Valuation of Demand Side Utility Programs

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ABSTRACT

This paper examines large scale demand side programs whose impacts require a change in utility supply plans. The benefits of the programs are defined in terms of the costs or value of power plants expected in service that are deferred by the programs in question. Case studies are developed for standards programs that increase the efficiency of residential appliances. The utilities studied are the Nevada Power Company and the Texas Utilities Electric Company. The annual energy and hourly load impacts of these programs are calculated using the LBL Residential Energy and Hourly Demand models calibrated to data for the specific utilities.

The Nevada Power case focuses on determining the optimal deferral period by using production simulation modelling techniques. In the Texas Utilities case we use cost data based on purchase terms offered to cogenerators as the valuation method. In this case the procedures for allocating capacity value are the focus of attention. Two different rules are examined.

The principal result of these studies is the divergence of social value from value to the utility. Programs which are cost-effective to the utility usually are net losers to society. This is due to the high cost of air-conditioning efficiency improvements and the low cost of power for these utilities. Expected reductions in the cost premium for efficient appliances still do not produce uniformly positive benefits to society.

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1. INTRODUCTION: The Definition of Large Scale Programs

This study examines the costs and benefits of large scale demand side programs. We consider situations in which electric utilities are facing substantial load growth and are planning major resource additions to meet this demand. In this situation utilities face a choice between supply-side and demand-side actions. We examine this choice in two specific cases to determine the nature of demand side programs that can help reduce costs to consumers and to society. It will become clear that integrated resource planning which balances the demand side against the supply side is quite a complex process. The methods available for minimizing cost in this integrated sense are not fully developed or unambiguous. The issues we will address include estimating the detailed load impact of demand side programs, adjusting supply plans to account for these impacts, forecasting regulatory effects, and examining the supplier markets for end-use efficiency.

Large scale demand-side programs require electric utilities to adjust their supply plans. This typically means that power plants scheduled to come into service in the intermediate future (3 to 7 years hence) must be deferred. Most of the cost/benefit literature on conservation and load management ignores this kind of case. (Association of Edison Illuminating Companies, 1984). The usual convention in this literature is the assumption that demand side programs are sufficiently small so that their value can be measured by reference to a static supply plan. We will refer to the case in which static methods are appropriate as small-scale.

The first step in examining large-scale programs is to identify the power plants which are likely to be deferred in response to demand-side programs. This will usually be the next utility resource addition to which irrevocable timing commitments have not been made. We will refer to such plants as proxies, because they represent the value of demand-side programs. Our concern in this paper is defining proxy plant value and associating it with the load impacts of demand side activities. We will show how this can be done for residential appliance standards in the case of two Western electric utilities; Nevada Power Company (NPC) and Texas Utilities Electric Company (TU).

Figure 1 summarizes the timing of supply and demand side activities in the large scale appliance standards cases we examine. We assume that our programs have a initial date, I, at which they begin, and an ending date, E, at which they end. The load impacts started in the period from I to E propagate until some date T. On the supply side we distinguish the date 01 at which the proxy plant, P1, was originally due in service from the data 02, which is the time to which it will be deferred. All other plants in the supply plan, P2, P3, etc are also deferred by the same amount. It should be noticed that I must precede 01 due to inertia in the demand side program and the definition of deferrability.

Although Figure 1 is generic, we will concentrate on different aspects of the process in each case study. In the Texas Utilities case we will focus on the match between the load impacts of appliance standards and the nature of the proxy plant. The interest of this case lies in something of a mismatch. Appliance standards in the Southwest have a strongly seasonal impact due to the importance of air-conditioning loads. The TU proxy is a baseload plant. Assigning capacity value in this case depends on allocation procedures. We discuss this general question in Section 3 before examining the case studies in detail. In the Nevada Power case we will concentrate on determination of the deferral period. This is given exogenously in the TU case. For NPC we use production cost simulation techniques to find a reasonable period.

The paper is organized in the following manner. Section 2 provides a brief characterization of the two companies studied and the impact of our standards cases. Section 3 discusses the separation of capacity and energy value in proxy plant data. The criteria for assigning these values to end-use load shape changes are reviewed as well. Section 4 applies these distinctions to the Texas Utilities context. Results on load impact are illustrated. In section 5 the Nevada Power case is examined. The system planning aspect of evaluation demand side programs is highlighted. Section 6 summarizes results on cost effectiveness for these cases from the utility and social perspectives.

2. Two Electric Utilities: Texas Utilities Electric and Nevada Power

The subjects of our case studies are the residential classes of the Texas Power and Light service territory of Texas Utilities Electric Company, and the Nevada Power Company. Both of these summer-peaking, southwestern US utilities expect continued strong demand growth into the 1990's (see Table I.). For Nevada Power, this growth in peak demand comes at the expense of further declines in an already low load factor. TU anticipates improved load factors as the penetration of of electric heating increases.

Table I. Summary of NPC and TUEC

Year	Peak Demand 1984 (MW)	Growth 85-99 (%/yr)	Energy 1984 (GWh)	Growth 85-99 (%/yr)	1984 Load Factor (%)	Residential Sales (% of system)	Avg Use per Cust. (kWh/yr)
Texas Utilities	15595	2.9	77049	3.3	56.4	33	12073
Nevada Power	1502	3.8	6572	3.7	49.9	44	13445

Both utilities have relatively low costs compared to national averages. Residential electric rates are 0.058 $/kWh for 1000 kWh/mo for Nevada Power and 0.064 $/kWh for Texas Utilities. The national average, also for 1985, is 0.076 $/kWh. (U.S. DOE, 1985). Both utilities are also in the process of phasing lower cost coal plants into the generation mix. Texas Utilities expects its generation mix to shift from 40% oil and gas in 1985 to slightly less than 20% in 1999. Over the same period, Nevada Power plans to reduce oil and gas generation from 14% to 6%. We expect lower costs to have important consequences for our financial analyses.

For each utility, we examine the financial impacts of three appliance efficiency standards starting in 1987. Table II. compares the efficiencies called for in each standard with existing efficiencies in the service area of each utility. Existing efficiencies are described by both a stock-average or existing efficiency and an incremental or new appliance efficiency. Level 8 refers to a set of appliance efficiencies that are life-cycle cost-effective based on a nation-wide analysis. Level 8/12 refers to the same standard with the addition of an extremely high efficiency central air conditioner standard. Level 12/AC refers to the isolated case of raising only room and central air conditioner efficiencies.

Table II. Appliance Efficiency Comparison

	Texas Utilities		Nevada Power		Appliance Standards		
Appliance	Existing	New	Existing	New	Level 8	Level 8/12	Level 12/CAC
Space Heating (AFUE%)[a]							
gas	63.79	70.18	64.36	71.45	85.72	85.72	--
oil	73.93	78.61	75.08	78.77	90.98	90.98	--
Air Conditioning							
room (EER)[b]	6.54	7.17	6.58	7.15	8.87	8.87	8.87
central (SEER)[c]	6.91	7.32	7.08	7.26	8.42	12.00	12.00
Water Heating (%)							
electric	80.75	81.31	81.01	82.86	93.60	93.60	--
gas	50.50	56.96	53.03	62.61	81.75	81.75	--
Refrigerators (ft^3/kWh/d)	4.88	6.35	4.96	6.64	11.28	11.28	--
Freezers (ft^3/kWh/d)	9.22	11.61	9.86	12.24	22.34	22.34	--
Ranges (%)[d]							
electric	39.64	43.73	39.40	44.27	47.51	47.51	--
gas	16.29	29.27	17.57	31.57	20.27	20.27	--
Dryer (lbs/kWh)							
electric	2.72	2.88	2.71	2.90	2.96	2.96	--
gas	2.22	2.63	2.28	2.65	2.61	2.61	--

a) Annual Fuel Utilization Efficiency
b) Energy Efficiency Ratio
c) Seasonal Energy Efficiency Ratio
d) useful Cooking Output/Total Input Energy

The impacts of the policies on projected residential class loads are summarized in Table III. The table compares residential energy and demand growth rates under the base and policy cases and quantifies the impacts for 1996.

3. Separating Capacity and Energy Value

Electricity is a commodity whose value has two principal dimensions. The energy value, measured in kWh, applies to all hours of the year. Capacity value, measured in kW, applies only in those hours where the system reliability is a potential problem. It is the real time nature of electric power supply which creates capacity value. One problem of using proxy plants to value large scale demand side programs is the separation of the capacity and energy value of the proxies and assignment of these values to the program load impacts.

Table III. Summary of Impacts for Residential Class

Case	Growth Energy (%/yr)	Growth Demand (%/yr)	Impact by 1996 Energy (GWh)	Impact by 1996 Demand (MW)
		Texas Utilities		
Base	3.48	3.07		
Level 8	2.84	2.28	826.3	222.1
Level 8/12	2.30	1.30	1469.4	465.8
Level 12/AC	2.67	1.52	1031.4	413.3
		Nevada Power		
Base	2.99	2.61		
Level 8	2.34	1.65	235.1	70.6
Level 8/12	1.92	0.11	380.3	142.7
Level 12/AC	2.37	0.36	226.1	122.7

The separation problem is particularly important when the proxy plants are baseload units and the demand side programs exhibit variable load impacts. This mismatch occurs in both of our case studies. We resolve the issue by appealing to a notion in the power system economics literature known as "energy-related capital" (ERC). The basic problem we must resolve is a joint cost allocation problem. The capital costs of a baseload generator produce two commodities, electric energy and capacity. The ERC method allocates to capacity the capital cost equivalent of a combustion turbine, and to energy all other costs. The rationale for this procedure is the standard argument in the marginal cost literature that the marginal cost of capacity is the cost of the least expensive type of generation for peaking purposes. This is a combustion turbine. All other baseload generation costs beyond the combustion turbine capital cost are incurred for the purpose of reducing energy costs. Therefore the capital costs of baseload units in excess of the combustion turbine are energy related. The ERC method has been used to price power purchased from private producers by the Montana Public Service Commission (1984).

To implement the ERC method, or any other procedure for assigning capacity value to load shape changes, there must be a determination of the capacity value of demand reductions during each hour. The most precise measurement of these effects is done with reliability indices such as the Loss of Load Probability or LOLP index. Hourly LOLP values can identify which hours are important and their relative importance, i.e. how to weight them.

In practice simple rules of thumb are often used to translate load shape changes into equivalent capacity value. The most extreme simplification is the use of only the peak hour. For strongly peaking systems as few as 150 hours may incorporate the bulk of the annual LOLP. In our case studies we will consider one rule based on the top 500 hourly loads and another rule based on annual performance criteria. The annual rule is adapted from performance criteria established for cogenerators selling power to the utility.

4. Texas Utilities Electric Company

We use the LBL Residential Energy Model and the Hourly and Peak Demand Model to calculate the effects of our standards programs (McMahon, 1986 and Verzhbinsky, et al. 1984). These models forecast appliance choices and the energy and demand impacts of those choices. Calibration to utility specific data is an important part of this process.

Figures 2 and 3 are two representations of the load impacts. Figure 2 shows the 1996 summer peak day for Texas Power and Light (TP&L) residential class loads. (TP&L) is a subsidiary of TU. Since the TU system is summer peaking; we assume this is also the system peak day as well. Figure 3 shows monthly variation in energy savings for the three standards programs in 1996. As these figures demonstrate the load impact from the programs is substantial. The capacity savings, using the top 500 hours criterion, range from 269 MW to 566 MW. These savings include both the direct load impacts and the savings in reserve margin requirements. Given these magnitudes it is appropriate to compare these demand-side options with supply alternatives. To assess the value to TU of the savings illustrated in these figures we rely on the utility's avoided cost offer to cogenerators. This offer is based on deferring the Forest Grove No. 1 baseload coal unit for two years from 1989 to 1991 (Texas Utilities Electric Company, 1985). We will describe this offer and how we use it to quantify the benefit of our standards programs.

TU calculates the present value of revenue requirements associated with a 1989 in-service date for Forest Grove No. 1. An adjustment is made to the fixed costs for deferring the plant to 1991. The total present value is then re-expressed as a 30 year escalating stream of values that increase uniformly at 7%/year from 1989. This is called the "progression stream." TU will pay cogenerators the progression stream of fixed costs for up to 15 years if they meet a capacity performance requirement. Energy is paid at the rate of Forest Grove fuel costs.

The TU capacity performance requirement is an average 65% annual capacity factor with 75% required during the summer months from June through September. The TU method allocates to capacity all the fixed costs of Forest Grove. The allocation rule together with the performance requirement imply that only baseload generation or demand-side programs with baseload characteristics will get full avoided cost. We will illustrate this by comparing the value of our three standards programs calculated by the TU method and by the ERC method. For convenience we normalize results to the price per kWh TU would pay a cogenerator for a 15 year contract starting in 1989. The total present value of such a contract is $0.342 per annual kWh.

Valuation results for the standards programs are given in Table IV below. We summarize results here. For the Level 8 case the two methods are roughly comparable to each other and to the value of a cogenerator meeting the TU performance requirement. The ERC method produces a price per kWh 3% less than the cogeneration payment; the TU method produces results 8% less. Since the standards programs are not completely equivalent to a 15 year supply contract, these results are essentially identical. In the Level 8/12 case (SEER 12 for space conditioning) the ERC price per kWh is 2% greater than the cogeneration payment, and the TU method is 8% less. The greatest difference is for the Level 12 case alone. Here, the ERC method produces a price per kWh 11% greater than the cogeneration price, but the TU method yields 8% less than the cogeneration price. It is the seasonality of load impacts in this case which penalizes the Level 12 standard under the TU criterion. Using the 500 hours definition of capacity value produces 2-2.5 times the MW impact of the TU definition. In Section 6 we present a complete cost/benefit analysis of these cases using the ERC method.

5. Nevada Power Company

The same standards cases examined for TU are also run for Nevada Power Company (NPC). Figures 4 and 5 illustrate 1996 load impacts for the summer peak day and monthly cycle respectively. Compared to TU the peak day load shape is flatter but the seasonality is more pronounced, i.e. the summer cooling season is shorter. The valuation method used for this case differs substantially from TU. It is based on system planning methods which are intended to match supply side adjustments with the load impacts illustrated in the figures.

The first step in the process is to identify the deferrable resource addition. NPC expects to purchase shares of coal plants coming on line in 1988 (Hunter 3), 1993 (White Pine 1) and 1994 (White Pine 2) (Nevada Power Company, 1984). Since our programs begin in 1987 and have considerable inertia, we believe that it would be premature to consider a deferral of Hunter 3. This means that White Pine 1 is the proxy for the value of our standards program.

The next step is to determine the optimal deferral period and to estimate the value of that deferral. We make these estimates using an interactive procedure that is based on production cost simulations of the NPC system. The procedure involves three basic steps.

1. Simulate the unperturbed expansion plan.
2. With loads fixed as in (1), simulate the deferral case
3. Adjust loads to reflect demand side programs and simulate the deferral case.

We used the EPRI model TELPLAN to perform these simulations (Tera Advanced Services, 1982). Step 1 therefore required calibration to NPC's more complex model. The details of this calibration are reported in Eto, et al. (1986). Steps 2 and 3 determine an optimal deferral when the present value of production costs of the case in Step 3 is equal to the present value of production costs in the unperturbed plan. In that case, the value of the demand side program is the avoided production costs measured by the difference between the present value of the cases in Step 2 and Step 1. If the simulations in Step 3 and Step 1 do not produce the same present-value of production costs, the deferral is not optimal with respect to the load impacts. The deferral period is too short if Step 3 results in lower costs than Step 1, and conversely it is too long if Step 3 costs are greater.

Once the optimal deferral period has been found, the valuation of the programs require two further elements. First, the period between the start of the program and the original on-line date of the proxy plant must be treated. Second, the deferral value must be separated into capacity and energy components. The "pre-proxy period" is from 1987 to 1993 in the NPC case. The same phenomenon exists in the TU case, but it is much shorter (1987 to 1989). The value of energy savings in this period is just the short-run marginal cost (SRMC). This was calculated for the unperturbed NPC expansion plan in the model calibration. There is no capacity value in the pre-proxy period. The production cost savings found in the iterative search for the optimal deferral include both capacity value and energy value. By analogy with the ERC method we subtract the revenue requirements of a combustion turbine from the production cost savings. This is the capacity value. All remaining value is assigned to energy. We also use the progression stream concept as a way of ordering these values to account for differences in timing of the various vintages of load impacts due to the phased in nature of standards programs savings.

For NPC and TU we assume that the appliance standards programs which begin in 1987 are terminated in 1996. This is essentially a computational convenience which simplifies economic analysis by allowing finite calculations. An intuitive rationale for this assumption is that a ten year standards program will have stimulated private sector R and D to the point where the market for appliance efficiency became more socially optimal.

The present value of standards to NPC is not strictly comparable to the TU case because of differences in the discounting conventions employed by each utility. The NPC discount rate used is just over 15%. This is based on the "weighted average cost of capital" (WACC). WACC is a conventional method in the utility industry, but it has less theoretical support than a lower rate sometimes known as "the rate of disadvantage" (ROD). ROD is essentially WACC reduced by the tax advantages of debt. TU uses the ROD method which under its planning assumptions is about 11.5%. These differences will be discussed further in the cost-effectiveness analysis of section 5. We summarize load impacts and avoided cost value for NPC and TU in Table IV.

Table IV. Avoided Cost-Value[a]
($/kWh)

	NPC		TU[b]	
	WACC	ROD	TU Method	ERC
8	.264	.415	.316	.330
8/12	.282	.437	.315	.347
12	.326	.489	.315	.378

a) 1985 present value of 12 years of savings

b) Discounted at ROD

6. Cost-Effectiveness

We calculate cost-effectiveness measures from the utility and social perspectives. The benefits in both cases are the avoided supply side costs associated with the standards cases. The cost to utilities is limited to lost revenues relative to a base case without demand side programs. In addition, appliance standards programs also impose a cost premium for efficient appliances that is not borne by the utility. These costs are a burden to society and so must be treated from the social perspective. A further difference between the two perspectives involves the discount rate appropriate for these calculations. It is reasonable to use the utility's own discount rate for cost-effectiveness from their perspective. Since these differ substantially for TU and NPC as noted above, results at this level are not strictly comparable. The social evaluation, however, would not be instructive unless both cases were treated comparably. To address this concern, we use the ROD for both utilities. Although the ROD method produces discount rates which are not strictly equal for NPC and TU, they are reasonably close (11.5% vs. 11.85%).

There is, of course a large literature on the appropriate discount rate for social cost benefit analysis. Without entering into this discussion, we note briefly that the ROD method for regulated utilities comes out mid-way between the more extreme positions advocated in the economics literature. In our cases the ROD is approximately 5-6% in real terms. The social time preference theory implies a 1-2% real discount rate. At the other extreme the opportunity cost theory based on market returns suggests a real rate in the 10-15% range. Details of these positions are found in Lind (1982).

The lost revenue cost requires further discussion. Demand side programs reduce the consumption base over which the utility's fixed costs must be recovered. This raises rates compared to the situation without such programs. It is possible, however, that short-run marginal fuel cost savings are greater than the revenue losses from demand-side programs. In this case, lost revenue is negated and the rate change is beneficial. To estimate the rate impact we calculate revenue losses using utility specific rate structures, and sales frequency distributions and subtract short-run marginal cost. Details on the revenue loss calculations are given in Kahn et al. (1984). To account for the indeterminate sign of this effect, we refer to it as a rate impact.

Tables V and VI summarize the cost-effectiveness evaluation of the programs. The NPC case shows positive net benefits for all programs from the utility perspective. When the social evaluation is made, however, only the Level 8 program is beneficial. This is due to the very substantial cost of efficient air conditioners. Even though benefits increase using the lower discount rate, they do not offset equipment costs. The TU case is roughly similar. Cost-effectiveness is more favorable from the utility perspective than from the social perspective. The magnitudes in the TU case are generally less favorable than the NPC. Favorable cases are less favorable than NPC and unfavorable ones are much worse.

Table V. Benefit Cost Analysis - NPC

Utility Perspective: Discount Rate = 15.07% (WACC)

	Load Shape Change GWh	MW	Avoided Cost (M$)	Rate Impact (M$)	Net (M$)	(= AC-RI)
8	235	71	62	(15)	77	
8/12	380	143	107	(25)	132	
12	226	123	74	(17)	91	

Social Perspective: Discount Rate = 11.85% (ROD)

	Equipment Cost	Avoided Cost	Rate Impact	Net	(= AC-(RI + EC))
8	61	98	(21)	58	
3/12	210	166	(37)	(7)	
12	189	111	(25)	(53)	

Table VI. Benefit Cost Analysis - TU

Utility Perspective: Discount Rate = 11.5% (ROD)						Social Perspective		
	Load Shape GWh	Change MW	Avoided Cost (M$)	Rate Impact (M$)	Net (M$)	Equipment Cost	Net	(=AC-(RI + EC))
8	826	222	273	246	27	196	(169)	
8/12	1469	466	510	481	29	672	(643)	
12	1031	413	390	394	(4)	605	(609)	

It is important to comment on the uncertainties of the various terms. Perhaps the greatest uncertainty is associated with the rate impact cost. This term depends on regulatory policy for its magnitude and its incidence i.e. on whom it will fall. The contrast between NPC and TU is greatest for this term. NPC shows a small benefit due to low current residential rates and expectations of rapid marginal cost increases and slow growth in rates. TU shows a large loss. This is due to an opposite configuration of factors. TU has higher current residential rates than NPC. Expectations of rapid rate increases and slowly growing marginal costs determine a large loss from the rate impact term.

The equipment cost term is also uncertain. It is likely to be high. Cost estimates for efficient air-conditioners collected by the California Energy Commission (1984) suggest that our estimate might be reduced by 20-50%. Such reductions would make programs for NPC more cost-effective, perhaps even resulting in net positive benefits for all programs. This would not occur for TU. Even with equipment costs reduced by half, the rate impact costs remain too large.

These results show that the social costs of demand-side programs can potentially outweigh the avoided cost benefits they produce. The specific balance will often depend on rate impacts which vary substantially from one utility to another. Even if we neglect the rate impact, the cost of demand reduction through mandated efficiency standards is high. Efficient air-conditioners can have substantial impacts on utility peak loads. But the demand diversity which is captured in our load impact model of each unit, acts as an extra cost burden compared to using combustion turbines. Not only is each kilowatt of efficiency expensive at the end-use, but they do not all "produce" simultaneously.

Even major cost reductions on the equipment side will not eliminate the diversity effect.

Nonetheless it is clear that the cost of equipment efficiency is a major consideration in the evaluation of demand side programs. The determinants of these costs involve the structure of the appliance manufacturing industry. California Energy Commission data suggest very different views of the long run cost of air-conditioner efficiency. This cost is a major determinant of the programs we have studied.

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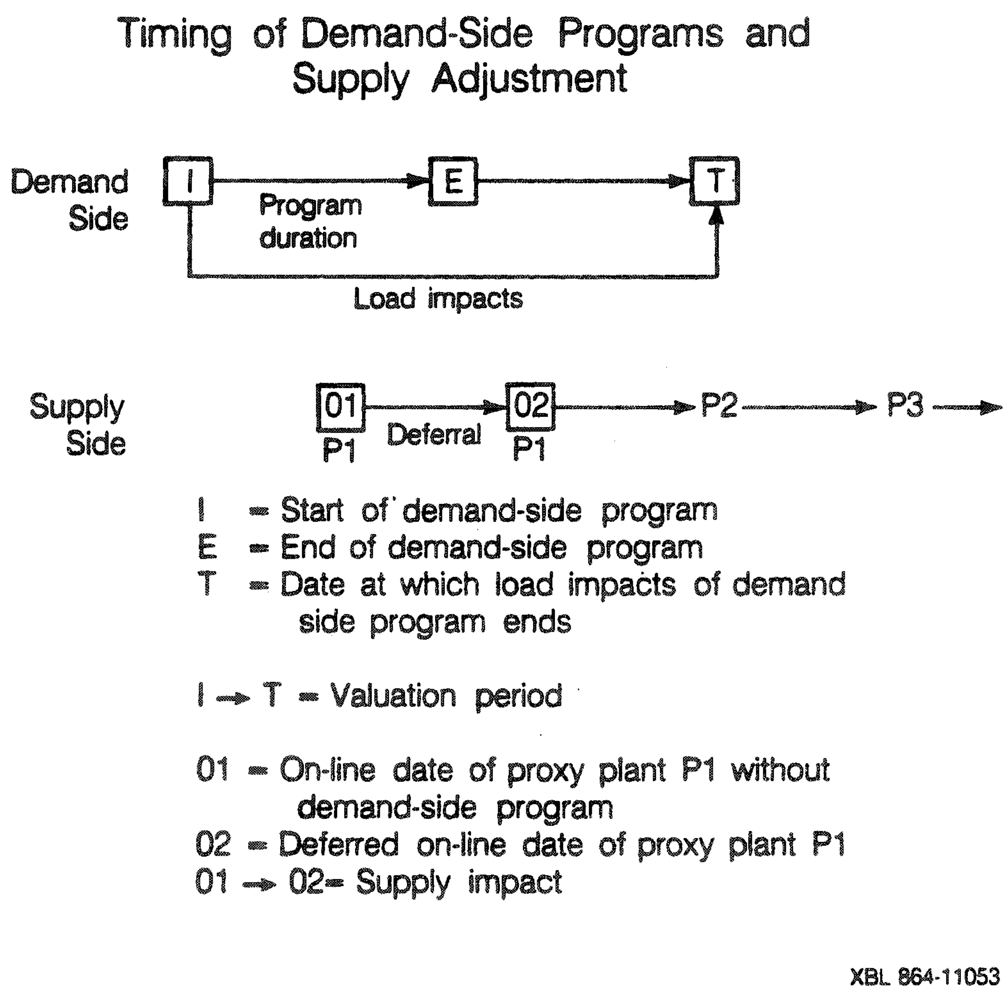

Figure 1. Timing of demand-side programs and supply adjustment.

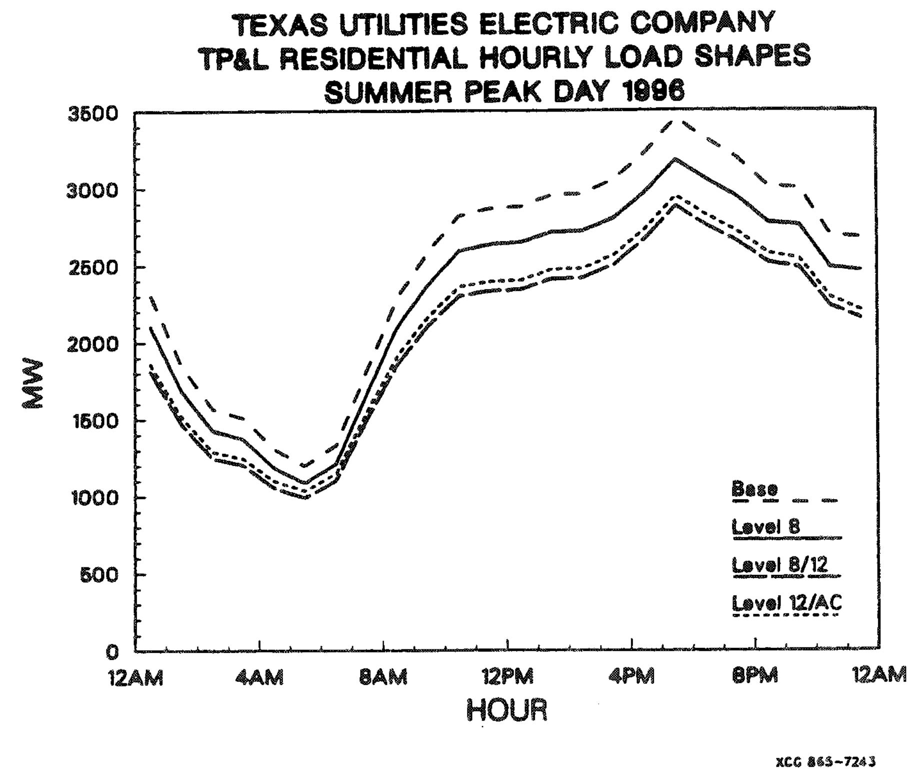

Figure 2. Residential class hourly load shape for the Texas Power and Light service territory of Texas Utilities Electric Company on the summer peak day in 1996.

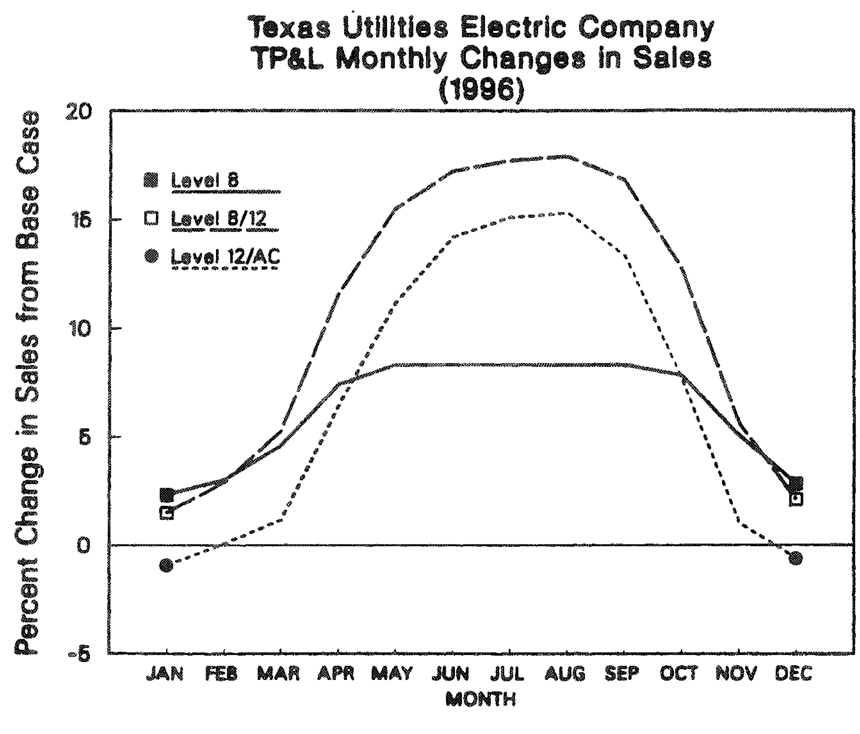

Figure 3. Percentage changes in monthly residential class sales for the Texas Power and Light service territory of Texas Utilities Electric Company in 1996.

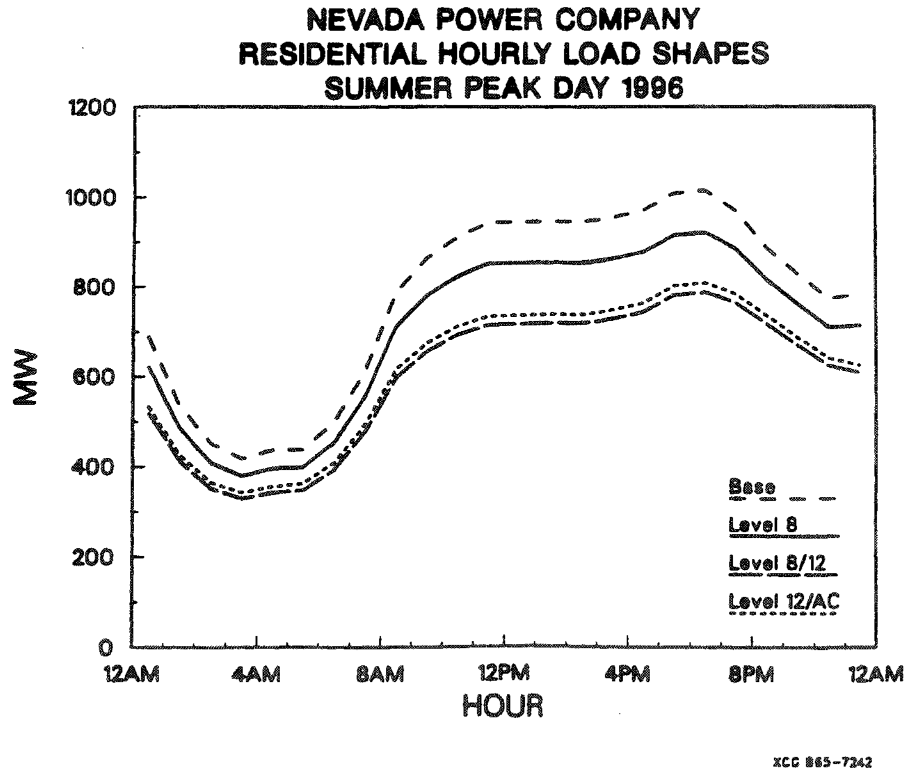

Figure 4. Residential class hourly load shape for the Nevada Power Company on the summer peak day in 1996.

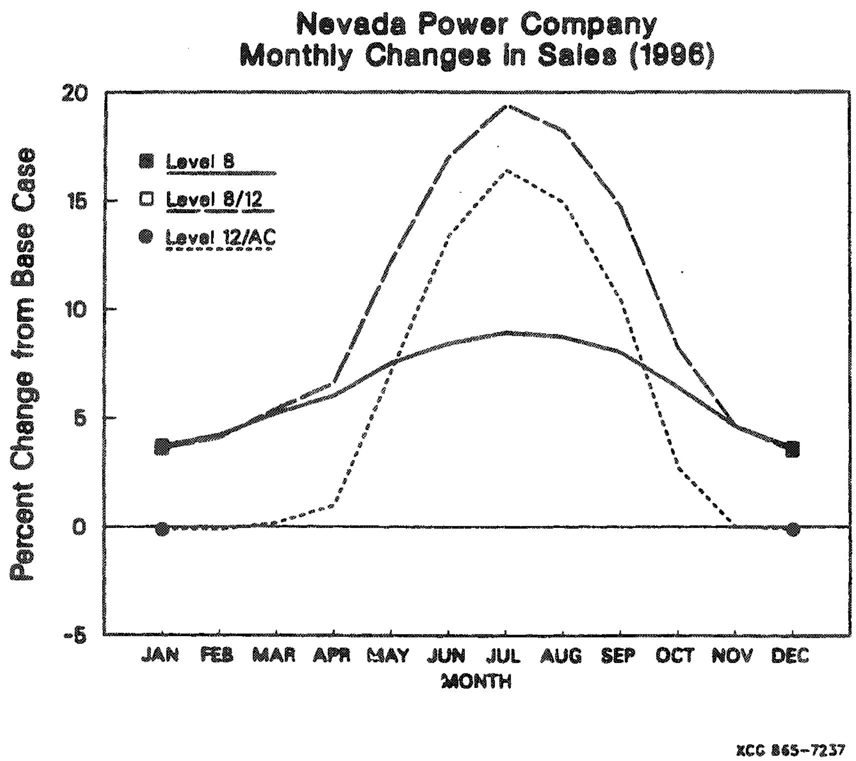

Figure 5. Percentage changes in monthly residential class sales for the Nevada Power Company in 1996.