The effect of conservation programmes on electric utility earnings

Results of two case studies

E. Kahn, C. Pignone, J. Eto, J. McMahon and M. Levine

This paper develops methods to measure the impact of conservation programmes on electric utility earnings. The methods are applied to two case studies. Detroit Edison represents a case where impacts are unfavourable. This utility has 'excess capacity' which is only made worse by conservation. Pacific Gas and Electric represents a case where conservation helps defer the need for new capacity. Even in this case, programmes targeted at summer peak demand are more beneficial than those which save baseload energy. Conditions determining the earnings impact of conservation are complex, involving regulatory factors that are specific to individual utilities.

Keywords: Electricity; Conservation; Utilities

The authors are with the Applied Science Division, Lawrence Berkeley Laboratory, University of California, Berkeley, CA 94720, USA.

This work was supported by the Assistant Secretary for Conservation and Renewable Energy, Office of Building Systems, Building Energy Research Division of the US Department of Energy, under Contract No DE-AC03-76SF00098.

Electric utilities have become increasingly involved in end-use conservation programmes over the past decade. Many of these programmes have originated within the industry itself, but many have also been mandated by state and local government agencies. Although the scope and magnitude of these efforts have increased steadily over time, utilities are not universally enthusiastic about conservation. Indeed, some utilities are now actively promoting load growth for the first time in ten years.[1] To account for this difference in behaviour, we have investigated the effect of conservation programmes on utility earnings. Most analyses of utility conservation programmes focus on the consumer viewpoint.[2] Within this perspective, it is common to distinguish between those consumers who participate in a conservation programme and those who do not. Participants receive direct benefits from conservation. Non-participants only benefit if there are long-run benefits from conservation which do not accrue to participants. There is much in common between the non-participant perspective and the viewpoint of the utility shareholder. In both cases the quantities of interest are avoided costs and lost revenues. If conservation programmes cause a revenue loss greater than avoided cost, either non-participants must pay higher prices through a rate increase, or shareholder earnings decline.

In this study we examine the case of imperfect regulation where conservation programmes reduce revenues and there is no corresponding rate increase to offset the loss. This case corresponds to mandated conservation programmes such as the proposed imposition of appliance efficiency standards by the US Department of Energy. This type of national policy can be expected to have different impacts on electric utilities shareholders in different regions. We examine the potential

0301-4215/87/030249-13$03.00

range of variation by considering two particular utilities where the effect of conservation programmes is quite different. To represent those utilities which would lose earnings from national appliance standards, we modelled Detroit Edison Company (DE). The favourable case was represented by Pacific Gas and Electric Company (PG&E).

The single most important determinant of the earnings effect of an exogenous conservation programme is the degree of excess capacity. Where excess capacity is substantial, conservation programmes can destabilize utilities. The 'spiral of impossibility' scenario which characterizes this instability is just a case of insufficient demand for an inflexible supply mix.[3] Where excess capacity is already substantial, additional conservation will only make the supply–demand mismatch worse. On the other hand, relative supply scarcity (lack of excess capacity) creates favourable conditions for increased earnings from conservation.

Our general approach to modelling conservation programmes is based on the use of the LBL/ORNL Energy Forecasting model.[4] This is an end-use forecasting model of residential energy consumption. We apply it at the rate class level to determine changes in energy sales and utility revenues. This is a unique application, since forecasting is not commonly done on a tariff class-specific basis. It is necessary to capture this level of detail to measure the revenue loss from conservation adequately. The results of the forecasting model are also used in the LBL Hourly Demand Model.[5] This model spreads monthly kWh consumption across the diurnal cycle. Hourly load changes are translated into avoided capacity costs using appropriate measures of value.

The analysis conducted here is important because it reveals a potential conflict between socially beneficial investments and the private interest of electric utility shareholders. It is common to find that conservation programmes represent part of the optimal least cost expansion of regional power systems.[6] Since the criterion used in these studies is a total social cost test, conflicts with private interests are not made apparent. This analysis shows that utility earnings may or may not decline if conservation is mandated. Where earnings losses would occur, utilities may be expected to oppose conservation programmes.

Definition and measurement of earnings

The shareholder perspective involves the changes in earnings associated with conservation. Because 'earnings' is the difference between revenues and costs, it is harder than either of its component terms to measure precisely. Given the complexity of the task, a somewhat simplified approach has been adopted. We focus on a figure-of-merit that is related to what accountants call Earnings Before Interest and Taxes (EBIT). EBIT allows us to capture the important economic and regulatory variables without the unnecessary detail of corporate tax and debt analysis.

A particularly important stage in this analysis is the estimation of revenues lost through conservation. This is a difficult task because residential electricity rates are often non-linear. Prices vary with the level of use, either directly (inverted rates) or inversely (declining rates). Thus, we need to know where in the price structure conservation is occurring. The data used to make such estimates is called the sales

[1]'Utilities look to discount rates to aid recovery', *Electrical World*, Vol 197, No 7, July 1983, pp 103–104, and 'Utilities must develop marketing expertise', *Electrical World*, Vol 198, No 4, April 1984, pp 105–106.
[2]K. White, 'The economics of conservation', *IEEE Transactions on Power Apparatus and Systems*, Vol PAS–100, 1981, pp 4546–4552.
[3]A. Ford and A. Youngblood, 'Simulating the spiral of impossibility in the electric industry', *Energy Policy*, Vol 11, No 1, March 1983, pp 19–38.
[4]US Department of Energy, *Consumer Products Efficiency Standards Economic Analysis Document DOE/CE–0029*, Washington, DC, USA, March 1982.
[5]G. Verzhbinsky, E. Vine, H. Ruderman and M. Levine, *The Hourly and Peak Demand Model: Descriptions and Validation, LBL–17784*, Lawrence Berkeley Laboratory, August 1983.
[6]A. Sanghvi, 'Least-cost energy strategies for power system expansion', *Energy Policy*, Vol 12, No 1, March 1984, pp 75–92.

frequency distribution. Previous conservation studies have neglected this distribution and the non-linear revenue effect. We use a simple technique for measuring revenue impacts in our test case utilities, both of which have non-linear rate schedules.

Broadly speaking, earnings is the difference between operating margin and fixed costs. The operating margin (OPM) is just the difference between revenues (R) and operating costs (OC). Formally, we may write

$$OPM = R - OC \tag{1}$$

Since we will be interested in changes in these quantities, it is useful to introduce subscripts to denote different cases and the first difference operator $\Delta(\Delta X = X_2 - X_1)$. With this notation, we define changes in the operating margin ΔOPM as follows:

$$\begin{aligned} \Delta OPM &= OPM_2 - OPM_1 \\ &= \Delta R - \Delta OC \end{aligned} \tag{2}$$

Next, we define EBIT as it is used in this study:

$$\begin{aligned} EBIT &= OPM - (\text{depreciation} + \text{investment}). \\ &= OPM - (\text{embedded fixed costs} + \text{marginal fixed costs}) \end{aligned} \tag{3}$$

This definition of EBIT differs from the accountant's usage by addition of the investment term. It is important to represent changes in utility investment due to conservation, because this is a major potential benefit of such programmes. Moreover, the unfavourable conditions for utility investment in today's markets means that a true measure of shareholder income must include the negative impact of marginal investment.[7]

Strictly speaking, Equation (3) could overstate the negative effects of investment if the earnings from future investment are not counted in future estimates of revenues. The argument for adopting Equation (3) rests on the 'capital minimization' strategy that utilities are now employing. When earnings are less than the cost of capital, investment is destabilizing.[8] Equation (3) emphasizes the negative short-term effect of these conditions. Finally, we must write Equation (3) in first difference form, since it is changes in $EBIT$ that we will measure, namely,

$$\Delta\, EBIT = \Delta OPM - \Delta EFC - \Delta MFC \tag{4}$$

where EFC = embedded fixed costs (depreciation), and MFC = marginal fixed costs (investment).

It is useful to describe the typical conditions affecting the sign and magnitude of each term in Equation (4). The first term, ΔOPM, is most sensitive to the fuel type associated with the utility's marginal cost. Utilities with a substantial dependence on oil and gas for incremental production will typically have smaller OPM than those which use coal or nuclear fuel on the margin. In the latter case, conservation will typically result in $\Delta OPM < 0$. The lost revenue will be greater than marginal cost. For oil- and gas-fired utilities ΔOPM can be either positive or negative, so an accurate measure of marginal revenues and marginal costs is important.

The second term in Equation (4), ΔEFC, should be identically zero. This follows from the fixed level of embedded cost and its re-allocation in the rate-making process. Load shape changes will induce changes in

[7]For an example of a similar approach, see National Economic Research Associates, *An Assessment of the Economic and Financial Impacts of North Anna and Its Alternatives*, New York, 1981.

[8]H.P. Chao, R. Gilbert and S. Peck, 'Customer and investor evaluations of power technologies: conflict and common grounds', *Public Utilities Fortnightly*, Vol 113, No 9, 26 April 1984, pp 36–40.

the class responsibility for embedded cost recovery, but not in the sum total. Thus, rate shifts are inevitably part of load shape changes, but there should be no impact on $\Delta EBIT$. Other studies of load shape changes estimate the size of the revenue shifts.[9] This is done by using the fixed cost allocation rules employed by particular utilities and calculating changes in class responsibility. It should be noted that fixed cost allocation methods differ widely[10] and are to some degree arbitrary. We make no analysis of such effects.

The last term in Equation (4), ΔMFC, reflects the long-run conservation benefit of avoided investment. Typically, $-\Delta MFC > 0$ because conservation programmes reduce capacity requirements. It is possible that $\Delta MFC = 0$, if the utility has substantial excess capacity. In this case, reducing the need for incremental capacity has no value because there was no such need to begin with. Where avoided investment does have value, there may be problems involved in valuing the benefit quantitatively. We follow methods used by the utilities studied.

Tools and methods

Load shape changes associated with particular conservation programmes for particular utilities are estimated using the LBL Hourly Demand Model coupled with the LBL Energy Forecasting Model.[11] The unique application made of these models here is to use them at the level of utility rate classes. In this section we describe the methods used to estimate each term in Equation (4) for $\Delta EBIT$.

The revenue term for a non-linear rate schedule can be written formally as:

$$R = \sum_{i=1}^{n} (Frac_i)(P_i)(\text{total sales}), \tag{5}$$

where $Frac_i$ = fraction of total sales in rate block i, P_i = price per kWh in rate block i, n = number of rate blocks.

The terms $Frac_i$ are typically read off a sales frequency distribution table. This table lists for any consumption level j the total number of kWh sold at or below that level. Then $Frac_i$ is just the cumulative total sold in the quantity range spanned by rate block i. In most cases there are only two or three blocks. The problem of revenue forecasting is estimating how the size of $Frac_i$ varies with total sales. We will rely on a standard industry procedure known as the block-adjustment method (see Figure 1). Formal definitions are found in the literature.[12]

Figure 1 shows two sales frequency distributions representing PG&E. Each curve has a mean value μ associated with it. In this case the average kWh/month occurs at about 75% of cumulative sales. The line drawn at $b_{1,0}$ represents the upper boundary of the first rate block (340 kWh/month). It intersects the base case curve at about 52% of cumulative sales. The block-adjustment method for altering sales frequency distributions amounts to changing the block boundary points in proportion to changes in average use. Formally, the rule is given by

$$B_{i,n}/B_{i,o} = \mu_o/\mu_n, \tag{6}$$

where $B_{i,o}$ = rate block i boundary in base case
$B_{i,n}$ = adjusted rate block i boundary in test case

[9] S. Barrager, G. Buckley, C. Clark, R. Fancher, M. Shealey and D. Stengel, *Load Management Strategy Testing Model Case Study*, EPRI Report No EA-2396, Palo Alto, CA, USA, 1982.
[10] National Association of Regulatory Utility Commissions, *Electric Utility Cost Allocation Manual*, Washington, DC, USA, 1983.
[11] These have been described elsewhere. See US Department of Energy, *op cit*, Ref 4, and Verzhbinsky *et al*, *op cit*, Ref 5.
[12] J. Liittschwagner, 'Mathematical models for public utility rate revisions', *Management Science*, Vol 17, No 6, February 1971, B 339–353.

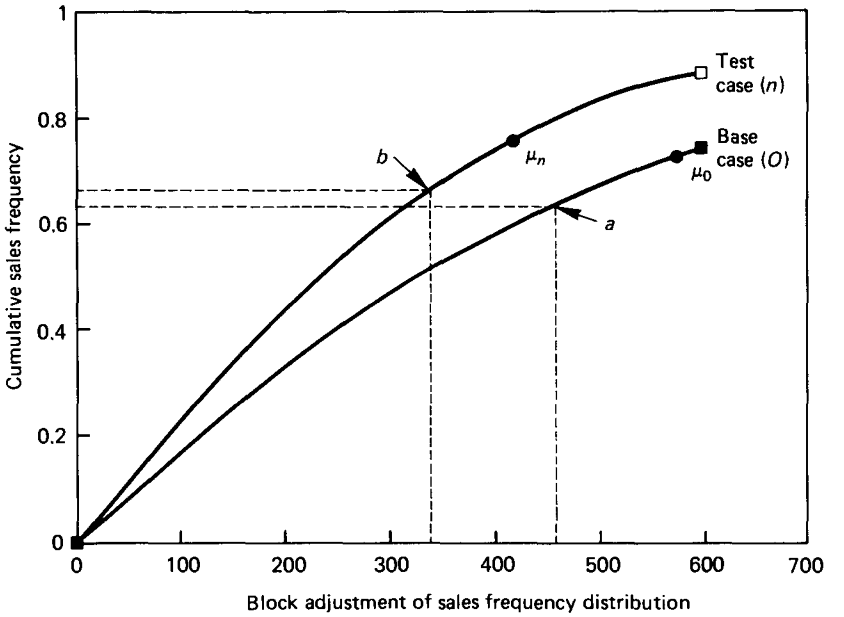

Figure 1. Block adjustment of sales frequency distribution.

μ_o = base case mean kWh/bill
μ_n = test case mean kWh/bill

Intuitively, the logic of Equation (6) is this: if consumption on the average decreased ($\mu_o/\mu_n > 1$), then more sales occur at lower levels of consumption. This means that the first (lowest quantity) rate block must have a larger fraction of total sales than in the base case. To reflect this larger fraction, Equation (6) just moves the rate block boundary up, rather than shift the sales frequency curve. This is a linear approximation to the actual process, which does involve a shift of the curve.

It should also be noted that in the case of a decrease in average use, Equation (6) will tend to underpredict changes in rate block fractions when large reductions in the average use occur. The block-adjustment rule identifies point *a* in Figure 1 as the end of rate block 1. This point corresponds to 63% of sales. The actual curve for the test case shows an intersection with the boundary of rate block 1 at point *b*. This corresponds to 66% of sales. A deviation of this kind means that Equation (6) will underpredict revenue loss with inverted rates and overpredict such losses with declining block rates.

The second term in ΔOPM is the marginal cost of production. Utilities typically use complex computer simulations of system operations to calculate marginal cost.[13] The detail of such calculations can be substantial. A heuristic representation of the marginal cost structure can help to identify the magnitude of profitable conservation potential by defining the high cost periods. Figure 2 is one such representation. This is an annual load duration curve (LDC) for DE representing conditions in the latter half of the 1980s. Using the results of a utility production cost analysis, the area under the curve is filled from the bottom up in the order of increasing cost. This allows a rough estimate of which generating units are the marginal producers and what fraction of the time they play this role. To illustrate this procedure, let us focus on the Monroe generating station in Figure 2.

The Monroe station consists of four 750 MW coal-burning units. These units, which were baseloaded in 1983, will become cycling units with the addition of DE's Fermi 2 nuclear station and the Belle River 1

[13] J. Bloom, 'Generation cost curves including energy storage', *IEEE Transactions on Power Apparatus and Systems*, Vol PAS-103, No 7, July 1984, pp 1725–1731.

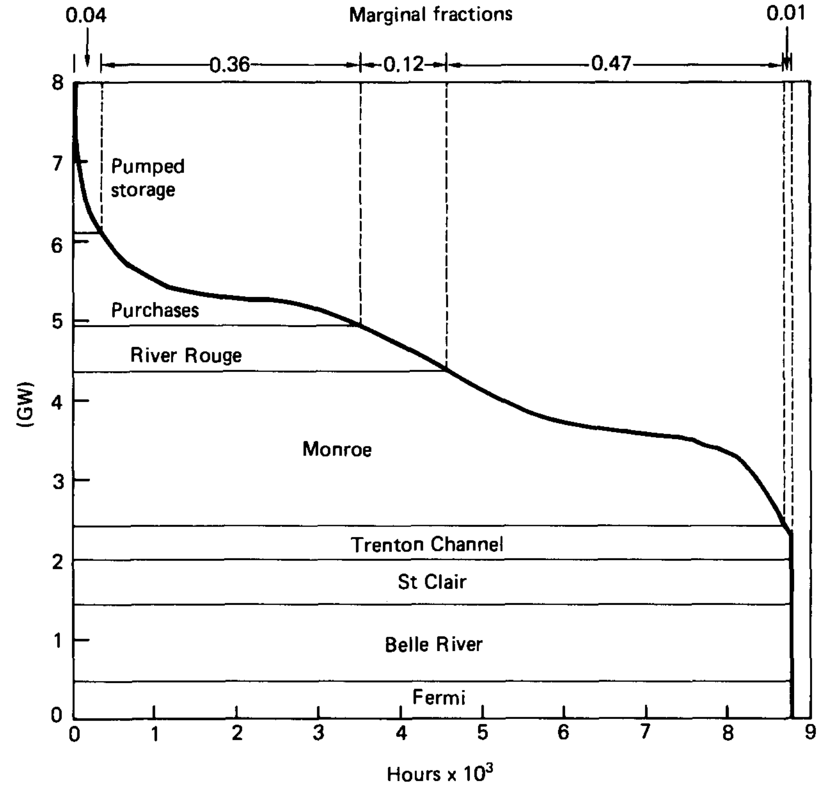

Figure 2. Fully dispatched load duration curve (LDC) for Detroit Edison (DE), 1988.

and 2 coal units. Figure 2 represents the fraction of time that a unit is marginal by projecting to the time axis the load variation served by that unit. The load variation is just the vertical distance between the horizontal lines denoting the unit's energy output. The curvature of the LDC determines how much load variation exists at any point. Figure 2 shows that the Monroe station is the marginal producer 47% of the year. The next highest units, River Rouge and Purchases, are also coal-fired units. Their costs are 10–15% greater than Monroe's. Only a small fraction of the load is met by oil- and gas-fired generation. The Figure 2 estimate is that such units are marginal less than 4% of the year.

To evaluate marginal cost changes due to conservation using a representation such as Figure 2 requires approximations about the coincidence of residential class and total system loads. If, for example, conservation load changes were equal in all hours, then the average marginal cost represents fuel savings. Where the load impact is more concentrated on the peak hours then the higher cost resources are the relevant marginal units. In our case study of DE, we found that appliance standards produced fuel savings approximating average marginal cost. An 'air-conditioning only' standard saves higher cost fuels. Because the residential peak (where such savings occur) is not fully coincident with DE's system peak, we approximate fuel savings by the cost of purchased power. This is above River Rouge coal cost but below pumped storage cost.

For marginal fixed costs we must translate load shape changes into capacity changes and then put a value on the unit of capacity. It is common to use reliability measures such as the Loss of Load Probability (LOLP) to measure capacity changes due to load changes. LOLP and other reliability indices are reviewed in Bhavaraju.[14] For PG&E, for example, we use monthly LOLP estimates and corresponding hourly

[14] M. Bhavaraju, *Generating System Reliability Evaluation*, IEEE Tutorial Course 82, EHO 195–8 PWR, IEEE, New York, NY, USA, 1982.

distributions to identify the hours in which load reductions have capacity value. We then use the price schedule PG&E has developed to pay small power producers for capacity as a valuation of load changes. This price schedule is based on combustion turbine costs. Where a utility has substantial excess capacity, as in the case of DE, avoided capacity costs are zero.

Overview of test utilities

Detroit Edison (DE) and Pacific Gas and Electric (PG&E) span a broad range of economic and regulatory parameters. The marginal cost structures differ, rate designs vary, and the supply/demand balance are all different.

Because DE has substantial reserve margins throughout our study period, we do not expect that any capacity savings will be associated with load reduction programmes. The operating margin term should be negative, since DE has highly inverted rates and coal-based marginal costs. DE's rate schedules are complex, involving a distinction between large and small families as well as special tariffs for space heating, water heating, and for senior citizens. Forecasting sales by tariff class requires forecasts of the number of customers on each tariff.

PG&E represents a polar opposite case to DE. Here the operating margin term can be expected to be zero. This is due to regulatory practices which take the load forecasting risk out of utility earnings. The Electric Revenue Adjustment Mechanism (ERAM) automatically guarantees earnings if there is a deviation from forecast loads. We estimate the value of ERAM by calculating changes in operating margin in the absence of ERAM. These changes should be negative, but less so than in the case of DE. PG&E has inverted rates, but the inversion is less steep than DE. Marginal costs are oil- and gas-based, therefore higher than DE's. PG&E should realize capacity savings from load reductions. We expect this term to show a sizable benefit.

Results for Detroit Edison

Table 1 shows results for the base case and appliance standards case for DE. The applicance standards case is the level 4 case evaluated by the US Department of Energy in considering – and ultimately rejecting – a mandatory appliance efficiency standard in 1982.[15] This standard level represents an increased energy efficiency for major appliances and heating and cooling equipment of approximately 25%, compared with current efficiency levels. The column labelled 'loss' is the loss of operating margin in millions of 1984 dollars. This is the product of

[15]US Department of Energy, *op cit*, Ref 4.

Table 1. Detroit Edison (DE) appliance standards summary.

Year	(1) Base sales (GWh)	(2) Base revenue (1984$ × 10^6)	(3) AS sales	(4) AS revenue	(5) Δ sales	(6) Δ revenue	(7) Production cost (1984$/kWh)	(8) Δ Total cost (5)*(7)*f[a]	(9) Loss (6)–(8)
1984	9 566	702	9 566	702	0	0	0.0265	0	0
1988	9 335	766	9 247	756	88	10	0.0312	3	7
1992	9 568	864	9 317	837	251	27	0.0368	10	17
1996	10 013	983	9 613	937	400	46	0.0430	19	27
2000	10 548	1 121	10 039	1 058	509	64	0.0501	29	35

[a]f ≡ 1.12, an allowance for transmission loss.

Table 2. Detroit Edison (DE) 'cooling only' summary.

Year	(1) Δ Sales	(2) Δ Revenue	(3) Production cost (1984$/kWh)	(4) Δ Total cost (1)*(3)*f	(5) Loss (2)–(4)
1984	0	0	0.0307[a]	0	0
1988	16	2	0.0345	0.5	1.5
1992	33	4	0.0399	1.5	2.5
1996	45	6	0.0468	2.0	4.0
2000	42	6	0.0547	2.0	4.0

[a]Production costs here are defined as costs of purchased power.

Table 3. Present value loss for Detroit Edison (DE) Appliance standards case (millions).

	4%	8%
1988–1991	33.0	25.6
1988–1995	87.7	62.3

changes in operating margin and the total loss of sales due to appliance standards. As anticipated, the change in operating margin is negative. Rates are always higher than avoided energy costs. On average, DE loses 4–5 cents/kWh (1984 $) from conservation. Over time, DE loses up to 5% of residential sales due to appliance standards.

These calculations assume a very simple model of rate-making. DE applied for a three year rate increase in 1983 which would have resulted in an extra $1 billion revenue requirement by 1985. This rate proposal reflects the costs associated with the new Belle River and Fermi 2 plants. Given DE's substantial reserves and the growing regulatory use of trended rate increases,[16] we assume that DE will only achieve this proposed real level of rates by 2000. All revenue estimates are based upon this assumed price trajectory. Given that DE will make no substantial capital additions before 2000, this simple model is plausible. In other cases we will use similar simple representations.

We test the sensitivity of Table 1 by considering the case of an 'air-conditioner only' standard. Table 2 summarizes the results. Although these results are a subset of the Table 1 data, they show a proportionally greater negative impact. Revenue losses associated with cooling are large since they come in the tail blocks of the inverted rate structure. Even though avoided costs are somewhat higher than in the case of Table 1, this does not offset larger revenue loss.

One basic dynamic neglected in our approach is the eventual recognition of the revenue losses we estimate. In practice, rates would eventually be re-adjusted and future losses eliminated. It is difficult to estimate how long this process would take. For illustrative purposes, we consider four-year and eight-year lags. To estimate the cumulative effects of losses estimated in Table 1 for DE, we consider the present value of losses discounted at the utility's real cost of capital. We use the real rate because Table 1 results are already in 1984 dollars. To bring 1988 values back to 1984, we discount by $(1 + r)^4$, and so on. Table 3 presents these calculations for four- and eight-year lags at 4% and 8% real cost of capital.

Results for Pacific Gas and Electric

The cost structure of PG&E is considerably more complex than that of DE. PG&E experiences large seasonal swings in hydropower availability. During the spring snowmelt, non-oil and gas resources are the marginal producers for substantial periods of time. The marginal cost structure of PG&E is best represented on a monthly basis with costs broken down into the oil- and gas-based component and the non-oil and gas component. The relative size of each component varies monthly. The monthly distribution varies with the annual fraction of non-oil and gas resources on the margin. Figure 3 plots the monthly distribution of

[16]S. Streiter, 'Trending the rate base', *Public Utilities Fortnightly*, Vol 109, 13 May 1982, pp 32–37.

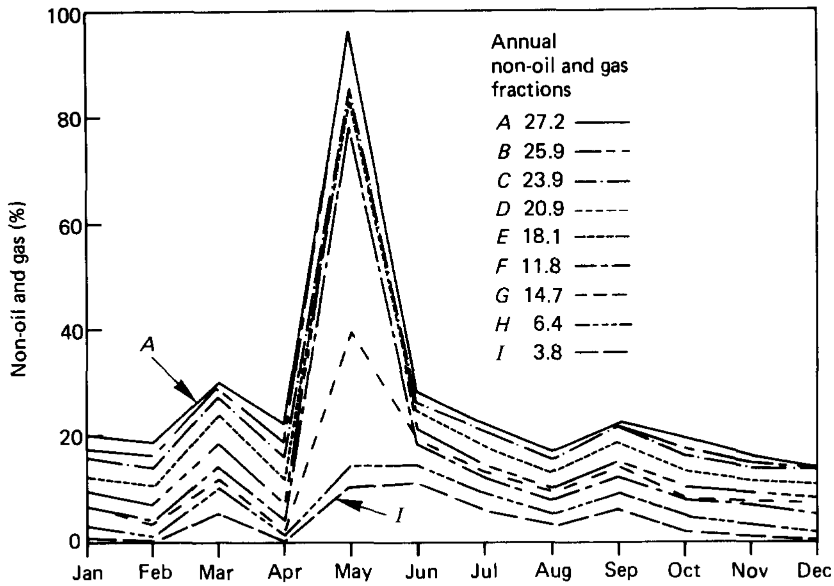

Figure 3. Pacific Gas and Electric (PG&E) monthly non-oil and gas fraction.

the non-oil and gas fraction for various annual values. As the annual non-oil and gas fraction increases, the efficiency (heat rate) of the oil and gas generation improves. Only the most efficient units are called on to meet load. This relationship is illustrated in Figure 4.

Using the relations indicated in Figures 3 and 4, the marginal cost structure for PG&E is specified by the following variables: (1) a price trajectory for oil and gas; (2) a price trajectory for non-oil and gas resources; (3) a trajectory of the annual non-oil and gas fraction of marginal cost. PG&E has made many estimates of these variables. They do not all agree with one another. For our purposes, we will rely principally on estimates associated with PG&E's proposal to rate base the Diablo Canyon power plant.[17] The main feature of the scenario described in that case is a decline in the annual non-oil and gas component from over 30% of marginal cost at present to about 5% by the late 1990s. We incorporate these bounds and estimate a smooth

[17]S. Reynolds, *The Economic Benefits and Cost of Diablo Canyon*, testimony in California Public Utilities Commission Appl No 84-06-014, Pacific Gas and Electric Company, San Francisco, CA, USA, June 1984.

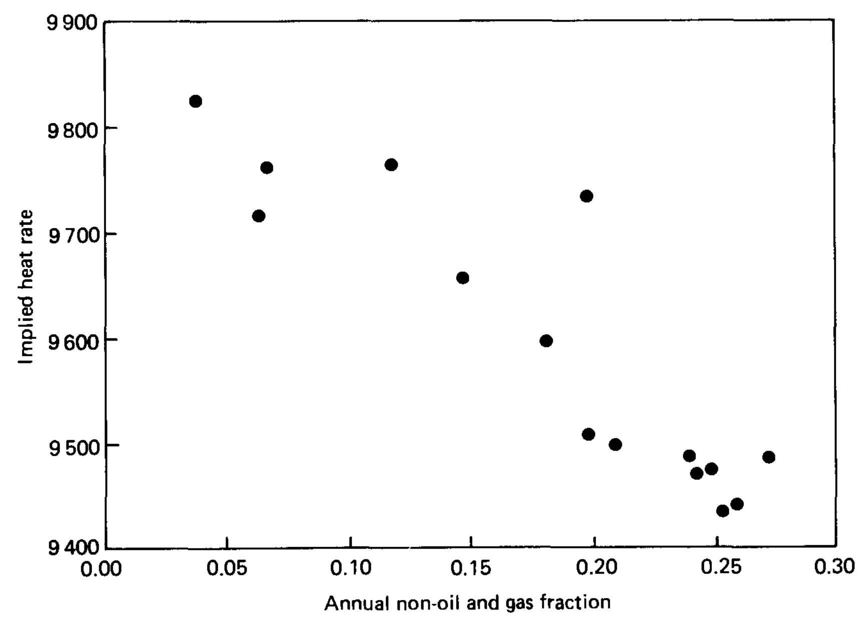

Figure 4. Heat rate *v* annual non-oil and gas fraction.

Table 4. PG&E marginal cost assumptions.

Year	Non-oil and gas fraction	Geothermal price (1984 mills/kWh)	Oil price (1984$/$10^6$ Btu)
1986	0.23	25.2	5.21
1988	0.19	24.8	5.59
1990	0.15	25.7	6.01
1992	0.11	28.1	6.63
1994	0.07	30.0	7.21
1996	0.03	36.4	7.82

trajectory between them. These assumptions for item (3), as well as our assumptions for (1) and (2), represented by geothermal prices, are given in Table 4.

To estimate changes in EBIT, we specify an appliance standards scenario which is more strict than the corresponding scenario used for DE. This is necessary because California already has appliance standards approximating those which are under discussion by the US Department of Energy. To measure a conservation case relative to current Californian conditions requires tighter standards. Table 5 summarizes changes in revenues and production costs for the base case and the stricter standards case. This table shows net losses to PG&E from these two terms; however, it does not include the beneficial effects of capacity savings on EBIT for PG&E, presented in Table 7. Because PG&E has many climate zones for rate purposes, a large number of rate schedules must be examined to estimate revenue and revenue changes. We focus on the four largest climate zones, which account for 85% of all residential sales. Even these involve 16 sales frequency distributions: one for space heating and one for non-space heating in each zone, and a summer and winter differentiation for each schedule.

We tested another appliance standards case for PG&E which included a central air-conditioning standard that specified a Seasonal Energy Efficiency Rating (SEER) of 12. This is substantially more efficient than the current market, but is technically and economically feasible. The energy savings in this case are 30–40% greater than without this air-conditioning standard. Table 6 shows the changes in revenues and production costs associated with this case. Like Table 5, it does not include the effects of capacity savings on EBIT.

The calculations in Table 5 and 6 reflect impacts that would occur in the absence of the California ERAM procedure. ERAM is designed to immunize utility earnings from the kind of demand-side changes we have estimated. Therefore, the lost revenues net of avoided fuel costs would automatically be recovered by a rate increase, and there would be no change in EBIT. In any other regulatory environment (no other state has an ERAM), the utility would suffer the earnings loss estimated in Tables 5 and 6. We may think of these results as an estimate of the value of ERAM.

Table 5. PG&E four regions: appliance standards operating margin.

Year	(1) Base sales (GWh)	(2) Base revenue (1984 $ million)	(3) AS sales	(4) AS revenue	(5) Δ sales	(6) Δ revenue	(7) Production cost (1984$/kWh)	(8) Δ total cost	(9) Loss
1986	15 466	1 631	15 466	–	–	–	–	–	–
1988	15 612	1 655	15 443	1 645	68	10	0.0484	3	7
1990	15 999	1 701	15 863	1 683	136	18	0.0533	8	10
1992	16 486	1 775	16 275	1 744	210	31	0.0601	13	18
1994	16 981	1 857	16 696	1 822	285	35	0.0678	20	15

Table 6. Appliance Standards (AS) + Central Air Conditioning (CAC): PG&E four regions: SEER = 12.

Year	Δ sales	Δ revenue	Production cost	*Δ total cost	Loss
1986	–	–	–	–	–
1988	97	13	0.0505	5	8
1990	184	25	0.0545	11	14
1992	279	39	0.0612	18	21
1994	376	48	0.0685	27	21

Table 7 shows results for the capacity changes between the hours of noon and 8 pm resulting from the impact of the two standard cases. These are measured by looking at kW changes on the peak day of the twelve highest summer load weeks, and averaging. These hours are responsible for almost all of the annual LOLP. Therefore, reduced demand at this time has capacity value. There are dramatic differences in capacity impact between the two standards cases. Without the central air conditioning (CAC) standard of SEER = 12, there is an essentially flat load impact.

The greater the reduction of kWh on-peak compared to baseload, the more favourable the impact of the conservation programme on a utility that needs to add peak capacity to meet projected demand growth. We define a ratio of peak load change to average load change to represent this effect. For the standard case without strict CAC standards, the reduction in peak demand in 1994 is 35 MW. If a similar reduction occurred every hour of the year, it would correspond to an annual energy reduction of 306 GWh. Table 5 shows actual energy reduction of 285 GWh. The ratio of these (peak/annual reductions) is 1.07, illustrating only slightly greater reductions on-peak than throughout the rest of the year. With strict CAC standards only, the peak demand reduction is 204 MW in 1994. If a similar demand reduction occurred each hour of the year, then energy use would decline 1 787 GWh. Actual energy use declines 376 GWh (see Table 6). The ratio of peak to annual reductions is 4.75, showing the high capacity of strict air conditioner standards to reduce peak power needs.

Table 7 also shows the value of these savings. This is based on an assumed 15-year duration of benefits. The 1988 value is derived starting

Table 7. PG&E four regions capacity savings.

Year	Δ MW load	Δ Capacity[a]	Incremental MW	Capacity payment (1984$/kW-year)	Capacity (1984$ million)
Appliance Standards					
1988	8	11	11	73	7
1990	17	22	11	82	8
1992	26	33	11	96	9
1994	35	45	12	103	10
1996	44	57	12	115	12
2000	62	79	12	145	27
Appliance Standards (AS) + Central Air Conditioning (CAC) SEER = 12					
1988	60	76	76		48
1990	105	134	58		41
1992	153	195	61		50
1994	204	260	65		58
1996	254	324	64		63
2000	325	415	91		113

[a]Capacity = Δ load × 1.11 × 1.15, where 1.11 = transmission loss and 1.15 = reserve margin.

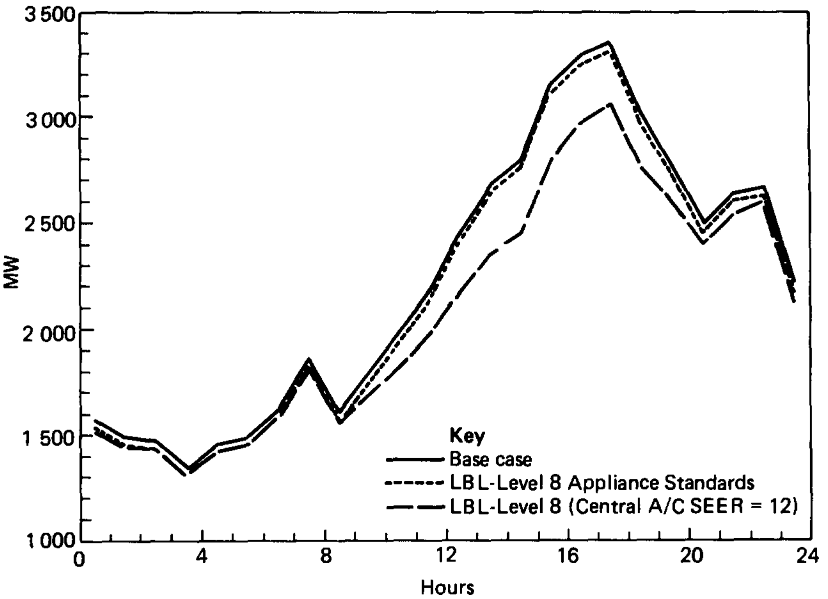

Figure 5. Pacific Gas and Electric (PG&E) residential hourly load profile, peak summer day, 1996.

with a $124/kW annual value of capacity in 1984 dollars. Since these payments reflect revenue requirements, they must be reduced to reflect capital costs. The corresponding 1986 value is $73/kW in 1984 dollars. This 15-year stream is discounted at an 8% real rate to reflect the utility's cost of capital. The present value of this stream is multiplied by the incremental change in capacity requirement to get a total capacity value. To translate load changes into capacity changes, we account for transmission loss and reserve margin effects. The cumulative present value of capacity changes up to 1995 is $73 million for the standards case without the strict CAC standards, and $373 million with them.

Table 8 sums the operating margin losses and the capacity benefits. As in the DE case, we examine four- and eight-year lags and 4% and 8% real discount rates. When these losses are added to the capacity benefits from Table 7, it is clear that the net impact is always favourable, for all cases considered for PG&E. The result is a present value benefit of $17–48 million in the appliance standards case. Strict central air conditioner standards add about $300 million to this.

Table 8. PG&E summary present-value (1984$ million).

Operating margin losses			Capacity benefit	Net
	4%	8%		
Appliance standards				
1988–91	30	25	73	48
1988–95	75	56	73	17
Appliance Standards (AS) + Central Air Conditioning (CAC): SEER = 12				
1988–91	39	30	373	343
1988–95	96	71	373	302

Conclusions

There are several lessons to be learned from the two case studies about the financial effects of conservation programmes on utilities. The full financial analysis is complex, because sales changes must be estimated by rate schedules and load shape changes associated with production cost changes. Sales forecasts by rate class, use of sales frequency distributions to estimate revenue impacts, assessment of load shape impacts of conservation programmes, details of production costing, and uncertainty regarding how regulatory commissions will incorporate impacts of programmes into rate decisions all contribute to a complex and data intensive analysis. Financial impacts of conservation programmes will vary significantly among utilities, depending on the financial circumstances of the utility, existing generating capacity and supply mix, likely demand growth, and regulatory environment.

Nonetheless, the case studies permit a qualitative understanding of the effects of conservation programmes. Three terms are most important in impacting EBIT. Reduced sales from conservation programmes (1) reduce revenue, (2) reduce production costs, and (3) reduce the need for new capacity.

For the two utilities studied, the net of the first two terms – which we call changes in operating margin – is negative. This is likely to generally be the case for utilities with inverted rate structures, as conservation programmes will reduce sales of relatively higher priced electricity. For utilities with declining block rates, the changes in operating margins may be positive; however, declining block rates themselves are a strong disincentive to consumers' engaging in conservation practices or investments.

The third term – reductions in new capacity costs – represents a positive effect of conservation programmes.

We observe that for DE – a utility with much more capacity than is required to meet demand for many years – the third term is zero: new demand does not cause any new investment in new capacity.

For PG&E, for which expected demand growth (in the absence of conservation programmes being evaluated) will necessitate capacity additions, the third term is significant. For a conservation programme that has very little impact on the load shape of PG&E, the reduced cost of new capacity is sufficiently greater than the losses in operating margin to justify expenditure of utility funds in support of the conservation programme, probably without harming the non-participating ratepayer. (The amount of such support depends on the nature of the programme and other variables not treated in this paper.) However, for a conservation programme that impacts peak load much more than baseload, the financial benefits to the utility are greatly increased. The strict air conditioner standard, which reduces peak five times as much as base, produces substantial financial advantages. One way to see this is to note that the net present benefit of strict air conditioner standards per kWh of energy savings is over 20 times greater than the net benefit of appliance standards per kWh of reduced demand. Nonetheless, even the appliance standards are beneficial to a utility such as PG&E.

The particular method used to value capacity savings in this case overstates the benefits if future rate-making fully values the investments. The current environment in which utilities, including PG&E, have adopted the capital minimization strategy suggest considerable scepticism about the likelihood of this occurring.

Because of the significance of the third term in the equation for EBIT – cost of new capacity – we conclude that the relationship between existing capacity (as well as capacity under construction and certain to be completed) and present and forecasted demand is the most critical determinant of the near-term financial effects of conservation programmes. Utilities that need more capacity are likely to benefit from conservation programmes in the near term. If the conservation reduces peak power more than baseload, then the financial benefits are increased considerably. (We note that these benefits will flow either to the utility shareholder or the ratepayer, depending on rate decisions of the regulatory commission.) Utilities with more capacity than required to meet demand are not likely to benefit from conservation programmes until such time as additional capacity is required.