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Energy Analysis Program

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FINANCIAL IMPACTS ON UTILITIES OF LOAD SHAPE CHANGES PROJECT:

STAGE I TECHNICAL REPORT

The Detroit Edison Company

Energy Analysis Program

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I THE DETROIT EDISON COMPANY

1. Introduction

History has shown that the responses of investor-owned electric utilities to proposals for residential energy conservation have been very different depending on the immediate generating and financial circumstances of each company. The long range goal of the Financial Impacts on Utilities of Load Shape Changes Project is to build a model of the electricity industry as a whole that can anticipate the financial implications to individual companies, or groups of companies, of various energy policies, given their very different local circumstances. As the first step in this process, we chose as subjects three electric utilities whose reserve margins and financial circumstances are quite different. These three utilities are the Detroit Edison Company (DECO), Pacific Gas and Electric (PG&E), and Virginia Electric Power Company (VEPCO). This report describes our attempt to model DECO and outlines our financial modelling results.

Our intention was to derive a rough estimate of profit increases or decreases that DECO might experience resulting from some hypothetical conservation policy scenarios. It was not our intent to develop a definitive sales forecast for the company, nor to carry out a complete financial analysis. A complete picture of the full financial situation of a company would, of course, require careful consideration of many details other than simply revenues and costs. Our approach is to derive credible estimates of company revenues under three conservation policy scenarios and compare the difference between those figures and a base case revenue projection to the likely production cost savings that each conservation program would yield. The figures we derive in this way are akin to the accountant's Earnings Before Interest and Taxes, and they serve as our measure of the net effect that a conservation policy has had on the utility.

Our forecast of sales and loads was generated by the LBL Energy and Peak Load Models calibrated to recent DECO history. We ran four cases, a base (BS) case and three policy initiatives. The first initiative, AS, simulates the introduction of Department of Energy (DOE) Consumer Product Efficiency Standards in 1987. The second, CO, has the DOE introduce a standard for cooling appliances only, in the same year. The final case, HP, constrained all new, post-1977 central electric heating to be heatpumps in such a way that the ownership of heatpumps matched the known saturation for 1982. Although we believe these are relevant and interesting scenarios, our real intent is to establish procedures for analyzing many different sales changes. There are two reasons for our emphasis on appliance efficiency. First, our expertise is largely in this area, and second, the engineering nature of the LBL model makes it more amenable to this kind of influence. For example, price initiatives, such as time of use rates, are not easily treated by the model which currently uses only an average price of each domestic fuel.

Our initial hypothesis is that DECO has adequate reserve margins to meet foreseeable loads without adding capacity and is also in a favorable fuel cost situation since it can provide almost all of its output by cheap coal generation. On the revenue side, DECO has steeply inverted lifeline rates with high steps between the tiers but large lifeline allowances so that the fraction of its sales made at the high tier prices is small. Thus, a small loss of sales among the valuable high tier purchases would hurt company revenues proportionately more than the raw kWh sales loss would suggest. Consequently, DECO is a utility that would rarely find its load at such a high level that a reduction could create cost savings in excess of the revenue loss, and is, therefore, a company that would likely suffer financially from almost any conservation policy.

2. DECO's Circumstances[1]

DECO serves approximately 1.7 million residential customers in the south east corner of Michigan.[2] The system has a large industrial customer class and residential sales are less than a third of the company total. The fraction of sales going to each class varies seasonally; the residential class takes a larger share in wintertime, while the industrial share varies inversely, and the shares of the other classes are fairly stable.[3]

DECO is a strongly coal-based utility which has typically used other, more costly, fuels for only 5% or so of its generation. The company has several large coal plants ranging in size up to the enormous Monroe plant with a capacity of over 3 GW. The substantial coal generating capacity of DECO has enabled it to meet most of its load requirements with coal generated power, a very favorable situation with regard to fuel costs, and it has needed to resort to other fuels only to a limited extent in recent years. To meet peak loads, DECO also purchases power from its neighboring utilities, including Ontario Hydro, and uses pumped storage from its Luddington plant. In addition to its small peaking units, DECO also has a 0.8 GW oil burning plant, Greenwood, available. This situation will change somewhat as the large Enrico Fermi boiling water reactor on the shore of Lake Erie takes its place as one of two significant new baseload suppliers in the DECO system. The other large newcomer is the Belle River Coal plant.

Although the Detroit area is quite stable demographically, the local business climate has been volatile in recent years, the driving force being the changing fortunes of the US auto industry.

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[1] Our thanks go to all the members of DECO's staff who gave us very cordial and generous assistance during this study. We would especially like to mention Lois Brandenburg, Edward Falletich, Ron Fryzel, Tony Sammut, Timothy Vorce, and Alexander Zakem.

[2] Source for most of this information is *Moody's Public Utility Manual 1984*.

[3] See Appendix 1.

3. DECO's Cost Structure

One of the principal reasons for choosing DECO as a member of the study group of utilities was our belief there are strong rigidities in its cost structure. Such a large fraction of the company's capacity requirement can be met with its own coal plants or by purchases from other coal-based utilities that the changeover to expensive oil or gas occurs only very near to the peak. The seasonal range in costs is shown in Figure 1 (page 9). Even at times of highest cost, generation is cheap on the DECO system, compared to other utilities that rely more heavily on oil and gas.

One way to characterize the cost structure of an electrical generating system is through a Load Duration Curve (LDC). Figure 2 (page 9) shows a hypothetical fully loaded LDC for DECO for 1988. It shows how many hours (x axis) any level of load (y axis) is exceeded on the system. Since the area under the curve represents energy (power x time), it can be "loaded" with plants in roughly the order that costs suggest the utility would actually dispatch them.

The cost differentials between DECO's plants are small and the LDC can be almost filled by them. An estimate of marginal cost can be derived by calculating the sum of plant costs weighted by the fraction of time they spend on the margin.

At the outset of the project, we believed this method could be used to estimate DECO's costs under the BS scenario and then again under the policy alternatives. This proved difficult because of the ticklish problem of coincidence. Since we are only looking at the residential sector, there is no easy way to map a change in the load of this sector onto the LDC of the whole system and hence derive a new weighted marginal cost. This is a critical problem that must be resolved before this methodology can be advanced.

Fortunately, with DECO the two scenarios of interest, the AS and CO policy options, brought about load changes in such a way that the problem could be circumnavigated. For the AS case, the load shaving was seen to be even throughout the year and so the effect is an even downward shift of the LDC. One way to represent this would be by loading conservation at the bottom of the LDC, below Fermi, and so shift all the marginal plants up a little. As it happened, the net effect of this exercise on the marginal fractions in DECO's case was so small that we finally assumed they were fixed. In the CO case, we knew that the savings come at times of relatively high load, DECO being a summer peaking utility, so we concluded that using the purchased energy price as a proxy for an actual marginal cost calculation was reasonable. That is, since purchases appear in the upper shoulder of the LDC, as seen in Figure 2, it is reasonable to assume that any energy saving arising from air conditioning efficiency improvements will lead to lower levels of purchases from neighboring utilities. Notice that our confidence in these cost approximations rests on two company-specific features of DECO's LDC. First, the non-coal generation, i.e. the area marked "pumped storage" in Figure 2, is small relative to the total area under the LDC so that a change in its size would only have a very small effect on overall company costs. Second, there is no fuel switch along the shoulder of the LDC that would bring about a drastic change in marginal cost, and therefore, no section of the LDC is particularly sensitive to policy induced shifts in the LDC.

Thus, our final cost savings estimates are based on very rudimentary methods that would not be satisfactory for more complex cases, that is, for utilities with LDC's less amenable than DECO's. However, if comprehensive cost data were available for the system by time of day and season, the need for the LDC method would be avoided. Alternatively, if an actual historical hourly load curve for an entire year were available, then an estimated LDC could be derived for the base case, and subsequently the post policy LDC easily calculated by physically recording the hour by hour loads. However, this is a stringent data requirement that would be difficult to meet for most utilities, both because few companies could provide such information and because it would be difficult to obtain available information in a standard format.

4. Deriving an LDC for DECO

A common method of estimating the LDC of a given system is to use a normal approximation. This method treats the LDC as a cumulative normal function laid on its side. The mean of the distribution is the load factor, LF, of the system and the flatness of the curve is set by assuming that the peak is some number of standard deviations, SD, above the mean. This number of standard deviations we have called the rule of thumb, r, and a commonly used value for r is 3.1.[4]

Since the load factor, LF, here is defined as

$$\mathrm{LF} = \frac{\text{average (GW)}}{\text{peak (GW)}}$$

$$\mathrm{LF} = \frac{\frac{\text{sales (GWh)}}{\text{8766 (h)}}}{\text{peak (GW)}}$$

and since

$$\text{peak(GW)} = (\mathrm{LF} \times \text{peak}) + (\mathrm{r} \times \mathrm{SD}),$$

after normalizing

$$\mathrm{SD} = \frac{1 - \mathrm{LF}}{\mathrm{r}}.$$

So the whole curve can be defined with only two pieces of data about the system, its sales and

[4] Appendix 2 contains a calculator program, NAPPROX that generates LDC's by this procedure. Both programs in this report are written for a HP41CV with SIZE 100, and will also run on a 41C with sufficient storage.

peak. Therefore, this method is remarkably simple and requires little input. However, of course, it yields a simplistic answer suitable for only broad analysis. Appendix 3 contains a matrix of examples worked for varying values of LF and r. It illustrates that a higher r gives the LDC a flatter pitch, while a higher LF lifts the entire curve upwards. The last three examples show a slightly refined approach that involves deriving the curve as if the year were 10 kh instead of the actual 8.8 kh. Truncating the resulting curve at the 8.8 kh point produces a very convincing LDC.[5]

A second method of approximating the LDC of a system is by using a polynomial function of the form:[6]

$$y = a_0 - a_1(x - q) - Aa_2(x - q)^2 - Ba_3(x - q)^3 - Ca_4(x - q)^4 - Da_5(x - q)^5$$

where,

$q =$ minimum load ratio (the ratio of minimum load peak load) (assumed 0.5 for DECO)

$LF =$ load factor (the ratio of average load peak load)

$p = -0.5 + \frac{4}{3}LF$

$x =$ fraction of hours in the period that ratio of load peak load exceeds y

$y =$ ratio of load peak load

$a_0 = LF$ $\qquad a_1 = (1 - p)$

$a_2 = (1 + p) - 2LF$ $\qquad a_3 = 1 - LF$

$a_4 = a_2$ $\qquad a_5 = a_3$

and the parameters estimated for the DECO system in 1980 are

$$A = 1.194,\ B = -12.83,\ C = -6.00,\ D = 48.45.$$

This equation is credited to Paul Fine and Artha Snyder[7] so we shall call this approach the Fine

[5] This shape is very like the graph of VEPCO's LDC provided to us by the company and reproduced as Appendix 4. By using the truncated curve approach, VEPCO's LF, and a visually-derived standard deviation from the LDC, we were able to obtain a rough estimate of the implied r in VEPCO's LDC as 4.

[6] Our special thanks to John Locher at Detroit Edison for explaining this method to us.

[7] Smith, Edward W., "There's a Better Way to Forecast Duration Curves," *Electric Light and Power,* Oct.

method.[8]

Figure 4 (page 11) shows estimates of the DECO LDC for 1992 derived by the normal (with r = 3.1) and Fine methods. While the difference is not striking at first glance, it is significant. Notice that the areas of widest divergence are in the shoulder of the curve, and, particularly, that the Fine curve is much flatter in the vicinity of the changeover from coal-generated power to purchases. For DECO, this point is not, at the moment, an important cost transition, because its neighboring utilities also enjoy low generation costs, but it could be if purchases became less readily available in DECO's area. Then, the two approximations would yield contradictory results because the cost transition would be taking place at higher loads using the Fine equation. Nevertheless, the difference between the areas under the two curves is not great at any point, and r = 3.1 does seem an appropriate assumption for DECO.

To the extent that we have used the LDC, which is much less than anticipated, we have used the Fine equation, as is clear from the shape of Figure 2 which is not symmetrical and smooth like a normal distribution.

Developing techniques such as the normal approximation and the Fine Equation is more than an academic exercise. It is essential that we develop methods such as these that would allow us to approximate quickly, and with some accuracy, the salient features of a utility, such as its LDC.

5. DECO's Rate Structure

DECO has a quite complicated rate structure with steeply inverted, lifeline, rates for many of its rate schedules. Figure 3 (page 11) shows a generic lifeline rate structure for the DECO system. A customer is able to buy his/her first k1 kWh at a price of p1, the next k2 – k1 kWh at p2, and must then pay the ceiling price of p3 for all usage above k2 kWh per period. The most used schedule, D1, accounts for over 80% of all residential sales. Within D1 there are two sets of lifeline allowances, for small and large families, although the tier prices, p1, p2, and p3, are the same. Seniors are eligible for a separate rate schedule, D1.3. D1.3 has different allowances and tier prices from D1. Customers with electric space heat can obtain a special, virtually flat, rate in winter, D2, but they revert to D1 in summertime.[9] Also, customers with electric water heaters can choose among three different water heater rates, D5 I, II, and III. There are also some other minor rate classes for farmers, interruptible air conditioning, etc.[10]

20, 1975.

[8] Appendix 5 contains a parallel program to NAPPROX called FINE for estimating LDC's by this method.

[9] DECO's definition of summer is June through October.

[10] Appendix 12 shows the breakdown of sales between the rate classes for 1983.

For our purposes we needed to simplify this structure. The LBL model is not designed to accommodate different rate schedules, but by careful definition of the housing types built into the model, it was possible to subdivide the output into small and large family categories. All other subdivision of sales had to be made manually after the output from the model was available. We defined as below a five-rate-schedule characterization of DECO's residential class and did all of the revenue calculations based on these simplifications.

(1) Sales to seniors, on D1.3, are assumed to be a fixed fraction of total system sales, 5%. However, as explained below, the number of senior customers was not assumed constant, but rather grows slightly.

(2) Every customer with space heating was billed under the D2 heating rate in winter, November through May. Further, D2, which carries no fixed charge, was simplified to a flat energy charge. When heat pumps were introduced, they too were billed on D2 during the winter, but enjoyed no special rate in summer.

(3) All water heating was billed under the D5 I interruptible water heating rate, with a fixed charge, but with only one flat energy charge.

(4) All remaining sales were assumed to be in the main D1 category, subdivided only by large and small family. However, the revenues were calculated separately for summer and winter using the appropriate bill frequencies.

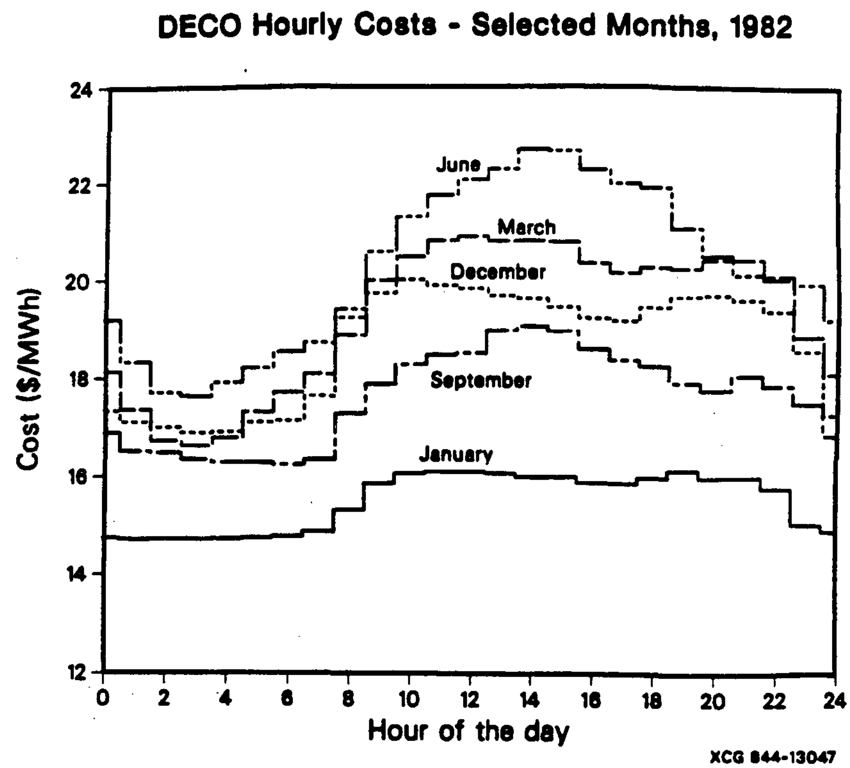

Figure 1

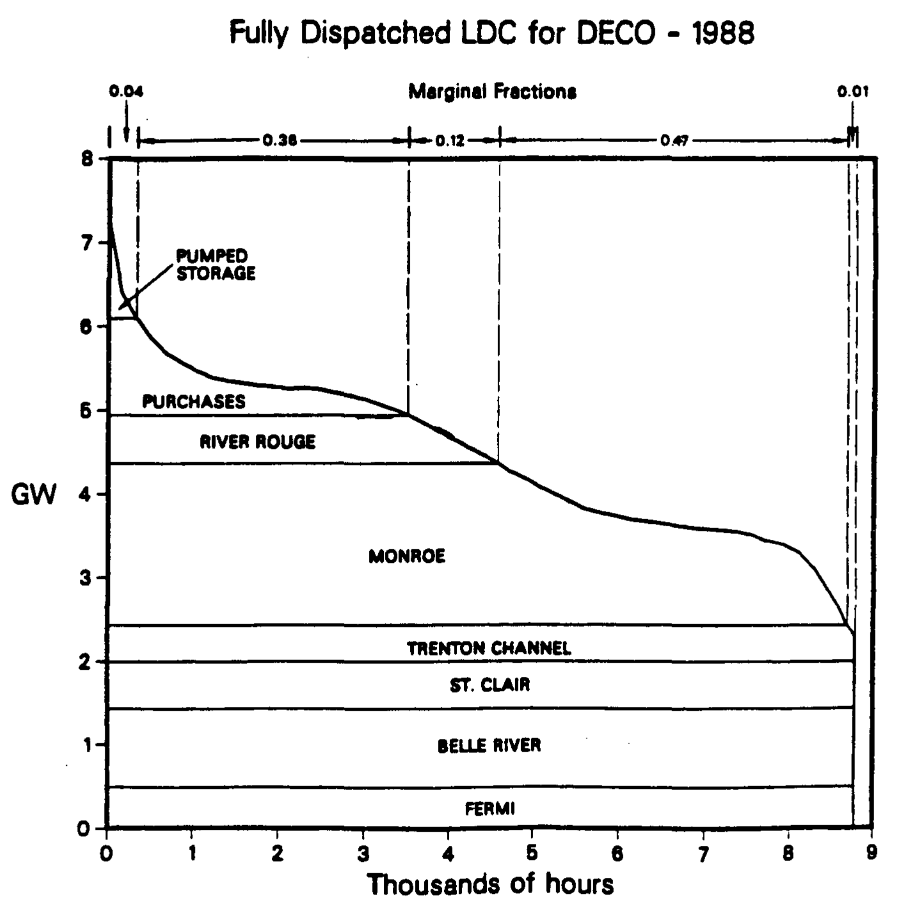

Figure 2

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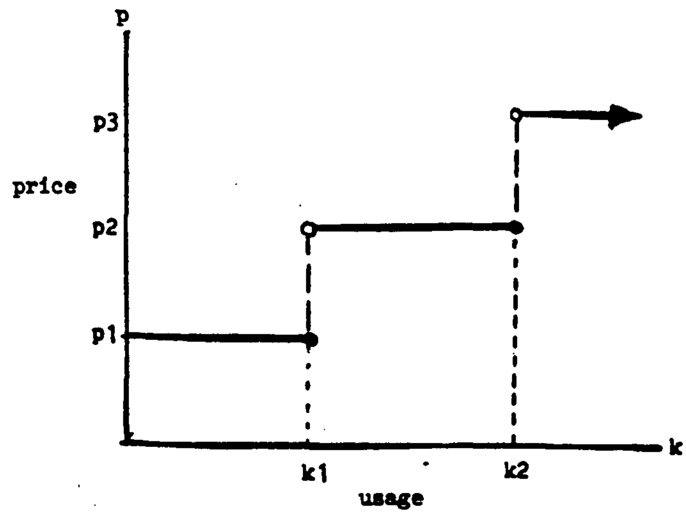
Fundamental Structure of DECO Lifeline Rates



- in DECO tariff sheets the usage allowances, k1 & k2, are defined as daily kWh's but in this study we have used monthly allowances defined as 30 days

- in DECO tariff sheets price is usually defined in \$/kWh; we have used both ¢/kWh and \$/kWh

Figure 3

-- XBL 8512-4890 --

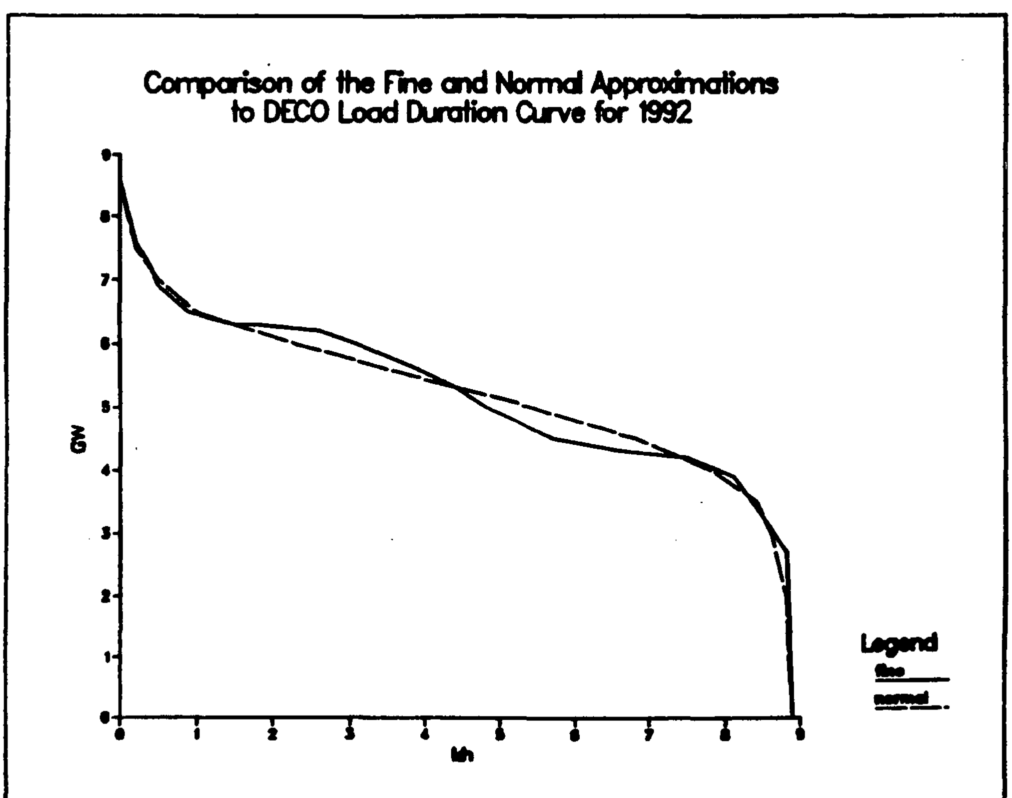


Figure 4

II MODEL INPUTS

1. Projecting Appropriate Model Inputs

The LBL model takes projected energy prices, incomes, and numbers of customers among its inputs. Both the direct energy outputs of the model and the revenue calculations depend on these inputs. All of these input forecasts are no more or less than our "best guess" of future economic conditions. We were not able to test the sensitivity of our results to these assumptions because the cost and complications involved in doing multiple runs was prohibitive. This limitation springs from our manual treatment of the revenue calculations, not from the running of the LBL model, and if these can be automated, more sensitivity analysis would be possible. In general, however, we believe the model is not highly responsive to short run economic fluctuations.

2. Prices

We took the rates requested in DECO's current rate case to be the real 2000 prices and made an even interpolation between existing prices and those 2000 levels. The logic underlying this approach was simply that DECO will most likely not be granted the full amount of its rate request at the current hearings and, as mentioned above, the DECO system is a very stable one for which few additions will be needed in the period of this projection.

Appendix 6 presents the full details of the assumed prices and allowances. We used the same prices throughout the revenue calculation and the allowances are fixed. There is a critical assumption implicit in this approach, namely that there is no regulatory adjustment to the company's changing revenue situation. This is clearly an unrealistic assumption, and a modification to the current forecasting procedure would require a built-in model of regulatory response in addition to the sales response of the LBL model. However, having no strong prior conviction about the process of regulatory adaptation and wanting to keep our results as general as possible, we chose to calculate the effect before regulatory reaction.[11] Given the complications, we believe that this provides the clearest picture of the effects we are attempting to measure. Regulatory response might well truncate the loss (or gain) stream in a future year.

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[11] This assumption has a special twist in the case of PG&E which operates under the California Electric Revenues Adjustment Mechanism (ERAM), which guarantees that the company's revenue requirements will be met, irrespective of sales fluctuations because of conservation. In this case, therefore, our intent is to determine the value of this adjustment to the company rather than a potential profit loss.

3. Customers

Appendix 13 presents our assumptions on numbers of customers. In keeping with general demographic trends, we have assumed a steady shift in family size towards smaller families. However, this is not in keeping with DECO's recent history during which there has been a shift towards large families. This reveals a very ticklish problem with respect to these kinds of assumptions. We believe that the recent growth in customers on the large family rate is counter to demographic facts. It has probably come about because customers are schedule jumping to decrease their electricity bills. This effect is accentuated by Detroit's harsh economic times and may have been triggered by the rate increase that accompanied the introduction of lifeline rates by DECO in 1981. These rates exhibit a steep inversion that translated into large increases for many customers.

We derive the number of customers on the D2 and D5 rate schedules from the ownerships of electric space heating and electric water heating predicted by the model. We assume the number of senior customers to rise slightly from 9 to 10 % of all customers, and the residual customers in D1 to be divided by the changing fractions of small and large families.

We used these same numbers of customers throughout the revenue calculations because the changes in appliance saturations the model yields cannot be converted directly into numbers of customers by rate schedule. This is a critical point. The model can predict for us the number of customers with space heat, for example, but not all of them would opt for a special rate, either because they are unaware of it or because they feel they can get a better deal under another schedule, as farmers for example. This is unfortunate because the revenue calculations depend on the number of customers in two important ways. First, one of the rate schedules, D5, carries a fixed charge, so its revenues are directly related to the number of customers. Second, the block adjustment method used to predict the fractions of sales in each of the revenue tiers uses movements in the mean level of usage as a guide to the moving tier fractions. Since we are deriving the mean usage directly, using the number of customers in the schedule, we are clearly going astray if the numbers of customers are incorrect.[12]

4. Incomes

We considered two sets of income data for the Detroit area. We read into the model the set from the National Bank of Detroit, whose metropolitan Detroit region closely resembles DECO's service territory. The preliminary runs of the model showed declining sales for 1983 and further

[12] In future studies, the model will output the numbers of customers being assumed, and consequently the revenue calculations can be done totally consistently with the model assumptions. The accuracy and credibility of the revenue results will be much greater as a result.

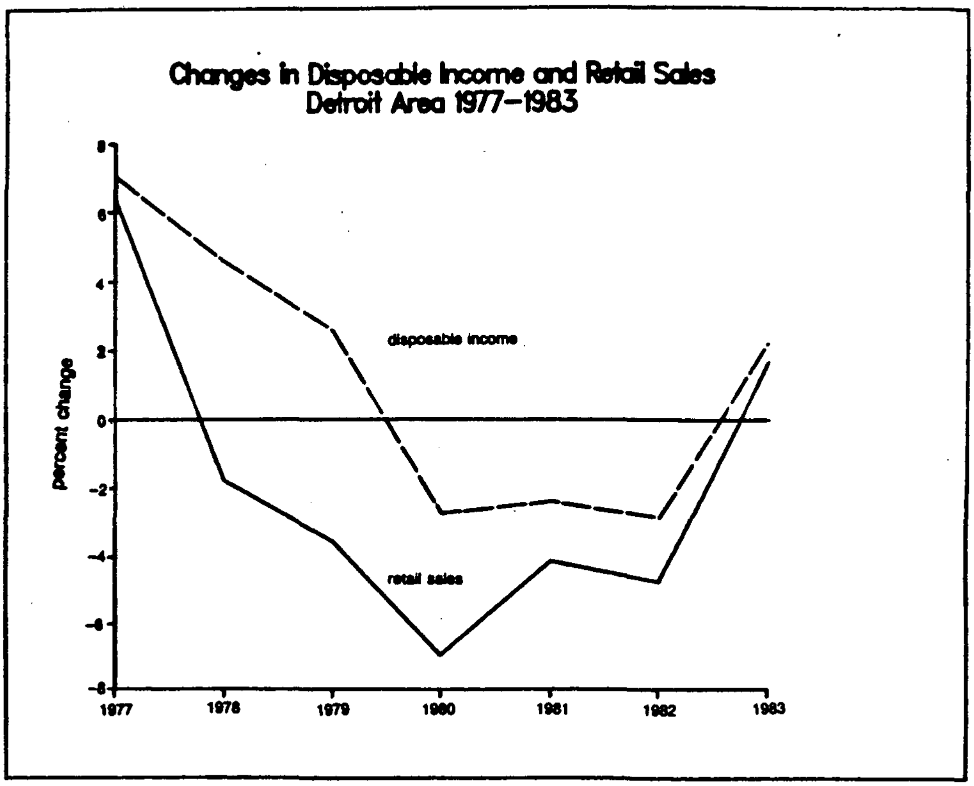
declines for 1984, although experience suggests this is not the actual case for DECO. In fact, as Figure 5 shows, 1983 saw a dramatic economic turnaround in the Detroit area. This discrepancy is a result of the model's relative insensitivity to its short run economic inputs. The lag in the model's response to higher incomes was too slow to react to the 1983 reversal. This is not surprising since the model was never intended to forecast the short run business cycle phenomena. In fact, the retail sales curve in Figure 5 (page 17) demonstrates that purchasing behavior is more volatile than income changes suggest in the short run and electricity sales may well track retail sales more closely than income.

5. Appliance Efficiencies

In addition to the economic inputs described, the model also takes in account the average efficiency of ***new appliances***. In the BS case, the model was free to choose efficiencies based on its analysis of new appliance purchase decisions, and Appendix 14 (i) details the efficiencies it chose. In the AS case, the effect of the hypothesized introduction of standards in 1987 is an immediate improvement in the average efficiency of almost all new appliances, but relatively little improvement afterwards, as shown in Appendix 14 (ii). The steadily improving BS efficiencies, therefore, catch up in the latter years for some appliances, notably space heating and cooking. The cooling technologies, air conditioning and refrigeration, do not catch up by 2000, but again, the gap is narrowing. Notice that some efficiencies are still improving under AS, notably the SEER of central air conditioning, because the average represents only the slowly increasing mean of a distribution of *new* appliance efficiencies. The effect of the standards on the efficiency of appliances sold is only temporary, lasting only until the BS efficiencies catch up to the AS ones. The average efficiency of the existing appliance stock is calculated by the model on the basis of new appliance efficiencies, which is a distribution, a fixed replacement rate for appliances, and a life-cycle cost calculation that models consumer purchase choices using an historically calculated personal discount rate. However, the fact that we assume efficiency improvements in the BS case implies our forecasts of sales will be lower than any analysis that excludes this consideration, irrespective of changes made to the efficiency assumptions in policy cases.

For the CO case, the only efficiency change is a dramatic increase in the SEER of central air conditioning equipment to 12 in 1987.[13] Room air conditioners are constrained to the same efficiencies as in the AS case.

[13] The highest SEER equipment currently available is about 15.



Sources: retail sales, Detroit Chamber of Com. -- XBL 8512-4883 --
income, National Bank of Detroit

Figure 5

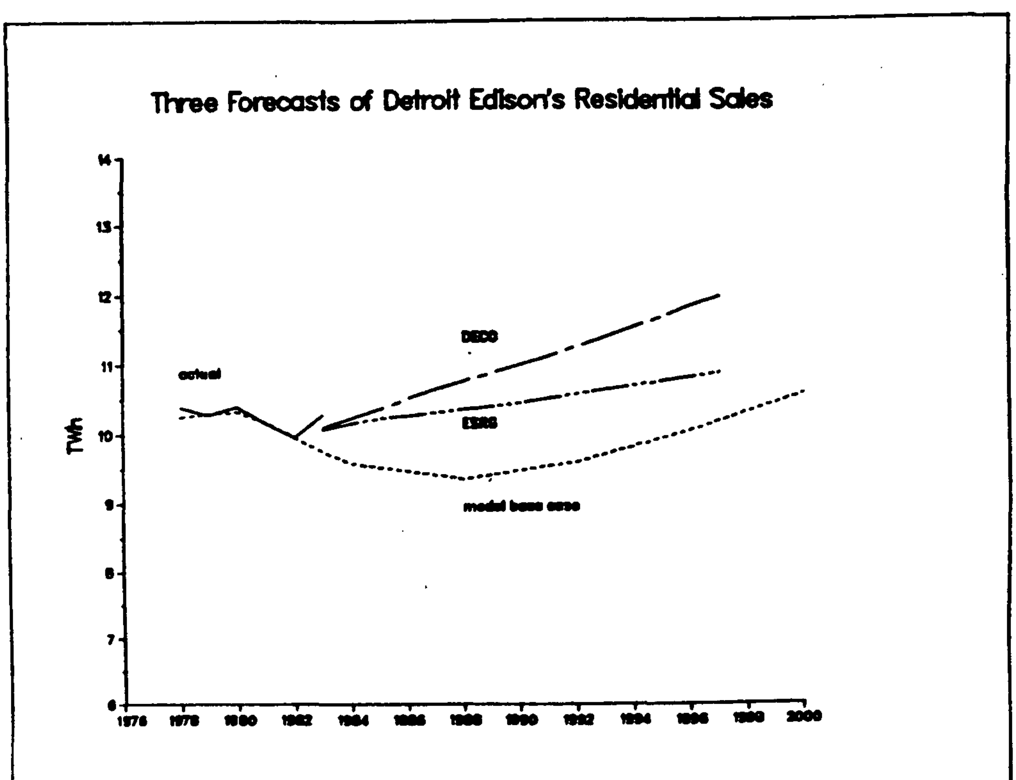


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Figure 6

III RESULTS

1. Model Output

First, we calibrated the model to recent DECO sales history and ran the BS case. Figure 6 shows the sales projection generated by the model's BS case compared to two other projections of future sales.[14] The model BS case produced lower sales than either of the two other forecasts, and interestingly, projects declining sales through 1988. As mentioned above, model sales do not turn upward in 1983, although actual company history shows a dramatic turnaround, far more so than could be explained by weather fluctuations.

We then changed the model's input assumptions to simulate the effects of three policy cases in turn and reran it. All of the sensitivity cases resulted in lower sales than the BS case, although the differences were small, as can be seen in Figure 7 (page 31).[15] The AS case resulted in the largest sales loss, about five percent in the year 2000. The maximum sales loss from the cooling case was only a half a percent, and the loss from heat pumps was about three percent.

The AS case resulted in a remarkably even load reduction. Figures 8 through 10 (pages 33 and 35) show this. Figures 8 and 9 show a winter and summer month peak day from 2000. The residential load shapes are derived from the model outputs directly, while the system shape is a hypothetical one based on the 1983 system load shape for DECO. As these curves show, load saving occurs throughout the day, in both winter and summer. Figure 10 shows that the monthly percentage peak load reduction in the year 2000 does not vary enormously through the year. This is explained by the nature of the assumed appliance standards which have a stronger effect on some non-weather-sensitive appliances than on heating, which provides very little opportunity for efficiency improvement. Notice that the savings are fairly constant during winter, spring, and fall, the main deviation coming as a result of improved air conditioning efficiency in summertime. Finally, Figure 11 (page 35) shows that the annual system peak saving grows over the period of the forecast. We hypothesize that this curve is the left half of a dome because eventually the appliance efficiencies of the AS case would be matched by the steadily improving efficiencies of the BS case. In other words, the model has inbuilt efficiency improvements and the policy scenarios only accelerate the rate of improvement in the short run. Since Figure 11 (page 35) represents the gap between the policy and BS cases, the gap will eventually disappear, i.e. the curve will return to zero. Another interesting result is that the residential sector becomes winter peaking by 1996. This arises because air conditioning efficiency is improving while heating

[14] The Energy System Research Group (ESRG) estimates are from the testimony of Stephen Bernow in State of Michigan Public Service Commission case No. U-7660, exhibit SB-2, Jan. 18, 1984. The DECO projection is from a company document.

[15] The raw sales figures are shown in Appendix 7.

efficiency is not. At the same time, more people are choosing electric heating over other fuels. These changes are far short of what would be required to shift the system peak, however, because the non-residential loads are so big on DECO's system.

The CO case generated a smaller load saving. The net effect of the cooling standard on the residential load is shown by Figure 13 (page 37). The saving at the residential peak is three percent of residential load, but interestingly the percent saving at 15:00 hrs. is higher, 3.3 percent. In fact, the load shaving at the residential peak is only 2 MW above the midafternoon saving. This may be the result of one of the model's suspected weaknesses, namely that the air conditioning load shape is too flat. The model calculates its loads by estimating the fraction of all air conditioners that are turned on. Once all the air conditioners are on, the load reduction associated with the standards has reached its maximum and this may occur at temperatures too low for some local conditions. This problem may have arisen because the original observations on which the model's responses are based were made in the humid northeast. Another explanation is that a much higher share of the load than we assume comes in the evening hours from end uses other than air conditioning, for example, cooking. Figures 12 and 14 (pages 37 and 39) parallel Figures 10 and 11. Figure 13 is a contrast to 10 because in the CO case peak saving is confined to the summer months. Figure 14 lends a little more credence to our hypothesis that these curves should be dome-shaped. However, the above comment regarding air conditioning loads being too flat, i.e. not exhibiting sufficiently peaking behavior, makes the results in this figure suspect. We speculate that actual savings at the peak would be higher because we are underestimating the fraction of load accounted for by air conditioning at peak times.

2. Revenue Projections

DECO has a mixed rate structure. Some of its schedules have increasing blocks, some are virtually flat, and some, since there is a fixed charge, exhibit falling average price for much of their domains. For the purposes of this study, we treated D2 and D5 as flat rates, and we calculated the revenues by simple multiplication of sales and price, with the fixed charge times the number of customers added. We treated three schedules, D1, small and large families, and the seniors rate, as increasing block rates. We further subdivided the D1 categories between winter and summer because usage patterns are somewhat different, making five increasing block schedules in all.

We projected revenues using the block adjustment method commonly used in the industry. This approach uses the bill spread, or Ogive curve, to determine what fractions of sales in a schedule were made at each tier price during some recent year.[16] When usage levels are projected

[16] Appendix 8 shows an example of a DECO spread.

to change, new tier fractions are obtained by artificially shifting the tier boundaries, k1 and k2, in the opposite direction but by the same proportion as the change in the mean level of use. This simulates the actual changes in tier sales that would result from shifts in typical usage. While this method is widely used in the industry, it produces biased results, which in the case of conservation suggest that the revenue loss will be underestimated.[17] We made no attempt to correct for this bias for two reasons. First, a better estimate could be obtained only if actual bill frequencies could be obtained for the changed circumstances, which would involve sophisticated modelling. Second, and more importantly, since the objective of this project is to view conservation policies through the eyes of the utility companies, we wanted to duplicate their methods of analysis.

Table 1 (page 29) shows the sales matrix output of the model for a typical case (CO 1984). By far the messiest part of the financial analysis is dividing up the sales satisfactorily between the rather complex rate classes.[18] As mentioned above, the share of sales on the senior rate was assumed to be fixed at five percent, so we calculated this number first.

The model's output of water heater usage was consistently larger than the sales billed under the water heating rate. We deflated the model's output of total electricity usage for water heating by one third to simulate historical D5 rate schedule sales. This does not necessarily mean that the model's output is incorrect. Water heating may very well be billed under other rates, and, particularly, it is important to remember that we did not model DECO's two smaller water heating rate options, D5 II and D5 III, partially because under II the water heater is not separately metered. In other words, the usage billed on D5 I should not be taken as a guide to total water heater consumption; the former is the value needed for this analysis, but the latter is the value computed by the model.

The model consistently generated heating use that was different between large and small families, but for the most part, this result was not important because all wintertime heating sales were billed at the D2 rate. Since the heating sales were low relative to DECO's reported D2 sales, we used the total of room and space heat as our estimate of electric heating. Once again a dilemma occurs here because of the noncomparability of the model outputs and the sales reports by rate schedule. Because many other end uses are billed together with heating to D2 customers, there is no way to tell with precision what fraction of D2 wintertime sales represents the heating end use alone. One attempt to resolve this problem is based on the assumption that the sales reported by DECO for D2 included only wintertime sales. In fact, summertime sales to the D2

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17 See Kahn, Edward, *et al,* "Regulatory Factors Affecting the Financial Impact of Conservation Programs on Utilities." ***Doing Better: Setting an Agenda for the Second Decade. vol I.*** Proceedings of the Utility Programs Panel at the American Council for an Energy-Efficient Economy 1984 Summer Study on Energy Efficiency in Buildings, August 14-22, 1984 at the University of California, Santa Cruz, Santa Cruz, CA

18 Appendix 9 outlines the steps we took to allocate the gross output figures among the seven rate subdivisions used in the revenue analysis.

customers were included, about 20 percent of the annual totals. We adjusted our heating usages to match the weather-adjusted totals for small and large families. By this means, we concluded that a fair estimate of the D2 billings to small families could be obtained by inflating the heating usage by 5 percent, and by inflating that of the large families by 67 percent, we could be obtain a reasonable approximation to their sales. Roughly reworking the problem shows that we would have been closer to actual history without this adjustment. Sales would have been underestimated for 1982 but overestimated for 1983. One should remember that the error amounts to only about one percent of sales whose revenues were calculated at the D1 rather than D2 rates. Finally, we noticed that the split between summer and winter sales was not quite in agreement with DECO's reported split so we inflated our summertime sales by five percent. Frustratingly, nothing concrete can be said about the accuracy of the model as a result of this discrepancy because of the interference of numerous other factors. One of these is the considerable confusing effect of billing lag, which makes our summer and winter modelling periods different from the periods actually billed. Table 2 shows the results of subdividing the sales according to these steps and compares the results to actual DECO sales for 1982 and 1983 derived in a parallel way.

Table 2

Percent Shares of Sales in Rate Classes
Model Base Case Versus Actual DECO**

year	D1(1-2)	D1(>=3)	D2	D5	D1.3	total
1982	34.32	51.11	3.95	5.62	5.00*	100.00
	(33.91)	(49.00)	(3.52)	(5.37)	(4.72)	(96.52)***
1983	34.67	50.94	4.19	5.20	5.00	100.00
	(32.63)	(48.80)	(4.83)	(5.29)	(4.73)	(96.28)

* five percent by assumption

** actual DECO figures in parenthesis

*** the missing 3-4% of DECO's sales are in the small rate classes

3. Revenue Results

Table 3

Revenue Calculation Comparison
(DECO 1985* vs. LBL 1984 BS Case)

rate schedule	(1) DECO sales	(2) model sales	(3) (2)/(1)	(4) DECO** revenues	(5) model revenues	(6) (5)/(4)
D1(1-2)	3134	3352	1.070	242.062	257.554	1.064
D1(>=3)	5041	4852	0.963	382.507	364.073	0.952
D2	739	428	0.579	50.285	27.906	0.555
D1.3	502	478	0.952	26.688	28.980	1.086
D5	509	455	0.898	28.049	23.357	0.833
total	9925	9565	0.964	729.591	701.870	0.962

sales are expressed in GWh and revenues in millions of 1984 dollars
* source, Loeher/Falletich U7660 A-13 E6
** excluding power cost recovery

Table 3 describes a test revenue calculation we carried out. We used the sales derived from the model for 1984 as the basis for a revenue calculation for that year. The figure also shows the same calculation done for 1985 by DECO as part of their rate hearing testimony. Since DECO's sales predictions for 1985 in the five rate schedules are close to our sales in all categories except D2, where DECO anticipates large sales increases, the comparison is useful and valid. In addition, our revenue results are encouragingly similar to DECO's, so that if the sales can be correctly determined, we are confident of being able to replicate internal utility revenue calculations.

To estimate revenues, we tallied the raw data from the model output of the form of Table 1 and retabulated by rate schedule with all of the appropriate adjustments mentioned. We then estimated revenues for each schedule, applying the block adjustment method to the lifeline rates, D1 and D1.3. We named the adjusted tier boundaries k1* and k2*. They generally rise because mean usage is falling. The tier fractions, f1*, f2*, and f3*, are the adjusted fractions at the new boundaries. Figure 15 (page 39) shows an example of the effect of the rising adjusted tier boundaries over time. The fractions of sales being made in the more lucrative tiers 2 and 3 slowly decline, thus reducing the average price received by the company over its entire system, *ceteris paribus*. Note that the average price per kWh is close to the first tier price, p1, for DECO. This shows the small fraction of sales that are being billed in the high tier is initially low. We repeated this same calculation for the three sensitivity cases.

Appendix 10 shows the full details of the revenue projection for the BS case. First, we converted the sales output of the model to sales by rate schedule according to the steps of Appendix 9. Then, we derived a revenue result for each of the rate classes, using the block adjustment method where there are tiers. The last table in Appendix 10 (v) shows the derivation of totals for the entire residential rate class. We followed the same procedure for the sensitivity cases, and as an example, Appendix 11 reproduces the parallel tables for the AS case. An interesting story is seen by comparing the right column in the Revenues By Rate Schedule tables for the two case. They show that the lost sales of the AS case actually measurably reduce the average price per kWh collected from the entire rate class.

Tables 4 and 5 show how we reduced the revenue results for the AS case to a net loss figure for the company. Table 4 details the projected production costs assumed in the net cost saving calculations. Table 5 compares the sales and revenues of DECO under the BS and AS assumptions. Sales are lost in every year the standards are in effect, but the revenue losses are proportionately greater.

The 'bottom line' question is whether the lost sales would have generated more revenues than the costs involved in producing them. The cost savings have been estimated by use of the marginal fractions outlined in Figure 2 and using the costs shown in Table 4. The net cost savings (col. 8) are subtracted from the net revenue losses for the test years (col. 6) to give a bottom line loss or gain (col. 9). As expected, DECO sustains losses in all of the test years, and the losses are growing over time.

Table 6 shows the same estimations for the CO case. The sales losses are much smaller in this case, but they are even more lucrative ones; consequently, the bottom line company loss is proportionally greater.

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[20] This assumption implies a line loss of 10.7%. Two comments we have received on this assumptions are, first, that this is not an appropriate loss for the residential sector, and second, that it is incorrect to assume that the loss on increments will be constant and equal to average line loss. This is important because of the small size of the effect being measured, only 0-5% of residential sales, and so a poor choice of f would result in misleading cost forecasts. However, we must say that a fixed f is normally used in rate calculations and testimony, and our intent here is mostly to duplicate such calculations, not improve on them.

Table 4

Generation Costs Assumed in Cost Calculations*
(current mills/kWh)

plant	1984	1988	1992	1996	2000
Fermi	23.27	28.46	34.82	41.26	56.93
Belle River	21.58	29.28	41.60	58.84	83.26
St. Clair	26.15	33.53	52.45	73.18	104.44
Trenton Ch.	26.86	34.05	48.15	67.75	95.81
Monroe	23.10	35.50	50.04	70.93	99.92
River Rouge	25.70	35.62	55.83	79.01	111.72
purchases	30.72	41.95	58.93	84.10	119.42
pump stor.	31.57	38.92	59.50	85.51	123.96
weighted MC (current mills)	26.53	37.96	54.30	77.20	109.29
real MC** (1984 cents/kWh)	0.0265	0.0312	0.0368	0.0430	0.0501

* source, PROMOD run of DECO system, 12.05.83
** inflation assumed at constant 5%

With regards to the HP case, we have less confidence in the results. The model yielded rather undramatic outputs for this case because it projects that few people would buy heat pumps. The net result was a small reduction in sales that grows dramatically in the latter years.

4. Conclusion

This was the first attempt to model an individual utility using the LBL Models, and the experience has been a valuable one. The results themselves confirmed our initial hypotheses and much was learned in the process of deriving them.

There is little question that without regulatory relief DECO will indeed suffer badly from a general appliance standards policy akin to our AS case. With regard to the CO case, we have less

Table 5

Summary of Revenue and Cost Consequences
AS Case

year	(1) base sales (GWh)	(2) base rev.	(3) AS sales	(4) AS rev.	(5) sales loss (1)-(3)	(6) revenue loss (2)-(4)	(7) cost (1984 c/kWh)	(8) *	(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

* saving of total cost = (5) * (7) * f
where f = 1.12, an allowance for transmission loss[20]

confidence in our results because we suspect the model may not be generating sufficiently peaking behavior. In other words, we are confident that the revenue losses are as we have described them, but there is a danger we have understated the cost savings. However, it is extremely unlikely the qualitative result could be changed. Once again we can take heart in the specifics of the DECO system because the lack of coincidence between the system and residential peaks reduces the potential of any residential policy to reduce the system peak in a way financially appealing to DECO.[21] The HP case was less significant. The "answer" presented to us by the model that no one buys heat pumps under our assumptions may well be correct, but such an answer doesn't yield anything interesting for us to analyze.

Several methodological stumbling blocks arose; we overcame some, and simply sidestepped others. The important ones were:

[21] The cost saving of a reduction in peak resulting from an initiative in the residential sector will almost certainly be overwhelmed, in the company's eyes, by the loss of sales revenue at non-peak times.

Table 6

Summary of Revenue and Cost Consequences
CO Case

year	(1) base sales (GWh)	(2) base rev.	(3) AS sales (GWh)	(4) AS rev.	(5) sales loss (1)-(3)	(6) revenue loss (2)-(4)	(7) cost (1984 c /kWh)	(8) *	(9) loss (6)-(8)
1984	9566	702	9566	702	0	0	0.0307	0	0
1988	9335	766	9319	764	16	2	0.0345	1	1
1992	9568	864	9535	860	33	4	0.0399	1.5	2.5
1996	10013	983	9968	977	45	6	0.0468	2	4
2000	10548	1121	10506	1115	42	6	0.0547	2	4

* saving of total cost = (5) * (7) * f
where f = 1.12, an allowance for transmission loss

(1) Our inability to map load reductions in the residential sector onto shifts in the LDC is a major unresolved problem. If accurate cost data is available by time of generation, the LDC does not have to be used as a source of marginal cost estimates and the question is mute. When cost information is not at hand, however, application of one of the LDC estimating techniques described above would be an excellent route to reliable marginal cost estimates.

(2) Had we foreseen the complexity of the revenue calculations, especially the difficulties involved in subdividing sales into the rate schedules, we would have made greater efforts to make the model do more of the work for us. Techniques for judicious planning of model output formats so that the numbers of customers, etc., are kept consistent have certainly been the skills most painfully learned. However, in our ongoing efforts to model PG&E, these skills have already paid handsome dividends, and they will pay again manyfold in future work. Since the rate structure of each utility is unique, and typically quite complex, there can never be a general methodology for approaching the revenue calculations, but we do expect over time to gain enough experience to do a much better and more accurate job than was done for DECO, and to be able to automate the process somewhat. The size of the bill frequency data sets, however, is a serious barrier to computer modelling. But, as a first step, we hope to duplicate the calculations done so far on a programmable calculator on an IBM PC.

(3) One of the crucial aspects of the revenue loss calculations is the length of time that regulators tolerate the failure of their utility to meet its revenue requirements before rates are

adjusted. We have attempted to model only the affects of our policy cases before regulatory response; in other words, we assume the losses keep piling up indefinitely. Once again, every regulatory body's response would be different and come with a different lag. However, we hope in future to include an elementary model of regulatory response in our calculations in order to obtain a somewhat more realistic estimate of actual potential losses.

(4) We obtained many valuable insights into the model's behavior, but two stand out.
First, the insensitivity of the model to economic inputs became apparent. Certainly valuable work towards improving the model could be done in this area.
Second, the apparent lack of air conditioning peaking lead us to some promising new thinking about climatic influences on electrical usage behavior. A large data set of air conditioning load observations has been obtained from PG&E and we hope to compare the behavior it reveals with that built into the model on the basis of New Jersey data. We have already learned that by adjusting the temperature responses in the model, we can obtain a closer approximation to PG&E's observations.

Understanding the unique circumstances of utility companies is the object of the exercise, and further, it is their very uniqueness that makes the problems encountered and results derived important and interesting. No approach to understanding a specific company could be sufficiently general to be applied at will, but we have made significant progress towards establishing a set of methods that, used judiciously and eclectically, could characterize many utilities and thereby begin to sketch an outline of the industry as a whole.

SUMMARY OF RESIDENTIAL LOADS FOR YEAR 1984

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	WINTER	SUMMER
ELECTRICITY USE (GW														
ALL HOUSES (192.5 THOUSAND CUSTOMERS)														
1 CENT. S.H.	52.4	36.4	14.3	7.8	0.1	0.0	0.0	0.0	0.0	6.6	30.7	65.3	213.8	0.0
2 ROOM S.H.	7.7	5.3	2.1	1.1	0.0	0.0	0.0	0.0	0.0	1.0	4.5	9.6	31.4	0.0
3 HP (HEAT)	11.5	8.1	3.2	1.8	0.0	0.0	0.0	0.0	0.0	1.5	6.8	14.3	47.2	0.0
4 HP (COOL)	0.0	0.0	0.0	0.9	11.8	12.8	17.9	13.9	9.4	0.7	0.0	0.0	13.5	54.0
5 ROOM A/C	0.0	0.0	0.1	0.4	4.0	4.8	9.8	8.4	4.8	0.5	0.1	0.0	5.1	27.9
6 CENT. A/C	0.0	0.0	0.4	6.8	86.8	94.4	132.4	102.3	69.7	5.3	0.1	0.0	99.4	398.8
7 WATER HT.	23.3	21.0	23.6	20.1	18.9	18.2	18.8	18.9	18.2	21.3	22.7	22.9	173.8	74.1
8 REFRIG.	31.5	28.4	31.5	30.0	30.7	29.7	30.6	30.7	29.7	31.1	30.5	31.4	245.2	120.7
9 FREEZER	4.7	4.3	4.7	5.2	6.0	5.8	6.0	6.0	5.8	5.4	4.6	4.7	39.7	23.6
10 COOKING	5.8	5.2	5.8	5.6	5.8	5.6	5.8	5.8	5.6	5.8	5.6	5.8	45.4	23.0
11 DRYER	7.7	7.0	7.7	6.3	5.2	5.0	5.2	5.2	5.0	6.5	7.5	7.7	55.6	20.5
12 LIGHTING	39.7	35.9	39.7	33.0	28.5	27.6	28.5	28.5	27.6	34.3	38.4	39.7	289.3	112.1
13 MISC.	41.7	37.6	41.7	38.1	37.1	35.9	37.1	37.1	35.9	39.5	40.3	41.7	317.6	146.0
TOTAL	226.0	189.4	175.0	157.2	234.9	240.0	292.2	256.8	211.8	159.4	191.9	243.2	1577.0	1000.8
PEAK LOAD (MW)	517.0	475.8	449.1	528.6	755.8	831.5	831.5	799.8	711.1	391.8	480.7	499.9		
LOAD FACTORS	0.5876	0.5922	0.5236	0.4129	0.4178	0.4009	0.4724	0.4316	0.4137	0.5469	0.5545	0.6539		
DATE OF PEAK	JAN 18	FEB 16	MAR 29	APR 16	MAY 29	JUN 27	JUL 4	AUG 30	SEP 4	OCT 18	NOV 27	DEC 18		
HOUR OF PEAK	7:30PM	6:30PM	6:30PM	5:30PM	6:30PM	6:30PM	6:30PM	5:30PM	5:30PM	6:30PM	6:30PM	6:30PM		
TEMP AT PEAK (F)	33	42	47	94	103	106	109	107	102	55	41	38		
THI AT PEAK	38	46	49	75	81	84	84	84	82	52	44	44		
MONTHLY HDD (65)	564.	421.	249.	156.	11.	1.	0.	0.	1.	150.	385.	661.		
MONTHLY CDD (65)	1.	1.	37.	119.	542.	594.	723.	643.	509.	101.	14.	0.		

COMPONENTS OF PEAK HOUR DEMAND (MW) FOR YEAR 1984

END USE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1 CENT. S.H.	147.8	103.8	84.5	0.0	0.0	0.0	0.0	0.0	0.0	42.2	107.3	121.4
2 ROOM S.H.	21.7	15.2	12.4	0.0	0.0	0.0	0.0	0.0	0.0	6.2	15.8	17.8
3 HP (HEAT)	32.1	22.9	18.4	0.0	0.0	0.0	0.0	0.0	0.0	9.5	23.7	26.8
4 HP (COOL)	0.0	0.0	0.0	35.7	60.5	68.5	68.5	65.6	55.6	0.0	0.0	0.0
5 ROOM A/C	0.0	0.0	0.0	10.8	21.0	29.5	29.5	26.7	21.5	0.0	0.0	0.0
6 CENT. A/C	0.0	0.0	0.0	263.6	446.5	505.6	505.6	484.1	410.6	0.0	0.0	0.0
7 WATER HT.	43.5	44.5	44.5	31.2	33.9	33.9	33.9	33.2	33.2	44.5	44.5	44.5
8 REFRIG.	46.3	46.3	46.3	45.7	49.1	49.1	49.1	48.6	48.6	46.3	46.3	46.3
9 FREEZER	6.4	6.4	6.4	8.4	8.4	8.4	8.4	8.4	8.4	6.4	6.4	6.4
10 COOKING	15.0	22.5	22.5	31.0	23.3	23.3	23.3	31.0	31.0	22.5	22.5	22.5
11 DRYER	10.0	11.7	11.7	10.0	9.9	9.9	9.9	10.0	10.0	11.7	11.7	11.7
12 LIGHTING	138.2	146.5	146.5	42.4	53.4	53.4	53.4	42.4	42.4	146.5	146.5	146.5
13 MISC.	56.0	56.0	56.0	49.9	49.9	49.9	49.9	49.9	49.9	56.0	56.0	56.0

Table 1

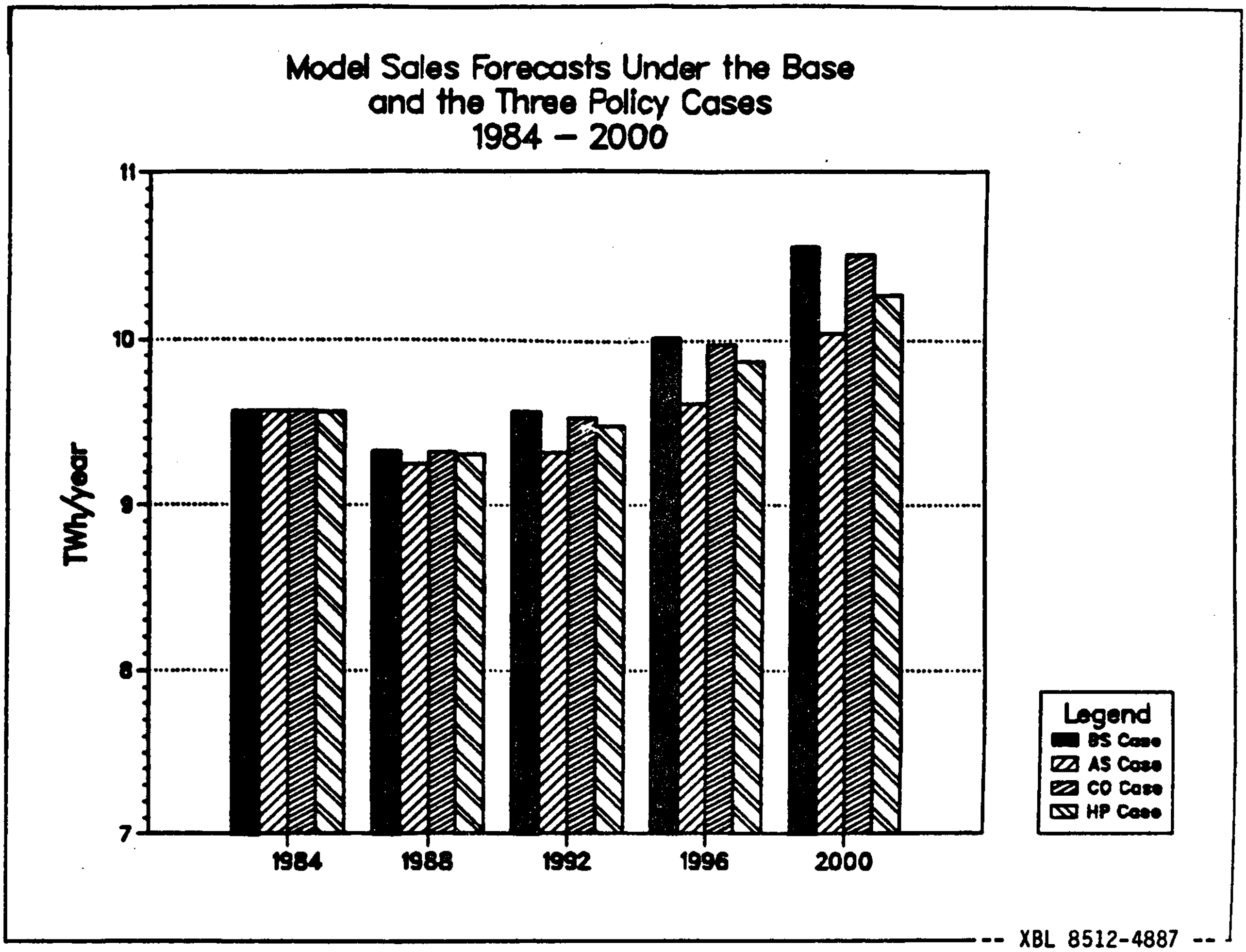
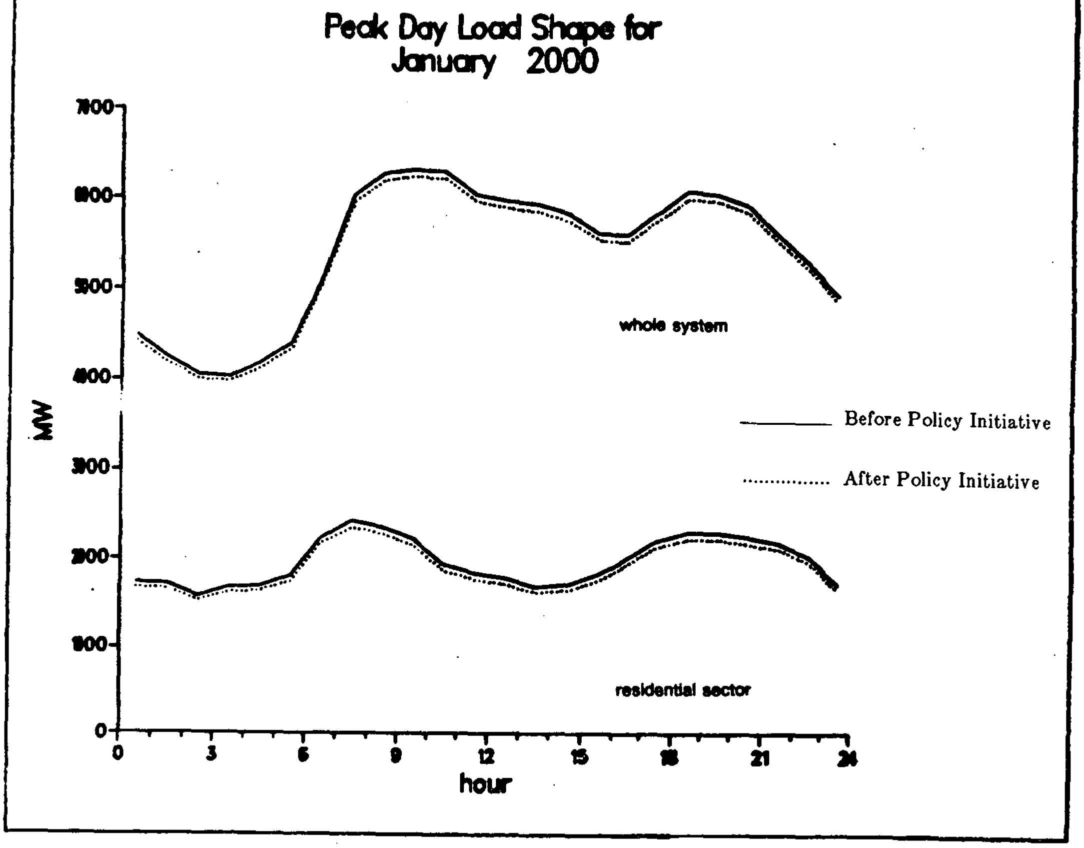
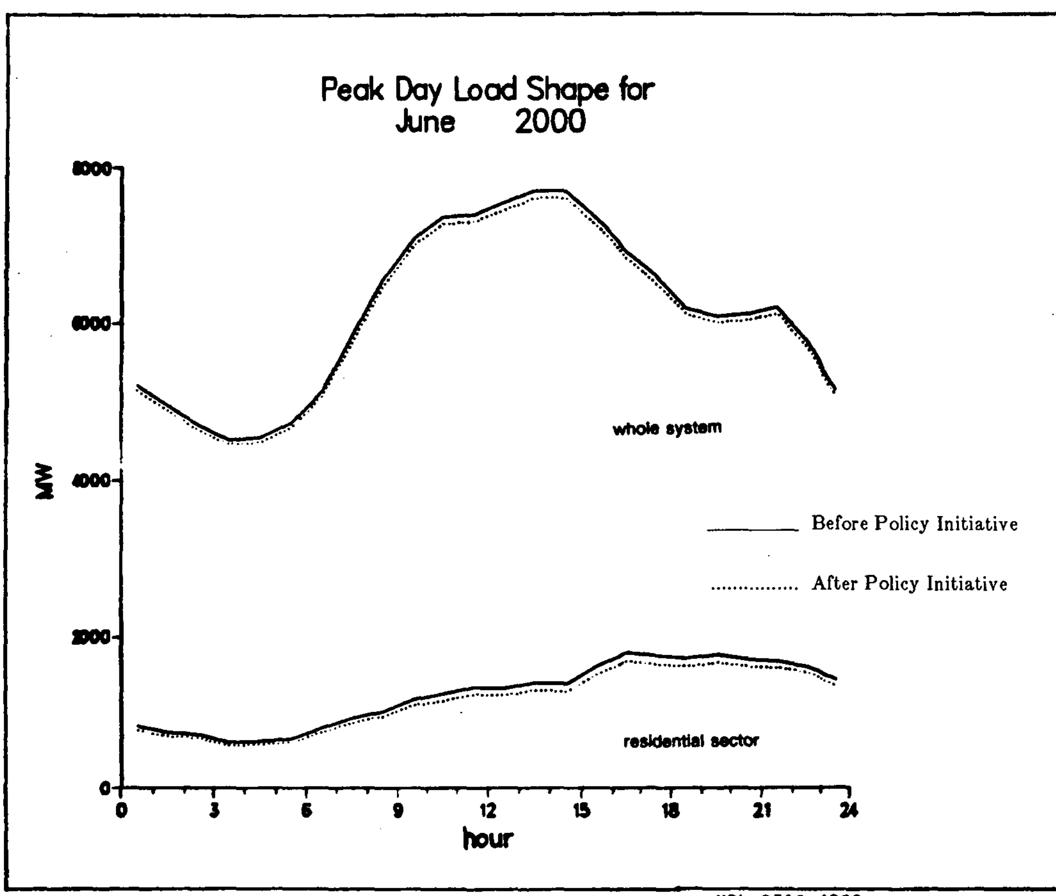

Model Sales Forecasts Under the Base
and the Three Policy Cases
1984 – 2000
TWh/year
11
10
9
8
7
1984
1988
1992
1996
2000
Legend
BS Case
AS Case
CO Case
HP Case
XBL 8512-4887

Figure 7



-- XBL 8512-4881 --

Figure 8



-- XBL 8512-4882 --

Figure 9

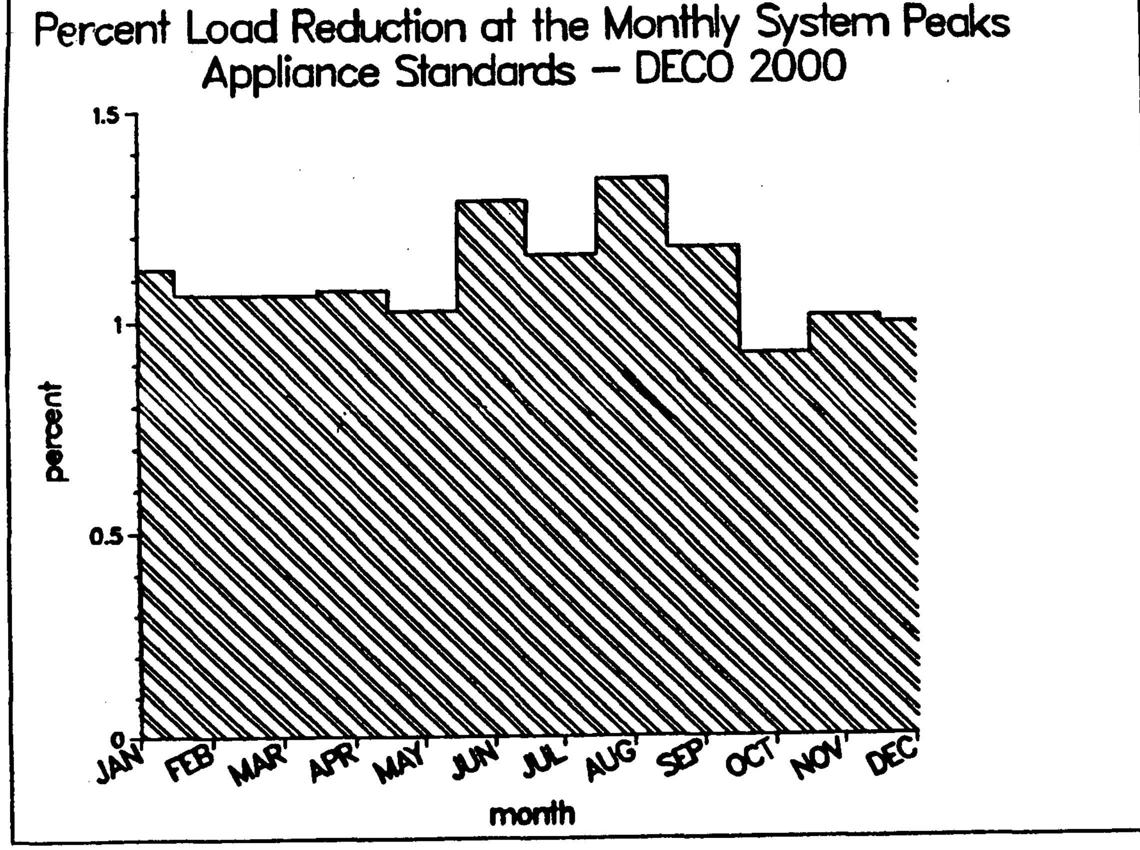
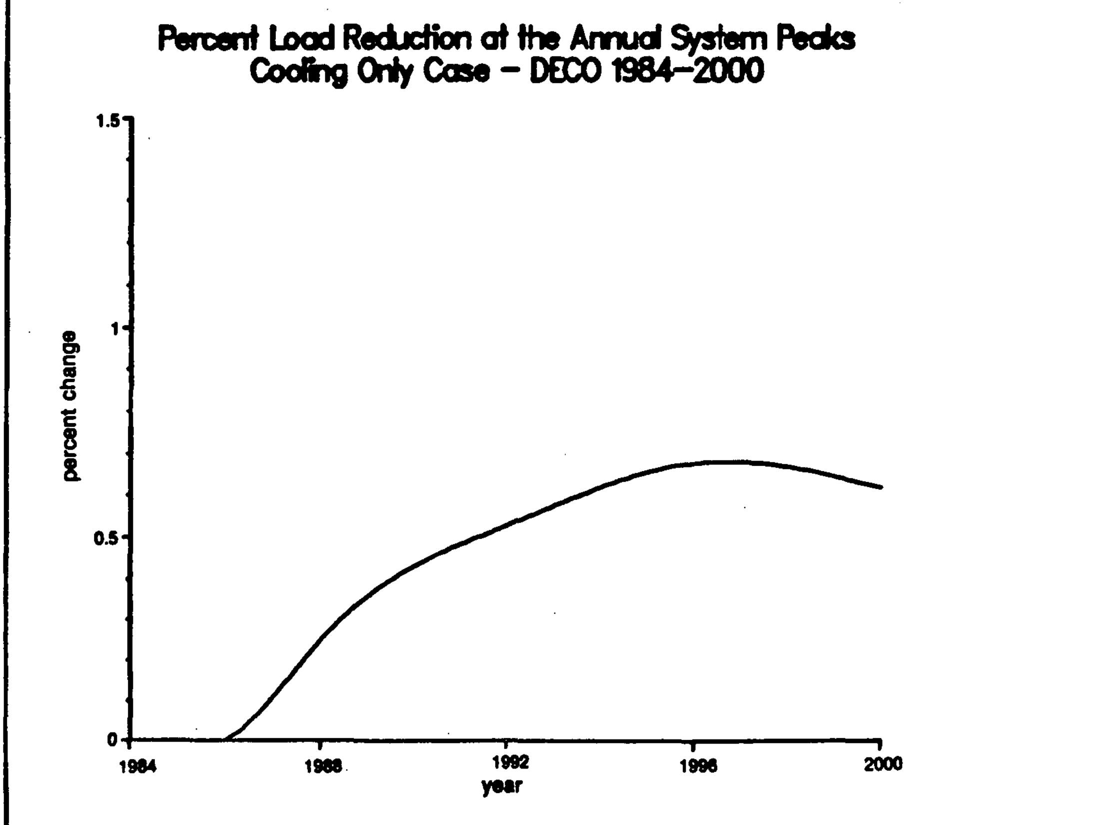


Figure 10

-- XBL 8512-4886 --



-- XBL 8512-4880 --

Figure 11

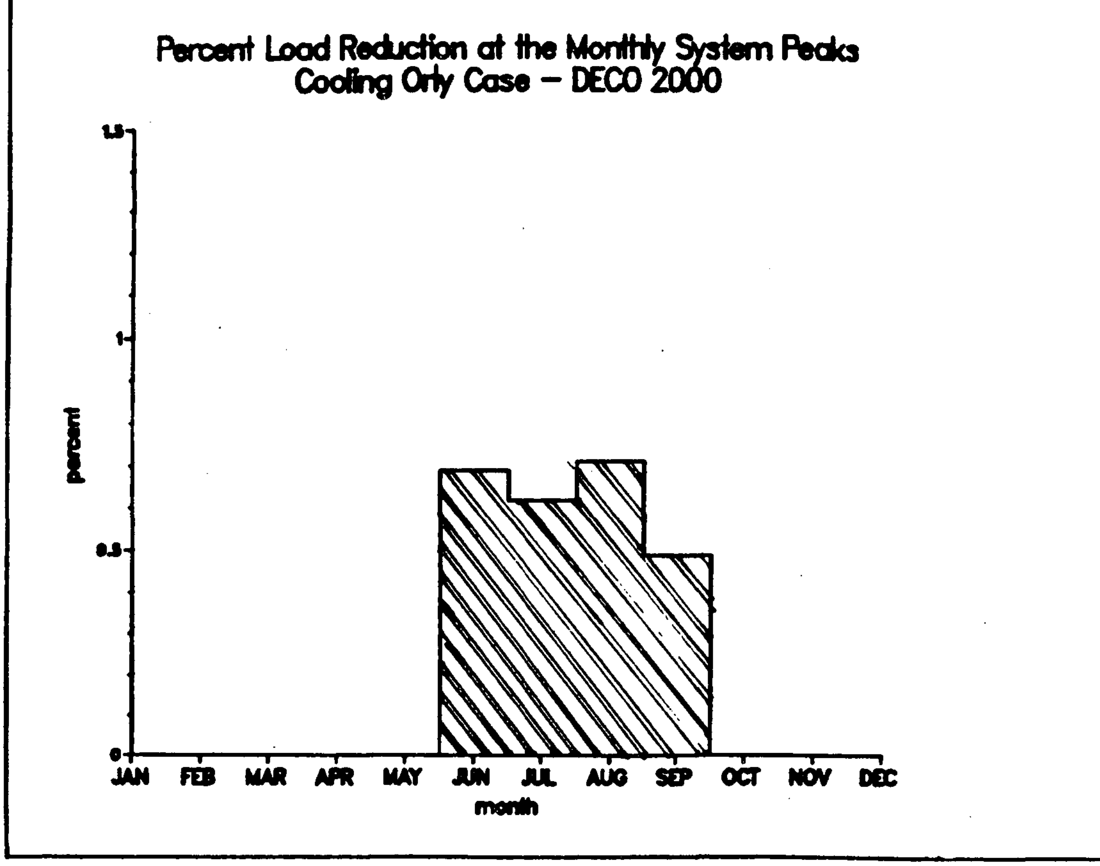
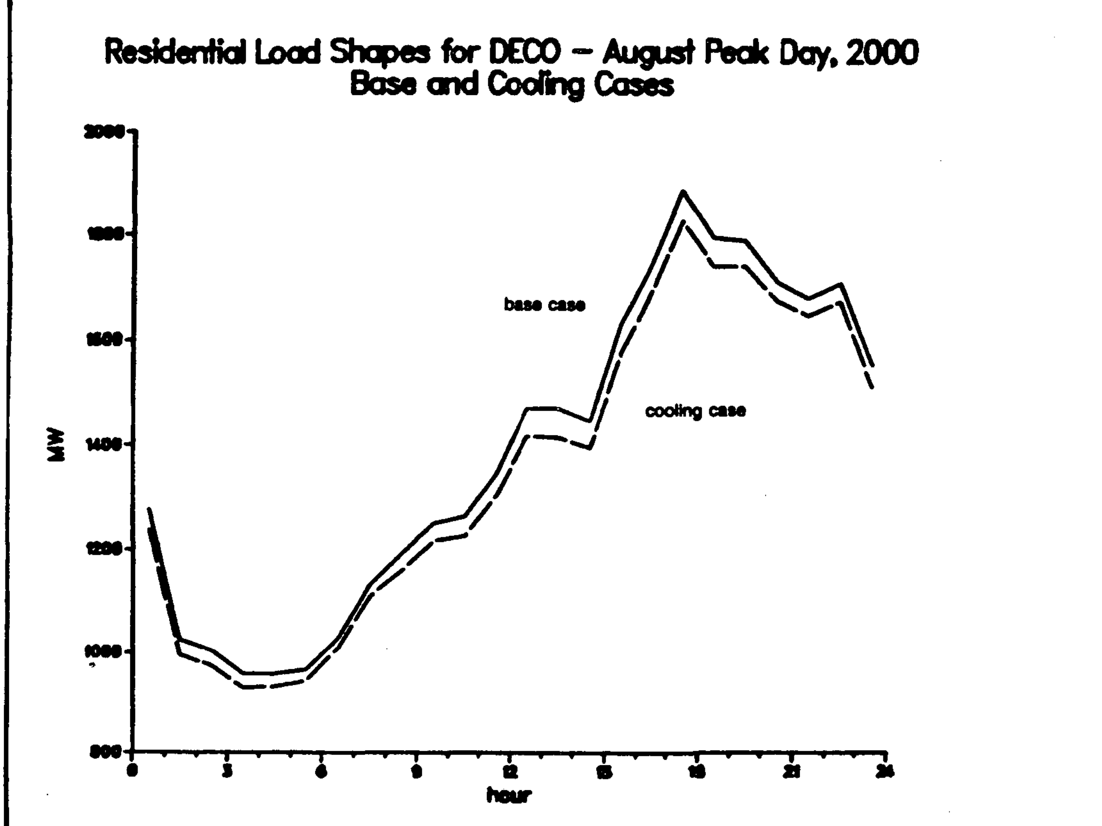


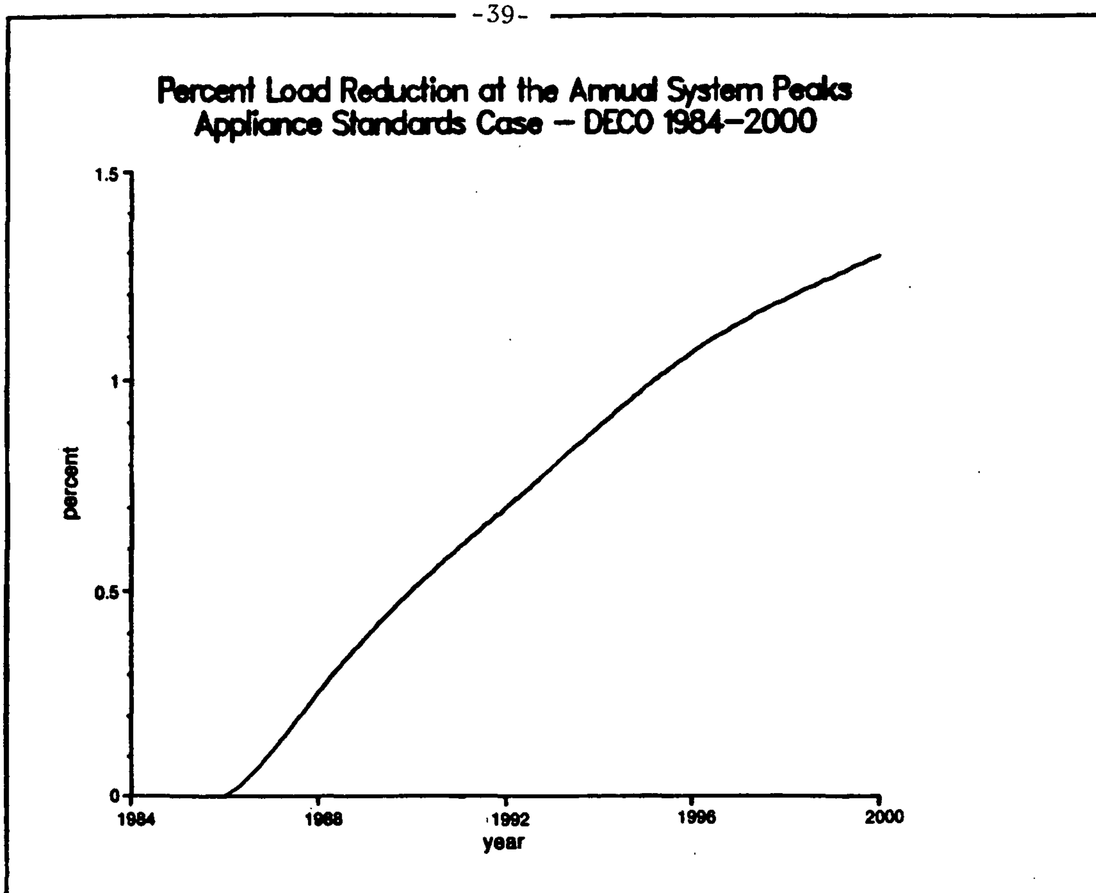
Figure 12

-- XBL 8512-4885 --



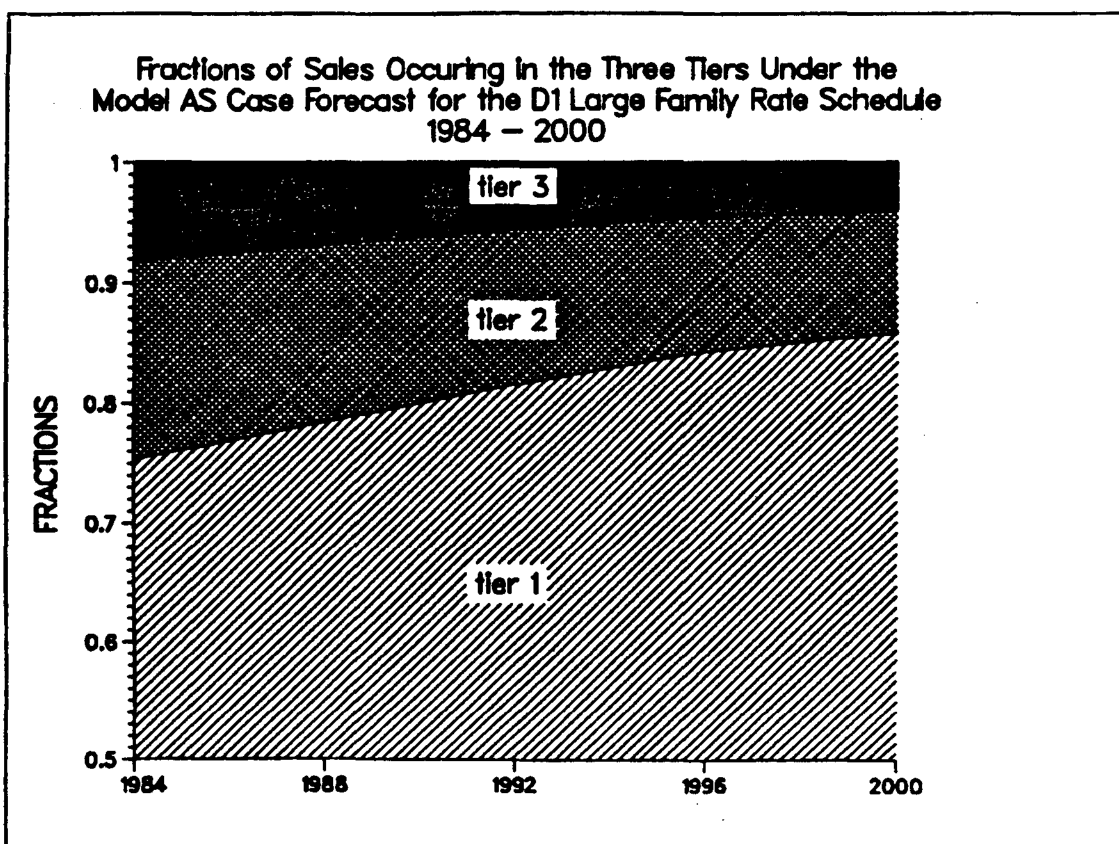
-- XBL 8512-4879 --

Figure 13



-- XBL 8512-4878 --

Figure 14



-- XBL 8512-4884 --

Figure 15

IV APPENDICES

Appendix 1

Fraction of Sales Going to Each Sector

(1982-83)

1983 (percent)

	Residential	Commercial	Industrial	Other
Jan	36	20	38	6
Feb	30	19	44	7
Mar	29	19	45	7
Apr	29	18	45	8
May	27	18	46	8
June	27	19	47	8
July	31	19	43	7
Aug	32	20	42	6
Sept	31	19	44	7
Oct	28	19	46	7
Nov	28	18	47	7
Dec	31	19	43	7
Total	30	19	44	7

1982 (percent)

	Residential	Commercial	Industrial	Other
Jan	37	20	37	6
Feb	33	20	41	6
Mar	31	19	43	7
Apr	30	19	44	6
May	28	19	47	7
June	28	19	46	7
July	30	20	44	7
Aug	31	20	43	6
Sept	30	20	44	6
Oct	30	20	44	6
Nov	31	20	43	7
Dec	35	20	43	6
Total	31	20	43	6

Appendix 2

PROGRAM TO GENERATE AN LDC USING THE NORMAL APPROXIMATION

This program uses the polynomial approximation to the cumulative normal found in HP1C *Stat Pack Handbook,* pp 66-67.

```
001'NAPROX
002 CLRG
003 CLST
004 8766
005 STO 01
006 3.1
007 STO 12
008 24
009 STO 04
010 TONE 1
011'PEAK GW = ?
012 PROMPT
013 STO 02
014 TONE 2
015'GWH OUT = ?
016 PROMPT
017 STO 03
018 RCL 01
019 /
020 RCL 02
021 /
022 STO 05
023 CHS
024 1
025 +
026 RCL 12
027 /
028 STO 03
029 20
030 STO 08
031 LBL 01
032 RCL 04
033 RCL 02
034 /
035 RCL 05
036 -
037 RCL 03
038 /
039 STO 06
040 X^2
041 2
042 /
043 CHS
044 E^X
045 2
046 PI
047 *
048 SQRT
049 1/X
050 *
051 ST0 07
052 RCL 06
053 ABS
054 0.2316419
055 *
056 1
057 +
058 1/X
059 STO 09
060 0.31938153
061 *
062 RCL 09
063 X^2
064 -0.356563782
065 *
066 +
067 RCL 09
068 3
069 Y^X
070 1.781477937
071 *
072 +
073 RCL 09
074 4
075 Y^X
076 -1.821255978
077 *
078 +
079 RCL 09
080 5
081 Y^X
082 1.330274429
083 *
084 +
085 RCL 07
086 *
087 STO 07
088 RCL 06
089 X<0?
090 XEQ A
091 RCL 01
092 RCL 07
093 *
094 1 E3
095 /
096 STO 10
097 8.5
098 -
1099 X>0?
100 GTO 01
101 RCL 11
102 X=0?
103 XEQ B
104 RCL 10
105 STO IND 08
106 1
107 ST+ 08
108 RCL 02
109 RCL 04
110 X>Y?
111 GTO 02
112 0.2
113 ST+ 04
114 GTO 01
115 LBL 02
116 BEEP
117'READY?
118 PROMPT
119 20
120 STO 08
121 LBL 03
122 FIX 1
123'LOAD =
124 ARCL 11
125 AVIEW
126 0.2
127 ST+ 11
128 TONE 1
129'KHRS =
130 ARCL IND 08
131 AVIEW
132 STOP
133 1
134 ST+ 08
135 RCL IND 08
136 X=0?
137 GTO 04
138 GTO 03
139 LBL A
140 RCL 07
141 CHS
142 1
143 +
144 STO 07
145 RTN
146 LBL B
147 RCL 04
148 STO 11
149 RTN
150 LBL 04
151 FIX 4
152'LF =
153 ARCL 05
154 AVIEW
155 STOP
156'SD =
157 ARCL 03
158 AVIEW
159 STOP
160'DONE
161 AVIEW
162 TONE 1
163 END
```

Appendix 3 (i)

Matrix of Examples of NAPPROX for a Hypothetical System with a Peak of 5 GW				
		r=		
		2	3	4
LF=	0.4	A	B	C
	0.53*	J	K	L
	0.6	D	E	F
	0.8	G	H	I
* uses a 10 kh year				

The sales, or sums under the curves can be derived as follows:

$$LF = \frac{average\ \ load\ \ (GW)}{peak\ \ load\ \ (GW)}$$

$$LF = \frac{\frac{sales\ \ (GWh)}{8766\ h}}{5\ GW}$$

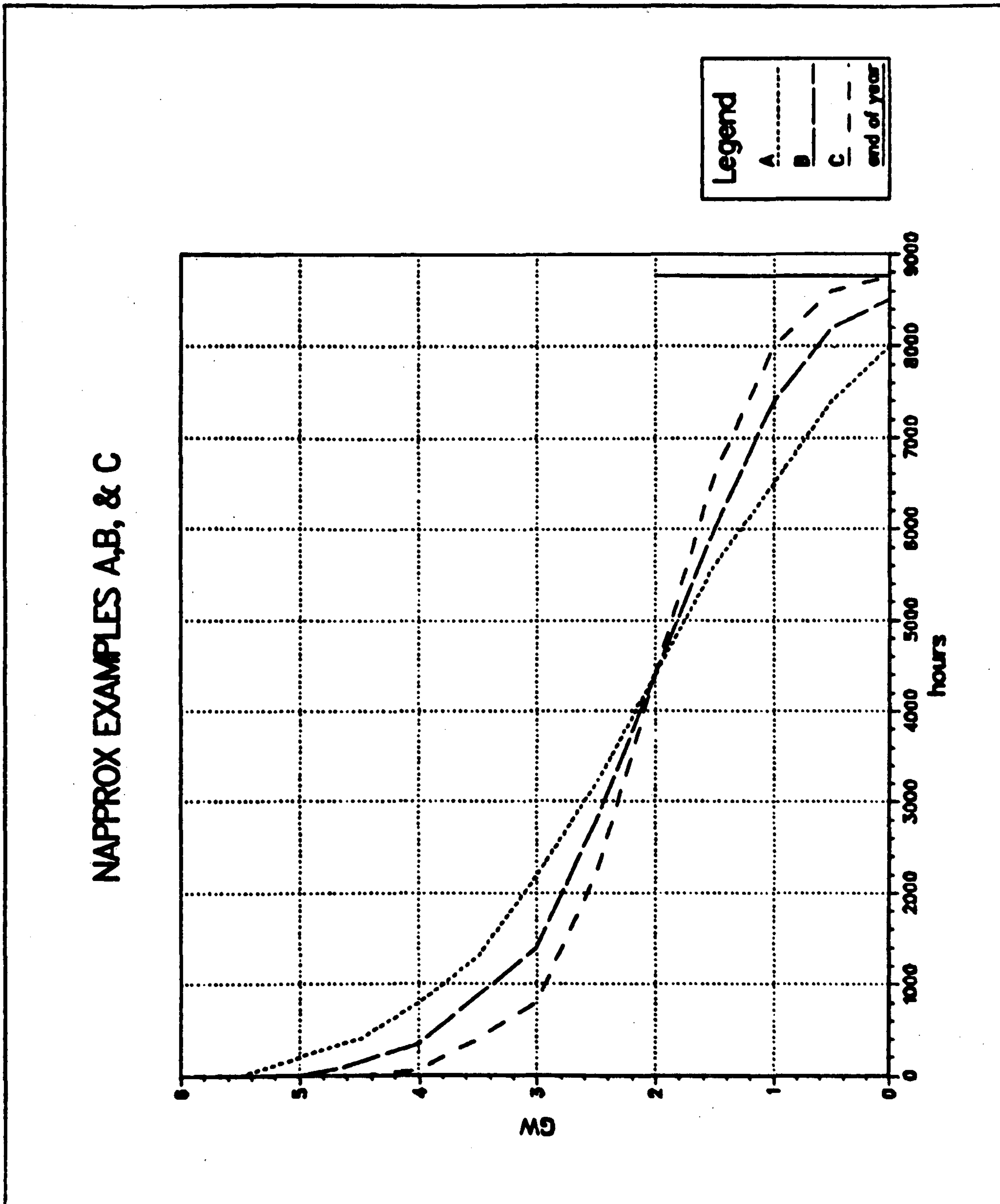
$$sales = 8766 \times 5 \times LF$$

$$sales = 43830 \times LF$$

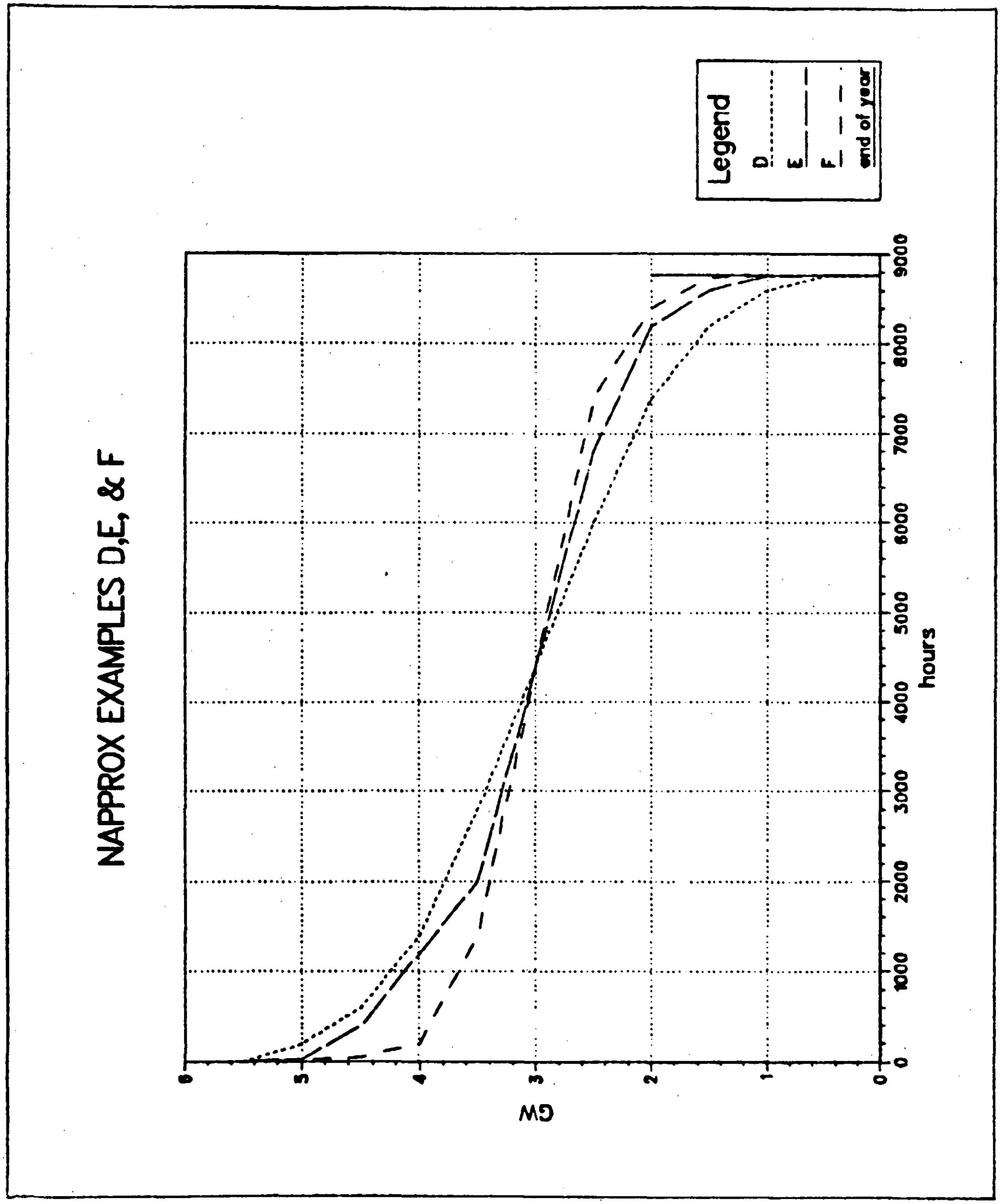
The sales for the various cases are as follows:

$$\begin{aligned} \text{A,B,C} &= 17\ 532\ \text{GWh} \\ \text{D,E,F} &= 26\ 298\ \text{GWh} \\ \text{G,H,I} &= 35\ 064\ \text{GWh} \\ \text{J,K,L} &= 26\ 298\ \text{GWh} \end{aligned}$$

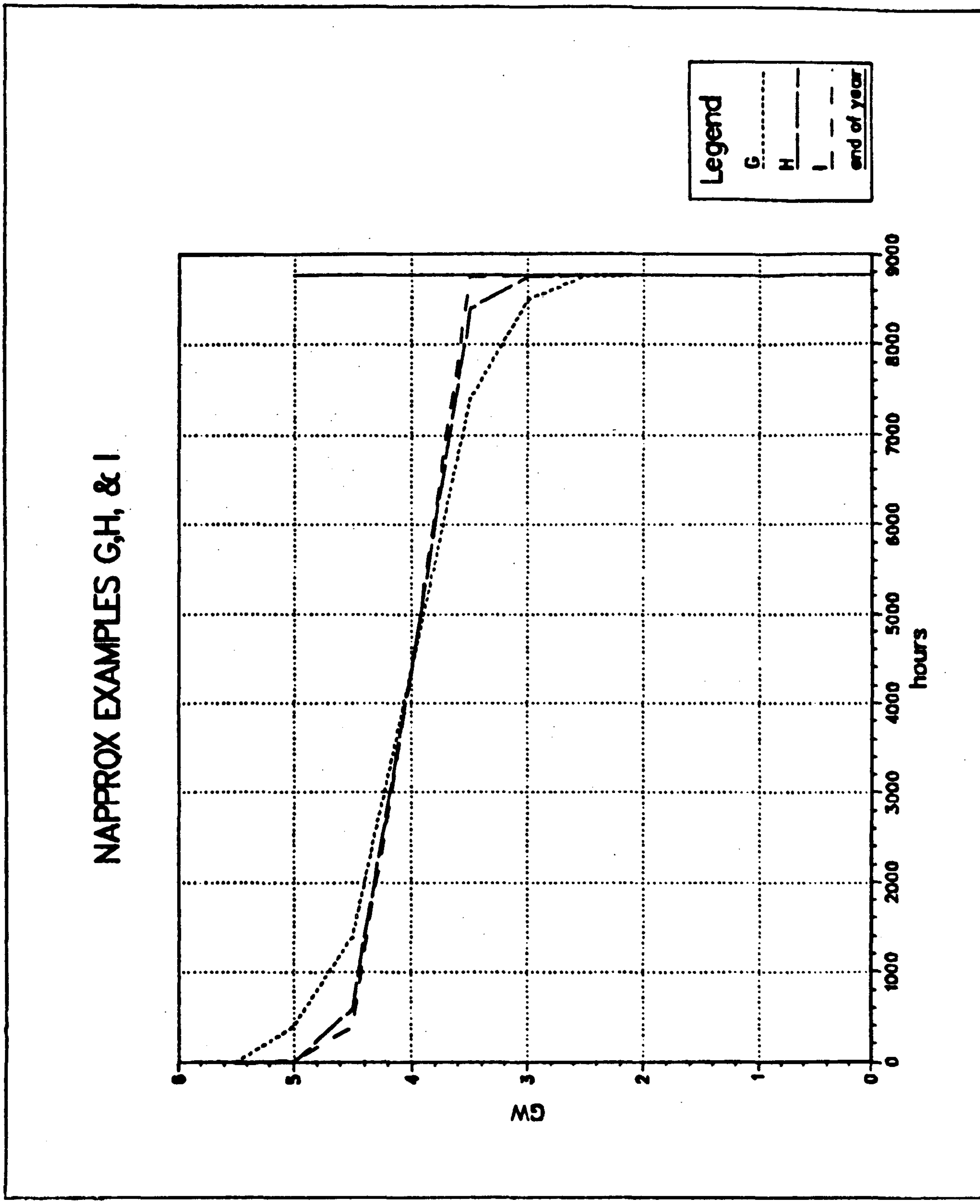
Appendix 3 (ii)



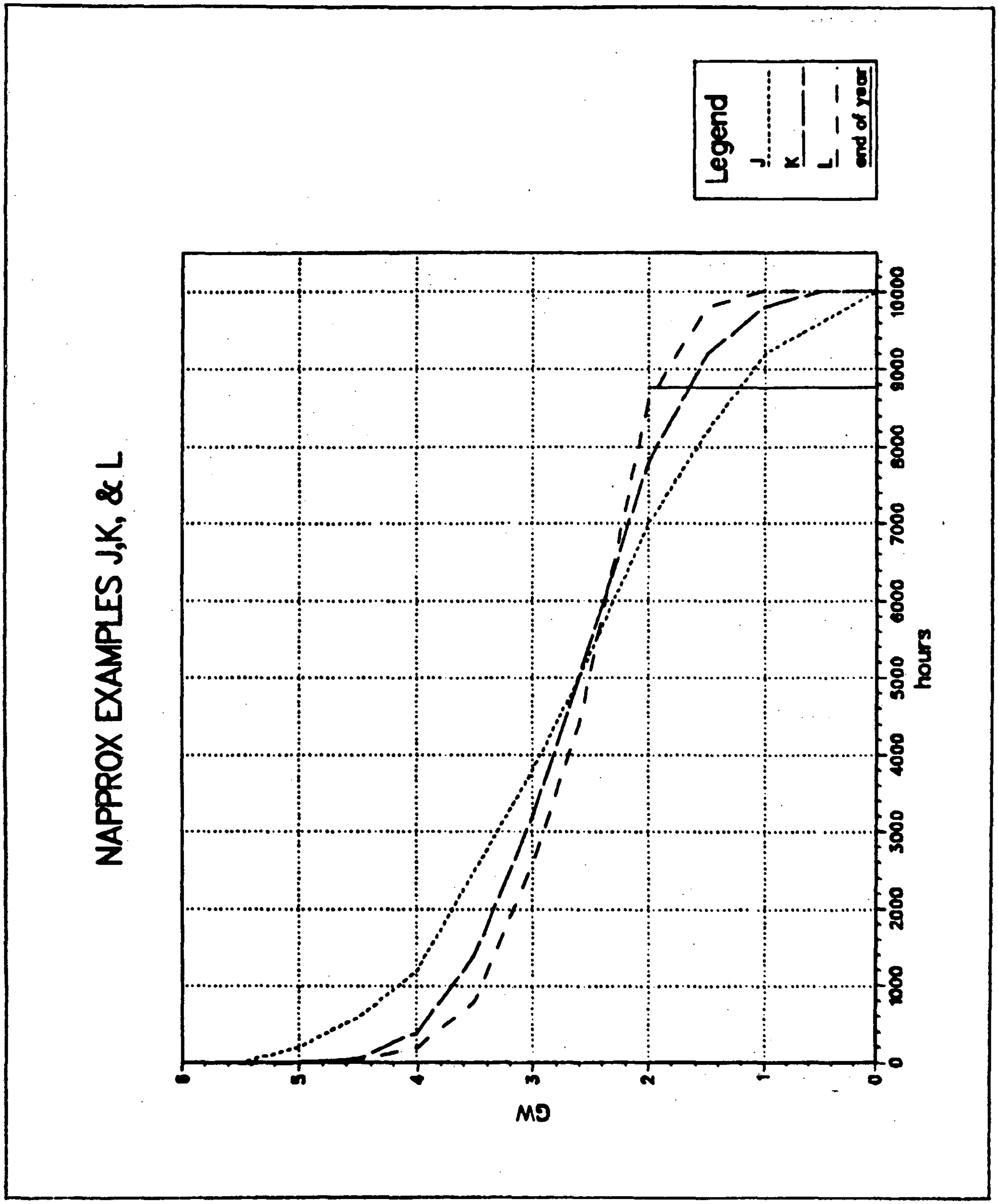
Appendix 3 (iii)



Appendix 3 (iv)

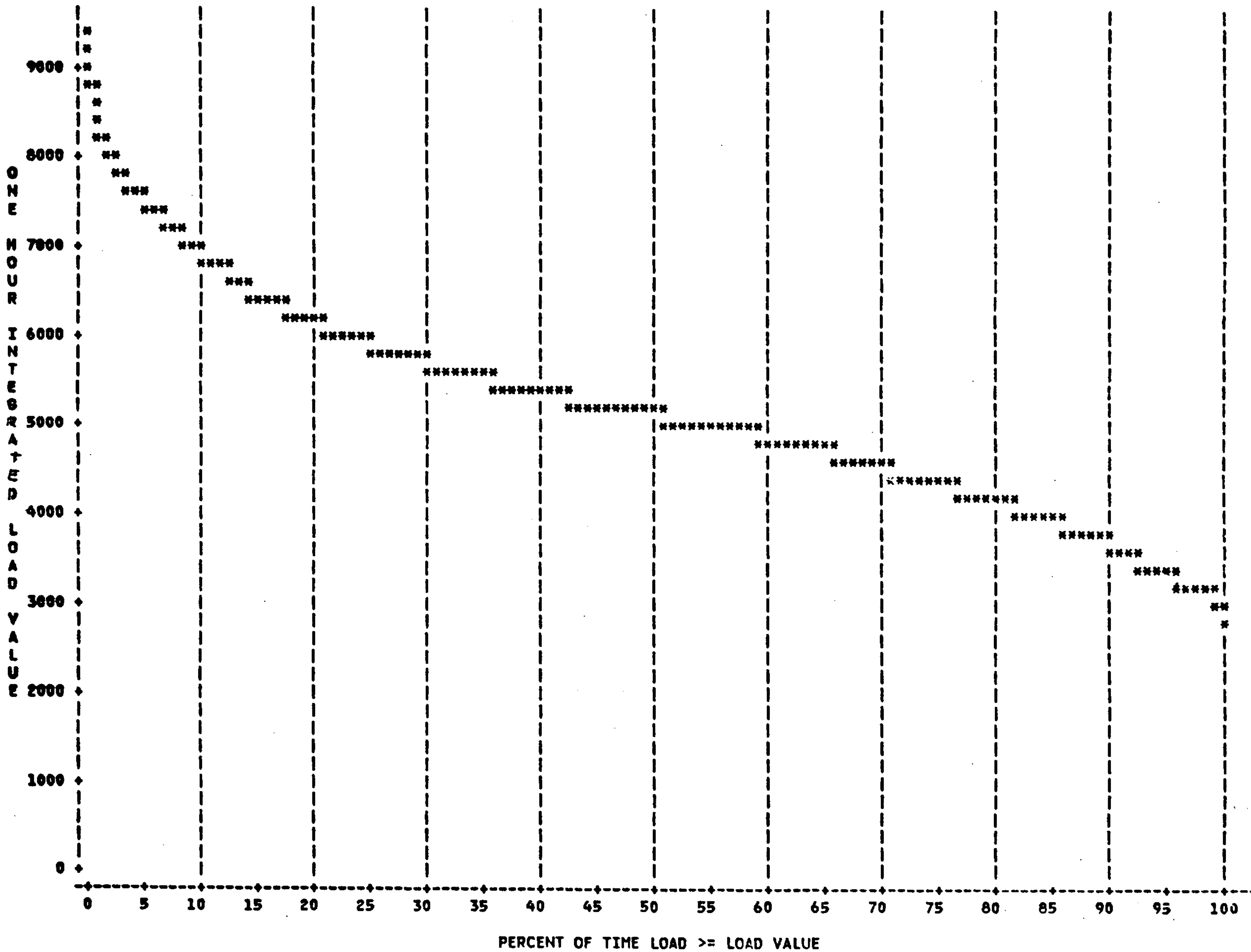


Appendix 3 (v)


NAPPROX EXAMPLES J,K, & L
Legend
J
K
L
end of year
hours
GW
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
0
1
2
3
4
5
6

YEAR=83

PLOT OF HLOAD*PERCENT SYMBOL USED IS *



NOTE: 8606 OBS HIDDEN

Appendix 4

Appendix 5 (i)

The following program runs on a HP41CV with sufficient storage modules, with SIZE 100. The main features of it are:

1. The main routine executes the subroutines A through F.
2. The user is prompted for only two data inputs, the peak of the system (at line 18) and the output of the system (at line 22), in GW and GWh respectively.
3. The parameters of the problem are input in subroutine B. The key ones are: hours of the year, and the parameters A through D.
4. The output is performed by subroutine E. The outputs are the percent of time the load is above the indicated level, the hours (x axis of Appendix 3), and the load (y axis of Appendix 3).

Appendix 5 (ii)

PROGRAM TO GENERATE AN LDC BY THE FINE METHOD

```
001'FINE
002 XEQ A
003 XEQ B
004 LBL 01
005 XEQ C
006 XEQ D
007 RCL 04
008 0.2
009 -
010 X=0?
011 GTO 02
012 GTO 01
013 LBL 02
014 XEQ E
015 XEQ F
016 LBL A
017 CLST
018 CLRG
019 TONE 1
020'PEAK GW = ?
021 PROMPT
022 STO 02
023 TONE 2
024'GWH OUT = ?
025 PROMPT
026 STO 03
027 RTN
028 LBL B
029 8766
030 STO 01
031 RCL 03
032 RCL 01
033 /
034 RCL 02
035 /
036 STO 03
037 1.0
038 STO 04
039 20
040 STO 05
041 RCL 03
042 4
043 *
044 3
045 /
046 0.5
047 -
048 STO 06
049 STO 11
050 1.194
050 STO 12
051 -12.83
052 STO 13
053 -6.0
054 STO 14
055 48.45
055 STO 15
056 1
057 RCL 11
058 -
059 STO 16
060 RCL 1
061 1
062 +
063 RCL 03
064 2
065 *
066 -
067 STO 17
068 1
069 RCL 03
070 -
071 STO 18
072 RTN
073 LBL C
074 RCL 03
075 RCL 04
076 0.5
077 -
078 STO 07
079 RCL 16
080 *
081 -
082 RCL 07
083 X^2
084 RCL 17
085 *
086 RCL 12
087 *
088 -
089 RCL 07
090 3
091 Y^X
092 RCL 18
093 *
094 RCL 13
095 *
096 -
097 RCL 07
098 4
099 Y^X
100 RCL 17
101 *
102 RCL 14
103 *
104 -
105 RCL 07
106 5
107 Y^X
108 RCL 18
109 *
110 RCL 15
111 *
112 -
113 STO IND 05
114 RTN
115 LBL D
116 0.02
117 ST- 04
118 1
119 ST+ 05
120 RTN
121 LBL E
122 1.0
123 STO 04
124 20
125 STO 05
126 BEEP
127'READY?
128 PROMPT
129 LBL 03
130 RCL 04
131 100
132 *
133 STO 06
134 CF 28
135 CF 29
136 FIX 0
137'%=
138 ARCL 06
139 AVIEW
140 RCL 04
141 RCL 01
142 *
143 STO 06
144'HRS=
145 ARCL 06
146 AVIEW
147 STOP
148 RCL 04
149 X=0?
150 GTO 04
151 RCL IND 05
152 RCL 02
153 *
154 STO 06
155 LBL 05
156 SF 28
157 SF 29
158 FIX 3
159'LOAD=
160 ARCL 06
161 AVIEW
162 STOP
163 ARCL 04
164 X=0?
165 RTN
166 XEQ D
167 GTO 03
168 LBL 04
169 RCL 02
170 STO 06
171 GTO 05
172 RTN
173 LBL F
174 TONE 9
175 DONE
176 AVIEW
177 STOP
178 END
```

Appendix 6

Assumptions On Tier Prices 1984-2000

D1

	p1	p2	p3
1984	0.0656	0.0994	0.1335
1988	0.0740	0.1130	0.1523
1992	0.0824	0.1265	0.1710
1996	0.0907	0.1401	0.1898
2000	0.0991	0.1536	0.2085
growth	2.61	2.76	2.83

allowances
families (1-2) k1=360, k2=630
families (>=3) k1=510, k2=810
no fixed charge

D1.3

	p1	p2	p3
1984	0.0530	0.0930	0.1800
1988	0.0597	0.1055	0.2025
1992	0.0665	0.1180	0.2250
1996	0.0733	0.1305	0.2475
2000	0.0800	0.1430	0.2700
growth	2.61	2.73	2.57

k1=300, k2=510

D2

	p1
1984	0.0652
1988	0.0736
1992	0.0820
1996	0.0904
2000	0.0987
growth	2.63

one tier

D5

year	p1	month ch.
1984	0.0510	1.65
1988	0.0550	1.71
1992	0.0591	1.78
1996	0.0631	1.84
2000	0.0671	1.90
growth	1.73	0.89

Appendix 7

Sales Projections for Deco
Base and Sensitivity Cases
(1976-200) (TWh)

	BASE	AS	CO	HP
1976	10.18			
1977	10.25			
1978	10.25			
1979	10.29			
1980	10.32			
1981	10.16			
1982	9.94			
1983	9.74			
1984	9.57	9.57	9	57
1988	9.33	9.25	9.32	9.31
1992	9.57	9.32	9.53	9.48
1996	10.01	9.61	9.97	9.87
2000	10.55	10.04	10.51	10.27

Case No. ________
Exhibit No. [illegible]
Line No. 11(L)
Page No. ELP-WP-26
Date 30 APR 83
Name FALLETICH

OGIVE CURVE FOR RATE CLASS & PERIOD:
BILL FREQ RATE 060 - LIFELINE 2 OR LESS
NOV81+DEC+FEB+MAR+APR82 -- WINTER OGIVE

11/22/82
16:15

	KWH	CUST	BAND MAX	OGIVE % UPC	OGIVE % CONSOL
1	78746	41204	10	.02676	.02648
2	185275	11941	20	.05351	.05284
3	314384	12290	30	.08027	.07910
4	488241	13725	40	.10703	.10526
5	716996	15717	50	.13379	.13129
6	1033976	18594	60	.16054	.15718
7	1499037	22829	70	.18730	.18290
8	1903179	25166	80	.21406	.20841
9	2554877	29843	90	.24082	.23370
10	3049499	31892	100	.26757	.25872
11	3746536	35485	110	.29433	.28346
12	4418709	38222	120	.32109	.30790
13	5201276	41433	130	.34785	.33200
14	6162356	45471	140	.37460	.35573
15	6981848	47961	150	.40136	.37907
16	7934804	51007	160	.42812	.40199
17	8670678	52389	170	.45487	.42448
18	9932701	56586	180	.48163	.44651
19	10653252	57398	190	.50839	.46807
20	12725410	65069	200	.53515	.48911
21	16390725	79737	210	.56190	.50954
22	14381861	66693	220	.58866	.52936
23	15478867	68674	230	.61542	.54859
24	15354630	65222	240	.64218	.56726
25	16041788	65347	250	.66893	.58538
26	16452713	64396	260	.69569	.60295
27	17310205	65188	270	.72245	.61999
28	17545077	63674	280	.74920	.63647
29	18433532	64565	290	.77596	.65242
30	18851788	63793	300	.80272	.66782
31	19358183	63353	310	.82948	.68269
32	19561955	61997	320	.85623	.69703
33	20256876	62223	330	.88299	.71084
34	20539842	61221	340	.90975	.72414
35	20763748	60102	350	.93651	.73692
36	21323961	59982	360	.96326	.74919
37	20889729	57158	370	.99002	.76097
38	21386885	56970	380	1.01678	.77226
39	21591175	56012	390	1.04354	.78308
40	21923745	55421	400	1.07029	.79343
41	21176078	52213	410	1.09705	.80333
42	21470874	51678	420	1.12381	.81279
43	21490629	50513	430	1.15056	.82181
44	21143952	48558	440	1.17732	.83042
45	21491775	48245	450	1.20408	.83861
46	20684434	45418	460	1.23084	.84641
47	20948680	45004	470	1.25759	.85383
48	20088084	42243	480	1.28435	.86089

49	20313667	41838	490	1.31111	.86759
50	19138149	38622	500	1.33787	.87[illegible]
51	19519876	38612	510	1.36462	.8[illegible]998
52	18275496	35454	520	1.39138	.88569
53	18299558	34831	530	1.41814	.89111
54	18169374	33933	540	1.44489	.89624
55	16937110	31052	550	1.47165	.90109
56	16871739	30374	560	1.49841	.90569
57	15944336	28195	570	1.52517	.91004
58	15894897	27619	580	1.55192	.91415
59	14806551	25290	590	1.57868	.91804
60	14835705	24915	600	1.60544	.92171
61	13943695	23029	610	1.63220	.92519
62	13322245	21649	620	1.65895	.92847
63	13349371	21343	630	1.68571	.93157
64	12138357	19100	640	1.71247	.93450
65	11960312	18530	650	1.73923	.93727
66	11130235	16981	660	1.76598	.93990
67	11004070	16535	670	1.79274	.94238
68	10280731	15219	680	1.81950	.94472
69	9[illegible]99381	14588	690	1.84625	.94694
70	9385691	13495	700	1.87301	.94905
71	89[illegible]0635	12645	710	1.89977	.95104
72	89[illegible]5065	12475	720	1.92653	.95292
73	7926877	10927	730	1.95328	.95471
74	7844146	10666	740	1.98004	.95640
75	7667708	10286	750	2.00680	.95800
76	7173417	9495	760	2.03356	.95953
77	6516923	8513	770	2.06031	.96097
78	6538146	8432	780	2.08707	.96235
79	6183805	7873	790	2.11383	.96365
80	5871978	7381	800	2.14058	.96489
81	5728445	7112	810	2.16734	.96607
82	5278616	6473	820	2.19410	.96719
83	5079531	6154	830	2.22086	.96826
84	4978760	5959	840	2.24761	.96928
85	4595943	5436	850	2.27437	.97025
86	4333960	5067	860	2.30113	.97117
87	4297713	4966	870	2.32789	.97206
88	3886471	4439	880	2.35464	.97290
89	3930964	4439	890	2.38140	.97370
90	3577785	3995	900	2.40816	.97447
91	3441556	3801	910	2.43492	.97521
92	3379274	3692	920	2.46167	.97592
93	3176889	3433	930	2.48843	.97659
94	3059682	3271	940	2.51519	.97724
95	2893219	3060	950	2.54194	.97786
96	2794263	2924	960	2.56870	.97845
97	2623513	2717	970	2.59546	.97902
98	2597757	2663	980	2.62222	.97957
99	2413455	2449	990	2.64897	.98009
100	2326489	2337	1000	2.67573	.98060
101	10207091	9966	1050	2.80952	.98286
102	8305613	7728	1100	2.94330	.98475
103	6999097	6226	1150	3.07709	.98634
104	5763156	4907	1200	3.21088	.98770
105	4947374	4040	1250	3.34466	.98888

107	3734129	2819	1350	3.61224	99079
108	3334627	2426	1400	3.74602	99156
109	2930391	2056	1450	3.87981	.99225
110	2578127	1748	1500	4.01360	.99286
111	2351174	1542	1550	4.14738	.99339
112	1998346	1270	1600	4.28117	.99387
113	1757198	1081	1650	4.41496	.99430
114	1610798	962	1700	4.54874	.99468
115	1459734	846	1750	4.68253	.99503
116	1231248	694	1800	4.81632	.99534
117	1247189	683	1850	4.95010	.99562
118	1059539	565	1900	5.08389	.99588
119	980168	509	1950	5.21768	.99612
120	770112	390	2000	5.35146	.99633
121	2813386	1345	2200	5.88661	.99705
122	2132624	929	2400	6.42175	.99757
123	1618143	649	2600	6.95690	.99796
124	1262436	468	2800	7.49205	.99826
125	945087	326	3000	8.02719	.99850
126	793936	257	3200	8.56234	.99868
127	600580	182	3400	9.09748	.99883
128	441347	126	3600	9.63263	.99895
129	407570	110	3800	10.16778	.99906
130	253760	65	4000	10.70292	.99914
131	290707	71	4200	11.23807	.99922
132	331458	77	4400	11.77322	.99928
133	161803	36	4600	12.30836	.99934
134	239202	51	4800	12.84351	.99938
135	162040	33	5000	13.37865	.99942
136	148472	29	5200	13.91380	.99946
137	132543	25	5400	14.44895	.99949
138	110064	20	5600	14.98409	.99952
139	96892	17	5800	15.51924	.99954
140	82801	14	6000	16.05438	.99956
141	309615	48	7000	18.73012	.99964
142	134372	18	8000	21.40585	.99968
143	93256	11	9000	24.08158	.99972
144	94742	10	10000	26.75731	.99975
145	126392	12	12000	32.10877	.99978
146	64006	5	14000	37.46023	.99980
147	0	0	16000	42.81169	.99982
148	0	0	18000	48.16315	.99984
149	39721	2	20000	53.51462	.99986
150	348962	9	60000	160.54385	1.00000

TOTALS FROM DATA USED FOR OGIVE

KWH TOTAL	1185772509
CUST TOTAL	3172808
USE PER CUST	374

Appendix 9 (i)

Steps to Subdivide Sales

SCHEDULES	SALES
D1 (1-2) summer	$= S^s$
D1 (1-2) winter	$= W^s$
D1 (>= 3) summer	$= S^l$
D1 (>= 3) winter	$= W^l$
D2 space heat	$= P$
D1.3 seniors	$= N$
D5 water heat	$= H$
all residential sales	$= SALES$
all sales in month i	$= TOTAL_i$

(i) seniors are 5% of all sales by assumption:

$$N = (0.05)\,(SALES\,)$$

(ii) water heating is reduced by $\frac{1}{3}$:

$$H = \frac{2}{3}\sum_i H_i \qquad\qquad i = Jan\,,...,Dec$$

(iii) space heat is inflated for both small and large families:

$$P^s = \frac{\sum_j P_j^s}{0.95} \qquad\qquad j = Nov.\,,...,May$$

$$P^l = \frac{\sum_j P_j^l}{0.60}$$

(iv) totals for the D1 small and large families are overall totals minus the above schedules; all seniors are taken from the large families:

Appendix 9 (ii)

$$T^s = \sum_i TOTAL_i^s - P^s - H^s$$

$$T^l = \sum_i TOTAL_i^l - P^l - H^l - N$$

(v) summer totals are inflated versions of the same formula, except that there is no space heat:

$$S^s = 1.05 \left[\sum_k TOTAL_k^s - \frac{2}{3} \sum_k H_k^s \right] \qquad k = June ,....,Oct$$

$$S^l = 1.05 \left[\sum_k TOTAL_k^l - \frac{2}{3} \sum_k H_k^l - \frac{5}{12} N \right]$$

(vi) winter is the difference between the totals and summer:

$$W^s = T^s - S^s$$
$$W^l = T^l - S^l$$

Appendix 10 (i)

RAW MODEL OUTPUT
(BASE CASE)

Year	Total Resident. Sales	Small Families Total	W.H.	S.H.	Summer	S.WH	Large Families Total	W.H.	S.H.	Summer	S.WH
1982	9943.2	3784.1	304.7	160.7	1483.1	120.8	6159.2	534.0	134.4	2449.5	196.5
1983	9735.3	3735.7	276.6	167.9	1460.2	109.6	5999.3	482.8	139.0	2382.5	177.7
1984	9565.7	3704.7	249.5	177.5	1440.0	98.8	5860.9	433.6	144.8	2324.6	159.5
1988	9334.2	3810.4	167.5	319.0	1434.6	66.4	5524.2	279.7	199.4	2168.6	103.0
1992	9568.3	4187.3	169.7	626.4	1469.4	67.2	5381.1	257.7	298.2	2067.2	94.8
1996	10012.8	4660.8	239.3	958.7	1532.2	94.8	5351.7	335.0	406.3	2003.0	123.3
2000	10547.0	5152.9	333.6	1249.8	1619.6	132.2	5394.7	440.7	487.2	1979.0	162.2

SALES BY RATE SCHEDULE
(BASE CASE - GWH)

	D1				D2	D3	D5		D1	
	families 1-2		families => 3				I		Total	Total
Year	summer	winter	summer	winter	Space Heat	Seniors (N.S.H)	Water Heating	Total Sales	Small Family	Large Family
1982	1473	1939	2217	2865	393	497	559	9943	3412	5082
	(1391)*	(1974)	(1997)	(2866)	(350)	(469)	(533)	(9924)	(3365)	(4863)
1983	1456	1918	2164	2795	408	487	506	9735	3375	4959
	(1419)	(1864)	(2107)	(2803)	(486)	(476)	(532)	(10061)	(3283)	(4911)
1984	1447	1904	2120	2732	428	478	455	9566	3352	4852
1988	1460	1903	2001	2538	668	687	298	9335	3363	4539
1992	1496	1919	1895	2339	1156	478	285	9568	3415	4234
1996	1542	1950	1798	2153	1686	501	383	10013	3492	3951
2000	1608	2007	1734	2028	2128	527	516	10548	3615	3762

*Actual DECO sales in parentheses.

Appendix 10 (ii)

REVENUE PROJECTION
BASE CASE -- D1(1-2) SUMMER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1984	758	1447	350	612	0.7272	0.1817	0.0910	112.754	382	29.75
1988	792	1460	362	634	0.7415	0.1746	0.0839	127.569	369	32.21
1992	829	1496	370	647	0.7502	0.1701	0.0797	145.060	361	35.00
1996	866	1542	745	656	0.7555	0.1672	0.0773	164.405	356	37.97
2000	902	1608	375	656	0.7555	0.1675	0.0775	187.661	357	41.61

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUE PROJECTION
BASE CASE -- D1(1-2) WINTER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1984	740	1904	366	641	0.7566	0.1782	0.0652	144.800	368	27.95
1988	762	1903	377	660	0.7693	0.1707	0.0600	162.430	357	30.45
1992	771	1919	379	663	0.7707	0.1698	0.0594	182.603	356	33.83
1996	776	1950	375	656	0.7667	0.1723	0.0611	205.258	359	37.79
2000	782	2007	367	643	0.7577	0.1775	0.0648	232.533	367	42.48

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

Appendix 10 (iii)

REVENUE PROJECTION
BASE CASE -- D1(=>3) SUMMER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1984	727	2120	498	792	0.7542	0.1636	0.0822	162.628	583	44.74
1988	726	2001	527	838	0.7799	0.1496	0.0704	170.789	551	47.05
1992	724	1895	555	882	0.8024	0.1366	0.0611	177.814	523	49.12
1996	722	1798	584	927	0.8228	.01240	0.0532	183.567	498	50.85
2000	718	1734	602	956	0.8384	0.1163	0.0488	192.097	483	53.51

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUE PROJECTION
BASE CASE -- D1(=>3) WINTER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1984	710	2732	467	741	0.8038	0.1520	0.0441	201.445	550	40.53
1988	698	2538	494	784	0.8218	0.1324	0.0358	208.035	519	42.58
1992	674	2339	517	822	0.8508	0.1190	0.0302	244.264	496	44.78
1996	647	2153	540	857	0.8680	0.1059	0.0260	212.101	475	46.83
2000	623	2028	552	876	0.8766	0.0993	0.0241	217.306	465	49.83

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

Appendix 10 (iv)

REVENUE PROJECTION
BASE CASE -- D2

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1984	35	428						27.906	1747	113.90
1988	58	668						49.165	1645	121.10
1992	109	1156						94.792	1515	124.24
1996	165	1686						152.414	1460	131.96
2000	215	2128						210.034	1414	139.56

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUE PROJECTION
BASE CASE -- D1.3 SENIORS

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1983	147	487	288	490	0.8418	0.1325	0.0256	29.978	276	16.99
1984	150	478	299	509	0.8569	0.1212	0.0219	28.980	266	16.10
1988	158	467	323	549	0.8839	0.1...	0.0161	31.134	246	16.42
1992	165	478	329	560	0.8906	0.0946	0.0148	35.237	241	17.80
1996	501	329	560	0.8907	0.0944	0.0148	40.723	241	19.62	
2000	180	527	326	554	0.8870	0.0975	0.0155	46.974	244	21.73

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

Appendix 10 (v)

REVENUE PROJECTION
BASE CASE -- D5

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1984	92	455						23.357	412	21.16
1988	61	298						16.494	407	22.53
1992	61	285						16.952	389	23.16
1996	83	383						24.320	385	24.42
2000	113	516						34.838	381	25.69

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUES BY RATE SCHEDULE
(BASE CASE - MILLIONS OF 1984 $)

Year	D1 (1-2) summer	D1 (1-2) winter	D1 (=>3) summer	D1 (=>3) winter	D2	D1.3	D5	Total Revenue	Total Sales (GWh)	Average Price ($/kWh)
1984	112.754	144.800	162.628	201.445	27.906	28.980	23.357	701.870	9566	0.0734
1988	127.569	162.430	170.789	208.035	49.165	31.134	16.494	765.616	9335	0.0820
1992	145.060	182.603	177.814	211.264	94.792	35.237	16.952	863.722	9568	0.0903
1996	164.405	205.258	183.567	212.101	152.414	40.723	24.320	982.788	10013	0.0982
2000	187.661	232.533	192.097	217.306	210.034	46.974	34.838	1121.446	10548	0.1063

Appendix 11 (i)

REVENUE PROJECTION
AS CASE D1 (small) WINTER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1988	762	1889	377	660	0.7690	0.1709	0.0601	161.264	354	30.23
1992	771	1879	384	671	0.7762	0.1665	0.0573	178.168	348	33.01
1996	776	1885	385	674	0.7775	0.1657	0.0568	197.005	347	36.27
2000	782	1921	381	666	0.7729	0.1685	0.0587	220.334	351	40.25

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUE PROJECTION
AS CASE D1 (large) SUMMER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1988	726	1978	533	847	0.7850	0.1467	0.0682	168.260	545	46.35
1992	724	1834	574	911	0.8160	0.1283	0.0558	170.557	507	47.12
1996	722	1706	615	977	0.8430	0.110	0.0460	171.859	473	47.61
2000	718	1625	642	1020	0.8585	0.1007	0.0409	177.218	453	49.36

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

Appendix 11 (ii)

REVENUE PROJECTION
AS CASE - D1 (large) WINTER

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1988	698	2520	497	790	0.8336	0.1316	0.0349	206.291	516	42.22
1992	674	2287	529	841	0.8602	0.1119	0.0279	205.384	485	43.53
1996	647	2070	561	891	0.8830	0.0942	0.0228	202.055	457	44.61
2000	623	1992	582	924	0.8959	0.0840	0.0201	203.504	441	441

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUE PROJECTION
D2 - SPACE HEAT

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1988	58	664						48.870	1635	120.37
1992	109	1144						93.808	1499	122.95
1996	165	1167						150.697	1443	130.47
2000	215	2103						207.566	1397	137.92

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

Appendix 11 (iii)

REVENUE PROJECTION
AS CASE - D1.3 SENIORS

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1988	158	462	326	555	0.8875	0.0982	0.0143	30.646	244	16.16
1992	165	466	388	574	0.8987	0.0879	0.0134	34.087	235	17.22
1996	173	481	343	583	0.9036	0.0800	0.0164	38.834	232	18.71
2000	180	502	342	582	0.9027	0.0846	0.0127	44.050	232	20.39

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

REVENUE PROJECTON
D5 - WATER HEAT

Year	(1) Number of Customers (x1000)	(2) Sales (GWh)	(3) K_1^*	(4) K_2^*	(5) f_1^*	(6) f_2^*	(7) f_3^*	(8) Total Revenue (1984$) x 10^6	(9) Average Use (kWh/mo)	(10) Average Bill ($/mo)
1988	61	291						14.942	398	20.41
1992	61	258						15.356	352	20.98
1996	83	333						21.165	334	21.25
2000	113	447						30.208	330	22.28

K_1^*, K_2^* are the adjusted tier boundaries
f_1^*, f_2^*, f_3^* are the adjusted tier fractions

Appendix 11 (iv)

REVENUES BY RATE SCHEDULE
(AS CASE - *E6 1984 $)

	D1 fam.(1-2)		D1 fam.(≥3)		D2 space heat	D1.3 seniors	D5 I water heat	Total Rev.	Total Sales	Av.Price ($/kWh)
1984										
1988	125.687	161.264	168.260	206.291	48.870	30.646	14.942	755.960	9247	0.0818
1992	139.316	178.168	170.557	205.384	93.808	34.087	15.356	836.676	9317	0.0898
1996	154.886	197.005	171.859	202.055	150.697	38.834	21.165	936.501	9613	0.0974
2000	174.747	220.334	177.218	203.504	207.566	44.050	30.208	1057.627	10039	0.1054

Appendix 12

DECO's Residential Sector
(1983)

Schedule	Sub-Class	# Cust.	Percent	Sales (GWh)	Percent
D1	families (1-2)	738 060	43.52	3 282.830	32.63
	families (>=3)	701 950	41.39	4 910.730	48.81
	total	1 440 010	84.91	8 193.560	81.44
D1.A	farms	2 210	0.13	69.400	0.69
D1.1	interr. AC	6 260	0.37	14.430	0.14
D1.3	seniors				
	N.S.H.	144 880	8.54	476.320	4.73
	S.H.	2 560	0.15	20.660	0.21
	total	147 440	8.69	496.980	4.94
D1.4	T.O.D.	3 350	0.20	66.910	0.67
D2	space heat				
	families (1-2)	18 300	1.08	202.160	2.01
	families (>=3)	16 140	0.95	283.560	2.82
	total	34 440	2.03	485.720	4.83
D5	I	106 350	6.27	531.690	5.28
	II	68 480	4.04	195.980	1.95
	III	970	0.06	6.330	0.06
	total	175 800	10.37	734.000	7.29

total meters = 1 809 510, total customers = 1 695 930, total sales = 10 061

Appendix 13

Assumptions on Base Case Numbers of Customers by Rate Schedule (thousands)

	D1				D2	D1.3	D5	total
	Summer		Winter					
	(1-2)	(>=3)	(1-2)	(>=3)				
1983	(738)	(702)			(34)	(147)	(106)	
1984	758	727	740	710	35	150	92	1 635
1988	792	726	762	698	58	158	61	1 677
1992	829	724	771	674	109	165	61	1 719
1996	866	722	776	647	165	173	83	1 761
2000	902	718	782	623	215	180	113	1 800

- actual numbers in parentheses
- share of small families grows from 51 to 56 %
- share of seniors grows from 9 to 10 %
- summer/winter division of D1 same as total

Appendix 14 (i)

Assumed Appliance Efficiencies (BS case)					
year	1984	1988	1992	1996	2000
space heating (AFUE)*					
electric	100	100	100	100	100
gas	77	85	87	88	89
oil	86	88	89	90	90
air conditioning					
room (EER)	7.4	7.7	7.9	8.1	8.3
central (SEER)	7.0	7.4	7.8	8.1	8.5
water heater (percent)					
electric	82	83	83	83	84
gas	62	71	74	75	75
refrigerators (ft^3/kWh/d)	7.1	7.4	7.7	8.0	8.3
freezers(ft^3/kWh/d)	13	14	14	15	16
ranges (percent)					
electric	44	44	45	45	46
gas	26	32	34	35	35

* annual fuel use efficiency

Appendix 14 (ii)

Assumed Appliance Efficiencies (AS case)					
year	1984	1988	1992	1996	2000
space heating (AFUE)*					
electric	100	100	100	100	100
gas	77	86	87	88	89
oil	86	91	91	91	91
air conditioning					
room (EER)	7.4	9.0	9.0	9.1	9.1
central (SEER)	7.0	8.5	8.6	8.7	8.8
water heater (percent)					
electric	82	93	93	93	93
gas	62	82	82	82	82
refrigerators (ft^3/kWh/d)	7.1	11	11	11	11
freezers(ft^3/kWh/d)	13	22	22	22	22
ranges (percent)					
electric	44	45	45	46	46
gas	26	32	34	35	35

* annual fuel use efficiency

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