MASTER

Power Plant Dispatch Study
An Analysis of the PIES Model of
Electric Utility Dispatch

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James E. Sustman

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Energy Management Associates, Inc.
100 Northcreek, Suite 500
Atlanta, Georgia 30327

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ABSTRACT

The electric utility sector sub-model within PIES uses a number of modeling approximations in order to formulate the power plant dispatch in a linear programming framework. Several such modeling details were studied using a probabilistic dispatch model (PROMOD III) to quantify the error introduced by each. These tests indicate that PIES tends to significantly underpredict the consumption of high cost fuels (distillates, etc.) by the electric utility sector. Two adjustments to the PIES model are suggested as means of overcoming this problem.

TABLE OF CONTENTS

I. Introduction	1
II. Benchmark Methodology.	3
III. The Effect of the PIES Dispatch Using An Annual Load Curve	4
IV. Effects of the Maintenance Schedule.	7
V. Dispatch of Derated Capacity	13
VI. PIES' Use of Generic Capacity Factors.	18
VII. Direct Comparison of PIES and PROMOD	23
VIII. Conclusions.	26

Appendix A

I. INTRODUCTION

The PIES model is used by the Department of Energy (DOE) in many applications requiring detailed energy forecasts. The results of such studies are used in major policy studies impacting the energy plan for the nation. Based on linear programming techniques, however, PIES has had many approximations incorporated into its model in order to reduce the massive problem to a manageable size. Such is particularly the case in the electric utility sector sub-model in PIES. Whereas the most sophisticated computer models used by the electric utility industry employ advanced probabilistic techniques to represent the effects of generating unit forced outages, PIES uses generic capacity factors developed from historical data to model the generation dispatch. The study presented here attempts to quantify the effects of some of the modeling approximations used by PIES in order to validate the model or to suggest areas for improvement.

The methodology employed to accomplish this benchmark is based around PROMOD, a probabilistic production costing program licensed by the Department of Energy from Energy Management Associates, Inc., and currently being used by companies comprising approximately 50% of the U. S. generating capacity. Using data provided by DOE's Energy Information Administration, PROMOD base cases were prepared for five centrally dispatched entities (CDE's). By modifying the data and using various optional features within PROMOD, the effects of a number of PIES' model approximations could be quantitatively measured. Finally, the data and results of the PROMOD base cases were transcribed into PIES formats, and corresponding PIES studies were run to compare with the PROMOD results. These tests provided a basis for evaluating the merits of individual PIES model features as well as the composite PIES model.

The major characteristics of PIES' dispatch model are:

- single dispatch against an annual load duration curve.
- load duration curve representation as four blocks of energy.
- operation of capacity at historical annual capacity factor, according to the class of capacity and region of load being served.
- no direct model of unit planned and forced outages, except as they affect the historical capacity factors.
- no modeling of startup costs.

Based on these characteristics, four separate modeling methodologies were identified as worthwhile for specific study:

- Dispatching against a load curve representing annual diversity rather than typical weekly diversity.
- Representing planned maintenance as part of a unit's average annual availability, rather than as a discrete removal of a block of capacity at the planned time.
- Dispatching by the derated capacity block-loading method, rather than by probabilistic modeling of unit outages.
- Effectively assigning to each unit the capacity factor of its unit class.

The analysis of these modeling details is presented in this report with the aim of identifying their individual and composite effects on the accuracy of PIES' results.

II. BENCHMARK METHODOLOGY

The goal of this project is to measure the effects of modeling approximations used within PIES. Consequently, it was not necessary to specifically match established forecasts obtained from PIES. It was sufficient to select typical utilities representative of the range of load and generation characteristics in the U. S. and use data for these as the basis for comparison. A PROMOD-format generation equipment data base for most of the U. S. utilities, grouped as centrally dispatched entities (CDE's) was provided by the Energy Information Administration (EIA). This data was based on utility-reported values for 1976. Also available from EIA was hourly load data for 1975, for most of the CDE's. Using this data, PROMOD base cases for 1975 were put together for five typical CDE's. Because the intended use was to compare the PROMOD results for this data with the PIES results for the same data, no attempt was made to benchmark the base case results exactly with historical data; they were, however, verified to be reasonable.

In selecting five CDE's as the basis for this study, two primary utility operating characteristics - generation mix and load factor - were considered. Each CDE from the EIA data base was analyzed in terms of these characteristics, and a final selection of five was made. These five CDE's, and their associated characteristics, are as follows:

- Allegheny Power System (APS) - high load factor, high coal-fired generation
- Commonwealth Edison (CE) - low load factor, high nuclear generation
- Florida - medium load factor, high oil-fired generation
- PJM - medium load factor, evenly distributed generation mix
- Texas - medium load factor, high natural gas-fired generation

The specific quantities justifying this selection are presented in Appendix A for each of the CDE's considered as candidates.

For each of these five CDE's, a PROMOD base case was constructed for 1975. These runs provided nominally accurate historical results for each of the CDE's with which to compare alternative results. These comparisons have been performed for individual degradations of the modeling details within PROMOD, corresponding to the various PIES modeling approximations. Therefore, these cases constitute an indirect assessment of the effects of these modeling assumptions on the PIES results by measuring the change in PROMOD's results due to the same modeling approximations. Finally, a direct comparison of PIES' and PROMOD's results is provided to confirm that the predicted effects of the combined PIES assumptions are demonstrated by PIES itself.

III. THE EFFECT OF THE PIES DISPATCH USING AN ANNUAL LOAD CURVE

One of the most obvious approximations in the PIES model is that it dispatches against a single annual load duration curve (ldc) rather than against monthly or seasonal curves. Because a utility in reality dispatches against a daily load curve, which typically has a much higher load factor than the annual curve, a significant potential for error exists.

The primary effect of the annual dispatch should be to over-predict combustion turbine (CT) operation. It is the daily variation in load from minimum to peak which causes the CT's to be committed. The annual load duration curve includes both this daily diversity and the seasonal diversity introduced by the different weather conditions over the year. Consequently, when used as the basis for the dispatch, the excessive diversity of the annual load duration curve should cause the commitment of more cycling and peaking units, resulting in higher CT operation. Because of PIES' use of historical average capacity factors, rather than a detailed unit commitment process, the specific effect of the annual ldc is difficult to consider separately from that of PIES' overall dispatch. The specific effect is measured here, however, so that its share in the composite effects studied in Section VI can be identified.

A complicating influence on this problem is that of the seasonal nature of planned maintenance. Because most maintenance is scheduled in the low load months, the utilization of peak and intermediate equipment is higher during these months than it would be if maintenance were uniformly distributed over the year. Consequently, the sole effect of the maintenance schedule must be given due consideration in any analysis and will specifically be addressed in the next section.

In order to measure the effect of using the annual load duration curve, an alternative PROMOD case was run where the load shape used for each month is identical in peak and shape to the annual curve. This effectively gave a PROMOD dispatch against an annual ldc. Because the load then appeared to be uniform over the entire year PROMOD was allowed to compute a new, levelized maintenance schedule consistent with the identical monthly load curves. Otherwise, the maintenance schedule itself would introduce additional load diversity. Furthermore, the monthly hydro schedule was levelized over the year to insure that it would not introduce monthly diversity. The amount of hydro generation, however, was not significant in any of the five CDE's tested.

The quantities that can be used to measure the effect of this annual ldc are:

- a) fuel consumption, by fuel type
- b) average capacity factor for units burning each fuel type
- c) loss-of-load hours (LOLH)
- d) emergency energy requirements (EER)

The first two are a measure of the degree of shifting among the different fuels as unit capacity factors change, while the last two are a measure of how much additional capacity PIES would calculate as the necessary system expansion of combustion turbine capacity. Because of PIES' quite different method of calculating expansion requirements, based simply on system reserve, the LOLH and EER obtained from PROMOD are not direct, quantitative measures for comparison.

The results of this comparison with the PROMOD base case are shown in Figure III-1. They demonstrate a consistent increase in distillate-fired generation and emergency energy. The effects, then, are to overestimate costs and underestimate reliability. However, the changes are all quite small. In particular, the average energy cost for each CDE changes by less than 0.2 mills, or less than 1.5%. The changes seem to be smallest for APS, which has a very high annual load factor, indicating little difference between the monthly and annual ldc's.

From this comparison, it appears that the effect of the dispatch against an annual load duration curve rather than on a monthly basis is very small. For the macro-analyses performed with PIES, it is probably not a significant error, considering the potential errors introduced elsewhere in the model and in the input data. Its importance is primarily in its possible reinforcement or counterbalancing of the effects due to other modeling approximations which are to be studied in subsequent sections of this report.

		Emer. Energy (GWH)	LOLH	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
					COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
APS	Base Case	38.8	121.6	9.269	38.030	0.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Annual LDC	<u>53.7</u> + 14.9	<u>149.0</u> + 27.4	<u>9.300</u> + .031	<u>37.980</u> - .050	<u>0.692</u> 0.0	<u>.020</u> + .001	<u>.157</u> + .017	<u>.073</u> + .010	<u>56.6</u> - .1	<u>87.8</u> - .0	<u>22.8</u> + 1.1	<u>4.0</u> + .5	<u>3.3</u> + .5
CE	Base Case	47.2	76.4	5.823	28.451	33.315	0.750	.374	.108	45.8	75.8	12.9	3.1	2.2
	Annual LDC	<u>101.2</u> + 54.0	<u>117.5</u> + 41.4	<u>5.915</u> + .092	<u>27.922</u> - .529	<u>33.358</u> + .043	<u>1.153</u> + .403	<u>.413</u> + .039	<u>.128</u> + .020	<u>45.0</u> - 1.0	<u>75.9</u> + .1	<u>19.8</u> + 6.9	<u>3.5</u> + .4	<u>2.6</u> + .4
FLA	Base Case	3.1	7.8	16.298	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Annual LDC	<u>31.1</u> + 28.0	<u>51.9</u> + 44.1	<u>16.478</u> + .180	<u>10.031</u> - .043	<u>8.962</u> - .007	<u>.414</u> - .001	<u>13.447</u> - .464	<u>38.637</u> + .475	<u>80.9</u> - .4	<u>76.8</u> - .1	<u>65.6</u> - .2	<u>51.0</u> - 1.8	<u>38.0</u> + .5
PJM	Base Case	.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Annual LDC	<u>23.9</u> + 23.6	<u>19.9</u> + 19.4	<u>10.978</u> + .164	<u>98.899</u> - 1.269	<u>28.098</u> + .122	<u>1.563</u> .0	<u>17.470</u> - .807	<u>5.830</u> + 1.891	<u>69.8</u> - .9	<u>78.6</u> + .4	<u>64.6</u> .0	<u>26.9</u> - 1.3	<u>6.8</u> + 2.2
TX	Base Case	0.0	0.0	7.791	14.508	-	150.656	.000	.000	79.9	-	53.2	0.0	0.0
	Annual LDC	<u>2.6</u> + 2.6	<u>3.9</u> + 3.9	<u>7.862</u> + .071	<u>14.504</u> - .004	<u>-</u> -	<u>150.612</u> - 0.044	<u>.001</u> + .001	<u>.032</u> + .032	<u>79.9</u> 0.0	<u>-</u> -	<u>53.2</u> 0.0	<u>0.2</u> + 0.2	<u>0.3</u> + 0.3

FIGURE III - 1:

EFFECT OF DISPATCHING AGAINST AN ANNUAL LOAD DURATION CURVE
(12 Identical Load Months With Redistributed Maintenance)

IV. EFFECTS OF THE MAINTENANCE SCHEDULE

As mentioned in the previous section, the seasonal nature of the maintenance schedule can have a significant effect on the generation mix over the year. By performing maintenance on large base load units during the low-load months, the impact of the outage on total operating cost is reduced. However, whereas the capacity factor of the large units changes seasonally, going down during the months of heavy maintenance activity, the higher cost units (which might otherwise be forced to increase their generation during high-load months) tend to exhibit a level capacity factor. During lowload months, the maintenance requirements of the base load units force the higher cost units to tend to operate as they did in higher load months. Hence, a large portion of the seasonal diversity of load is utilized to reduce the capacity factor of base load equipment (as planned maintenance), tending to levelize the monthly capacity factors of the higher cost intermediate units and CT's throughout the year.

There is currently no formal model of maintenance scheduling within PIES. The maintenance requirements of each unit are included in the calculation of the average annual capacity factor for the unit.

A measurement of the effect of modeling maintenance scheduling in PROMOD was made by constructing a case where the forced outage rates of all units include their maintenance requirements, in effect distributing the maintenance evenly over the year. This adjusted forced outage rate data was then used with the base case monthly load data, as well as with the annual load duration curve data. These cases were run using the alternative load curves described in Section III above, thereby allowing comparison of the two ways of considering maintenance along with their interaction with the ldc representation, so as to provide an indication of whether PIES' even distribution of maintenance (through the capacity factors) is consistent with its annual load duration curve representation.

The first test was to dispatch with the adjusted forced outage rates on a monthly basis, using the base case load data (in which seasonal diversity is preserved). The results of this test are shown in Figure IV-1. This comparison shows a general behavior consistent with the predicted increase in CT generation, with the exception of Florida which shows a decrease. This case demonstrates a counter-balancing phenomenon to the predicted CT generation increase. If the planned maintenance schedule specified that an intermediate cost unit was to be out of service during a month A in which it would economically generate more than in another month B,

		Emer. Energy (GWH)	LOLH	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
					COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
AFS	Base Case	38.8	121.6	9.269	38.030	.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Adj. FOR	<u>131.3</u> +92.5	<u>301.4</u> +179.8	<u>9.344</u> + .075	<u>37.809</u> - .121	<u>.692</u> - .000	<u>.021</u> + .002	<u>.215</u> + .075	<u>.114</u> + .051	<u>56.4</u> - .3	<u>87.8</u> - .0	<u>24.0</u> + 2.3	<u>5.4</u> + 1.9	<u>5.1</u> + 2.3
CE	Base Case	47.2	76.4	5.823	28.451	33.315	.750	.374	.103	45.8	75.8	12.9	3.1	2.2
	Adj. FOR	<u>121.9</u> +74.7	<u>157.8</u> + 81.4	<u>5.805</u> - .018	<u>28.112</u> - .339	<u>33.527</u> + .208	<u>.661</u> - .089	<u>.474</u> + .100	<u>.159</u> + .051	<u>45.3</u> - .5	<u>76.3</u> + .5	<u>11.3</u> - 1.6	<u>4.0</u> + .9	<u>3.2</u> + 1.0
FLA	Base Case	3.1	7.8	16.293	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Adj. FOR	<u>43.4</u> +40.3	<u>68.7</u> + 60.9	<u>16.239</u> - .059	<u>10.058</u> - .016	<u>8.996</u> + .027	<u>.415</u> - .000	<u>14.409</u> + .498	<u>37.615</u> - .547	<u>81.1</u> - .2	<u>77.1</u> + .2	<u>65.8</u> - .0	<u>54.7</u> + 1.9	<u>37.0</u> - .5
PJM	Base Case	.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Adj. FOR	<u>18.4</u> +18.1	<u>15.3</u> + 14.8	<u>10.839</u> - .005	<u>99.899</u> - .279	<u>28.024</u> + .048	<u>1.561</u> - .002	<u>17.476</u> - .801	<u>4.976</u> + 1.037	<u>70.5</u> - .2	<u>78.4</u> + .2	<u>64.6</u> - .0	<u>26.9</u> - 1.3	<u>5.8</u> + 1.2
TX	Base Case	.0	.0	7.791	14.508	.000	150.656	.000	.000	79.9	.0	53.2	.0	.0
	Adj. FOR	<u>9.4</u> + 9.4	<u>10.4</u> + 10.4	<u>7.792</u> + .001	<u>14.483</u> - .025	<u>.000</u> - .000	<u>150.635</u> - .021	<u>.001</u> + .001	<u>.034</u> + .034	<u>79.8</u> - .1	<u>.0</u> - .0	<u>53.2</u> - .0	<u>.2</u> + .2	<u>.3</u> + .3

FIGURE IV - 1

EFFECT OF MODELING SCHEDULED MAINTENANCE

AS AN ADJUSTMENT OF THE FORCED OUTAGE RATES

(Seasonal Load Diversity Preserved)

removing the firm outage from that unit allows it to generate more in that month A than it did in the other month B with a zero maintenance outage rate. A review of the base case maintenance schedule for Florida showed a distribution of most of the maintenance for coal-fired and nuclear units in the first seven months of the year. When the maintenance was distributed evenly, by adjusting the forced outage rates, the distillate consumption dropped considerably during this part of the year, reflecting the increased coal and nuclear energy, and increased slightly during the final five months because of the slightly worse outage rates for the base load units during that period, this resulting in a small net decrease in annual distillate consumption. This effect is shown in Figure IV-2, which shows the monthly difference in fuel consumption.

This particular effect, it should be noted, is due to a relatively poor distribution of maintenance for that one system. The other four CDE's showed the expected increase in distillate consumption, and this is the effect which should be considered foremost, since a utility will, in practice, certainly try to schedule maintenance economically.

Reviewing again the increase in distillate consumption reflected in the annual ldc dispatch (Figure III-1) and comparing them with the same values from the Figure IV-1, the increases are of the same order of magnitude. However, in some cases this still amounts to as much as a 50% to 100% increase in distillate generation. While having little effect on the average costs of the particular systems, these excess consumptions may be significant as inputs to the fuel balancing model in PIES.

Because the effect of both of these modeling procedures is a general increase in distillate consumption, a test was run using the adjusted forced outage rates in conjunction with the annual ldc data, to determine whether the effects tended to be additive. The results of this test are shown in Figure IV-3. Comparing these results with those of Figures III-1 and IV-1, it appears that the two modeling changes together do result in almost additive changes to the distillate consumption. Because of this reinforcement, some adjustment to the PIES model may be necessary.

A relatively straightforward modification to the model which would tend to compensate for both of these effects is to develop the PIES annual ldc as an additive combination of monthly ldc's. As it is now, PIES introduces too much diversity into its ldc because it uses annual load data that naturally includes seasonal diversity. This excess diversity has been shown here to produce excess cycling and peaking generation. In practice, however, the monthly diversity of a utility tends to be

FUEL CONSUMPTION (1000 UNITS)

January February March April May June July August September October November December

COAL (tons)

Base	256	249	387	313	285	372	413	383	371	382	369	384
Adj. FOR	363 +42%	326 +31%	363 - 6%	352 +13%	363 +27%	351 - 6%	363 -12%	339 -11%	328 -12%	338 -12%	328 -11%	338 -12%

NUCLEAR (MBTU)

Base	9237	8343	9239	8941	7301	4493	5240	9238	8939	9238	8939	7750
Adj. FOR	8250 -11%	7456 -11%	8253 -11%	7986 -11%	8248 +13%	7981 +78%	8248 +57%	8247 -11%	7982 -11%	8250 -11%	7986 -11%	8252 + 6%

GAS (MCF)

Base	302	236	355	343	355	342	355	355	343	330	219	327
Adj. FOR	326 + 8%	296 -25%	326 - 8%	317 - 8%	326 - 8%	317 - 8%	326 - 8%	326 - 8%	317 - 8%	326 - 1%	317 +45%	326 - 0%

RESIDUAL (BBL)

Base	1670	1663	1765	1728	1810	1825	1794	1908	1806	1814	1792	1876
Adj. FOR	1759 + 5%	1655 - 0%	1811 + 3%	1761 + 2%	1869 + 3%	1872 + 3%	1943 + 8%	1948 + 2%	1876 + 4%	1894 + 4%	1866 + 4%	1867 - 0%

DISTILLATE (BBL)

Base	4447	3820	4045	4591	6356	6798	6677	6779	5999	5087	4079	4654
Adj. FOR	4033 - 9%	3601 - 6%	4202 + 4%	4532 - 1%	5854 - 8%	6333 - 7%	6235 - 7%	7002 + 3%	6229 + 4%	5268 + 4%	4225 + 4%	4731 + 2%

COMPARISON OF MONTHLY FUEL CONSUMPTION
FOR FLORIDA BASE CASE AND
ADJUSTED FORCED OUTAGE RATE CASE
FIGURE IV - 2

		Emer. Energy (GWH)	LOLH	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
					COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
APS	Base Case	38.3	121.6	9.269	38.030	.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Cap. Fac.	<u>141.5</u> +102.7	<u>311.5</u> +189.9	<u>9.324</u> + .055	<u>37.784</u> - .246	<u>.692</u> - .000	<u>.012</u> + .007	<u>.226</u> + .086	<u>.121</u> + .058	<u>56.4</u> - .3	<u>87.8</u> - .0	<u>13.7</u> - 8.0	<u>5.7</u> + 2.2	<u>5.4</u> + 2.6
CE	Base Case	47.2	76.4	5.823	28.451	33.315	.750	.374	.108	45.8	75.8	12.9	3.1	2.2
	Cap. Fac.	<u>156.3</u> + 9.1	<u>175.3</u> + 98.9	<u>5.841</u> + .018	<u>27.978</u> - .473	<u>33.586</u> + .271	<u>.641</u> - .109	<u>.512</u> + .138	<u>.173</u> + .065	<u>45.6</u> - .2	<u>76.4</u> + .6	<u>11.0</u> - 1.9	<u>4.3</u> + .8	<u>3.5</u> + 1.3
FLA	Base Case	3.1	7.8	16.298	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Cap. Fac.	<u>60.8</u> + 57.7	<u>85.9</u> + 78.1	<u>16.326</u> + .028	<u>10.055</u> - .019	<u>8.995</u> + .026	<u>.415</u> - .000	<u>13.995</u> - .084	<u>38.001</u> - .161	<u>81.1</u> - .2	<u>77.1</u> + .2	<u>65.8</u> - .0	<u>53.1</u> + .3	<u>37.4</u> - .1
PJM	Base Case	.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Cap. Fac.	<u>51.0</u> + 50.7	<u>33.3</u> + 32.8	<u>10.969</u> + .135	<u>98.820</u> - 1.348	<u>28.011</u> + .035	<u>1.560</u> - .003	<u>17.993</u> - .284	<u>5.480</u> +1.541	<u>69.7</u> - 1.0	<u>78.3</u> + .1	<u>64.5</u> - .1	<u>27.7</u> - .5	<u>6.4</u> + 1.8
TX	Base Case	.0	.0	7.791	14.508	.000	150.656	.000	.000	79.9	.0	53.2	.0	.0
	Cap. Fac.	<u>20.8</u> + 20.8	<u>20.1</u> + 20.1	<u>7.851</u> + .060	<u>14.479</u> - .029	<u>.000</u> - .000	<u>150.595</u> - .061	<u>.001</u> + .001	<u>.055</u> + .055	<u>79.8</u> - .1	<u>.0</u> - .0	<u>53.2</u> - .0	<u>.2</u> + .2	<u>.5</u> + .5

FIGURE IV - 3

EFFECT OF DISPATCHING AGAINST AN ANNUAL LOAD DURATION CURVE
AND MODELING MAINTENANCE AS FORCED OUTAGE RATE ADJUSTMENTS

relatively constant, with the seasonal diversity appearing in large part as a monthly shift of the base load.

The four blocks of energy (seasonal peak, daily peak, intermediate, and base) representing the annual ldc in PIES are currently derived from the actual annual ldc by slicing it horizontally at three specified percentage durations of load (e.g. 17%, 35%, and 50%) and calculating the energies of the resulting four pieces. A relatively simple modification to this method which may provide a better distribution of energy among the four blocks is to apply the cutoff percentages to each of the twelve monthly ldc's, compute the four blocks of energy each month, and add the monthly values to obtain the annual energy for each of the four regions of load. As a further enhancement, the cutoff percentages could be changed from month to month to simulate any variation in CT capacity factor over the seasons of the year. These seasonal or monthly cutoff percentages could perhaps be determined from historical monthly operating data.

This suggested change requires no modification of the linear programming formulation of PIES. The extra detail would occur in the electric utility sector preprocessor for PIES, and would amount to little extra computational expense.

V. DISPATCH OF DERATED CAPACITY

A frequent approximation used in production costing models is to treat the forced outage rate as a deration of the capacity of a generating unit. While this method properly predicts the expected capacity available at any particular time, it fails to consider the effect of concurrent forced outages of base load units on the output of peaking equipment. The sum of the expected capacities of the base load units may be sufficient to satisfy the demand, which would predict zero output of the peakers. However, there is the finite chance that several base load units could break down simultaneously, which would require the peakers to operate. Consider for example, the situation shown in Figure V-1. Here three generating units are serving a system having a 800 MW peak load. According to the deration method, each generating unit is derated by its forced outage rate, giving an effective capacity which is used in the dispatch. According to this example, Unit 3 would never be used at all. However, Unit 1 is completely unavailable 20 percent of the time, during which time Unit 3 clearly must be dispatched. Consequently, Unit 3's operations are severely underpredicted. From this it is easy to see that the deration method tends to underestimate CT operation.

In order to measure this effect, a PROMOD case was run with the forced outage rate of each unit applied as a capacity deration rather than the correct use of the outage rate in a fully probabilistic method. The results of this case give a direct measurement of the impact of this modeling detail. Figure V-2 shows the results of this test. They confirm the premise presented above that higher cost fuels would be replaced by lower cost fuels. This effect shows up in every utility, although over different fuels depending on the generation mix of the particular system.

Because the absolute changes seen here are in the opposite direction as those obtained in Sections III and IV, a second test of the derated capacity dispatch method was performed using the annual ldc and forced outage rates data adjusted for planned maintenance. This test would show whether the one effect consistently compensates for the other two.

Figure V-3 displays the results of this comparison. In general, there is indeed some compensation, but only in the case of PJM do the changes in distillate-fired generation due to the different modeling details come close to balancing. Even there the residual and coal consumptions still show very significant error. In general, the under-prediction of high-cost fuel use due to the derated capacity method clearly tends to dominate. In both Figure V-2 and Figure V-3, the energy shifted off of the

<u>UNIT</u>	<u>UNIT CAPACITY (MW)</u>	<u>FORCED OUTAGE RATE</u>	<u>DERATED CAPACITY</u>
1	600	20%	480
2	400	10%	360
3	200	25%	150

Illustration of the Failure of
the Deration Method of
Modeling Forced Outages

FIGURE V - 1

		Emer. Energy (GWH)	LOLH*	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
					COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
APS	Base Case	38.8	121.6	9.269	38.030	.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Cap. Fac.	.0	.0	9.105	38.235	.692	.003	.001	.000	57.1	87.8	3.4	.0	.0
		-38.8	-121.6	-.164	+.255	-.000	-.016	-.139	-.063	+.4	-.0	-18.3	-3.5	-2.8
CE	Base Case	47.2	76.4	5.823	28.451	33.315	.075	.374	.108	45.8	75.8	12.9	3.1	2.2
	Cap. Fac.	11.5	20.9	5.571	28.634	33.887	.330	.152	.029	46.1	77.1	5.7	1.3	.6
		-35.7	-55.5	-.252	+.183	+.572	-.420	-.222	-.079	+.3	+1.3	-7.2	-1.8	-1.6
FLA	Base Case	3.1	7.8	16.298	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Cap. Fac.	.0	.0	16.038	10.101	8.981	.416	15.841	36.190	81.5	77.0	66.0	60.1	35.6
		-3.1	-7.8	-.260	+.027	+.028	+.001	+1.930	-1.972	+.2	+.1	+.2	+7.3	-1.9
PJM	Base Case	.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Cap. Fac.	.0	.0	10.478	103.253	28.037	1.567	16.441	2.873	72.9	78.4	64.8	25.3	3.3
		-.3	-.5	-.356	+3.085	+.061	+.004	-1.836	-.066	+2.2	+.2	+.2	-2.9	-1.3
TX	Base Case	.0	.0	7.791	14.508	.000	150.656	.000	.000	79.9	.0	53.2	.0	.0
	Cap. Fac.	.0	.0	7.723	14.514	.000	150.644	.000	.000	80.0	.0	53.2	.0	.0
		.0	.0	-.068	+.006	-.000	-.012	-.000	.000	+.1	-.0	-.0	.0	.0

*Loss-of-Load Hours

FIGURE V - 2

EFFECT OF THE DERATED CAPACITY METHOD OF DISPATCH
(Capacities Derated For Forced Outages Only;
Monthly Load Diversity Represented)

		Emer. Energy (GWH)	LOLH	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
					COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
APS	Base Case	38.8	121.6	9.269	38.030	0.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Combined	<u>2.5</u>	<u>38.8</u>	<u>9.132</u>	<u>38.250</u>	<u>.692</u>	<u>.004</u>	<u>.016</u>	<u>.012</u>	<u>57.0</u>	<u>87.8</u>	<u>4.6</u>	<u>0.4</u>	<u>0.5</u>
		-36.3	-82.8	-.137	+.220	.0	-.015	-.124	-.051	+.3	.0	-17.1	-3.1	-2.3
CE	Base Case	47.2	76.4	5.823	28.451	33.315	0.750	.374	.108	45.8	75.8	12.9	3.1	2.2
	Combined	<u>61.0</u>	<u>53.3</u>	<u>5.591</u>	<u>28.354</u>	<u>34.054</u>	<u>.328</u>	<u>.198</u>	<u>.050</u>	<u>45.7</u>	<u>77.5</u>	<u>5.6</u>	<u>1.7</u>	<u>1.0</u>
		+13.8	-23.1	-.232	-.097	+7.39	-.422	-.176	-.058	-.1	+1.7	-7.1	-1.4	-1.2
FLA	Base Case	3.1	7.8	16.298	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Combined	<u>2.8</u>	<u>29.1</u>	<u>16.105</u>	<u>10.084</u>	<u>9.014</u>	<u>.416</u>	<u>15.833</u>	<u>36.169</u>	<u>81.3</u>	<u>77.3</u>	<u>66.0</u>	<u>60.1</u>	<u>35.6</u>
		-.3	+21.3	-.193	+.010	+.045	+.001	+1.922	-1.993	.0	+.4	+.2	+7.3	-1.9
PJM	Base Case	.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Combined	<u>5.8</u>	<u>11.7</u>	<u>10.512</u>	<u>103.124</u>	<u>28.122</u>	<u>1.566</u>	<u>15.043</u>	<u>3.980</u>	<u>72.8</u>	<u>78.6</u>	<u>64.8</u>	<u>23.7</u>	<u>4.6</u>
		+5.5	+11.2	-.322	+2.956	+.146	+.003	-3.234	+.041	+2.1	+.4	+.2	-.5	.0
TX	Base Case	0.0	0.0	7.791	14.508	-	150.656	.000	.000	79.9	-	53.2	0.0	0.0
	Combined	<u>0.0</u>	<u>0.0</u>	<u>7.746</u>	<u>14.504</u>	<u>-</u>	<u>150.643</u>	<u>.000</u>	<u>.001</u>	<u>79.9</u>	<u>-</u>	<u>53.2</u>	<u>0.0</u>	<u>0.0</u>
		.0	.0	-.045	-.004	-	-.013	.0	+.001	.0	-	.0	.0	.0

FIGURE V - 3

EFFECT OF DERATED CAPACITY DISPATCH METHOD ON ANNUAL
LOAD DURATION CURVE WITH CAPACITIES DERATED FOR
BOTH FORCED OUTAGES AND MAINTENANCE OUTAGES

CT's is seen to be picked up by the base load units. Percentage-wise, these errors in base generation are small, but in absolute GWH's they are significant.

Unfortunately, no clear method of correcting for this type of error suggests itself. The shift in generation mix is inherent in the derated capacity method of dispatch and cannot be corrected by some mere adjustment in the data preparation methodology. PIES does, however, use historical capacity factors for the different classes of generation to try to force an accurate generation mix. The power and success of this technique will be studied in the next section.

VI. PIES' USE OF GENERIC CAPACITY FACTORS

In order to achieve the same operating level from each class of units, PIES computes an average annual capacity factor for each unit class serving the different areas of load. These capacity factors are essentially treated in PIES as upper bounds on the generation that can be obtained from each class of units. The capacity factor of a unit is composed of several elements, however. The different causes for the capacity factor to be less than 100% are:

- a) the forced outage rate of the unit
- b) its scheduled maintenance, and
- c) the duration of load at the economic point where the unit is dispatched

The first two quantities are characteristics of the unit, but the third varies widely over a region of load and could easily lead to error in calculating the average capacity factor since the change in duration over the region of load is non-linear. The units at the low end of the region of load could be assigned too low a capacity factor, while those at the high end are assigned too high a factor.

A further complication is that sometimes an intermediate unit, in actual operation, serves at a high capacity factor as replacement capacity for scheduled or forced outages, and at other times at a very low capacity factor when there is a surplus of capacity. By computing an annual capacity factor for the unit and assigning it to the intermediate load range, where it in fact only operates part of the time, the predicted operation of other classes of units, especially peakers, could be affected.

Still another possibility under the PIES dispatch is that two coal units, for example, might historically have significantly different capacity factors because of one of them having a high forced outage rate. If unit A had a capacity factor of 90% and unit B one of 45%, with this low capacity factor due to its poor availability, unit A would contribute to setting a high capacity factor for coal units operating in base load, while unit B would be considered as serving intermediate load. In the PIES dispatch, both units would be grouped together, however, and unit B would likely be operated in base load - at the higher capacity factor - because of economics. This potential flaw would tend to overstate the average capacity factor of the lower cost generation.

This same effect may arise in the case of units being commissioned late in the historical year. These units would appear to have very low capacity factors that year but would be operated in practice at the typical capacity factor of its class, while PIES might use these historical values to set too low a capacity factor for some regions of load.

In order to study the effect of this calculation of a generic annual capacity factor, the capacity factors indicated by the PROMOD base cases were used to calculate similar capacity factors characteristic of the base cases. The same cutoff criteria used in PIES to assign units to different modes of load according to their capacity factors were used to perform the same calculation for PROMOD. Using the capacity factor for its class, each unit was assigned an equivalent forced outage rate such that, when combined with its required operating time in the base case, its capacity factor would match that of its class. The dispatch sequence of the units in the base case was then preserved to insure that its required operating time would be the same. These two sets of inputs - the equivalent forced outage rates and the dispatch order from the base case - were then input into PROMOD, using the annual ldc data and PROMOD's probabilistic dispatch.

The results of this test appear in Figure VI-1. They confirm the predicted behavior in demonstrating a general shift toward lower cost fuels.

In Figure VI-2 are presented the results when the same data is dispatched using the derated capacity method described in Section V. Here an even greater tendency to under-predict oil consumption is demonstrated, as the two effects are combined. This particular test, by combining all of the modeling details studied in this project, represents the closest approximation to the PIES model.

Considering the negative effect the class capacity factor seems to produce, an adjustment to the PIES model may be appropriate. Fortunately, if the data is available there is a relatively simple change that could reduce this negative impact. At present PIES computes the capacity factor at which each class of units will operate for each of the four regions of load in which it may be dispatched. But since the capacity factor is composed of two multiplicative terms - the availability of the unit class and the duration of load at the level of demand at which the class is dispatched - the least reliable units of a given capacity class are going to set the capacity factors for the higher regions of load. A more accurate representation would be to calculate a single average availability for each class of units to be used no matter where in the ldc the capacity is dispatched, and to also calculate the

		Emer. Energy (GWH)	LOLH	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
					COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
APS	Base Case	38.8	121.6	9.269	38.030	0.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Cap. Fac.	<u>2.6</u>	<u>9.2</u>	<u>9.240</u>	<u>38.289</u>	<u>.765</u>	<u>.002</u>	<u>.021</u>	<u>.007</u>	<u>57.1</u>	<u>97.0</u>	<u>2.3</u>	<u>0.5</u>	<u>0.3</u>
		-36.2	-112.4	-.029	+ .259	+ .072	- .017	- .119	- .056	+ .4	+9.2	-19.4	+3.0	-2.5
CE	Base Case	47.2	76.4	5.823	28.451	33.315	0.750	.374	.108	45.8	75.8	12.9	3.1	2.2
	Cap. Fac.	<u>25.4</u>	<u>40.0</u>	<u>5.320</u>	<u>25.378</u>	<u>37.327</u>	<u>.350</u>	<u>.191</u>	<u>.056</u>	<u>40.9</u>	<u>84.9</u>	<u>6.0</u>	<u>1.6</u>	<u>1.1</u>
		-21.8	-36.0	-.503	-3.073	+4.012	- .400	- .183	- .052	-4.9	+9.1	-6.9	-1.5	-1.1
FLA	Base Case	3.1	7.8	16.298	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Cap. Fac.	<u>1.8</u>	<u>4.1</u>	<u>16.012</u>	<u>11.083</u>	<u>10.062</u>	<u>.449</u>	<u>14.717</u>	<u>35.468</u>	<u>89.4</u>	<u>86.2</u>	<u>71.2</u>	<u>54.8</u>	<u>36.4</u>
		-1.3	-3.1	-.068	+1.009	+1.093	+ .034	+ .806	-2.694	+8.1	+9.3	+5.4	+2.0	-2.9
PJM	Base Case	.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Cap. Fac.	<u>7.4</u>	<u>6.8</u>	<u>10.325</u>	<u>105.246</u>	<u>30.240</u>	<u>1.693</u>	<u>13.693</u>	<u>2.133</u>	<u>74.3</u>	<u>84.6</u>	<u>70.0</u>	<u>21.1</u>	<u>2.5</u>
		7.1	+6.3	-.509	+5.078	+2.264	+ .130	-4.584	-1.806	+3.6	+6.4	+5.4	-7.1	-2.1
TX	Base Case	0.0	0.0	7.791	14.508	-	150.656	.000	.000	79.9	-	53.2	0.0	0.0
	Cap. Fac.	<u>0.0</u>	<u>0.0</u>	<u>7.717</u>	<u>18.445</u>	<u>-</u>	<u>147.094</u>	<u>.000</u>	<u>.002</u>	<u>75.7</u>	<u>-</u>	<u>50.8</u>	<u>0.0</u>	<u>0.0</u>
		0.0	0.0	-.074	+ 3.937	-	- 3.562	-.000	+ .002	-4.2	-	-2.4	0.0	0.0

FIGURE VI - 1

EFFECT OF GENERIC CAPACITY FACTORS ON THE DISPATCH
 (Using (Using Annual Load Curve, Equivalent Forced Outage Rates, And
 Probabilistic Dispatch)

			Emer. Energy (GWH)	LOLH	Aver. Cost (\$/MWH)	GENERATION (Thousand GWH)					CAPACITY FACTORS (%)				
						COAL	NUCLEAR	GAS	RESID	DIST	COAL	NUCLEAR	GAS	RESID	DIST
APS	Base Case		38.8	121.6	9.269	38.030	0.692	.019	.140	.063	56.7	87.8	21.7	3.5	2.8
	Cap. Fac.		0.0	0.0	9.149	38.321	.766	.000	.000	.000	57.2	97.2	0.0	0.0	0.0
			-38.8	-121.6	-.120	+2.291	+0.074	-.019	-.140	-.063	+5	+9.4	-21.7	3.5	-2.8
CE	Base Case		47.2	76.4	5.823	28.451	33.315	0.750	.374	.108	45.8	75.8	12.9	3.1	2.2
	Cap. Fac.		3.6	8.8	5.097	24.965	38.101	.183	.064	.010	40.2	86.7	3.1	0.5	0.2
			-43.5	-67.6	-.726	-3.486	+4.786	-.567	-.310	-.098	-5.6	+10.9	-9.8	-2.6	-2.0
FLA	Base Case		3.1	7.8	16.298	10.074	8.969	.415	13.911	38.162	81.3	76.9	65.8	52.8	37.5
	Cap. Fac.		0.0	0.0	15.670	11.166	10.081	.450	17.451	32.630	90.1	86.4	71.3	65.0	31.8
			-3.1	-7.8	-.628	+1.092	+1.112	+0.035	+3.540	-5.532	+8.8	+9.5	+5.5	+2.2	-5.7
PJM	Base Case		.3	.5	10.834	100.168	27.976	1.563	18.277	3.939	70.7	78.2	64.6	28.2	4.6
	Cap. Fac.		.0	.0	9.849	110.409	30.304	1.696	8.621	2.140	78.0	70.1	84.7	13.3	2.5
			-.3	-.5	-.985	+10.241	+2.328	+0.133	-9.656	-1.799	+7.3	-7.9	+20.1	-14.9	-2.1
TX	Base Case		0.0	0.0	7.791	14.508	-	150.656	.000	.000	79.9	-	53.2	0.0	0.0
	Cap. Fac.		0.0	0.0	7.602	18.489	-	147.048	.000	.000	75.9	-	50.8	0.0	0.0
			0.0	0.0	-.189	+3.981	-	-3.608	.000	.000	-4.0	-	-2.4	0.0	0.0

FIGURE VI - 2

EFFECT OF GENERIC CAPACITY FACTORS WHEN
USED WITH THE DERATED CAPACITY DISPATCH METHOD
AND ANNUAL LOAD CURVE

average duration of demand (as percent time) for each region of load. Then, instead of calculating the contribution of unit class i toward serving load in region j as

$$\text{capacity}_{ij} * \text{capacity factor}_{ij} ,$$

the generation would be calculated by the expression

$$\text{capacity}_{ij} * \text{availability}_i * \text{duration}_j$$

This different approach does not change the structure of PIES itself, since the availability and duration can be combined into a single coefficient for use in the LP, but would merely be a different, more detailed method of setting up the coefficients from the historical data.

VII. DIRECT COMPARISON OF PIES AND PROMOD

As a means of determining how thoroughly PIES actually responds under the modeling features studied in the previous four sections, the results and data for the PROMOD base cases were reconfigured into the input form for PIES. By comparing the results of PIES with the PROMOD base case, the ability of PIES to surmount the negative influences of the previously studied modeling questions can be determined. In particular, it is possible to compare any error in the PIES results with the behavior predicted.

Figure VII-1 presents the results of this test. Evident in this figure is the general shift by PIES to lower cost fuels that was predicted by the previous analyses presented here. Interestingly, however, one CDE out of the five - Florida - shows a very close match to the PROMOD results, as compared with the major deviations for the other CDE's. This can be explained by the fact that all of Florida's coal and nuclear capacity was already almost fully utilized serving base load in the PROMOD case. Consequently, the oil-fired generation was utilized by both PROMOD and PIES to serve all of the remaining load. This lack of freedom in the case of Florida prevented PIES from shifting to lower cost generation because there was no excess base capacity to pick it up.

A general estimate of the error introduced in PIES can be achieved by aggregating the generation by fuel class over all five CDE's and computing the error from the base cases. This calculation indicates a general underprediction of oil consumption by 22%. However, because Florida is so heavily dependent on oil, it tends to dominate this calculation. Computing the same aggregate error for only the other four CDE's, we arrive at an error of 69%.

This analysis, it should be noted, does not constitute a full benchmark of PIES, but instead was intended to confirm the tendencies predicted by the PROMOD-based analysis of the modeling details in PIES. Because the intent was to try to match PROMOD base case values, no capacity expansion was allowed in PIES, and no transmission was allowed between the areas. The unit classes and regions of load were defined on the basis of 50% load factor for base load, 35% for intermediate load, 17% for peak load, and below 17% for seasonal peak. These cutoff points may be at variance with those currently used by PIES. A complete benchmark of PIES would require calculating from the original PIES source data the actual historical generation and fuel consumptions so that the results from PIES could be compared

		GENERATION (Thousand GWH)			
		COAL	NUCLEAR	GAS	OIL
APS	PROMOD	38.03	.69	.02	.20
	PIES	<u>38.29</u>	<u>.69</u>	<u>.00</u>	<u>.00</u>
		+ .26	.0	- .02	- .20
CE	PROMOD	28.45	33.32	0.75	.48
	PIES	<u>27.45</u>	<u>34.93</u>	<u>.69</u>	<u>.00</u>
		-1.00	+1.61	- .06	- .48
FLA	PROMOD	10.07	8.97	.42	52.07
	PIES	<u>10.58</u>	<u>8.98</u>	<u>.40</u>	<u>51.65</u>
		+ .51	+ .01	- .02	- .42
PJM	PROMOD	100.17	27.98	1.56	22.22
	PIES	<u>108.04</u>	<u>27.56</u>	<u>9.12</u>	<u>7.19</u>
		+7.88	- .42	+7.56	-15.03
TX	PROMOD	14.51	-	150.66	.000
	PIES	<u>3.07</u>	<u>-</u>	<u>161.95</u>	<u>.000</u>
		-11.44		+11.29	.0

FIGURE VII - 1
DIRECT COMPARISON OF PIES AND PROMOD

directly with those values. Furthermore, by providing historical increases in fuel costs and demand, the accuracy of PIES in forecasting changes in fuel consumptions from the original base year (that used for developing the generating capacity and load duration curve data) to those subsequent historical years could be tested.

VIII. CONCLUSIONS

The analysis presented here demonstrates the errors that seem to be introduced into PIES by the various modeling techniques that are employed. The specific effects that have been seen are:

1. The dispatch against an annual load duration curve introduces a small (13% or less) overstatement of higher cost fuel consumptions.
2. The effectively even distribution of scheduled maintenance over the year as part of the annual outage rate of a unit causes an additional small overstatement of high cost fuel consumption.
3. The dispatch, by effectively using the forced outage rates of the units as deration factors on their capacities rather than using probabilistic techniques to model combinations of outages, shows a significant shift toward lower cost fuels.
4. The use of generic capacity factors for each region of load results in a further shift toward lower cost fuels.

The last two effects dominate the first two, yielding a consistent under-prediction of high cost fuel consumptions. The range of error for each fuel type is shown in Figure VIII-1. The net error in oil consumption for the various CDE's has been seen to be as high as 100%. The effect of these errors on the average production cost (\$/MWH), however, is greatly moderated by the fact that the high cost fuels serve only a small portion of the total energy.

Because the primary interest of this study was in the details of the dispatch process, several peripheral areas of the utility sector model of PIES were not considered. In particular, no transmission was allowed between regions in the PIES run since this would have complicated the analysis. In general, the capability to transfer energy among the regions according to economics ought to tend to reduce CT operation in at least some regions. This effect would have clouded the measurement of the effects of the dispatch details of specific interest.

In practical use, the transfer of power among regions may, in some instances, account itself for a reduction in CT operation, fortuitously eliminating the impact of the negative dispatch effects, but not eliminating the negative effects themselves. At best, the interregional transfers may merely delay the point at which the errors introduced by the dispatch itself show up. Furthermore, since the decision to transfer power is an economic one, it presupposes the accuracy of the dispatch in

RANGE OF ERROR (%)

MODEL CHANGES	COAL		NUCLEAR		GAS		OIL	
	High ¹	Low ²	High ¹	Low ²	High ¹	Low ²	High ¹	Low ²
Annual LDC	0	- 1.8	.43	- .08	53.8	- .24	13.3	0
Maintenance as Forced Outage Rate Adjustment	0	- 1.2	.62	0	10.5	- 11.9	62.0	- .09
Annual LDC and Adjusted Forced Outage Rate	0	- 1.66	.81	0	36.8	- 14.5	70.9	- .47
Derated Capacity Dispatch	3.1	0	1.7	0	.26	-560.0	0	- 99.5
Derated Capacity Dispatch With Annual LDC and Forced Outage Rates Adjusted For Maintenance	2.9	- .34	2.2	0	.24	- 78.9	0	- 86.2
Generic Capacity Factors With Probabilistic Dispatch	27.1	10.8	12.2	0	8.3	- 89.5	0	-100.0
Generic Capacity Factors With Derated Capacity Dispatch	27.4	-12.2	14.4	0	8.5	-100.0	0	-100.0
PIES	7.9	-78.8	4.8	-1.5	484.0	-100.0	0	-100.0

ERROR RESULTING FROM THE VARIOUS MODEL CHANGES

FIGURE VIII - 1

Note 1: Overstatement of fuel consumption

Note 2: Understatement of fuel consumption

order to justify the transfer. Therefore, the ability of the modeling details of the dispatch to produce the correct generation mix for an isolated system remains the central issue in PIES' utility sector model.

There are two relatively straightforward modifications to the way in which the data is prepared for PIES which may contribute toward eliminating these sources of error:

1. Redistribute the energy in PIES' load duration curve (as described in Section IV) so that its diversity is more compatible with the average monthly diversity for a region, with the seasonal diversity included in the calculation of the base load region.
2. Calculate separately the average duration of load within each region of the ldc, and the average availability for each class of units, which when combined together may give a more accurate approximation of the capacity factor of a particular class of units serving a region of load. This idea was discussed in Section VI.

These suggested modifications have no direct bearing on the formulation of the constraints and objective function of the LP for PIES; they are merely alternative ways of calculating certain coefficients. Provided that the data for these calculations is readily available, the effort required to implement and test these suggestions is relatively small, considering the potential for improvement in PIES' accuracy.

The first of these changes is likely to produce some improvement in the over-prediction of oil consumption that it is intended to remedy. However, that effect was dominated by the under-prediction of oil consumption due to the derated capacity dispatch and the use of the unit class capacity factors. Consequently, this first suggested change should only be adopted after some increase in oil consumption has been realized by the successful implementation of the other change.

The actual success of the second change is difficult to predict. It has already been demonstrated that the derated capacity method of dispatch introduces significant error into the calculations. The use of class capacity factors by PIES is intended to overcome this error, but the success of the proposed improvement in the model of these capacity factors is only speculative and must be demonstrated with detailed benchmarks.

Quite independently from the model adjustments recommended here, PIES should be subjected to a thorough historical benchmark, using data from several

recent years. Such a benchmark should be approached not only from the point of view of matching the fuel consumptions of some base year but also to project PIES' ability to forecast into the future by seeing if it can also match the consumptions in a later year, where the only data changes are the new demand, fuel costs, and capacities. Such a test is necessary in order to document its accuracy in projecting fuel usage, when those projections play such a major role in the energy policy-making process.

APPENDIX A

GENERATION MIX
AND
LOAD FACTORS
FOR THE MAJOR
CENTRALLY DISPATCHED ENTITIES

PERCENTAGE OF TOTAL ENERGY BY FUEL TYPE
(1976)

POOLNAME	AVERAGE MONTHLY LOAD FACTOR	ANNUAL LOAD FACTOR	PERCENTAGE OF TOTAL ENERGY BY FUEL TYPE (1976)						
			COAL	DISTILLATE OIL	RESIDUAL OIL	NATURAL GAS	HYDRO	NUCLEAR	OTHER
1. AEP and Assoc. Utilities	.70	.64	94.8	0.6	0.6	0.2	0.3	3.6	0.0
2. APS	.70	.65	98.5	0.9	0.5	0.1	0.0	0.0	0.0
3. Arizona	.66	.50	59.4	2.3	9.4	7.2	21.6	0.0	0.0
4. Cleveland	.67	.59	98.9	0.0	1.1	0.0	0.0	0.0	0.0
5. Commonwealth Edison	.64	.50	49.8	2.0	3.7	2.6	0.0	41.9	0.0
6. Florida	.63	.55	10.3	2.7	60.9	14.5	0.4	11.2	0.0
7. Illinois-Missouri	.64	.49	96.4	0.1	1.4	0.4	1.6	0.0	0.0
8. Inland	.65	.58	72.5	0.6	1.5	18.6	6.8	0.0	0.0
9. Kentucky-Indiana	.64	.55	98.5	0.0	0.1	0.0	1.5	0.0	0.0
10. Michigan	.67	.63	75.6	0.6	13.5	4.1	0.8	5.4	0.0
11. Midcontinent	.64	.54	52.5	0.7	1.3	4.5	17.4	23.6	0.0
12. Middle South	.69	.54	0.0	0.0	21.6	72.9	0.0	5.5	0.0
13. Missouri-Kansas	.64	.48	56.7	3.0	9.6	30.7	0.0	0.0	0.0
14. New England	.65	.56	2.9	0.3	53.7	0.3	5.0	37.7	0.0
15. New Mexico	.66	.58	25.1	0.2	7.2	66.4	1.1	0.0	0.0
16. Northern California	.66	.57	0.0	0.0	32.6	37.4	28.2	0.4	1.4
17. Pacific Northwest	.72	.60	24.0	0.0	0.1	0.2	70.9	4.8	0.0
18. New York	.66	.58	16.5	1.9	39.6	0.2	26.4	15.3	0.0
19. Oklahoma	.62	.46	0.0	0.0	0.1	99.4	0.5	0.0	0.0
20. PJM	.66	.54	55.2	1.6	22.6	0.4	2.4	17.8	0.0
21. Southern California	.65	.57	16.8	0.1	62.2	10.3	6.2	4.3	0.0
22. Southern Co.	.66	.54	75.1	1.1	6.0	2.3	12.1	3.4	0.0
23. Texas	.71	.61	12.2	0.0	1.8	85.8	0.3	0.0	0.0
24. TVA	.70	.60	83.8	1.3	0.0	0.0	14.8	0.0	0.0
25. Virginia-Carlinas	.67	.56	71.7	0.5	11.8	0.4	4.6	11.0	0.0
26. Wisconsin	.65	.58	61.6	0.3	0.7	1.4	3.0	33.0	0.0