regression 4 tested against Regression 3	42.3
4. Regression 3 tested against Regression 1	1.01

Demand for Electricity Equation

1. Regression with 9 explanatory variables, interaction terms for each of the three years (27 variables), and different intercepts for each year (4 variables).
ESS = 7.9 N = 324
2. Regression with 9 explanatory variables, interaction terms for each of the three years (27 variables), and one intercept.
ESS = 7.91 N = 324
3. Regression with 9 explanatory variables and different intercepts for each year (4 variables).
ESS = 8.16 N = 324
4. Regression with 9 explanatory variables one intercept.
ESS = 8.48 N = 324

	F statistic
1. Regression 4 tested against Regression 1	0.70
2. Regression 4 tested against Regression 2	0.75
3. Regression 4 tested against Regression 3	3.71

Average Cost of Electricity Equation

1. Regression with 13 explanatory variables, interaction terms for each of the three years (39 variables), and different intercepts for each year (4 variables)
ESS = 2.614 N = 324
2. Regression with 13 explanatory variables, interaction terms for each of the three years (39 variables), and one intercepts
ESS = 2.622 N = 324
3. Regression with 13 explanatory variables and different intercepts for each year (4 variables)
ESS = 2.875 N = 324
4. Regression with 13 explanatory variables one intercept
ESS = 2.90 N = 324

	F statistic
1. Regression 4 tested against Regression 1	0.70
2. Regression 4 tested against Regression 2	0.73
3. Regression 4 tested against Regression 3	0.75

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