Regulatory Factors Affecting the Financial Impact of Conservation Programs on Utilities

Edward Kahn, Chris Pignone, Joseph Eto,
James McMahon and Mark Levine
Lawrence Berkeley Laboratory

ABSTRACT

Conservation programs affect utility earnings through specific rate-making procedures. In this paper we simulate the effect of exogenous conservation programs on the earnings of Detroit Edison (DE) and Pacific Gas and Electric (P.G.&E.). Revenue losses associated with conservation programs are estimated on a rate schedule level using specific tariff structures and sales frequency distributions. The benefits of conservation are avoided fuel and capacity costs. These are estimated using simulations of utility reliability and production costs.

Since both DE and P.G.&E. have inverted residential rate schedules, we expect revenue losses to exceed avoided fuel costs. Revenue lost is disproportionately in the top (highest price) rate tier. This price is usually above marginal fuel cost, even for P.G.&E., where the marginal fuel is often oil and gas. Revenue loss net of avoided fuel is greater for DE than P.G.&E. because DE has low marginal costs and a steeply inverted rate schedule.

In addition to tariff design, P.G.&E differs from DE in that it benefits from a regulatory stabilization mechanism which prevents operating losses from unanticipated conservation. No state other than California has such a mechanism. In addition to this loss-preventing factor, P.G.&E. experiences reduced capacity costs from conservation. Because DE has substantial excess capacity, there is no such benefit in their case.

Regulatory Factors Affecting the Financial Impact of Conservation Programs on Utilities

E. Kahn, C. Pignone, J. Eto, J. McMahon and M. Levine
Lawrence Berkeley Laboratory
Berkeley California 94720

1.0 Introduction

Conservation programs may either increase or decrease the earnings of utility shareholders. The outcome depends upon the precise interaction of costs and rates associated with the load change induced by conservation actions. In this study a method is developed and tested to measure such financial impacts. Previous studies of conservation economics in the utility context focus on the consumer perspective. The issues which are relevant to consumers involve rate and revenue levels. The shareholder perspective involves the changes in earnings associated with conservation. Because earnings is the difference between revenues and costs, it is harder to measure precisely than either of its components terms. Given the complexity of the task, a somewhat simplified approach has been adopted. We will focus on a figure-of-merit that is related to what accountants call Earnings Before Interest and Taxes (EBIT). EBIT will allow us to capture the important economic and regulatory variables without the unnecessary detail of corporate tax and debt analysis.

To test the usefulness of EBIT we consider three utilities which differ substantially in their economic circumstances and regulatory practices. The companies studied are Detroit Edison (DE), Pacific Gas and Electric (PG&E) and Virginia Electric and Power Company (VEPCO). We simulate the impact of specific residential electricity conservation policies on the hourly loads of these utilities. The simulation is performed using the LBL Hourly Demand Model coupled with the ORNL/LBL Energy Forecasting Model. The results of these simulations are the input to our financial 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 frequency distribution. All previous conservation studies have neglected this distribution and the non-linear revenue effect. We will use a simple technique for measuring revenue impacts in our three test case utilities, all of which have non-linear rate schedules.

The plan of this paper is as follows. In section 2, we define EBIT for our problem and discuss its general properties. The methods and tools used to estimate the components of EBIT are reviewed in section 3. The characteristics of the three test utilities are outlined in section 4. Results are given in section 5 and conclusions in section 6.

2.0 Definition and Properties of EBIT

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

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

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 Δ ($\Delta X = X_2 - X_1$). With this notation, we define changes in the operating margin ΔOPM as follows:

$$\Delta\mathrm{OPM} = \mathrm{OPM}_2 - \mathrm{OPM}_1, \tag{2}$$

$$= \Delta\mathrm{R} - \Delta\mathrm{OC}.$$

Next we define EBIT as it will be used in this study,

$$\mathrm{EBIT} = \mathrm{OPM} - (\mathrm{Depreciation} + \mathrm{Investment}), \tag{3}$$

$$= \mathrm{OPM} - (\mathrm{Embedded\ Fixed\ Costs} + \mathrm{Marginal\ Fixed\ Costs}).$$

This definition of EBIT differs from the accountants 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 programs. Moreover, the unfavorable conditions for utility investment in today's markets means that a true measure of shareholder income must include the negative impact of marginal investment. An example of a similar approach is ref. (3). Finally we must write Eq. (3) in first difference form, since it is changes in EBIT that we will measure, namely,

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

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 Eq. (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 $\Delta\mathrm{OPM} < 0$. 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 Eq. (4), ΔEFC, should be identically zero. This follows from the fixed level of embedded cost and their re-allocation in the rate-making process. Load shape changes will induce changes in 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 ΔEBIT. Other studies of load shape changes estimate the size of the revenue shifts (Barrager, 1983). 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 (see NARUC) and are to some degree arbitrary. We make no analysis of such effects.

The last term in Eq. (4), ΔMFC, will reflect the long run conservation benefit of avoided investment. Typically, $-\Delta MFC > 0$ because conservation programs 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 will follow methods used by the utilities studied,

3.0 Tools and Methods

Load shape changes associated with particular conservation programs for particular utilities are estimated using the LBL Hourly Demand Model coupled with the ORNL/LBL Energy Forecasting Model. These have been described elsewhere (1), (2). 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 Eq. (4) for ΔEBIT.

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

$$R = \sum_{i=1}^{n} (\mathrm{Frac}_i)(P_i)(\text{Total Sales}), \qquad (5)$$

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 kilowatt-hours 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. It is illustrated in Figure 1. A modern treatment of this subject is ref. (5).

Figure 1 shows two sales frequency distributions representing the Pacific Gas and Electric Company. 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/mo). 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,
μ_o = Base case mean kWh/bill,
μ_n = Test case mean kWh/bill.

Intuitively the logic of Eq. (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, Eq. (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, Eq. (6) will tend to under-predict changes in rate block fractions when large reductions in the average use occur. The block-adjustment rule identifies point a in this Figure 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 Eq. (6) will under-predict revenue loss with inverted rates and over-predict 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. 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 represents one such representation. This is an annual load duration curve (LDC) for Detroit Edison representing conditions in the latter half of the 1980's. 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 base loaded in 1983, will become cycling units with the addition of DE's Fermi 2 nuclear station and the Belle River 1 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 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 certain approximation 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 Detroit Edison 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 co-incident 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. For Pacific Gas and Electric Company, for example, we use monthly LOLP estimates and corresponding hourly distributions to identify the hours in which load reductions have capacity value. We then use the price schedule P.G.&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 Detroit Edison, avoided capacity costs are zero.

4.0 Overview of Test Utilities

Detroit Edison, Pacific Gas and Electric and Virginia Electric and Power Company 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. Table 1 summarizes principal features of the costs, rates and allocation formulas used for fixed costs.

Because DE has substantial reserve margins throughout our study period, we do not expect that any capacity savings will be associated with load reduction programs. 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 senior citizens. Forecasting sales by tariff class requires forecasts of the number of customers on each tariff.

Pacific Gas and Electric (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 EARM by calculating changes in operating margin. 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.

VEPCO represents an intermediate case. VEPCO anticipates load growth so there should be capacity value to load reductions. Because VEPCO's rate structure is relatively flat, there should not be disproportional revenue losses which both DE and PG&E should experience. VEPCO's marginal costs show substantial on-peak/off-peak variation as well as aeasonal swings. A priori, it is difficult to estimate the balance of positive and negative effects for VEPCO.

5.0 RESULTS

5.1 Detroit Edison

Table 2 shows results for the Base Case and Appliance Standards Case for DE. The column labelled "Loss" is the loss of operating margin in millions of 1984 dollars. This is the product of 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 the average DE loses 4-5¢/kwh (1984 dollars) 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 is currently applying for a 3-year rate increase which would result 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 (see ref. 7), we assume 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 2 by considering the case of an air-conditioner only standard. Table 3 summarizes the results. Although these results are a subset of the Table 2 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 2, 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 4 year and 8 year lags. To estimate the cumulative effects of losses estimated in Table 2 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 2 results are already in 1984 dollars. To bring 1988 values back to 1984 we discount by $(1+r)^4$, and so on. Table 4 presents these calculations for 4 and 8 year lags at 4% and 8% real cost of capital.

Table 4
Present Value Loss for DE
Appliance Standards Case
(Millions)

	4%	8%
1988-1991	33.0	25.6
1899-1995	87.7	62.3

5.2 Pacific Gas and Electric

The cost structure of P.G.&E. is considerably more complex than that of Detroit Edison. P.G.&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 P.G.&E. is best represented on a monthly basis with costs decomposed 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 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 P.G.&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. P.G.&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 P.G.&E's proposal to rate base the Diablo Canyon power plant

(Reynolds, 1984). 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 1990's. We incorporate these bounds and estimate a smooth trajectory between them. These assumptions for item (3) as well as our assumptions for (1) and (2) are given in Table 5.

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 DOE. To measure a conservation case relative to current California conditions requires tighter standards. Table 6 summarizes changes in revenues and production costs for the base case and the stricter standards case. Because P.G.&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, one for non-space heating in each zone and a summer and winter differentiation for each schedule.

The calculation in Table 6 reflects 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 loss 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 a ERAM) the utility would suffer the earnings loss estimated in Table 6. We may think of these results as an estimate of the value of ERAM.

Table 7 shows results for the capacity between the hours of noon and 8 p.m. impact of the standards. 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 the annual LOLP. Therefore reduced demand at this time has capacity value. Comparing the peak demand reductions in Table 7 with the energy reductions in Table 6 shows that the standards selected are "baseload" in their impact. The "load factor" of the standards is about 90%. This can be calculated for the 1994 results as follows. The capacity difference between the two cases is 48MW. At 100% load factor this corresponds to 420 GWh. Table 6 shows 377 GWh. Therefore the appliance standards load factor is 377/420=89.8%.

Table 7 shows the value of these savings. This is based on an assumed 15 year duration of benefits. The 1988 value is derived starting with a $100/kW annual value of capacity. This is discounted back to 1984 and presen-valued at the utility cost od capital (12.5%). Subsequent year costs are escalated at a 6% real rate. The cumulative present value of the capacity benefit is $34.8 million 1984 dollars.

Table 8 sums the operating margin losses and capacity benefits. As in the DE case (Table 4) we examine 4 and 8 year lags and 4% and 8% real discount rates. In 3 of 4 cases the operating margin losses dominate capacity benefits. This result follows from the "baseload" nature of the standards case.

If more attention were paid to air-conditioning efficiency these results would change.

Table 8.
Operating Margin and Capacity Credit
P.G.&E.
Present Value Millions of 1984 $

	4%	8%
1988-91	(3.1)	5.4
1988-95	(54.5)	(29.4)

6.0 Conclusions

In this paper we have presented a method for estimating the earnings impact of exogenous conservation programs on electric utilities. The exercise is difficult because sales changes must be estimated by rate schedules and load shape changes associated with production cost changes. Results show substantial variations across the utilities studied. We anticipate further tests of this method. VEPCO is expected to be an intermediate case between DE and P.G.&E.

1. U.S. Department of Energy Consumer Products Efficiency Standards Economic Analysis Document DOE/CE-0029, March, 1982.

2. Verzhbinsky, G., Vine, E., Ruderman, H. and Levine, M. "The Hourly and Peak Demand Model: Description and Validation" LBL-17784, August 1983.

3. National Economic Research Associates, An Assessment of the Economic and Financial Impacts of North Anna and Its Alternatives, 1981.

4. National Association of Regulatory Utility Commissions, Electric Utility Cost Allocation Manual, 1983.

5. Liittschwagner, J. "Mathematical Models for Public utility Rate Revisions" Management Science v.17, no.6 (February, 1971) B-339-353.

6. Eto, J., Kahn, E., Pignone, C., McMahon, J. and Levine, M. "Technical Documentation of Conservation Impact on Utility Systems" LBL, 1984.

7. Barrager, S., Buckley, G., Clark, C., Fancher, R., Shealey, M. and Stengel, D. Load Management Strategy Testing Model Case Study. EPRI Project RP 1485-1, July, 1983.

Table 1.

	Detroit Edison	VEPCO	Pacific Gas & Electric
Marginal Costs Structure			
Energy	85% Flat = Coal	Summer & Winter Peaks = Oil	Large Monthly Variation (Mostly Oil)
Capacity	Excess Capacity In the Long Run	Load Growth and Capacity Additions	Load Growth, Few Capacity Additions
Rate Structure	Steeply Inverted Rates	Declining Block in Winter	Steeply Inverted Climate Zone Variations
	Tier Size Varies by Family Size	Slightly Inverted in Summer	Load Management Credits
	Heat Pump and Controlled Water Heating Rates	Heat Pump Rates	
Embedded Fixed Cost Allocators	Average of 12 Monthly Peaks	Average and Excess Demand	Relative LOLP

Table 2.
DECO Appliance Standards Summary*

Year	(1) Base Sales (GWh)	(2) Base Rev. (Millions 1984 dollars)	(3) AS Sales	(4) AS Rev.	(5) Δ Sales	(6) Δ Rev.	(7) Production Cost (1984$/kWh)	(8) Δ Total Cost (5)*(7) *f	(9) Loss (6)-(8)
1984	9566	702	9566	702	0	0	0.0265	0	0
1988	9335	766	9247	756	88	10	0.0312	3	7
1992	9568	864	9317	837	251	27	0.0368	10	17
1996	10013	983	9613	937	400	46	0.0430	19	27
2000	10548	1121	10039	1058	509	64	0.0501	29	35

f = 1.12, an allowance for transmission loss.

Table 3
DECO Cooling Only
Summary

Year	(1) Δ Sales	(2) Δ Rev	(3) Production Cost (1984 $/kWh) (1)x(3)	(4) Δ Total Cost (5)*(7)*f (2)-(4)	(5) Loss (6)-(8)
1984	0	0	0.0307*	0	0
1988	16	2	0.0345	1	1
1992	33	4	0.0399	1.5	2.5
1996	45	6	0.0468	2	4
2000	42	6	0.0547	2	4

*Production costs here are defined as costs of purchased power.

Table 5.
P.G.&E. Marginal Cost Assumptions

Year	Non Oil & Gas Fraction	Geothermal Price (1984 Mills/kWh)	Oil Price (1984 $/10^6 Btu)
1986	.23	25.2	5.21
1988	.19	24.8	5.59
1990	.15	25.7	6.01
1992	.11	28.1	6.63
1994	.07	30.0	7.21
1996	.03	36.4	7.82

Table 6.
P.G.&E. Appliance Standards Operating Margin

Year	(1) Base Sales (GWh)	(2) Base Rev. (Millions 1984 dollars)	(3) AS Sales	(4) AS Rev.	(5) Δ Sales	(6) Δ Rev.	(7) Production Cost (1984$/kWh)	(8) Δ Total Cost (5)*(7) *f	(9) Loss (6)-(8)
1986	20427	2155	20427	2155	0	0			
1988	20708	2195	20617	2182	91	13	.0485	5	8
1990	21328	2268	21147	2244	181	24	.0533	11	13
1992	22081	2378	21803	2336	278	42	.0601	19	23
1994	22833	2498	22456	2451	377	47	.0678	29	18

f = 1.12, allowance for line losses

Table 7.
Capacity Value for P.G.&E.

Year	Base Av. MW	Standards Av. MW	Δ	Incremental	$/KW	Total M $84
1988	2761	2749	12	12	600	7.2
1990	2845	2822	23	11	675	7.4
1992	2950	2914	36	13	760	9.9
1994	3049	3001	48	12	855	10.3
						34.8

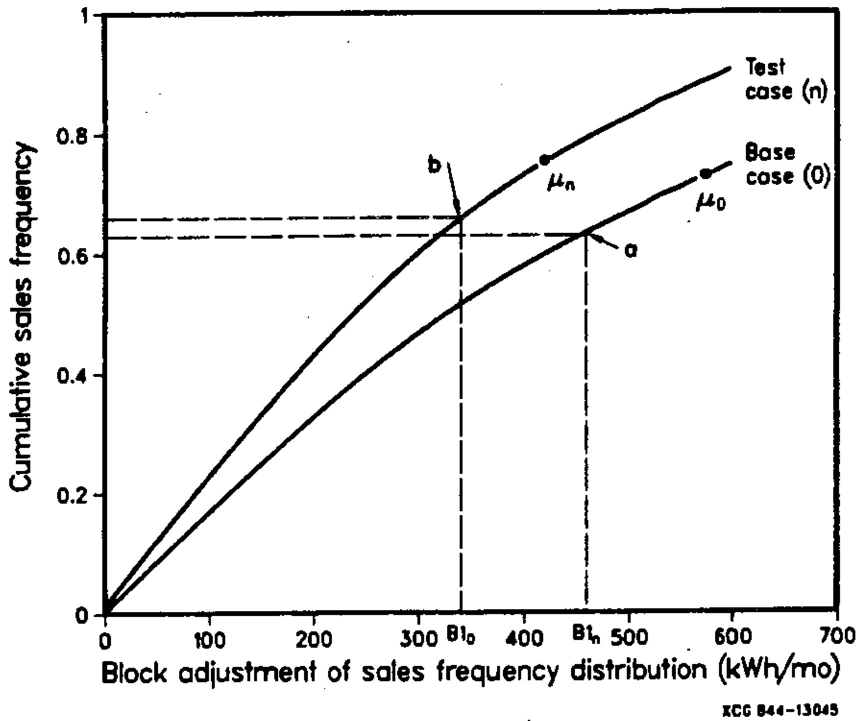

Figure 1

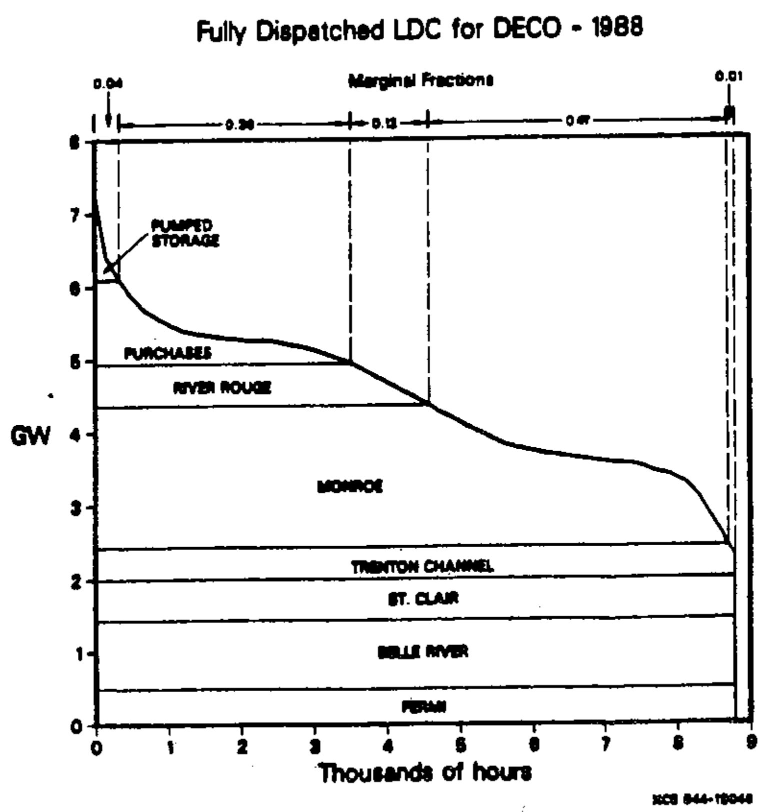

Figure 2

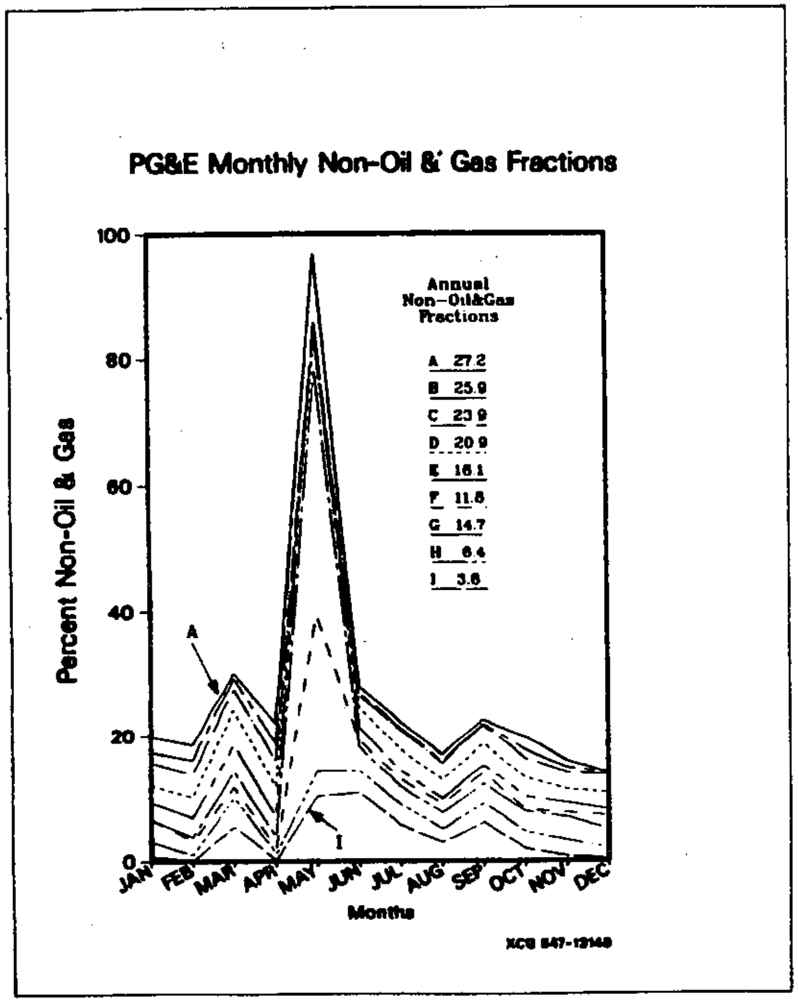

Figure 3

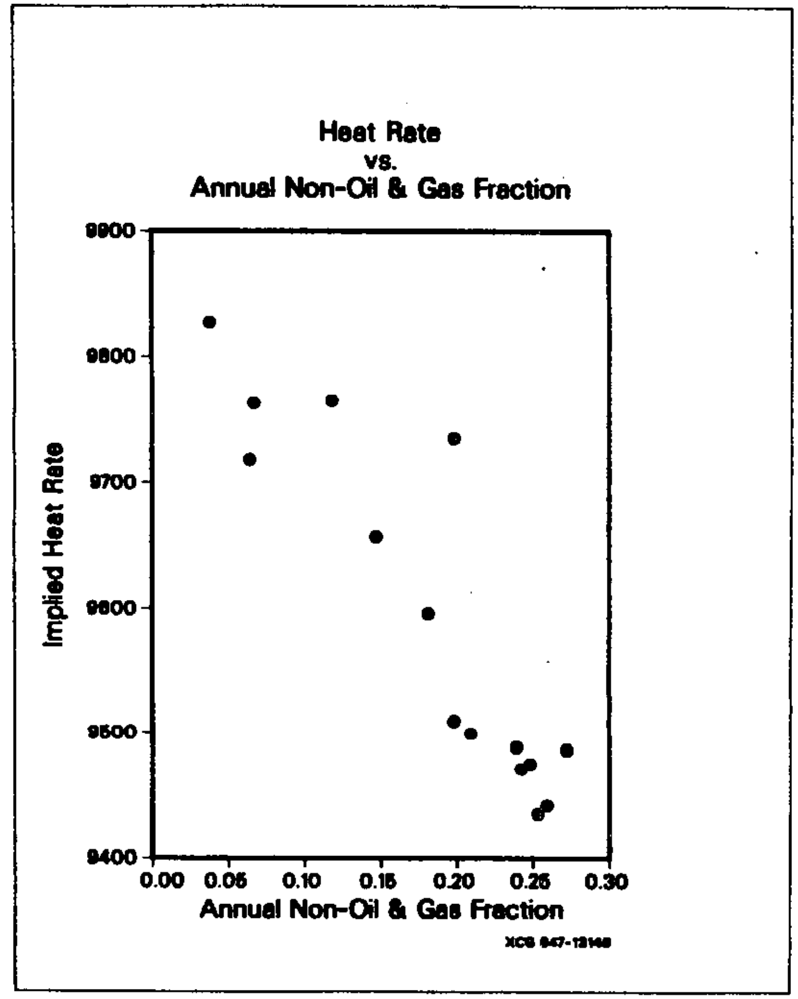

Figure 4