MASTER

REPORT ON THE
REGIONAL AND SYSTEM TYPE DISAGGREGATION
OF THE SINGLE FAMILY DWELLING
SPACE HEAT ENERGY DEMAND SECTOR

THOMAS J. MUENCH, MYRNA H. WOODERS, AND RICHARD MCLEAN

August 1976

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This study is an outgrowth of a program sponsored by the U.S. Energy Research and Development Administration to develop and apply an interfuel substitution model to national energy policy analysis. In BNL Report SEAG-1, "1969 and 1985 Validation of the BNL Energy System Optimization Model" it was shown that this model, BESOM, could be used to estimate price elasticities of demand for energy. This capability is enriched in this study by disaggregating demand by region and by type of end-use capital equipment and also by reformulating the model into a dynamic, multiple time period framework.

This work would not have been possible without William Marcuse's original price elasticity studies with BESOM, the computer programming assistance of Yasuku Sanborn, the project supervision by Raymond Tessmer, and the data and computer facilities of Brookhaven National Laboratory.

Abstract

Two models are developed which can estimate derived fuel demands in single family dwellings, given fixed final demand for space heat by states. One is an extension of a single period linear programming model of the nation's energy system, the Brookhaven Energy System Optimization Model. In it the demand for single family space heat is disaggregated by state and type of home heating system. The other is a multiple period dynamic programming model of single family space heat demand, also disaggregated by state and type of system. Preliminary results for each model are presented and compared.

Table of Contents

	Page
I. Purpose of the Project.....	1
II. General Modelling Strategy.....	1
III. Static Model, Addition to BESOM	
A. Description of the Disaggregation of the Space Heat Category in BESOM.....	2
B. Preliminary Results.....	4
IV. Dynamic Model, CURVE	
A. General Description of CURVE.....	6
B. Preliminary Results.....	10
V. Conclusions.....	20
VI. Suggestions for Further Research.....	21
Appendix A. Technical Description of Program CURVE	
I. Output of Calculation.....	25
II. Behavioral Assumptions.....	25
III. Method of Calculation.....	26
IV. Flow of Program.....	28
V. Input Data.....	32
VI. Output.....	32
VII. Curve Variables - Definitions and Units by Common Block.....	41
Appendix B. Data Construction	
I. System Size, Efficiency, and Cost Estimates...	45
II. Fuel Price Data.....	50
III. Climatic Data.....	51
IV. Housing Stock and Projections.....	51
V. Existing Fuel Systems.....	52
VI. CURVE and BESOM Data by State.....	53
References.....	56

List of Figures

	Page
Figure 1. Demand for Oil as a Function of the Price of Gas (BESOM).....	7
Figure 2. Demands for Oil, Gas, and Electricity as a Function of the Price of Oil (BESOM).....	8
Figure 3. Demand for Gas as a Function of the Price of Gas (Curve).....	11
Figure 4. Demand for Oil as a Function of the Price of Gas (Curve).....	12
Figure 5. Demand for Electricity as a Function of the Price of Gas (Curve).....	13
Figure 6. Demand for Gas as a Function of the Price of Oil (Curve).....	13
Figure 7. Demand for Oil as a Function of the Price of Oil (Curve).....	14
Figure 8. Demand for Electricity as a Function of the Price of Oil (Curve).....	15
Figure 9. Demand for Gas as a Function of the Price of Electricity (Curve).....	16
Figure 10. Demand for Oil as a Function of the Price of Electricity (Curve).....	17
Figure 11. Demand for Electricity as a Function of the Price of Electricity (Curve).....	18

List of Tables

		Page
Table I	Annual Fuel Use as a Function of the Price of Gas (BESOM).....	5
Table II	Fuel Use by State as a Function of the Price of Gas (BESOM).....	9
Table III	Fuel Use by States in 1935 as a Function of the Price of Gas (CURVE).....	19
Table IV	Global Flow of Program CURVE, Spot Version.....	29
Table V	Listing of Program CURVE (Spot version)...	33
Table VI	Standard Output (SPOT Version).....	40
Table VII	Standard Output (FLOOD Version).....	42
Table VIII	Investment Cost in \$/Design 10^3 Btu/hr of Output.....	48
Table IX	Operating and Maintenance as a Percentage of Capital Costs.....	48
Table X	Annual Amortized System Cost for BESOM....	48
Table XI	Matrices (BC and BOM) of Unit Capital Costs for CURVE.....	49
Table XII	State Specific Data for BESOM.....	54
Table XIII	State Specific Data for CURVE.....	55

I. PURPOSE OF THE PROJECT

The purpose of the project is to determine if "reasonably smooth" demand curves can be calculated for heating fuels (gas, oil, and electricity) used in single family dwellings. Note that demand here means derived demand, given a fixed final demand for space heat in energy terms. Equivalently, the demand curves taken together trace out a technological iso-quant in the 3-dimensional fuel space.

"Reasonably smooth" must be understood in the context of a linear programming model such as BESOM [3]. In such a model, demand curves are step functions, with local slopes of either zero or infinity (and corresponding elasticities). The question is, does regional disaggregation give rise to national demand curves with many small steps instead of a small number of large steps. If such "smoothing" can be done, the demand curves can be approximated by a small number of segments of functions of a simple form such as linear or log linear.

The main emphasis in the project is on a methodology of doing the disaggregation. Therefore, the numerical data used is necessarily a crude approximation.

In addition, the models developed and the preliminary results are expected to shed light on the following aspects of national heating fuel demand:

- a) how the geographical distribution of fuel use changes with price,
- b) the relative importance of climatic differences and fuel price differences between regions;
- c) predictions of geographical penetration of new technologies such as the heat pump;
- d) the dependence of demand on rates of price change, for both fuel and fixed investment, due to technological change and increased scarcity; and
- e) short run versus long run effects due to the conversion costs for systems in existing dwelling units.

II. GENERAL MODELLING STRATEGY

The general strategy was to develop two models, one static but with general equilibrium properties, and the other dynamic but with partial equilibrium properties.

The static model consists of disaggregating the space heat activity of BESOM, Brookhaven Energy System Optimization Model. This model takes all end-use demands for energy as given and imposes various constraints. In addition, BESOM allows instantaneous flexibility of the capital stock. In this sense it is a long run model; however, the demands and constraints are those appropriate to the year 1985. It is a "general equilibrium"

model in the sense that there are effects on and feedbacks from the other energy using sectors of the economy. For example, when the price of oil is varied, the prices of gas and electricity can in principle change concurrently.

The dynamic model, named CURVE, allows the three fuel prices to vary independently by modelling only the single family dwelling space heat demand. In return, CURVE allows us to analyze:

- a) the effects of expected price and technology changes over time; and
- b) long run versus short run demand effects by taking account of conversion costs for existing units and letting households switch fuels only when economically rational.

Both models are linear programming models, although the second, CURVE, is not solved by a standard linear programming routine but by dynamic programming.

III. STATIC MODEL, ADDITION TO BESOM

III. A. Description Of The Disaggregation Of The Space Heat Category In BESOM

Modifications were made to BESOM to disaggregate national space heat supply costs and demand into 52 sectors; one for each state (in the U.S.), one for the District of Columbia, and one for "other" space heat. The "other" sector dealt with that portion of national space heat not attributable to single family residences.

We will algebraically describe the modifications made to BESOM. For simplicity in description, we will refer to 52 states. The 51st "state" is the District of Columbia, and the 52nd is "other" space heat.

Notation. We introduce the following notation:

$I : I \in \{1, \dots, 52\}$, an index set of states;

$SHS(I)$; demand for space heat in state I in units of 10^6 BTUs in final energy form;

EF: electricity used in electric furnaces;

ER: electricity used in electric resistance heaters;

HP: electricity used in heat pumps;

EL: electricity used for space heat;

TYPE: TYPE $\in \{OIL, GAS, EF, ER, HP\}$

$X [TYPE] (I)$: the amount of the fuel TYPE used in state I to provide space heat to single family residential units, in units of 10^6 BTUs in intermediate energy form*(IEF):

$SH[TYPE]$: the total (national) amount of the fuel TYPE used in the 52 states (these are the space heat activity variables for space heat that appear in the unmodified BESOM);

*Delivered fuel oil, natural gas, or electricity.

$EFF(I)$: the efficiency of the heat pump in state I ;
 C_{OIL} : national cost of OIL, in $\$/10^6$ BTU IEF;
 C_{GAS} : national cost of GAS, in $\$/10^6$ BTU IEF;
 C_{EL} : National cost of electricity, in $\$/10^6$ BTU IEF.

Demand equations. For each of the first 51 states, the model is required to satisfy the following demand equation as an equality:

$$.60 \cdot X[GAS](I) + .55 \cdot X[OIL](I) + X[EF](I) + X[ER](I) + EFF(I) \cdot X[HP](I) = SHS(I) \quad (1)$$

where .60 is the efficiency of gas in providing space heat, .55 is the efficiency of oil, and the efficiencies of the electric furnace and electric resistance heater are both equal to 1.

It is assumed that the heat pump is not used to satisfy space heat demand in the 52nd state (other), or, equivalently, that $EFF(52) = 0$. Therefore, for the 52nd state, the demand equation is

$$.60 \cdot X[GAS](52) + .55 \cdot X[OIL](52) + X[EF](52) + X[ER](52) = SHS(52). \quad (2)$$

Balance equations. It is required that the sum of the amounts of a fuel used in the 52 states equals the total (national) amount of that fuel used.

$$\sum_{I=1}^{52} X[OIL](I) = SH[OIL] \quad (3)$$

$$\sum_{I=1}^{52} X[GAS](I) = SH[GAS] \quad (4)$$

$$\sum_{I=1}^{52} [X[EF](I) + X[ER](I) + X[HP](I)] = SH[EL]. \quad (5)$$

Objective function. We represent the objective function of the original (unmodified) BESOM model in the following form:

$$\text{Minimize } Z = C + C_{OIL} \cdot SH[OIL] + C_{GAS} \cdot SH[GAS] + C_{EL} \cdot SH[EL] \quad (6)$$

where C represents the non-space heat part of the objective function.

The objective function of the modified BESOM model with space heat disaggregated is:

$$\begin{aligned} &\text{Minimize} \\ &Z = C + C_{OIL} \cdot SH[OIL] + C_{GAS} \cdot SH[GAS] + C_{EL} \cdot SH[EL] + \\ &\sum_{I=1}^{51} \left\{ C_{OIL}(I) \cdot X[OIL](I) + C_{GAS}(I) \cdot X[GAS](I) \right. \\ &\quad \left. + C_{ER}(I) \cdot X[ER](I) + C_{EF}(I) \cdot X[EF](I) \right. \\ &\quad \left. + C_{HP}(I) \cdot X[HP](I) \right\} \quad (7) \end{aligned}$$

$C_{OIL}(I)$ represents the deviation of the cost of OIL in state I from the national price of oil in intermediate energy form plus the annualized investment cost of oil space heating equipment per 10^6 BTUs of intermediate energy form. Therefore, ceteris paribus an increase of one unit of oil usage in state I will raise the value of the objective function by $C_{OIL}(I) + C_{OIL}$.

In general, $C_{TYPE}(I)$ represents the deviation of the cost of the intermediate energy form TYPE in state I from the national average cost of TYPE plus the annualized investment cost of the space heating equipment required per 10^5 BTUs of the intermediate energy form.

We remark that the formulation of the objective function for the modified BESOM model implies that intermediate energy forms used to satisfy "other" space heat demand have national average costs, or, equivalently, $C_{TYPE}(52) = 0$.

III. B. Preliminary Results

The first experiment using the model was to generate national demands for fuels (in intermediate energy form) as functions of the price, or cost, of gas.

The supply constraints on gas and imported oil were both increased to 35×10^{15} BTUs so that the shadow (scarcity) prices of gas and oil were both initially zero.

The initial cost of oil in BESOM for space heat was \$2.56 per 10^6 BTU and the initial cost of gas was \$1.62 per 10^6 BTUs. The cost of gas was then increased until no space heat demand was satisfied by gas.

Table I gives the optimal annual total (national) amounts of gas, oil, and electricity in immediate energy forms used to provide space heat to single family residences as functions of the cost of gas. We remark that fuel use in the 52nd state is not included. The data in Table I were used to estimate the cross elasticity of demand for oil as a function of the cost of gas. The parameters estimated were a and b in the equation,

$$\ln Q = a \cdot \ln P + B, \quad (8)$$

where Q is the quantity of oil and P is the cost of gas. The estimated values were $a = 6.62602$ and $b = -6.759135$. The correlation coefficient was $r = .99$.

Figure 1 graphically illustrates some of the information of Table 1; in particular, the cross demand curve for oil as a function of the cost of gas. We observe that, for a large range, the cross demand curve appears quite smooth.

The figures in parentheses on the demand curve in Figure 1 indicate the costs (including scarcity costs) of electricity generated by the model for the associated costs of gas.

Figure 2 gives the demand for oil, gas, and electricity as a function of the price of oil. These curves are comparable to

Table 1

Annual Fuel Use as a Function of the Price of Gas (BESOM)

$\$/10^6$ BTUs of Gas	Gas*	Oil*	Electricity*
1.62	5.799166	.025273	.063600
1.95	5.65533	.066727	.097635
1.99	5.655333	.119091	.103378
2.06	5.4061667	.119091	.167643
2.28	5.212667	.330182	.167643
2.50	5.087500	.466727	.167643
2.65	4.465166	1.065273	.190723
2.76	4.356500	1.065273	.229464
2.78	4.219833	1.214364	.229464
2.79	4.057833	1.391091	.229464
2.83	4.057833	1.391090	.229464
2.94	3.899667	1.563636	.229464
3.05	3.574833	1.563637	.345269
3.12	3.546333	1.594728	.345269
3.16	3.326000	1.834992	.345269
3.18	3.099000	2.082728	.345269
3.19	3.067667	2.116909	3.45269
3.20	2.345000	2.905273	3.45269
3.24	2.095500	3.177455	3.45269
3.27	2.044000	3.177454	3.63484
3.30	1.810000	3.432727	3.63484
3.31	1.658833	3.597636	3.63484
3.36	1.245833	4.048182	3.63484
3.37	1.202833	4.095091	3.63484
3.38	1.145333	4.157818	3.63484
3.40	.767667	4.569818	3.63484
3.41	.707333	4.635638	3.63484
3.44	.666667	4.680000	3.63484
3.48	.401167	4.979636	3.63484
3.49	.364667	5.009454	3.63484
3.53	.308500	5.070727	3.63484
3.58	.239500	5.146000	3.63484
3.60	.199333	5.189818	3.63484
3.64	.108000	5.289454	3.63484
3.67	.075167	5.325272	3.63484
3.71	.038333	5.365454	3.63484
3.82	.000000	5.407272	3.63484

* Demand is in 10^{15} BTU (Intermediate Energy Form)
 Price of oil is $2.56\$/10^6$ BTU. See Fig. 2 for electricity prices.

figures 6-8 derived from CURVE, at least for gas and oil. Since the electricity price cannot presently be manipulated independently in BESOM, but it can be in CURVE, the electric demand, though low in both, exhibits a greater relative difference between the two models than do the oil/gas demands.

Table II shows the fuel used by each state as a function of the cost of gas. This table is derived from the same experiment as Table I and Figure 1.*

We observe that at the initial BESOM cost of gas without effective supply limits (\$1.62/10⁶ BTUs) all states are using gas except Alaska and Tennessee. In addition, we observe that the heat pump is not employed in the warmer regions of the country, but in the "middle" climatic areas such as New Jersey, Washington, and Oregon. A possible rationale for this is that the portion of the heat pump capital cost which is allocated to space heating is invariant with respect to the mix of space heating and air conditioning demands in any state. Thus, in the southern areas capital costs of the heat pump are relatively high per BTU of space heat demand because of the small unit demand for space heat. This is not offset by the high efficiency of the heat pump in southern climates. In the "middle" climatic areas, since relatively more space heat is required and the heat pump still has high efficiency**, the gains in efficiency offset the capital costs.

IV. DYNAMIC MODEL, CURVE

IV. A. General Description Of CURVE

The dynamic model, named CURVE, calculates the demand for fuel and fuel systems required to heat single family dwelling units to approximately 70° during the heating season. The objective of the model is to minimize total discounted future costs, including delivered fuel costs and capital and operating costs of home heating systems. Seven heating systems are considered: gas warm air, gas hot water, oil warm air, oil hot water, electric warm air (electric furnace), electric resistance, and heat pump. Demand for space heat is disaggregated by state and by year.

*When the constraints on the supply of gas and oil were set at 24.04×10^{15} BTU's and 26.44×10^{15} BTU's respectively (BNL BESOM estimates for 1985) the costs (including scarcity costs) of gas, oil, and electricity (IEF) were \$2.79, \$2.56 and \$4.65 per 10⁶ BTU's respectively.

**For example, in New Jersey the estimated efficiency of the heat pump is 1.72 and in Louisiana it is 1.96.

Figure 1. Demand for oil as a function of the price of gas (BESOM).

Figure 2. Demands for oil, gas, and electricity as a function of the price of oil (BESCM).

Fuel Use by State as a Function of the Price of Gas (BESOM)

	Cost of Gas in $\$/10^6$ BTUs IEF																																					
Location	1.62	2.00	2.10	2.20	2.30	2.40	2.50	2.60	2.70	2.80	2.90	3.00	3.10	3.20	3.30	3.40	3.50	3.60																				
PACIFIC																																						
Hawaii	NONE																																					
Alaska	OIL																																					
NEW ENGLAND																																						
Maine	OIL																																					
Vermont																																						
New Hampshire																																						
Mass.																																						
Connecticut																																						
Rhode Island	GAS																																					
MID ATLANTIC																																						
New Jersey	HEAT PUMP																																					
New York	OIL																																					
Pennsylvania	GAS																																					
SOUTH ATLANTIC																																						
Delaware	OIL																																					
District of Columbia																																						
Maryland																																						
Virginia																																						
North Carolina																																						
South Carolina	GAS																																					
West Virginia	HEAT PUMP																																					
Georgia																																						
Florida																																						
MOUNTAIN																																						
Idaho	OIL																																					
Montana																																						
Arizona																																						
New Mexico																																						
Wyoming																																						
Nevada	GAS																																					
Utah	OIL																																					
Colorado																																						
E.N. CENTRAL																																						
Wisconsin	OIL																																					
Michigan																																						
Illinois																																						
Indiana																																						
Ohio																																						
E.S. CENTRAL																																						
Tennessee	ELECTRIC RESISTANCE HEATERS																																					
Kentucky	HEAT PUMP																																					
Mississippi	GAS																																					
Alabama	OIL																																					
W.N. CENTRAL																																						
Minnesota	OIL																																					
North Dakota																																						
South Dakota																																						
Iowa																																						
Missouri																																						
Nebraska	GAS																																					
Kansas	OIL																																					
PACIFIC																																						
Washington																				HEAT PUMP																		
Oregon																				GAS																		
California	OIL																																					
W.S. CENTRAL																																						
Arkansas	OIL																																					
Alabama																																						
Texas																																						
Louisiana																																						
	GAS																																					

The optimal system to be used in a home in each year is computed by the method of dynamic programming. This is a solution procedure whose major stage consists of computing backwards in time. However, in order to describe the setup of the problem in more detail, it is convenient to do so from the point of view of the householder looking forward.

At the end of relative year T each dwelling unit has one of seven heating system types installed which has a given age from 1 to L years. An L year old system must be replaced. The task of the householder is to choose either to continue with the old system or to replace it with a new system so as to minimize discounted future total heating costs. Because of technological improvements the replacement is not necessarily to a different type of system.

The dynamic programming calculation starts at the end of the relative terminal year (1985 in this case). Since the cost parameters do not change after this year, the optimal path after this point is easily computed. Optimal decisions by year are then made backwards in time to the initial year (1970 in this case). When the optimal decisions are known for all years, fuel demands and the actual number of dwelling units with each fuel system type and age can be determined for each year.

IV. B. Preliminary Results

The results of basic runs with CURVE are presented in Figures 3-11. These demand curves are made on the assumption of constant prices and technologies over time. Thus the two curves in each graph are for 1975 and 1985. They may be interpreted as short and long run curves relative to each other.

Although Figures 3-11 are based on only a moderate number of price points, the curves seem to be fairly "smooth" in the sense discussed in Section I.

The short and long run curves do relate to each other in an expected way -- short run flatter with respect to the price axis than the long run.

The curves in Figures 6-8 have shapes very similar to the comparable curves generated by BESOM in Figure 2.

In Table III, the fuel system used by each state for new construction in 1985 as a function of the price of gas is shown graphically. This can be compared to Table II for BESOM and is practically the same, with fuel prices equal to 365.49¢/mcf (3.54\$/10⁶ BTU) for gas, 42.4¢/gal (3.06\$/10⁶ BTU) for oil and 1.9¢/kwh (5.8\$/10⁶ BTU) for electricity. The distribution of fuels for new construction by State seems to roughly correspond to current trends (Table III).

Figure 3. Demand for gas as a function of the price of gas (curve).

Figure 4. Demand for oil as a function of the price of gas (curve).

Figure 5. Demand for electricity as a function of the price of gas (curve).

Figure 6. Demand for gas as a function of the price of oil (curve).

Figure 7. Demand for oil as a function of the price of oil (curve).

Figure 8. Demand for electricity as a function of the price of oil (curve).

Figure 9. Demand for gas as a function of the price of electricity (curve).

Figure 10. Demand for oil as a function of the price of electricity (curve).

Figure 11. Demand for electricity as a function of the price of electricity (curve).

TABLE III

Fuel Use by States in 1985 as a Function
of the Price of Gas (CURVE)

Prices in \$/10 ⁶ BTU	2.58	2.77	2.96	3.16	3.35	3.54	3.74	3.93	4.13	4.32	4.52	4.71
PACIFIC												
Hawaii	ELECTRIC RESISTANCE											
Alaska	OIL WARM AIR											
NEW ENGLAND												
Maine												
Vermont												
New Hampshire												
Massachusetts	OIL WARM AIR											
Connecticut												
Rhode Island	GAS WARM AIR											
MID ATLANTIC												
New Jersey	HEAT PUMP											
Pennsylvania	GAS WARM AIR											
New York	OR WARM AIR											
MOUNTAIN												
Idaho	OIL WARM AIR											
Montana												
Arizona	HEAT PUMP											
N. Mexico	OIL WARM AIR											
Wyoming												
Nevada	HEAT PUMP											
Utah												
Colorado	OIL WARM AIR											
SOUTH ATLANTIC												
Delaware												
Wash. D.C.	HEAT PUMP											
Virginia												
W. Virginia												
N. Carolina	GAS WARM AIR											
Georgia												
S. Carolina	OIL WARM AIR											
Florida												
E.S. CENTRAL												
Tennessee	ELECTRIC RESISTANCE											
Kentucky	HEAT PUMP											
Alabama	GAS WARM AIR											
Mississippi	OIL WARM AIR											
W.N. CENTRAL												
N. Dakota												
Minnesota												
S. Dakota	GAS WARM AIR											
Iowa												
Nebraska	OIL WARM AIR											
PACIFIC												
Washington												
Oregon	GAS WARM AIR											
California	HEAT PUMP											
W.S. CENTRAL												
Missouri												
Louisiana												
Oklahoma	GAS WARM AIR											
Arkansas												
Texas	OIL WARM AIR											

These curves represent only a small set of possible experiments that can be done with this model. A whole set of these experiments should be done, of course, both for historical periods (to check the model parameters) and for future periods (to see which expected future technology and price developments are significant).

However, a gross check of the present results leads to several hypotheses:

- a) Between gas and oil the primary influence is the structure of regional prices: Oil almost flat, gas strongly transport dominated.
- b) Climatic effects have the greatest influence on the use of the heat pump.
- c) Gas and oil prices must be much higher relative to electricity than is presently the case for electricity to penetrate significantly into the SFDU space heat market.

V. CONCLUSIONS

The conclusions we draw here are really preliminary hypotheses. The funding of the study allowed only for development of methodology and crude data estimation. No large scale systematic validation and experimentation could be done with the models in this level of program effort. Nevertheless some strong preliminary conclusions which are worth following up emerge:

On smoothness. 1) It appears that for many applications the demand curves could be approximated in segments by linear and/or constant elasticity (log-log) curves. However, at a few price levels, there are large jumps in quantities demanded; and for some range of prices almost no price effect. 2) The phenomenon noted in (1.) is due to very regular geographical patterns in switches in fuels as national price changes.

On relationship to actual behavior. 3) With a suitable choice of prices, the model results appear upon casual observation to approximate the existing national mix of space heat devices. 4) Current regulated natural gas prices do not appear from the model to be market clearing prices since the model would then imply that gas would be the predominant choice in every state. 5) The actual and BESOM price data for electricity would lead to electricity being used very little. For a sufficiently low relative national price, however, the heat pump would be used in medium usage states such as the Middle Atlantic.

On BESOM vs. CURVE. 6) The demand curves generated by BESOM and by CURVE are very similar in shape. At this point it has not been determined if there are any significant systematic differences between the two sets.

On short run-long run. 7) Long run and short run demand curves which are significantly different in the expected direction are generated by CURVE.

On sensitivity analysis. 8) The relative demands for gas versus oil appear to be dominated by regional price differences. 9) The demand for heat pumps appears to be dominated by capital costs, electricity prices, efficiency data and climatic data. 10) The demand for electric resistance heating, when and where it exists, seems to be dominated by the geographically erratic electricity prices. Indeed, actual electric usage appears to be a local phenomenon dominated by widely varying residential rates even within a state. (Variations intra-state are the same order of magnitude as those inter-state.)

On data. 11) The most uncertain and yet important data are, first, the investment cost and efficiencies of heat pump versus gas-oil systems and, second, the regional price differences.

VI. SUGGESTIONS FOR FURTHER RESEARCH

Suggestions for further research can be divided into five lines of inquiry: Data improvement (including improved inter-regional price sub-model); Validation and comparison with econometric models; Experimentation; Inclusion of more fuel system options; and Reduction of CURVE to simple analytic form.

Data improvement (and inter-regional price sub-model).

As indicated in the conclusions, a dominant factor in gas-oil-electric resistance demand is the assumed set of fixed regional price differences from the national "average" price which is the figure varied to produce demand curves. However, as is indicated in the fuel price section of the Data Appendix, these price differences are based on scanty data and either crude models (in the case of gas and oil) or no model (in the case of electricity). More data, backed up by a theoretically believable model, should be developed to bolster this important part of the demand projections.

An important point relevant to this suggestion is that if simple but reasonably good regional price difference models are developed, they would be extremely useful for many other sectors besides space heat.

Of second importance in general, but of primary importance for new technologies such as the heat pumps, are better and more consistent estimates of capital costs, conversion costs, and, for the heat pump, the dependence of efficiency on climatic factors.

One way to estimate a part of the data is by comparing model output with actual data for historical periods. However, it should be clear that to gain enough degrees of freedom to do this estimation, it is necessary to first decompose the data set into a part to be set by prior belief or assumption and a part to be estimated

by trying to get the model output to approximate historical data. In the next suggestion, we discuss other aspects of such a procedure.

Validation and comparison with econometric models. It is important that a thorough statistical comparison of model outputs with historical data be undertaken. This is necessary to determine if any systematic and controllable elements have been left out of the model.

One factor that has obviously been left out of the model that could affect the data is consumer substitution of other commodities for heat, i.e., consumer conservation (economizing) behavior. One way to make a first validation of the model and take account of the above problem is to investigate if the residuals are consistent with the assumption that on average they are caused by consumer economizing, or, if consistent with other data sources and prior beliefs, the results can be seen to be consistent with economizing behavior. (This problem and procedure obviously ties in with the estimation procedure described at the end of the data improvement suggestion.)

In addition to, or in place of, comparison with the raw data, comparisons could be made with the results of other (non-process, non-engineering) econometric models. In this context, the technological models we have developed might be viewed as part of a structural system for which the (non-process) econometric models are reduced forms which do not allow technology and price expectations to be varied independently of present or recent fuel prices. (The last suggestion in this section is relevant to this effort at comparison.)

The validation and comparisons suggested here are often forgotten in the rush to add to the model to make it more "realistic", when, in fact, it is not yet known if the model is "unrealistic" in any way which could significantly affect prediction and policies.

Experimentation. The model is capable of a great many more experiments than we have conducted. In particular, we do not know if any of the more complicated behavior (such as a sequence of system switching for a given SFDU) will occur for any likely prices or technology paths. If simple behavior is more likely, then perhaps a simpler model than CURVE could be constructed.

We have not made a systematic comparison between the BESOM and CURVE models. We do not know, for instance, if the inertia of the capital stock is really significant in national projections, or if the computed minimum discounted future costs calculated by CURVE are consistent with the annual amortized costs used by BESOM.

We have not tested whether disaggregation has any overall effect. If, for instance, other sectors, when disaggregated, behave "like" space heat, will such behavior change the sources

and uses of national energy sufficient to warrant the disaggregation effort? Perhaps the biggest effect of disaggregation is the ability to link regional behavior with economic and technological parameters. This could, however, have large economic repercussions if inter-regional adjustments are difficult.

Inclusion of more fuel system options. The most-likely-to-be-important options would be (1) air conditioning in conjunction with heating, (2) insulation, and (3) economizing behavior.

Air conditioning: There are conceptual problems, but some strong and possibly reasonable assumptions would allow this to be included within the framework of BESOM or CURVE. The proof of the assumptions would be the empirical validation of the model predictions.

Insulation: The biggest problem here is the data on cost and effectiveness. Institutional factors which dictate heavy insulation of electric homes should be incorporated as well as market factors which permit the choice of alternative levels of home insulation.

Economizing behavior: To include this possibility could entail a major complication of the model. Unless, in the validation stage, economizing behavior turns out to be explained by a particularly simple scheme consistent with the present model.

Reduction of CURVE to simple analytic form. By this we mean developing a simple formula (or small set of formulae) which predicts the choice path of heating-systems for a given household as a function of climatic variables and variables parametrizing expected future paths of fuel prices, investment costs (as a function of system size), and technology (efficiencies).

This could be particularly important for (1) rapid (by hand) prediction of fuel demands in given regions, (2) insertion in more complicated models to reduce computation time and increase understanding of model behavior, and (3) more straightforward comparison with (non-process) econometric models.

The analytic form could be arrived at by two possible directions: (1) "Fitting" model output to algebraic forms or (2) Theoretical deduction.

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APPENDIX A. TECHNICAL DESCRIPTION OF PROGRAM CURVE

I. Output of calculations. Program curve calculates the demand for fuel and fuel systems required to heat single family dwelling units (SFDU's) to approximately 70° during the heating season. The system is chosen to minimize discounted future costs. The results are given by state and by year.

II. Behavioral assumptions.* 1) Seven heating systems are considered: gas warm air (GAS-WA), gas hot water (GAS-HW), OIL-WA, OIL-HW, electric WA (ELEC-WA), electric resistance (ELEC-RES), and heat pump (HEAT-P). 2) The number of SFDUs with each heating system during the initial year (year 1) is given. This is stored in BDU(J), in 10^3 SFDUs. 3) The total number of SFDUs in each state grows by a fixed rate, γ (GAM), and units are removed from the stock at a fixed rate ρ (RHO). 4) The costs of installing each type of system at the time of construction and converting existing systems is linear with respect to the design BTUs of the system. The basic cost coefficient for transforming system I-1 to system J at the start of year 1 (in $\$/10^3$ BTU/hour of output) is in array BC(I,J). (System 0 is new construction.) The basic costs decrease in subsequent years at fixed rates, BETA(J). 5) Basic operation and maintenance costs depend on the year in which the system is installed. For systems installed at the start of year 1, these costs are stored in BOM(J) in $\$/10^3$ BTU/hr output. A rate of decrease per year of O&M costs for systems installed at the beginning of a subsequent year is given in ETA(J). 6) The efficiency of system J purchased at the start of year T is given in EFF(J,T). 7) The conversion factors for input BTUs are stored in Q(J) as 1.0 (MCF of gas/ 10^6 BTU), 7.0423 (gal of oil/ 10^6 BTU), and 293.0 (KWH of electricity/ 10^6 BTU). 8) Fuel systems are given a lifetime of 20 years. Taxes and insurance are computed as a fixed percentage (TXIN) of installation costs in new construction at the beginning of the year. All payments are discounted at the rate R. 9) National price for fuel in year 1 is given in PIND(J). Actual prices in a given year, P(J), are computed by increasing prices at a rate ALPHA(J) per year and subtracting a pseudo-transportation cost for each state from this figure. For each state the transportation cost for fuel J is stored in TDP(J), "Transportation Difference in Price." Prices are measured in $\$/mcf$, $\$/gal$, and $\$/KWH$ (IEF). 10) Total BTUs per SFDU per year, TBTU (in 10^6 BTU) are given by the formula,

$$TBTU = DEGDAYS * 15./1000.$$

where DEGDAYS are degree days. Design output in 10^3 BTU/hr (size of the system needed in SFDU), is computed as $DMBTUH = 65-T97$,

*See Appendix B for derivation or source of formulas and assumptions.

where T97 is the 97th percentile temperature. 11) The heat pump operates alone down to a temperature of 35°F (=THP) and is assisted by electric resistance heating elements below that temperature. The percentage of the degree days supplied by a heat pump is computed as:

$$HPP = 1. - \frac{\max (THP - T97, 0)^2}{65. - T97}$$

The DMBTUH for the heat pump is always less than 30. 12) After the terminal year, TTERM, prices, unit costs, and efficiencies are assumed to remain fixed and constant at their values at that time.

III. Method of calculation. The optimal system to be used in a SFDU in each year is computed by the method of dynamic programming. This is a solution procedure whose major stage consists of computing backwards in time. However, in order to describe the set-up of the problem in more detail, it is convenient to do so from the point of view of the householder looking forward.

At the end of relative year T (initial calendar year, IY , is relative year 1) each SFDU has one of seven heating system types installed which has a given age from 1 to L years, where L is presently taken as 20, or is being newly constructed. Thus at the end of a year a SFDU is in one of 141 configurations indexed from 0 to 140. The zero configuration is new construction; the configurations indexed from $(K-1)*L+1$ to $K*L$ refer to the Kth heating system type from one to L years old. An L year old system must be replaced.

The task of the householder is to choose either to continue with the old system or to replace it with a new system so as to minimize discounted future total heating costs. Because of technological improvements, the replacement is not necessarily to a different type of system.

Let $EV(J)$ be the minimum discounted future cost after the end of the present year, if the system is in state J at the end of the year, discounted to the end of the year. The householder can then compute the cost discounted to the beginning of the year for any choice this year by computing the cost for the current year and adding to it the discounted value of EV (evaluated at the system chosen this year one year older). If the minimizing choice is made, BV , the minimum discounted future cost at the beginning of the year can be computed by expression (11) below, using the notation:

K - system type at the end of previous year, $K=0, \dots, 7$.

KK - system type at the end of present year, $KK=1, \dots, 7$.

J - age of system at end of previous year, $J=1, \dots, L$.

F - fuel index of system KK

$C(1+K, KK)$ - total cost of converting from system K to system KK.

(The first index must be increased by 1 since the index zero is not allowed on the computer.) If K and KK are the same,

it means that the old system is replaced by a new one of the same type.

OM(KK,M) - total operation and maintenance expenditures in relative year T.

M - index of relative year in which system KK was purchased.

$$\left. \begin{array}{l} \text{If } K \neq 0 \\ \text{If } K = 0 \end{array} \right\} \begin{array}{l} BV(K-D \cdot L+J) \\ BV \end{array} =$$

$$\begin{aligned} & OM(KK,M) \cdot TXIN \cdot C(1, KK) \\ & + Q(F) \cdot [TBTU/EFF(K,M)] \cdot P(F)/100. \\ & + \left\{ \begin{array}{l} (1+R)^{-1} \cdot EV(K-1) \cdot (L+J+1), \text{ if } KK=K \text{ and } J < L. \\ +C(1+K, KK) + (1+R)^{-1} EV(KK-1) \cdot (L+1), \text{ if } KK \neq K \text{ or } J=L. \end{array} \right. \end{aligned}$$

Both EV and BV are measured in dollars.

The decision of the householder can then be recorded in the variables:

MSFO(T) - index of system type installed in new construction at end of relative year T;

MSF(K,T) - index of system type installed in existing housing at end of relative year T, when existing system is type K.

MAGE(K,T) - age at which existing system K at end of relative year T is replaced.

Of course, BV becomes EV for the previous year. The common value of BV and EV at a year beginning (end) will be referred to as the value of the V function at that point in time.

The dynamic programming calculation starts at the end of the relative terminal year TTERM. Since the cost parameters do not change after TTERM, the optimal path after this point is easily computed, which gives EV at the end of TTERM. The V function is then moved backwards by means of (1). When the optimal decisions are known for the end of relative year 1, the actual number of SFDU's with each fuel system type and age can be determined for each year.

The number of (10^3) SFDU's in a given state with each system type is given at the beginning of year 1 and its age distribution is arbitrarily set as uniform over 1 to L.

The number of existing SFDU's at the end of relative year T in configuration (system type and age) J is stored in DU(J), J=1, ..., 140. The number of all SFDU's is given by Z. First the number of newly constructed SFDU's is given by (GAM + RHO) · Z = DUO. Then all components of DU are reduced by the removal rate and DU becomes (1 - RHO) · DU. Now, since the optimal decisions of SFDU's in each configuration are known, the SFDU's in each component of DU can be transferred and added to a component of a vector DDU. DUO is also added to the appropriate component of DDU. The values in DU are then replaced by those in DDU.

The DU thus computed is that effective throughout and at the end of year T+1. At this point the number of SFDU's with system type K, DUK(K), and the demand for fuel J, DE(J), can be computed.

IV. Flow of program. The program works through a sequence of sub-programs. A diagrammed flow of the program through main iterations and subprograms is given in Table IV.

(Note: There are two versions, SPOT and FLOOD. Version SPOT outputs a very abbreviated set of micro-data, while FLOOD outputs almost all calculated micro-data. The former should be used when extensive demand curves are calculated; the latter can be used to make detailed analyses at a few well chosen prices.)

The following is a fairly detailed explanation of each sub-program. For each sub-program, an outline of the tasks performed is given first. Then a more detailed explanation is given of the less obvious points in the form of numbered footnotes. The letters in the left margin of the outline match up with the letters in Table IV.

Curve

Reads in basic variable data.¹
Iterates on price of one fuel.²
Initializes AGDUK, NEWAG, and ADGE to zero.
A Calls report set-up routine, SPOT1.
Iterates on States³
Reads in State data³
(A) (Calls FLOOD1)
B Calls TIME
G Calls DEMAND⁴
Stores aggregate demand data on tape 15 for each price.⁵
I Calls REPORT
END

¹Relative year 1 is the initial year, IY, for which consumption data is given. First decision is made at end of year 1.

²An odd number, NDIV, of prices are used, equally spaced by DELP, with an equal number above and below the "base price" given by PIND (KF). KF is the index of the fuel whose price is changed and is read in from cards.

³The data for each state is stored unformatted on one record on tape 1. Each State is completely processed (for a given price) before data on next State is read. The tape must be rewound and used again for each price.

B* TIME¹

C Calls SETUP²
Iterates on T² from TTERM to 1 to compute V functions backwards

D Calls UPDATE

E For T=TTERM calls START

F For T<TTERM calls ITERATE

B* Returns to CURVE

Global Flow of Program CURVE, SPOT Version

¹This sub-program organizes the calculation backwards of the V function.

²T here indicates decisions are being made at the end of relative year T.

C* SETUP

Initializes¹ DMBTU, EFF, and OM for a given state.

C* Returns to TIME

D* (UPDATE)

Calculates C² and P for current T

D* Returns to TIME

¹Calculations involving the heat pump, system type 7, using THP and HPP, are explained in section on System Cost and Size Estimates.

²For C and BC the first computer index (1 to 8) must be decreased by one to give correct conceptual index (0 to 7).

E* START

Determines V function at end of TTERM (sets EV at TTERM)¹

E* Returns to TIME

¹The computation goes as follows (T=TTERM):

There is an outer loop over system types, K=1 to 7. New construction information is not needed since the exogenous data does not vary after TTERM, a switch is either made at TTERM or at the end of the life of the present system. Afterwards the same system is kept permanently, needing only replacement (by the same system type) every L years.

First, for each system type, K, we evaluate the discounted costs of switching permanently to system type KK. The costs are discounted back to the switching time. This cost is computed as:

$$\begin{aligned} VVV = & C(1+K, KK) + \sum_{a=1}^{\infty} (1+R)^{-aL} C(1+KK, KK) \\ & + \sum_{a=0}^{\infty} (1+R)^{-a} [TXJN * C(J, KK) + OM(KK, T) \\ & + Q * (P/100.) * TBTU/EFF(KK, T)] \end{aligned}$$

The system type index for which this cost is a minimum is stored in NN and the minimum cost is stored in VV. We immediately set $EV(K * L) = VV$ and $MSF(K, T) = NN$, since a system of L years is at the end of its life and the system to which a switch is made does not depend on age.

Now, the program initializes $MAGE(K, T) = 1$ and looks at switching at the end of life, L, versus immediately, i.e., it compares, for each J, VV with

$$\begin{aligned} VVV = & \sum_{a=0}^{L-J-1} (1+R)^{-a} [TXIN * C(1, K) + OM(K, M) + \\ & Q * (P/100.) * TBTU/EFF(K, M)] \\ & + (1+R)^{-(L-J)} * VV. \end{aligned}$$

If VVV is less than VV a switch is not made at age J, $EV((L-1)*K+J)=VVV$, and MAGE (K,T) is incremented by 1.
 IF VV is less than VVV a switch is made to KK for systems of type K of age J, and $EV((L-1)*K+J) = VV$. [MAGE(K,T) has already been set to J or less.]

F* ITERATE

Determines BV from EV and determines at the same time MSFO(T), MSF(K,T), and MAGE(K,T)

F* Returns to TIME

¹The calculation is done by first calculating the minimum cost system to which to switch if a switch is optimal. This also determines the decision for age=L and new construction.

Then starting with age J=1 and MAGE=1, staying with the same system is compared with switching for each J. If no switch is required, then BV is set for that age and MAGE is set up by 1 to J+1. If a switch is required, BV is set and MAGE is left at the age of first switching.

Finally, EV is replaced by BV.

G* DEMAND

Iterates forward from T=0 to TTERM-1 to determine DU, DUK, DE and update AGDUK, AGDE, and NEWAG for the consumption years T+1.¹

(H) (Calls FLOOD2 for each T in FLOOD version)

H Calls SPOT2 at end of iteration to give results for TTERM.

G* Returns to CURVE

¹DDU is initialized by spreading BDU equally over all ages, then demand for T=0 (consumption in year 1 = 1Y) is determined separately before DO loop. Then T loops from 1 to TTERM-1, computing for each T the new stock of SFDU's in each state during the consumption year (DDU) and branching to the end segment of the program to compute the fuel demands and update aggregate data. The end segment is used for all T and starts by setting DU=DDU.

SPTLITE

A* (SPOT1)

Writes heading for SPOT output.

A* Returns to CURVE

H* (SPOT2)

Writes one line report for current state in last year, LY.

H* Returns to DEMAND

(A*) (FLOOD1)

Writes state name heading for FLOOD output.

(A*) Returns to CURVE

(H*) (FLOOD2)

Writes detailed report for each state and each year.

(H*) Returns to DEMAND

I* REPORT

Prints heading

Iterates on prices.¹

Reads in one record for each price from tape 15

Writes report on aggregate demand for all years.

I* Returns to CURVE

¹This routine uses NDIV to determine number of records to read (unformatted). Actual price data is on record.

BSDATA

No call to this routine necessary. Fills basic data block.

The complete program listing for CURVE (Spot Version) is presented in Table V.

V. Input data. Input data is in two forms -- cards and tape. The card input is on 5 cards, free format.

Card 1 - PIND (base prices for 3 fuels), KF (index of fuel price varied), NDIV (number of price points computed on demand curve, must be odd)

DELP (increment between price points)

Card 2 - ALPHA (yearly rates of fuel price increases, 3, decimal)

Card 3 - BETA (yearly rates of investment cost decrease, 7, decimal)

Card 4 - ETA (yearly rates of O&M cost decreases, 7, decimal)

Card 5 - R (interest rate, decimal), TXIN (taxes and insurance rate, decimal)

The tape input on tape 1 is unformatted (i.e., binary to be read directly into core memory) with one record per state. The variables stored on the record in turn are: STNAME (state name, in holerith), BDU (number of SFDU's in 10^3 units of each system type at end of year 1, 7), GAM (rate of increase of total SFDU's, decimal), RHO (rate of removal of SFDU's, decimal), DEG DAYS (degree days), T97 (97½ percentile temperature in Fahrenheit), and TDP (transportation costs, 3, ¢/mcf, ¢/gal, ¢/kwh). This tape can be written by a program which writes the data onto the tape unformatted, one write statement per state.

VI. Output. The standard output (SPOT version) is shown in Table VI. It comes in two sections. The first, produced by SPOTLITE, shows the results state by state for a given year (now set at LY=1985). Each line gives: State name, chosen year, fuel demands (3), SFDU's with each system (7), systems chosen for new construction. This report is repeated for each price point.

Second, the aggregate report generated by REPORT is given and repeated for each price point. For each year, the report gives in order: aggregate fuel demand (3), aggregate SFDU's with each system (7), number of States where each system is chosen for new construction (7).

TABLE V

Listing of Program CURVE (SPOT Version)

```

PROGRAM CURVE (INPUT,OUTPUT,TAPE1,TAPE6=OUTPUT,TAPE15,TAPE5=
1 INPUT)
INTEGER I, TTERM,STNAME,F,FUEL,SFNAME
COMMON
5 1/P/NF,PIND(3),P(3),ALPHA(3),TDP(3),KF,NDIV,DELP
2/C/BC(8,7),C(8,7),BETA(7),KSF,L,R,TXIN,BOM(7),OM(7,16),ETA(7)
3/F/EFF(7,16),F(7),Q(3),FUEL(3),SFNAME(7)
4/V/MSF(7,16),MAGE(7,16),MSFO(15),BV(140),EV(140)
5/T/T,TTERM,IY,LY
10 6/N/NS,STNAME,BDU(7),Z1,GAM,RHO,DEGDAY5,T97
7/D/AGDE(3,16),DUO,DUK(7),DE(3),AGDUK(7,16),NEWAG(7,16)
8/H/TBTU,DMBTUH
READ(5,*) PIND, KF, NDIV, DELP
READ(5,*) ALPHA
15 READ(5,*) BETA
READ(5,*) ETA
READ(5,*) R, TXIN
PP = PIND(KF) * DELP*(NDIV-1)/2.
REWIND 15
20 C ITERATE ON PRICE
TTERM = LY - IY + 1
PIND(KF) = PIND(KF) - DELP
DO 100 KP=1,NDIV
PIND(KF) = PIND(KF) * DELP
25 DO 110 KT=1,TTERM
DO 105 K = 1, KSF
AGDUK(K,KT) = 0.0
NEWAG(K,KT) = 0
105 CONTINUE
30 DO 110 J = 1,NF
AGDE(J,KT) = 0.0
110 NS=51
C ITERATE ON STATES
CALL SPOT1
35 DO 200 KS = 1,NS
C READ IN STATE SPECIFIC DATA
READ(1,*) STNAME, BDU, GAM, RHO, DEGDAY5, T97, TDP
CALL TIME CALL FLOOD1
CALL DEMAND
40 IF (EOF(1)) 300,200
200 CONTINUE
300 CONTINUE
REWIND 1
WRITE(15) PIND(KF), AGDE,AGDUK, NEWAG
45 C STORE AGG DEMAND DATA ON TAPE
100 CONTINUE
ENDFILE 15
PIND(KF) = PP
CALL REPORT
50 STOP
END

```

```

SUBROUTINE TIME
INTEGER T, TTERM,STNAME,F,FUEL,SFNAME
COMMON
5 1/P/NF,PIND(3),P(3),ALPHA(3),TDP(3),KF,NDIV,DELP
2/C/BC(8,7),C(8,7),BETA(7),KSF,L,R,TXIN,BOM(7),OM(7,16),ETA(7)
3/F/EFF(7,16),F(7),Q(3),FUEL(3),SFNAME(7)
4/V/MSF(7,16),MAGE(7,16),MSFO(15),BV(140),EV(140)
5/T/T,TTERM,IY,LY
10 6/N/NS,STNAME,BDU(7),Z1,GAM,RHO,DEGDAY5,T97
7/D/AGDE(3,16),DUO,DUK(7),DE(3),AGDUK(7,16),NEWAG(7,16)
8/H/TBTU,DMBTUH
CALL SETUP
C COMPUTE V PNT BACKWARDS IN TIME
DO 1000 KT=1,TTERM
15 C T STARTS AT TTERM AND GOES BACK TO 1
T=TTERM-KT+1
CALL UPDATE
IF(T-TTERM) 1200,1100
1100 CALL START
20 GO TO 1000
1200 CALL ITERATE
1000 CONTINUE
RETURN
END

```

```

SUBROUTINE SETUP
  INTEGER T, TTERM, STNAME, F, FUEL, SFNAME
  COMMON
    1/P/NF,PIND(3),P(3),ALPHA(3),TDP(3),KF,NDIV,DELP
    2/C/BC(8,7),C(8,7),BETA(7),KSF,L,R,IXIN,BQM(7),OM(7,16),ETA(7)
    3/F/EFF(7,16),F(7),Q(3),FUEL(3),SFNAME(7)
    4/V/MSF(7,16),MAGE(7,16),MSF0(15),BV(140),EV(140)
    5/T/T,TTERM,IY,LY
    6/N/NS,STNAME,BDU(7),Z1,GAM,RHO,DEGDAY5,T97
    7/D/AGDE(3,16),DUO,DUK(7),DE(3),AGDUK(7,16),NEWAG(7,16)
    8/H/TBTU,DMBTUH
    THP = 35
    DMRTUH = 65.-T97
    TBTU = DEGDAY5*15./1000.
    15 T3=AMAX1(THP-T97,0.0)
    MPP= 1.+(T3/(65.-T97))**2
    DO 100 I = 1, TTERM
      EFF(7,I) = 1./(MPP/2. + (1. - MPP))
      EFF(1,I) = EFF(2,I) = .6
      20 EFF(3,I) = EFF(4,I) = .55
      EFF(5,I)=EFF(6,I) = 1.0
    100 CONTINUE
      DO 150 I = 1, TTERM
        DO 175 J = 1,6
          25 OM(J,I) = BQM(J)*DMBTUH*(1.-ETA(J))**(I-1)
          175 CONTINUE
          OM(7,I) = BQM(7)*AMIN1(DMBTUH,30.)*(1.-ETA(7))**(I-1)
          1 + BQM(5)*AMAX1(0.0,DMBTUH-30.)*(1.-ETA(5))**(I-1)
          150 CONTINUE
        ENTRY UPDATE
        DO 200 IK=1,8
          DO 200 IK=1,6
            C(I,IK)=BC(I,IK)*DMBTUH*(1.0-BETA(IK))**(I-1)
          200 CONTINUE
          DO 250 I=1,8
            35 C(I,7)=BC(I,7)*AMIN1(DMBTUH,30.)*(1.0-BETA(7))**(I-1)
            1 +BC(I,5)*AMAX1(0.0,DMBTUH-30.)*(1.0-BETA(5))**(I-1)
            250 CONTINUE
            C(6,7)=C(6,7)-.5*BC(6,5)*AMAX1(0.0,DMBTUH-30.)*(1.-BETA(6))**I
          40 DO 300 IF=1,3
            P(IF)=PIND(IF)*(1.0*ALPHA(IF))**(I-1)
            J +TOP(IF)
          300 CONTINUE
          RETURN
    45 END

```

```

SUBROUTINE START
INTEGER T, TTERM, STNAME, F, FUEL, SFNAME, FF
COMMON
1/P/NF, PIND(3), P(3), ALPHA(3), TDP(3), KF, NDI, DELP
5 2/C/BC(8,7), C(8,7), BETA(7), KSF, L, R, TXIN, BOM(7), OM(7,16), ETA(7)
3/F/EFF(7,16), F(7), Q(3), FUEL(3), SFNAME(7)
4/V/MSF(7,16), MAGE(7,16), MSF0(15), BV(140), EV(140)
5/T/T, TTERM, IY, LY
6/N/NS, STNAME, BDU(7), Z1, GAM, RHO, DEGDAYS, T97
10 7/D/AGDE(3,16), DUO, DUK(7), DE(3), AGDUK(7,16), NEWAG(7,16)
8/H/TBTU, DMBTUH
C COMPUTE TERMINAL V. FOR EACH SYSTEM K
DO 500 K=1, KSF
VV=1.E10
15 C EVAL IMMED SWITCH TO KK
DO 600 KK=1, KSF
FF=F(KK)
NNN=1+(KK-1)*L
RR=(1.+R)*SRR/RR+L
20 VVV=C(1+K, KK)*C(1+KK, KK)/(RR-1.)+(TXIN=C(1, KK)*Q(FF)*(P(FF)/100.)
1 *TBTU/EFF(KK, T)+OM(KK, T))*RR/(RR-1.)
IF(VVV-VV) 610, 600, 600
610 VV=VVV
NN=KK
25 600 CONTINUE
EV(K*L)=VV
MSF(K, T)=NN
C HYPOTHEZIZE MAGE = 1
MAGE(K, T)=1
30 FF=F(K)
C EVAL END OF LIFE SWITCH
MT=L-1
DO 700 J=1, MT
RRN=(1.0/(1.0+R))**(L-J)-1.0
35 RRD=1.0/(1.0+R)-1.0
RR=RRN/RRD
M=MAX0(1, T-J+1)
VVV=(TXIN=C(1, K)*Q(FF)*(P(FF)/100.)*TBTU/EFF(K, M)
1 *OM(K, M))*RR *VV/(1.+R)**(L-J)
40 IF(VVV-VV) 710, 710, 720
C 710 IF DON'T SWITCH YET, 720 IF SWITCH
710 EV((K-1)*L+J)=VVV
MAGE(K, T)=J+1
GO TO 700
45 720 EV((K-1)*L+J)=VV
700 CONTINUE
500 CONTINUE
RETURN
END

```

```

SUBROUTINE ITERATE
INTEGER T, TTERM, STNAME, F, FUEL, SFNAME, FF
COMMON
1/P/NF, PIND(3), P(3), ALPHA(3), TDP(3), KF, NOIV, DELP
5 2/C/BC(8,7), C(8,7), BETA(7), KSF, L, R, TXIN, BOM(7), OM(7,16), ETA(7)
3/F/EFF(7,16), F(7), Q(3), FUEL(3), SFNAME(7)
4/V/MSF(7,16), MAGE(7,16), MSFO(15), BV(140), EV(140)
5/T/T, TTERM, IY, LY
10 6/M/NS, STNAME, BDU(7), Z1, GAM, RHO, DEGDAYS, T97
7/D/AGDE(3,16), DUO, DUK(7), DE(3), AGUUK(7,16), NEWAG(7,16)
8/M/TBTU, DMBTUM
MT=KSF+1
DO 100 KD=1, MT
K = KD - 1
15 C EVAL NEW SYSTEM
VV = 1.E10
DO 200 KK = 1, KSF
FF = F(KK)
NNN = (KK-1)*L + 1
20 VVV=C(1,K,KK) * TXIN+C(1,KK) * OM(KK,T+1)
1.0*(FF)*(P(FF)/100.)*TBTU/EFF(KK,T+1)
2 * EV(NNN)/(1. * R)
IF(VVV-VV) 210, 200, 200
210 VV = VVV
NN=KK
25 200 CONTINUE
IF(K) 150, 110
110 CONTINUE
C SET NEW BUILDS
30 MSFO(T) = NN
GO TO 100
150 CONTINUE
C EVAL STAYING WITH OLD SYSTEM
MSF(K,T) = NN
35 MAGE(K,T) = 1
FF = F(K)
NNN = (K-1)*L + 1
MT2=L-1
DO 300 J=1, MT2
40 BV(NNN) = VV
M = MAX0(1, MT-J+1)
VVV = TXIN+C(1,K) * OM(K, M)
1.0*(FF)*(P(FF)/100.)*TBTU/EFF(K,M)
2 * EV(NNN + 1)/(1. * R)
45 IF(VVV-VV) 310, 310, 320
310 BV(NNN) = VVV
MAGE(K,T) = J - 1
320 NNN = NNN + 1
300 CONTINUE
50 BV(NNN) = VV
100 CONTINUE
MT3=KSF+L
DO 400 KR=1, MT3
400 EV(KR) = BV(KR)
55 RETURN
END

```

```

SUBROUTINE DEMAND
DIMENSION DDU(140), DU(140)
EQUIVALENCE(BV,DDU), (EV,DU)
INTEGER T, TTERM,STNAME,F,FUEL,SFNAME,FF,TT
COMMON
5 1/P/NF,PIND(3),P(3),ALPHA(3),TOP(3),KF,NDIV,DELP
2/C/BC(8,7),C(8,7),BETA(7),KSF,L,R,TXIN,BQM(7),QM(7,16),ETA(7)
3/F/EFF(7,16),F(7),Q(3),FUEL(3),SFNAME(7)
4/V/MSF(7,16),MAGE(7,16),MSF0(15),BV(140),EV(140)
10 5/T/T,TTERM,IY,LY
6/N/NS,STNAME,BDU(7),Z1,GAM,RHO,DEGDAY, T97
7/D/AGDE(3,16),DUO,DUK(7),DE(3),AGDUK(7,16),NEWAG(7,16)
8/H/TBTU,DMBTUH
Z1= 0.0
15 DO 100 K = 1, KSF
DO 100 J = 1, L
KJ = (K-1)*L + J
DDU(KJ)=BDU(K)/L
Z1=Z1+DDU(KJ)
20 100 CONTINUE
DUO= 0.0
T = 0
C COMPUTE DEMAND FOR YEAR 1
ASSIGN 1000 TO LEAP
25 1000 CONTINUE
C UPDATE DU FORWARD
Z = Z1
MT = TTERM - 1
30 DO 2000 TT = 1, MT
T = TT
C GIVEN DECISIONS AT END OF T COMPUTE DU FOR T+1
DUO = Z*(GAM + RHO)
Z = (1. + GAM)*Z
35 MT2 = KSF*L
DO 2002 KJ = 1, MT2
2002 DDU(KJ) = 0.0
MS=(MSF0(T)-1)*L+1
DDU(MS)=DUO
40 DO 2003 K = 1, KSF
M = MAGE(K,T) - 1
IF(M) 10, 20
10 DO 2004 J = 1, M
KJ = (K-1)*L + J
45 DDU(KJ + 1) = DU(KJ)*(1. - RHO)
2004 CONTINUE
20 CONTINUE
MT3 = M+1
DO 2005 J = MT3, L
50 KJ = (K-1)*L+J
NKJ = (MSF(K,T)-1)*L+1
DDU(NKJ) = DDU(NKJ) + DU(KJ)*(1.0 - RHO)
2005 CONTINUE
2003 CONTINUE
55 ASSIGN 2200 TO LEAP
GO TO 2500
2200 CONTINUE

2000 CONTINUE
GO TO 4000
60 2500 CONTINUE
C COMPUTE DEMAND FOR T+1
DO 2001 KM = 1,NF
2001 DE(KM) = 0.0
DO 3000 K = 1, KSF
65 DUK(K) = 0.0
FF = F(K)
DO 3000 J = 1, L
KJ = (K-1)*L + J
DU(KJ) = DDU(KJ)
70 DUK(K) = DUK(K) + DU(KJ)
AGDUK(K,T+1) = AGDUK(K,T+1) +DU(KJ)
M = MAX0(1, T-J+2)
DD=TBTU*Q(FF)*DU(KJ)/(EFF(K,M)*1000.)
AGDE(FF,T+1) = AGDE(FF,T+1) + DD
75 DE(FF) = DE(FF) + DD
3000 CONTINUE
IF(T)3040,3050
3040 CONTINUE
NEWAG(MSF0(T),T+1)= NEWAG(MSF0(T),T+1) + 1
80 3050 CONTINUE
GO TO LEAP(1000,2200) CALL FLOOD2
4000 CONTINUE
CALL SPOT2
RETURN
85 END

```

```

SUBROUTINE SPTLITE
  INTEGER T, TTERM, STNAME, F, FUEL, SFNAME
  COMMON
  1/P/NF, PIND(3), P(3), ALPHA(3), TOP(3), KF, NDIV, DELP
  2/C/BC(8,7), C(8,7), BETA(7), KSF, L, R, TXIN, BQM(7), OM(7,16), ETA(7)
  3/F/EFF(7,16), F(7), Q(3), FUEL(3), SFNAME(7)
  4/V/MSF(7,16), MAGE(7,16), MSFO(15), BV(140), EV(140)
  5/T/T, TTERM, IY, LY
  6/N/NS, STNAME, BDU(7), Z1, GAM, RHO, DEGDAYS, T97
  7/D/AGDE(3,16), DU0, DUK(7), DE(3), AGDUK(7,16), NEWAG(7,16)
  8/M/TBTU, OMBTUM
  ENTRY SPOT1
  WRITE(6,800) FUEL, SFNAME
  800 FORMAT(1H1,15X,10A10, " NEW SYS")
  WRITE(6,600) PIND
  15 600 FORMAT(1H, "PRICE", 5X, 3E10, 3//)
  RETURN
  ENTRY SPOT2
  WRITE(6,700) STNAME, IY, T, DE, DUK, SFNAME(MSF0(T))
  20 700 FORMAT(1H, A5, I5, 10F10.2, 3X, A10)
  RETURN
  ENTRY FLOOD1
  WRITE(6,100) STNAME
  100 FORMAT(1H, 50X, A10)
  RETURN
  ENTRY FLOOD2
  WRITE(6,200) IY, T, DUK, DE
  25 200 IF(T) 400, 500
  400 CONTINUE
  30 500 WRITE(6,300) (MSF(K,T), MAGE(K,T), K=1,7), DU0, SFNAME(MSF0(T))
  CONTINUE
  200 FORMAT(1H, I4, 1X, 7E10.3, " ", E10.3, "BMCF", 1X, E10.3, "BGAL", 1X, E10.3,
  1"RKWH")
  300 FORMAT(1H, 5X, 7(2I4, 2X), " ", E10.3, "MM NEW DU WITH ", A10)
  35 300 RETURN
  END

```

```

SUBROUTINE REPORT
  INTEGER T, TTERM, STNAME, F, FUEL, SFNAME
  COMMON
  1/P/NF, PIND(3), P(3), ALPHA(3), TOP(3), KF, NDIV, DELP
  2/C/BC(8,7), C(8,7), BETA(7), KSF, L, R, TXIN, BQM(7), OM(7,16), ETA(7)
  3/F/EFF(7,16), F(7), Q(3), FUEL(3), SFNAME(7)
  4/V/MSF(7,16), MAGE(7,16), MSFO(15), BV(140), EV(140)
  5/T/T, TTERM, IY, LY
  6/N/NS, STNAME, BDU(7), Z1, GAM, RHO, DEGDAYS, T97
  7/D/AGDE(3,16), DU0, DUK(7), DE(3), AGDUK(7,16), NEWAG(7,16)
  8/M/TBTU, OMBTUM
  REWIND 15
  WRITE(6,500) FUEL(KF), PIND(KF), FUEL(KF), FUEL, SFNAME, (I,I=1,7)
  DO 50 LL=1, NDIV
  15 READ(15) PIND(KF), AGDE, AGDUK, NEWAG
  130 WRITE(6,500) PIND(KF), (IY=1, 4RT, (AGUE(J,RT), J=1,NF),
  1(AGDUK(J,KT), J=1,7), (NEWAG(J,KT), J=1,7), KT=1, TTERM)
  50 CONTINUE
  PRINT(6,700)
  20 700 FORMAT(1H, "THATS ALL FOLKS")
  RETURN
  500 FORMAT(1H1, 30X, "DEMAND CURVES AS FUNCTIONS OF THE PRICE OF", 1X,
  1 A10, 1X, "WITH BASE PRICES OF", 1H, 28X,
  1 "C", F10.4, "MCF FOR GAS, ",
  25 1 "C", F10.4, "GAL FOR OIL, ",
  1 "C", F10.4, "KWH FOR ELEC, ", 1H,
  1 "PRICE OF", 10X, "DEMAND FOR", 30X, "SF DU WITH", 45X, "ST BUY NEW", 1H,
  1 2X, A3, 3X, 3(3X, A4, 3X), 7(2X, A8), 713)
  600 FORMAT(1H, F6.2, 1H, I5, 3X, 10F10.1, 713)
  30 600 END

```



```

BLOCK DATA BSDATA
INTEGER T, TTERM, STNAME, F, FUEL, SFNAME
COMMON
1/P/NF, PIND(3), P(3), ALPHA(3), TOP(3), KF, NDIV, DELP
5 2/C/RC(8,7), C(8,7), BETA(7), KSF, L, R, TXIN, BQM(7), OM(7,16), ETA(7)
3/F/EFF(7,16), F(7), Q(3), FUEL(3), SFNAME(7)
4/V/MSF(7,16), MAGE(7,16), MSFO(15), BV(140), EV(140)
5/T/T, TTERM, IY, LY
6/N/NS, STNAME, BDU(7), Z1, GAM, RHO, DEGDAYS, T97
10 7/D/AGDE(3,16), DUO, DUK(7), DE(3), AGDUK(7,16), NEWAG(7,16)
8/H/IBTU, DMRTUM
DATA
1 NF, PIND, ALPHA, KF, NDIV, DELP
15 1/3.40, 10, 1.6, 3(0.0), 1, 3, 20, /,
2 KSF, L, R, TXIN
2/ 7, 20, .10, .02/,
3 BQM, ETA /
4 .346, .346, .544, .544, .369, .390, 1.33,
5 7(0.0) /,
20 6 ((BC(I,J), J=1,7), I=1,8), BETA/
7 30.54, 30.54, 32.76, 32.76, 31.10, 19.48, 48.48,
8 8.66, 41.48, 10.88, 43.70, 9.22, 29.22, 26.60,
9 41.48, 8.66, 43.70, 10.88, 42.04, 29.22, 59.42,
1 8.66, 41.48, 10.88, 43.70, 9.22, 29.22, 26.60,
25 1 41.48, 8.66, 43.70, 10.88, 42.04, 29.22, 59.42,
2 8.66, 41.48, 10.88, 43.70, 9.22, 29.22, 26.60,
3 41.48, 41.48, 43.70, 43.70, 42.04, 0.0, 59.42,
4 8.66, 41.48, 10.88, 43.70, 9.22, 29.22, 26.60,
5 7(0.0) /,
30 DATA
6 SFNAME, F, FUEL, Q
7/6HGAS-WA, 6HGAS-HW, 6HOIL-WA, 6HOIL-HW,
8 7HELEC-WA, 8HELEC-RES, 6MHEAT-P,
1 1, 1, 2, 2, 3, 3, 3,
35 9 3HGAS, 3HOIL, 4HELEC,
1 1.0, 7.0423, 293.0
1 IY, LY/1970,1985/,
1 NS/ 51/
END

```

TABLE VI

Standard Output (SPOT Version)

PRICE	GAS .220E+03	OIL .200E+02	ELEC .800E+00	GAS-WA	GAS-HW	OIL-WA	OIL-HW	ELEC-WA	ELEC-RES	HEAT-P	NEW SYS
MAIN 1985	0.00	282.86	0.00	0.00	0.00	139.46	33.81	0.00	0.00	0.00	OIL-WA
VERM 1985	0.00	134.72	0.00	0.00	0.00	76.27	11.41	0.00	0.00	0.00	OIL-WA
NHAM 1985	0.00	225.55	0.00	0.00	0.00	127.14	29.42	0.00	0.00	0.00	OIL-WA
MASS 1985	0.00	1472.64	0.00	0.00	0.00	908.05	271.56	0.00	0.00	0.00	OIL-WA
CONN 1985	0.00	732.41	0.00	0.00	0.00	496.83	138.91	0.00	0.00	0.00	OIL-WA
RHIS 1985	0.00	222.92	0.00	0.00	0.00	145.51	47.93	0.00	0.00	0.00	OIL-WA
N.Y. 1985	0.00	4111.32	0.00	0.00	0.00	2625.14	942.51	0.00	0.00	0.00	OIL-WA
PENN 1985	15.94	2043.95	752.44	70.63	45.32	1621.83	313.10	0.00	31.13	0.00	OIL-WA
N.J. 1985	0.00	1390.48	0.00	0.00	0.00	1176.92	331.58	0.00	0.00	0.00	OIL-WA
MYLD 1985	0.00	1020.94	0.00	0.00	0.00	1082.83	98.42	0.00	0.00	0.00	OIL-WA
D.C. 1985	0.00	151.79	0.00	0.00	0.00	154.05	34.08	0.00	0.00	0.00	OIL-WA
DELA 1985	0.00	124.50	0.00	0.00	0.00	118.67	10.97	0.00	0.00	0.00	OIL-WA
WVA. 1985	2.87	307.25	115.31	24.86	.61	349.58	5.92	0.00	5.83	0.00	OIL-WA
VIRG 1985	0.00	980.28	0.00	0.00	0.00	1205.64	70.47	0.00	0.00	0.00	OIL-WA
N.C. 1985	0.00	945.45	0.00	0.00	0.00	1390.24	16.49	0.00	0.00	0.00	OIL-WA
S.C. 1985	1.35	318.57	130.25	21.61	0.00	654.10	9.37	0.00	11.85	0.00	OIL-WA
GEOR 1985	4.60	571.81	245.97	73.68	0.00	1185.01	5.88	0.00	22.39	0.00	OIL-WA
FLA. 1985	35.73	4.96	240.49	2362.11	19.82	36.42	6.61	0.00	91.20	0.00	GAS-WA
WISC 1985	0.00	1639.77	0.00	0.00	0.00	1041.07	67.72	0.00	0.00	0.00	OIL-WA
MICH 1985	0.00	2252.90	0.00	0.00	0.00	1491.17	72.83	0.00	0.00	0.00	OIL-WA
ILL. 1985	27.32	2750.80	0.00	132.54	59.16	2282.81	229.89	0.00	0.00	0.00	OIL-WA
IND. 1985	10.81	1412.44	0.00	74.55	1.29	1248.75	41.44	0.00	0.00	0.00	OIL-WA
OHIO 1985	28.22	2837.49	0.00	177.60	17.00	2451.87	95.33	0.00	0.00	0.00	OIL-WA
KTY. 1985	0.00	680.22	336.31	0.00	0.00	761.40	8.52	0.00	16.64	0.00	OIL-WA
TENN 1985	0.00	0.00	15868.11	0.00	0.00	0.00	0.00	176.17	855.40	0.00	ELEC-RES
MISS 1985	29.40	.12	90.94	534.30	.28	.20	.09	0.00	9.41	0.00	GAS-WA
ALAB 1985	48.98	.59	198.75	850.63	1.26	.91	.42	0.00	19.62	0.00	GAS-WA
NDAK 1985	0.00	225.70	0.00	0.00	0.00	116.33	10.33	0.00	0.00	0.00	OIL-WA
SDAK 1985	1.70	211.65	0.00	8.71	0.00	135.23	6.05	0.00	0.00	0.00	OIL-WA
MINN 1985	0.00	1691.40	0.00	0.00	0.00	904.77	84.72	0.00	0.00	0.00	OIL-WA
NEB. 1985	4.95	419.82	0.00	28.29	1.24	318.25	7.99	0.00	0.00	0.00	OIL-WA
IOWA 1985	8.38	824.05	0.00	47.50	1.80	609.01	21.96	0.00	0.00	0.00	OIL-WA
KAN. 1985	68.40	.81	0.00	519.02	7.12	.55	.26	0.00	0.00	0.00	GAS-WA
MSHI 1985	11.24	1031.18	0.00	84.17	7.62	1060.82	34.89	0.00	0.00	0.00	OIL-WA
OKLA 1985	63.46	.08	0.00	703.80	1.34	.08	.04	0.00	0.00	0.00	GAS-WA
ARK. 1985	2.58	267.17	0.00	34.35	0.00	463.35	.33	0.00	0.00	0.00	OIL-WA
TEX. 1985	199.09	.43	0.00	3178.64	6.83	.61	.28	0.00	0.00	0.00	GAS-WA
LSNA 1985	37.49	.12	44.98	935.00	2.17	.27	.13	0.00	6.40	0.00	GAS-WA
IDA. 1985	0.00	174.15	0.00	0.00	0.00	137.17	2.33	0.00	0.00	0.00	OIL-WA
MONT 1985	0.00	209.39	0.00	0.00	0.00	132.07	4.20	0.00	0.00	0.00	OIL-WA
WYO. 1985	12.88	.23	0.00	65.92	1.84	.11	.05	0.00	0.00	0.00	GAS-WA
NEV. 1985	22.67	1.28	0.00	143.03	.90	.76	.30	0.00	0.00	0.00	GAS-WA
UTAH 1985	37.32	.45	0.00	241.24	3.50	.50	.23	0.00	0.00	0.00	GAS-WA
COL. 1985	88.90	.62	0.00	544.85	19.62	.35	.16	0.00	0.00	0.00	GAS-WA
ARIZ 1985	1.69	309.16	0.00	20.42	.12	487.17	.61	0.00	0.00	0.00	OIL-WA
NMEX 1985	2.75	395.80	0.00	23.56	.34	446.51	1.49	0.00	0.00	0.00	OIL-WA
WASH 1985	0.00	784.42	0.00	0.00	0.00	741.98	14.35	0.00	0.00	0.00	OIL-WA
ORE. 1985	0.00	536.57	0.00	0.00	0.00	483.68	6.81	0.00	0.00	0.00	OIL-WA
CAL. 1985	18.28	2734.29	0.00	236.17	7.51	4720.61	24.88	0.00	0.00	0.00	OIL-WA
ALSK 1985	0.00	158.57	0.00	0.00	0.00	61.48	7.32	0.00	0.00	0.00	OIL-WA
HAW. 1985	.00	.00	5.92	14.66	1.39	.40	.22	3.11	131.56	0.00	ELEC-RES

The non-standard output (FLOOD version) substitutes an extensive report in place of the first, SPOT, report above. A full report is generated for each price, state, and year. A sample output for a given price and state, is given in Table VII.

The output is given in two lines. Line 1: year, DUK (7), DE (3). Line 2: MSF (7), MAGE (7), DUO, name of system chosen for new buildings.

VII. Curve variables - definitions and units by common block. (*denotes input data)

/P/	*NF	number of fuels (=3)
	*PIND (3)	nat'l. price indices: ¢/mcf, ¢/gal., ¢/kwh at start of relative year 1.
	P(3)	prices in given state and time.
	*ALPHA (3)	rate of fuel price increase (initial value is PIND)
	*TDP (3)	nat'l. price minus state price:
	*KF	index (1,2,3) of price to be changed
	*NDIV	number of prices above base to be tested
	*DELP	change (delta) in price for each iteration
/C/	*BC(8,7)	cost of transforming basic system I to basic
	BC(I,J)	system J at start of relative year 1, expressed in $\$/10^3$ BTU/h output
		I = 1,2,..., 8 (= 0,1,...,7), J = 1,...,7.

Systems:

(system-fuel types)

	0 - New unit, unbuilt
	1 - Gas-WA gas forced war air
	2 - Gas-HW gas hot water
	3 - Oil-WA oil forced warm air
	4 - Oil-HW oil hot water
	5 - Elec-WA electric furnace forced warm air
	6 - Elec-RES electric baseboard resistance
	7 - Heat-P heat pump
C(8,7)	cost of transforming actual sized system I to system J in state being processed, \$.
*BETA (7)	rate of decrease of BC over time
KSF = 7	number of system-fuel types
L=20	life of system
R =	interest rate
TXIN=.02	taxes and insurance
BOM(7)	basic operation and maintenance
BOM(J)	costs of system J purchased at start of relative year 1 in $\$/10^3$ BTU/h output
OM(7,16)	actual (for given state) O&M Costs
OM(J,I)	of system J purchased at start of relative year I in \$.

TABLE VII
Standard Output (FLOOD Version)

TENN														
1971	.346E+03	0.	.397E+02	.172E-02	.105E+03	.261E+03	0.	*	.303E+02	BMCF	.383E+02	BGAL	.562E+04	BKWH
1972	.489E+03	.804E+00	.352E+02	.153E-02	0.	.243E+03	0.	*	.429E+02	BMCF	.339E+02	BGAL	.374E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.659E+02	MM NEW	DU WITH GAS-WA			
1973	.526E+03	.150E+01	.312E+02	.135E-02	0.	.227E+03	0.	*	.461E+02	BMCF	.300E+02	BGAL	.350E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.673E+02	MM NEW	DU WITH GAS-WA			
1974	.561E+03	.210E+01	.275E+02	.119E-02	0.	.212E+03	0.	*	.493E+02	BMCF	.265E+02	BGAL	.327E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.686E+02	MM NEW	DU WITH GAS-WA			
1975	.596E+03	.262E+01	.242E+02	.105E-02	0.	.198E+03	0.	*	.523E+02	BMCF	.233E+02	BGAL	.305E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.700E+02	MM NEW	DU WITH GAS-WA			
1976	.629E+03	.306E+01	.212E+02	.917E-01	0.	.185E+03	0.	*	.553E+02	BMCF	.204E+02	BGAL	.285E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.713E+02	MM NEW	DU WITH GAS-WA			
1977	.662E+03	.343E+01	.185E+02	.800E-01	0.	.173E+03	0.	*	.582E+02	BMCF	.178E+02	BGAL	.266E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.728E+02	MM NEW	DU WITH GAS-WA			
1978	.693E+03	.373E+01	.160E+02	.693E-01	0.	.162E+03	0.	*	.610E+02	BMCF	.154E+02	BGAL	.248E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.742E+02	MM NEW	DU WITH GAS-WA			
1979	.724E+03	.399E+01	.138E+02	.598E-01	0.	.151E+03	0.	*	.637E+02	BMCF	.133E+02	BGAL	.232E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.757E+02	MM NEW	DU WITH GAS-WA			
1980	.755E+03	.419E+01	.118E+02	.512E-01	0.	.141E+03	0.	*	.664E+02	BMCF	.114E+02	BGAL	.217E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.772E+02	MM NEW	DU WITH GAS-WA			
1981	.785E+03	.435E+01	.100E+02	.435E-01	0.	.132E+03	0.	*	.690E+02	BMCF	.966E+01	BGAL	.202E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.787E+02	MM NEW	DU WITH GAS-WA			
1982	.814E+03	.447E+01	.843E+01	.365E-01	0.	.123E+03	0.	*	.716E+02	BMCF	.812E+01	BGAL	.189E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.803E+02	MM NEW	DU WITH GAS-WA			
1983	.843E+03	.455E+01	.700E+01	.303E-01	0.	.115E+03	0.	*	.742E+02	BMCF	.674E+01	BGAL	.177E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.819E+02	MM NEW	DU WITH GAS-WA			
1984	.872E+03	.468E+01	.572E+01	.248E-01	0.	.107E+03	0.	*	.767E+02	BMCF	.551E+01	BGAL	.165E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 20	1 1	*	.835E+02	MM NEW	DU WITH GAS-WA			
1985	.900E+03	.463E+01	.458E+01	.198E-01	0.	.100E+03	0.	*	.792E+02	BMCF	.441E+01	BGAL	.154E+04	BKWH
	1 20	2 20	1 20	2 20	1 1	6 19	1 1	*	.851E+02	MM NEW	DU WITH GAS-WA			

ETA (7)	rate of decrease of O&M costs for new system of given output.
EFF (7,16)	efficiency of system J purchased at start of
EFF (J,1)	relative year 1.
F (8)	fuel index of system K.
F (k)	
Q (3)	conversion factors: mcf/ 10^6 BTU, gal/ 10^6 BTU, kwh/ 10^6 BTU
FUEL (3)	fuel names: GAS, OIL, ELEC
SFNAME (7)	names of system fuel types, see /C/BC
/V/ MSF (7,16)	index of system to which system J
MSF (j,T)	switches at end of relative year T.
MAGE (7,16)	age at which system J switches
MAGE (J,T)	at end of relative year T.
MSFO (15)	index of new system built at end of
MSFO (T)	year T.
EV (140)	vector of V function in state K at end of
EV (k)	period T+1. Vector is ordered as follows: V of system 1 in ages 1-20, ..., V of system 7 in ages 1-20, \$.
	V function gives discounted cost of heating optimally from end of T+1.
BV (140)	holding vector for V values at beginning of
BV (k)	period T+1. \$.
T	relative year.
TTERM	relative last year = LY-IY+1
IY	true first year
LY	true last year
/N/ NS	number of States
STNAME	State name
BDU (J)	d.u.'s with system J at start of first year, 10^3 d.u.
Z1	total d.u.'s in first year, 10^3 d.u.
GAM	rate of growth of total d.u.'s
RHO	rate of removal of existing d.u.'s
DEGDAYS	degree days
T97	97th percential temperature; only 3% of degree days occur at temperatures lower than this.
/D/ ADGE (3,15)	aggregate demand for fuel
AGDE (J,I)	J in year I, 10^6 $\left\{ \begin{array}{l} \text{mct} \\ \text{gal} \\ \text{kwh} \end{array} \right.$
DUO	new d.u.'s built, 10^3 d.u.'s
DUK (7)	d.u.'s of type K, 10^3 d.u.'s
DUK (K)	
DE (3)	demand for fuel J, 10^6 $\left\{ \begin{array}{l} \text{mcf} \\ \text{gal} \\ \text{kwh} \end{array} \right.$
DE (J)	

/H/ TBTU total BTU's per d.u. per year, 10^6 BTU
DMBTU design BTU/hr, 10^3 BTU/hr

Variables unique to subroutines

SETUP: THP Minimum operating temperature of heat pump
 HPP Percentage of degree days supplied by heat
 pump

START: VV, VVV Preliminary values for computing V function, \$.

ITERATE: VV, VVV Preliminary values for computing V function,

DEMAND: DU (140), DU(K) d.u.'s in configuration K at start of
 period T+1

 DUU(140) Holding values for computing DU.

APPENDIX B. DATA CONSTRUCTION

I. System Size, Efficiency, And Cost Estimates

All estimates are supposed to be for a 1970 time frame. Lack of timely and dated data has made the actual result, at best, only approximate.

I. 1. System size. The system size is determined by the design BTU's per hour of effective heat output to the home (in thousands), denoted DMBTUH.

Reference [1, p. 667] indicates that the main governing variable in determining DMBTUH for an actual home is the 97 1/2th percentile temperature, denoted here T97, for an area. This means that for only 2.5% of the degree days, the temperature falls below the T97.

Reference [12, p.6, Table 3] contains actual engineer's estimates of furnace size for an "average" home in 13 cities. Using this data, a rough linear fit is determined between DMBTUH and T97:

$$\text{DMBTUH} = 65. - \text{T97}.$$

The fit is rough since the engineering estimates are not made on a necessarily consistent basis and many other design and locational factors have a bearing. For instance, the "average home" could change among cities.

Note: The heat pump must be handled separately. References [12, p.5-7] and [13, p.5-18] indicate that the heat pump has a significantly greater efficiency than other electric heat sources only for DMBTUH less than 30. Thus the excess of DMBTUH over 30 is provided by electric furnace which uses the same duct system. [See section on Climate Data for source of T97's.]

I. 2. System efficiencies. System efficiencies (effective heating output in BTU's/input fuel BTU) are taken from Reference [12, p.5-7] to be .60 for gas, .55 for oil, 1.0 for electric resistance and electric furnace, and 2 for pure heat pump.

Note: Since heat pump systems generally require both heat pump and electric furnace, a combined efficiency must be determined. This was done by first determining for each state the proportion of the degree days of heating, denoted HPP, that were contributed by the heat pump. Then the efficiency was taken as the weighted efficiency:

$$\text{EFF} = 1/[\text{HPP}/2 + (1-\text{HPP})]$$

The HPP was determined by assuming that an equal number of days were spent at each temperature between the T97 temperature and 65°. Let THP=35, the temperature to which the heat pump is effective.

$$\begin{aligned}
HPP &= \left(\frac{THP - T97}{65 - T97} \right) (65 - THP) + \left(\frac{1}{65 - T97} \right) \int_{THP}^{65} (65-t) dt \\
&\quad \left(\frac{1}{65 - T97} \right) \int_{T97}^{65} (65-t) dt \\
&= 1 - \left(\frac{THP - T97}{65 - T97} \right)^2 \text{ if } T97 \leq 35 \\
HPP &= 1 \text{ if } T97 > 35.
\end{aligned}$$

I. 3. System costs. The basic data for capital costs for new construction was taken from Reference [12, p. 15-17, Tables 9-11]. The basic assumptions made to use these tables were:

- Costs are proportional to DBMTUH.
- The proportionality factor was determined by using a 50×10^3 BTU/hr output system (30×10^3 BTU/hr for the heat pump).
- A 3 ton rating for heat pump and duct work is interpreted as 36×10^3 BTU/hr output.
- An installation labor index of 1.3 is used.

The capital costs in \$/DMBTUH can then be determined from the formulae below separately for (1) duct work, (2) gas furnace, (3) oil furnace, (4) electric furnace, and (5) electric resistance (baseboard).

Investment costs of 50 DMBTUH output system =
 = cost of system in Table 9 with labor index 1.3/cost given in Table (labor index 1.0)
 x [(cost given in table)
 + ((required size minus table size)/increment size)
 x (cost of increment)]

This yields:

$$\text{Duct: } I_1 = (400 + 1.3 \times 400)/800 \left[800 + \frac{(50-36)}{6} \times 50 \right] = 1054$$

$$K_1 = I_1/50 = 21.08$$

$$\text{Gas: } I_2 = (300 + 1.3 \times 150)/450 \left[450 + \frac{83-130}{1.0} \times 12 \right] = 433$$

$$K_2 = I_2/50 = 8.66$$

$$\text{Oil: } I_3 = (400 + 1.3 \times 150)/550 \left[550 + \frac{91-130}{1.0} \times 12 \right] = 544$$

$$K_3 = I_3/50 = 10.88$$

$$\text{Elec. Furn: } I_4 = (350 + 1.3 \times 150)/500 \left[500 + \frac{14.6-19.2}{4.8} \times 80 \right] = 461$$

$$K_4 = I_4/50 = 9.22$$

$$\text{Elec. Res.: } I_5 = (300 + 1.3 \times 600)/900 \left[900 + \frac{14.6-19}{1.0} \times 30 \right] = 975$$

$$K_5 = I_5/50 = 19.48$$

The heat pump capital cost is determined by backing out the cost of electric furnace with size indicated in Table.

Step A Combined (3 ton) heat pump and (14.4 kw) electric at table size:

in table = 1550 with 1.3 labor index = 1625

Step B Electric furnace at 14.4 kw
with labor index 1.0 = $\left[500 + \frac{14.4-19.2}{4.8} \times 80 \right] = 420$

with index 1.3 = $(350 + 1.3 \times 150) \left[458 \right] = 458$

Step C Heat pump at 3 tons capacity

with labor index 1.0 = $1550 - 420 = 1130$

with labor index 1.3 = $1625 - 158 = 1167$

Step D Heat pump at 2.5 tons = 30 DMBTUH

$$I_6 = 1167/1130 \left[1130 + \frac{30-36}{6} \times 100 \right] = 1064$$

$$K_6 = I_6/30 = 35.47$$

For hot water systems the piping cost is taken to be the same as the ducting cost.

The K's are summarized in Table VIII.

Annual operation and maintenance cost are assumed proportional to capital cost. They are given in Table IX.

I. 4. BESOM input. For BESOM input, the annual capital charge equal to 10% plus the O&M percentage of the K's is computed. These total capital plus O&M costs are given as A's in Table X. The objective function coefficients in $\$/10^6$ BTU of input IEF usage for BESOM for each state are then computed as follows:

$$c(\text{gas}) = \text{DMBTUH} \times (A_1 + A_2) \times .6/\text{TBTU} + \text{IDP} \quad (1)$$

$$c(\text{oil}) = \text{DMBTUH} \times (A_1 + A_2) \times .55/\text{TBTU} + \text{TDP} \quad (2)$$

$$c(\text{elect.f.}) = \text{DMBTUH} \times (A_3 + A_4) \times 1.0/\text{TBTU} + \text{TDP} \quad (3)$$

$$c(\text{el.res.}) = \text{DMBTUH} \times (A_5) \times 1.0/\text{TBTU} + \text{TDP} \quad (3)$$

$$c(\text{h.p.}) = \text{DMBTU} \times A_1 + \min(\text{DMBTUH}, 30) \times A_6^* \\ + \max(\text{DMBTUH} - 30, 0) \times A_4 \text{ EFF}/\text{TBTU} \\ + \text{TDP} \quad (3)$$

See Appendix, Sec. 6, for table of data by state. Note that A_6^* is $.75 \times A_6$, i.e., .25 of the cost is attributed to air conditioning. See the section on fuel costs for explanation of TDP.

I. 5. Curve input. The BC and BOM matrices are computed for CURVE with following assumptions.

- To replace piping with duct work or the reverse, the cost is 1.5 times that for new construction.
- Air conditioning bears .25 of heat pump costs.
- Furnaces must be replaced at L years at the cost of a new furnace. Duct and piping has infinite life.
- Electric resistance has zero replacement cost.
- Furnaces can be converted at cost of new furnace.

The BC and BOM matrices are given in Table XI.

I. 6. Comments on data. 1) Many relationships were assumed to be linear with no constant term and eyeballed at that. However, to build up more exact and consistent representations from micro

TABLE X

Annual Amortized System
Cost for BESOM

Duct:

$$A_1 = 2.1080$$

Gas Furnace:

$$A_2 = 1.2124$$

Oil Furnace:

$$A_3 = 1.6320$$

Electric Furnace:

$$A_4 = 1.2908$$

Electric Baseboard:

$$A_5 = 2.3376$$

Heat Pump:

$$A_6 = 5.32$$

TABLE IX

Operating and Maintenance
as a Percentage of Capital Costs

Duct:

$$\frac{OM_1}{K_1} = 0.0$$

Gas Furnace:

$$\frac{OM_2}{K_2} = 4.0$$

Oil Furnace:

$$\frac{OM_3}{K_3} = 5.0$$

Electric Furnace:

$$\frac{OM_4}{K_4} = 4.0$$

Electric Baseboard:

$$\frac{OM_5}{K_5} = 2.0$$

Heat Pump:

$$\frac{OM_6}{K_6} = 5.0$$

TABLE VIII

Investment Cost in \$/Design
 10^3 BTU/hr of Output

Duct:

$$K_1 = 21.08 \text{ } \$/10^3 \text{ BTU/h}$$

Gas Furnace:

$$K_2 = 8.66 \text{ } \$/10^3 \text{ BTU/h}$$

Oil Furnace:

$$K_3 = 10.88 \text{ } \$/10^3 \text{ BTU/h}$$

Electric Furnace:

$$K_4 = 9.22 \text{ } \$/10^3 \text{ BTU/h}$$

Electric Baseboard:

$$K_5 = 19.48 \text{ } \$/10^3 \text{ BTU/h}$$

Heat Pump:

$$K_6 = 35.47 \text{ } \$/10^3 \text{ BTU/h}$$

$$.75K_6 = \boxed{26.60} \text{ AC disc.}$$

TABLE XI
Matrices (BC and BOM) of Unit Capital Costs for CURVE.

BC (x=relevant switches)	GAS-WA	GAS-HW	OIL-WA	OIL-HW	ELEC-WA	ELEC-RES	HEAT-P
	1	2	3	4	5	6	7
0	$K_1 + K_2^x$ 30.54	$K_1 + K_2^x$ 30.54	$K_1 + K_3^x$ 32.76	$K_1 + K_3^x$ 32.76	$K_1 + K_4^x$ 31.10	K_5^x 19.48	$K_1 + K_6^x$ 48.48
1 GAS-WA	K_2^x 8.66	$1.5K_1 + K_2^x$ 41.48	K_3^x 10.88	$1.5K_1 + K_3^x$ 43.70	K_4^x 9.22	$1.5K_5^x$ 29.22	K_6^x 26.60
2 GAS-HW	$1.5K_1 + K_2^x$ 41.48	K_2^x 8.66	$1.5K_1 + K_3^x$ 43.70	K_3^x 10.88	$1.5K_1 + K_4^x$ 42.04	$1.5K_5^x$ 29.22	$1.5K_1 + K_6^x$ 59.42
3 OIL-WA	K_2^x 8.66	$1.5K_1 + K_2^x$ 41.48	K_3^x 10.88	$1.5K_1 + K_3^x$ 43.70	K_4^x 9.22	$1.5K_5^x$ 29.22	K_6^x 26.60
4 OIL-HW	$1.5K_1 + K_2^x$ 41.48	K_2^x 8.66	$1.5K_1 + K_3^x$ 43.70	K_3^x 10.88	$1.5K_1 + K_4^x$ 42.04	$1.5K_5^x$ 29.22	$1.5K_1 + K_6^x$ 59.42
5 ELEC-WA	K_2^x 8.66	$1.5K_1 + K_2^x$ 41.48	K_3^x 10.88	$1.5K_1 + K_3^x$ 43.70	K_4^x 9.22	$1.5K_5^x$ 29.22	K_6^x 26.60
6 ELEC-RES	$1.5K_1 + K_2^x$ 41.48	$1.5K_1 + K_2^x$ 41.48	$1.5K_1 + K_3^x$ 43.70	$1.5K_1 + K_3^x$ 43.70	$1.5K_1 + K_4^x$ 42.04	0	$1.5K_1 + K_6^x$ 59.42
7 HEAT-P	K_2^x 8.66	$1.5K_1 + K_2^x$ 41.48	K_3^x 10.88	$1.5K_1 + K_3^x$ 43.70	K_4^x 9.22	$1.5K_5^x$ 29.22	K_6^x 26.60
BOM	$.04 * K_2$.346	$.04 * K_2$.346	$.05 * K_3$.544	$.05 * K_3$.544	$.04 * K_4$.369	$.02 * K_5$.390	$.05 * K_6$ 1.33

data would be costly and cumbersome. 2) Better techniques and more balanced data collection (experimental design) should be used to improve the approximation by simple relationships. 3) The best short term method would be to calibrate using the macro results of the model over a few years and regions. That is, estimate the parameters using the predictions of the models developed in the study.

II. Fuel Price Data

Since fuel prices generally vary across the country, a simple scheme was sought so that demand curves could be calculated as functions of a single exogenous price for each fuel. This was done by assuming that whatever caused the price difference was in long run equilibrium and that its influence would stay constant under fuel demand and supply changes. Thus the exogenous price was taken to be the national average price. Regional home fuel prices were computed by taking fixed differences from the national average. These differences are labelled TDP(3) (meaning "transportation differences in price"). All references for price are to [7].

The national average price used to compute the TDP's were the Chicago commercial prices of : 68¢/mcf (Table 5-a, p. 190), 10¢/gal (Table 5-b, p. 192), and 1.6¢/kwh (Table 5-d, p. 196).

All price series were quite stable up to 1967, so that year was used to compute the State specific prices for the TDP's. Since prices are given for only a few cities, guesses had to be made about the reasons for the differences so that they could be extended to a list covering all states. This is discussed by fuel.

II. 1. Gas. When the residential price data points given in table 4b, p. 182 are put on a map and compared to gas sources in Reference [8], they appear in the major part to be determined by transport costs. The actual list of TDP's was then determined by roughly interpolating and extrapolating the given data, assuming they are caused by transportation differences.

II. 2. Oil. Residential oil prices given in Table 4-c, p. 184 appear very flat as if subject to very low long distance transportation costs. Therefore a price of 16¢/gal was set for each state with a slight increase to 17¢/gal in New England.

II. 3. Electricity. Geographical price variations in Table 4-e, p. 188 for residential consumers appear very erratic. Since it is very costly to transport electric power, prices seem to depend on very local generation and distribution conditions such as: closeness to hydropower, age and efficiency of existing system, and physical structure of the area to be supplied. Reference [9] also strongly indicates that differences in fixed charges (not fuel prices) account for most of the regional price differences in electricity. Under this supposition, guesses were made to extend the given data to a list for all states.

II. 4. Comments on data: 1) The biggest question is "How to represent regional price differences?" 2) To do better, more explicit models generating regional differences would have to be developed and more extensive data found or collected to estimate the models.

III. Climatic Data

III. 1. Degree days. A crude approximation to the degree days of each state was obtained by employing a map with the average annual degree days [9] and a list of average annual degree days for various cities located in each state [2, p. 43.3-8, Table 2]. If a state was populous and geographically flat, we averaged the degree day zones that may cross through a particular state. If a state was mountainous and hence had regions of high average degree days, we tended to use the average of degree days of the major cities since that is where the population tends to concentrate.

III. 2. T97's. To compute the 97½ percentile temperatures, we used [1, p. 669-681, Table 2] and "averaged" the values for major cities in a state, as with degree days.

IV. Housing Stock And Projections

IV. 1. SFDU at the beginning of 1970. The report of A.D. Little [11, p. 56, Table 2.6] provides estimates of SFDU in four geographical regions: north, south, central and west. Using the 1970 census of population, [14, p. 32, Table 2], we determined the fraction of regional population in each state in that region by summing the population in all states in a region and dividing each states population by this total. The product of this number with the A.D. Little figure yields an estimate of SFDU in each state.

IV. 2. Growth rates of SFDU. The same A.D. Little report provides projections of SFDU for the four regions mentioned above for 1980, 1985, and 1990 [11, p. 56, Table 2.6].

A simple log linear regression of total regional SFDU on time gives a crude approximation to the growth rate. Each state in a particular region is then assigned the regional growth rate.

IV. 3. Removal rate of SFDU. The same A.D. Little study has provided estimates of the removal rate by region for 1980, 1985, and 1990 [11, p. 53, Table 2.4]. Since the effects of this parameter are relatively small, the average of the numbers for the three years for each region was taken to be the removal rate between 1970 and 1985. Again, each state in a given region is assumed to have the removal rate of the region in which it is located.

V. Existing Fuel Systems

Only national data for a full table of fuel and heat distribution system was available, so we estimated these parameters, using a constrained least squares formulation, from known marginal data, by state, for fuels and heat systems, and known national conditionals for systems given fuels.

Let: s_i = % of all occupied DU in a given state using system i ,
 f_j = % of all occupied DU in a given state using fuel j ,
 B_{ij} = % of single family DU nationally using fuel j that have system i ,
 b_{ij} = % of single family DU in a given state using fuel j that have system i (these are the numbers to be estimated).

The problem is to minimize $\sum_i \sum_j (B_{ij} - b_{ij})^2$

subject to $\sum_j b_{ij} f_j = s_i$

$\sum_i b_{ij} = 1, b_{ij} \geq 0.$

In our model, the fuels $j=1-4$, are oil, gas, electricity, and an "other" category. Similarly, the distribution systems, $i=1,5$, are warm air furnaces (WAF), steam or hot water (SHW) systems, floor, wall or pipeless furnaces (FWP), built in electric units (BIE) and an "other" classification. The s_i and f_j figures were obtained for each state from the 1970 Census of Housing [5, p. 1-248-1.259, Table 23-4]. The components of our numbers in terms of the census data are provided below:

<u>Systems:</u>	<u>SHW</u>	<u>WAF</u>	<u>RLE</u>	<u>FWP</u>	<u>OTHER</u>
	same	same	same	same	room heaters w/flue room heaters w/o flue fireplaces
<u>Fuels:</u>	<u>GAS</u>	<u>OIL</u>	<u>ELEC.</u>	<u>OTHER</u>	
	utility gas	fuel oil	same	coal	
	bottled gas	kerosene		coke	
				wood	
				other fuel	

The known national figures for the B_{ij} were obtained from 4, p. 6-7, Table A-4 and are included here.

	<u>OIL</u>	<u>GAS</u>	<u>OTHER</u>	<u>ELEC.</u>
WAF	.4380	.5493	.2500	.2560
OTHER	.2018	.2318	.6200	.0892
SHW	.3178	.0832	.1036	0
FWP	.0425	.1357	.0264	0
BIE	0	0	0	.6548

The estimated b_{ij}, although estimated using all occupied housing data, were then used for the conditional percentages for SFDUs in the given state.

In CURVE we used 7 fuel heating distribution system pairs with the following definition

$$\text{GAS-WA} = (\text{GAS} \times \text{WAF}) + (\text{GAS} \times \text{OTHER}) + (\text{GAS} \times \text{FWP})$$

$$\text{GAS-HW} = (\text{GAS} \times \text{SHW})$$

$$\text{OIL-WA} = (\text{OIL} \times \text{WAF}) + (\text{OIL} \times \text{OTHER}) + (\text{OIL} \times \text{FWP})$$

$$\text{OIL-HW} = (\text{OIL} \times \text{SHW})$$

$$\text{ELEC-WA} = (\text{WAF} \times \text{ELEC}) + (\text{OTHER FUEL} \times \text{ELEC})$$

$$\text{ELEC-RES} = (\text{BIE} \times \text{ELEC})$$

$$\text{HEAT-P} = \text{Assumed zero in 1970}$$

VI. CURVE And BESOM Data By State

State specific data is presented in Table XII for BESOM and in Table XIII for CURVE.

TABLE XII
State Specific Data for BESOM

STNAME	DRYS	T97	DBTU	T8TU	POP70	POP85	DEMO	CGAS	CCIL	CEFN	CEHS	CHEP	EFF
MAIN	8500.	-3.	68.0	127.5	150.3	178.7	22.7791	2.5825	1.5903	6.7917	6.2257	8.7096	1.5241
VERM	8000.	-8.	73.0	120.0	67.5	90.7	10.8861	2.7319	1.7445	7.0466	6.4010	9.0510	1.4848
NHAM	7500.	0.	65.0	112.5	112.1	159.2	17.9107	2.6711	1.6817	6.9428	6.3296	9.1397	1.5505
MASS	6500.	5.	60.0	97.5	861.0	1190.6	116.0809	2.6460	1.7590	9.1216	8.4685	11.7053	1.6000
CONN	6000.	3.	62.0	90.0	459.1	640.3	57.6225	2.3924	1.9102	7.3204	6.5893	10.0977	1.5793
RHIS	6000.	10.	55.0	90.0	143.7	194.5	17.5071	2.2375	1.7502	7.9350	7.2865	10.7921	1.6575
N.Y.	6000.	10.	55.0	90.0	2758.6	3657.4	329.1649	2.0375	1.7150	6.1770	5.5285	9.0341	1.6575
PENN	5500.	12.	53.0	82.5	1794.6	2362.4	194.8956	1.4999	1.7794	4.8185	4.1367	7.9618	1.6830
N.J.	4800.	15.	50.0	72.0	1067.0	1538.5	110.7689	2.4035	1.8865	5.5813	4.8443	9.2295	1.7241
MYLD	4500.	15.	50.0	67.5	903.7	1214.8	81.9994	2.1457	1.9465	5.7386	4.9526	9.6301	1.7241
D.C.	4200.	15.	50.0	63.0	173.5	187.2	11.7929	2.2511	2.0553	5.9185	5.0762	10.0879	1.7241
DELA	5000.	15.	50.0	75.0	108.7	132.0	9.9033	2.3482	1.7941	5.4869	4.7794	8.9892	1.7241
WVA.	4500.	13.	52.0	67.5	400.8	457.3	30.8685	1.6048	2.0074	5.2533	4.4358	9.1117	1.6964
VIRG	4000.	18.	47.0	60.0	1068.1	1423.5	85.4103	2.2306	2.0341	5.8834	5.0521	10.3167	1.7686
N.C.	3500.	21.	44.0	52.5	1168.6	1519.1	79.7514	2.2397	2.1467	6.6555	5.7661	11.7815	1.8161
S.C.	2500.	23.	42.0	37.5	595.9	741.0	27.7885	2.5513	2.7256	7.6137	6.4251	14.8385	1.8491
GEOR	2500.	23.	42.0	37.5	1056.4	1377.9	51.6707	2.4713	2.7266	7.6137	6.4251	14.8385	1.8491
FLA.	600.	44.	21.0	9.0	1571.2	2459.3	22.1340	4.7886	5.2224	13.2025	10.7264	33.7293	2.0000
WISC	7700.	-5.	70.0	115.5	973.0	1144.9	132.2304	1.4574	1.6694	7.0389	6.3957	9.1417	1.5077
MICH	7500.	5.	60.0	112.5	1169.3	1609.4	181.0537	1.2525	1.5198	6.7917	6.2257	9.0310	1.6000
ILL.	5700.	0.	65.0	85.5	2444.4	2952.7	252.4525	1.7646	1.9866	8.4419	7.6351	11.3326	1.5505
IND.	5700.	4.	61.0	85.5	1143.1	1425.4	121.8723	1.6414	1.8903	7.4039	6.6468	10.3387	1.5895
OHIO	5800.	5.	63.0	87.0	2345.8	2848.0	247.7782	1.4440	1.8414	6.4440	5.7121	9.3396	1.6000
KTY.	4600.	12.	53.0	69.0	740.0	944.7	65.1838	2.1003	2.0028	5.2457	4.4305	9.0040	1.6830
TENN	3500.	18.	47.0	52.5	902.6	1211.8	63.6191	2.3535	2.2643	2.4547	1.5047	7.5213	1.7686
MISS	2200.	24.	41.0	33.0	508.7	595.8	19.6617	2.3952	2.9784	8.3228	7.0043	16.5565	1.8657
ALAB	2300.	24.	41.0	34.5	792.1	976.9	33.7024	2.3876	2.8673	8.1392	6.8780	16.0149	1.8657
NDAK	9300.	-19.	84.0	139.5	135.6	134.6	18.7724	1.4196	1.6614	5.8536	5.2146	7.5247	1.4152
SDAK	7800.	-12.	73.0	117.0	146.2	153.2	17.9271	1.4311	1.7765	6.0438	5.3454	8.0748	1.4571
MINN	8900.	-13.	76.0	133.5	838.9	1019.9	136.1520	1.3840	1.6246	5.7928	5.1728	7.5676	1.4504
NEB.	6700.	-1.	66.0	100.5	327.0	359.9	36.1749	1.3183	1.7736	6.3320	5.6351	8.7824	1.5414
IOWA	6800.	-3.	68.0	102.0	521.1	694.1	70.7960	1.4482	1.7941	7.2449	6.5374	9.6422	1.5241
KAN.	5200.	6.	55.0	78.0	493.4	531.2	41.4310	1.3770	1.9787	6.6709	5.8682	9.9135	1.6108
MSRI	4900.	8.	57.0	73.5	1030.0	1234.0	90.7008	1.6850	2.0180	7.6148	6.7918	11.0842	1.6335
OKLA	3600.	15.	50.0	54.0	590.4	717.7	38.7534	1.8547	2.3274	7.5400	6.5574	12.4044	1.7241
ARM.	3000.	23.	42.0	45.0	442.1	543.2	24.4449	1.9294	2.3426	7.2722	6.2818	13.2929	1.8491
TEX.	2500.	30.	35.0	37.5	2583.3	3213.5	120.5055	1.8694	2.3426	7.2722	6.2818	14.5499	1.9600
LSNA	1600.	30.	35.0	24.0	836.5	959.2	23.0216	2.7854	3.4226	9.0566	7.5090	20.4279	1.9600
IDA.	6500.	8.	57.0	97.5	155.1	154.5	15.0600	1.6847	1.6253	5.7940	5.1736	8.4094	1.6335
MONT	8000.	-16.	81.0	120.0	150.8	142.4	17.0900	1.6648	1.8112	6.1012	5.3849	8.0592	1.4322
WYO.	7600.	-5.	70.0	114.0	72.2	70.9	8.0795	1.1433	1.6858	5.8940	5.2424	8.0245	1.5077
NEV.	6300.	10.	55.0	94.5	106.6	145.6	13.7635	1.0795	1.6200	5.4921	4.8745	8.2132	1.6575
UTAH	6100.	9.	56.0	91.5	231.2	263.2	24.0788	1.0293	1.6817	5.5941	4.9447	8.3926	1.6453
COL.	6300.	3.	62.0	94.5	481.3	580.4	54.8497	1.1171	1.7723	6.3299	5.6337	8.9749	1.5793
ARIZ	3300.	33.	32.0	49.5	387.5	521.2	25.7977	1.3379	1.7525	5.7112	5.0252	11.1503	1.9922
NMEX	4600.	18.	47.0	69.0	421.5	500.3	34.5189	1.4070	1.8239	6.4151	5.6923	10.2701	1.7686
WASH	5400.	24.	41.0	81.0	738.5	784.2	63.5188	2.1084	1.4640	5.5274	4.9902	8.8819	1.8657
ORE.	5700.	27.	38.0	85.5	454.7	517.4	44.2344	1.4054	1.3370	5.3176	4.8459	8.5137	1.9151
CAL.	3000.	37.	28.0	45.0	4324.9	5034.7	226.5629	1.2596	1.7027	5.6288	4.9685	11.1026	2.0000
ALSK	12000.	-20.	85.0	180.0	66.0	77.2	13.8968	2.7608	1.3941	5.7050	5.2039	6.9968	1.4098
HAW.	10.	61.	4.0	.2	164.8	194.5	.0292	54.9464	55.2761	94.7347	66.4360	329.3267	2.0000

TABLE XIII
State Specific Data for CURVE

STNAME	RDU	1	2	3	4	CURVE DATA 5	6	7 GAMMA	RHO	DOYS T97	TDP 1	2	3
MAIN	4.431	.429	74.141	63.920	1.005	1.858	0.000	.0116	.0420	8500. -3.	152.00	7.00	1.70
VERM	6.331	.643	33.255	21.066	.131	3.843	0.000	.0199	.0420	8000. -8.	152.00	7.00	1.70
NHAM	13.058	1.947	36.329	54.052	.609	4.258	0.000	.0237	.0420	7500. 0.	152.00	7.00	1.70
MASS	178.077	72.230	122.960	444.649	1.913	33.227	0.000	.0218	.0420	6500. 5.	142.00	7.00	2.40
CUNN	79.794	21.302	87.690	243.087	2.418	21.592	0.000	.0224	.0420	6000. 3.	102.00	7.00	1.70
RHIS	29.191	11.956	18.527	79.272	.279	3.648	0.000	.0204	.0420	6000. 10.	102.00	7.00	2.00
N.Y.	599.645	475.862	248.991	1318.060	10.344	38.091	0.000	.0190	.0420	6000. 10.	82.00	6.50	1.40
PENN	537.730	345.002	291.091	337.180	11.392	59.247	0.000	.0185	.0420	5500. 12.	22.00	6.50	.90
N.J.	259.380	198.142	139.913	432.962	4.021	31.403	0.000	.0234	.0420	4800. 15.	102.00	6.50	1.10
MYLD	339.050	97.736	219.759	176.357	15.933	29.913	0.000	.0199	.0660	4500. 15.	67.00	6.00	1.10
D.C.	47.798	59.424	25.231	35.481	0.000	6.609	0.000	.0051	.0660	4200. 15.	67.00	6.00	1.10
DELA	30.925	4.308	40.707	26.248	1.011	3.545	0.000	.0130	.0660	5000. 15.	102.00	6.00	1.10
WVA.	276.893	6.796	25.319	11.381	2.356	16.236	0.000	.0088	.0660	4500. 13.	7.00	6.00	.90
VIRG	313.123	29.281	352.746	166.978	21.260	74.083	0.000	.0193	.0660	4000. 18.	67.00	6.00	1.10
N.C.	231.180	.394	678.957	45.533	31.982	94.143	0.000	.0176	.0660	3500. 21.	57.00	6.00	1.30
S.C.	240.736	0.000	239.922	26.098	20.666	33.013	0.000	.0146	.0660	2500. 23.	32.00	6.00	1.30
GEOR	820.699	0.000	36.099	16.386	51.114	62.343	0.000	.0179	.0660	2500. 23.	24.00	6.00	1.30
FLA.	598.251	0.000	405.695	73.582	276.022	253.966	0.000	.0303	.0660	600. 44.	14.00	6.00	1.80
WISC	501.051	41.297	262.415	119.447	5.598	12.503	0.000	.0109	.0560	7700. -5.	25.00	6.00	1.70
MICH	757.392	89.527	173.440	83.353	8.128	21.605	0.000	.0217	.0560	7500. 5.	19.00	6.00	1.70
ILL.	1258.389	561.658	220.742	124.441	14.991	58.606	0.000	.0127	.0560	5700. 0.	25.00	6.00	2.00
IND.	707.810	12.284	218.825	89.156	10.857	56.509	0.000	.0148	.0560	5700. 4.	22.00	6.00	1.70
OHIO	1686.268	161.429	225.131	105.222	18.725	61.544	0.000	.0130	.0560	5800. 5.	7.00	6.00	1.40
KTY.	484.689	3.254	46.164	20.481	15.253	46.326	0.000	.0164	.0660	4600. 12.	57.00	6.00	.90
TENN	346.298	0.000	39.710	17.206	104.592	260.520	0.000	.0198	.0660	3500. 18.	57.00	6.00	-.20
MISS	404.892	0.000	2.224	1.032	30.329	26.192	0.000	.0106	.0660	2200. 24.	-8.00	6.00	1.40
ALAB	584.807	0.000	13.112	4.664	53.552	54.645	0.000	.0141	.0660	2300. 24.	2.00	6.00	1.40
NDAK	53.491	4.393	44.899	20.130	1.122	3.328	0.000	-.0005	.0560	9300. -19.	22.00	6.00	1.30
SDAK	82.670	0.000	41.163	14.364	1.004	3.887	0.000	.0031	.0560	7800. -12.	12.00	6.00	1.30
MINN	411.632	93.153	179.551	107.949	6.474	15.113	0.000	.0131	.0560	8900. -13.	22.00	6.00	1.30
NEB.	268.649	11.790	22.233	10.130	3.849	6.588	0.000	.0064	.0560	6700. -1.	1.00	6.00	1.40
IOWA	450.961	17.059	89.650	39.322	3.414	8.353	0.000	.0074	.0560	6800. -3.	12.00	6.00	1.70
KAN.	451.448	15.064	5.259	2.440	7.066	8.190	0.000	.0049	.0560	5200. 6.	-13.00	6.00	1.40
MSRI	799.207	72.333	61.316	28.557	8.447	21.331	0.000	.0121	.0560	4900. 8.	14.00	6.00	1.70
OKLA	545.875	3.426	.906	.422	15.634	13.925	0.000	.0131	.0660	3600. 15.	1.00	6.00	1.50
ARK.	382.602	0.000	2.004	.931	11.493	8.288	0.000	.0138	.0660	3000. 23.	7.00	6.00	1.40
TEX.	2321.445	16.643	6.796	3.161	143.798	69.620	0.000	.0147	.0660	2500. 30.	1.00	6.00	1.40
LSNA	762.932	4.991	3.024	1.406	32.970	17.813	0.000	.0092	.0660	1600. 30.	-12.00	6.00	1.40
IUA.	62.600	0.000	53.081	9.270	2.738	12.382	0.000	-.0003	.0880	6500. 8.	52.00	6.00	1.30
MONT	107.536	10.150	14.121	6.593	1.343	4.528	0.000	-.0038	.0880	8000. -16.	32.00	6.00	1.30
WYO.	58.202	6.748	1.682	.786	.578	1.241	0.000	-.0013	.0880	7600. -5.	-8.00	6.00	1.30
NEV.	52.330	0.000	12.083	4.788	23.477	13.484	0.000	.0210	.0880	6300. 10.	-8.00	6.00	1.20
UTAH	186.394	11.200	7.896	3.652	2.431	4.120	0.000	.0087	.0880	6100. 9.	-19.00	6.00	1.20
COL.	367.399	76.155	5.573	2.615	7.695	9.055	0.000	.0126	.0880	6300. 3.	-19.00	6.00	1.40
AKIZ	325.216	1.971	2.018	.937	32.494	15.440	0.000	.0199	.0880	3300. 33.	5.00	6.00	1.20
NMEX	375.302	5.398	4.048	1.876	4.875	6.115	0.000	.0115	.0880	4600. 18.	5.00	6.00	1.40
WASH	185.769	.531	244.930	56.612	30.197	194.212	0.000	.0040	.0880	5400. 24.	110.00	6.00	1.30
ORE.	123.322	0.000	145.139	27.113	20.937	114.558	0.000	.0086	.0880	5700. 27.	52.00	6.00	1.30
CAL.	3761.558	119.592	20.122	9.355	92.002	283.146	0.000	.0102	.0880	3000. 37.	2.00	6.00	1.20
ALSK	13.700	4.557	12.768	24.604	.684	2.482	0.000	.0105	.0880	12000. -20.	182.00	6.00	1.40
HAW.	16.387	2.919	6.413	3.494	49.585	49.487	0.000	.0111	.0880	10. 61.	182.00	6.00	1.40

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