

STMP0-008

# SOLAR THERMAL CONVERSION MISSION ANALYSIS

## Southwestern United States Demand Analysis



THE AEROSPACE CORPORATION



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SOLAR THERMAL CONVERSION MISSION ANALYSIS

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DEMAND ANALYSIS

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## FOREWORD

This report describes in detail the Electric Power Demand Analysis in support of the follow-on Solar Thermal Conversion Mission Analysis performed by The Aerospace Corporation under contract to the National Science Foundation/Research Applied to National Needs. The time period of the contract extended from November 1, 1973 to August 15, 1974. This report is the second of five volumes; the remaining four volumes include a Summary Report of the complete study and detailed reports concerning the Southwestern United States Area Definition and Siting Analysis, Insolation Climatology, and Comparative Technical and Economic Evaluation.

This study was conducted under NSF Contract C797 by the Energy Programs Group of the Energy and Resources Division. Mr. D. F. Spencer and subsequently Mr. G. Kaplan were the NSF Program Managers for this contract, and Dr. A. B. Greenberg, General Manager of the Energy and Resources Division, was the Principal Investigator. Dr. M. B. Watson is Associate Group Director of the Energy Programs Group. Mr. P. B. Bos, Associate Director, Solar Projects, provided the Program Management. Mr. G. F. Kuncir, Mr. W. A. Kammer, and Dr. F. D. Maxwell authored this Demand Analysis report.

The authors wish to recognize and acknowledge the efforts of the following for their contributions to the demand analysis and the preparation of this report: S. M. Barnes, R. E. Flowers, P. L. Merryman, and H. A. Rodriguez for development and implementation of the data manipulation and analysis programs; R. B. Gladson for modifying his plot program specifically for this project; J. D. Tweedie for providing the illustrations; P. E. Burleigh, M. G. Bythway, and R. L. Devaney for typing this document; and M. M. Metfessel for editorial assistance.

## ABSTRACT

The objectives of this demand analysis were to develop and extend a computer model, methodology, and data base capable of characterizing the hourly electric power demand for selected Southwestern United States load centers from 1980 to 2000.

The approach used in meeting these objectives consists of several steps. Background information, technical reports, and raw data were acquired from governmental agencies and utilities throughout the Southwestern United States. Computer programs were developed to reformat the historical load data into a form suitable for analysis. The decomposition/recomposition methodology developed under the preceding contract was extended to permit segmented inputs, continuous and long-term projections, and to output simulated demand data tapes. Raw demand data histories were processed and accumulated in standard format, and future demand profiles incorporating the historic cyclic variations with projected trends were generated for further analysis. A parallel effort was also undertaken to attempt a correlation between the electric power demand and certain weather and insolation parameters.

This report discusses the results of this analysis: the computer programs, data base, and forecast methodology. It also outlines the activities undertaken to achieve these results.

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## 1. INTRODUCTION

The objective of any advanced power generation system proposed for application in the future is to satisfy future energy demands with equal reliability as competing systems. To evaluate solar power plants from this viewpoint, a detailed electric power demand analysis was performed in support of the Solar Thermal Conversion Mission Analysis performed by The Aerospace Corporation under contract to the National Science Foundation/Research Applied to National Needs program.

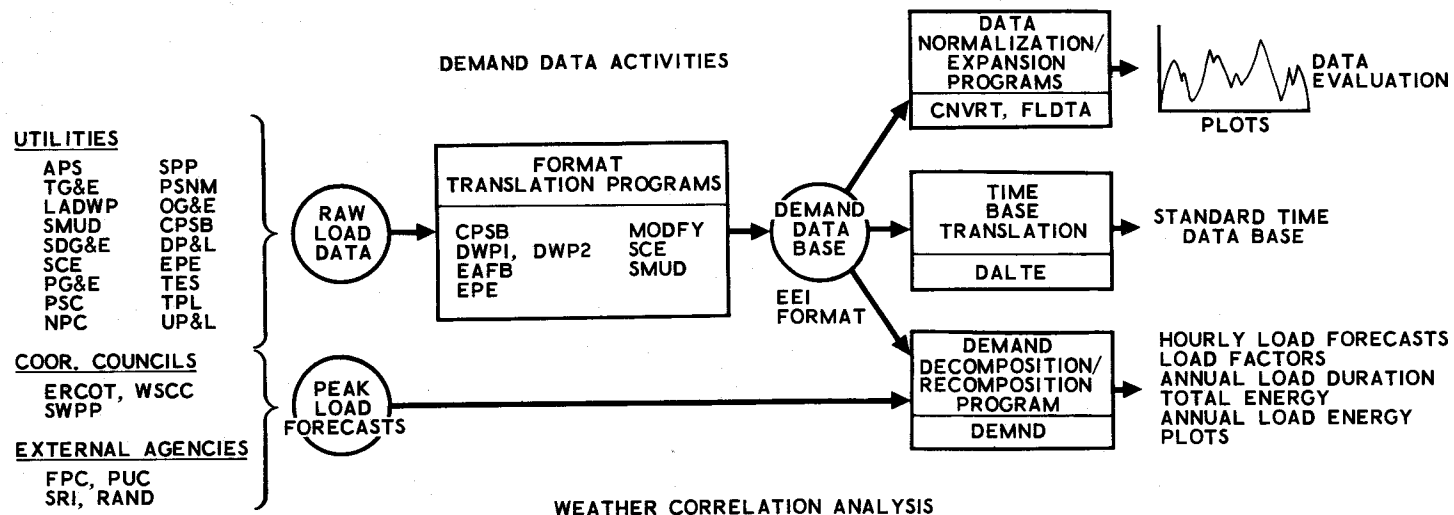
Demand analysis activities were directed at the development of a computer methodology capable of forecasting the detailed hourly electric power demand profiles for selected load centers within the Southwestern United States during the years 1980-2000. In this effort emphasis was placed on the time varying demand profile which must be matched with the time varying insolation with secondary concern for the absolute magnitude of the projected demand. Both the region and time period were selected to be consistent with the scope of the NSF/RANN program. During the preceding Solar Thermal Conversion Mission Analysis, a demand forecast model was conceptually developed and applied to Southern California area (Reference 1). This methodology was automated and extended during this follow-on contract to permit its systematic use on a broader scale. As will be shown in subsequent sections, the model and methodology are applicable to any region for which historical demand measurements can be acquired and for any future time period during which peak demand can be forecasted. The demand forecast program must be capable of defining a varying hourly demand profile which exhibits both seasonal and load peak trends.

The sections which follow describe the various activities that were undertaken to acquire a demand information data base, to manipulate the acquired data into a standard format, and to extrapolate this information into future demand forecasts. Efforts which sought to develop a correlation model defining the relationships between demand and certain weather and

insolation parameters are also described. These demand analysis activities are summarized in Figure 1-1.

Data gathering activities are outlined in Section 2. Also included in this section is a description of the Southwestern United States power regions and a summary of the historical demand and peak load forecast data base acquired during this study. The analysis and use of acquired power and energy forecasts are discussed in Section 3. Section 4 contains a detailed discussion of necessary data manipulation procedures which transformed demand data, acquired in various formats, into a standard form for demand analysis and distribution to other NSF contractors. Computer programs developed to perform this data manipulation are described in both a functional and logical sense. Section 5 contains a description of the demand decomposition/recomposition forecast model and its computer implementation. Underlying assumptions, current capabilities, and limitations are outlined. Examples of demand forecasts are provided with a narrative providing rationale for its logical construction and its analysis procedures. Weather correlation analysis activities are described in Section 6. Flow charts and listings of computer programs developed during the study are included in an appendix.

It should be emphasized that the products of this study are not only detailed forecasts of electric power demand at selected Southwest load centers during some future time period, but an extensive historical electric power demand data base and an automated computer model capable of processing this data base in order to satisfy the needs for electric power demand analyses in support of present and future system analyses.



**WEATHER CORRELATION ANALYSIS**

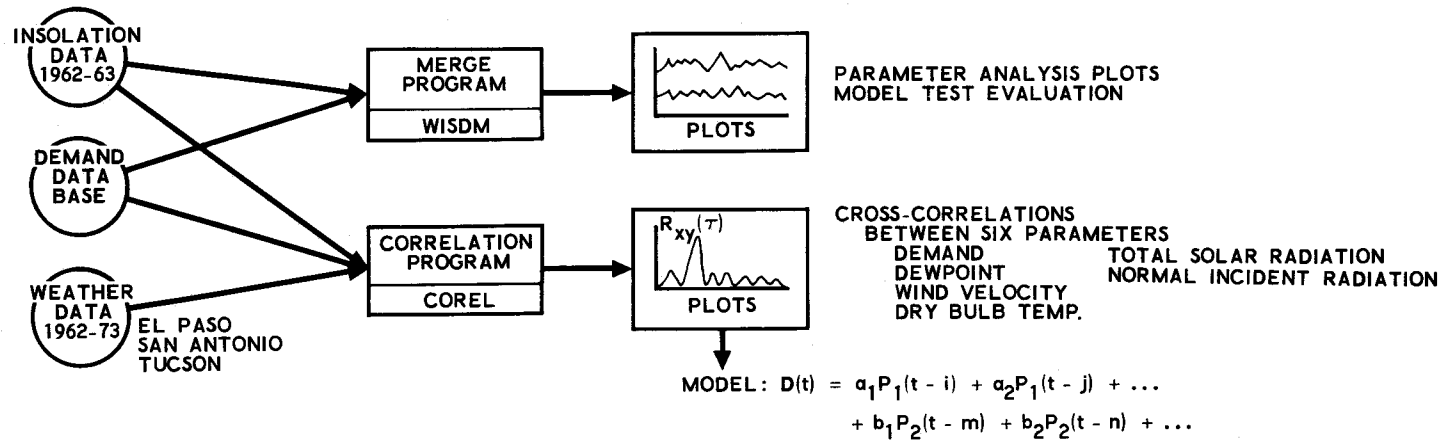


Figure 1-1. Demand Analysis Summary

## 2. DATA ACQUISITION

To appraise the potential application of solar-thermal conversion systems in the Southwestern United States during the years 1980-2000, it is necessary to examine the area's electric power geography (e.g., its supply areas and load centers), to study its historical load behavior, and to assess its projected growth. These requirements essentially define the data acquisition activities undertaken as part of the electric power demand analysis.

### 2.1 SOUTHWESTERN UNITED STATES AREA DEFINITION

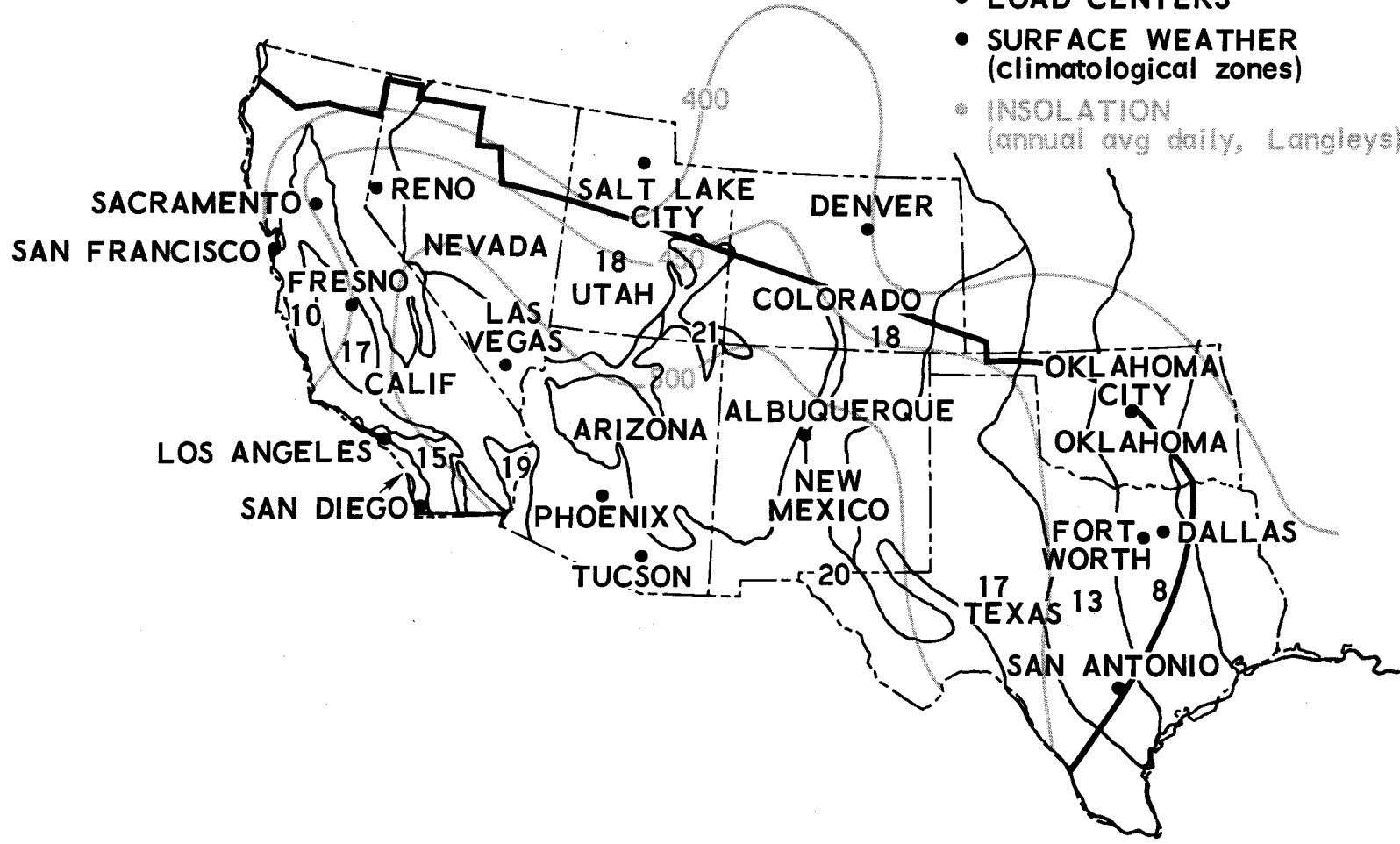
At the onset of this analysis it was necessary to define the Southwest region in terms of its geographic location, climatology, and electrical power demand. Political boundaries as well as power supply areas and utility service regions influenced this definition. The rationale for selecting the particular Southwestern United States area presented in Figure 2-1 is addressed in more detail within the Southwestern United States Area Definition and Siting Analysis volume of this report.

### 2.2 LOAD CENTER DESIGNATION

After the study area had been defined, an assessment was made of published Federal Power Commission (FPC) forecast data to identify specific load centers and to determine the potential power and energy load represented by those centers at some future time. From an analysis of expected population levels as extrapolated from U.S. Census reports, it was determined that approximately 75% of the population within the Southwest resides within the seventeen major load centers listed in Table 2-1. These load centers are served by three municipal and thirteen investor-owned utilities. A summary of peak power demand and energy consumption values achieved by these utilities in 1972 is shown in Table 2-2.

**CONSIDERATIONS**

- STATES
- LOAD CENTERS
- SURFACE WEATHER (climatological zones)
- INSOLATION (annual avg daily, Langleys)



2-2

Figure 2-1. Area Definition

Table 2-1. Major Load Centers Within FPC Power Supply Areas

Power Supply Area	Major Load Centers
PSA 46	San Francisco Area Sacramento
PSA 47	Santa Barbara Los Angeles Area San Diego
PSA 48	Las Vegas Phoenix Tucson
PSA 41	Salt Lake City
PSA 32	Denver
PSA 39	Santa Fe Albuquerque El Paso
PSA 36	Odessa
PSA 37	Dallas Fort Worth
PSA 38	San Antonio
PSA 33	Oklahoma City



Table 2-2. Electric Power and Energy Data (1972)

STATE	UTILITY	(PSA)	ENERGY SALES 10 <sup>9</sup> KWH	SYSTEM PEAK - MW **
ARIZONA	APS*	(48)	7.2	1,660 (S)
	TG&E*	(48)	3.2	662 (S)
CALIFORNIA	LADWP	(47)	17.3	3,630 (S)
	SMUD	(46)	3.9	1,099 (S)
	SDG&E*	(47)	7.2	1,649 (W)
	SCE	(47)	52.3	9,815 (S)
	PG&E*	(46)	53.0	10,469 (S)
COLORADO	PSC*	(32)	8.4	1,615 (W)
NEVADA	NPC	(48)	3.7	828 (S)
	SPP	(48)	2.1	434 (W)
NEW MEXICO	PSNM	(39)	2.5	491 (S)
OKLAHOMA	OG&E*	(33)	12.0	2,645 (S)
TEXAS	CPSB	(38)	5.8	1,274 (S)
	DP&L	(37)	9.3	2,193 (S)
	EPE	(39)	2.7	543 (S)
	TES	(37)	13.0	2,820 (S)
UTAH	UP&L	(41)	7.8	1,525 (S)
TOTAL			207.9	43,038 (non-concident)

\*Gas and Electric Utilities

\*\*S - Summer peaking; W - Winter peaking

The sixteen major utilities, listed in Table 2-3, were contacted for additional information regarding their service territories and associated load data. Three of the utilities contacted were found to be sponsoring internal, company-funded solar energy research and development efforts, and all utilities contacted showed an interest in solar power activities. The material presented in Table 2-4 represents pertinent demographic information on each utility as derived from the responses to these inquiries. Figure 2-2 shows the service territories of the sixteen utility companies as constructed from individual utility data. Note that the study area boundary depicted in Figure 2-2 cuts through several utility service regions, among them being the Pacific Gas & Electric Co., Nevada Power Co., Sierra Pacific Power Co., Utah Power & Light Co., Public Service Co. of Colorado, Oklahoma Gas & Electric Co., Texas Utility Co., and the City Public Service Board of San Antonio.

### 2.3 DATA REQUESTS

The next step toward acquiring the data needed to support the Southwestern United States regional power demand analysis was to formally request the required historic and peak forecast load information from power regulatory commissions, regional power associations, and individual utility companies. It was found, from prior investigations, that no single agency could supply all of the needed data.

Each utility was asked for records of hourly system demand data covering a period of ten years as well as data on system growth and planned generation additions needed to satisfy the anticipated peak loads. These data were used for analysis purposes only and the utility companies were assured that these data would not be released to anyone without their permission.

The Western Systems Coordinating Council (Denver) and the Electric Reliability Council of Texas (San Antonio), listed in Table 2-3, were

Table 2-3. Major Electric Utilities and Agencies in the Southwestern United States

<u>Utilities</u>	<u>Type</u>
ARIZONA	
Arizona Public Service Co. (APS)	Private
Tucson Gas & Electric Co. (TG&E)	Private
CALIFORNIA	
Los Angeles Department of Water & Power (LADWP)	Public
Sacramento Municipal Utility District (SMUD)	Public
San Diego Gas & Electric Co. (SDG&E)	Private
Southern California Edison Co. (SCE)	Private
Pacific Gas & Electric Co. (PG&E)	Private
COLORADO	
Public Service Co. of Colorado (PSC)	Private
NEVADA	
Nevada Power Co. (NPC)	Private
Sierra Pacific Power Co. (SPP)	Private
NEW MEXICO	
Public Service Co. of New Mexico (PSNM)	Private
OKLAHOMA	
Oklahoma Gas & Electric Co. (OG&E)	Private
TEXAS	
City Public Service Board of San Antonio (CPSB)	Public
Dallas Power & Light Co. (DP&L)*	Private
El Paso Electric Co. (EPE)	Private
Texas Electric Service Co. (TES)*	Private
UTAH	
Utah Power & Light Co. (UP&L)	Private

Agencies

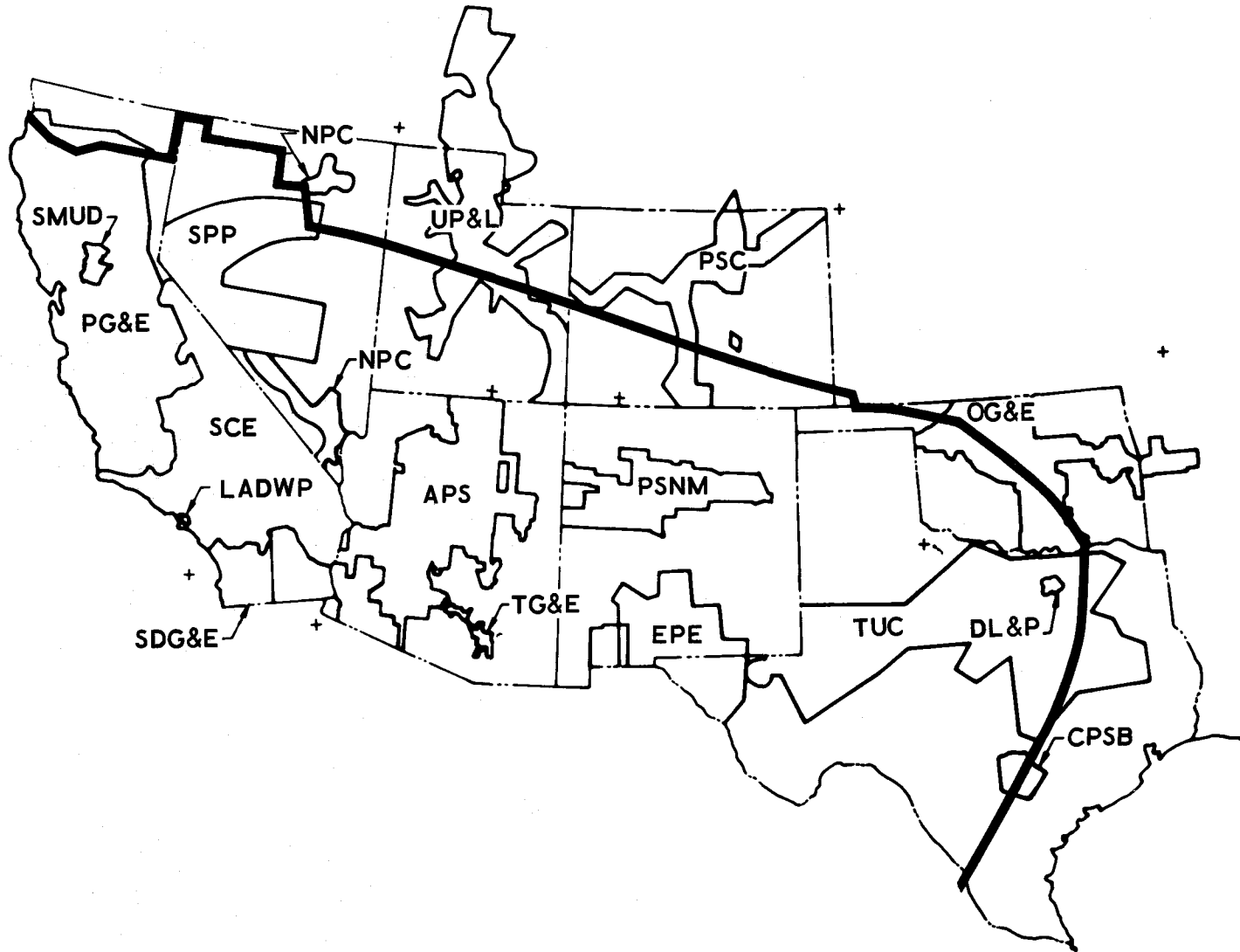
Public Utilities Commissions  
 State Corporation Board  
 State Governor's Energy Office  
 Electric Reliability Council of Texas (ERCOT)  
 Southwest Power Pool (SWPP)  
 Western Systems Coordinating Council (WSCC)  
 Edison Electric Institute (EEI)

\* Both Dallas Power & Light and Texas Electric Service are part of the Texas Utilities Co. (TUC).

Table 2-4. Utility Demographic Data (1972)

State	Utility	Service Territory (Square Miles)	Customers/Population (thousands)	Growth Rate KWH Sales (Percentage)
ARIZONA	APS	40,000	278/1300	17.0
	TG&E	1,155	130/403	14.0
CALIFORNIA	LADWP	460	1102/ -	- -
	SMUD	656	245/ -	7.9
	SDG&E	4,100	1600/ -	7.0
	SCE	45,000	2600/ -	7.1
	PG&E	94,000	2800/8500	7.8
COLORADO	PSC	31,200	583/ -	9.7
NEVADA	NPC	9,348	107/ -	9.1
	SPP	39,600	101/ -	- -
NEW MEXICO	PSNM	26,000	152/1061	8.8
OKLAHOMA	OG&E	30,000	473/1300	11.7
TEXAS	CPSB	1,600	261/ -	11.0
	DP&L	600	247/ -	3.0
	EPE	10,000	133/475	11.0
	TES	83,000	406/ -	- -
UTAH	UP&L	57,000	322/ -	16.0
TOTAL	Utility Service Area	473,719	11,549/30,550*	
	Southwestern U. S.	1,005,000	/40,000	

\*Adjusted from 1970 census data (3% annual growth)



2-8

Figure 2-2. Utility Service Areas

asked to provide regional peak power forecasts consistent with the 1980-2000 period, and the regional offices of the Federal Power Commission were asked for copies of specific utility Power System Statements (Form 12) containing samples of hourly system demand data during the first full week of April, August, and December for the period 1962 through 1972. Furthermore, the Southern California Edison Company and the Los Angeles Department of Water and Power were asked for their latest hourly demand data to update the previously provided hourly demand data.

In addition to the efforts directed at acquiring demand data from utilities, several industrial companies were contacted in an attempt to define a base "total energy" (electrical-thermal) system for solar thermal application. Among those contacted were Bethlehem Steel Corporation, Los Angeles, California; Denver Technology Center, Denver, Colorado; Dow Chemical U.S.A., Freeport, Texas; Texaco Incorporated, Los Angeles, California; and the Phoenix Post Office, Phoenix, Arizona. Contacts were also made with the engineering staff at Edwards Air Force Base, California, in the hope of acquiring community load data containing the industrial, commercial, and residential load information.

#### 2.4 ACQUIRED INFORMATION

As a result of these inquiries, a large volume of data was received. Some of these data, unfortunately, were not received early enough to permit full utilization in the reported analyses. In particular, historic data from the Arizona Public Service Co. and the Pacific Gas & Electric Co. arrived shortly after the contract time period; and, consequently, these data have not yet been incorporated into the demand data base.

With the single exception of El Paso Electric Co. data, all electric utility load data were acquired from the Federal Power Commission (in the form of System Load Summaries) or directly from the utility companies. El Paso Electric data were purchased from the University Computing Company,

Energy Industries Division, Dallas, Texas, after authorization from El Paso Electric and the Edison Electric Institute.

In addition to the load and forecast data received and summarized in Table 2-5, Edwards Air Force Base provided strip chart recordings of five 1971 substation hourly load histories and a single substation hourly load history for February 1973. Bethlehem Steel supplied a typical load history describing its operations and Texaco offered to supply data useful for further analysis.

In addition to the above demand data, magnetic tapes containing twelve years (1962 - 1973) of weather observations at Tucson, Arizona, and at El Paso and San Antonio, Texas, were purchased from the National Climatic Center in anticipation of weather correlation analysis activities. The content and use of these tapes are discussed in Section 6.

Table 2-5. Electric Utility Data Collection Summary\*

<u>Utilities/Agencies</u>	<u>FPC Form 12 Hourly Data</u>	<u>Hourly Load Data</u>	<u>Growth Forecast</u>	<u>Generation Forecast</u>
Arizona Public Service Co.	11	10	20	20
Tucson Gas & Electric Co.	11	ND	NR	NR
Los Angeles Department of Water & Power	1	12	10	27
Sacramento Municipal Utility District	11	11-2/3	5	10
San Diego Gas & Electric Co.	1	ND	10	10
Southern California Edison Co.	2	12-1/2	10	10
Pacific Gas & Electric Co.	9	5	10	10
Public Service Co. of Colorado	11	NR	NR	NR
Nevada Power Co.	9	ND	ND	ND
Sierra Pacific Power Co.	11	--	--	--
Public Service Co. of New Mexico	11	12	27	27
Oklahoma Gas & Electric Co.	11	NR	NR	NR
City Public Service Board of San Antonio	11	17	21	ND
Dallas Power & Light	9	NR	NR	NR
El Paso Electric Co.	11	10	20	20
Texas Electric Service Co.	8	NR	NR	NR
Texas Power & Light Co.	11	--	--	--
Utah Power & Light Co.	11	NR	NR	NR
Electric Reliability Council of Texas	--	--	20	20
Western Systems Coordinating Council	--	--	26	26

\* Column number indicates years of data.

ND - no data received

NR - no response



### 3. POWER AND ENERGY FORECASTS

A primary input requirement of the demand forecast model is the forecasted annual peak load. The magnitude of the annual peak load establishes the relative magnitude of each hourly load. The load profile forecast methodology is discussed in detail in Section 5.

#### 3.1 LOAD FORECAST METHODS

Methods for forecasting the peak load at some future time are either deterministic or probabilistic. Both methods are used in the utility industry. Because of the great controversy over the validity of long-range forecast data (Reference 2) and in view of current energy and economic uncertainties, it was decided not to attempt to develop an independent forecast. In fact, it was considered more appropriate to adopt the existing forecast data as being the most authoritative, rather than making an independent forecast in order to avoid clouding the analysis with a subjective evaluation of the future demand. Furthermore such an effort was clearly beyond the scope of this study, while the final results of this analysis would not be altered significantly. The approach selected in determining the peak load forecast was to accumulate and analyze all available authoritative forecasts that appeared suitable for use in the demand forecast model. During the early stages of data collection and review, it became evident that no single authoritative source of forecasts existed for the Southwestern United States. Hence it became necessary to contact various organizations and request available forecast information.

Originally it had been planned to use the Federal Power Commission (FPC) load forecast data. However, the published FPC data is typically delayed by several years. (The most recent FPC forecast is contained in the 1970 National Power Survey Report, which uses 1969 data.)

Furthermore, it was found that use of FPC peak load forecasts would be inconsistent with the historic utility hourly load data, since the FPC and the utilities use different boundary definitions. A better understanding of these inconsistencies can be realized by examining the FPC/PSA boundary map and accompanying table of load forecasts shown in Figure 3-1 and Table 3-1.

Power Supply Area data are not available as continuous hourly demand load records and the PSA boundaries are such that it is difficult to define a complete set of utility load records within each PSA. Therefore a complete hourly load analysis is difficult to make on the basis of PSA data. The only known records of continuous yearly system load data are those maintained by the utility companies. Unfortunately, FPC forecast data cannot be used with system load records because FPC-prepared peak loads do not generally coincide with the same boundaries as used by the utilities. It was concluded, therefore, that the direct use of FPC data in the load forecast analysis should be limited to prevent any inaccuracies that might result from attempts to correlate load and specific geographic areas.

Load forecast data obtained from eleven utilities and two coordinating council reliability regions are plotted in Figure 3-2. Data shown in the figure by continuous lines were supplied from these sources. The dashed portions of the curves are extrapolations of the given forecast to the year 2000. These extrapolations were made on the basis of a straight-line logarithmic projection computed from the last two supplied forecasts. The basic data used in developing Figure 3-2 are tabulated in Table 3-2. Underlined values in the table identify the projections estimated by this technique.

### 3.2

#### GROWTH RATES

Table 3-2 also contains values of compound growth rates, showing projected growth for the eleven utilities ranging from 6.6 to 13 percent. The high

Table 3-1. Federal Power Commission Load Forecasts by Power Supply Area (PSA)

PSA	1970		1980		1990		2000	
	Peak Load (MW)	Total Energy 10 <sup>9</sup> (KWH)	Peak Load (MW)	Total Energy 10 <sup>9</sup> (KWH)	Peak Load (MW)	Total Energy 10 <sup>9</sup> (KWH)	Peak Load* (MW)	Total Energy 10 <sup>9</sup> (KWH)**
32	2,271	11.5	4,226	23.4	7,190	45.3	12,232	69.5
33	6,120	26.5	13,800	60.1	26,600	116.3	51,272	291.5
36	1,775	9.2	3,089	18.2	5,190	33.8	8,720	49.7
37	7,970	35.6	18,000	82.0	36,200	168.0	72,802	414.5
38	8,510	43.6	19,700	102.7	41,500	219.9	87,423	497.6
39	1,041	5.4	2,259	11.5	4,268	21.6	8,048	45.8
41	2,840	15.7	5,690	31.4	11,460	63.2	23,081	131.0
46	11,400	63.4	24,300	136.0	52,200	291.0	120,483	685.6
47	13,300	72.5	26,700	151.0	53,600	298.0	107,601	612.7
48	4,480	23.6	9,560	50.3	20,500	108.0	43,959	250.3
Total		307.0		666.6		1365.1		3047.2
Non-Coincident Peak	59,707		127,324		258,708		535,621	

\* Straight line projection based on 1980-1990 annual compound rate of increase

\*\* Assumed load factor of 0.65

3-4

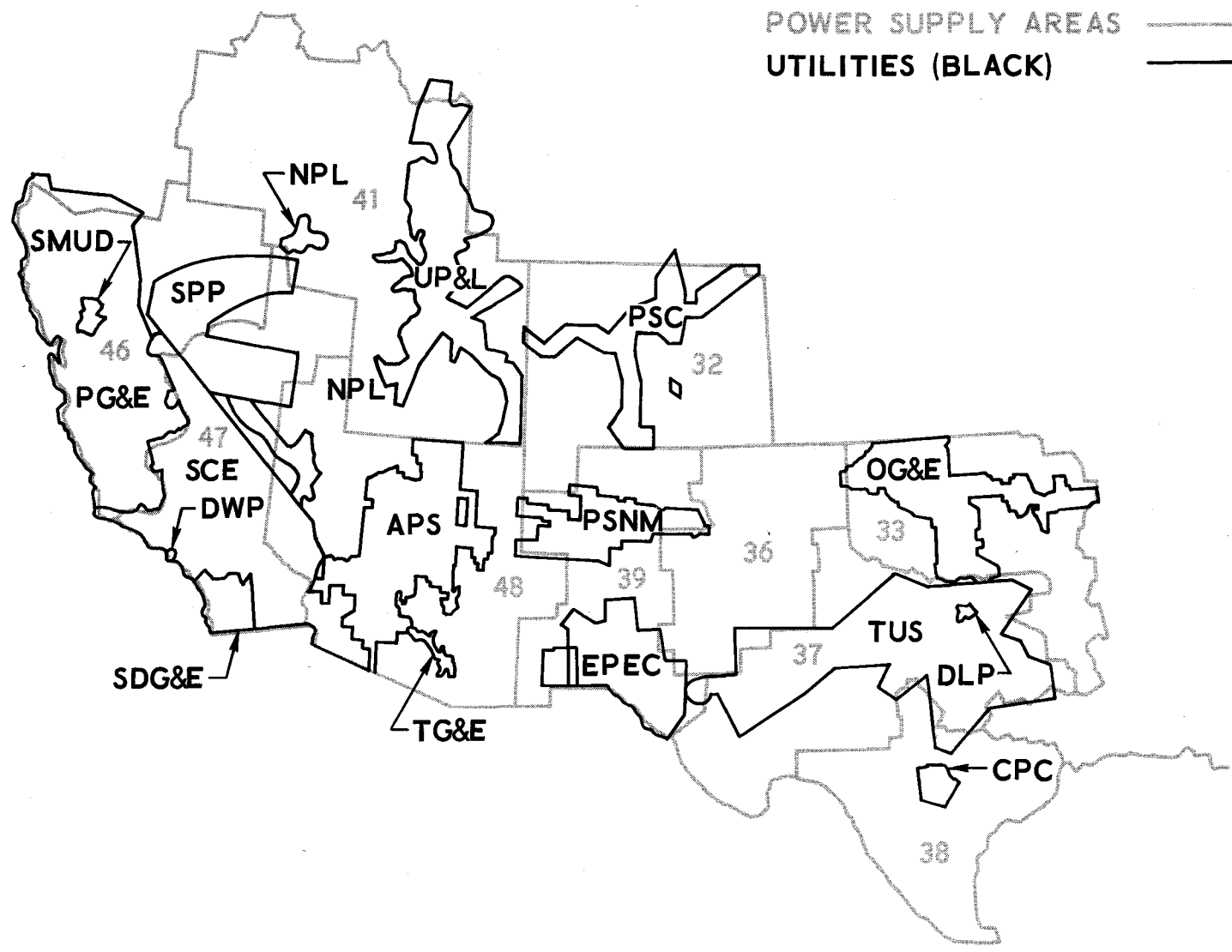
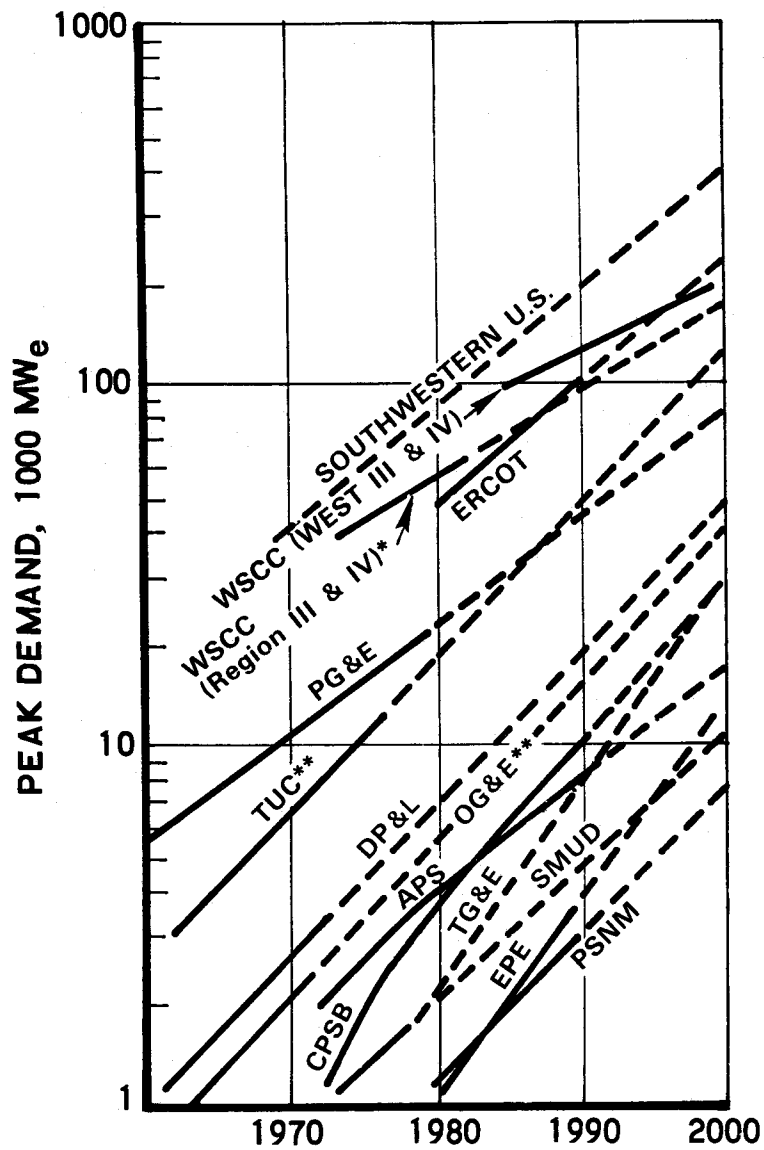


Figure 3-1. Power Supply Area/Utility Boundaries



YEAR PEAK DEMAND , MW<sub>e</sub>

1970	35,000	} 7.4% GROWTH RATE
1980	79,000	
1990	170,000	
2000	334,000	

\*WSCC 10 year forecasts (Sept 1973)

\*\*Texas and Oklahoma Utility Reports (1972-1973)

Figure 3-2. Peak Electric Demand Trends

electric power consumption growth rates of utilities such as Tucson, Arizona, and San Antonio, Texas, reflect the rapid increase in population and city or community facilities experienced in those areas. It has been suggested that these high growth rates cannot continue very long into the future. However, it is difficult to specify reduced growth rates. One rapid growing utility, San Antonio City Public Service Board, is planning increases in its generating capacity on the basis of an 11 percent growth rate through the year 1996, as reported in the company's 1973 annual report. The Pacific Gas and Electric Co. replying to an inquiry concerning its 7.7 percent projected growth rate and the recent reduction in electric energy consumption, stated, "Our judgment at this early date is that, after a year or two of near-level demand, the rate of load growth will once again approach the trend of recent years. We believe this to be the case because of the large segment of the population which will be entering the mainstream of the purchasing public for the first time." Responses of a similar nature were received from other members of the utility industry and government. The general feeling is that, if economic growth is to continue its present trend, the rate of energy consumption growth must be at a comparable level.

### 3.3 PEAK LOADS

The best approximation of the total load within the study area is the aggregate sum of data from several selected utilities and portions of Western Systems Coordinating Council regions. The data sources selected are the Western System Coordinating Council Regions III and IV, San Antonio City Public Service Board, Oklahoma Gas and Electric Co., and the Texas Utilities Co. The summation of forecast peak annual loads for each year (1980, 1990, and 2000), for each of these utilities and organizations, produced the forecast shown on Figure 3-2 by the dashed line near the top of the graph. Values for each of the 10-year periods beginning in 1970 are also shown in Table 3-2. From this accumulated information the projected study area peak load for

Table 3-2. Projected Peak Loads for Southwest Utilities and Agencies

Utility / Agency	1962	1965	1972	1973	1980	1982	1985	1990	2000	Growth Rate(%)
Arizona Public Service (APS)	760		1,661		3,361			7,109		7.8
Dallas Power and Light (DP&L)	1,306	1,656	2,936							8.5
El Paso Electric Co. (EPA)			543		984			2,209		8.4
Oklahoma Gas & Electric Co. (OG&E)*	1,041	1,372	2,645		5,587			14,300	36,200	9.8
Pacific Gas and Electric Co. (PG&E)	5,346	6,686	10,469		19,991					7.7
Public Service Co. of Colorado (PSC)	817	1,057	1,767							7.6
Public Service Co. of New Mexico (PSNM)			492		1,034			2,572		9.5
Sacramento Municipal Utility District (SMUD)		570	1,099		1,839					6.6
San Antonio City Public Service Board (CPSB)*			1,274		3,425			9,720	27,500	11.0
Texas Utilities Co. (TUC)*	3,382	4,379	8,435		17,198			43,800	111,500	9.8
Tucson Gas & Electric (TG&E)	254	279	662							13.0
Western System Coordinating Council (WSCC)				64,326		102,287				5.2
WSCC (Westwide Region III & IV)							80,810		178,312	5.4
WSCC (Region III & IV, 1973)*				36,400	53,400	59,600		102,700	158,800	5.6
Southwest United States Study Area Total					79,600			170,500	334,200	7.4

the year 2000 is forecasted to be 334,000 megawatts, with an average growth rate during the 1980-2000 time period of 7.4 percent.

The individual utility system peak loads used in the forecast are expected to occur at about the same time during the year. With only a few exceptions all of the Southwest utilities realize their annual system peak in the summer. The month of this occurrence is usually August and is generally attributed to the higher temperatures at that time of summer. The expected error in the peak forecast because of inter-system diversity is expected to be small. Therefore, the method of using simple algebraic summation of the peak load values appears reasonable.

#### 3.4 ENERGY AND CONSUMPTION FORECASTS

The development of a description for the total annual electric energy consumption in the time frame of interest (1980-2000) was considered important for two reasons. The value of annual energy consumption permits a simple accuracy check of the load profile generated by the demand forecast model. Energy consumption values may also be used as a basis for determining siting feasibility, an effort accomplished in the Southwestern United States siting analysis and described in a separate volume.

The electric energy consumption forecast shown in Table 3-1 applies to all eight southwestern states by PSA. While an energy consumption approximation could be made on the basis of this data, the consumption attributed to the land areas outside of the study area boundary would result in an approximation at least 30 percent too large and could not be used for comparative purposes. To correct this situation, it would be necessary to compile load energy forecast data from each utility serving the study area. Unfortunately, this information was not available; therefore, it was necessary to calculate the energy forecasts by other methods utilizing existing data sources.



Two methods were identified as possible energy forecast calculation techniques. The first method uses a load factor derived from a load factor trend analysis and available from FPC data. The second technique uses the integrated value of the load profile as generated by the demand forecast model. The latter method, although more accurate for specific utilities, had to be ruled out due to unavailability of complete load histories for all utilities in the Southwestern United States study area. Consequently, the load factor method was used in making the electric energy consumption forecasts summarized in Table 3-3. Several electric energy consumption forecasts provided by Southwest utilities are also shown for comparison.

Table 3-3. Electric Energy Consumption Within the Southwest United States

	Annual Consumption ( $10^9$ KWH)		
	1980	1990	2000
Southwest U. S. Study Area	467.7	1,024.9	2,023.0
Arizona Public Service Co.	14.6	31.9	69.6
Tucson Gas and Electric Co.	--	--	28.8
Southern California Edison Co.	--	--	315.3

#### 4. DEMAND DATA MANIPULATION

The historic electric demand data listed in Table 2-5 were received in a variety of formats, a different one corresponding to each major data source. With this multiplicity of formats, the decision was made to correct all of the data to be compatible with the Edison Electric Institute (EEI) System Load Data Card Format,\* established as an internal standard during the previous NSF Solar Thermal Conversion Mission Analysis. In this manner the logic for all subsequent analysis and model simulation programs which used demand data inputs could be minimized. This also permitted the standardization of a demand data base which could be made available to other NSF contractors with utility consent, in a manner similar to the practice now followed with solar insolation data base tapes.\*\* A definite need exists for an industry standard for data exchange.

The EEI data card format consists of two cards, each containing twelve hours of load measurements with various identifiers defining the data, utility (in terms of FPC, EEI, PSA, and ownership codes), day of the week, time zone, average temperature, and departure from average. The subset selected for The Aerospace Corporation data base does not presently contain all numeric utility identifiers. It does, however, contain a two-character alphabetic utility designation and a day-of-year counter ordinarily left blank in the standard EEI data cards. Temperature and temperature deviation are also not defined in The Aerospace Corporation data base, with the exception of those data cards acquired through EEI.

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\* The System Load Data Card Formats defined by EEI for their load diversity study (cf. Reference 3) are shown in Figure A-1, Appendix A. The Aerospace Corporation additions and modifications to the EEI format are also listed in Table A-1, Appendix A.

\*\* Details concerning the format and distribution of the solar insolation data base can be found in the Southwestern United States Insolation Climatology volume of this report and the corresponding volume (Reference 4) of the final report describing the previous study.

Computer programs were written to read and decode each unique demand data format and generate the desired EEI data card images. These data were then assembled on data base library tapes through the use of a standard Control Data Corporation utility program UPDATE\* (Reference 5). The utility demand data base can be further manipulated to remove the local daylight savings discontinuities using a specially developed program DALTE. Data base information, in standard format, can be tabulated using an available library tape list program LISTL, or selected utility data can be plotted after translation by either of two conversion programs and operated upon by the adaptation of the general Aerospace Corporation plotting program VALPLOT (Reference 6).

It is the intent of this section to discuss the computer programs and processes that were developed in order to create the demand data base. The current data base content and organization are also outlined. The computer programs considered are shown in Table 4-1. Many of the programs and processes that are described are straightforward and lack sophistication. However, it should be noted that much of the manpower and computer costs expended in the demand analysis effort were directed toward the creation of the demand data base.

#### 4.1 FPC FORM-12 DATA

The individual operations required to process the 160 two-page FPC-Form 12 (Schedule 15) Power System Statements\*\* acquired for the study involved considerable effort. Each Schedule 15 statement contains integrated hourly demand observations recorded during the first week in April, August, and December of each year. Before the data could be entered into the demand data base, the data were keypunched from copies supplied by the FPC offices.

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\* The Aerospace Corporation's Information Processing Facility contains both a CDC 6400 and a CDC 7600. These systems were used for the data manipulation and analysis tasks described in this report.

\*\* A sample FPC Form-12 (Schedule 15) is provided in Figure A-2, Appendix A.

Table 4-1. Data Manipulation Programs Developed\*

Utility Specific

- CPSB - Translates CPSB Card Image Demand Data to EEI Card Format
- DWP1,  
DWP2 - Translates LADWP EBCDIC Tape Data to EEI Card Format
- EAFB - Calibrates Edwards A.F.B. Demand Strip Short Data to EEI Card Format
- EPE - Transcribes Identification from EEI Supplied EPE Data to FPC Supplied Records
- SCE - Translates SCE Data Records (Two Formats) to Standard EEI Card Format
- SMUD - Translates SMUD Supplied Monthly Data Record Blocks to Standard EEI Card Format (Standard Time Identifiers)

General Purpose

- CNVRT - Translates Demand Data Base Card Images to Floating or Normalized Floating Output for Plotting
- DALTE - Translates Demand Data Base Histories from Local to Standard Time
- FLDTA - Translates Long Demand Data Histories to Floating Decimal Form for Plotting
- MODFY - Translates Keypunched FPC Form 12 (Schedule 15) Data to Standard EEI Card Format

\* Program logic and flow diagrams of each data manipulation program are included in Appendix A. In addition, listings of general purpose programs are provided.

Once the original data were prepared, the data units were translated from kilowatts to megawatts. The forms associated with each utility were sent to keypunch with instructions for preparation of the data cards. Some of the information required in the adaptation to the EEI System Load Data Card Format, namely, the day-of-week and day-of-year, could not be conveniently keypunched without requiring manual annotation of this information on each data sheet prior to keypunching. For this reason and keypunch operational considerations, it was decided to write a data translation program to modify the keypunched data cards to conform with the intended standard. The straightforward logic of this program, MODFY, is illustrated in Figure A-4, Appendix 4.

#### 4.2 LOS ANGELES DEPARTMENT OF WATER AND POWER DATA

One of the earliest data reduction efforts undertaken was to reformat data obtained from the Los Angeles Department of Water and Power (LADWP). The LADWP demand data history was supplied on a nine-track, 1600-bit per inch EBCDIC\* magnetic tape, with each record containing one month of data. Records were identified by two data words which indicated the month and year; data words that ordinarily would be assigned to high numbered days of the month were set to zero if those days were not present in the month.

Two programs, logically shown in Figure A-6, Appendix A, were written to process the LADWP data. The first program reads the tape supplied by the utility, converts the information from EBCDIC to binary integers, and generates an intermediate seven-track BCD\*\* tape with records containing twelve hours of data identified by month, day, and year. The second

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\* EBCDIC - Extended Binary Coded Decimal Interchange Code. A system using eight binary bits to represent decimal digits, alphabetic, and special characters.

\*\* BCD - Binary Coded Decimal. A system using six binary bits to represent decimal digits, alphabetic, and special characters.

program reads this tape and creates data in the standard EEI card format, appending necessary identification with day-of-week and day-of-year counters.

At the time the LADWP reduction took place, it seemed necessary to visually inspect the data before assigning values to day counters. Later programs eliminated this second step by using an algorithm to compute those quantities, although detection of missing data (eight values in the LADWP file) still requires manual inspection.

#### 4.3 SOUTHERN CALIFORNIA EDISON COMPANY DATA

The first bulk utility data processed by the solar thermal conversion demand analysis program were supplied by the Southern California Edison Company (SCE). Although SCE data were manipulated during the previous NSF study contract, no effort was made to convert the data to standard EEI format. The SCE data, which had originally been supplied in two card formats, was recorded on magnetic tape during the previous study for ease of handling. This tape with card additions for 1973-74 became the data source treated by the reformatting program, SCE.

The difficulties encountered in processing SCE data were attributed to the three data formats (two on tape and one on cards) and the fact that several unexpected duplicate daily records were encountered in December 1972. Although the SCE program logic, illustrated in Figure A-9, Appendix A, does not indicate the program instruction sequence required to circumvent the latter problem, it is shown in the accompanying detailed flow diagram.

Other problems associated with the processing of SCE data were encountered as a result of one hourly measurement being 300,000 MW too large and a mispositioned day appearing fifteen days ahead of its intended position. Unfortunately, these conditions were discovered only when projected forecasts using the erroneous data did not look reasonable. This problem

dramatically illustrates the need for input data validity checking in the demand analysis program.

#### 4.4 SAN ANTONIO CITY PUBLIC SERVICE BOARD DATA

The program required for reformatting City Public Service Board (CPSB) data represented the most direct conversion of bulk utility data undertaken during the project. Initially CPSB had supplied a listing of their seven-year historical load data. When asked for this information on magnetic tape, they responded with a nine-track EBCDIC copy of this data history.

The magnetic type version of the CPSB load history contained sets of daily load card images, the first of which held ten hourly observations, and the second card held fourteen.

In order to convert data into standard format, a program was written to read the pairs of daily load cards and punch (or write) new card images, each containing twelve hours of data with PSA, utility, time zone, day-of-week and day-of-year identification. This program is illustrated in Figure A-5, Appendix A. Only two missing observations and two cards with improperly identified dates were found among the 12,422 cards received from CPSB.

#### 4.5 SACRAMENTO MUNICIPAL UTILITY DISTRICT DATA

Sacramento Municipal Utility District (SMUD) card image data was unique in that it came blocked in groups of monthly observations, with all data recorded irrespective of the prevailing time system. Although the information was not organized into standard time observations, sufficient information was provided to permit reformatting the data into that condition. As discussed in a succeeding subsection describing the time base translation program DALTE, all of the utilities which transmitted data, with the exception of SMUD, recorded their data according to a local time base. This means that one observation was usually repeated in the spring when



changing to daylight savings time and another observation was lost in the fall when returning to standard time.

In the SMUD data file all observation days contained twenty-four hours, except the last weeks in April and September. These contained twenty-three and twenty-five hours, respectively. The SMUD-supplied data were translated into a standard time reference by the reformatting program called SMUD, which is illustrated in Figure A-10, Appendix A. This program shifted the daylight savings hourly demand observations back one hour and assigned standard or daylight savings time reference identifiers to each card depending upon its date and the appropriate time base change dates. The reformatting program provided standard utility, PSA, day-of-week, and day-of-year identifiers, and punched (or wrote) the SMUD load data in EEI card image format, twelve observations per card. Since original SMUD data cards did not include the day of the month, this was also supplied.

#### 4.6 EL PASO ELECTRIC COMPANY DATA

As indicated above, the only data purchased specifically for this study were the El Paso Electric Co. load data. Eight years of information were procured from the University Computing Co. (UCC), Energy Industries Division, Dallas, Texas, on a seven-track, 800-bit per inch, BCD magnetic tape with 132-character records, the first 80 of which represented the EEI card image. Each year of the data was provided in a separate file on tape.

University Computing's EPE data file did not contain the years 1967, 1968, and 1972. However, FPC Form-12 data was acquired for the first weeks in April, August, and December during the missing periods. Once the UCC data were translated into a single file tape under UPDATE edit control, the data from the missing years were merged with this file and the composite was processed by the program EPE, illustrated in Figure A-8, Appendix A, to copy the numerical EEI utility and time zone identification from the

UCC cards to the FPC cards and incorporate the day-of-year and alphabetical utility identifiers on the UCC cards. During this process another difference between The Aerospace Corporation and standard EEI formats was discovered. EEI indicates a holiday by setting the day-of-week identifier to 8. The Aerospace Corporation data base does not now contain this feature.

In addition to the normal reformatting problems, several data peculiarities in the UCC data had to be circumvented: (1) All utility data handled by UCC for the Edison Electric Institute's Load Diversity Study are translated to Eastern standard time. The data we received had been translated back to the original time zone, leaving two missing hourly loads at the end of each year. These data (sixteen hourly loads) were replaced by interpolation or substitution from neighboring-day information observed at the same time. (2) Two data card images were missing and three card images were off-shifted with some missing hourly observations. These data were replaced after telephone calls to UCC offices in Dallas. (3) Thirty missing (zero) hourly observations, including one set of PM observations and eighteen others (mostly at 8 AM), were replaced by interpolation.

#### 4.7 EDWARDS AIR FORCE BASE DATA

Several sets of strip charts, including one partially shown in Figure A-3, Appendix A,\* were acquired from Edwards Air Force Base, California. These data consisted of fifteen-minute interval, daily integrated load histories from five substations during the year 1971 and one substation during February 1973. Each month of data was provided an individual chart.

Processing of the Edwards data involved two tasks; hourly data points were digitized on a Benson-Lehner OSCAR, Model S-2, Optical Reader, and the resulting output cards, containing data in digitizer counts, were

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\* Note that time runs backwards on the EAFB strip chart, beginning at the lower right and ending at the upper left.

converted to standard EEI card format, using the program EAFB as illustrated in Figure A-7, Appendix A.

OSCAR digitization consisted of manually measuring every fourth load data point and punching those values into an 80-column card. The EAFB computer program calibrates each recording by multiplying it by the ratio of a meter factor (meter units/megawatt) and the OSCAR calibration (counts/meter unit). Each input card contained a data and substation identification which were translated to the output. Day-of-week and day-of-year were supplied by algorithm.

#### 4.8 TIME BASE TRANSLATION

With the single exception of SMUD data, all of the utility data placed in standard EEI card form were recorded in local time. As a result, at least two discontinuities occur in each data year: when the time base changed from standard to daylight savings in April, and when it returned to standard time in October. An exception to this rule occurred in 1973 with the adoption of a continuous daylight savings time. Utilities varied in the manner of recording data during the April shift and with respect to the time selected to make the time base change. Often measurements were repeated or one of the observations was arbitrarily set to zero. All utilities lost the load measurement preceding the return to standard time.

Due to this state of inconsistency and an operational need to merge electric power demand (local time) with weather and insolation parameters (standard time), a program was written to modify or time-translate the utility demand data base (in standard format) to a consistent standard time base, with identifiers indicating the originally recorded time (standard time or daylight savings time). This program, DALTE, illustrated in Figure A-11, Appendix A, shifts the data base according to input time interval (date-hour) specifications. Optionally, either an input-supplied load or an

interpolated value can be inserted in the void created during the daylight savings/standard time transition period.

#### 4.9 DATA NORMALIZATION / EXPANSION

Although the demand data base generated by the programs described above is in a form acceptable to specially developed routines used by the solar thermal conversion mission analysis study, the EEI format data cards are not immediately compatible for use by standard, general-purpose utility programs such as those designed for pen or film plotting. In order to circumvent this difficulty, two additional programs were written: FLDTA and CNVRT. These are illustrated in Figures A-12 and A-13, Appendix A.

FLDTA, the simpler of the two, reads demand data cards in standard EEI format and creates a magnetic tape with records containing as many as twenty-four three-word frames (sets) in each record. The first word is a floating-decimal hour counter, which begins at one in the first hour of the first year and recycles to one at each subsequent year. The second word of each set is the data recorded in the first six characters of a ten-character display code\* word as MMDDYY,\*\* and the third word is the floating-decimal load measurement in megawatts. Although the program will continue to process data without regard to utility description changes, in practice only one utility data base is processed at a given time, producing a single file of information.

The program CNVRT serves two purposes: like program FLDTA, it has the ability to output demand data in a direct (unmodified) form, and it can normalize its output demand according to the maximum demand in one

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\* Display code is the internal code used for Hollerith data within The Aerospace Corporation's CDC 6400/CDC 7600. In this application the data is written in a core image format.

\*\* The date, in this form, is used for an additional time scale annotation by the VALPLOT program. Examples of plots created by FLDTA, CNVRT, and VALPLOT are provided in Section 5.

or more data segments (a data segment being a set of continuous demand observations for a given utility and a specific year). CNVRT also outputs records containing a multiple of three-word frames: a floating-decimal hour measured from the beginning of the first year of a given set of utility data (the first hour of the first year being hour one), a display code date in the form MMDDYY, and a floating-decimal load measurement in megawatts or a nondimensional normalized load. Records generated by DNVRT contain as many as 170 three-word frames. The output from CNVRT also differs from that provided by FLDTA in the fact that CNVRT puts each output data segment in a tape file of its own and summarizes its output in a printed resume listing, which lists the utility system, segment time spans (hour and date) and data extremes (minimum and maximum) with dates of occurrence.

#### 4.10 DATA BASE STRUCTURE AND CONTENT

The demand data base created by the programs outlined in this section is presently maintained on three sets of master tapes (A, B, and D) in UPDATE library format.\* Each tape is identified by a unique data base letter, generation number, and copy number. For example, the tape DMD/A2.3/U contains data base A, second generation, third copy. The terminal letter U signifies that it is in UPDATE format.

For simplicity and to minimize potential tape processing time, utility data are assigned to data base A or B, depending upon the first character in the utility abbreviation. Utilities A through M are assigned to data base A and utilities M through Z to data base B. The third data base (D) contains only utility load data that have been converted to a standard time base (that is, had daylight savings time effects removed).

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\* An UPDATE library tape is an odd parity tape containing compressed and identified card images which are stored and organized according to assigned deck names. Word compression (removal of blank characters) and record blocking provide a reduction in overall tape length.

The content of the existing demand data base tapes is summarized in Table 4-2. The utility data on each tape are organized into decks (sets of cards) identified by utility abbreviations. Header comment cards are included in each deck listing the full utility name, and all data cards are uniquely numbered so that they may be retrieved individually or in groups for subsequent modification or analysis.

#### 4.11 PROGRAM LIBRARY

All of the computer programs described in this section and illustrated in Appendix A are stored on a program library tape in UPDATE format. The programs are grouped in decks, each identified by a name equivalent to the program name. In addition to the program in FORTRAN source card format, each deck contains the control cards necessary for its compilation and execution. Sample case input with control cards required for their execution are also included for those programs which read card image inputs. Program library tapes are identified by generation and copy numbers such as PRG/4.2/U, where U indicates that the tape is in UPDATE format.

#### 4.12 FUTURE WORK

The data received from Arizona Public Service and Pacific Gas & Electric and data yet to be received in response to requests should be processed into standard form so that they, too, can be used in various analyses.

The identification used on the individual data cards should be standardized to that defined by the Edison Electric Institute. This means that a "one-shot" program would have to be written to read the existing data base cards and replace the present alphabetic time zone designations (P - Pacific, M - Mountain, and C - Central) by EEI defined numeric codes (1-8) signifying both time zone and time base (standard or daylight). It would also eliminate the need for the added alphabetic character presently defining the time base (S - Standard, D - Daylight). At the same time the proposed format

Table 4-2. Demand Data Base Content

<u>Data Base / Utility-Agency</u>	<u>Deck Name*</u>	<u>Card Abbreviation**</u>	<u>Time Spans***</u>	
DATA BASE DMD/A (Local time)				
Arizona Public Service Co.	APS	AR	1962-1972	(Form 12)
City Public Service Board	CPSB	CP	1967-1973	(Continuous)
Dallas Power & Light Co.	DPL	DA	1964-1972	(Form 12)
Edwards Air Force Base	EAFB	ED	1971	(Continuous) 2 Subst.
El Paso Electric Co.	EPE	EP	Feb. 1973	(Continuous) 1 Subst.
			1962-1966	(Continuous)
			1967-1968	(Form 12)
			1969-1971	(Continuous)
Los Angeles Department of Water & Power	LADWP	LA	1972	(Form 12)
			1962-1973	(Continuous)
DATA BASE DMD/B (Local time)				
Nevada Power Co.	NPC	NP	1962-1965	(Form 12)
Oklahoma Gas & Electric Co.	OGE	OK	1968-1972	(Form 12)
			1962-1972	(Form 12)
Pacific Gas & Electric Co.	PGE	PG	1962-1972	(Form 12)
Public Service Co. of Colorado	PSCO	CO	1962-1972	(Form 12)
Public Service Co. of New Mexico	PSNM	NM	1962-1968	(Form 12)
			1969-1973	(Continuous)
Southern California Edison Co.	SCE	SC	1962-1973	(Continuous)
Sacramento Municipal Utility District	SMUD	SM	1962-1972	(Form 12)
Sierra Pacific Power Co.	SPPC	SP	1962-1972	(Form 12)
Texas Electric Service Co.	TES	TE	1965-1972	(Form 12)
Tucson Gas & Electric Co.	TGE	TU	1962-1972	(Form 12)
Texas Power & Light Co.	TPL	TP	1962-1972	(Form 12)
Utah Powr & Light Co.	UPL	UP	1962-1972	(Form 12)
DATA BASE DMD/D (Standard time)				
Los Angeles Department of Water & Power	LADWP	LA	1962-1973	(Continuous)
Sacramento Municipal Utility District	SMUD	SM	Jul. 1964-	(Continuous)
			Feb. 1974	

\* UPDATE deck identifiers cannot contain special characters such as ampersands (&). Therefore, the above abbreviations were selected.

\*\* Utility abbreviations are constrained to two characters on the Aerospace Corporation adaptation of the EEI card format.

\*\*\* The notation Form 12 is used to indicate hourly observations during the first full weeks of April, August, and December. Continuous implies a sequence of hourly observations without chronological breaks.

conversion program would introduce EEI system identification, FPC designation, power pool, and ownership codes. These new identifiers would be used by all subsequent reformatting programs. It is unfortunate that all EEI format conventions were not known until well after the major reformatting effort had been completed.

One additional identifier should be added to the data base format: a column indicating whether the recorded loads are in megawatts (MW), the standard form, or kilowatts (KW). EEI specifies that hourly load data should be rounded to the nearest megawatt and, in this respect, the proposed change would depart from that standard. The change seems warranted, however, since it would permit the use of developed analysis tools to be extended to load centers smaller than the normal megawatt range — say, to small businesses or individual residences.

The final recommendation is the development of a modular reformatting program whose input processing logic can easily be retuned to read various utility load data formats and generate standard EEI data cards for incorporation within the demand data base. This requirement would not be necessary if the utility industry maintained a standard for data exchange.



## 5. DEMAND DATA ANALYSIS

Demand data analysis activities were concentrated in two areas: (1) a study and comparative analysis of electric power demand data histories, and (2) the automation and enhancement of the demand decomposition/recomposition forecast model conceptually defined and developed in the previous NSF-sponsored Solar Thermal Conversion Mission Analysis. Each of these activities is described in this section. Also included are recommended areas for future work which are natural extensions of current efforts.

### 5.1 COMPARATIVE ANALYSES OF DEMAND DATA

As southwestern utility demand data histories were accumulated in data bases described in the previous section, it became possible to examine individual utility load profiles, to compare profiles of various utilities, and to compare the year-to-year utility profile variation. These comparisons were made in the qualitative sense with the aid of the CNVRT and FLDTA programs which are also described in the previous section.

An examination of the normalized utility load profiles provided in Figure 5-1\* illustrates the similarities in the behavior of Southwest utility loads. Although detailed variations which result from individual load center characteristics and time dependent factors are evident, the similarities in gross behavior can readily be seen in Figure 5-2, where the normalized profiles from four Southwest utilities - City Public Service Board of San Antonio (CPSB), Dallas Power & Light (DP&L), El Paso Electric (EPE), and Southern California Edison (SCE) - are compared.

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\* The peak loads indicated on Figures 5-1, 5-2, and 5-3 are the maximums occurring in the time periods plotted. These may be less than the absolute yearly utility maximum.

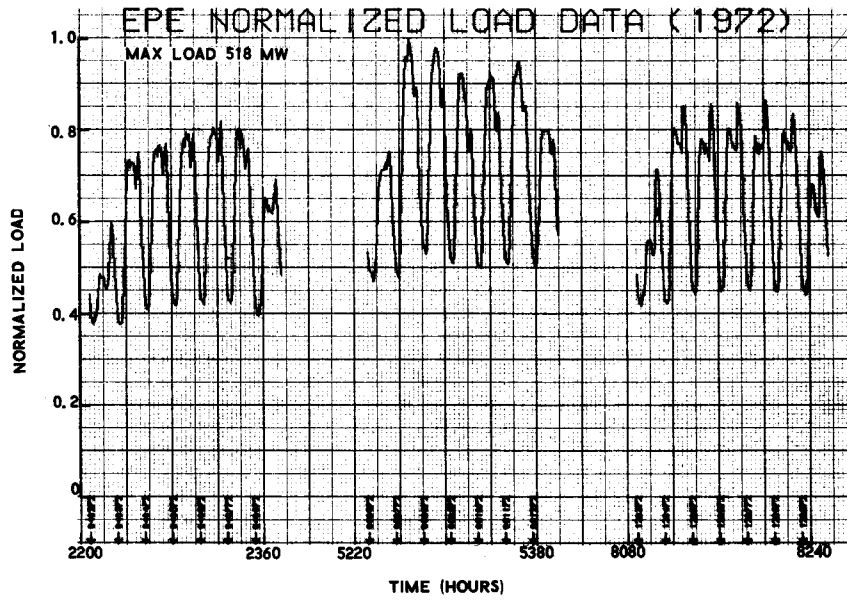
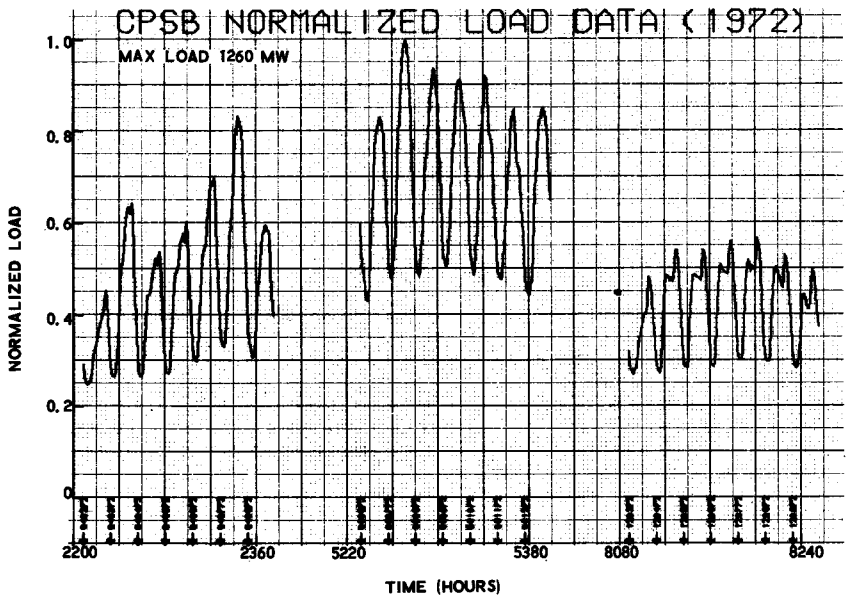
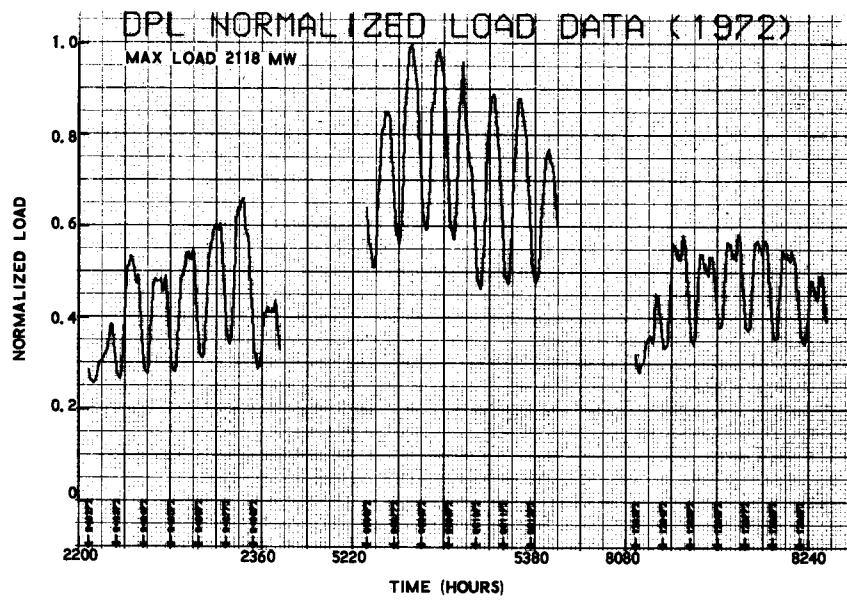
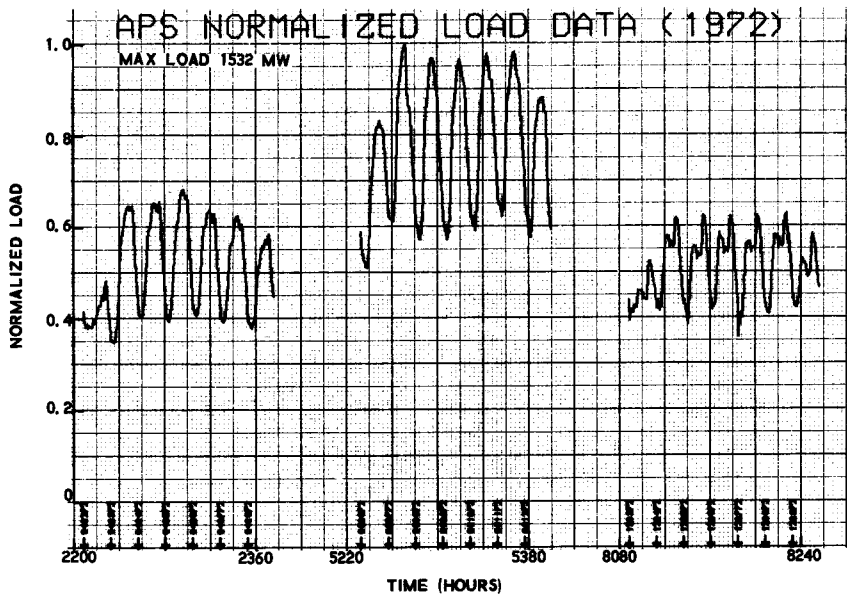
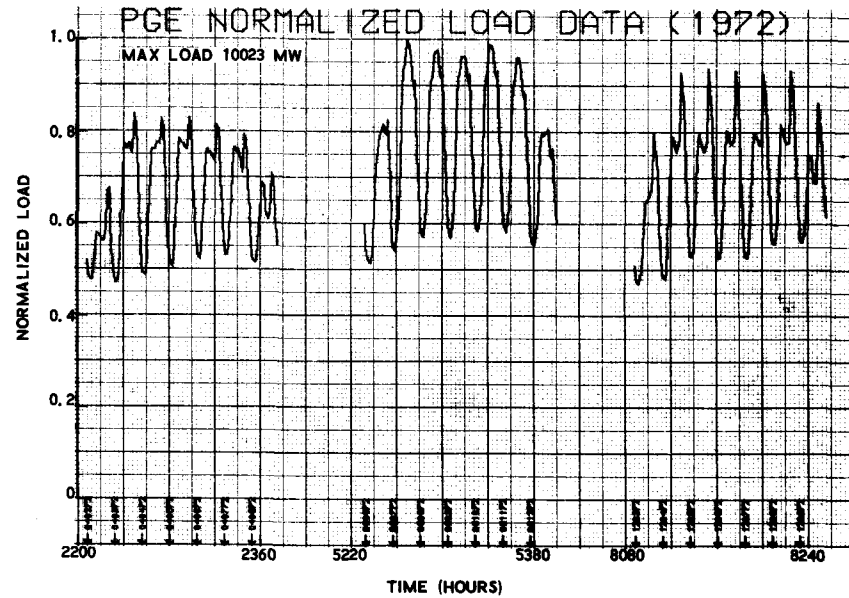
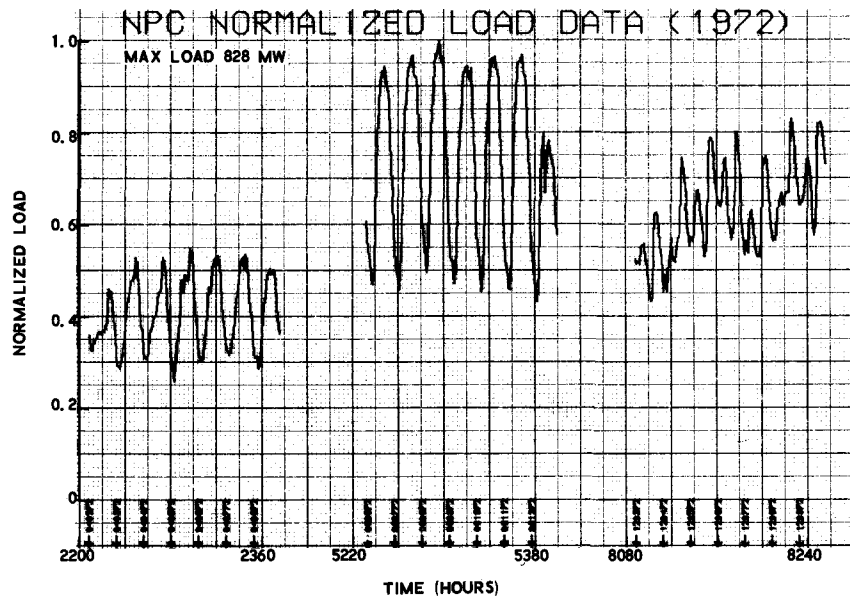
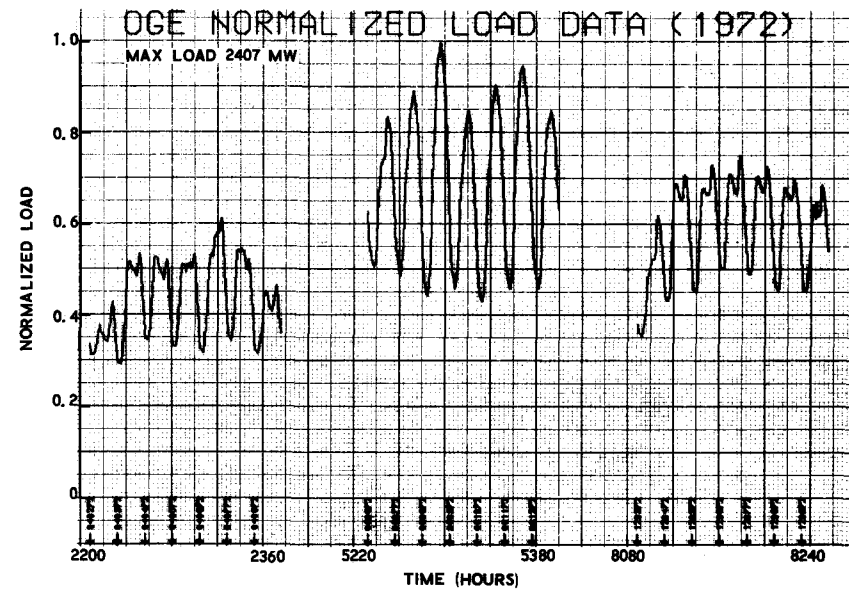
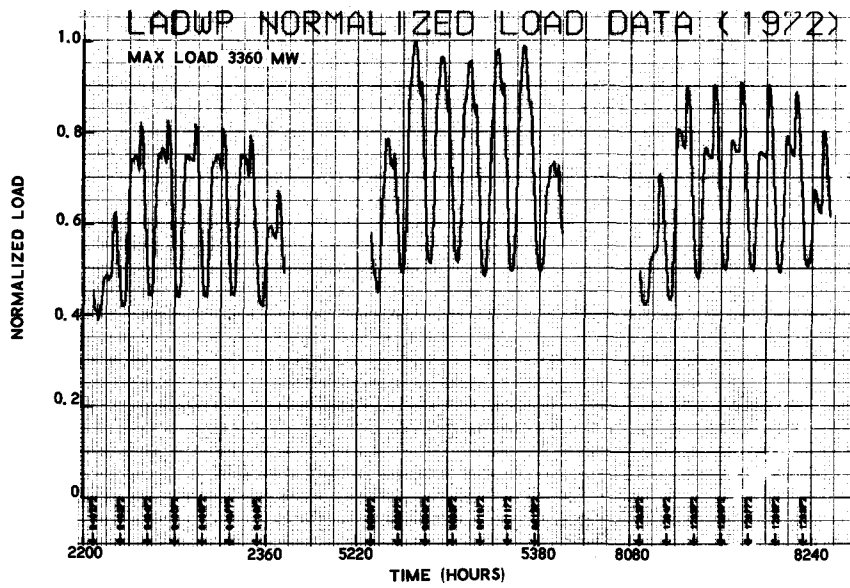
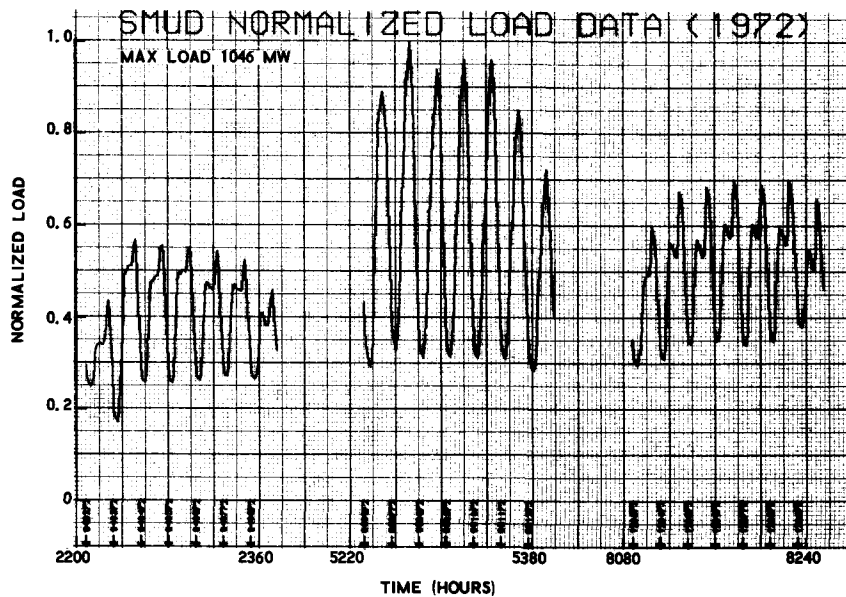
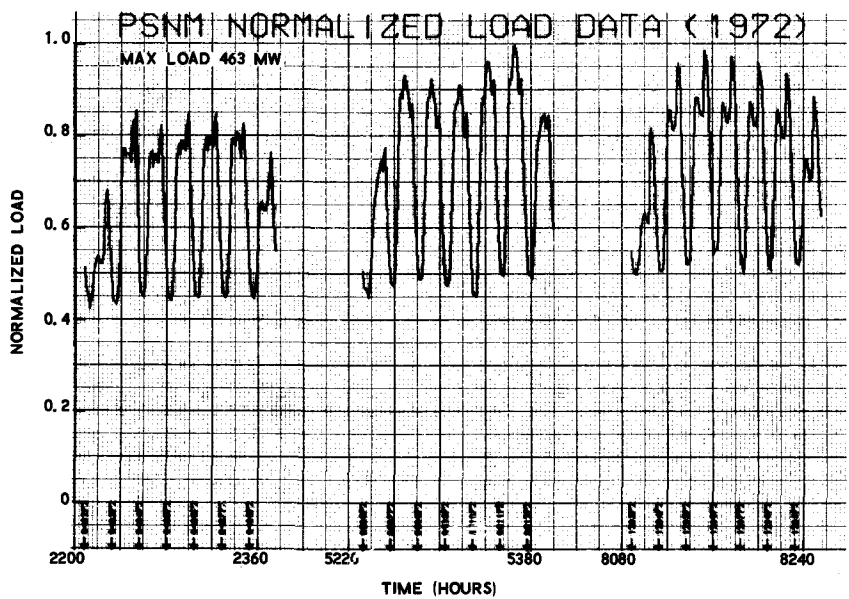
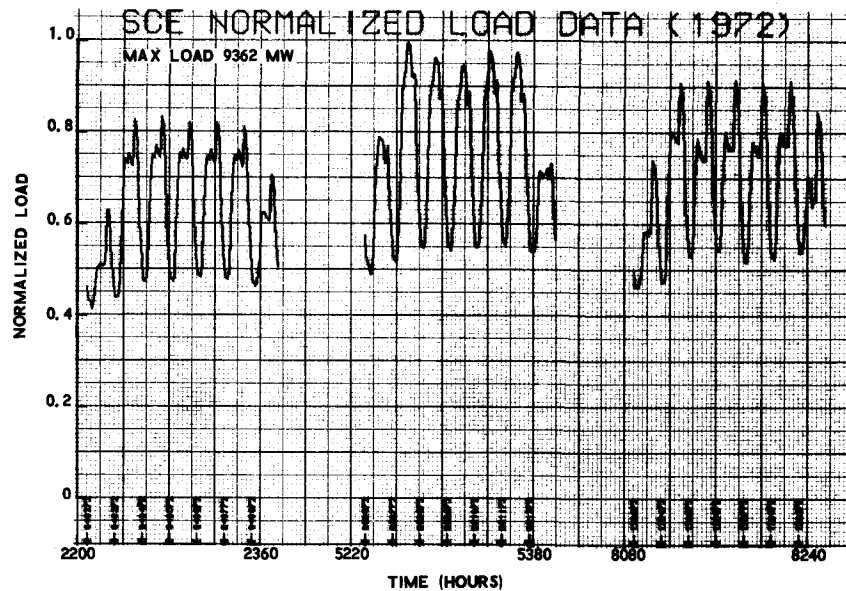
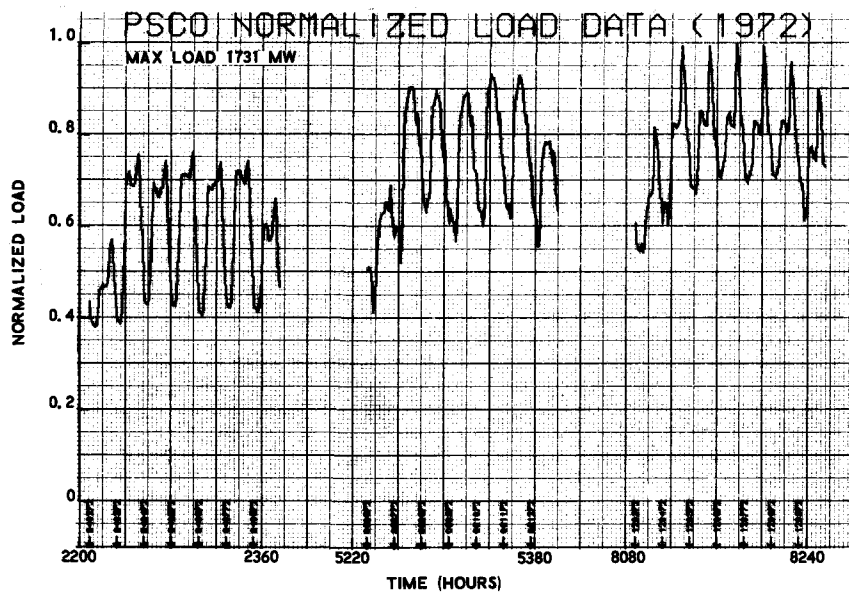


Figure 5-1. Normalized Load Profiles (1972) (Sheet 1 of 4)



5-3

Figure 5-1. Normalized Load Profiles (1972) (Sheet 2 of 4)



5-4

Figure 5-1. Normalized Load Profiles (1972) (Sheet 3 of 4)

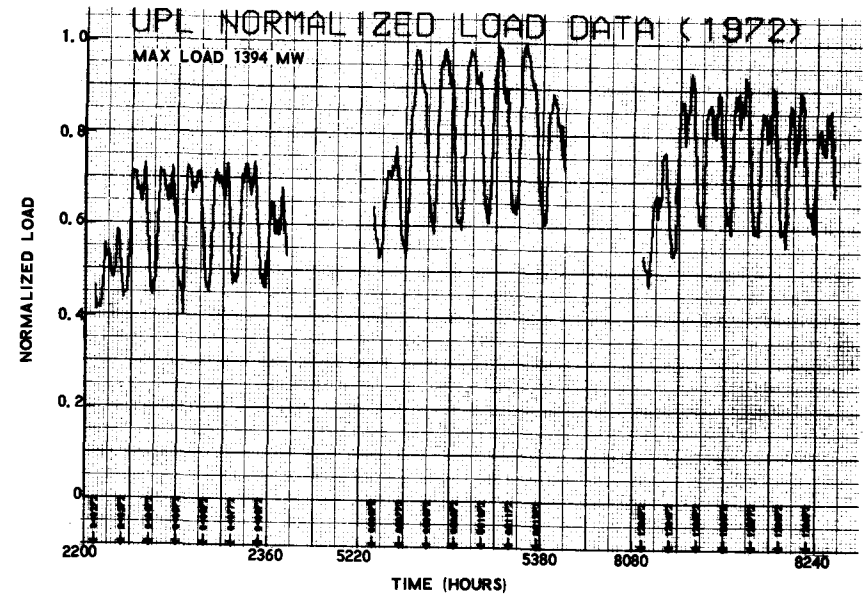
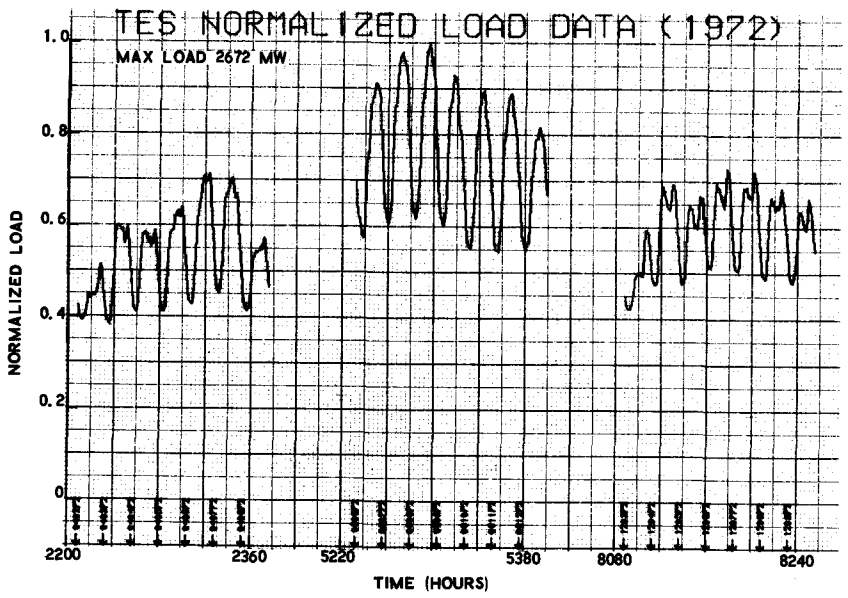
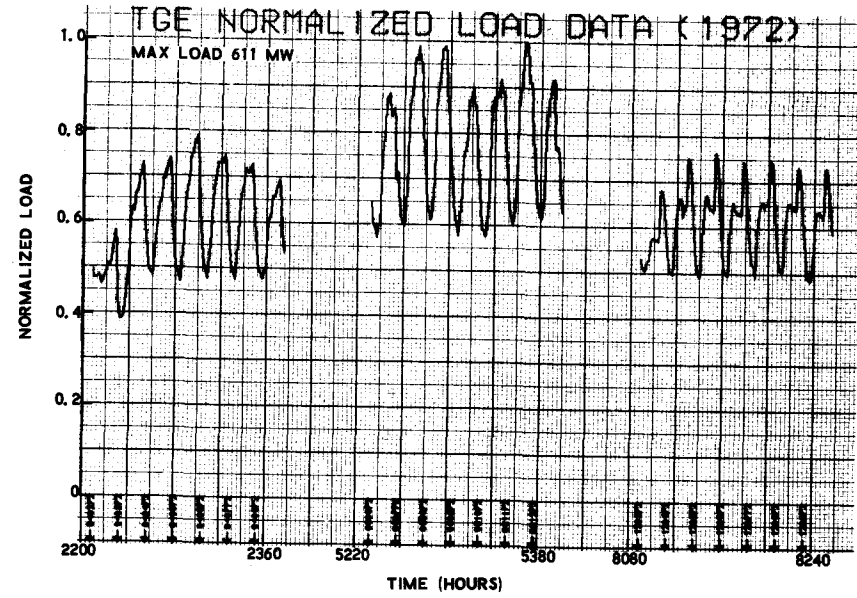
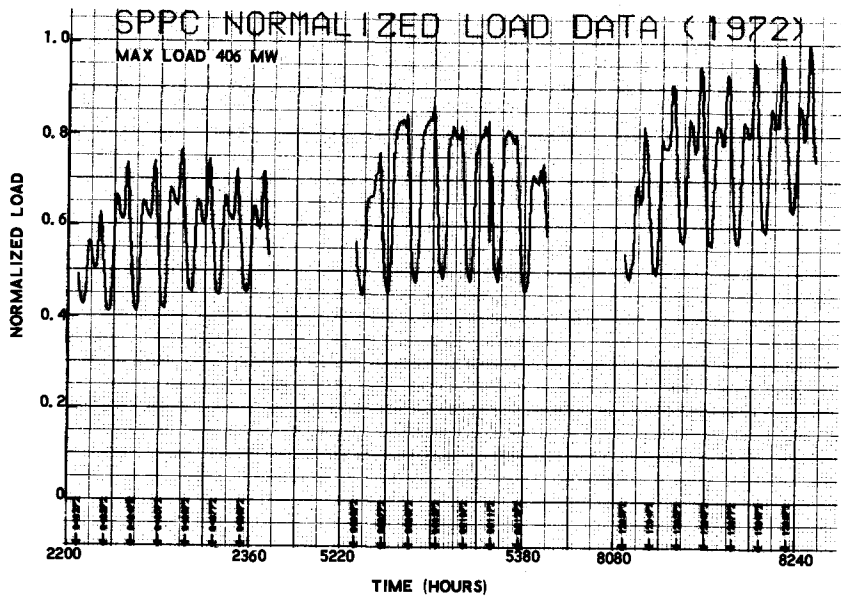


Figure 5-1. Normalized Load Profiles (1972) (Sheet 4 of 4)

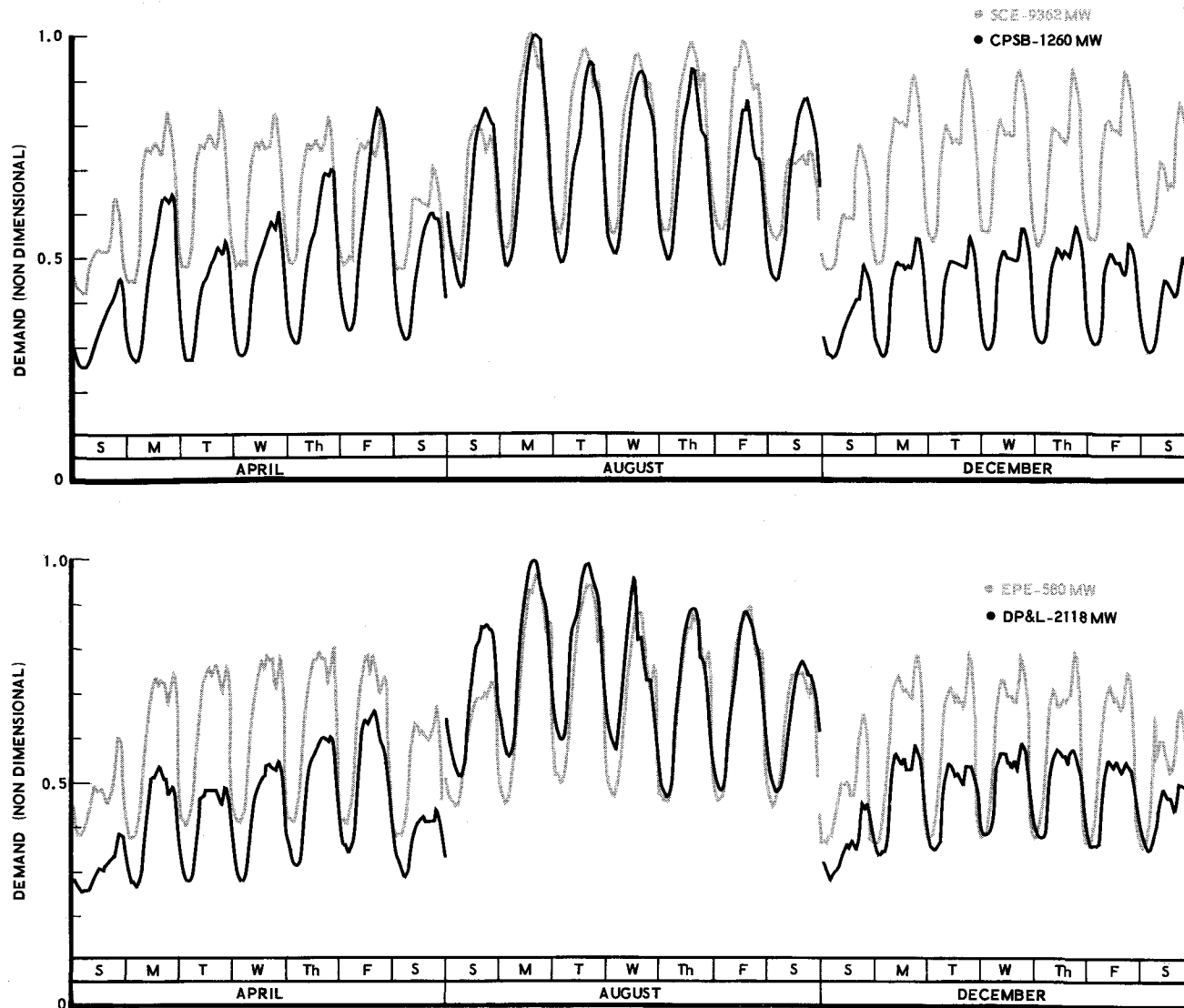


Figure 5-2. Comparison of Utility Load Profiles (1972)

Figure 5-3 demonstrates how the load profiles of two Southern California utilities (LADWP and SCE) have remained fairly consistent during successive years (1972-73) despite an increase in peak load.

Spring and winter substation load profiles for Edwards Air Force Base (EAFB), shown in Figures 5-4 and 5-5, are also quite similar with their dual cusp, mid-week peaking behavior during the years 1971 and 1973.\* With respect to the February 1973 load history (Figure 5-5), some of the variation can be attributed to reduced weekend power requirements and to the influence of Washington's Birthday (2/19/74), a national holiday. A detailed examination of EAFB load characteristics would have to be made to explain the cyclic base load phenomenon seen in Figure 5-5.

The results of another attempt to examine the collective behavior of utility load data are exhibited in Figure 5-6. Shown are three-dimensional surface representations of various SCE load profiles during the period of October 1971 through April 1972 - a period of three weeks in which Daylight Savings time was in force. Three views of Monday, Tuesday, and average Monday-through-Friday hourly load profiles are presented. The final line shows the surface generated by a family of least-squares cubic polynomials fit to Tuesday hourly demand observations as a function of a weekly counter, beginning with the first week in October 1971. Prior to the fit, observation data within the first four weeks of October and the last week in April were removed because these data were outside the Daylight Savings time period. Furthermore, "anomalous" data associated with weeks that included Thanksgiving, Christmas, and New Year's Day were also discarded. This resulted in the smooth surface, representing a simple but fairly representative approximation to the general trend without the influence of holidays. The Tuesday profile was selected since it closely resembled the average

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\* The upper trace in Figure 5-4 and Figure 5-5 are histories from the same substation satisfying a mixed residential-commercial load. The lower trace in Figure 5-4 represents an industrial load profile.

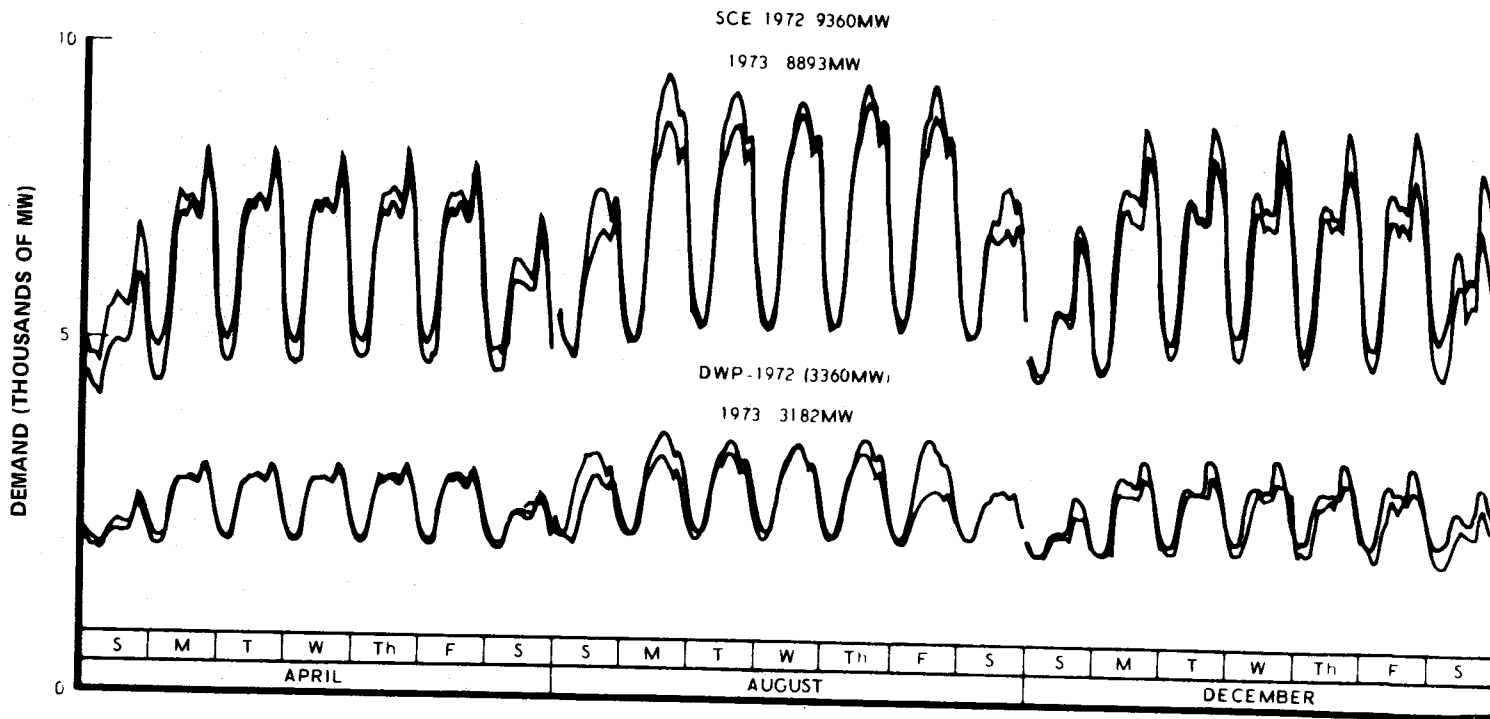


Figure 5-3. Comparison of Utility Load Profiles (1972 and 1973)



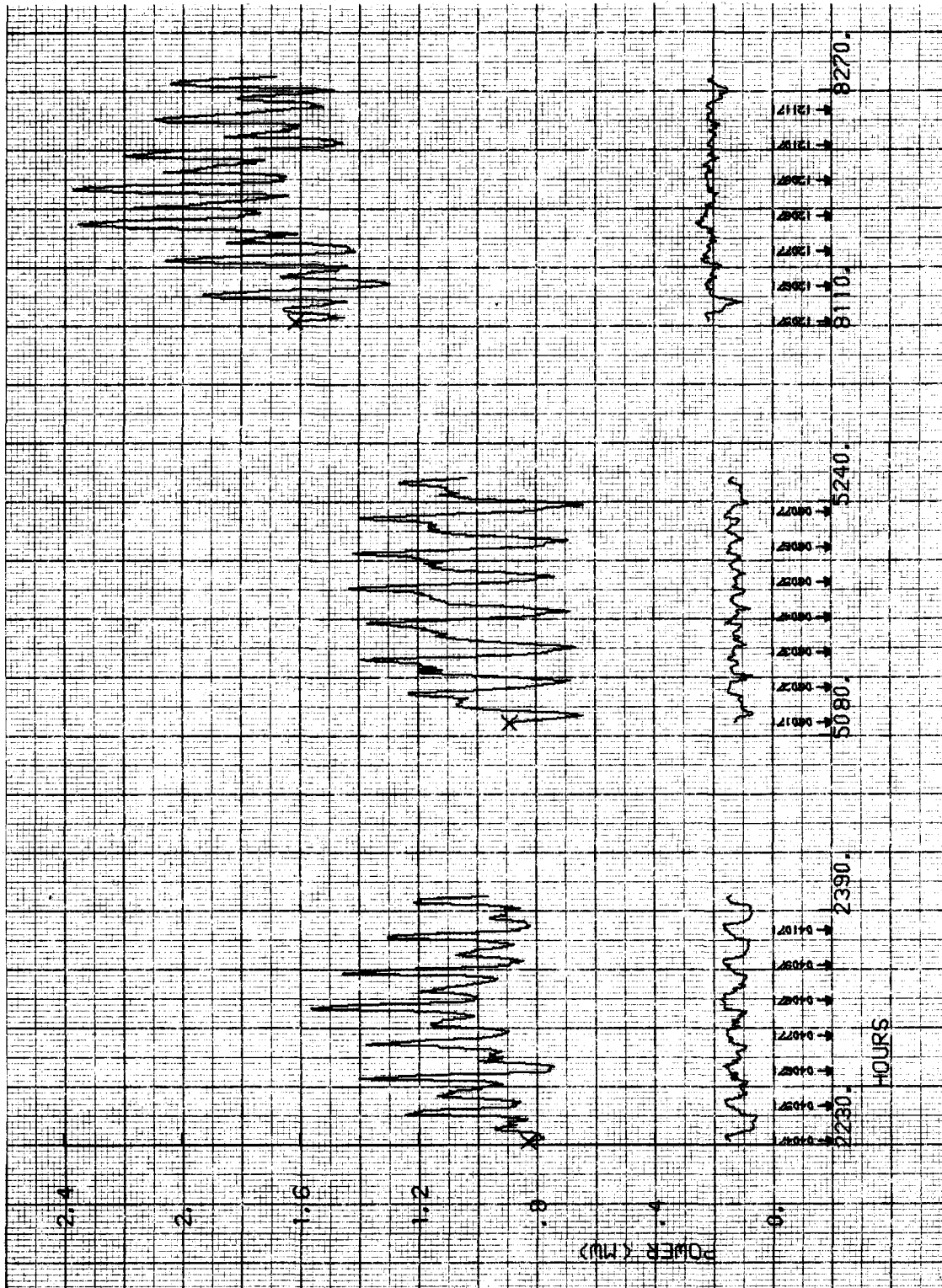


Figure 5-4. EAFB Substation Load Profiles (1971)

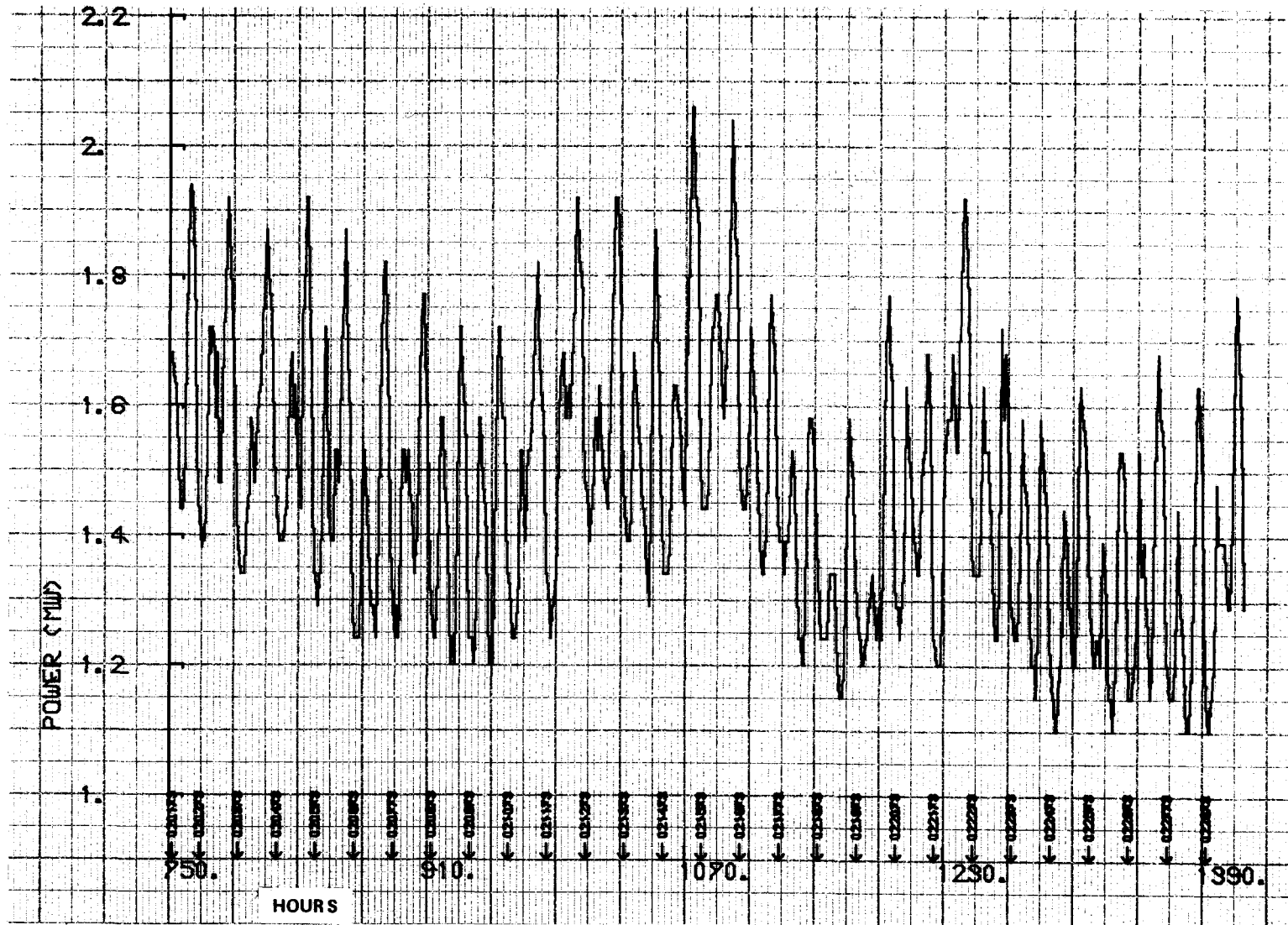
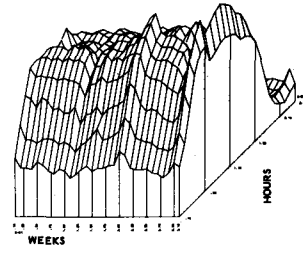
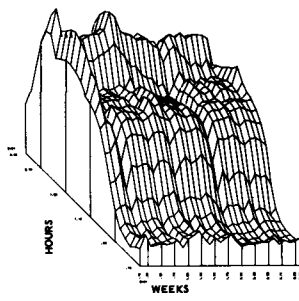
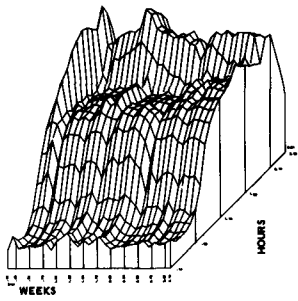
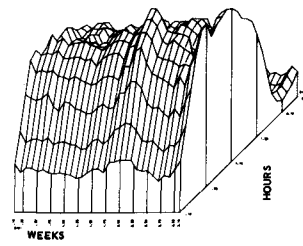
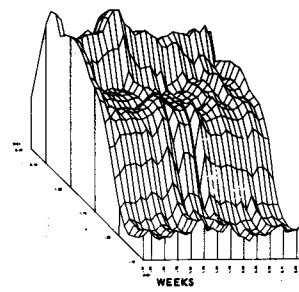
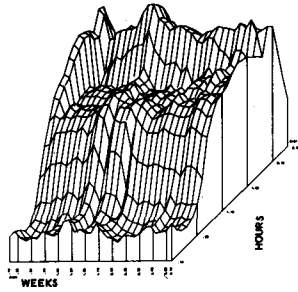


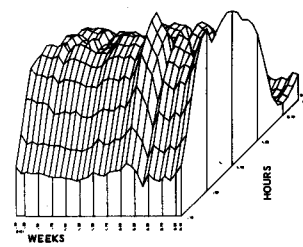
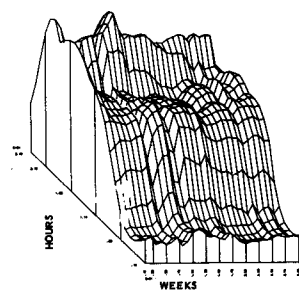
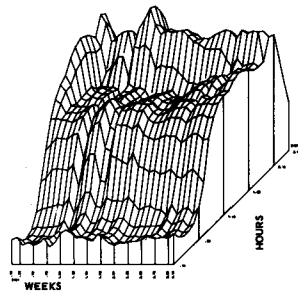
Figure 5-5. EAFB Substation Load Profile (February 1973)



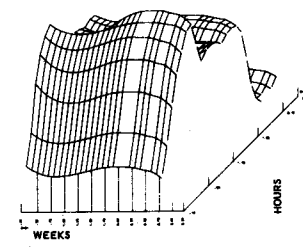
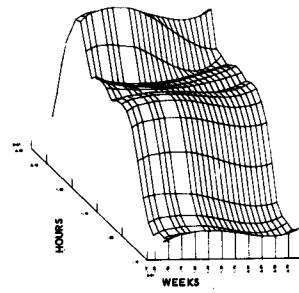
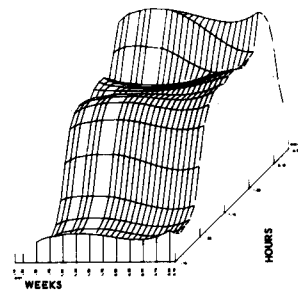
MONDAY HOURLY DEMAND



TUESDAY HOURLY DEMAND



MONDAY - FRIDAY HOURLY DEMAND AVERAGE



TUESDAY HOURLY DEMAND MODEL

Figure 5-6. SCE Load Profile Modeling (October 1971 - April 1972)

weekday profile. Mondays were considered departures from the weekday norm.

Although much discussion concerning the similarities and local influences responsible for the load profiles exhibited in the above figures would be given, this type of investigation was not considered germane to the main analysis effort. Insofar as this work is concerned, two obvious and simplistic facts emerge from this mass of data: (1) Southwest utility load profiles are similar in terms of gross envelope characteristics, albeit they are quite complex in underlying structure; (2) profiles of utility loads are fairly consistent from year to year, differing only in microscopic daily features which probably result from time-dependent factors such as the weather, the appearance of a holiday, an outage, or an extraordinary load.

In essence, a fairly good approximation to a future utility load profile can be formed from a composite of historical load profiles. Although this assumption has not been demonstrated, it is indicated by a qualitative review of historical Southwest electric power utility data.

## 5.2 DEMAND FORECAST MODEL

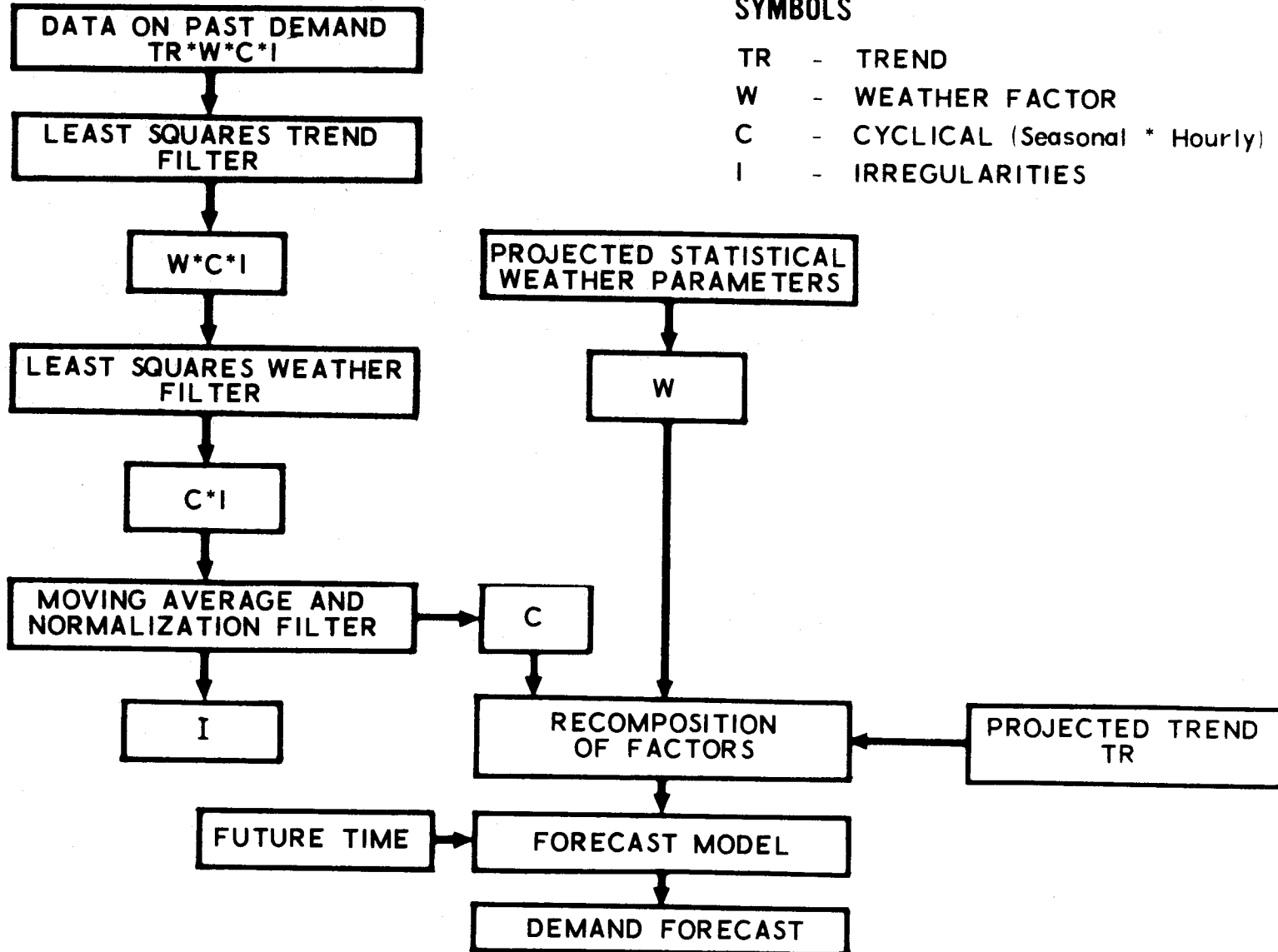
In the previous Solar Thermal Conversion Mission Analysis, a demand decomposition/recomposition forecasting model was conceived and developed to define a "reasonable" hourly electric power demand forecast at some future time period (Reference 1). This model, schematically shown in Figure 5-7, was demonstrated by generating a forecast of Southern California Edison demand for the year 1990.

Underlying the demand forecasting model design was the assumption that an electric power demand time series was a composite of several factors, such as a growth trend, weather conditions, weekly or seasonal influences, and hourly cyclic variations. Further, it was assumed that the historical growth

# TIME SERIES DECOMPOSITION AND RECOMPOSITION

## SYMBOLS

- TR - TREND
- W - WEATHER FACTOR
- C - CYCLICAL (Seasonal \* Hourly)
- I - IRREGULARITIES



5-13

Figure 5-7. Demand Forecasting Model

trend was exponential in character, that the seasonal and hourly variations repeated from year to year, and that the weather contribution was random in the short run and followed some long-term cyclic pattern difficult to quantize from the available data without a high degree of uncertainty. Deferring any discussion of weather-demand correlation to Section 6, it can be stated that the repeatability characteristics seen in demand data from Southern California electric power utilities, which permitted the application of the demand decomposition/recomposition forecasting model, have also been seen in utility data acquired throughout the Southwestern United States. Therefore, the model appears equally appropriate for other Southwest electric power utility forecast applications.

In order to put future discussion into proper perspective, a review of the demand forecasting methodology (Figure 5-7) is offered herewith. Electric power demand is assumed to be the product of factors describing a trend, weather influences, seasonal and hourly variations, and residuals. The decomposition methodology attempts to separate these elemental factors from a time series of historic demand data by the successive application of filters, each designed to extract specific demand components.

Given a sufficiently extensive history of demand data amenable to computer analysis, the first decomposition step is to remove the influence of the historical growth trend by treating the data with a least-squares filter which assumes a linear exponential form. This is accomplished by fitting an exponential to the data and subsequently dividing each observation by the exponential function evaluated at the proper time point. Next, the weather contribution is extracted by applying a least-squares filter of a form discussed in Section 6. Finally, cyclical components are extracted by the application of a moving average filter to isolate the slower responding seasonal (or weekly) variations, while a corresponding point averaging technique is used to represent year-to-year hourly variation. The cyclic factors are removed by division, leaving the residual.

The recomposition methodology generates an hourly demand forecast projection at some future time. Given cyclic phenomena representing hourly and seasonal variations, a statistical description of the expected weather, and a projected demand trend, the methodology will combine these factors in a form prescribed by the model and generate a time series proportional to its components, which defines the varying hourly electric power demand over the time period of interest. This time series may then be used as input to system simulation studies.

A feature inherent in the recomposition model is its versatility. Any demand component can be modified or replaced by substitution, if there is a reasonable basis for selecting something other than projections developed from historical data. Similarly, any trend forecast can be used to develop the future peak demand. This permits application of the forecast model to studies which assume more than one electric power consumption scenario for parametric evaluation.

### 5.3 INITIAL STATUS OF DEMAND FORECASTING PROGRAM

In the previous Solar Thermal Conversion Mission Analysis, the electric power demand decomposition/recomposition capability was conceived and demonstrated using a data base consisting of 1965-1972 Southern California Edison data. A 1990 SCE forecast was made and plotted in standard FPC data format showing the hourly demand during the first full weeks in April, August, and December.

Three IBM 370 computer programs were written to produce this forecast: the first fit the raw demand observations with a least-squares exponential, the second decomposed the demand time series into its cyclic components, and the third generated the 1990 forecast. Each was tied closely to the SCE data format and file organization, since these were the only data available at that time.

The demand forecast approach was conceptually developed in a short period of time. It successfully demonstrated the demand decomposition/recomposition methodology and produced results which were used in the previous Solar Thermal Conversion Mission Analysis. It did not, however, incorporate a sophisticated automated capability for electric power demand forecasting which could be applied to any utility demand data base.

#### 5.4 DEMAND PROGRAM DEVELOPMENT

A two-part program development effort was undertaken to improve the demand forecasting methodology. Primary attention was given to the development of a single computer program capable of accepting demand data from any utility (in standard EEI card format) and producing a demand forecast without detailed knowledge of specific data behavior and the manual interaction that was formerly required. Once an automated program was developed and produced results comparable to those generated by the three existing IBM 370 programs, a subsequent effort to enhance the program's capabilities was undertaken to increase its accuracy, efficiency, and effectiveness. This development effort was necessary to provide a demand forecasting capability sufficiently viable to complement and support the enlarged scope of the analysis activities.

The CDC 7600 computer program DEMND, shown in Figure 5-8, was developed to fulfill the demand forecast requirements of the current study and any future studies to which the demand decomposition/recomposition methodology would apply. Specifically, the DEMND program contains the following features and improvements:

- The ability to process both continuous and segmented (FPC Form-12) demand inputs in standard EEI format.
- Input data monitoring, a consistency check which provides a printed record of continuous input demand data time spans and defines the demand extremes (minima and maxima) within each year of data input.



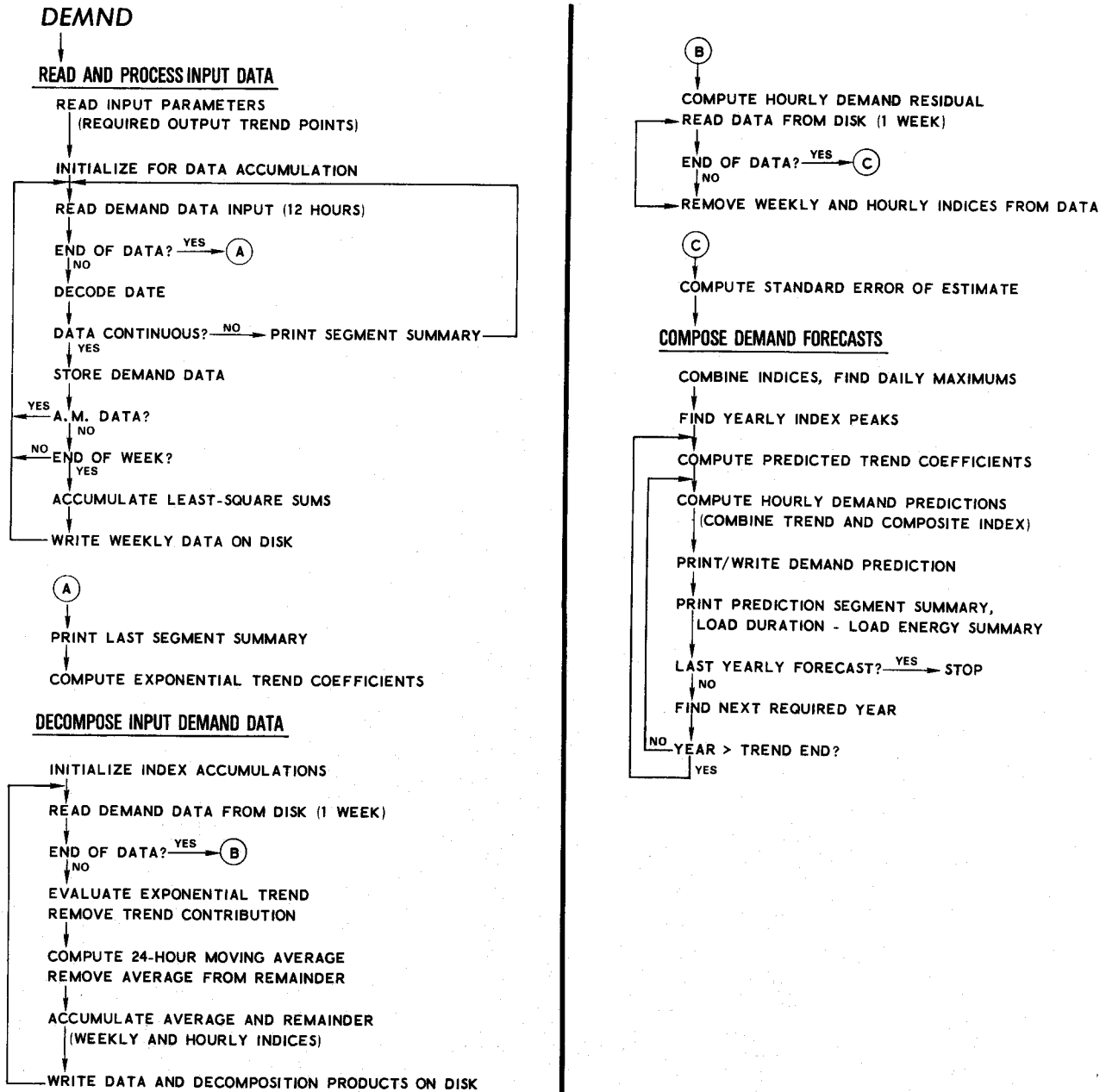


Figure 5-8. DEMND Program Logic

- Internal calendar algorithms which aid in the monitoring of input data continuity, the accumulation of weekly and hourly indices, and the generation and identification of forecast outputs.
- A modified index filtering technique which eliminates former weekend break points and the resulting "dead band" in the weekly index profile. The weekly index average formerly used to represent the seasonal variation was also eliminated.
- A technique for weighting the weekly and hourly index accumulations.
- A statistical measure of decomposition effectiveness.
- An optional output tape containing all decomposition products for plotting and analysis.
- An output demand forecast tape (in standard EEI card image format) with demand data optionally in continuous or segmented (FPC Form-12) blocks.
- Output data monitoring, a consistency check listing the time spans included on the demand forecast tape and the demand extremes (minima and maxima) within optionally selected data segments - weekly or yearly.
- Printed annual load duration and load energy distributions, load factor, and total energy measures for each forecast year.

A detailed description of program DEMND is provided in the subsections which follow. A complete flow diagram and program listing of DEMND is included in Appendix B.

#### 5.4.1 Input Processing

DEMND program input consists of a single parameter card defining the utility system, desired output mode (full, partial, or debug), type of printed forecast output (card image, weekly, or segment summary), forecast time span, and yearly increment. Subsequent cards define the predicted utility peak power trend.

Demand data, constituting the largest volume of program input, may be provided on cards (in standard format) or as card images on tape or disk. Cards are rarely used because demand forecasting based on historical information requires a massive data base in order to establish statistical credibility.

The DEMND decomposition processing logic is keyed to the manipulation of historical demand data in blocks of 168 points which compose one complete week of data observations, beginning at 1:00 a.m. Sunday and ending at 12:00 p.m. Saturday. Fragments of weeks are discarded. (The rationale for this constraint will become more apparent in the discussion which follows.)

The DEMND input logic was developed to screen the input data stream by examining dates, day-of-week, day-of-year, and AM/PM identifiers to insure that the data appears in correct chronological order and contains no gaps to fragment weekly data blocks. Internal calendar algorithms aid in this determination. Both continuous and segmented (FPC Form-12) data are acceptable, although only segmented forecasts can be generated from completely segmented source data.

In the course of performing this screening process, a demand input summary is prepared. This summary lists the continuous demand data time spans and the yearly demand extremes by value and date. An example of this summary is shown in Figure 5-9, where the demand input to the 1990 El Paso Electrical (EPE) forecast consists of both continuous data (1962-1966, 1969-1971) and segmented data (1967, 1968, and 1972).

The object of the input data summary is to provide the user with an input-generated data base description which will qualify the resulting forecast and a consistency check with which users may identify obviously erroneous input data points that could influence the character of demand forecasts. The need for this consistency check became apparent after forecast spikes

DEMAND FORECAST

SYSTEM - EPE

INPUT SUMMARY --

OUTPUT MODE - FULL    TYPE - SGMT    SY = 1990    EY = 1990    DEL = 1

TREND -  
 TYR = 1980    TFK = 984.  
           1990               2209.

DEMAND TIME SPANS -

010162 (AM)	TC	123166 (PM)
040267 (AM)	TC	040867 (PM)
080667 (AM)	TC	081267 (PM)
120367 (AM)	TC	120967 (PM)
040768 (AM)	TC	041368 (PM)
080468 (AM)	TC	081068 (PM)
120168 (AM)	TC	120768 (PM)
010169 (AM)	TC	123171 (PM)
040272 (AM)	TC	040872 (PM)
080672 (AM)	TC	081272 (PM)
120372 (AM)	TC	120972 (PM)

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DEMAND EXTREMES -

TIME PERIOD		DATE		DEMAND INPUT		DATE	
DATE	HOUR	DATE	HOUR	MINIMUM	DATE	MAXIMUM	DATE
010762	145	123162	8760	83.00	031162	271.00	083062
010163	8761	123163	17520	92.00	021063	298.00	062563
010164	17521	123164	26304	101.00	042664	310.00	072064
010165	26305	123165	35064	112.00	051665	339.00	070765
010166	35065	123166	43824	106.00	042266	374.00	080266
040267	46000	120967	52056	117.00	040267	352.00	080767
040768	54913	120768	60792	122.00	041368	393.00	080868
010169	61369	123169	70128	129.00	011769	448.00	081869
010170	70129	123170	78888	141.00	033070	469.00	071370
010171	78889	123171	87648	104.00	040371	501.00	090771
040272	89857	120972	95736	196.00	040272	518.00	080772

DECOMPOSITION -  
 N = 71232    S = .6864993E-01

OUTPUT SUMMARY --

DEMAND EXTREMES -

TIME PERIOD		DATE		DEMAND FORECAST		DATE	
DATE	HOUR	DATE	HOUR	MINIMUM	DATE	MAXIMUM	DATE
010190	245449	123190	254208	612.00	033190	2209.00	071090

Figure 5-9. DEMND Output Listing, EPE 1990 Forecast (Sheet 1 of 2)

LOAD FACTOR .6170098E+00

TOTAL ENERGY .1193966E+08

LOAD DURATION (LOAD VS FRACTION OF TOTAL HOURS)

50.00	.100000E+01	650.00	.99989E+00	1250.00	.61484E+00	1850.00	.96461E-01
100.00	.100000E+01	700.00	.99989E+00	1300.00	.58390E+00	1900.00	.77397E-01
150.00	.100000E+01	750.00	.99989E+00	1350.00	.55719E+00	1950.00	.60731E-01
200.00	.100000E+01	800.00	.99578E+00	1400.00	.52317E+00	2000.00	.45890E-01
250.00	.100000E+01	850.00	.96404E+00	1450.00	.48516E+00	2050.00	.28196E-01
300.00	.100000E+01	900.00	.90674E+00	1500.00	.43276E+00	2100.00	.14726E-01
350.00	.100000E+01	950.00	.85034E+00	1550.00	.36370E+00	2150.00	.45662E-02
400.00	.100000E+01	1000.00	.81324E+00	1600.00	.29909E+00	2200.00	.68493E-03
450.00	.100000E+01	1050.00	.77831E+00	1650.00	.24053E+00	2250.00	
500.00	.100000E+01	1100.00	.73527E+00	1700.00	.18527E+00		
550.00	.100000E+01	1150.00	.69121E+00	1750.00	.14863E+00		
600.00	.100000E+01	1200.00	.65285E+00	1800.00	.11906E+00		

LOAD ENERGY (LOAD VS FRACTION OF TOTAL ENERGY)

50.00	.36680E-01	650.00	.47684E+00	1250.00	.84517E+00	1850.00	.99175E+00
100.00	.73361E-01	700.00	.51352E+00	1300.00	.86675E+00	1900.00	.99454E+00
150.00	.11004E+00	750.00	.55020E+00	1350.00	.88696E+00	1950.00	.99671E+00
200.00	.14672E+00	800.00	.58671E+00	1400.00	.90600E+00	2000.00	.99833E+00
250.00	.18340E+00	850.00	.62215E+00	1450.00	.92371E+00	2050.00	.99934E+00
300.00	.22008E+00	900.00	.65555E+00	1500.00	.93949E+00	2100.00	.99983E+00
350.00	.25676E+00	950.00	.68705E+00	1550.00	.95277E+00	2150.00	.99998E+00
400.00	.29344E+00	1000.00	.71712E+00	1600.00	.96353E+00	2200.00	.10000E+01
450.00	.33012E+00	1050.00	.74579E+00	1650.00	.97202E+00	2250.00	.10000E+01
500.00	.36680E+00	1100.00	.77292E+00	1700.00	.97875E+00		
550.00	.40348E+00	1150.00	.79842E+00	1750.00	.98402E+00		
600.00	.44016E+00	1200.00	.82244E+00	1800.00	.98826E+00		

5-21

Figure 5-9. DEMND Output Listing, EPE 1990 Forecast (Sheet 2 of 2)

and valleys had repeatedly been traced to bad input. (In one case the SCE data base was found to contain a point 300,000 MW too large, while zero values were found in several input data bases.)

#### 5.4.2 Demand Decomposition

Consistent with the demand decomposition methodology outlined above (Section 5.2), the DEMND decomposition technique, portrayed in Figures 5-7 and 5-8, progressively reduces a historical demand time series into its several components, leaving a residual which is attributed to unresolved irregularities. Electric power demand at any given time is assumed to be the product of factors due to growth trend, weather conditions, weekly or seasonal influences, hourly variations, and an unresolved residual which should approach unity as the model is refined.

As the first step in the DEMND decomposition, a least-squares exponential of the form  $A \exp(Bt)$ , representing a growth trend, is fit through the accumulated demand observations and is subsequently removed by a point-by-point division, leaving a remainder composed of unresolved seasonal and hourly variations. (The structure of the weather component is yet to be defined from correlation analyses described in Section 6.) As in the previous study, the seasonal variation is found by applying a moving 24-hour average filter through the remainder, and the hourly components are found by averaging the resultants after a point-by-point division by 24-hour filter outputs. Weekly and hourly indices, used to typify the historic seasonal and hourly demand variations, are then developed by averaging weekly and hourly point values on a like-hour basis from year to year.

Figure 5-10 shows SCE demand decomposition products generated by using techniques developed in the previous study. Note that only data associated with the first full weeks in April, August, and December have been shown in order to simplify the illustrations. The upper set of curves show the

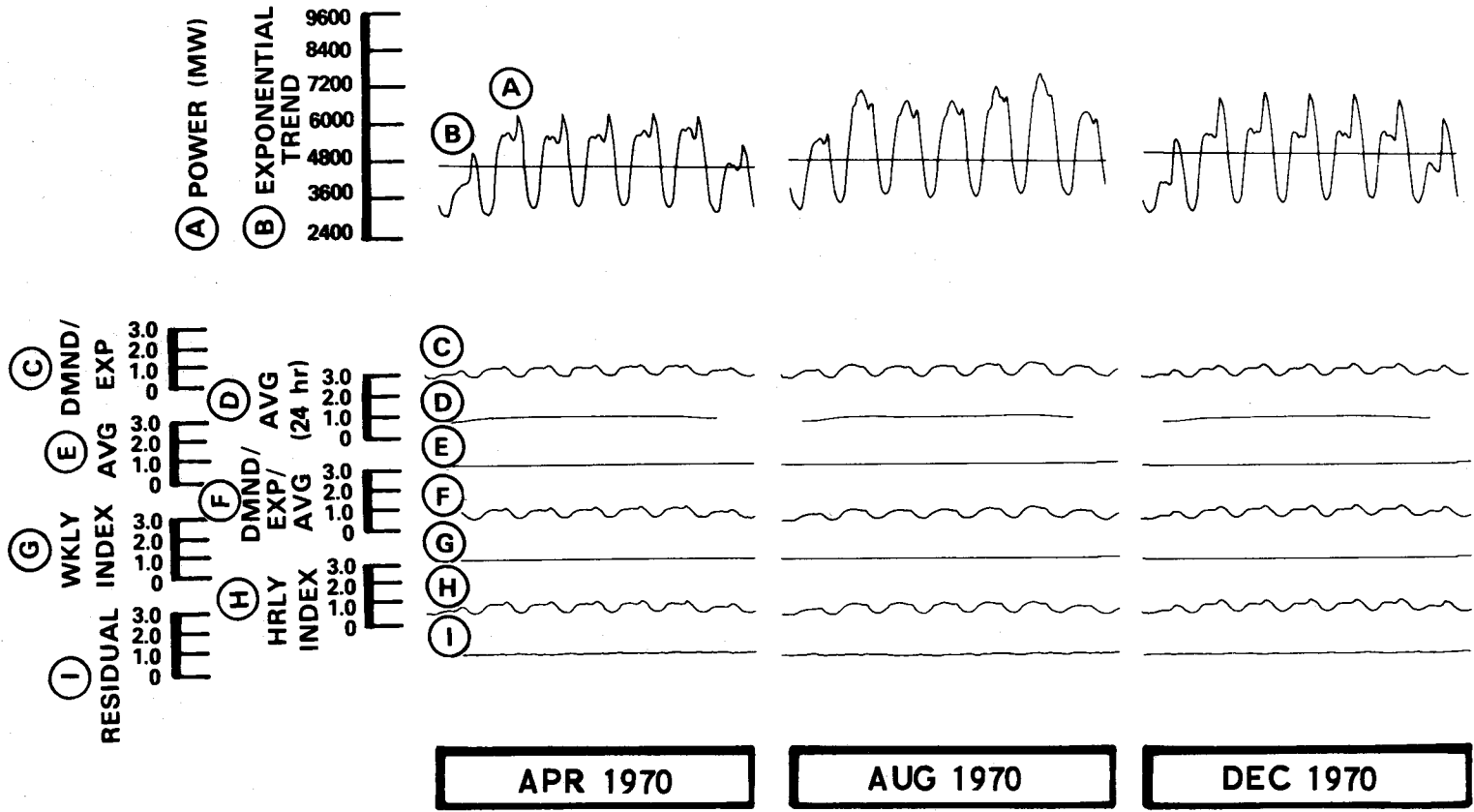


Figure 5-10. SEC Demand Decomposition (1970)  
(Extended Weekly Index)

demand profile (A) crossed by the exponential least-squares fit (B). The second trace (C) represents the remainder after dividing the demand by the exponential. Trace (D) shows the envelope of the moving 24-hour filter output. Note that it does not continue to the end of the week because the first filter output was at its midpoint twelve hours into the week. Similarly, the last filter output came twelve hours before the end of the week. Trace (E) represents the average of the weekly filter outputs extended throughout the full week, the assumption here being that each weekly index could best be represented by a single member. Trace (F) contains the remainder after each weekly average has been removed by division. Trace (G) shows the average weekly average index, that is, the average of all weekly averages after processing the entire demand data base and combining the results of like weeks. Trace (H) shows the average hourly index - the result of averaging the hourly remainders (F) for all like weeks. The last trace identified, (I), displays the residual after removing the hourly index contribution (H) from the remainder (F).

Several process deficiencies have been eliminated by the modified filter logic presently contained within DEMND. Results of the new decomposition process are presented in Figure 5-11. The deficiencies addressed in the new system are: (1) the arbitrary start and stop of 24-hour filter spans on weekly boundaries, resulting in a 12-hour "dead band" on either side of the filtered output, and (2) the selection of a single numerical average to represent the entire week, thereby degrading weekday amplitudes and reinforcing weekend profiles.

The upper two curves in Figure 5-11 present the demand profile (A) and the least-squares exponential trend (B). Trace (C) shows the remainder after the exponential trend has been removed from the demand by division. Trace (D) represents the extended weekly index envelope - the output from a moving 24-hour filter which is employed continuously from week to week and does not reinitialize at weekly boundaries. DEMND also contains logic



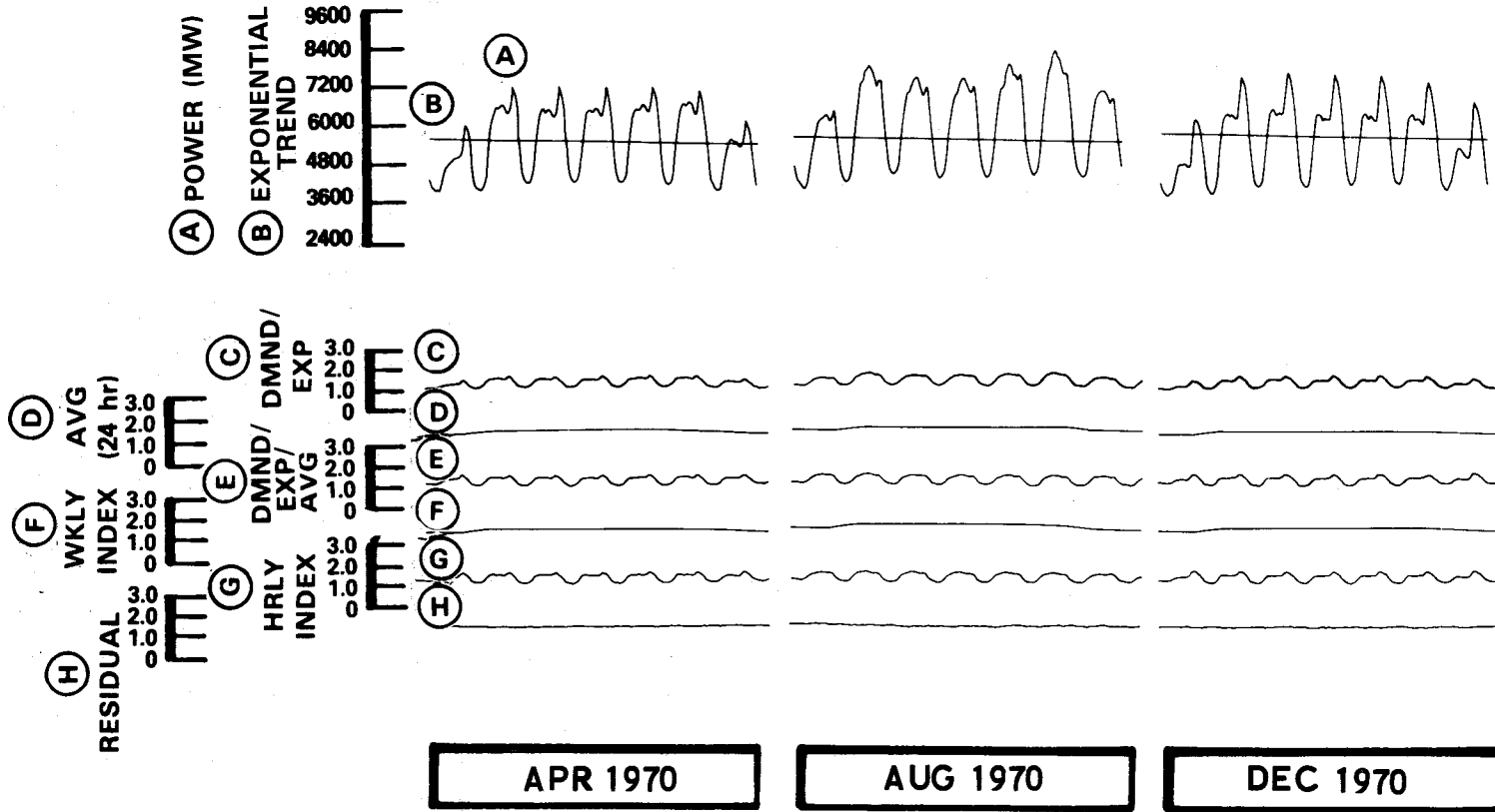


Figure 5-11. SCE Demand Decomposition (1970)  
(Extended Weekly Index)

to initialize filter spans to be used on disjointed weekly demand segments, such as those provided in the FPC Form 12 Power System Statements. This logic uses Saturday demand data to initialize a prior Sunday and, if no contiguous Sunday follows, the prior Sunday data to terminate a following Saturday. This capability was used to initialize the first weekly filter span in the SCE decomposition shown in Figure 5-11 and to terminate the last weekly filter span.

The weekly index average used formerly is not computed. It is considered an unnecessary and detrimental step. In Figure 5-11, trace (E) shows the remainder after dividing the data plotted in (C) by the extended weekly index (D). Note how all daily envelopes, weekdays and weekends alike, exhibit comparable structure and amplitude. Trace (F) represents the average weekly index, the average of like-week index values. (G) shows the average hourly index and (H) the residual after decomposition. All decomposition products are optionally available on magnetic tape for plotting and subsequent evaluation.

It should be noted that the new procedure yields a more exact decomposition as defined by the standard error of estimate statistic, which measures the aggregate deviation of the residual from constant unity. This statistic (S) is a standard program output.

Before discussing the DEMND recomposition process, it is appropriate to elaborate on the brief description of weekly and hourly index accumulation provided above. In the previous work little attention was given to a mechanization of "like-hour accumulation from year to year." In point of fact, index averaging was performed on the basis of a 52-week year beginning with the first full week in January (not necessarily on January 1). No attempt was made to match weeks with months. This had very little effect when the historic data base was limited but resulted in an increasing mismatch between weeks from year to year as additional demand data was

incorporated into the decomposition. It was also difficult to appropriately handle disjointed or functional weeks at the beginning and end of each month.

To circumvent this problem, an internal calendar was developed consisting of 60 "weeks" per year, with each month containing five "weeks." Index accumulation is accomplished by assigning data from the first full week in each month (a week which contains the first Sunday of the month) to week one, and so forth (some months could contain only three full weeks while others could contain as many as five). Data from any week which overlaps two months are combined to form the last full week of the prior month. In this manner variations in monthly length are accommodated.

#### 5.4.3 Demand Recomposition

As shown in Figures 5-7 and 5-8, the DEMND forecast composition process combines predicted trends with composite indices to form hourly demand predictions. Yearly peak load predictions generated by this process are constrained to be identical to those defined by the input data.

To establish this required forecast consistency, it was necessary to survey the accumulated index data base and fix the occurrence of peak maxima to coincide with index maxima, as defined by the calendar associated with the corresponding forecast year. This is accomplished in several steps. First, weekly and hourly indices for each hour of the internal 60-week year are combined (multiplied) and stored. Daily composite index maxima are determined during this process and recorded with the hour of their occurrence. Using internal calendar algorithms, this array of daily index maxima is then screened on a day-by-day basis to determine the maximum index and its hour of occurrence during each year to be considered for the demand forecast generation. This includes every year defined in the peak power trend suggested by input and every year required in the output demand forecast. Duplicate requests for the same year are eliminated to minimize the search.

The demand forecast is undertaken with the aid of this accumulated information. It is assumed that a piecewise exponential trend exists between peak loads defined by the input. As a precursor to the computation of hourly demand forecasts for years bracketed by input defined peak loads, coefficients for appropriate trend equations are developed such that the defined peak loads, degraded by yearly index maxima, will occur at times coincident with those maxima. This becomes the trend upon which all hourly demand forecasts are developed. The remaining forecast composition logic simply contains algorithms to define the desired day of year, month, day of week, and hour. Hourly forecasts are obtained by multiplying the hourly composite index by the load growth trend, evaluated at the proper hour. This forecast data identified by date is optionally written onto tape in standard EEI format in continuous or segmented (FPC Form 12) blocks.

Before demonstrating results of the DEMND utility demand forecasts and explaining some of the program features which permit a better understanding of forecast outputs, it is beneficial to introduce a problem detected in the DEMND output and to describe the technique selected for its correction. On inspection of SCE 1990 demand forecasts, it was found that the DEMND program generated a load profile that peaked in December, whereas the utility was experiencing summer load peaking. A review of SCE historical data, illustrated in Figure 5-12, indicates that the summer peaking trend has been gradually building up over the span of several years and has produced a summer peak only during the last four years. The major portion of the SCE data base has load peaks during the winter. Therefore, a winter peak forecast was generated by DEMND by virtue of the index averaging which considered all years to be equally valid.

In order to correct this situation, a system of geometric weekly and hourly index weighting was adopted to emphasize utility load characteristics experienced in recent years. This technique, discussed in Reference 7, changed the SCE load forecasts but did not appreciably change load forecasts

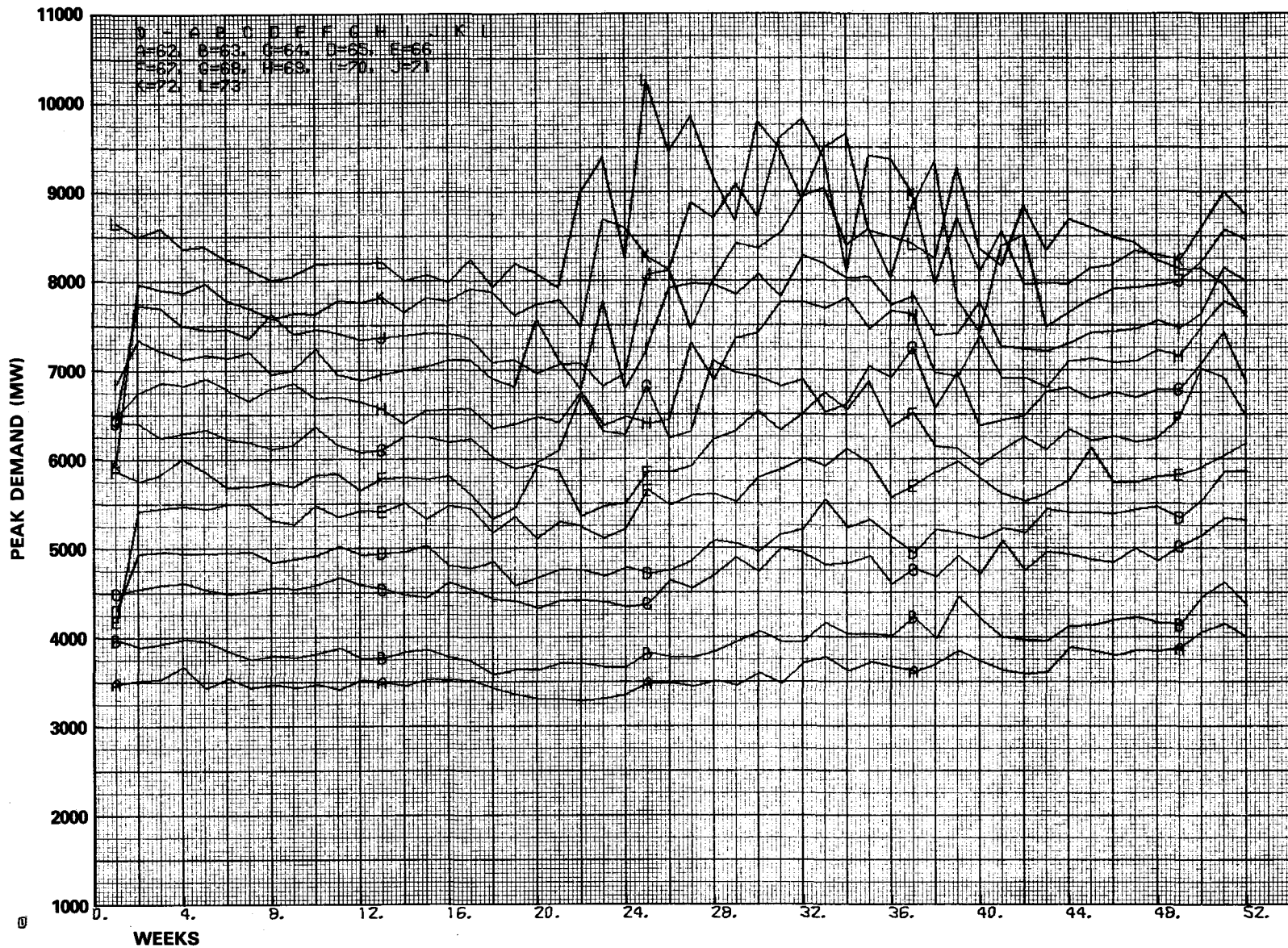


Figure 5-12. SCE Weekly Peak Loads (1962-1973)

generated for utilities having consistent summer or winter peaking histories. A comparison of SCE 1990 forecast projections is shown in Figure 5-13. Note how daily profiles generated by either weighted or unweighted index accumulations are similar. The weekly peak profiles are quite different, however. As expected, the weighted peak profile shows more variation during the course of the year. This closely follows actual load behavior as exhibited by peak profile curves in Figure 5-12. Index averaging has been adopted as a standard DEMND practice.

A standard output from DEMND, accompanying the EEI card image utility forecast, is a magnetic tape file containing information for plotting. Figure 5-14 presents a complete 1990 SCE predicted load profile which was produced from this tape. Note that the forecast profile peaks on July 30, 1990.

Several other DEMND capabilities are exhibited in Figure 5-9 (the sample DEMND output listing) and in Figures 5-15 and 5-16 which follow. Output forecast monitoring, illustrated in Figure 5-9, provides the user with a means for verifying that the required peak load, defined by program input, was in fact realized in the DEMND forecast. Listed are demand forecast extremes (maxima and minima) during optionally selected time periods (weekly or yearly segments).

Figure 5-9 also contains examples of forecast quality measures and distributions provided by all DEMND outputs. Included are: total energy, load factor, annual load duration distribution, and annual load energy distribution. The total energy is the result of an hour-by-hour annual demand forecast integration. The load factor is a ratio of the average load to peak load, where the average load is defined as the total energy divided by the time duration in hours. The annual load duration distribution defines the fraction of total time for which the utility load equals or exceeds the value indicated. The annual load energy distribution defines the fraction of total energy that exists at or below the given loads. Both distributions indicate only the

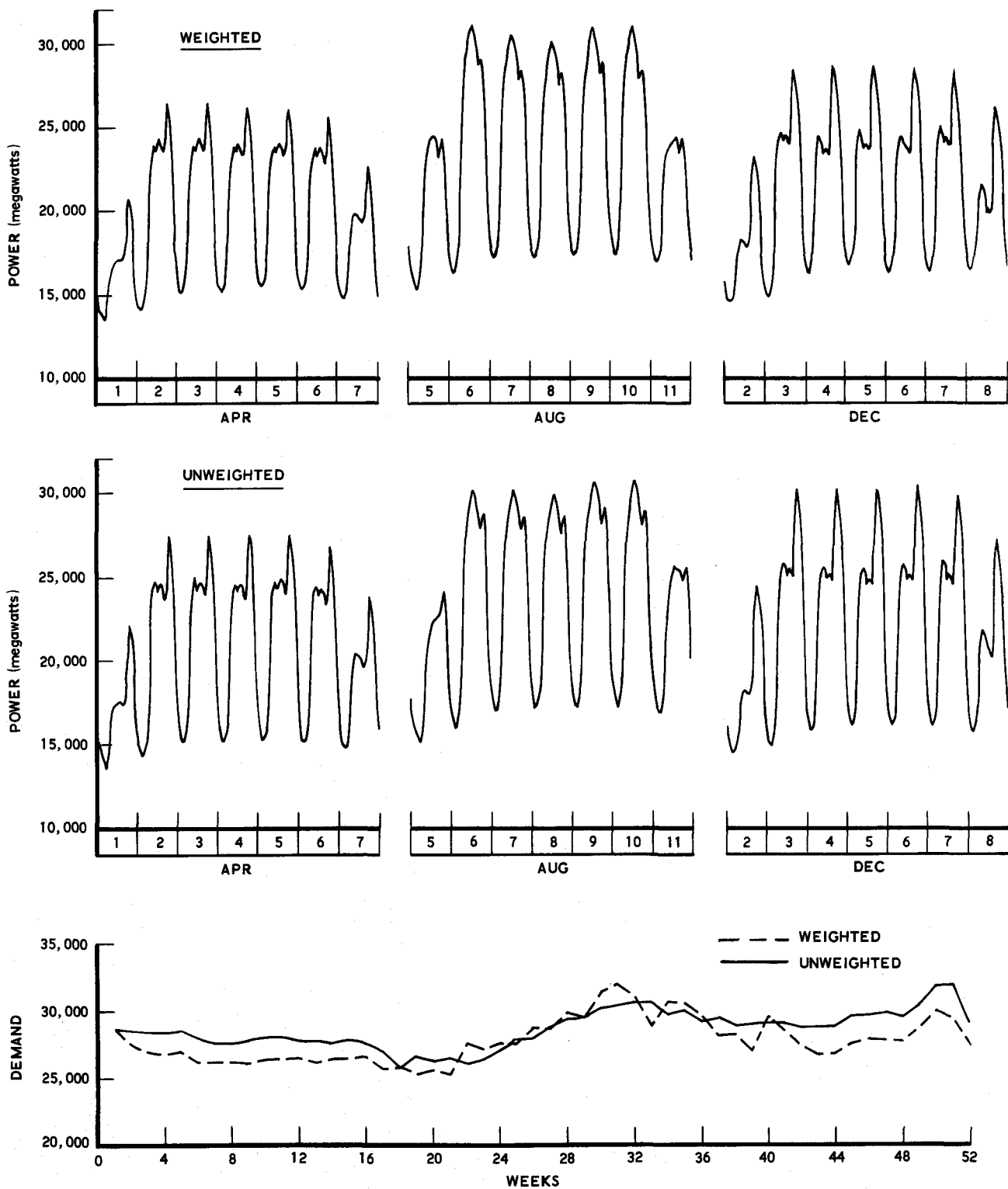


Figure 5-13. Comparison of SCE Load Projections (1990)

5-32

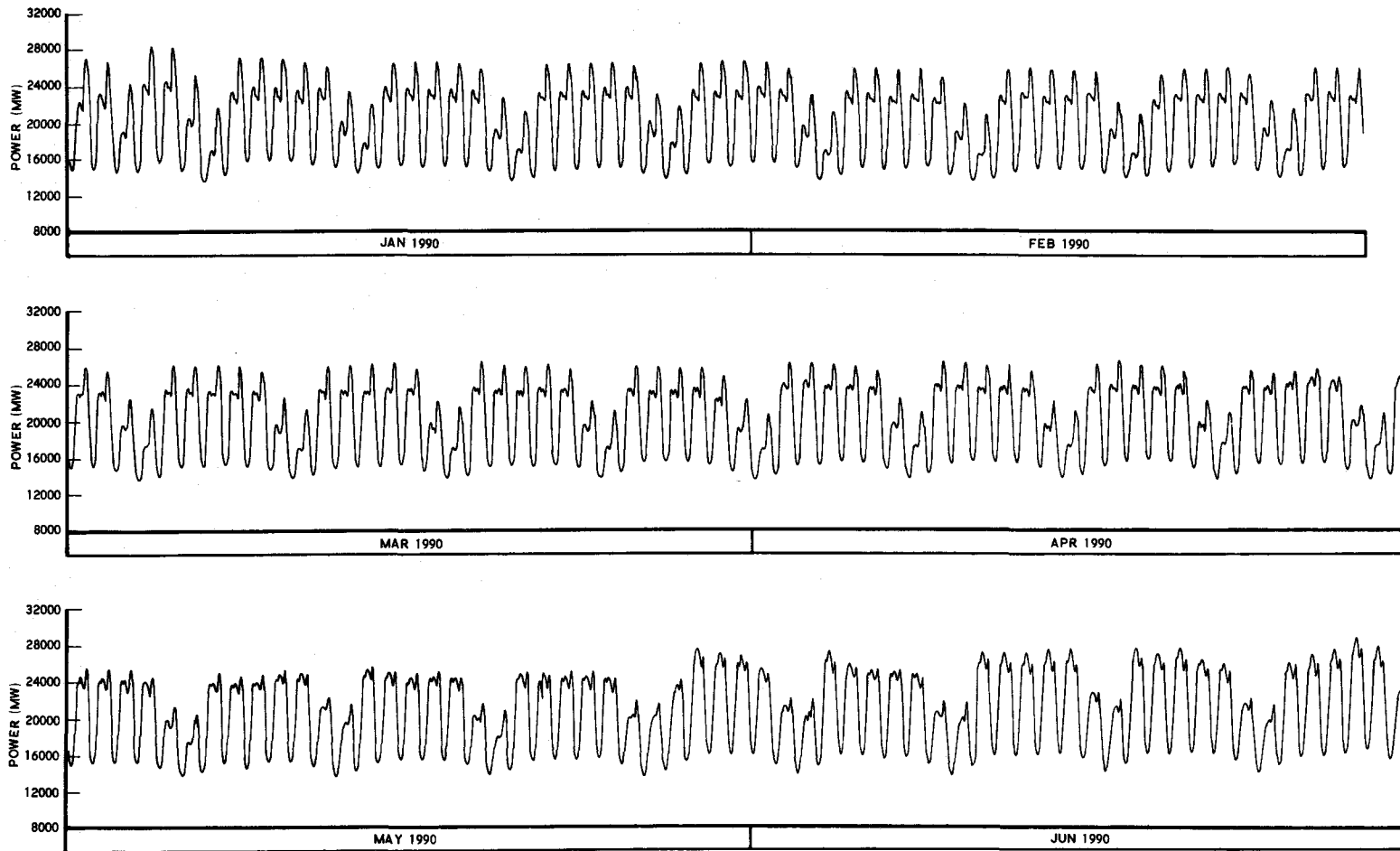


Figure 5-14. SCE Predicted Load Profile (1990) (Sheet 1 of 2)



5-33

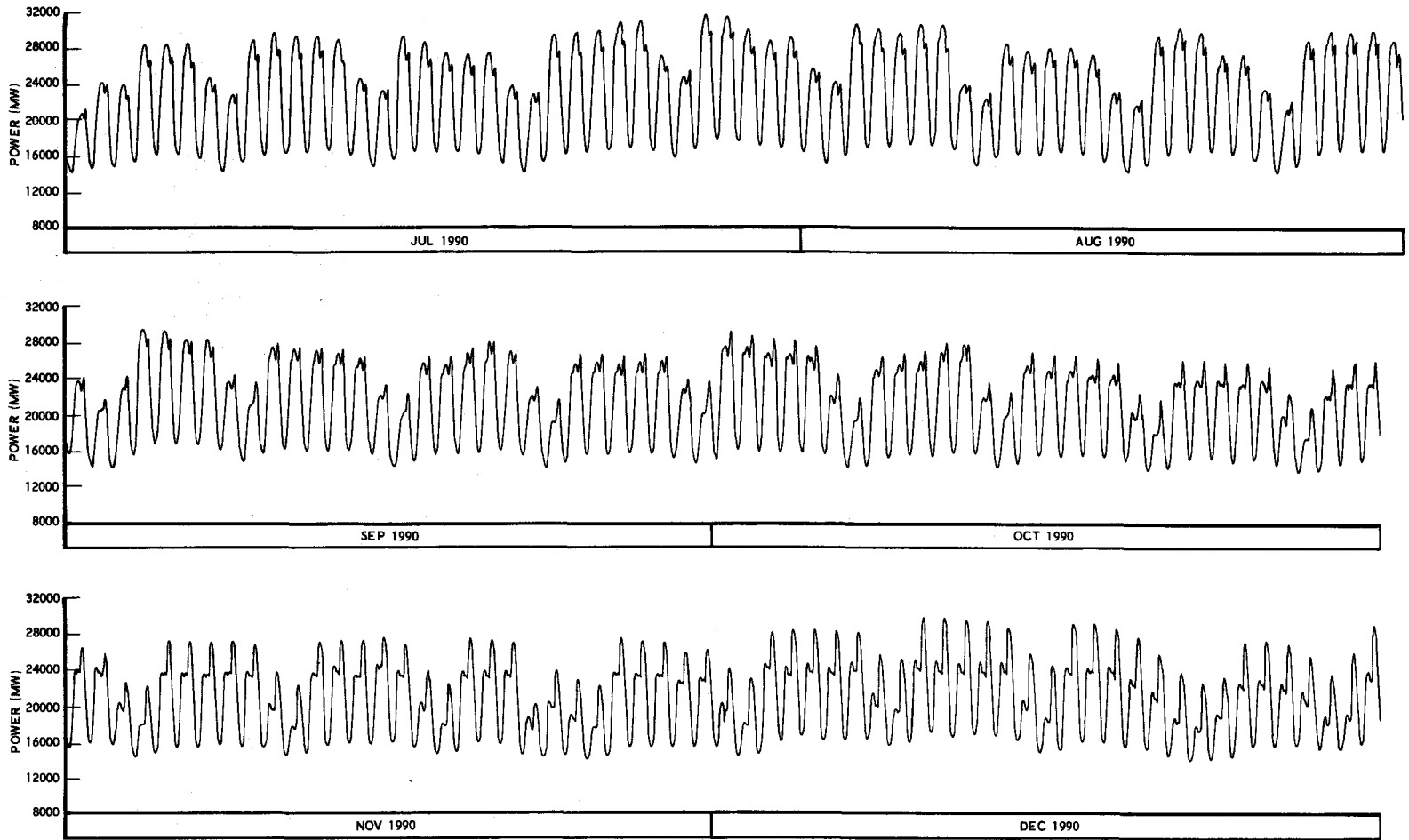
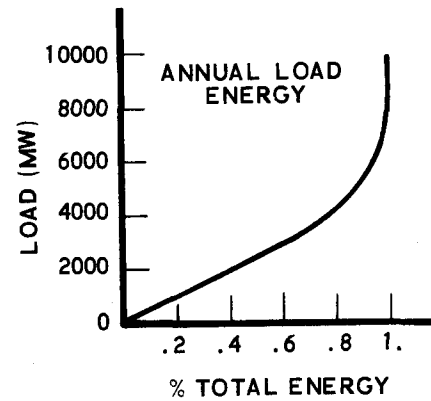
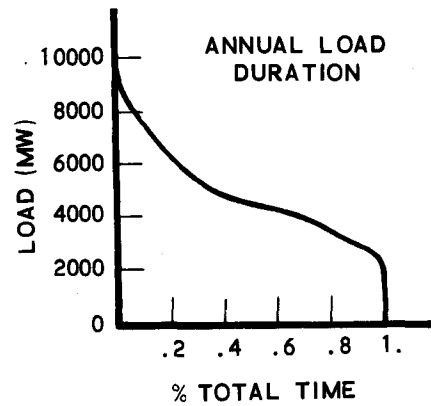
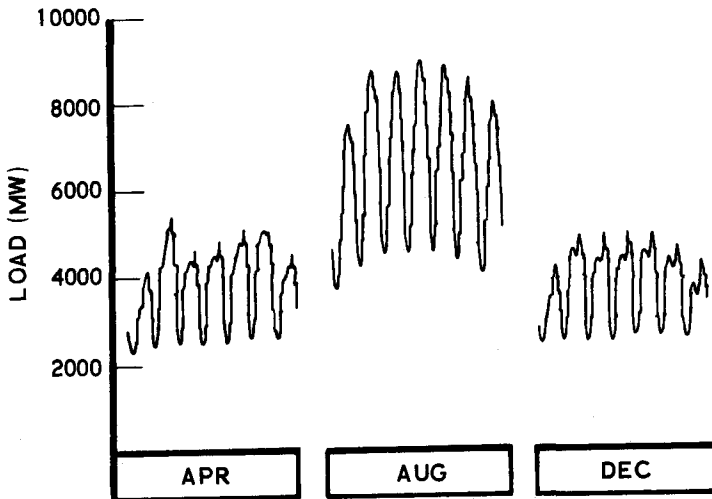


Figure 5-14. SCE Predicted Load Profile (1990) (Sheet 2 of 2)

**CPSB 1990 FORECAST**

MAXIMUM LOAD: 9747 MW (8/21/90)  
 MINIMUM LOAD: 2285 MW (1/2/90)  
 LOAD FACTOR: .4892  
 TOTAL ENERGY:  $4.165 \times 10^7$  MWh



**EPE 1990 FORECAST**

MAXIMUM LOAD: 2209 MW (7/10/70)  
 MINIMUM LOAD: 612 MW (3/31/90)  
 LOAD FACTOR: .6170  
 TOTAL ENERGY:  $1.194 \times 10^7$  MWh

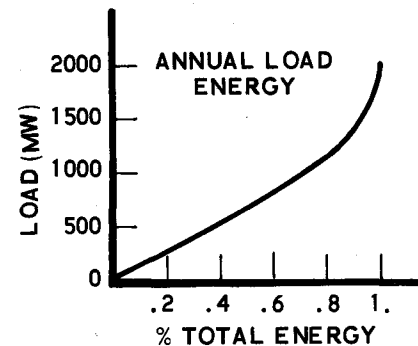
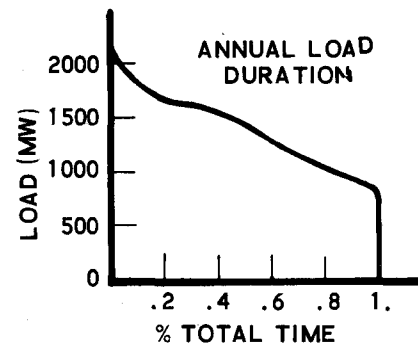
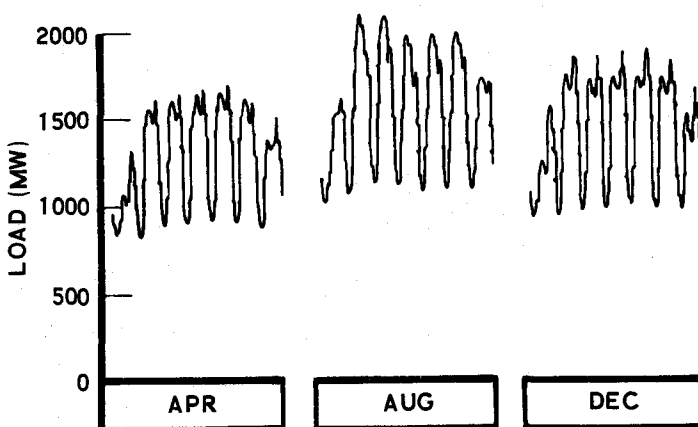
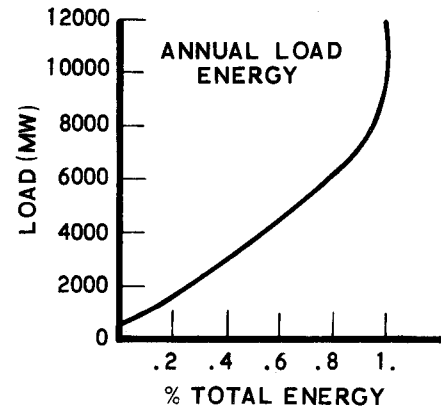
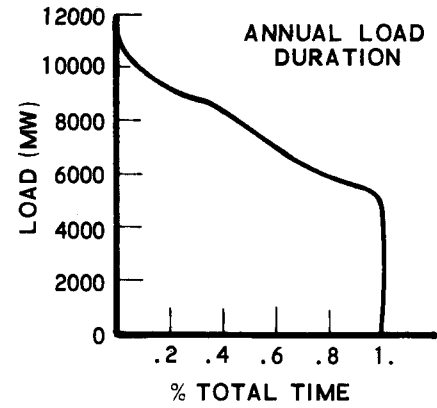
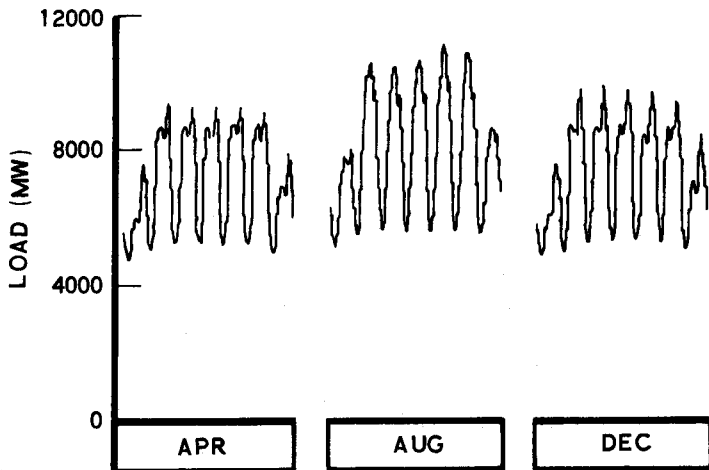


Figure 5-15. Utility Load Forecasts (1990) (Sheet 1 of 2)

**LADWP 1990 FORECAST**

MAXIMUM LOAD: 11900 MW (8/21/90)  
 MINIMUM LOAD: 4539 MW (12/23/90)  
 LOAD FACTOR: .6234  
 TOTAL ENERGY:  $6.499 \times 10^7$  MWh



**SCE 1990 FORECAST**

MAXIMUM LOAD: 32000 MW (7/30/90)  
 MINIMUM LOAD: 13337 MW (4/1/90)  
 LOAD FACTOR: .6540  
 TOTAL ENERGY:  $1.833 \times 10^8$  MWh

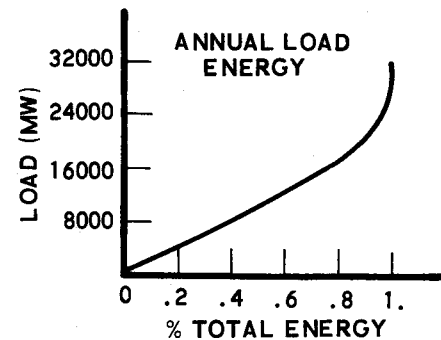
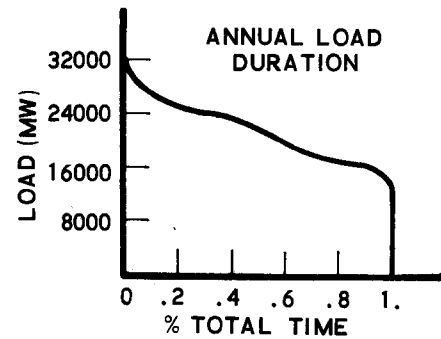
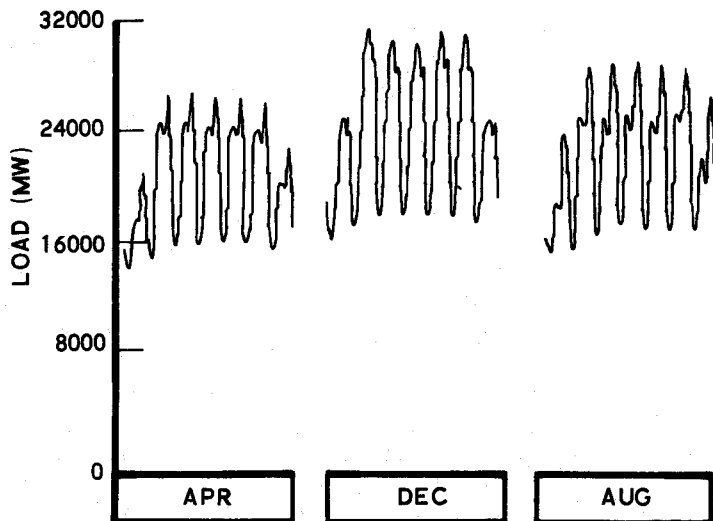


Figure 5-15. Utility Load Forecasts (1990) (Sheet 2 of 2)

5-36

PSNM FORECASTS	1980	1990	2000
MAXIMUM LOAD:	1034 MW (7/14/80)	2572 MW (7/9/90)	6374 MW (7/10/00)
MINIMUM LOAD:	410 MW (5/25/80)	1020 MW (9/3/90)	2527 MW (9/4/00)
LOAD FACTOR:	.6482	.6467	.6467
TOTAL ENERGY:	$5.887 \times 10^6$ MWh	$1.457 \times 10^7$ MWh	$3.621 \times 10^7$ MWh

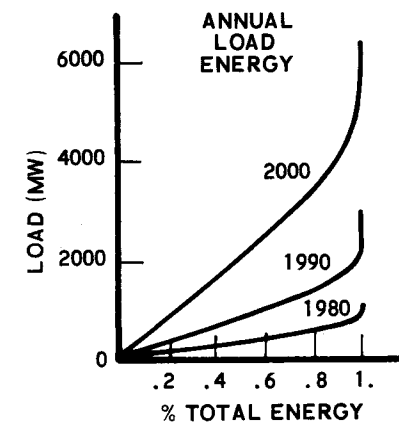
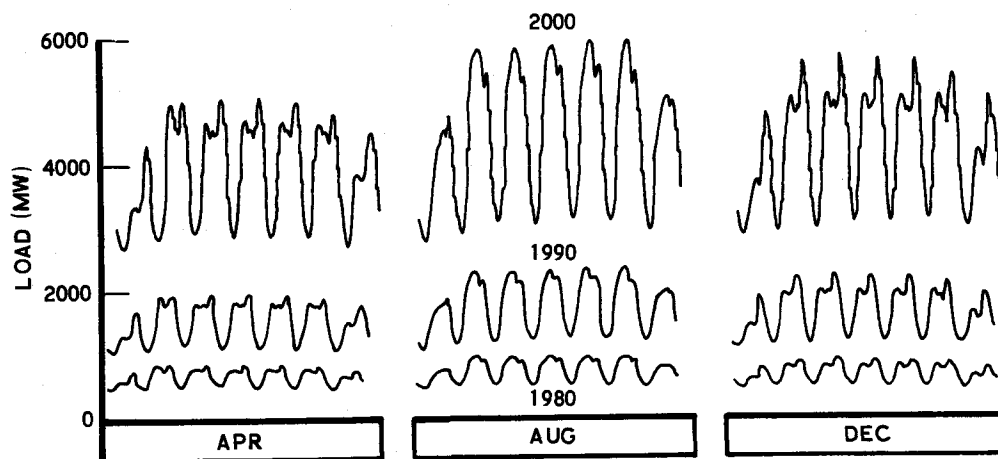
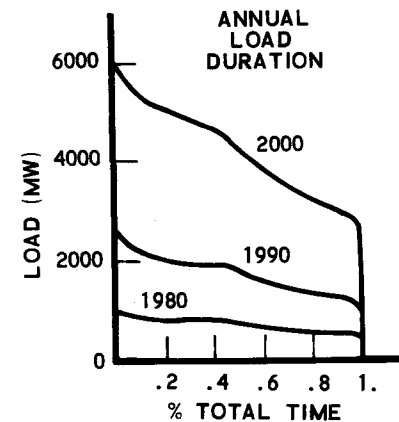


Figure 5-16. PSNM Load Forecasts (1980, 1990, 2000)

upper bounds of each load interval. DEMND logic will define the load increment such that no more than fifty intervals are in each distribution and that the increment is divisible by 2, 5, or 10.

Shown in Figure 5-15 are the results of 1990 utility load forecasts for San Antonio City Public Service Board (CPSB), El Paso Electric Co. (EPE), Los Angeles Department of Water and Power (LADWP), and Southern California Edison Co. (SCE). Each of the four illustrations in this figure incorporates maximum and minimum loads, load factors, and total energy measures, accompanied by plots of the load duration and load energy distributions and a sample (FPC Form-12) load profile. (The EPE forecast corresponds to the sample output in Figure 5-9.) Figure 5-16 presents the same information summarizing three forecasts (1980, 1990, and 2000) for the Public Service Co. of New Mexico (PSNM).

#### 5.5 FUTURE WORK

Several needed demand forecast model enhancements were identified during the course of this analysis. Primary among these is the necessary incorporation of a demand-weather dependency model (probably a periodic time-lagged relationship), which will permit the complete decomposition of historic demand data according to the demand forecast methodology. From this model a statistical description of demand-weather variation can be developed such that future demand forecasts can be modulated with random fluctuations consistent with actual observation. A substantial step toward this goal has been achieved, but much is yet to be done. Section 6 will address itself to analysis accomplishments of the current study in the area of weather correlation.

Another area requiring further attention deals with the demand decomposition practice of exponential trend removal. The underlying assumption which justified this operation stemmed from the observation that historical electric power demand has grown at an exponential rate. While future

growth behavior is a topic of controversy, it is generally agreed that the past has normally displayed exponential growth characteristics. The decrease in electric power demand resulting from the energy conservation movement in late 1973 may not signal the beginning of a lasting change in energy consumption, as indicated by members of the electric power industry, but it does point out a deficiency in the demand decomposition system. Presently electric power demand growth is represented in the model by a continuous exponential with a linear time dependence. While this model seems adequate for short-time demand growth trends, it lacks the complexity or parametric freedom necessary to follow trend variations experienced by a demand history over the span of many years, unless the demand closely follows an exponential growth scenario. This was not the case, however, when the SCE demand dipped during the latter months of 1973, as shown in Figure 5-12. When 1973 data were included in the decomposition of the SCE demand history, it was found that a least-squares fit through the entire demand history (1962-1973) degenerated in 1973, as shown in Figure 5-17. The degeneration or misfit was sufficiently severe that large magnitude residuals after trend removal caused a distortion of the forecast trend beyond the projected future peak. It was for this reason that 1973 SCE data were not used in the 1990 forecast shown previously.

The current model is not sophisticated enough to accommodate these dramatic changes in demand trends. To correct this shortcoming it is planned that the model be modified to incorporate a series of linear exponential trends, each fit to one year of demand data. In this manner the exponential is kept in its simplest form, and the trends are defined such that residuals are minimized on a yearly basis. It is not necessary to constrain the exponentials to be continuous, since the emphasis of decomposition is to capture the essence of, or closely approximate, historic behavior for use in future projections.

In addition to the necessary improvement of trend characterization, some work must be done to provide the model with the capability of handling the

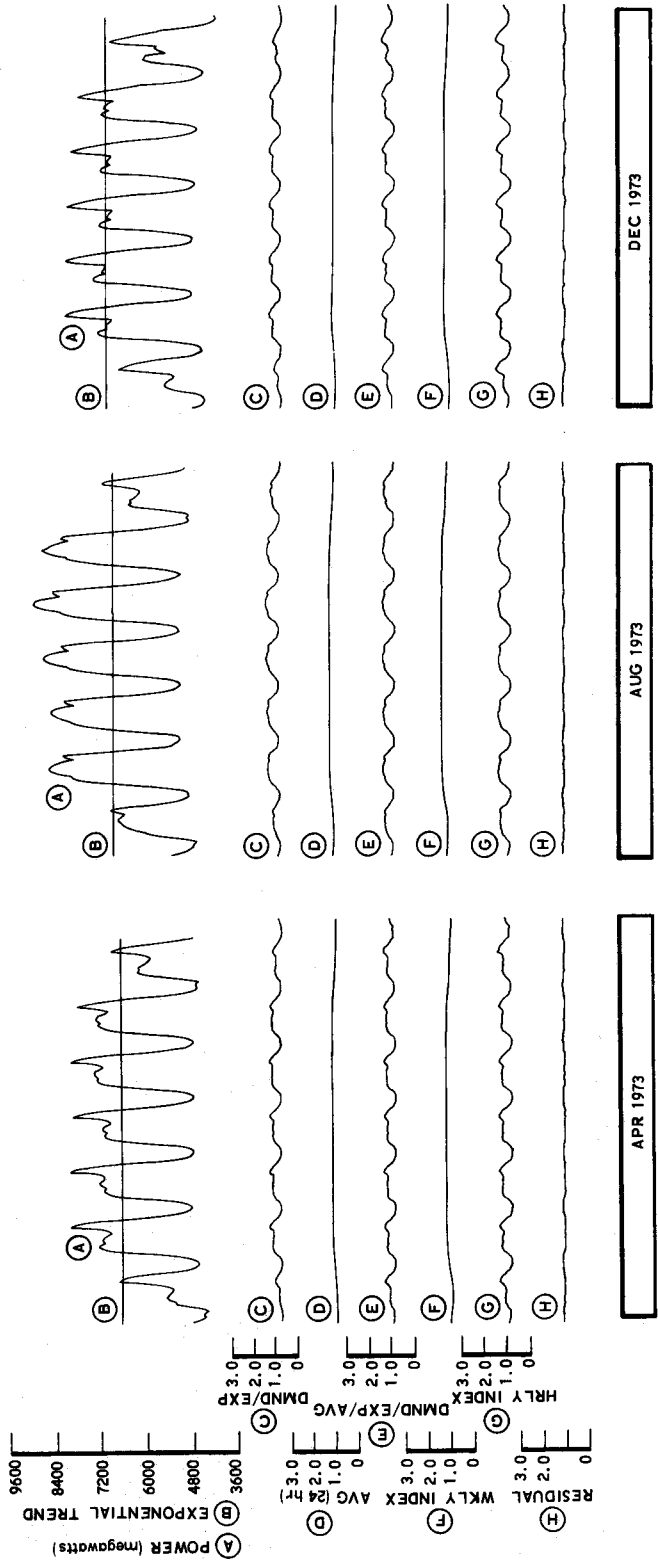


Figure 5-17. SCE Demand Decomposition (1973)

demand variations introduced by national and local holidays. Weekend variation is accommodated by the week-oriented alignment index accumulations, but holiday demand variation is allowed to affect average indices randomly, thus distorting any demand forecasts generated from this base. (The effect of holiday demand variation on weekly index profiles is shown in Figure 5-18.) Consequently, holidays should be treated differently. Their individual effects must be characterized for use in future forecasts, yet they must not be allowed to distort accumulations by their random distribution effects. One way to accomplish the special treatment of holidays would be to detect, record, and remove their effect on the hourly index profile by smoothing. This would permit the accumulation of indices without holiday distortion and, with the aid of a more elaborate calendar, the modification of future demand forecasts for holiday influences in order to make them more realistic.

It is further planned that decomposition variability measures be included in the hourly and weekly index accumulation logic. A standard deviation should be computed for each accumulation, so that future forecasts can be given  $3\sigma$  limits. The calculation of those values was avoided in the present DEMND program due to computer core storage limitations.

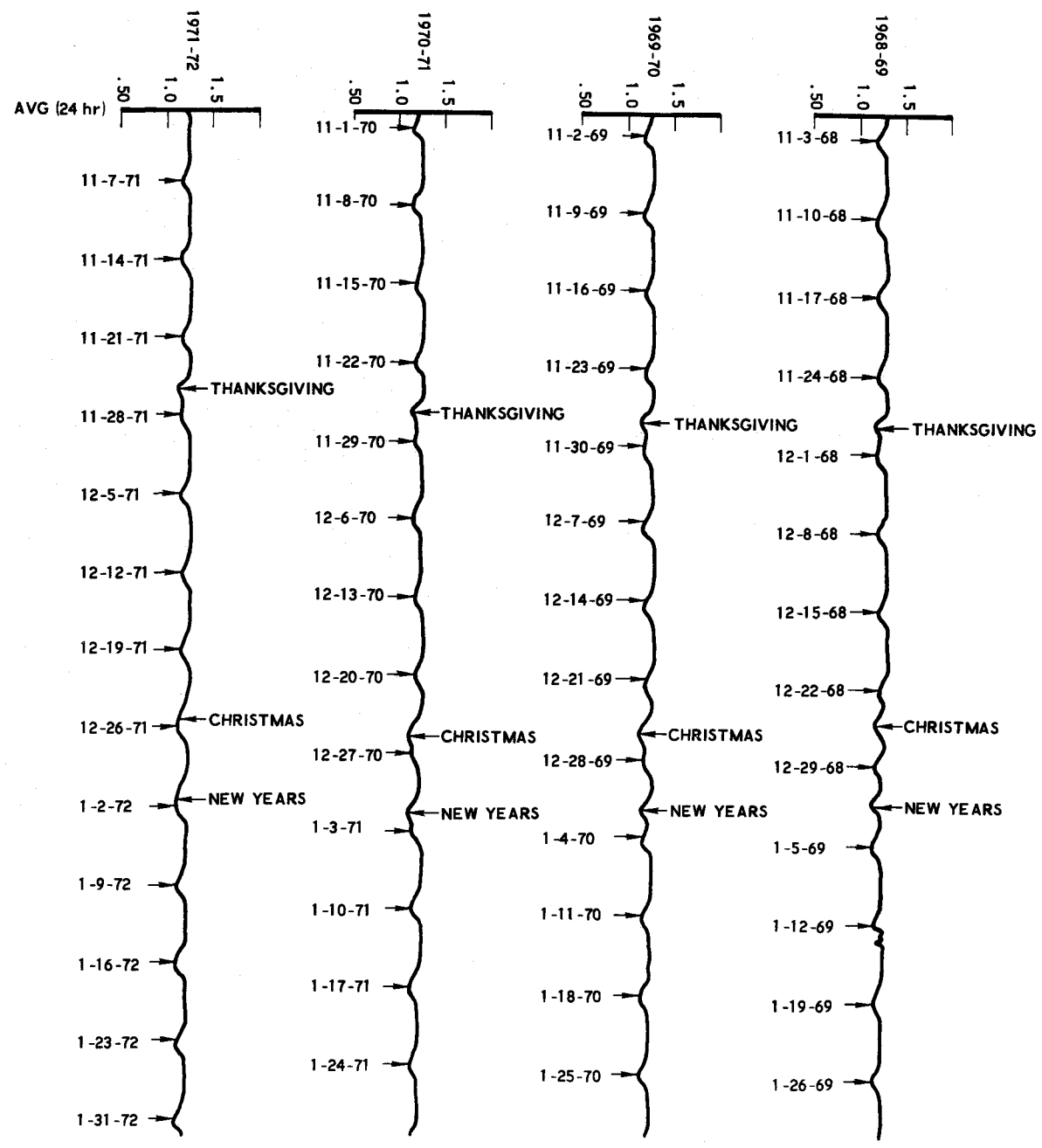
As a final observation, an organized data base for the accumulation of demand forecasts should be established and maintained in a form similar to that presently used for utility demand histories. Individual component forecasts within this data base should be identified by utility and be date-keyed to computer outputs.

#### 5.6 FINAL STATUS OF THE DEMND PROGRAM

The DEMND program as described above has been placed in the UPDATE program library file which contains the demand data manipulation programs described in this report. As in other programs, DEMND is stored in FORTRAN source form with the system control cards necessary to the program's compilation and the execution of a sample test case.



Figure 5-18. Holiday Weekly Index Profiles (SCE)



## 6. WEATHER CORRELATION ANALYSIS

A cursory demand weather correlation analysis was undertaken to investigate and quantify the possible effects of weather on electric power demand using a limited subset of spatially restricted demand/weather data. Auto-correlation techniques were employed to examine meteorological parameter characteristics. Cross-correlations between demand and those parameters intuitively showing dependence have defined time lagged relationships which may be exploited in the design of weather effect demand data filters.

Two computer programs have been developed to support this analysis: WISDM to merge electric power demand with single site meteorological parameters for plotting and eventual model-test evaluation; and COREL to perform meteorological parametric auto- and cross-correlation analyses with demand data that has been adjusted to remove long-term trends. Flow charts and listings of those programs are included in Appendix C.

The compiled weather data (Reference 9) normally include the following parameters:

Sky Ceiling Height (CH)	Dry-Bulb Temperature (DBT)
General Cloud Conditions (CC)	Wet-Bulb Temperature (WBT)
Visibility (V)	Relative Humidity (RH)
Liquid and Frozen Precipitation (PC)	Description of First Four Cloud Layers (4C)
Sea-Level Pressure (P)	Percent Opaque Sky Cover (OS)
Dew Point (DEW)	Normal Incidence Radiation (NIR)
Wind Vector (W)	Total Solar Radiation (TSR)

The effects of solar insolation are specifically addressed in the Insolation Analysis volume of this series. Parameters CH, CC, V, 4C, and OS are covered directly or indirectly in the insolation analysis. The other

parameters of direct significance are DEW, W, DBT, WBT, and RH. The number of independent parameters may be further reduced to DEW, W, DBT, TSR, and NIR for exploratory analysis.

Primary analytical efforts have been concentrated on the conditional effects of the meteorological conditions on electric power demand. The hypothesis that there is significant correlation between demand and the meteorological parameters at well defined lag times is premised upon the recorded data made available by power companies and related studies found in the literature by Heinemann, et al.; Thomas, et al.; and Kutchenreuter, et al. (References 10, 11, and 12). Also, the demand sensitivity to dry-bulb temperature is clearly established as a predominant factor in adaptive forecasting outside the range of  $50^{\circ}\text{F} < T < 65^{\circ}\text{F}$  as described by Cohen and Winter (Reference 13). It is expected that above  $65^{\circ}\text{F}$  the correspondence (correlation if linearly related) between temperature and power demand will be positive, below  $50^{\circ}\text{F}$  a negative correspondence is normally expected.

#### 6.1 METHODS OF ANALYSIS

Generally, to facilitate forecasting of demand data, a decomposition of the historic data or time series is made into the following components:

- 1) Trends - long-term variations
- 2) Oscillations - variations about the trend
- 3) Seasonal Effects - pseudo-periodic variations
- 4) Transients - unsystematic variations
- 5) Noise Residue - random, stochastic low level variations

For any future time period, these components can be recombined to provide hourly forecasted data. In the previous analysis (Reference 1) a decomposition of the historic demand data into the long-term exponential trend and cyclical (seasonal and daily) components was made.

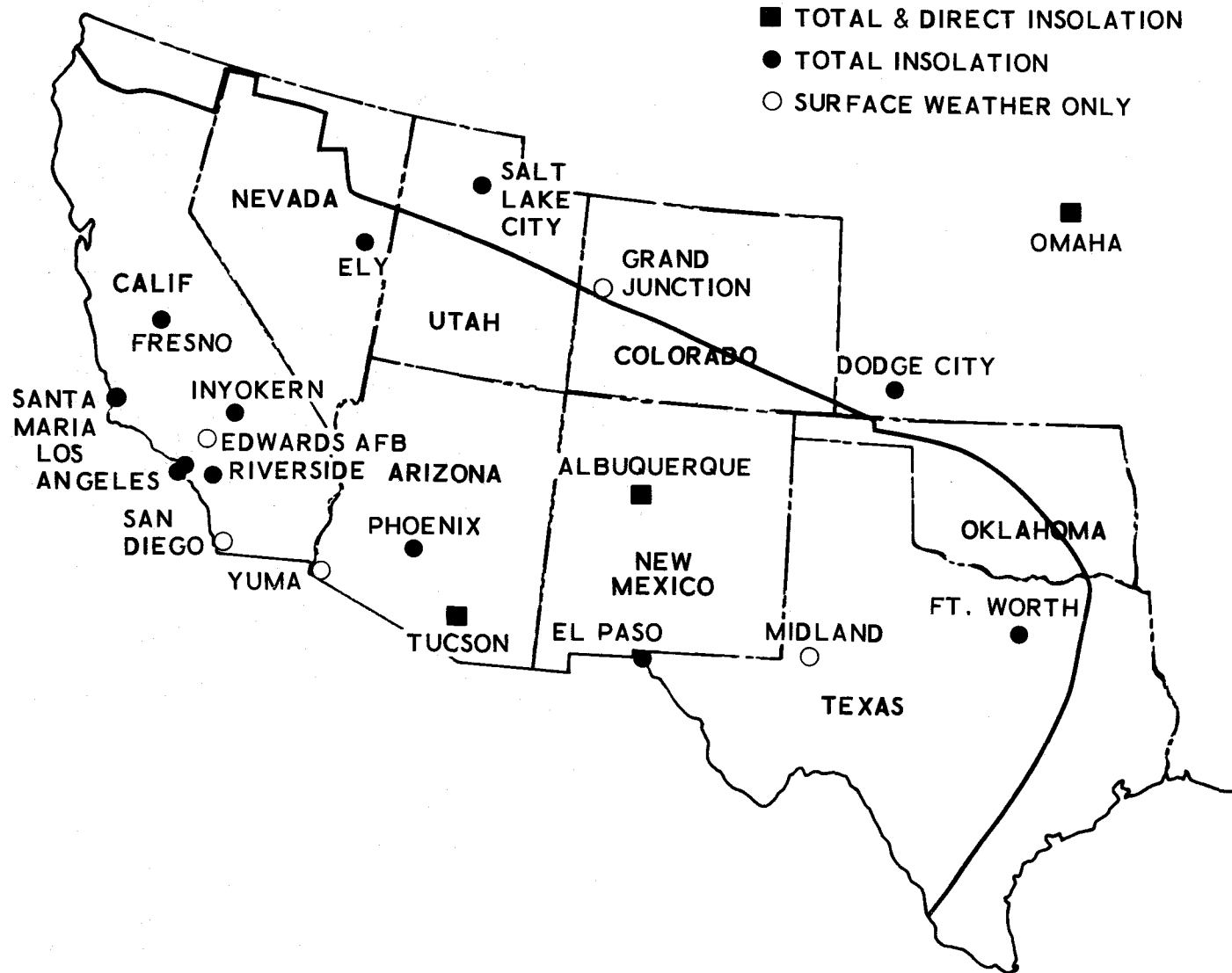
The selection of a site for the pilot weather correlation analysis was based on the availability of data for a relatively small homogeneous climatological area. The spatial ergodicity (repeatability) of meteorological parameters within the Southwest area as observed from the data suggests that almost any one of the sample areas is representative of the ensemble for all areas. Further, we see that there is also time ergodicity over a given number of months. These factors greatly reduce the data analysis requirements.

For the Southwest environment, the demand will not be a function of heterogeneous climatology which tends to mask dynamics. The immediate objective is to provide a model that will interrelate demand with the meteorological conditions and insolation. The long range objective is to establish relationships to facilitate the modeling and forecasting of the demand as a function of the meteorological and insolation data for the Southwest profile as illustrated in Figure 6-1. The pilot analysis will be restricted to the El Paso data base. Figure 6-2 represents the typical period of the power demand for the El Paso area from the first week of November 1962 through the last week of January 1963. There is some trend to the data shown, but it is easily separable. Alternatively, the trend can be removed by differencing techniques. The periodicity of the other parameters TSR, NIR, DBT, and DEW may be observed in Figures 6-3a, b, and 6-4a, b, respectively. Wind data are not available.

The apparent strong periodicity of the data facilitates considerable simplification. Specifically, it may be assumed (without loss of generality) that the first moment (mean) is zero, for both temperature and load, when computing parameters such as the variance and cross-correlation. These parameters and the intermediate parameter of cross-covariance provide a convenient description or measure of the correlations with the demand.

## 6.2 AUTO-CORRELATION

The auto-correlation coefficients of the demand over two seasonal boundaries were computed (fall-winter) and over the April-May-June



6-4

Figure 6-1. Isolation and Weather Data Stations

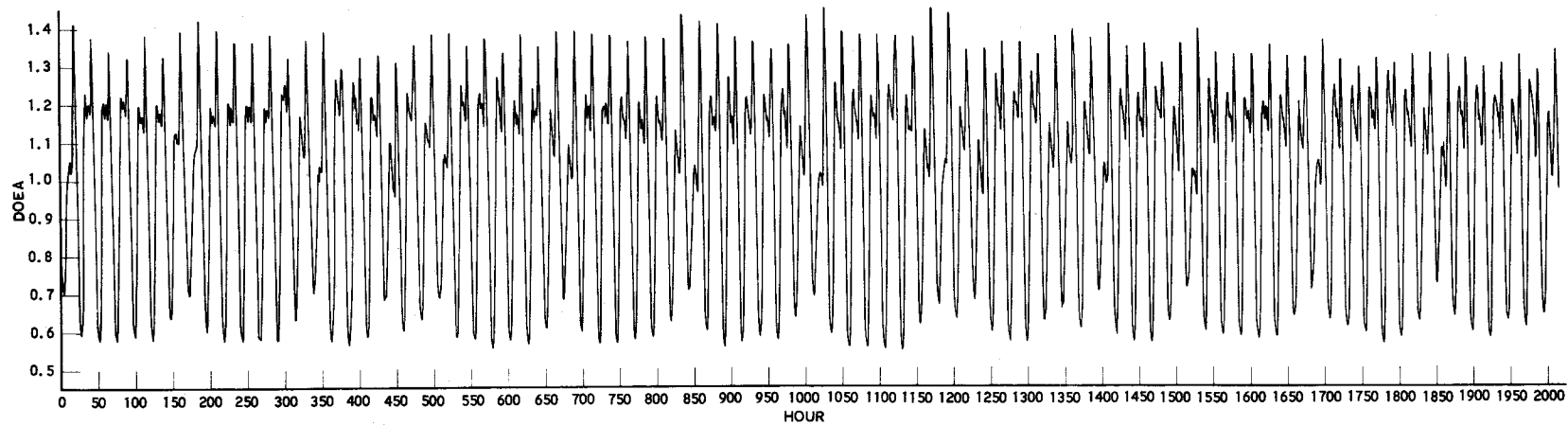


Figure 6-2. Demand Data (El Paso)  
Nov., Dec., Jan. ~ 1962 - 1963

9-9

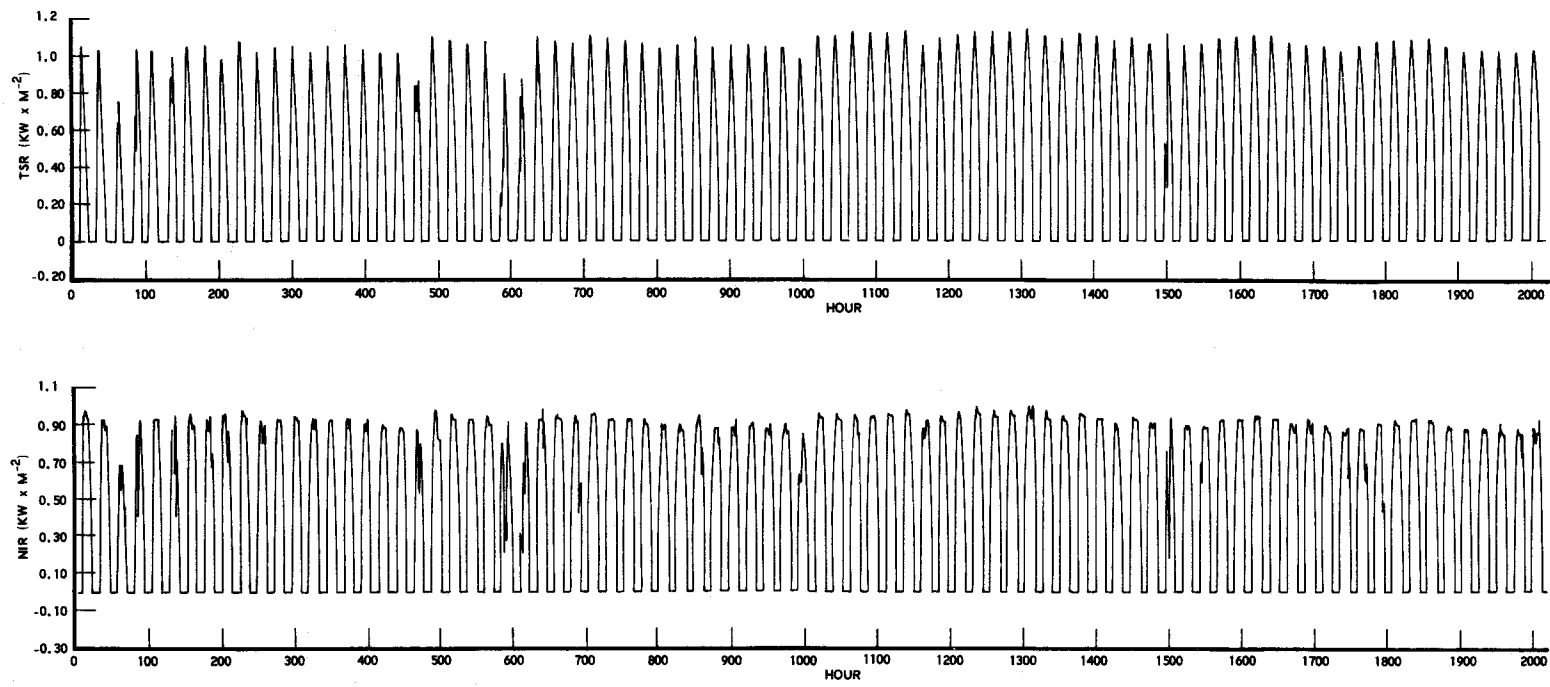


Figure 6-3. Insolation Data (El Paso)  
Nov., Dec., Jan. 1962 - 1963

6-7

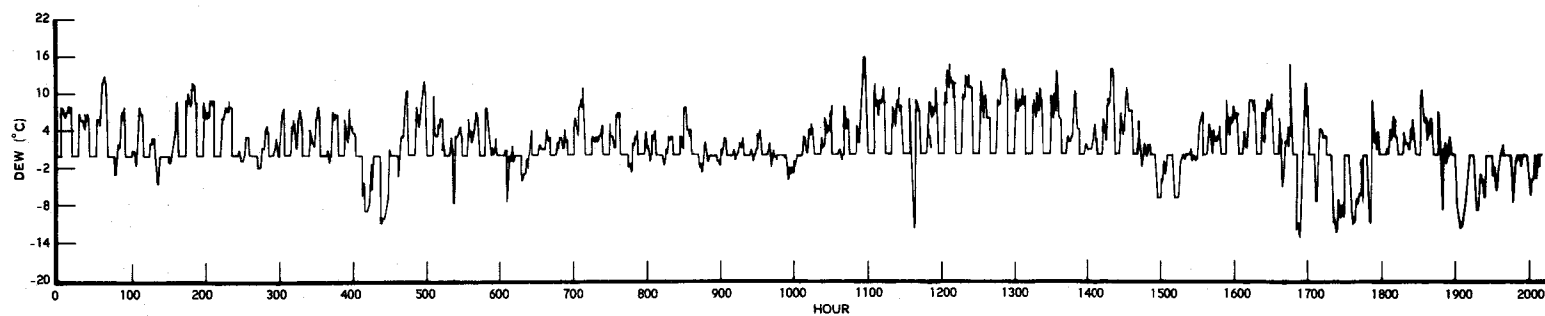
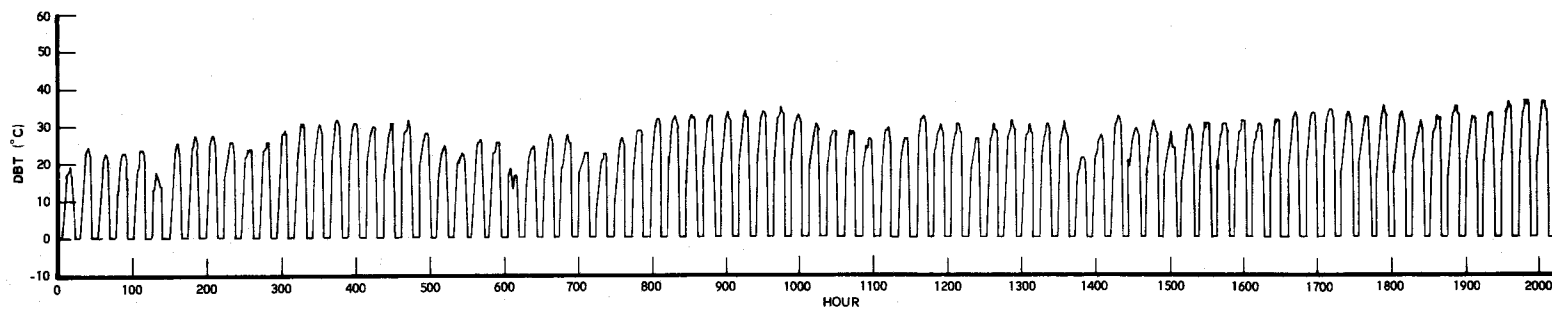


Figure 6-4. Meterological Data (El Paso)  
Nov., Dec., Jan. ~ 1962 - 1963

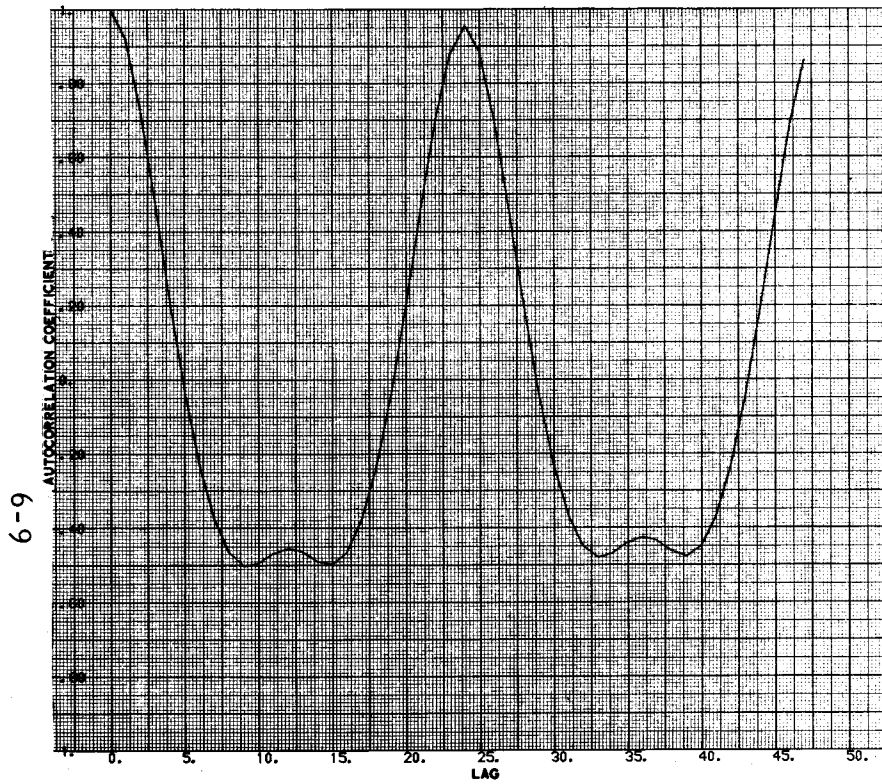


(AMJ) 12-week interval for a maximum of 48 contiguous hour lags. As might be expected, the auto-correlation is strongly periodic as shown in Figure 6-5a. It may be observed that except for trend, 24 one-hour lags are sufficient and the nondecreasing correlation coefficient does not represent nonstationarity but simple "overlags." The maximum positive correlation occurs at a lag of 24 hours; the maximum negative correlation occurs at a lag near 12 hours. The maximum negative auto-correlation -0.5 occurs at a lag of 9 and 15 hours. There is an increase at 12 lag hours that appears to be a superposition of third harmonic (8-hour variations). For the same 12-week period, half of the days were sampled and be noted from Figure 6-5b, the maximum positive correlation is unchanged. There are no apparent differences between the auto-correlation of demand as a function of a sample size ratio of two-to-one taken over the fall-winter seasonal boundary.

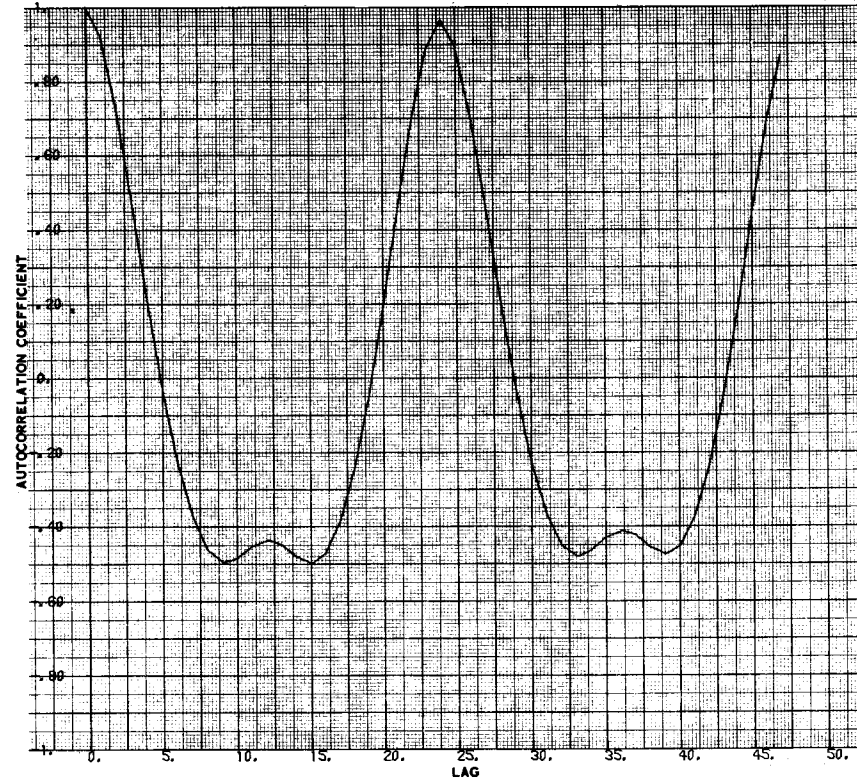
For the same comparison of dry bulb temperature (DBT) no significant differences are noted for the two sample sizes. The maximum excursions for the full sample are 0.80 and -0.45 as shown in Figure 6-6a; the corresponding correlations for the half-sample size are 0.78 and -0.36 as shown in Figure 6-6b.

The same comparisons for total insolation (TSR) are given in Figures 6-7a and 6-7b, which exhibit the 24-hour periodicity with a range of 0.92 to -0.43 and 0.92 and -0.44 for the six-week sample and 12-week samples, respectively.

The final auto-correlation over the fall-winter boundary is represented by Figures 6-8a and 6-8b for the normal incidence radiation (NIR) which have excursions of 0.86 and -0.53 and 0.86 and -0.56 for the 12-week and six-week samples, respectively. The total insolation maximum negative correlation extends over a longer period of time than that of the corresponding normal incidence radiation; however, it is more significant to



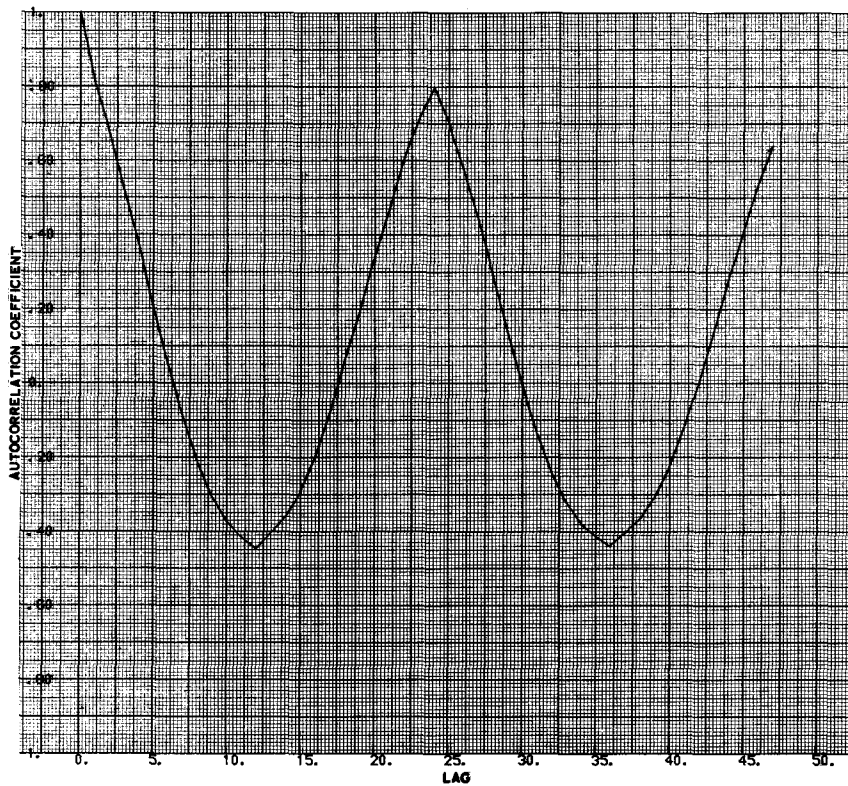
6-5(a). Full Sample



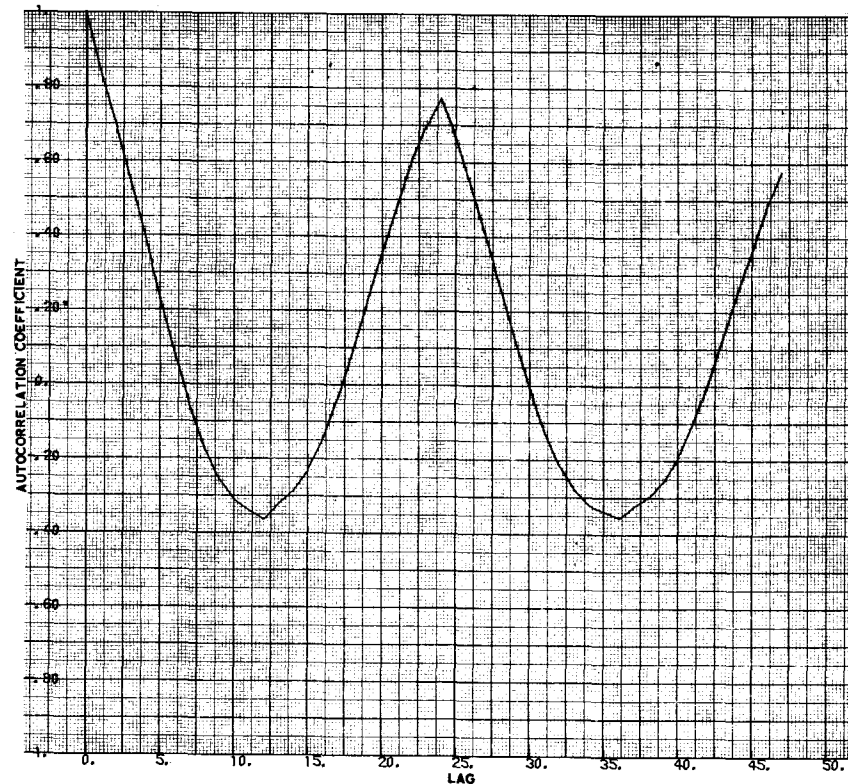
6-5(b). Half Sample

Figure 6-5. Demand Autocorrelation  
Nov., Dec., Jan. ~ 1962 - 1963

6-10



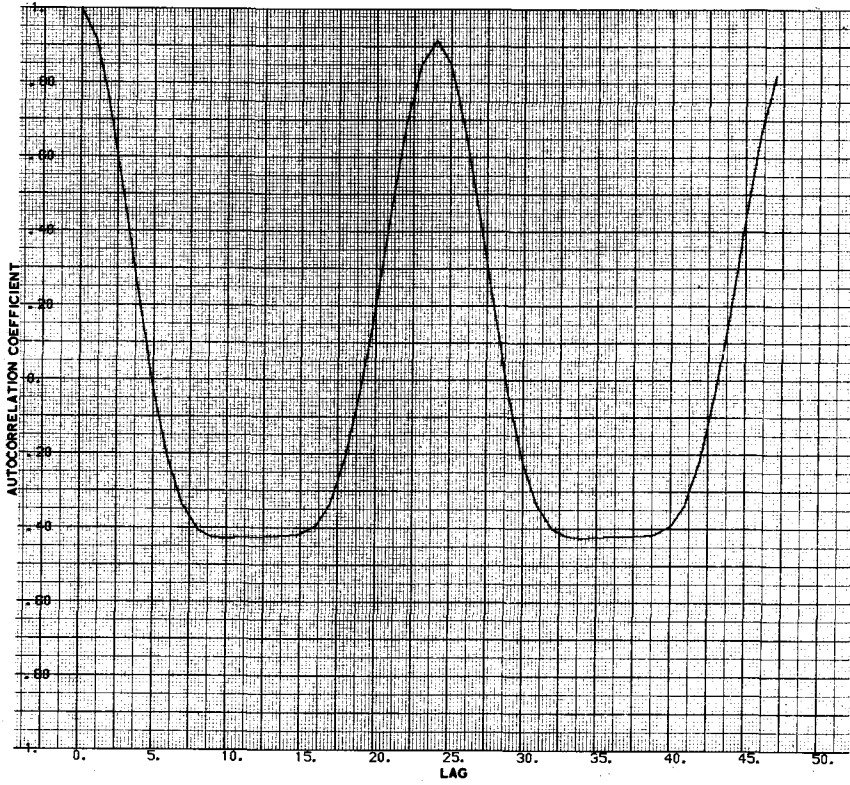
6-6(a). Full Sample



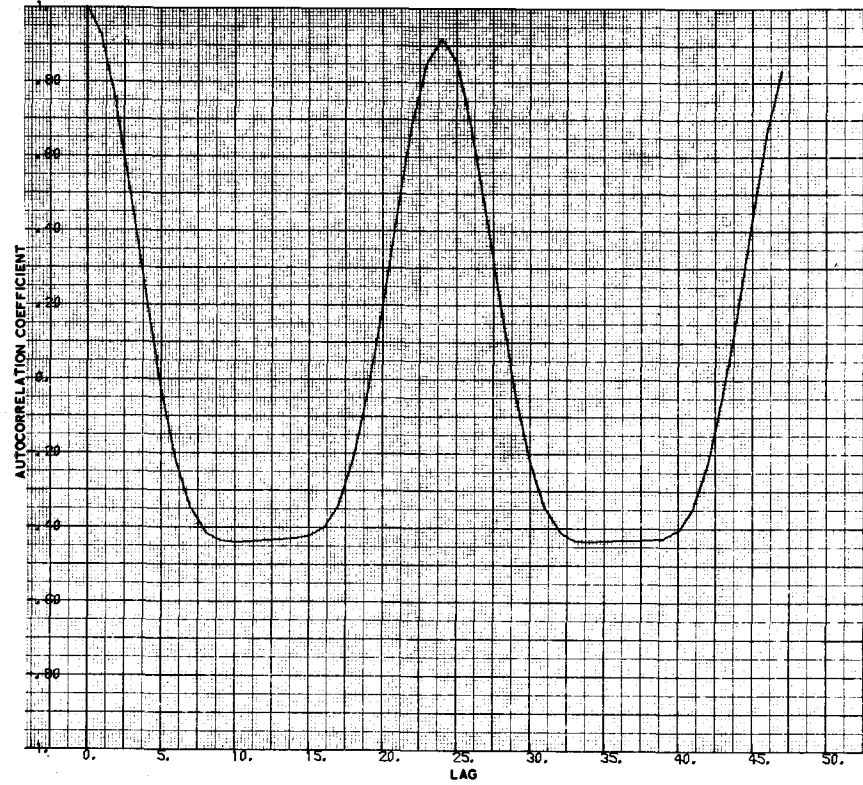
6-6(b). Half Sample

Figure 6-6. Dry Bulb Temperature Autocorrelation  
Nov., Dec., Jan. ~ 1962 - 1963

11-9

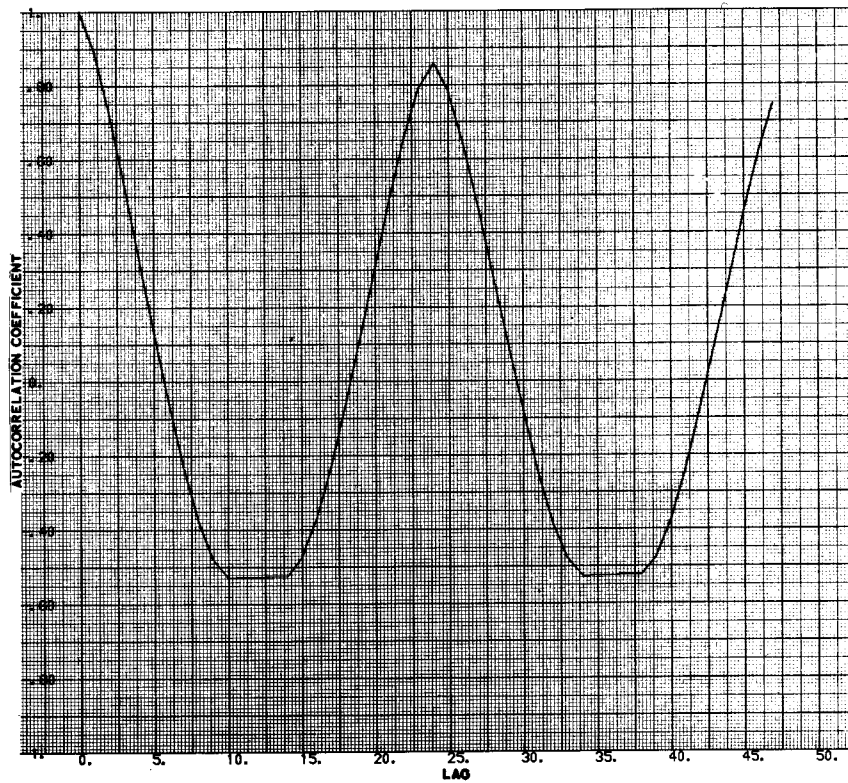


6-7(a). Full Sample

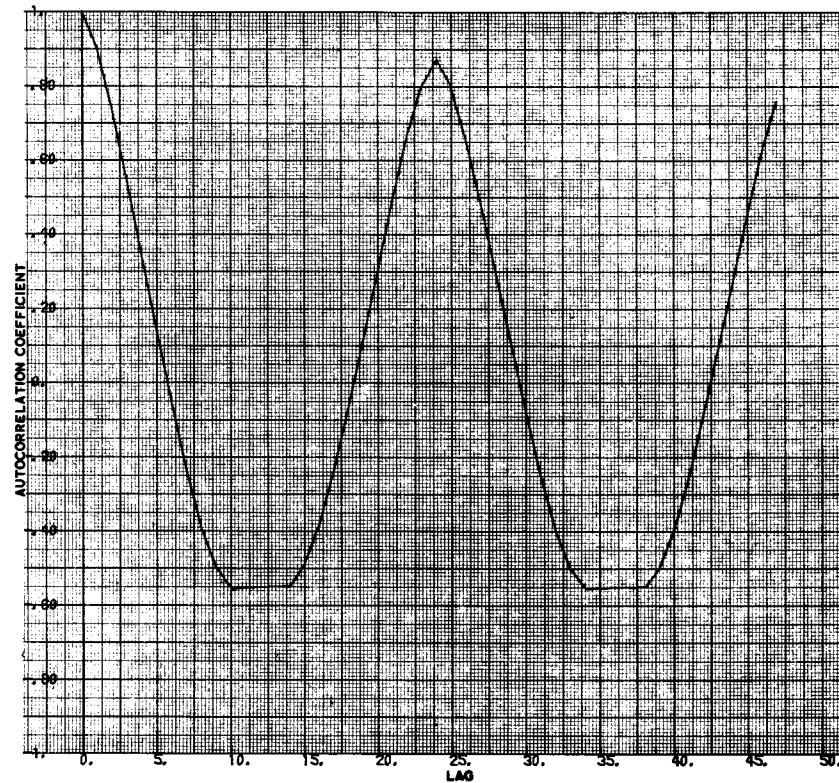


6-7(b). Half Sample

Figure 6-7. Total Solar Radiation Autocorrelation  
Nov., Dec., Jan. ~ 1962 - 1963



6-8(a). Full Sample



6-8(b). Half Sample

Figure 6-8. Normal Incidence Radiation Autocorrelation  
Nov., Dec., Jan. ~ 1962 - 1963

note that the area under the negative part of the correlation curves are approximately the same. This observation may be useful for the following two purposes:

- 1) A check on the estimate of parameters by comparison of the integrals of the parametric functions.
- 2) Implications for optimizing storage time and time interval for storage.

The data corresponding to the previous figures are summarized in Table 6-1(a). The same correlations are performed for April-May-June, and the results are presented in tabular form in Table 6-1(b). The only significant differences between the auto-correlation across the two seasons are that the maximum positive and negative correlations are greater.

These analyses indicate that the significance of the auto-correlation coefficient does not change with sample size. Also, since there is a high positive correlation for a given lag interval for each meteorological parameter (with the exception of wind), one may hypothesize that the parameters are not independent. Therefore, the correlation matrix reduces to a single equation for a generalized estimate. If the hypothesis is true, the variance would be small for the cross-correlations between any given parameter and each respective parameter. This hypothesis is examined in the following section.

### 6.3 CROSS-CORRELATION

Analysis of the cross-correlations of demand (DOEA) during the November 1962 to January 1963 period against DBT, TSR, and NIR are given in Figures 6-9, 6-10, and 6-11, respectively. It may be observed that DOEA is not independent of any of the meteorological parameters. Further, it may be observed that the distribution as weighted by value and plotted against the number of lags is not far removed from an aberrant normal, truncated at the points of inflection. The same appears to be true for the

Table 6-1a. AUTO-CORRELATION OF DEMAND AND MET PARAMETERS  
November, December, January 1962-1963 (48 Lag Hours)

Sample Size	Parameter	Significant No. of Lags	+r Max.	-r Max.	99% Confidence Limits for +ρ	Comments
12 Weeks	DOEA	24	0.95	0.5	$0.94 \leq \rho \leq 0.96$	At 24-hour Lag
6 Weeks		24	0.96	0.5	$0.95 < \rho \leq 0.97$	At 12-hour Lag
12 Weeks	DBT	24	0.80	0.45	$0.77 \leq \rho \leq 0.82$	At 12-hour Lag
6 Weeks		24	0.78	0.36	$0.75 \leq \rho \leq 0.80$	At 12-hour Lag
12 Weeks	TSR	24	0.92	0.43	$0.91 \leq \rho \leq 0.93$	At 24-hour Lag
6 Weeks		24	0.92	0.44	$0.91 \leq \rho \leq 0.93$	At 12-hour Lag
12 Weeks	NIR	24	0.86	0.53	$0.85 \leq \rho \leq 0.87$	At 24-hour Lag
6 Weeks		24	0.86	0.56	$0.86 \leq \rho \leq 0.88$	At 12-hour Lag

6-14

Table 6-1b. AUTO-CORRELATION OF DEMAND AND MET PARAMETERS  
April, May, June 1962 (48 Lag Hours)

Sample Size	Parameter	Significant No. of Lags	+r Max.	-r Max.	99% Confidence Limits for +ρ	Comments
12 Weeks	DOEA	24	0.97	0.77	$0.96 \leq \rho \leq 0.98$	At 24-hour Lag
6 Weeks		24	0.97	0.69	$0.96 \leq \rho \leq 0.98$	At 12-hour Lag
12 Weeks	DBT	24	0.98	0.71	$0.965 \leq \rho \leq 0.975$	At 24-hour Lag
6 Weeks		24	0.97	0.69	$0.96 \leq \rho \leq 0.98$	At 12-hour Lag
12 Weeks	TSR	24	0.99	0.72	$0.985 \leq \rho \leq 0.995$	At 24-hour Lag
6 Weeks		24	0.99	0.73	$0.985 \leq \rho \leq 0.995$	At 12-hour Lag
12 Weeks	NIR	24	0.95	0.86	$0.94 \leq \rho \leq 0.96$	At 24-hour Lag
6 Weeks		24	0.96	0.87	$0.95 \leq \rho \leq 0.97$	At 12-hour Lag

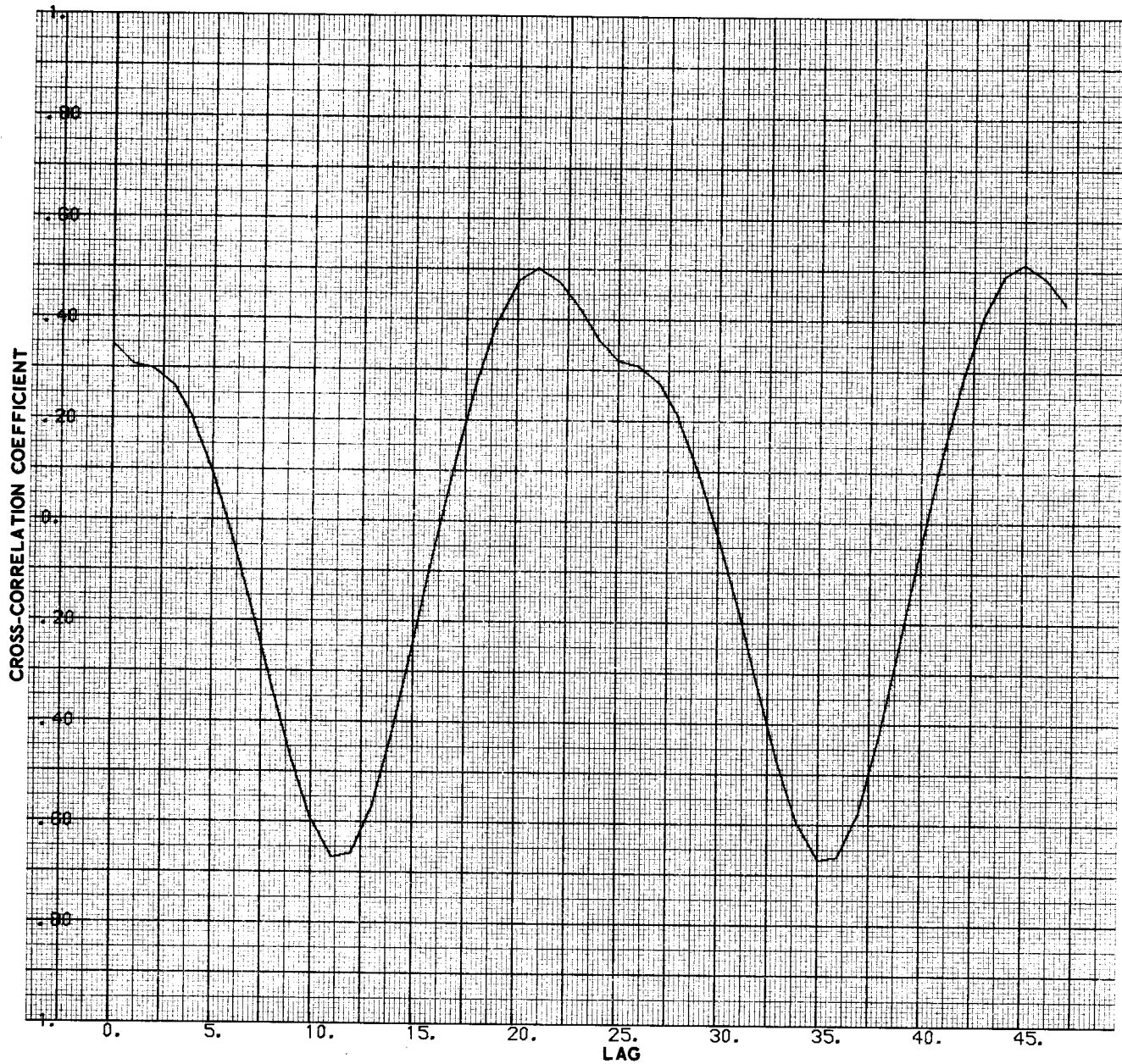


Figure 6-9. Demand - Dry-Bulb Temperature Cross-Correlation  
 Nov., Dec., Jan. 1962 - 1963



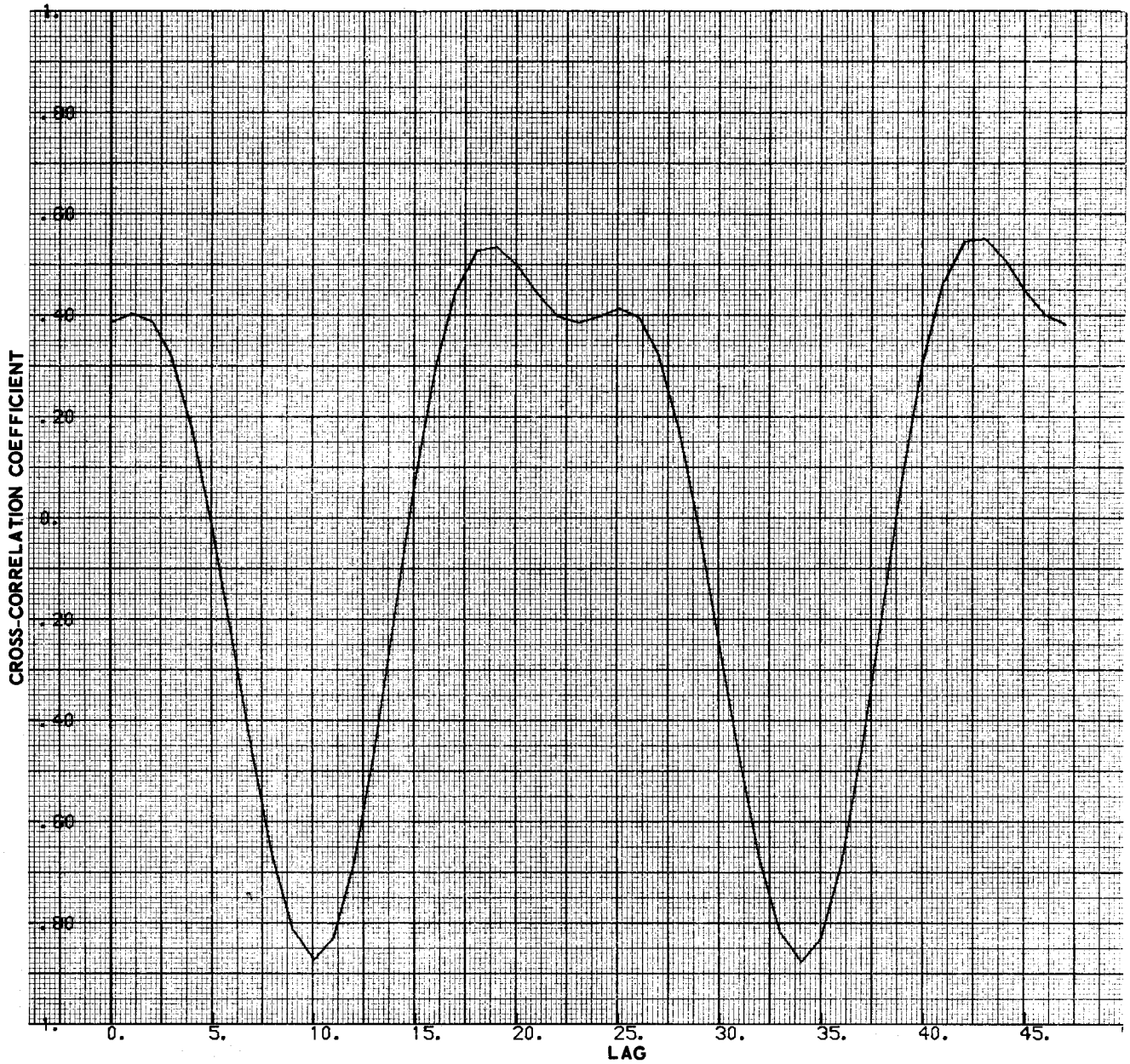


Figure 6-10. Demand - Total Solar Radiation Cross-Correlation  
Nov., Dec., Jan. ~ 1962 - 1963

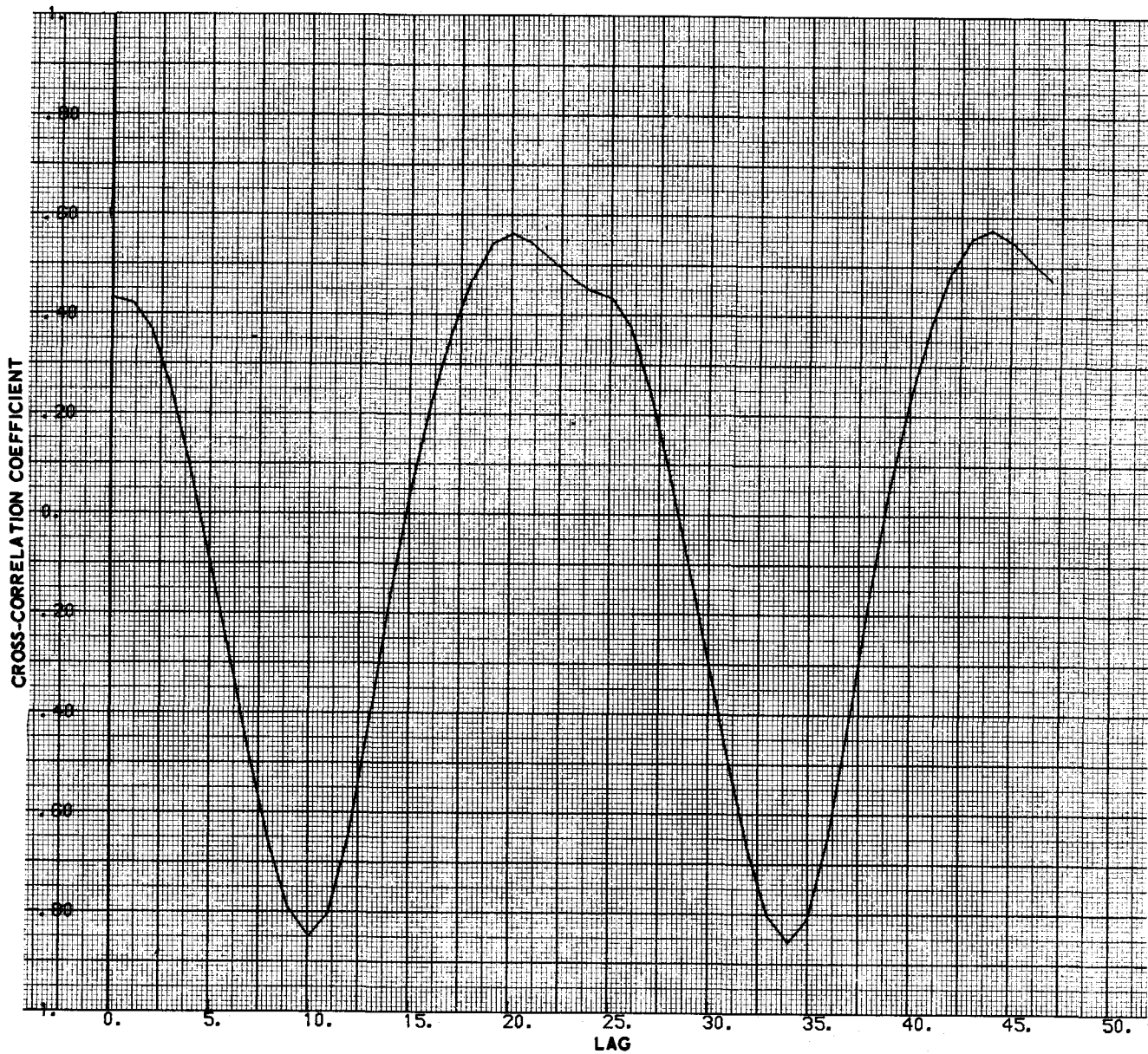


Figure 6-11. Demand-Normal Incident Radiation Cross-Correlation  
 Nov., Dec., Jan. ~ 1962 - 1963

cross-correlation of DBT with TSR as shown in Figure 6-12. The 12-week sample plots (not included in this report) are similar. The tabulated data for both sample sizes are given in Table 6-2.

From the plots of the cross-correlation coefficients, periodicities of all cross-correlations can be observed. The functions appear to be the superpositions (linear combination) of sinusoids. The range of the maximum values for positive and negative correlation of DOEA with DBT, TSR, and NIR, respectively, indicate strong dependence between parameters. For example, the mean maximum cross-correlation is 0.54 with a variance of only 0.00046. Since the product-moment correlation coefficient is invariant under changes of origin and scale, strong interdependence of meteorological parameters is implied. However, a phase difference of one hour is observed between the maximum positive cross-correlation of DOEA-DBT and DOEA-NIR; a two-hour lag between DOEA-TSR and DOEA-NIR; and a three-hour lag between DOEA-TSR and DOEA-DBT. It is also of interest (but of uncertain significance) to note that the lag time for the maximum correlation between DOEA and DEW is only two hours. As an additional check on the dependence of parameters, the cross-correlation of DBT with TSR was found to be 0.60, which is significant.

Although the absolute value of the maximum negative correlation coefficients are greater than the positive, the positive values show a more consistent lag period. The positive correlation coefficient is retained as the principal reference throughout this report.

The corresponding analysis data for the April-May-June 1962 interval are given in Table 6-2(b). The data are essentially a replication of the November-December-January data with a few notable exceptions which include:

- 1) Higher positive cross-correlation of DOEA with DBT, TSR, and NIR (0.83 as compared to 0.55).

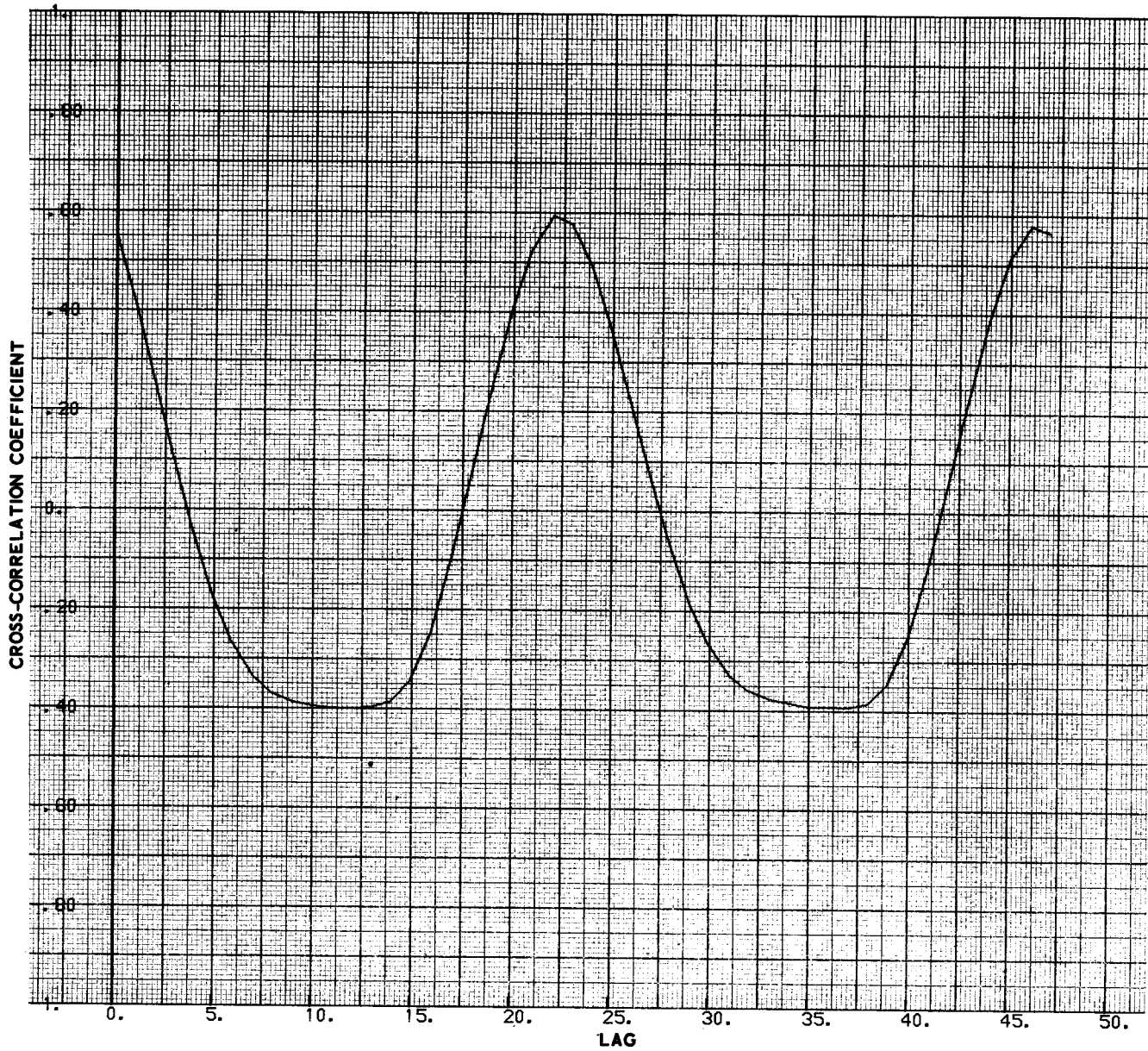


Figure 6-12. Dry-Bulb Temperature-Total Solar Radiation Cross-Correlation  
Nov., Dec., Jan. ~ 1962 - 1963

Table 6-2a. CROSS-CORRELATION OF DEMAND AND MET PARAMETERS  
November, December, January 1962-1963 (48 Lag Hours)

Sample Size	Parameters	Significant No. of Lags	+r Max.	-r Max.	99% Confidence Limits for + $\rho$	No. of Lags for Largest	
						+r	-r
12 Weeks	DOEA-DBT	24	0.55	0.69	$0.50 \leq \rho \leq 0.60$	3	13
6 Weeks		24	0.50	0.67	$0.44 \leq \rho \leq 0.56$	3	13
12 Weeks	DOEA-TSR	24	0.55	0.85	$0.50 \leq \rho \leq 0.60$	6	14
6 Weeks		24	0.53	0.88	$0.48 \leq \rho \leq 0.59$	6	14
12 Weeks	DOEA-NIR	24	0.56	0.84	$0.51 \leq \rho \leq 0.61$	4	14
6 Weeks		24	0.56	0.86	$0.51 \leq \rho \leq 0.61$	4	14
12 Weeks	DOEA-DEW	24	0.28	0.26	--	2	15
6 Weeks		24	0.22	0.20	--	2	15
12 Weeks	DBT-TSR	24	0.65	0.43	$0.56 \leq \rho \leq 0.64$	2-3	10-12
6 Weeks		24	0.60	0.40		2-3	13-14

Table 6-2b. CROSS-CORRELATION OF DEMAND AND MET PARAMETERS  
April, May, June 1962 (48 Lag Hours)

Sample Size	Parameters	Significant No. of Lags	+r Max.	-r Max.	99% Confidence Limits for + $\rho$	No. of Lags for Largest	
						+r	-r
12 Weeks	DOEA-DBT	24	0.89	0.78	$0.88 \leq \rho \leq 0.90$	3	13
6 Weeks		24	0.89	0.78	$0.88 \leq \rho \leq 0.90$	2	13
12 Weeks	DOEA-TSR	24	0.74	0.95	$0.71 \leq \rho \leq 0.77$	3	14
6 Weeks		24	0.76	0.95	$0.74 \leq \rho \leq 0.78$	2-3	14
12 Weeks	DOEA-NIR	24	0.85	0.83	$0.84 \leq \rho \leq 0.86$	3	15
6 Weeks		24	0.86	0.87	$0.85 \leq \rho \leq 0.87$	3	16
12 Weeks	DOEA-DEW	24	0.26	0.34	--	1-2	10
6 Weeks		24	0.21	0.28	--		9
12 Weeks	DBT-TSR	24	0.79	0.81	--	2-3	12-13
6 Weeks		24					

- 2) No peak distortions - almost "pure" sinusoids.
- 3) Shorter lag times - e.g., three hours compared to six hours for DOEA cross-correlated with TSR.

In the interest of brevity, the plots are not included, but the reader may refer to Table 6-2(b) for a synopsis of the data analysis.

#### 6.4 SUMMARY

Most of the quantitative analyses corroborate intuition of the correlation between the power demand and meteorological conditions. Specifically, we established the following:

- The climatological conditions of the Southwest region of study are homogeneous and, therefore, most sites are representative of the region as a whole;
- The demand is highly correlated with the meteorological measured parameters of temperature and solar radiation;
- The maximum values of auto-correlations and cross-correlations of parameters are strongly periodic at 24-hour lag intervals;
- There is high interdependence of the meteorological parameters which suggests the possible use of a single parameter for forecasting demand.

## 7. REFERENCES

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APPENDIX A

DEMAND DATA MANIPULATION

**FIRST CARD**

MONTH	DAY	YEAR	IDENTIFICATION					LOAD MIDNIGHT 1 AM	LOAD 1-2 AM	LOAD 2-3 AM	LOAD 3-4 AM	LOAD 4-5 AM	LOAD 5-6 AM	LOAD 6-7 AM	LOAD 7-8 AM	LOAD 8-9 AM	LOAD 9-10 AM	LOAD 10-11 AM	LOAD 11 AM NOON
			I.D. No.	FPC	EI	PSA	OWN												
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	00

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**SECOND CARD**

MONTH	DAY	YEAR	IDENT	TEMP	LOAD NOON 1 PM	LOAD 1-2 PM	LOAD 2-3 PM	LOAD 3-4 PM	LOAD 4-5 PM	LOAD 5-6 PM	LOAD 6-7 PM	LOAD 7-8 PM	LOAD 8-9 PM	LOAD 9-10 PM	LOAD 10-11 PM	LOAD 11 PM MIDNIGHT
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51
52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68
69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	
85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	00	

GLOBE NO. 1 STANDARD FORM 5081

Figure A-1. Edison Electric Institute System Load Data Card Format

Table A-1. EEI Format Additions/Modifications

The following additions or modifications to the Edison Electric Institute load data card format are currently used in The Aerospace Corporation demand data base:

FIRST CARD

Column 17: Time Zone

P - Pacific

M - Mountain

C - Central

Column 18: Time Base

D - Daylight

S or blank - Standard

Columns 12, 20: Utility Identification

Two Alphabetic Characters

SECOND CARD

Columns 17-19: Day-of-year

**Schedule 15**  
**SYSTEM LOAD DATA FOR SPECIFIED WEEKS**

Load data should be furnished by all class I systems. Class II systems may omit this schedule unless otherwise instructed.

1. Show the 60-minute integrated kilowatt demand for each clock-hour of the days specified in this schedule, determined (as for the peak hour in schedule 13) from coincident demands as follows:

- (a) Combined net demand on all system generating plants.
- (b) Plus: Power received from other systems and industrial companies listed in schedule 8, part B, column 5.
- (c) Minus: Power delivered, for resale, to each class I and class II system that obtained a part of its power supply during the year from its own generating facilities or from systems other than the respondent's. These systems are listed in schedule 8, part B column 6.
- (d) Total net demand for load data-(a) plus (b) minus (c).

Note that power delivered by the respondent to another class III or class V system is included in the respondent's system load for purposes of this schedule.

2. Where integrated demands for 60-minute clock-hour intervals are not available, it is desired that available data be adjusted to approximate the integrated demand for 60-minute clock-hour intervals. Adjustments made should be explained in footnotes. Where such adjustments cannot be made, load data should be furnished in the form available.

3. The loads represented by the demands to be entered in this schedule will, in accordance with instruction 1, include the sales for resale to systems listed in schedule 8, part A.

4. State whether the system operates on Eastern, Central, Mountain, or Pacific time

5. If the system operated on daylight-saving time during the year, give beginning and ending dates of the daylight-saving period.

6. If any of the reported data are given in daylight-saving time, indicate which readings are so given

7. If unusual conditions (storms, floods, industrial disturbances, etc.) greatly affected the system load characteristics during any of the specified weeks, describe such influences briefly on an addenda sheet and give the dates affected.

**Schedule 15**  
**SYSTEM LOAD DATA FOR SPECIFIED WEEKS**

Demand Interval .....  
**INTEGRATED DEMAND IN KILOWATTS**

First Full Week of April Starting With Sunday (Indicate dates)

Time Interval (1)	Sunday (2)	Monday (3)	Tuesday (4)	Wednesday (5)	Thursday (6)	Friday (7)	Saturday (8)	
Midnight								1
12-1								2
1-2								3
2-3								4
3-4								5
4-5								6
5-6								7
6-7								8
7-8								9
8-9								10
9-10								11
10-11								12
11-12								13
Non								14
12-1								15
1-2								16
2-3								17
3-4								18
4-5								19
5-6								20
6-7								21
7-8								22
8-9								23
9-10								24
10-11								25
11-12 Total hours								26

Note.—In order that systems may collect data in advance, the same weeks in the following year will be selected for schedule 15.

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Figure A-2. Federal Power Commission, Form-12 (Schedule 15)  
Power System Statement (Sheet 1 of 2)

Schedule 15—Continued								
SYSTEM LOAD DATA FOR SPECIFIED WEEKS								
Demand Interval								
INTEGRATED DEMAND IN KILOWATTS								
Time Interval	First Full Week of August Starting With Sunday (Indicate date)							
(1)	Sunday (2)	Monday (3)	Tuesday (4)	Wednesday (5)	Thursday (6)	Friday (7)	Saturday (8)	
Midnight								1
12-1								2
1-2								3
2-3								4
3-4								5
4-5								6
5-6								7
6-7								8
7-8								9
8-9								10
9-10								11
10-11								12
11-12								13
Sum								14
12-1								15
1-2								16
2-3								17
3-4								18
4-5								19
5-6								20
6-7								21
7-8								22
8-9								23
9-10								24
10-11								25
11-12								26
Sum								27
First Full Week of December Starting With Sunday (Indicate date)								
	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	
Midnight								28
12-1								29
1-2								30
2-3								31
3-4								32
4-5								33
5-6								34
6-7								35
7-8								36
8-9								37
9-10								38
10-11								39
11-12								40
Sum								41
12-1								42
1-2								43
2-3								44
3-4								45
4-5								46
5-6								47
6-7								48
7-8								49
8-9								50
9-10								51
10-11								52
11-12								53
Sum								54

Rev. (12-

Figure A-2. Federal Power Commission, Form-12 (Schedule 15)  
Power System Statement (Sheet 2 of 2)

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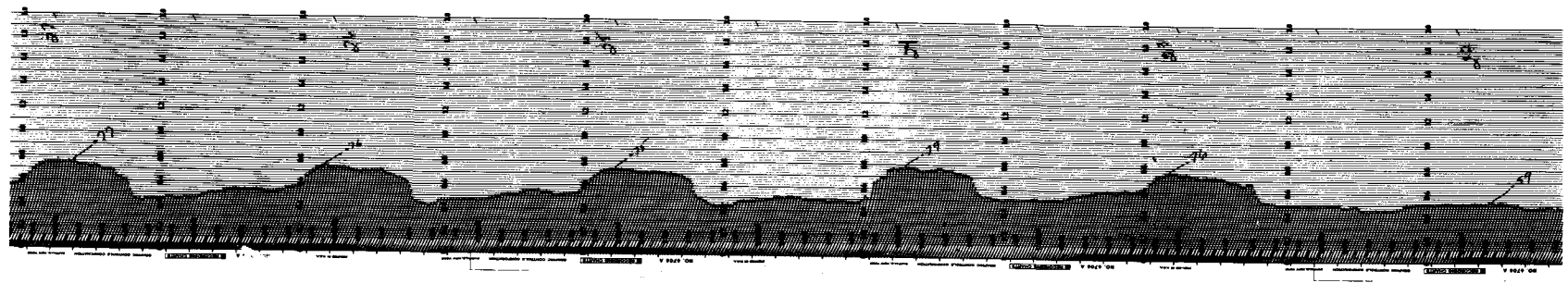
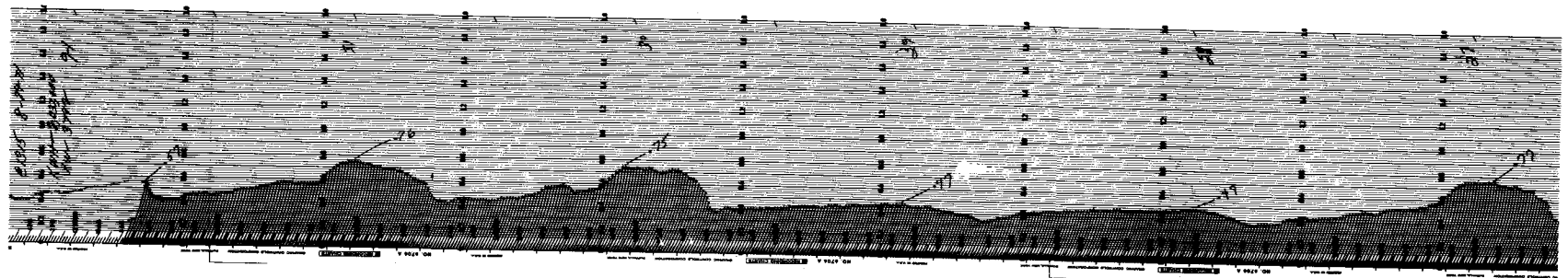
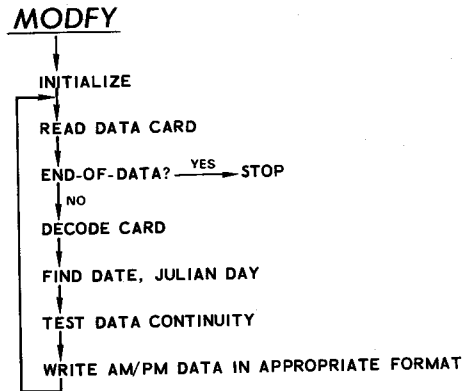
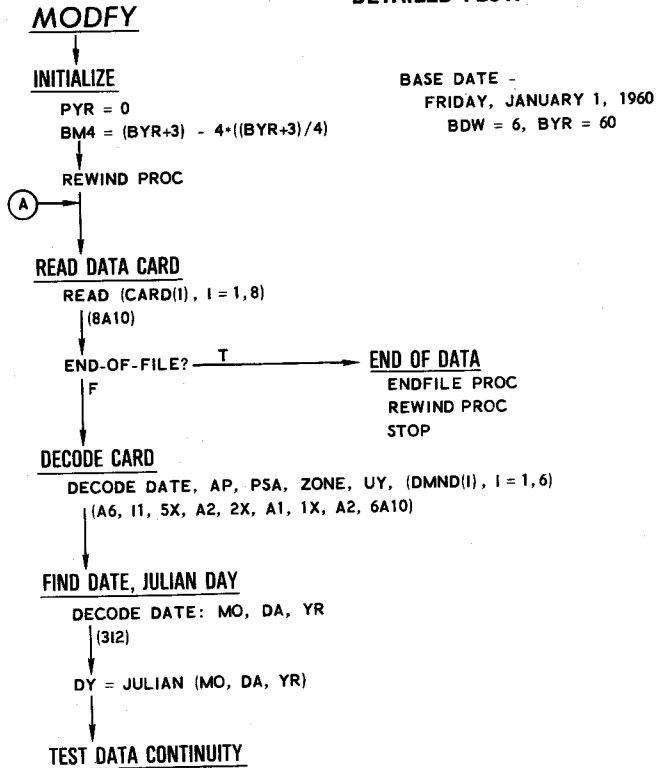


Figure A-3. Edwards Air Force Base Substation Load Data

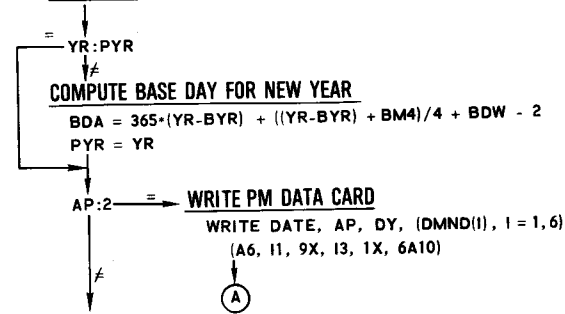
PROGRAM LOGIC



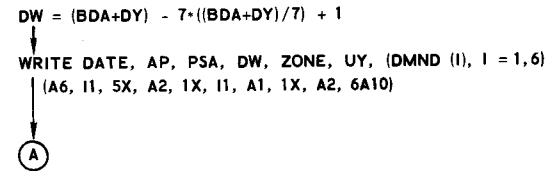
DETAILED FLOW



TEST DATA CONTINUITY

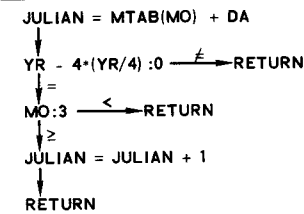


WRITE AM DATA CARD



JULIAN (MO, DA, YR)

FIND DAY OF YEAR



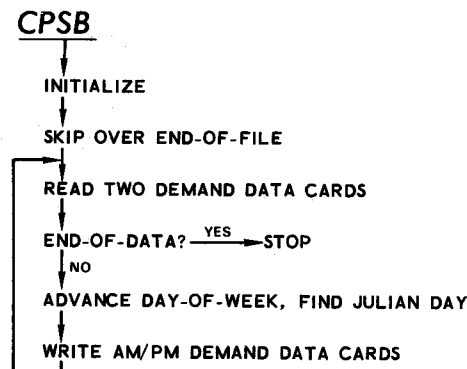
MTAB:

0	31	59	90
120	151	181	212
243	273	304	334

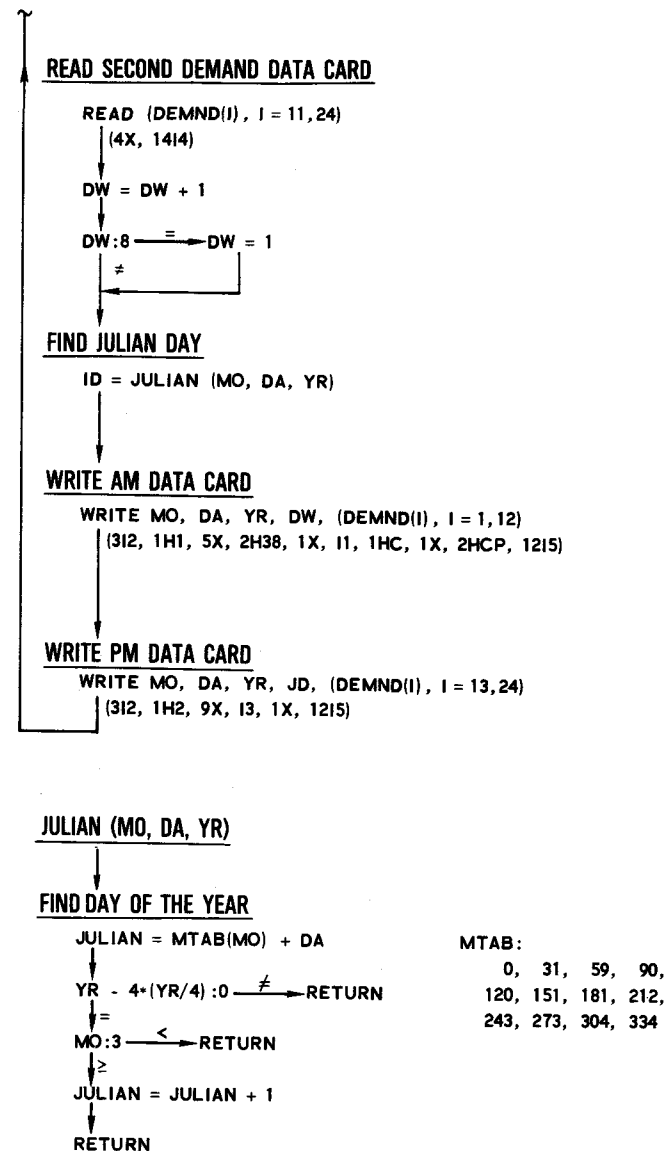
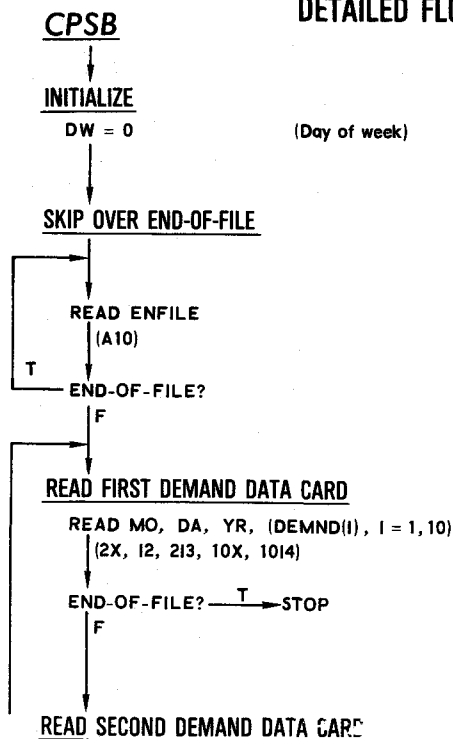
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Figure A-4. MODIFY Program Flow Charts

**PROGRAM LOGIC**



**DETAILED FLOW**



MTAB:

0	31	59	90
120	151	181	212
243	273	304	334

Figure A-5. CPSB Program Flow Charts



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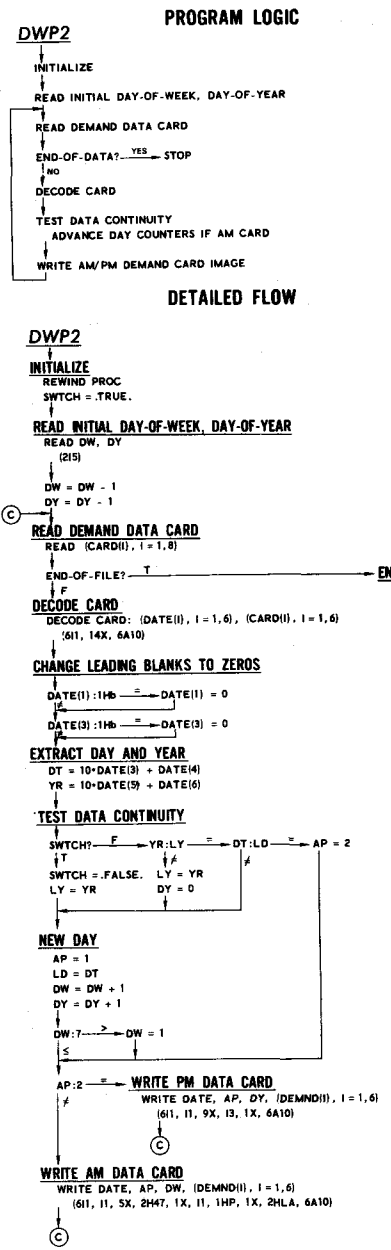
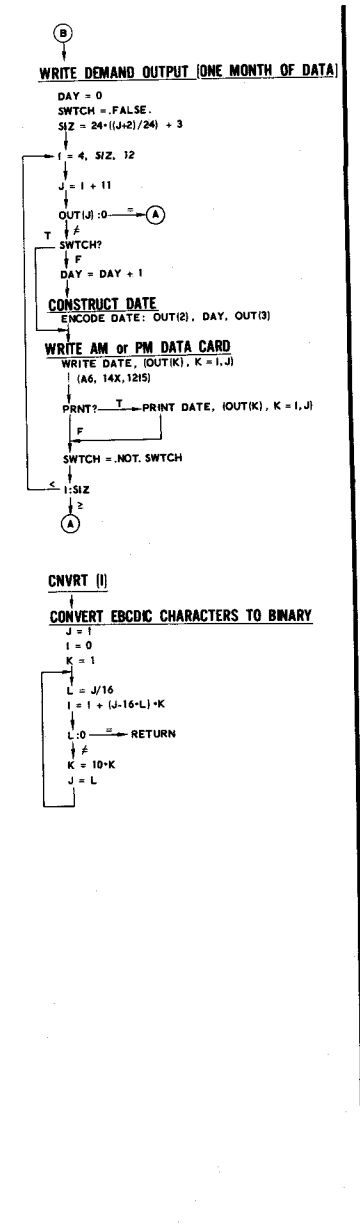
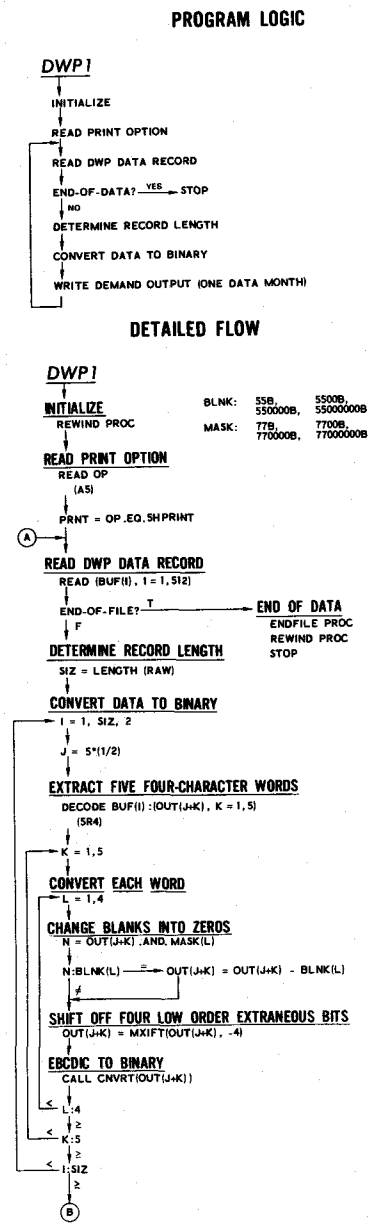
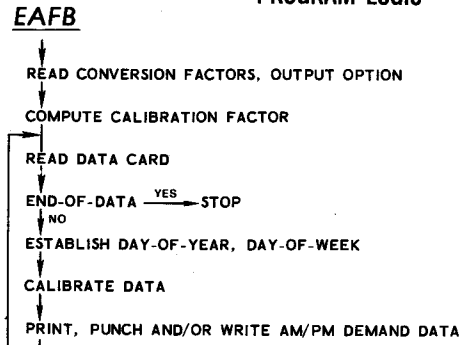
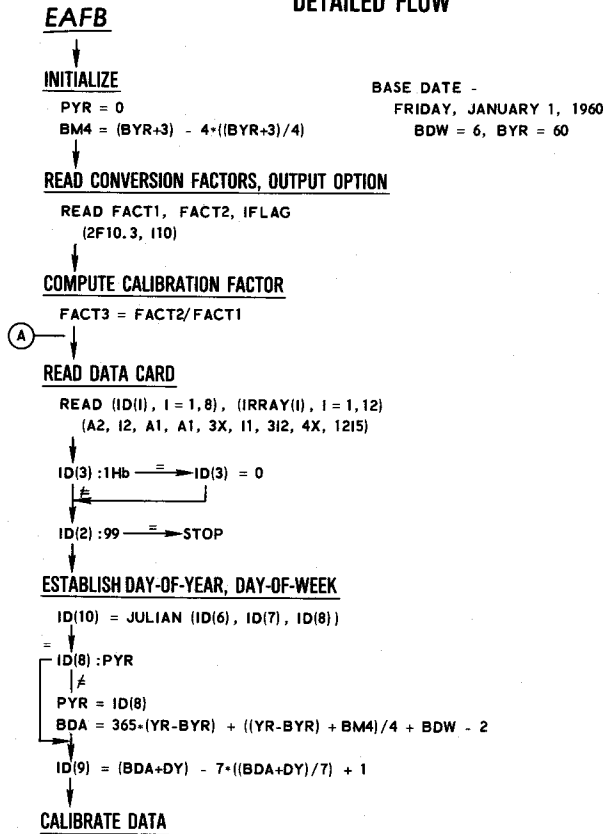


Figure A-6. DWP1, DWP2 Program Flow Charts

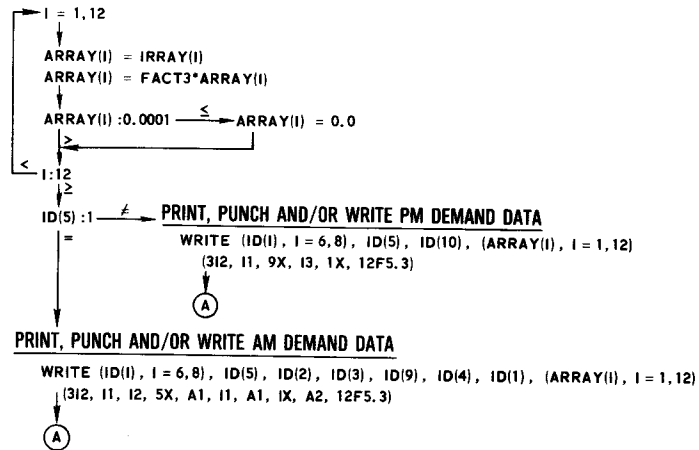
**PROGRAM LOGIC**



**DETAILED FLOW**

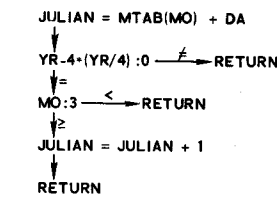


**CALIBRATE DATA**



**JULIAN (MO, DA, YR)**

**FIND DAY OF YEAR**



MTAB:

0	31	59	90
120	151	181	212
243	273	304	334

Figure A-7. EAFB Program Flow Charts

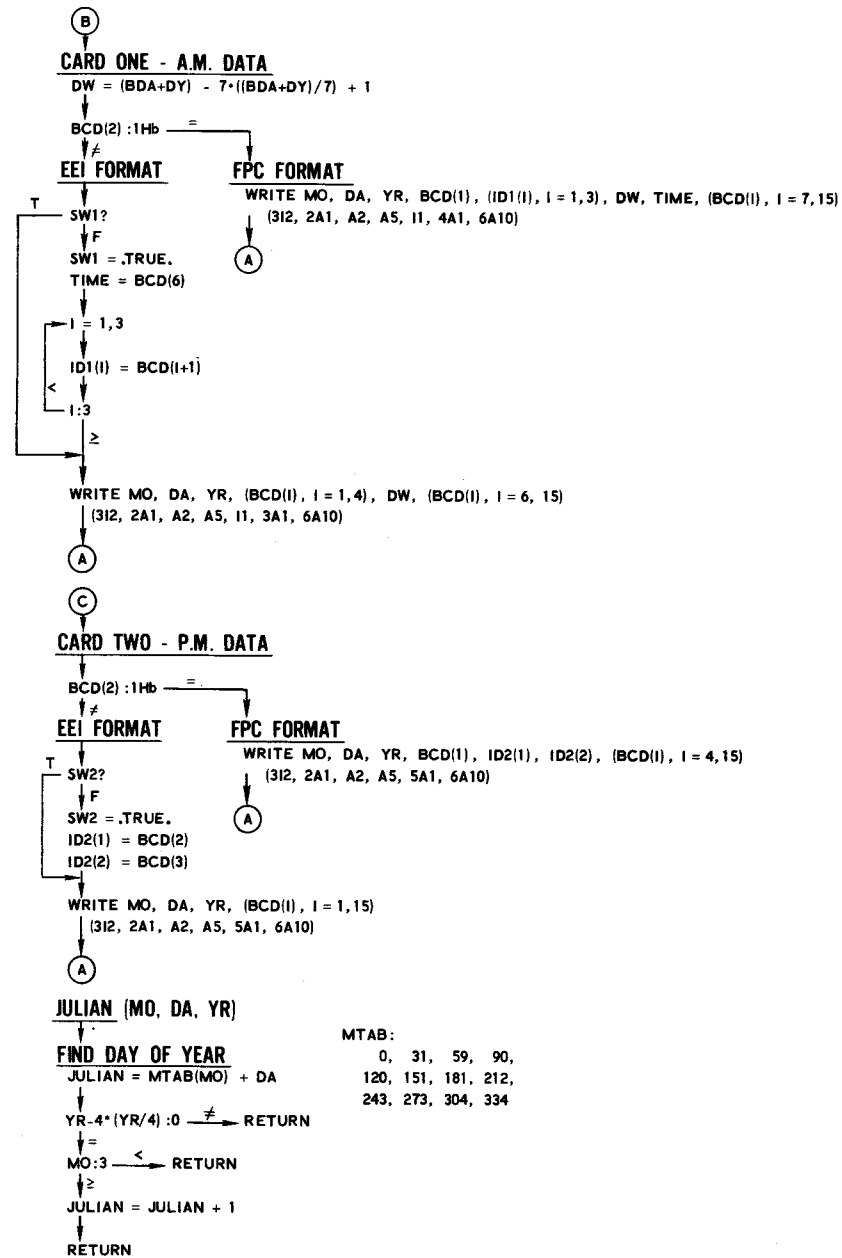
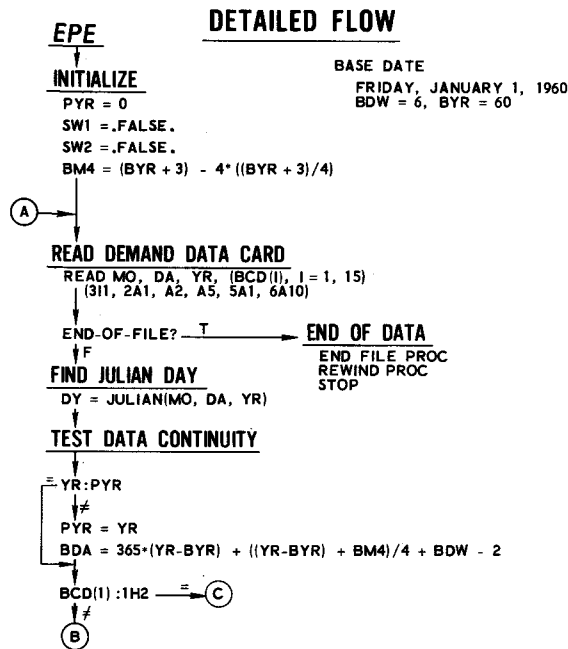
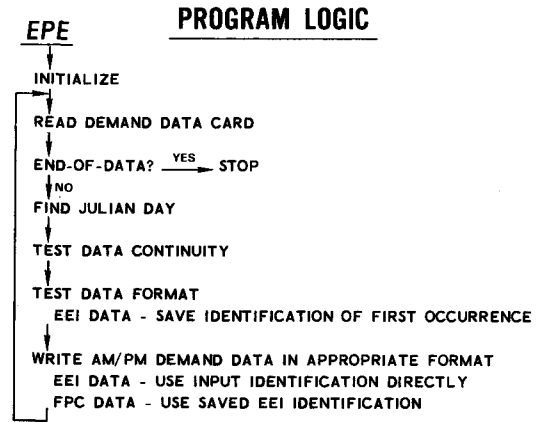
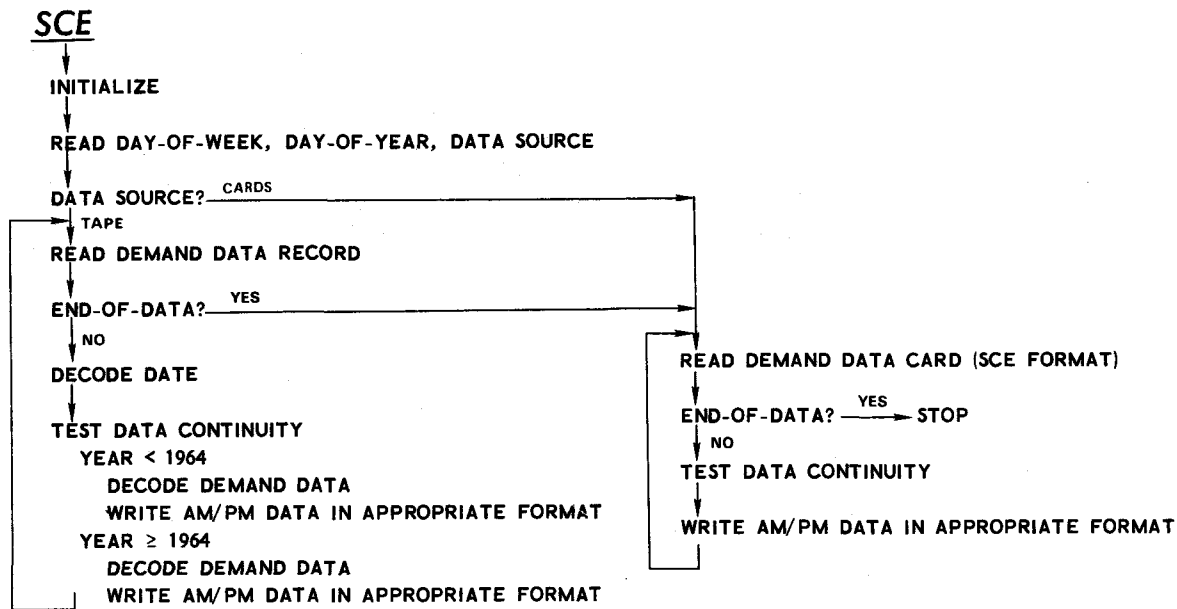


Figure A-8. EPE Program Flow Charts

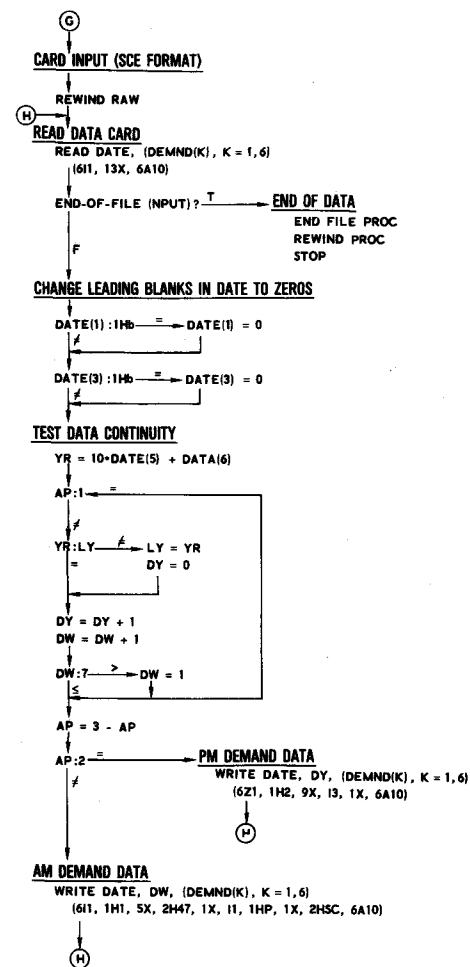
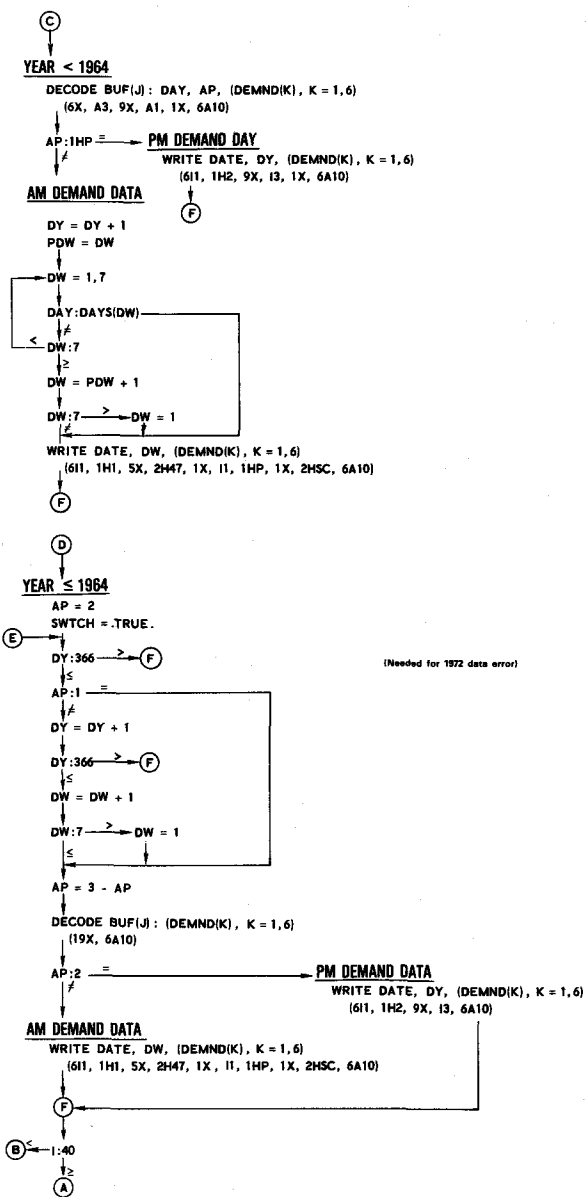
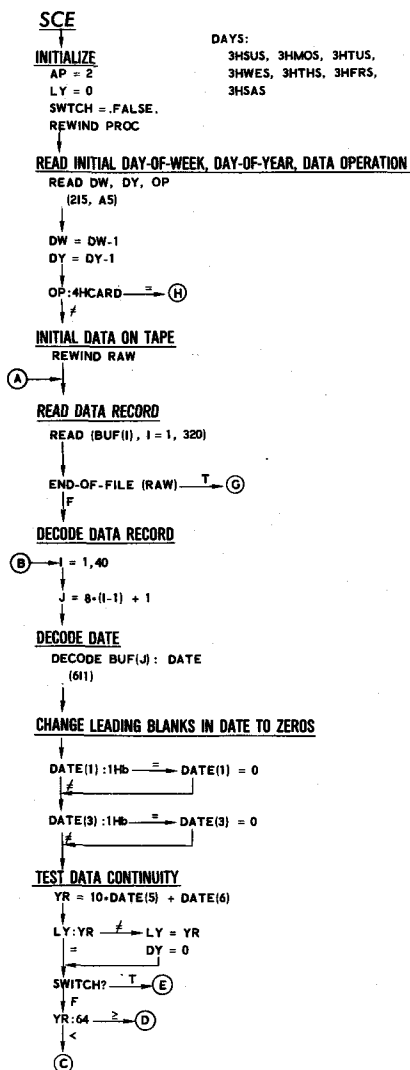
# PROGRAM LOGIC



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Figure A-9. SCE Program Flow Charts (Sheet 1 of 2)

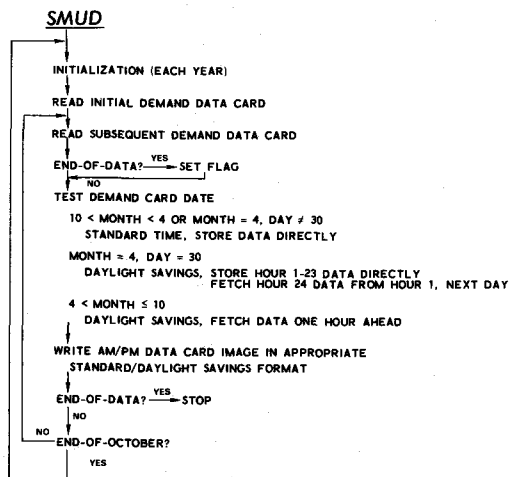
DETAILED FLOW



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Figure A-9. SCE Program Flow Charts (Sheet 2 of 2)

PROGRAM LOGIC



DETAILED FLOW

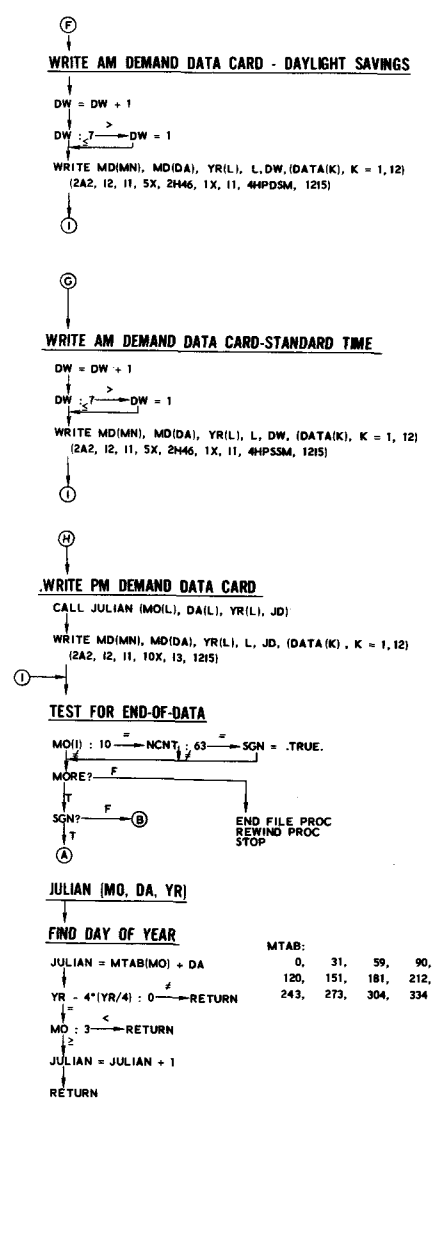
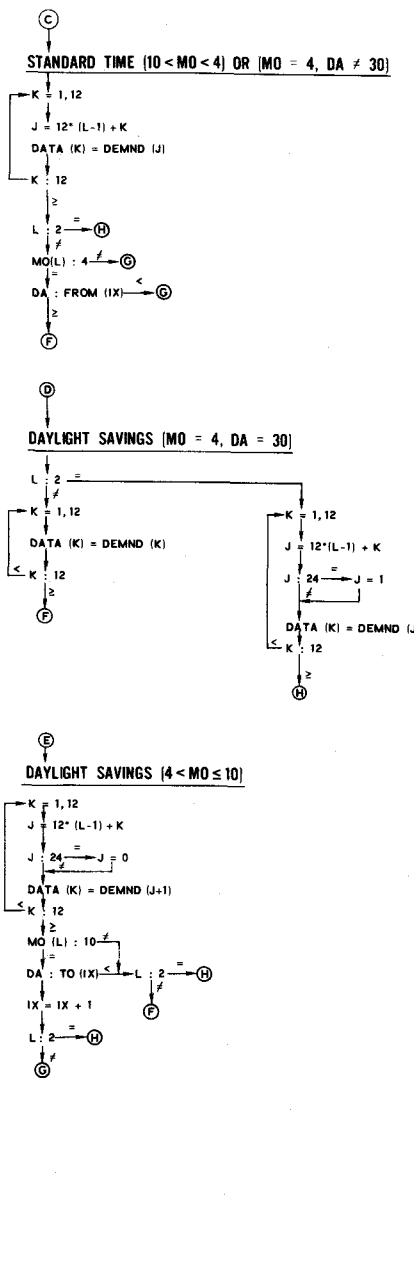
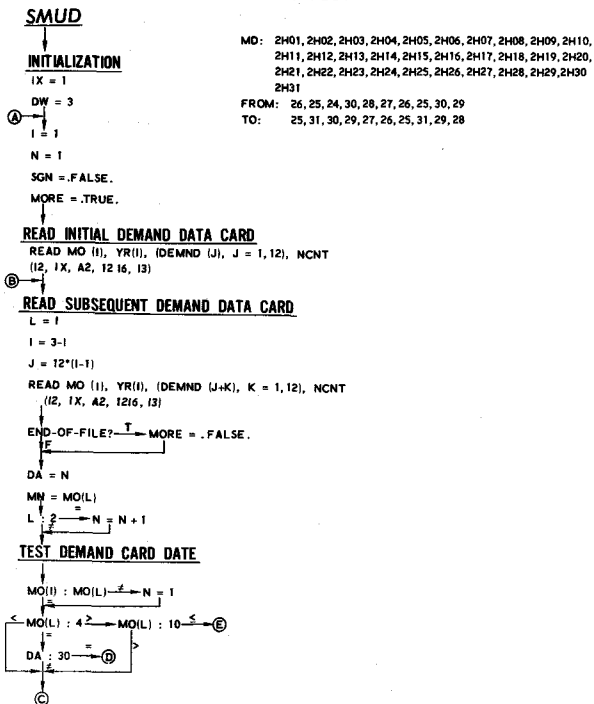
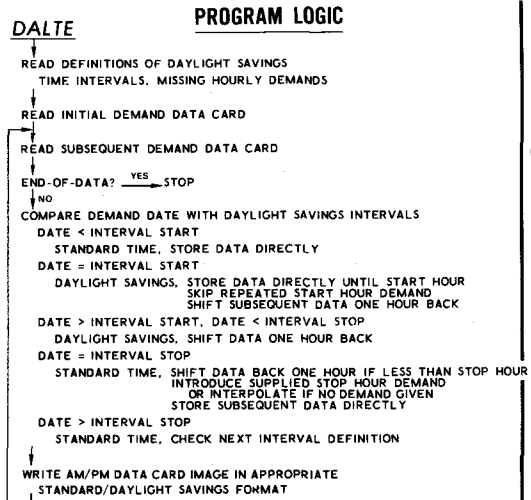


Figure A-10. SMUD Program Flow Charts



**DALTE DETAILED FLOW**

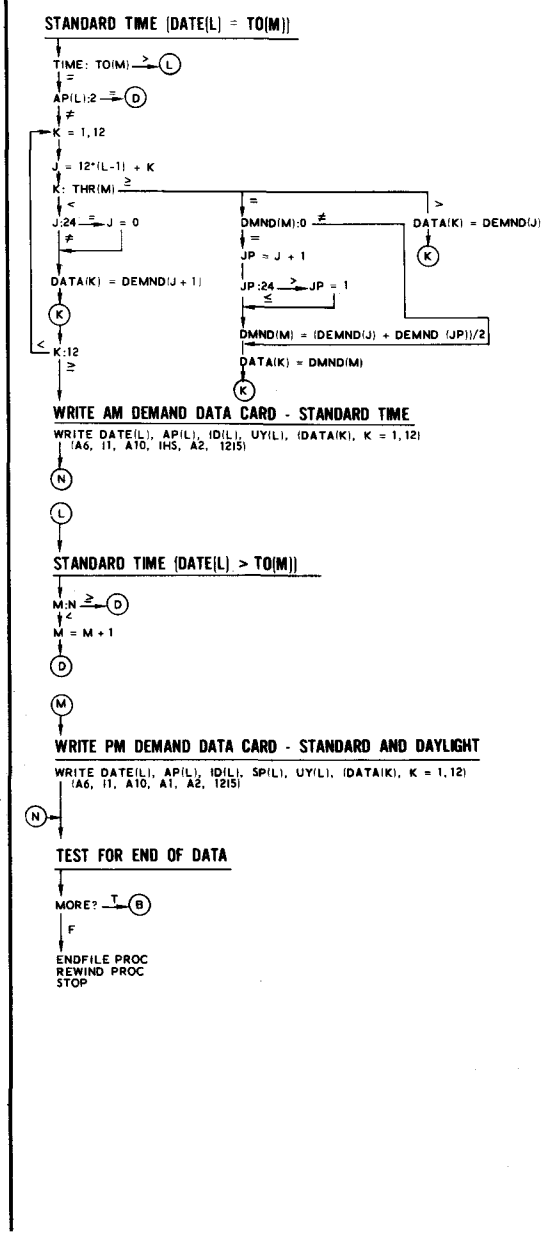
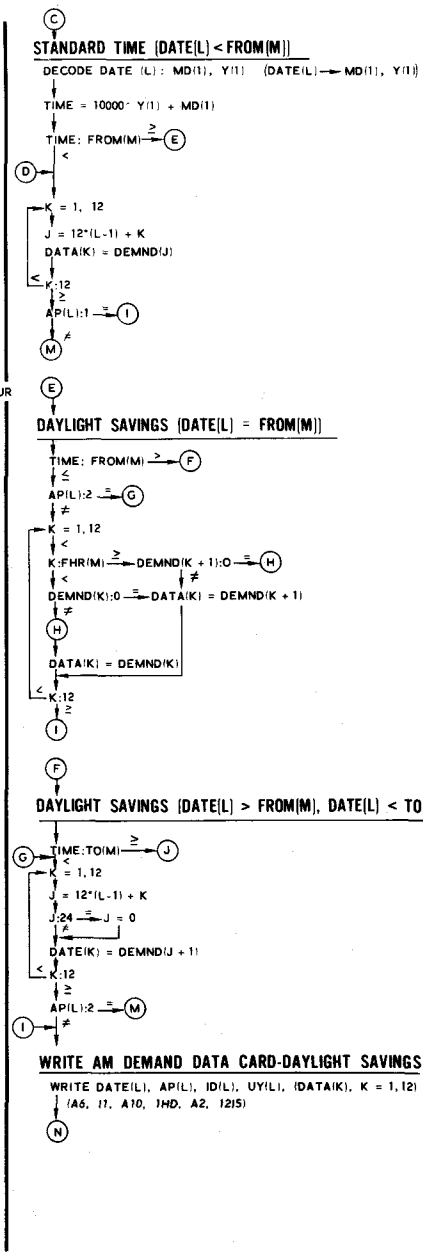
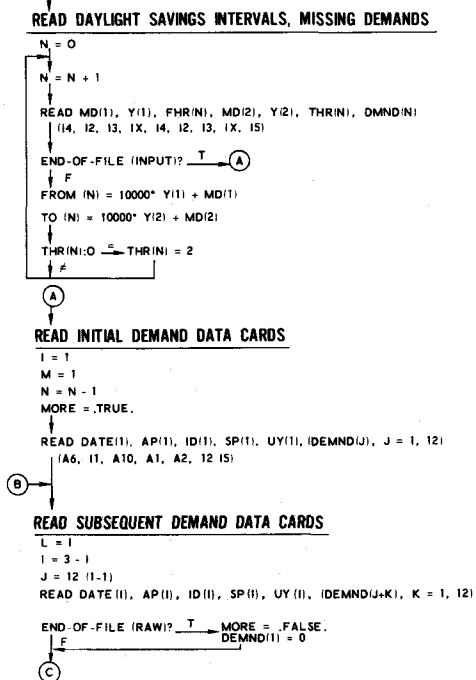
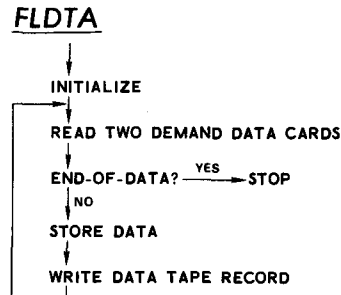


Figure A-11. DALTE Program Flow Charts

## PROGRAM LOGIC



## DETAILED FLOW

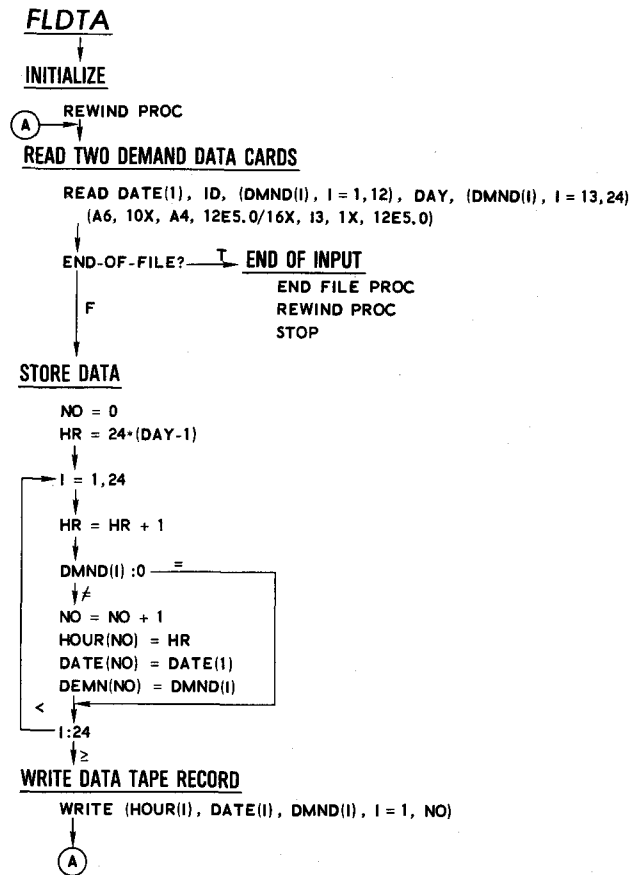


Figure A-12. FLDTA Program Flow Charts



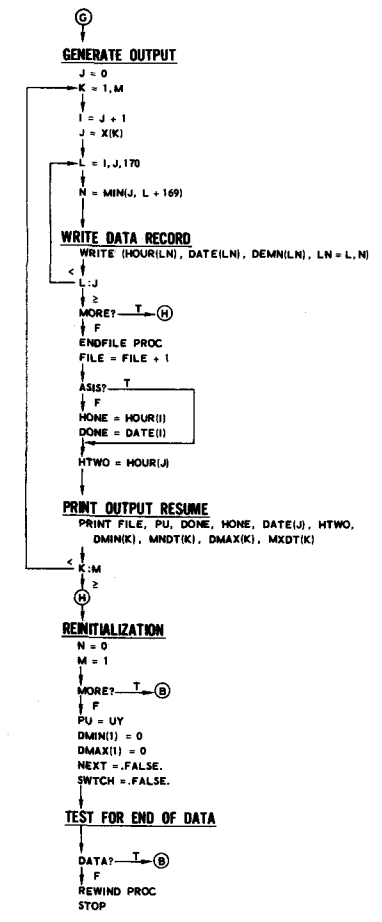
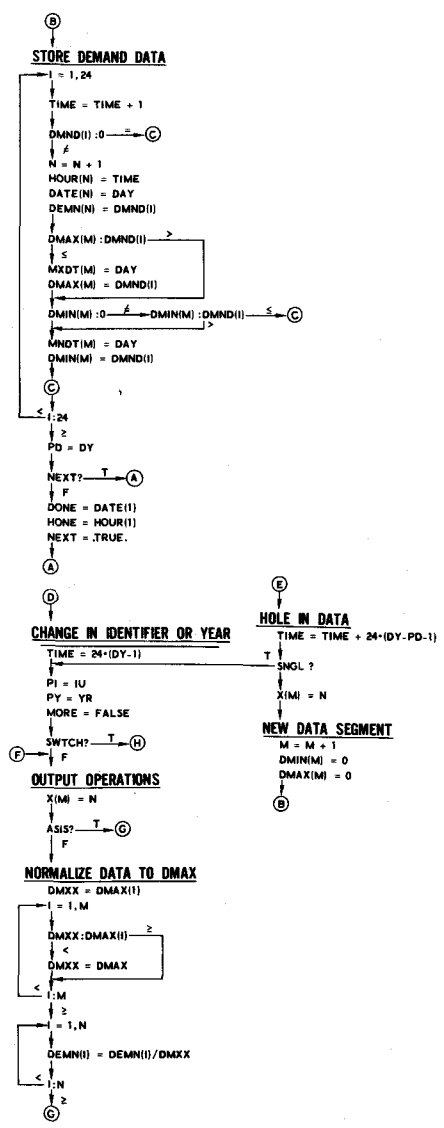
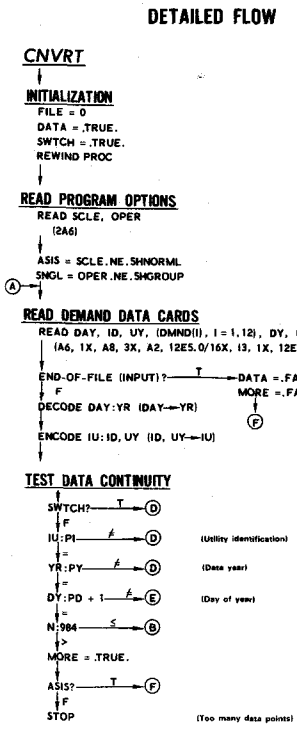
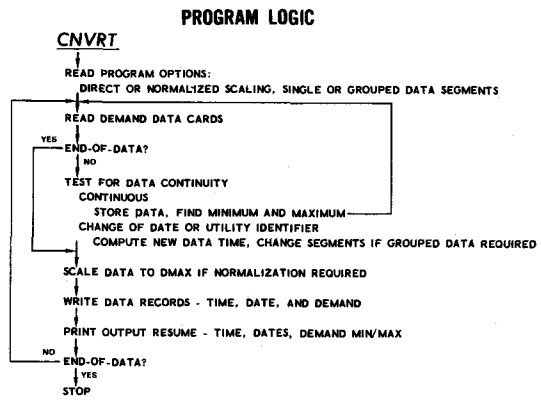


Figure A-13. CNVRT Program Flow Charts

```

PROGRAM DALTE(RAW,PROC,INPUT,OUTPUT,
*           TAPE1=RAW,TAPE2=PRCC,TAPE3=INPUT,TAPE4=OUTPUT)
C SHIFTS DEMAND DATA BASE TO COMPENSATE FOR DAYLIGHT SAVINGS TIME
C ** INTERPOLATION PROVIDED IF TO DEMND NOT GIVEN
C
C INTEGER      AP(2),      CARD(8),  DATA(12), DATE(2),  DEMND(24),
*             DMND(20),  FHR(20),  FROM(20), ID(2),   MD(2),
*             SP(2),    THR(20),  TIME,   TO(20),  UY(2);
C LOGICAL      Y(2)
C             MORE
C
C READ DAYLIGHT SAVINGS INTERVALS, MISSING DEMANDS
N=0
WRITE (4,410)
10 N=N+1
READ (3,420) MD(1),Y(1),FHR(N),MD(2),Y(2),THR(N),DMND(N)
IF (EOF,3) 20,15
15 IF (DMND(N).EQ.0) DMND(N)=0
WRITE (4,430) MD(1),Y(1),FHR(N),MD(2),Y(2),THR(N),DMND(N)
FROM(N)=10000*Y(1)+MD(1)
TO(N)=10000*Y(2)+MD(2)
IF (THR(N).EQ.0) THR(N)=2
GO TO 10
20 N=N-1
C
C READ *DECK CARD
READ (1,510) (CARD(I),I=1,8)
WRITE (2,510) (CARD(I),I=1,8)
C
C READ */COMMENT CARD
READ (1,510) (CARD(I),I=1,8)
WRITE (2,510) (CARD(I),I=1,8)
C
C READ DEMAND DATA
* INITIAL CARD
I=1
M=1
MORE=.TRUE.
READ (1,520) DATE(I),AP(I),ID(I),SP(I),UY(I),(DEMND(J),J=1,12)
C * SUBSEQUENT CARDS
30 L=I
I=3-I
J=12*(I-1)
READ (1,520) DATE(I),AP(I),ID(I),SP(I),UY(I),(DEMND(J+K),K=1,12)
IF (EOF,1) 40,50
C * END OF DATA
40 MORE=.FALSE.
DEMND(1)=0
C * DATE(L).LT.FROM(M) (STANDARD TIME)
50 DECODE (6,530,DATE(L)) MC(1),Y(1)
TIME=10000*Y(1)+MD(1)
IF (TIME.GE.FROM(M)) GO TO 80

```

```

60 DO 70 K=1,12
   J=12*(L-1)+K
70 DATA(K)=DEMND(J)
   IF (AP(L).EQ.1) GO TO 200
   GO TO 220
C   * DATE(L).EQ.FROM(M) (DAYLIGHT SAVINGS)
80 IF (TIME.GT.FROM(M)) GO TO 110
   IF (AP(L).EQ.2) GO TO 120
   DO 100 K=1,12
   IF (K.GE.FHR(M)) GO TO 90
   IF (DEMND(K).EQ.0) GO TO 95
85 DATA(K)=DEMND(K)
   GO TO 100
90 IF (DEMND(K+1).EQ.0) GO TO 85
95 DATA(K)=DEMND(K+1)
100 CONTINUE
   GO TO 140
C   * DATE(L).GT.FROM(M), DATE(L).LT.TO(M) (DAYLIGHT SAVINGS)
110 IF (TIME.GE.TO(M)) GO TO 150
120 DO 130 K=1,12
   J=12*(L-1)+K
   IF (J.EQ.24) J=0
130 DATA(K)=DEMND(J+1)
   IF (AP(L).EQ.2) GO TO 220
140 WRITE (2,540) DATE(L),AP(L),ID(L),UY(L),(DATA(K),K=1,12)
   GO TO 230
C   * DATE(L).EQ.TO(M) (STANDARD TIME)
150 IF (TIME.GT.TO(M)) GO TO 210
   IF (AP(L).EQ.2) GO TO 60
   DO 190 K=1,12
   J=12*(L-1)+K
160 IF (K-THR(M)) 160,170,180
   IF (J.EQ.24) J=0
   DATA(K)=DEMND(J+1)
   GO TO 190
170 IF (DMND(M).NE.0) GO TO 175
   JP=J+1
   IF (JP.GT.24) JP=1
   DMND(M)=FLOAT(DEMND(J)+DEMND(JP))/2+.5
175 DATA(K)=DMND(M)
   GO TO 190
180 DATA(K)=DEMND(J)
190 CONTINUE
200 WRITE (2,550) DATE(L),AP(L),ID(L),UY(L),(DATA(K),K=1,12)
   GO TO 230
C   * DATE(L).GT.TO(M) (STANDARD TIME)
210 IF (M.GE.N) GO TO 60
   M=M+1
   GO TO 60
C   * SECOND OUTPUT CARD (STANDARD AND DAYLIGHT)
220 WRITE (2,520) DATE(L),AP(L),ID(L),SP(L),UY(L),(DATA(K),K=1,12)
230 IF (MORE) GO TO 30

```

C

```
ENDFILE 2  
REWIND 2  
REWIND 1
```

C

```
410 FORMAT(1H1,35X,*- FROM -*,10X,*- - TO - -*/  
*27X,2(9X,*DATE*,2X,*HOUR*),4X,*LCAO*)  
420 FORMAT(2(I4,I2,I3,1X),I5)  
430 FORMAT(27X,2(7X,I4,I2,3X,I3),3X,I5)  
510 FORMAT(8A10)  
520 FORMAT(A6,I1,A10,A1,A2,12I5)  
530 FORMAT(I4,I2)  
540 FORMAT(A6,I1,A10,1HD,A2,12I5)  
550 FORMAT(A6,I1,A10,1HS,A2,12I5)  
END
```

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```

C      PROGRAM MODFY (RAW, PROC, OUTPUT, TAPE1=RAW, TAPE2=PRCC, TAPE3=OUTPUT)
C      MODIFY KEYPUNCHED LOAD DATA CARDS (EEI FCRMAT)
C      INTEGER          AP,          BDA,          BDW,          BM4,          BYR,
*      *              CARD(8),      COL,          DA,          DATE,          DMND(6),
*      *              DW,          DY,          PSA,          PYR,          UY,
*      *              YR,          ZONE
C      BASE DATE - FRIDAY, JANUARY 1, 1960
C      DATA          BDW          /6/,          BYR          /60/
C      INITIALIZE
C      PYR=0
C      BM4=(BYR+3)-4*((BYR+3)/4)
C      PROCESS INPUT DATA
C      REWIND 2
10     READ (1,510) (CARD(I),I=1,8)
      IF (ECF,1) GO TO 20
20     COL=MXIFT(CARD(1),6).AND.778
C      * CONTROL CARD
      IF (COL.NE.1R*) GO TO 30
      WRITE (2,510) (CARD(I),I=1,8)
      GO TO 10
C      * DATA CARD
30     DECODE (80,520,CARD(1)) DATE,AP,PSA,ZONE,UY,(DMND(I),I=1,6)
      DECODE (6,540,DATE) MC,DA,YR
      DY=JULIAN(MC,DA,YR)
      IF (YR.EQ.PYR) GO TO 40
      BDA=365*(YR-BYR)+((YR-BYR)+BM4)/4+BDW-2
      PYR=YR
40     IF (AP.EQ.2) GO TO 50
C      ** AM CARD
      DW=(BDA+DY)-7*((BDA+DY)/7)+1
      WRITE (2,530) DATE,AP,PSA,DW,ZONE,UY,(DMND(I),I=1,6)
      GO TO 10
C      ** PM CARD
50     WRITE (2,550) DATE,AP,DY,(DMND(I),I=1,6)
      GO TO 10
C      END OF DATA
60     ENDFILE 2
      REWIND 2
      STOP
C      510  FORMAT(8A10)
      520  FORMAT(A6,I1,5X,A2,2X,A1,1X,A2,6A10)
      530  FORMAT(A6,I1,5X,A2,1X,I1,A1,1X,A2,6A10)
      540  FORMAT(3I2)
      550  FORMAT(A6,I1,9X,I3,1X,6A10)
      END

```

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```

C      FUNCTION JULIAN(MO,DA,YR)
      INTEGER      DA,      MTAB(12), YR
      DATA      MTAB/0,      31,      59,      90,      120,
*      151,      181,      212,      243,      273,
*      304,      334/
C
      JULIAN=MTAB(MO)+DA
      IF ((YR-4*(YR/4).EQ.0).AND.(MO.GE.3)) JULIAN=JULIAN+1
      RETURN
      END

```

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```

PROGRAM FLDTA(RAW,PROC,INPUT,OUTPUT,
* TAPE1=RAW,TAPE2=PROC,TAPE3=INPUT,TAPE4=OUTPUT)
C CONVERT DEMAND FILE FROM CARD IMAGE TO FLOATING DECIMAL
C
C INTEGER          DATE(24),          DAY,          HR
C REAL            DEMN(24),          DMND(24),          HOUR(24)
C
C REWIND 2
C
10 READ (1,500) DATE(1),ID,(DMND(I),I=1,12),DAY,(DMND(I),I=13,24)
IF (ECF,1) 40,20
20 NO=0
HR=24*(DAY-1)
DO 30 I=1,24
HR=HR+1
IF (DMND(I).EQ.0.) GO TO 30
NO=NO+1
HOUR(NO)=HR
DATE(NO)=DATE(1)
DEMND(NO)=DMND(I)
30 CONTINUE
WRITE (2) (HOUR(I),DATE(I),DEMND(I),I=1,NO)
GO TO 10
C
40 ENDFILE 2
REWIND 2
STOP
C
500 FORMAT(A6,10X,A4,12E5.0/16X,I3,1X,12E5.0)
END

```

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```

PROGRAM CNVRT(RAW,PROC,INPUT,OUTPUT,
* TAPE1=RAW,TAPE2=PROC,TAPE3=INPUT,TAPE4=OUTPUT)
CONVERTS DEMAND DATA FROM CARD IMAGE TO FLOATING DECIMAL

```

C  
C

```

INTEGER      DATE(1008),      DAY,      DONE,
*            DY,              FILE,      HONE,
*            HTWO,           MNDT(10),   MXDT(10),
*            OPER,          PD,        PI,
*            PU,            PY,        SCLE,
*            X(10),        UY,        YR,
LOGICAL      ASIS,          DATA,   MORE,
*            NEXT,        SNGL,    SWITCH
REAL        DEMN(1008),     DMAX(10), DMIN(10),
*            DMND(24),     HOUR(1008)

```

C

```

FILE=0
REWIND 2
DATA=.TRUE.
SWTCH=.TRUE.

```

C  
C  
C

```

* READ PROGRAM OPTIONS
(SCLE - DIRCT/NORML), (OPER - SINGL/GRUP)
READ (3,3100) SCLE,OPER
ASIS=SCLE.NE.5HNORML
SNGL=OPER.NE.5HGROUP
WRITE (4,4100) SCLE,OPER

```

C

10  
20  
30

```

* READ DATA
READ (1,1100) DAY,ID,UY,(DMND(I),I=1,12),DY,(DMN((I),I=13,24)
IF (EOF,1) 20,30
DATA=.FALSE.
MORE=.FALSE.
GO TO 90
CECODE (6,9100,DAY) YR
ENCODE (10,9200,IU) ID,UY
IF (SWTCH) GO TO 60
IF (IU.NE.PI) GO TO 60
IF (YR.NE.PY) GO TO 60
IF (DY.NE.PD+1) GO TO 70
IF (N.LE.984) GO TO 40
MORE=.TRUE.
IF (ASIS) GO TO 90
** TOO MANY POINTS
WRITE (4,4200)
STOP

```

C

C  
C

40

```

* STORE DATA
DO 55 I=1,24
TIME=TIME+1.
IF (DMND(I).EQ.C.) GO TO 55
N=N+1
HOUR(N)=TIME

```

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```

DATE(N)=DAY
DEM(N)=DMND(I)
IF (DMAX(M).GT.DMND(I)) GO TO 45
MXDT(M)=DAY
DMAX(M)=DMND(I)
45 IF (DMIN(M).EQ.0) GO TO 50
IF (DMIN(M).LE.DMND(I)) GO TO 55
50 MNDT(M)=DAY
CMIN(M)=DMND(I)
55 CONTINUE
PD=DY
IF (NEXT) GO TO 10
DONE=DATE(1)
HONR=HOUR(1)
NEXT=.TRUE.
GO TO 10

C
C * CHANGE OF IDENTIFIER OR YEAR
60 TIME=24.*FLOAT(DY-1)
GO TO 80
C * HOLE IN DATA
70 TIME=TIME+24.*FLOAT(DY-PD-1)
IF (SNGL) GO TO 80
X(M)=N
M=M+1
CMIN(M)=0.
DMAX(M)=0.
GO TO 40
80 PI=IU
PY=YR
MORE=.FALSE.
IF (SWTCH) GO TO 150

C
C * OUTPUT OPERATIONS
90 X(M)=N
IF (ASIS) GO TO 120
** NORMALIZE TO DMAX
DMXX=DMAX(I)
DO 100 I=1,M
IF (DMXX.LT.DMAX(I)) DMXX=DMAX(I)
100 CONTINUE
DO 110 I=1,N
110 DEMN(I)=DEM(N)/DMXX
C ** GENERATE OUTPUT
120 J=0
DO 145 K=1,M
I=J+1
J=X(K)
DO 130 L=I,J,170
N=MIN0(J,L+169)
130 WRITE (2) (HOUR(LN),DATE(LN),DEM(LN),LN=L,N)
IF (MORE) GO TO 150

```

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```

ENDFILE 2
FILE=FILE+1
IF (ASIS) GO TO 140
HONE=HOUR(I)
DONE=DATE(I)
140 HTWO=HOUR(J)
WRITE (4,4300) FILE,PU,DONE,HONE,DATE(J),HTWO,
* DMIN(K),MNDT(K),DMAX(K),MXDT(K)
145 CONTINUE
C
C * INITIALIZATION
150 N=0
M=1
IF (MORE) GO TO 40
PU=UY
DMIN(1)=0.
DMAX(1)=0.
NEXT=.FALSE.
SWTCH=.FALSE.
IF (DATA) GO TO 40
REWIND 2
STOP
C
1100 FORMAT(A6,1X,A8,3X,A2,12E5.0/16X,I3,1X,12E5.0)
3100 FORMAT(2A6)
4100 FORMAT(*1*,32X,*DEMAND DATA - *,A5,* OUTPUT, *,A5,* FILES*/
*0*,20X,*TIME PERIOD*,4(3H -),20X,*DEMAND EXTREMES*,4(3H -)/
*3X,*FILE*,3X,*SYSTM*,8X,2(*DATE*,5X,*HOUR*,7X),1X,*MINIMUM*,
*6X,*DATE*,7X,*MAXIMUM*,6X,*DATE*)
4200 FORMAT(*TOO MANY DATA POINTS - JOB TERMINATED*)
4300 FORMAT(5X,I2,6X,A2,6X,2(A6,2X,I7,5X),1X,2(F9.2,4X,A6,5X))
9100 FORMAT(4X,I2)
9200 FORMAT(A8,A2)
END

```

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APPENDIX B  
DEMAND DATA ANALYSIS

# PROGRAM LOGIC

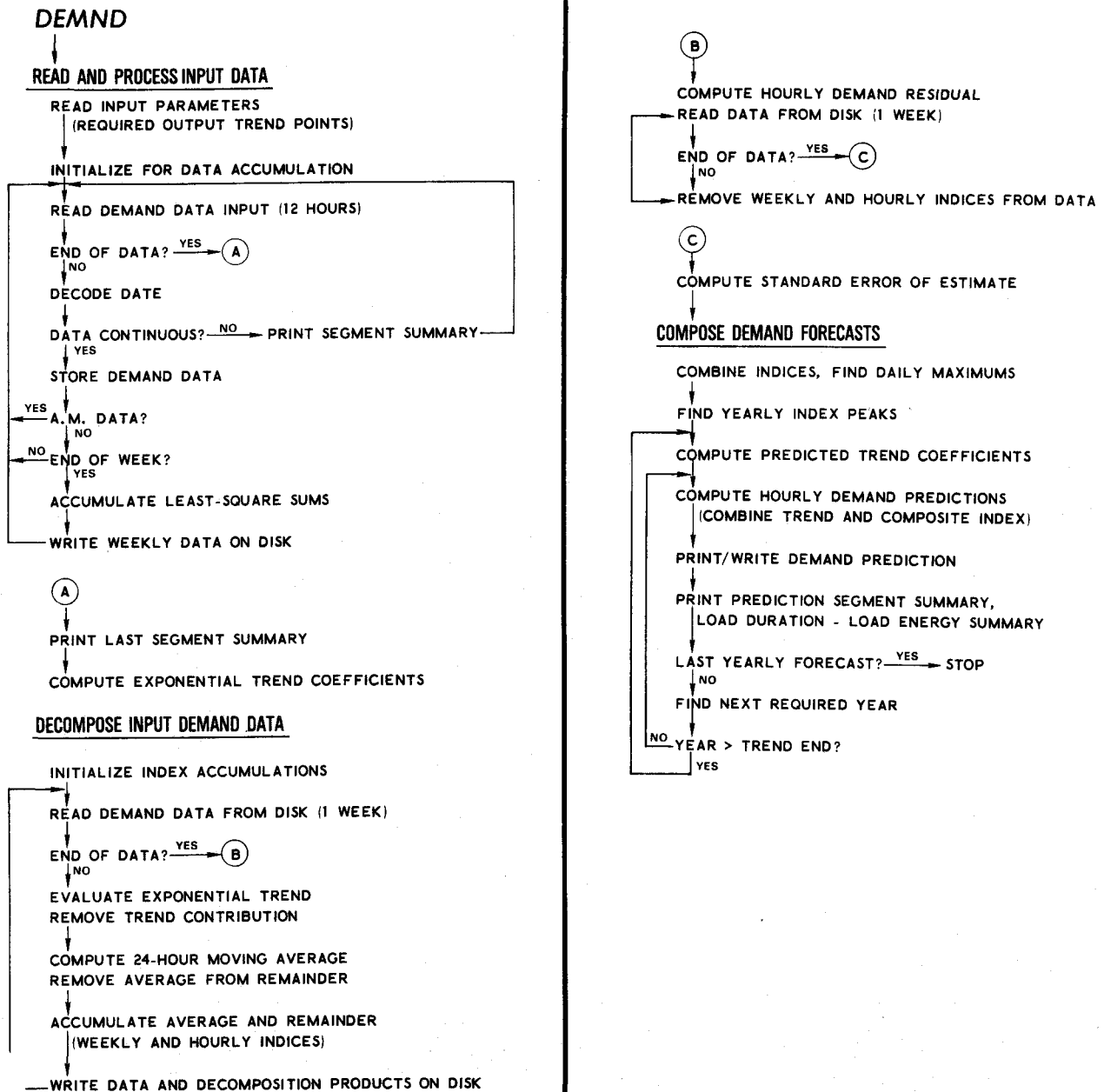
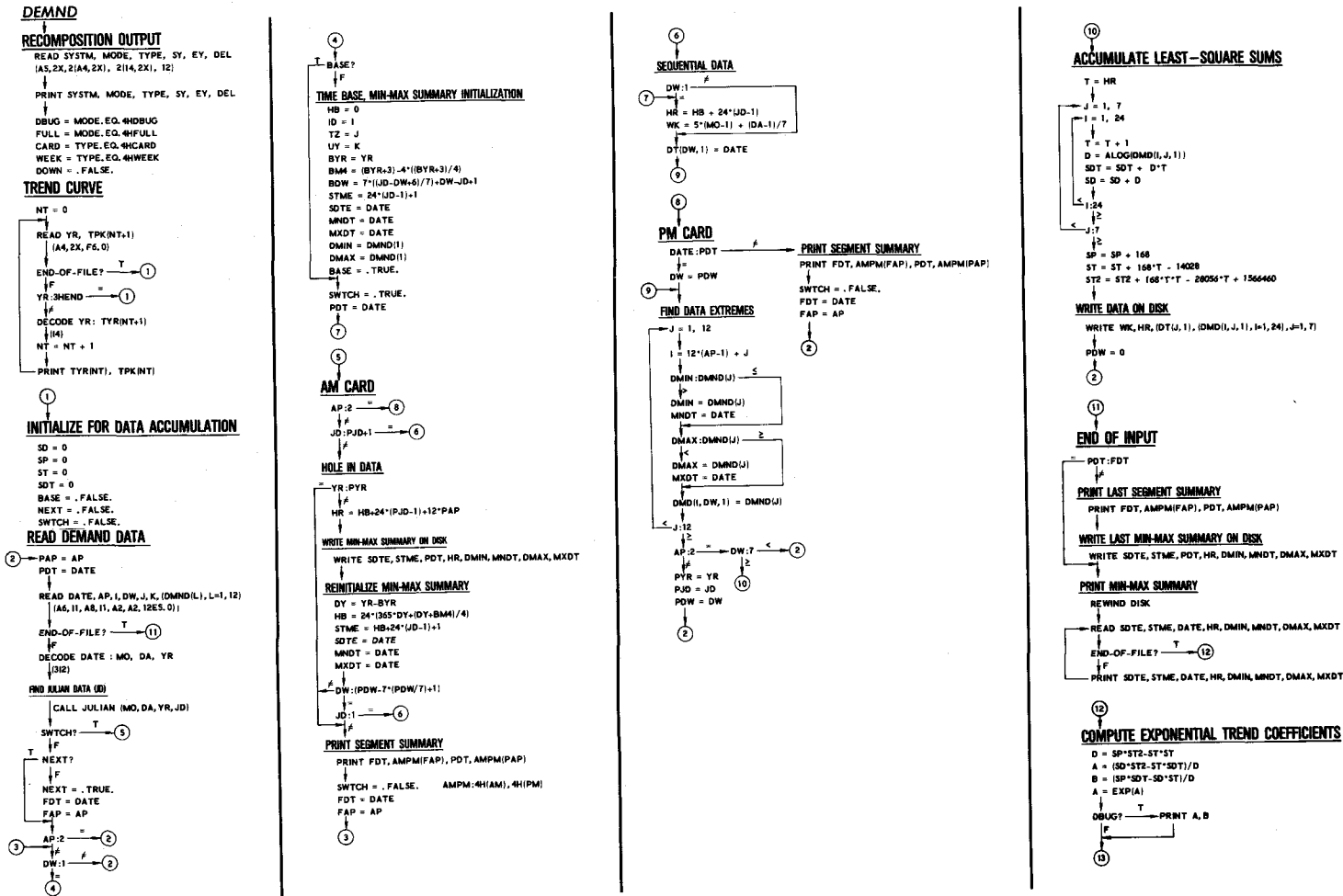


Figure B-1. DEMND Program Flow Charts (Sheet 1 of 5)

**DETAILED FLOW  
READ AND PROCESS INPUT DATA**



B-3

Figure B-1. DEMND Program Flow Charts (Sheet 2 of 5)

DETAILED FLOW  
DECOMPOSE INPUT DEMAND DATA

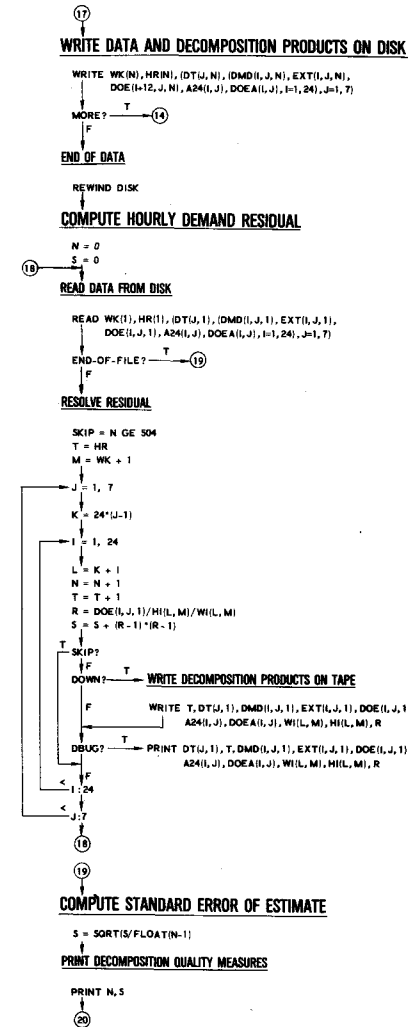
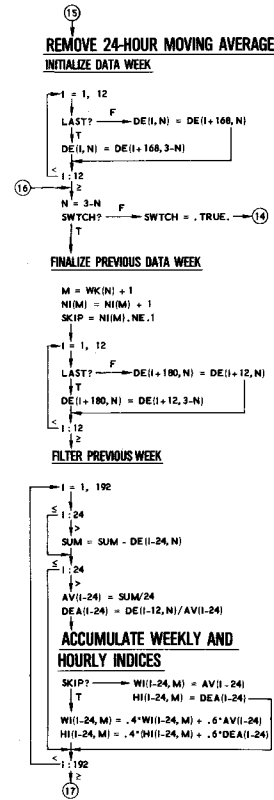
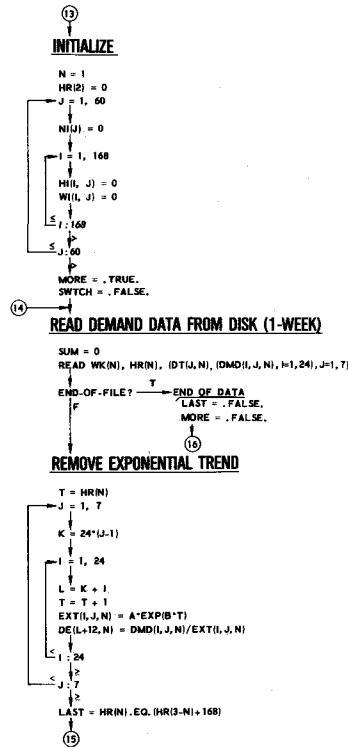
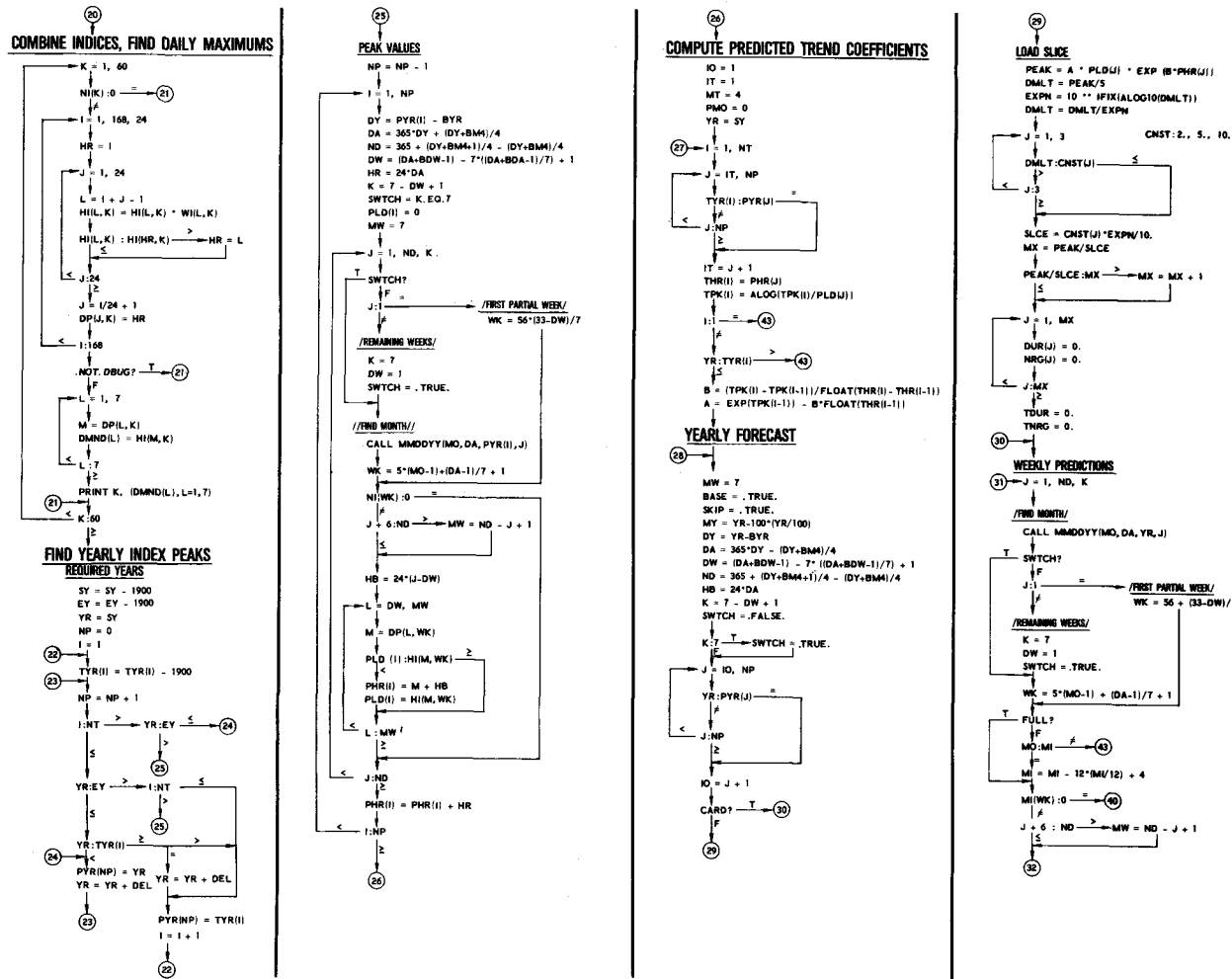


Figure B-1. DEMND Program Flow Charts (Sheet 3 of 5)

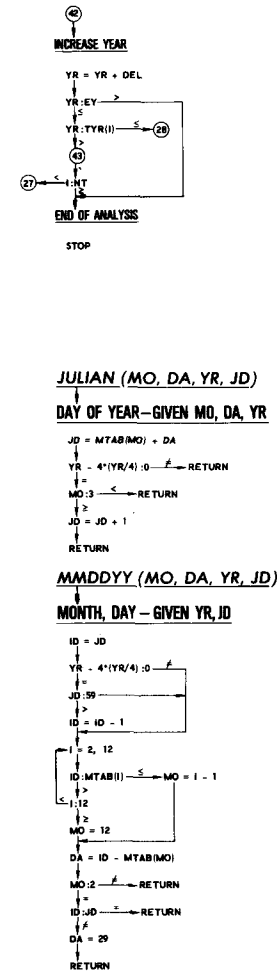
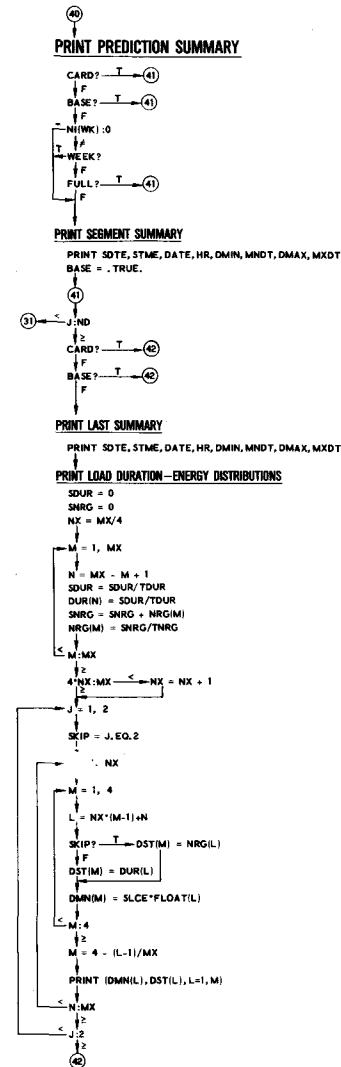
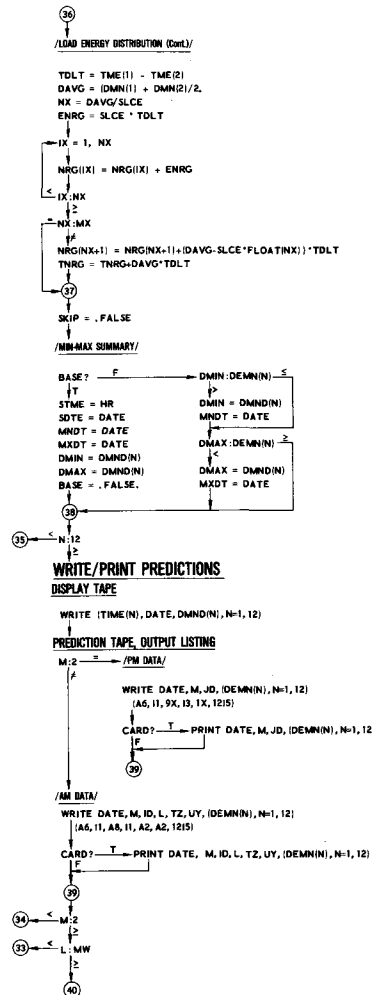
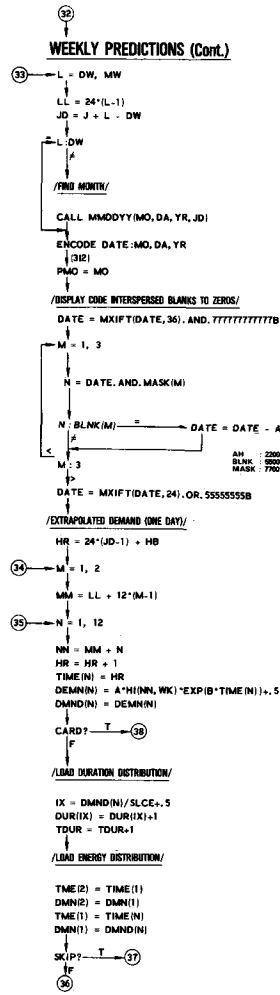
**DETAILED FLOW  
COMPOSE DEMAND FORECASTS**



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Figure B-1. DEMOND Program Flow Charts (Sheet 4 of 5)

**DETAILED FLOW  
COMPOSE DEMAND FORECASTS (Cont.)**



B-6

Figure B-1. DEMND Program Flow Charts (Sheet 5 of 5)



```

PROGRAM DEMND(LOAD,INPUT,DISP,PRED,OUTPUT,TAPE1=LOAD,TAPE2=INPUT,
* TAPE3=DISP,TAPE4=PRED,TAPE5=OUTPUT,TAPE6,TAPE7)

```

C

```

REAL
* A24(24,7), AV(168), CNST(3),
* DE(192,2), DEA(168), DMND(12),
* OMD(24,7,2), DMN(4), DOE(24,8,2),
* DOEA(24,7), DST(4), DUR(50),
* EXT(24,7,2), HI(168,60), NRG(50),
* PLO(30), TIME(12), TME(?),
* TPK(10), WI(168,60)
INTEGER
* AH(3), AMPM(2), AP,
* BDW, BLNK(3), BM4,
* BWK, BYR, CA,
* DATE, DEL, DEMN(12),
* DP(7,60), DS, DT(7,2),
* DW, DY, EY,
* FAF, FCT, HB,
* HR(2), MASK(3), NI(6),
* PAP, PDT, PDW,
* PJC, PHR(30), PMO,
* PYR(30), SDTE, STME,
* SY, SYSTM, THR(10),
* TYPE, TYR(10), TZ,
* UY, WK(?), YR
LOGICAL
* BASE, CARD, DEBUG,
* DOWN, FULL, LAST,
* MORE, NEXT, SKIP,
* SWITCH, WEEK
EQUIVALENCE
* (AV,A24), (DE,DCE), (DEA,DOEA),
* (DUR,A24), (NRG,DOE)
DATA
* AH /22008, 220000008, 2200000000008/,
* BLNK /55008, 550000008, 5500000000008/,
* MASK /77008, 770000008, 7700000000008/,
* CNST /2., 5., 10./,
* AMPM /4+(AM), 4H(FM)/

```

C  
C  
C

```

READ INPUT PARAMETERS
* RECOMPOSITION OUTPUT
READ (2,2010) SYSTM,MODE,TYPE,SY,EY,DEL
WRITE (5,5005) SYSTM,MODE,TYPE,SY,EY,DEL
DEBUG=MODE.EQ.4HDEBUG
FULL=MODE.EQ.4HFULL
CARD=TYPE.EQ.4HCARD
WEEK=TYPE.EQ.4HWEEK
DOWN=.FALSE.
* TREND CURVE

```

C

```

NT=0
5 READ (2,2020) YR,TPK(NT+1)
IF (EOF,2) 20,10
10 IF (YR.EQ.3HEND) GO TO 20
DECODE (4,2030,YR) TYR(NT+1)
NT=NT+1

```

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```

IF (NT.NE.1) GO TO 15
WRITE (5,5010) TYR(NT),TPK(NT)
GO TO 5
15 WRITE (5,5015) TYR(NT),TFK(NT)
GO TO 5

C
C
C
20 READ DEMAND DATA
* INITIALIZE
SD=0.
SP=0.
ST=0.
SDT=0.
ST2=0.
BASE=.FALSE.
NEXT=.FALSE.
SWTCH=.FALSE.
WRITE (5,5020)
SWTCH=.FALSE.
25 PAP=AP
PDT=DATE
READ (1,1010) DATE,AP,I,DW,J,K,(DMND(L),L=1,12)
IF (EOF,1) 110,30
30 CECODE (6,2040,DATE) MO,CA,YR
CALL JULIAN(MO,DA,YR,JD)
IF (SWTCH) GO TO 50
IF (NEXT) GO TO 35
NEXT=.TRUE.
PDT=DATE
FAP=AP
35 IF (AP.EQ.2) GO TO 25
40 IF (DW.NE.1) GO TO 25
IF (BASE) GO TO 45
HB=0
ID=I
TZ=J
UY=K
FYR=YR
BM4=(BYR+3)-4*((BYR+3)/4)
BOW=7*((JD-DW+6)/7)+DW-JD+1
STME=24*(JD-1)+1
SDTE=DATE
MNOT=DATE
MXDT=DATE
DMIN=DMND(1)
DMAX=DMND(1)
BASE=.TRUE.
45 SWTCH=.TRUE.
PDT=DATE
GO TO 65
C
50 * AM CARD **
IF (AP.EC.2) GO TO 75
IF (JD.EC.PJD+1) GO TO 60

```

B-8

```

C      ** HOLE IN DATA
      IF (YR.EG.PYR) GO TO 55
      HR=HB+24*(PJD-1)+12*PAP
      WRITE (7) SCTE,STME,PDT,HR(1),DMIN,MNDT,CMAX,MXDT
      DY=YR-BYR
      HB=24*(365*DY+(DY+BM4)/4)
      STME=HB+24*(JC-1)+1
      SDTE=DATE
      MNDT=DATE
      MXDT=DATE
      DMIN=DMND(1)
      CMAX=DMND(1)
      IF (DW.NE.(PDW-7*(PDW/7)+1)) GO TO 55
      IF (JD.EG.1) GO TO 60
55     WRITE (5,5025) FCT,AMPM(FAP),PDT,AMPM(PAP)
      SWITCH=.FALSE.
      FDT=DATE
      FAP=AP
      GO TO 40
C      ** SEQUENTIAL DATA
60     IF (DW.NE.1) GO TO 70
65     HR=HB+24*(JC-1)
      WK=5*(MO-1)+(DA-1)/7
70     CT(DW,1)=DATE
      GO TO 85
C      * PM CARD *
75     IF (DATE.EG.PDT) GO TO 80
      WRITE (5,5025) FCT,AMPM(FAP),PDT,AMPM(PAP)
      SWITCH=.FALSE.
      FDT=DATE
      FAP=AP
      GO TO 25
80     DW=PDW
85     DO 95 J=1,12
      I=12*(AP-1)+J
      IF (DMIN.LE.DMND(J)) GO TO 90
      DMIN=DMND(J)
      MNDT=DATE
90     IF (DMAX.GE.DMND(J)) GO TO 95
      CMAX=DMND(J)
      MXDT=DATE
95     DMD(I,DW,1)=DMND(J)
      IF (AP.EG.2) GO TO 100
      PYR=YR
      PJD=JD
      PDW=DW
      GO TO 25
C
C      COMPLETE WEEK, FORM LEAST-SQUARES SUMS
100    IF (DW.LT.7) GO TO 25
      T=HR
      DO 105 J=1,7

```

```

DO 105 I=1,24
T=T+1.
D=ALOG(DMD(I,J,1))
105 SDT=SDT+D*T
SD=SD+D
SP=SP+168.
ST=ST+168.*T-14028.
ST2=ST2+168.*T*T-28056.*T+1566460.
WRITE (6) WK(1),HR(1),(DT(J,1),(DMD(I,J,1),I=1,24),J=1,7)
PDW=0
GO TO 25
C * END OF DATA
110 IF (PDT.EQ.FDT) GO TO 115
WRITE (5,5025) FDT,AMPM(FAP),PDT,AMPM(PAP)
WRITE (7) SDTE,STME,PDT,HR(1),DMIN,MNDT,DMAX,MXDT
115 ENDFILE 6
ENDFILE 7
REWIND 6
REWIND 7
C ** MIN-MAX SUMMARY
WRITE (5,5030)
120 READ (7) SDTE,STME,DATE,HR(1),DMIN,MNDT,CMAX,MXDT
IF (EOF,7) 130,125
125 WRITE (5,5035) SDTE,STME,DATE,HR(1),DMIN,MNDT,DMAX,MXDT
GO TO 120
130 REWIND 7
C
C COMPUTE EXPONENTIAL TREND COEFFICIENTS
C=SP*ST2-ST*ST
A=(SD*ST2-ST*SDT)/D
B=(SP*SDT-SC*ST)/D
A=EXP(A)
IF (DBUG) WRITE (5,5040) A,B
C
C DECOMPOSE INPUT DEMAND DATA
C * INITIALIZE
N=1
HR(2)=0
DO 140 J=1,60
NI(J)=0
DO 140 I=1,168
140 HI(I,J)=0.
WI(I,J)=0.
MORE=.TRUE.
SWTCH=.FALSE.
C * READ ONE WEEK OF DATA
145 SUM=0.
READ (6) WK(N),HR(N),(DT(J,N),(DMD(I,J,N),I=1,24),J=1,7)
IF (EOF,6) 150,155
C * COMPUTE EXPONENTIAL AND 24-HOUR MOVING AVERAGE
150 LAST=.FALSE.
MORE=.FALSE.

```

```

155 GO TO 175
    I=HR(N)
    DO 160 J=1,7
      K=24*(J-1)
      DO 160 I=1,24
        L=K+I
        T=T+1.
        EXT(I,J,N)=A*EXP(B*T)
160 DE(L+12,N)=DMD(I,J,N)/EXT(I,J,N)
    LAST=HR(N).EQ.(HR(3-N)+168)
C    ** INITIALIZE DATA WEEK
    DO 170 I=1,12
      IF (LAST) GO TO 165
      DE(I,N)=DE(I+168,N)
      GO TO 170
165 DE(I,N)=DE(I+168,3-N)
170 CONTINUE
175 N=3-N
    IF (SWTCH) GO TO 180
    SWTCH=.TRUE.
    GO TO 145
C    ** FINALIZE PREVIOUS DATA WEEK
180 M=WK(N)+1
    NI(M)=NI(M)+1
    SKIP=NI(M).NE.1
    DO 190 I=1,12
      IF (LAST) GO TO 185
      DE(I+180,N)=DE(I+12,N)
      GO TO 190
185 DE(I+180,N)=DE(I+12,3-N)
190 CONTINUE
C    ** FILTER PREVIOUS WEEK
    DO 205 I=1,192
      IF (I.LE.24) GO TO 195
      SUM=SUM-DE(I-24,N)
195 SUM=SUM+DE(I,N)
      IF (I.LE.24) GO TO 205
      AV(I-24)=SUM/24.
      DEA(I-24)=DE(I-12,N)/AV(I-24)
C    ** INDEX ACCUMULATIONS
      IF (SKIP) GO TO 200
      HI(I-24,M)=CEA(I-24)
      WI(I-24,M)=AV(I-24)
      GO TO 205
200 HI(I-24,M)=.4*HI(I-24,M)+.6*DEA(I-24)
      WI(I-24,M)=.4*WI(I-24,M)+.6*AV(I-24)
205 CONTINUE
      WRITE (7) WK(N),HR(N),(DT(J,N),(DMD(I,J,N),EXT(I,J,N),
*      DCE(I+12,J,N),A24(I,J),DOEA(I,J),I=1,24),J=1,7)
      IF (MORE) GO TO 145
C    * END OF DATA
      ENDFILE 7

```

```

REWIND 7
C
C AVERAGE WEEKLY AND HOURLY INDICES
N=0
S=0
IF (DEBUG) WRITE (5,5045)
* READ ONE WEEK OF DATA
C 220 READ (7) WK(1),HR(1),(DT(J,1),(DMD(I,J,1),EXT(I,,1),
* DOE(I,J,1),A24(I,J),DOEA(I,J),I=1,24),J=1,7)
C 230 IF (EOF,7) 250,230
* RESIDUAL IRREGULARITIES
SKIP=N.GE.504
T=HR
M=WK+1
DO 240 J=1,7
K=24*(J-1)
DO 240 I=1,24
L=K+I
N=N+1
T=T+1.
R=DOE(I,J,1)/HI(L,M)/WI(L,M)
S=S+(R-1.)*(R-1.)
IF (SKIP) GO TO 240
IF (DOWN) WRITE (3) T,DT(J,1),DMD(I,J,1),EXT(I,J,1),
* DOE(I,J,1),A24(I,J),DOEA(I,J),WI(L,M),HI(L,M),R
IF (DEBUG) WRITE (5,5050) DT(J,1),T,DMD(I,J,1),EXT(I,J,1),
* DOE(I,J,1),A24(I,J),COEA(I,J),WI(L,M),HI(L,M),R
240 CONTINUE
GO TO 220
250 IF (DOWN) ENDFILE 3
S=SQR(S/FLCAT(N-1))
WRITE (5,5060) N,S
C
C COMBINE INDICES, FIND DAILY MAXIMUMS
255 DO 270 K=1,60
IF (NI(K).EQ.0) GO TO 270
IF (DEBUG) WRITE (5,5070)
DO 265 I=1,168,24
HR=I
DO 260 J=1,24
L=I+J-1
HI(L,K)=HI(L,K)*WI(L,K)
IF (HI(L,K).GT.HI(HR,K)) HR=L
260 CONTINUE
J=I/24+1
DP(J,K)=HR
265 CONTINUE
IF (.NOT.DEBUG) GO TO 270
DO 267 L=1,7
M=DP(L,K)
267 DMND(L)=HI(M,K)
WRITE (5,5080) K,(DMND(L),L=1,7)

```

```

270 CONTINUE
C
C FIND YEARLY INDEX PEAKS
C * REQUIRED YEARS
SY=SY-1900
EY=EY-1900
YR=SY
NP=0
I=1
280 TYR(I)=TYR(I)-1900
290 NP=NP+1
IF (I.GT.NT) GO TO 310
IF (YR.GT.EY) GO TO 330
IF (YR-TYR(I)) 320,300,340
300 YR=YR+DEL
GO TO 340
310 IF (YR.GT.EY) GO TO 350
320 PYR(NP)=YR
YR=YR+DEL
GO TO 290
330 IF (I.GT.NT) GO TO 350
340 PYR(NP)=TYR(I)
I=I+1
GO TO 280
350 NP=NP-1
C * PEAK VALUES
DO 410 I=1,NP
CY=PYR(I)-BYR
DA=365*CY+(CY+BM4)/4
ND=365+(CY+BM4+1)/4-(CY+BM4)/4
DW=(DA+80W-1)-7*((DA+80W-1)/7)+1
HR=24*DA
K=7-DW+1
SWTCH=K.EQ.7
PLD(I)=0.
MW=7
DO 400 J=1,ND,K
IF (SWTCH) GO TO 370
IF (J.NE.1) GO TO 360
C ** FIRST PARTIAL WEEK
WK=56+(33-DW)/7
GO TO 380
C ** REMAINING WEEKS
360 K=7
DW=1
SWTCH=.TRUE.
370 CALL MMDDYY(MO,DA,PYR(I),J)
WK=5*(MO-1)+(DA-1)/7+1
380 IF (NI(WK).EQ.0) GO TO 400
IF (J+6.GT.ND) MW=ND-J+1
HB=24*(J-DW)
DO 390 L=DW,MW

```

```

M=DP(L,WK)
IF (PLD(I).GE.HI(M,WK)) GO TO 390
FHR(I)=M+HB
PLD(I)=HI(M,WK)
390 CONTINUE
400 CONTINUE
410 PHR(I)=PHR(I)+HR

C
C COMPOSE DEMAND FORECASTS
IO=1
IT=1
MI=4
PMO=0
YR=SY
IF (CARD) WRITE (5,5090)
IF (.NOT.CARD) WRITE (5,5100)
C * TREND EXPONENTIAL COEFFICIENTS
DO 660 I=1,NT
DO 420 J=IT,NP
IF (TYR(I).EQ.PYR(J)) GO TO 430
420 CONTINUE
430 IT=J+1
THR(I)=PHR(J)
TPK(I)=ALOG(TPK(I)/PLD(J))
IF (I.EQ.1) GO TO 660
IF (YR.GT.TYR(I)) GO TO 660
B=(TPK(I)-TPK(I-1))/FLCAT(THR(I)-THR(I-1))
A=EXP(TPK(I-1)-B*FLOAT(THR(I-1)))
C * YEARLY FORECAST
440 MW=7
BASE=.TRUE.
SKIP=.TRUE.
MY=YR-100*(YR/100)
DY=YR-8YR
DA=365*DY+(DY+8M4)/4
DW=(DA+80W-1)-7*((DA+80W-1)/7)+1
ND=365+(DY+8M4+1)/4-(DY+8M4)/4
HB=24*DA
K=7-DW+1
SWTCH=.FALSE.
IF (K.EQ.7) SWTCH=.FALSE.
DO 445 J=IO,NP
IF (YR.EQ.PYR(J)) GO TO 450
445 CONTINUE
450 IO=J+1
IF (CARD) GO TO 470
C ** LOAD SLICE
PEAK=A*PLD(J)*EXP(B*PHR(J))
DMLT=PEAK/5.
EXPN=10.**IFIX(ALOG10(DMLT))
DMLT=DMLT/EXPN
DO 455 J=1,3

```



```

IF (DMLT.LE.CNST(J)) GO TO 460
455 CONTINUE
460 SLCE=CNST(J)*EXPN/10.
MX=PEAK/SLCE
IF (PEAK/SLCE.GT.FLOAT(MX)) MX=M)+1
DO 465 J=1,MX
465 DUR(J)=0.
NRG(J)=0.
TDUR=0.
TNRG=0.
C ** WEEKLY PREDICTIONS
WRITE (5,5110)
470 CO 610 J=1,ND,K
CALL MMDDYY(MO,DA,YR,J)
IF (SWTCH) GO TO 480
IF (J.NE.1) GO TO 475
C ** FIRST PARTIAL WEEK
WK=56+(33-DW)/7
GO TO 490
C ** REMAINING WEEKS
475 K=7
DW=1
SWTCH=.TRUE.
480 WK=5*(MO-1)+(DA-1)/7+1
490 IF (FULL) GO TO 500
IF (MO.NE.MI) GO TO 660
MI=MI-12*(MI/12)+4
500 IF (NI(WK).EQ.0) GO TO 590
IF (J+6.GT.ND) MW=ND-J+1
DO 580 L=DW,MW
LL=24*(L-1)
JD=J+L-DW
IF (L.EQ.DW) GO TO 510
CALL MMDDYY(MO,DA,YR,JD)
510 IF ((CARD.OR.WEEK).AND.(MO.NE.PMC)) WRITE (5,5070)
ENCODE (6,2040,DATE) MO,DA,MY
PMC=MC
C *** DISPLAY CODE INTERSPERSED BLANKS TO ZEROS
DATE=MXIFT(DATE,36).AND.777777777777B
DO 520 M=1,3
N=DATE.AND.MASK(M)
IF (N.EQ.BLNK(M)) DATE=DATE-AH(M)
520 CONTINUE
DATE=MXIFT(DATE,24).OR.55555555B
C *** EXTRAPOLATED DEMAND
HR=24*(JD-1)+HB
CO 570 M=1,2
MM=LL+12*(M-1)
DO 550 N=1,12
NN=MM+N
HR=HR+1
TIME(N)=HR

```

```

DEMND(N) = A*HI(NN,WK)*EXP(B*TIME(N))+.5
DMND(N) = DEMND(N)
IF (CARD) GO TO 550
C *** / LOAD DURATION
IX = DMND(N) / SLCE + .5
DUR(IX) = DUR(IX) + 1.
TOUR = TOUR + 1.
C *** / LOAD ENERGY
TME(2) = TME(1)
DMN(2) = DMN(1)
TME(1) = TIME(N)
DMN(1) = DMND(N)
IF (SKIP) GO TO 530
TOLT = TME(1) - TME(2)
DAVG = (DMN(1) + DMN(2)) / 2.
NX = DAVG / SLCE
ENRG = SLCE * TOLT
DO 525 IX = 1, NX
525 NRG(IX) = NRG(IX) + ENRG
IF (NX.EQ.MX) GO TO 530
NRG(NX+1) = NRG(NX+1) + (DAVG - SLCE * FLOAT(NX)) * TOLT
TNRG = TNRG + DAVG * TOLT
530 SKIP = .FALSE.
C *** / MIN-MAX SUMMARY
IF (BASE) GO TO 540
IF (DMIN.LE.DEMND(N)) GO TO 535
DMIN = DMND(N)
MNDT = DATE
535 IF (DMAX.GE.DEMND(N)) GO TO 550
DMAX = DMND(N)
MXDT = DATE
GO TO 550
540 STME = HR
SOTE = DATE
MNDT = DATE
MXDT = DATE
DMIN = DMND(N)
DMAX = DMND(N)
BASE = .FALSE.
550 CONTINUE
WRITE (3) (TIME(N), DATE, DMND(N), N=1, 12)
IF (M.EQ.2) GO TO 560
C *** / AM CARD
WRITE (4, 4010) DATE, M, IO, L, TZ, UY, (DEMND(N), N=1, 12)
IF (CARD) WRITE (5, 5120) DATE, M, IO, L, TZ, UY, (DEMND(N), N=1, 12)
GO TO 570
C *** / PM CARD
560 WRITE (4, 4020) DATE, M, JO, (DEMND(N), N=1, 12)
IF (CARD) WRITE (5, 5130) DATE, M, JO, (DEMND(N), N=1, 12)
570 CONTINUE
580 CONTINUE
590 IF (CARD) GO TO 610

```

```

IF (BASE) GO TO 610
IF (NI(MK).EQ.0) GO TO 600
IF (WEEK) GO TO 600
IF (FULL) GO TO 610
600 WRITE (5,5140) SCTE,STME,DATE,HR(1),DMIN,MNOT,DMAX,MXDT
    BASE=.TRUE.
610 CONTINUE
    IF (CARD) GO TO 650
    IF (BASE) GO TO 650
    WRITE (5,5140) SCTE,STME,DATE,HR(1),DMIN,MNOT,DMAX,MXDT
C    ***/ LOAD FACTOR, TOTAL ENERGY
    FCTR=TNRG/TCUR/PEAK
C    WRITE (5,5150) FCTR,TNRG
    ***/ LOAD DURATION-ENERGY
    SDUR=0.
    SNRG=0.
    NX=MX/4
    DO 615 M=1,MX
    N=MX-M+1
    SDUR=SDUR+DUR(N)
    DUR(N)=SDUR/TCUR
    SNRG=SNRG+NRG(M)
615   NRG(M)=SNRG/TNRG
    IF (4*NX.LT.MX) NX=NX+1
    DO 645 J=1,2
    SKIP=J.EQ.2
    IF (SKIP) GO TO 620
    WRITE (5,5160)
    GO TO 625
620   WRITE (5,5170)
625   DO 640 N=1,NX
    DO 635 M=1,4
    L=NX+(M-1)+N
    IF (SKIP) GO TO 630
    DST(M)=DUR(L)
    GO TO 635
630   DST(M)=NRG(L)
635   DMN(M)=SLCE*FLCAT(L)
    M=4-(L-1)/MX
640   WRITE (5,5180) (DMN(L),DST(L),L=1,M)
645   CONTINUE
C    ** INCREASE YEAR
650   YR=YR+DEL
    IF (YR.GT.EY) GO TO 670
    IF (YR.LE.TYR(I)) GO TO 440
660   CONTINUE
C
C    END OF ANALYSIS
670   ENDFILE 3
    ENDFILE 4
    REWIND 3
    REWIND 4

```

B-17

STOP

C

```
1010 FORMAT(A6,I1,A8,I1,A2,A2,12E5.0)
2010 FORMAT(A5,2X,2(A4,2X),2(I4,2X),I2)
2020 FORMAT(A4,2X,F6.0)
2030 FORMAT(I4)
2040 FORMAT(3I2)
4010 FORMAT(A6,I1,A8,I1,A2,A2,12I5)
4020 FORMAT(A6,I1,9X,I3,1X,12I5)
5005 FORMAT(*1/*0DEMAND FORECAST*/*0*,10X,*SYSTEM - *,A5/
**0INPUT SUMMARY --*/*0*,10X,*OUTPUT MODE - *,A4,4X,
**TYPE - *,A4,4X,*SY = *,I4,4X,*EY = *,I4,4X,*DEL = *,I2)
5010 FORMAT(*0*,10X,*TREND -*/16X,*TYR = *,I4,4X,*TPK = *,F6.0)
5015 FORMAT(23X,I4,10X,F6.0)
5020 FORMAT(*0*,10X,*DEMAND TIME SPANS -*/)
5025 FORMAT(16X,A6,1X,A4,* TO *,A6,1X,A4)
5030 FORMAT(*0*,10X,*DEMAND EXTREMES -*/
**0*,15X,*TIME PERIOD*,4(3H -),19X,*DEMAND INPUT*,4(3H -)/
*16X,2(2X,*DATE*,5X,*HOUR*,5X),2X,*MINIMUM*,5X,*DATE*,6X,
**MAXIMUM*,5X,*DATE*)
5035 FORMAT(16X,2(A6,2X,I7,5X),2(F9.2,3X,A6,4X))
5040 FORMAT(*1A = *,E13.7,7X,*B = *,E13.7/)
5045 FORMAT(*0*,4X,*DI*,12X,*T*,10X,*DMO*,10X,*EXT*,10X,*DOE*,
*10X,*A24*,9X,*DOEA*,11X,*WI*,11X,*HI*,12X,*R*)
5050 FORMAT(1X,A6,10E13.7)
5060 FORMAT(*0*,10X,*DECOMPOSITION -*/16X,*N = *,I7,5X,*S = *,E13.7)
5070 FORMAT(1X)
5080 FORMAT(1X,I2,7E15.7)
5090 FORMAT(1H1)
5100 FORMAT(*0OUTPUT SUMMARY --*)
5110 FORMAT(*0*,10X,*DEMAND EXTREMES -*/
**0*,15X,*TIME PERIOD*,4(3H -),19X,*DEMAND FORECAST*,4(3H -)/
*16X,2(2X,*DATE*,5X,*HOUR*,5X),2X,*MINIMUM*,5X,*DATE*,6X,
**MAXIMUM*,5X,*DATE*)
5120 FORMAT(13X,A6,I1,A8,I1,A2,A2,12I6)
5130 FORMAT(13X,A6,I1,9X,I3,1X,12I6)
5140 FORMAT(16X,2(A6,2X,I7,5X),2(F9.2,3X,A6,4X))
5150 FORMAT(*0*,10X,*LOAD FACTOR*,E14.7,21X,*TOTAL ENERGY*,E14.7)
5160 FORMAT(*0*,10X,*LOAD DURATION (LOAD VS FRACTION OF TOTAL HOURS)*/)
5170 FORMAT(*0*,10X,*LOAD ENERGY (LOAD VS FRACTION OF TOTAL ENERGY)*/)
5180 FORMAT(13X,4(F10.2,E11.5,2X))
END
```

B-18

```

SUBROUTINE JULIAN(MO,DA,YR,JD)
INTEGER      DA,      MTAB(12),      YR
DATA        MTAB      /      0,      31,
*           59,      90,      120,
*           151,      181,      212,
*           243,      273,      304,
*           334/

```

```

JD=MTAB(MO)+DA
IF ((YR-4*(YR/4).EQ.0).AND.(MO.GE.3)) JD=JD+1
RETURN

```

C

```

ENTRY MMDYY
ID=JD
IF ((YR-4*(YR/4).EQ.0).AND.(JD.GT.59)) ID=ID-1
DO 10 I=2,12
IF (ID.GT.MTAB(I)) GO TO 10
MO=I-1
GO TO 20
10 CONTINUE
MO=12
20 DA=ID-MTAB(MO)
IF ((MO.EQ.2).AND.(ID.NE.JD)) DA=29
RETURN
END

```

B-19

APPENDIX C  
WEATHER CORRELATION ANALYSIS

CARD DECK 144 WBAN HOURLY SURFACE OBSERVATIONS

STATION NUMBER	DATE		CEILING		SKY CONDITION		WEATHER AND/OR OBSERVATIONS TO WHICH WEATHERED		SEA-LEVEL PRESSURE (MBS)	DEW POINT (°F)	WIND DIR (°)	WIND SPD (KTS)	STATION PRESSURE (INCHES)	DRY BULB (°F)	WET BULB (°F)	REL HUM (%)	CLOUDS AND OBSCURING PHENOMENA																									
	YEAR	MO	DAY	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)									HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)	HT (FEET)														
0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

MISSING DATA: Blanks in appropriate columns are used to indicate missing data. Identification cards were punched for missing observations at AWS stations unless a whole month's record was missing. Punching of ID cards for AWS stations was phased out from Sep-Dec 1968.

COLUMNS AND ELEMENTS PUNCHED: Columns 1-79 are punched. Elements punched are:

- Ceiling Height
- Sky Condition
- Clear
- Scattered
- Broken
- Overcast
- Partial Obscuration
- Visibility
- Weather and/or
- Obstruction to
- Vision
- Thunderstorm
- Tornado
- Squall
- Rain
- Rain Showers
- Freezing Rain
- Drizzle
- Freezing Drizzle
- Snow
- Snow Pellets
- Ice Crystals
- Snow Showers
- Snow Grains
- \*Sleet
- Hail
- \*Small Hail
- Fog
- Ice Fog
- Ground Fog
- Blowing Dust
- Blowing Sand
- Smoke and/or Haze
- Dust
- Blowing Snow
- Blowing Spray
- Sea Level Pressure
- Dew Point Temperature
- Wind Direction
- Wind Speed
- Station Pressure
- Dry Bulb Temperature
- Wet Bulb Temperature
- Relative Humidity
- Total Sky Cover
- Amount, Type and Height of Cloud Layers
- Opaque Sky Cover

\*Reported as Ice Pellets, effective 1 Apr 70.

ADDITIONAL REMARKS: Card content is generally for recent years. Prior punching or processing procedures are described in "Remarks Column" or in SUPPLEMENTARY NOTES.

Effective 1 Jan 68, the Air Force began the use of the METAR Code at nearly all stations located outside the North American Continent. Observations for these stations are not available on punched cards but on magnetic tape only.

Decks with similar data are listed on page 14.

CORRECTIONS: Any errors detected in this manual should be called to the attention of the Director, National Climatic Center, Environmental Data Service, NOAA; or Chief, Data Processing Division, Environmental Technical Applications Center, USAF. Please give specific instances of error and correct information if available.

AREA COVERAGE: United States, Caribbean and Pacific Islands and other overseas stations of U. S. Weather Bureau, Air Force and Navy.

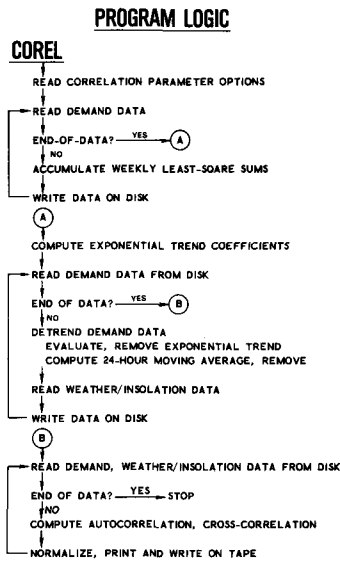
PERIOD OF RECORD: Navy Apr 1945- Weather Bureau Jan 1948- Air Force Jan 1949-  
Note: Some prior periods are included in this deck. A status of the period of record for each station is maintained at the National Climatic Center, Asheville, North Carolina.

OBSERVATION TIME: Local Standard Time (LST). For information relating to changes in time of observation, refer to SUPPLEMENTARY NOTE A, page 9. Beginning 1 Jan 65, the Weather Bureau reduced the number of hourly observations punched from 24 to 8 per day. These 3-hourly observations correspond to record observations at 0000, 0300, 0600, 0900, 1200, 1500, 1800, and 2100 GMT. As a result of special studies, some WB stations may have 24 observations per day punched.

CODES: WBAN and WMO

SOURCE: WBAN Forms 10A, 10B and 10 or similar forms. In addition to WBAN Forms for weather Bureau, air Force and Navy, those of FAA and Signal Corps are included. Effective 1 apr 70, forms redesignated as MF 1-10A, 1-10B and 1-10C. MF indicates Meteorological Form.

Figure C-1. WBAN (Card Deck 144) Surface Weather Data Format



### DETAILED FLOW

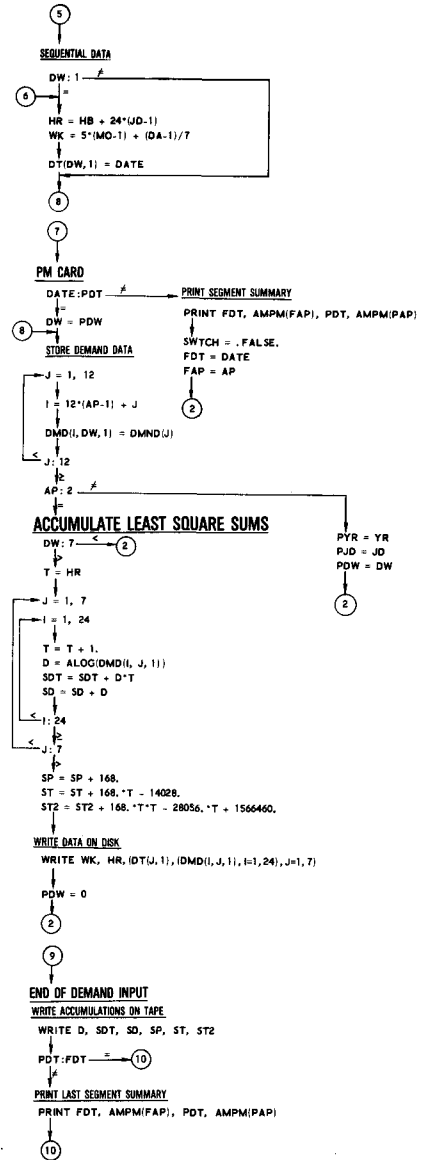
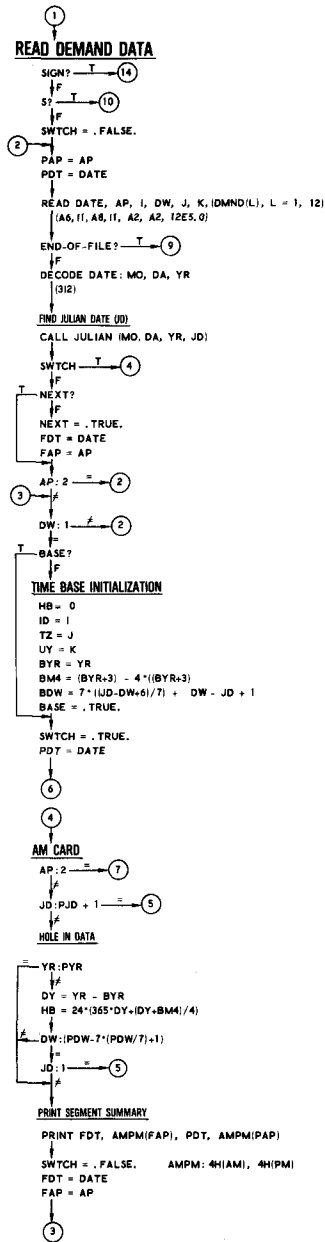
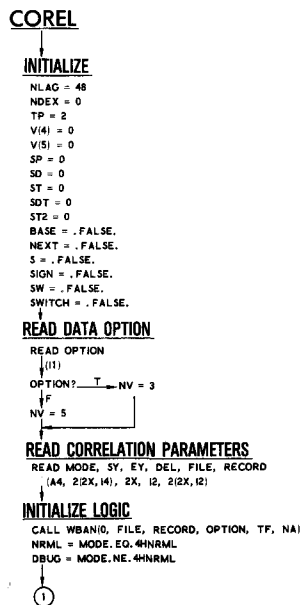


Figure C-2. COREL Program Flow Charts (Sheet 1 of 3)



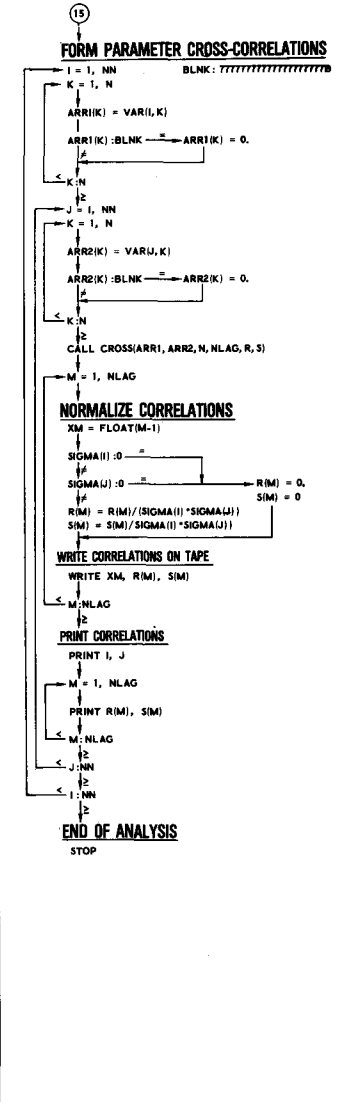
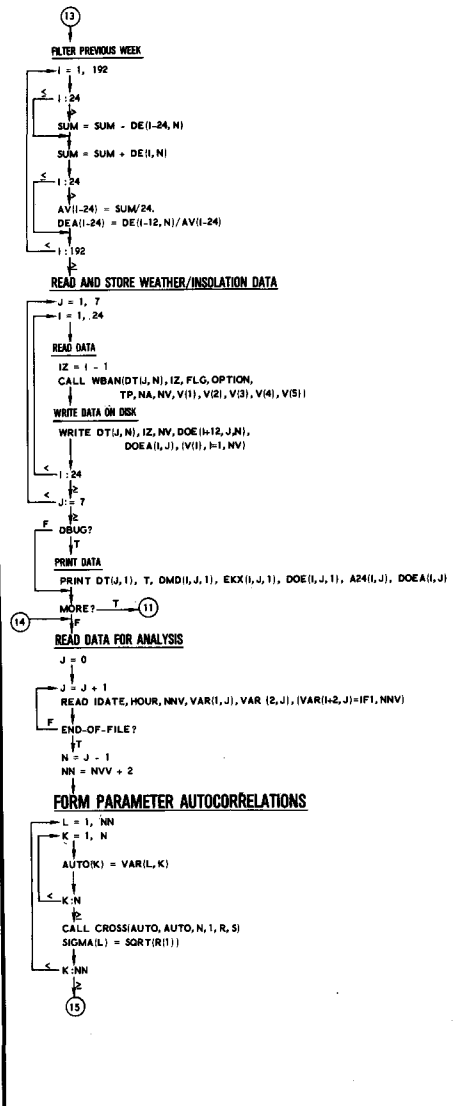
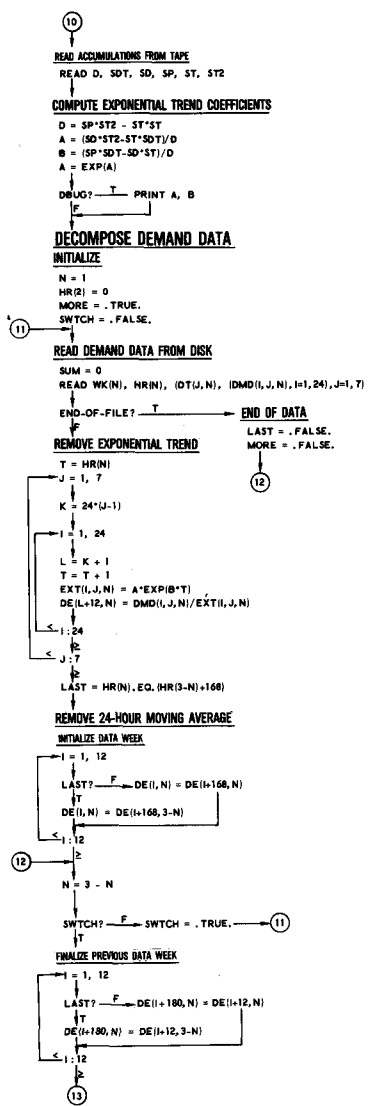


Figure C-2. COREL Program Flow Charts (Sheet 2 of 3)

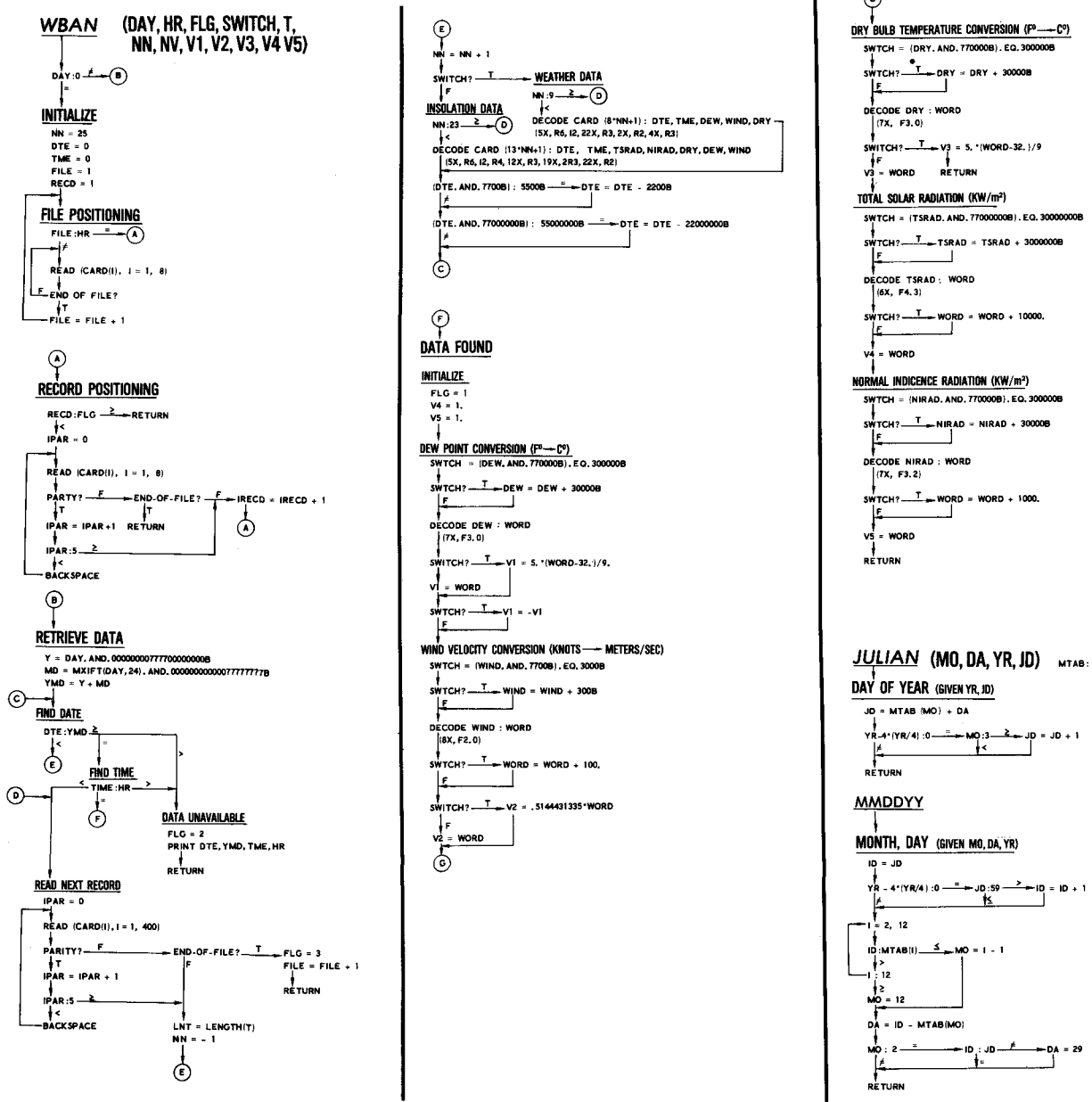
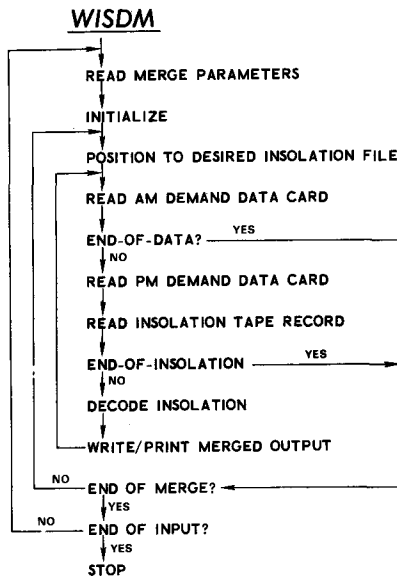


Figure C-2. COREL Program Flow Charts (Sheet 3 of 3)

**PROGRAM LOGIC**



**DETAILED FLOW**

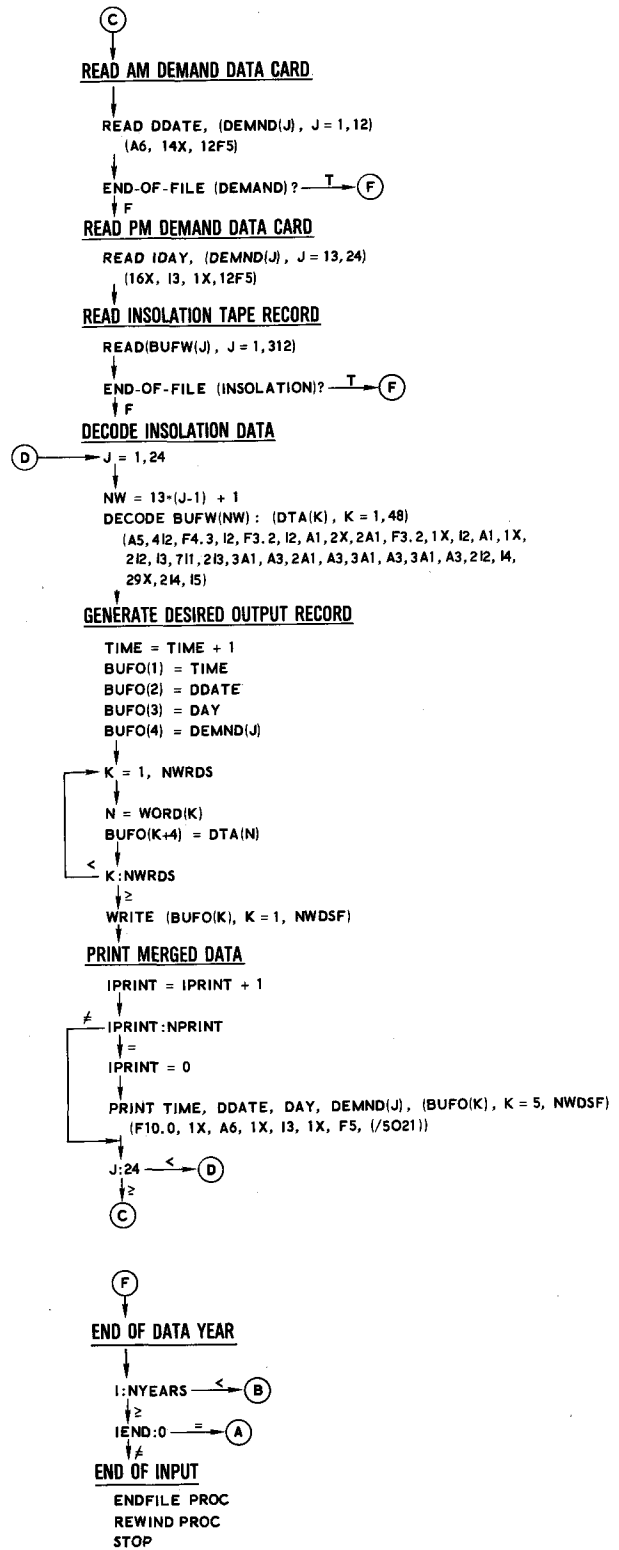
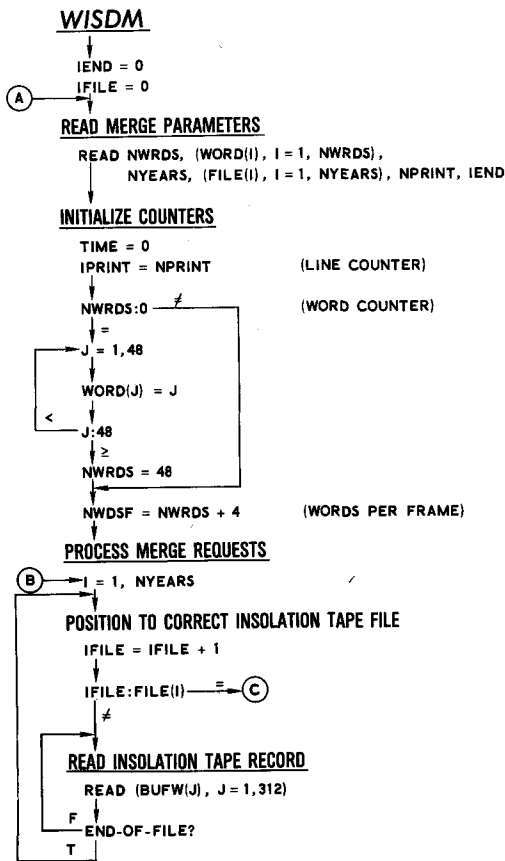


Figure C-3. WISDM Program Flow Charts

```

* PROGRAM COREL (LOAD, WTHR, INPUT, DISP, OUTPUT, TAPE1=LOAD, TAPE2=WTHR,
* TAPE3=INPUT, TAPE4=DISP, TAPE5=OUTPUT, TAPE6, TAPE7,
* TAPE8, TAPE9, TAPE10)

```

C

```

COMMON LEVEL 2, VAR
REAL VAR (7, 2352)
* A24 (24, 7) ARR1 (2352), ARR2 (2352),
* AV (168), AUTO (2352), DE (192, 2),
* DEA (168), DMND (12), DMD (24, 7, 2),
* DOE (24, 8, 2), DOEA (24, 7), EXT (24, 7, 2),
* P (200), S (200), SIGMA (7),
* V (5), VV (5)
INTEGER AH (3), ANPM (2), AP,
* BDW, BLNK (3), BM4,
* BWK, IYR, CA,
* DATE, DEL, DS,
* DT (7, 2), DW, CY,
* EY, FAP, FDT,
* FILE, FLG, HB,
* HOR, HCUR, FR (2),
* MASK (3), OP, PAP,
* POT, PDW, PJD,
* PNC, RECORD, SY,
* IP, IZ, UY,
* WK (2), YR
LOGICAL BASE, DEBUG, LAST,
* MORE, NEXT, NRML,
* OPTION, S, SIGN,
* SW, SWITCH, SWTCH
EQUIVALENCE (AV, A24), (DE, DOE), (DEA, DOEA),
* (OP, OPTION)
DATA AH /2200B, 22000000B, 22000000000000B/,
* BLNK /55000B, 55000000B, 55000000000000B/,
* MASK /7700B, 77000000B, 77000000000000B/,
* AMFM /4H (AM), 4H (PM)/

```

C  
C

```

INITIALIZE
NLAG=48
NOEX =0
TP=2
V(4)=0.
V(5)=0.
SP=0.
SD=0.
ST=0.
SDT=0.
ST2=0.
BASE=.FALSE.
NEXT=.FALSE.
S=.FALSE.
SIGN = .FALSE.
SW = .FALSE.

```

```

      SWITCH=.TRUE.
C
C  READ OPTION (WEATHER - OPTION=.T., INSCLATION - OPTION=.F.)
  READ (3,3000) OP
  IF (OPTION) 5,10
5   NV=3
   GO TO 15
10  NV=5
C
C  READ INPUT PARAMETERS
  * CORRELATION CUTPUT
C 15  READ (3,3010) MODE,SY,EY,DEL,FILE,RECORD
  WRITE (5,5010) MODE,SY,EY,DEL,FILE,RECORD
  CALL WBAN(0,FILE,RECORD,OPTICN,TP,NA)
  NRML=MODE.EQ.4HNRML
  DBUG=MODE.NE.4HNRML
C
C  READ SYSTEM LOAD DATA
  IF (SIGN) GO TO 259
  IF (S) GO TO 132
  WRITE (5,5020)
  SWITCH =.FALSE.
25  PAP=AP
  PDT=DATE
  READ (1,1010) DATE,AP,I,CW,J,K,(DMNC(L),L=1,12)
  IF (EOF,1) 130,30
30  DECODE (6,3020,DATE) MO,DA,YR
  CALL JULIAN(MC,DA,YR,JC)
  IF (SWTCH) GO TO 50
  IF (NEXT) GO TO 35
  NEXT=.TRUE.
  FDT=DATE
  FAP=AP
35  CONTINUE
  IF (AP.EQ.2) GO TO 25
40  CONTINUE
  IF (CW.NE.1) GO TO 25
  IF (BASE) GO TO 45
  HB=0
  ID=I
  TZ=J
  UY=K
  BYR=YR
  BM4=(BYR+3)-4*((BYR+3)/4)
  BDW=7*((JD-DW+6)/7)+DW-JC+1
  BASE=.TRUE.
45  SWITCH=.TRUE.
  PDT=DATE
  GO TO 70
  * AM CARD **
C 50  CONTINUE
  IF (AP.EQ.2) GO TO 90

```

```

C      IF (JD.EQ.PJD+1) GO TO 60
      ** HOLE IN DATA
      IF (YR.EQ.PYR) GO TO 55
      DY=YR-BYR
      HB=24*(365*DY+(DY+BM4)/4)
      IF (DW.NE.(PDW-7*(PDW/7)+1)) GO TO 55
      IF (JD.EQ.1) GO TO 60
55     WRITE (5,5025) FCT,AMPM(FAP),PCT,AMPM(PAF)
      SWITCH=.FALSE.
      FDT=DATE
      FAP=AP
      GO TO 40
C      ** SEQUENTIAL DATA
60     CONTINUE
      IF (DW.NE.1) GO TO 80
70     HR=HB+24*(JD-1)
      WK=5*(MC-1)+(DA-1)/7
80     DT(DW,1)=DATE
      GO TO 100
C      * PM CARD **
90     CONTINUE
      IF (DATE.EQ.PDT) GO TO 95
      WRITE (5,5025) FCT,AMPM(FAP),PCT,AMPM(PAP)
      SWITCH=.FALSE.
      FDT=DATE
      FAP=AP
      GO TO 25
95     DW=PDW
100    DO 110 J=1,12
      I=12*(AP-1)+J
110    DMD(I,DW,1)=DMND(J)
      IF (AP.EQ.2) GO TO 115
      PYR=YR
      PJD=JD
      PDW=DW
      GO TO 25
C
C      COMPLETE WEEK, FORM LEAST-SQUARES SUMS
115    CONTINUE
      IF (DW.LT.7) GO TO 25
      T=HR
      DO 120 J=1,7
      DO 120 I=1,24
      T=T+1.
      D=ALOG(DMD(I,J,1))
      SDT=SDT+C*T
120    SD=SD+D
      SP=SP+168.
      ST=ST+168.*T-1.028.
      SI2=SI2+168.*T*T-28056.*T+1566460.
      WRITE (6) WK(1),HR(1),(DT(J,1),(DMC(I,J,1),I=1,24),J=1,7)
      PDW=0

```

```

C      GO TO 25
C      * END OF DATA
130 CONTINUE
      WRITE (8) D,SD1,SC,SP,ST,ST2
      ENDFILE 8
      REWIND 8
      IF (PDT.EQ.FDT) GO TO 135
      WRITE (5,5025) FCT,AMPM(FAP),PCT,AMPM(PAF)
135 ENDFILE 6
      REWIND 6

C
C      COMPUTE EXPONENTIAL TREND COEFFICIENTS
132 READ (8) D,SOT,SC,SP,ST,ST2
      D=SP*ST2-ST*ST
      A=(SD*ST2-ST*SOT)/D
      B=(SP*SOT-SD*ST)/D
      A=EXP(A)
      IF (DEBUG) WRITE (5,5030) A,B

C
C      DECOMPOSE INPUT DEMAND DATA
C      * INITIALIZE
      N=1
      HR(2)=0
      MORE=.TRUE.
      SWTCH=.FALSE.
C      * READ ONE WEEK OF DATA
      IF (DRUG) WRITE (5,5040)
145 SUM=0.
      READ (6) WK(N),HR(N),(CT(J,N),(DMD(I,J,N),I=1,24),J=1,7)
      IF (EOF,6) 150,155
C      * COMPUTE EXPONENTIAL AND 24-HOUR MOVING AVERAGE
150 LAST=.FALSE.
      MORE=.FALSE.
      GO TO 175
155 T=HR(N)
      DO 160 J=1,7
      K=24*(J-1)
      DO 160 I=1,24
      L=K+I
      T=T+1.
      EXT(I,J,N)=A*EXP(B*T)
160 DE(L+12,N)=DMD(I,J,N)/EXT(I,J,N)
      LAST=HR(N).EQ.(HR(3-N)+168)
C      ** INITIALIZE DATA WEEK
      DO 170 I=1,12
      IF (LAST) GO TO 165
      DE(I,N)=DE(I+168,N)
      GO TO 170
165 DE(I,N)=DE(I+168,3-N)
170 CONTINUE
175 N=3-N
      IF (SWTCH) GO TO 180

```

```

      SWITCH=.TRUE.
      GO TO 145
C     ** FINALIZE PREVIOUS DATA WEEK
180  DO 190 I=1,12
      IF (LAST) GO TO 185
      DE(I+180,N)=DE(I+12,N)
      GO TO 190
185  DE(I+180,N)=DE(I+12,3-N)
190  CONTINUE
C     ** FILTER PREVIOUS WEEK
      DO 200 I=1,192
      IF (I.LE.24) GO TO 195
      SUM=SUM-DE(I-24,N)
195  SUM=SUM+DE(I,N)
      IF (I.LE.24) GO TO 200
      AV(I-24)=SUM/24.
      DEA(I-24)=DE(I-12,N)/AV(I-24)
200  CONTINUE
C
C     **CROSS-CORRELATE AND STORE RESULTS WITH GIVEN TIME LAGS ON TAPE
      DO 240 J=1,7
      DO 240 I=1,24
      CALLWBAN(DT(J,N),I-1,FLG,OPTION,TP,NA,NV,V(1),V(2),V(3),V(4),V(5))
C     **FOR GIVEN TIME, IF DATA NOT AVAILABLE, IGNORE DEMAND DATA
C     OTHERWISE STORE BOTH DEMAND AND OTHER VARIABLES.
      IZ=I-1
      WRITE (7)DT(J,N),IZ,NV,DOE(I+12,J,N),DOEA(I,J),(V(I),I=1,NV)
240  CONTINUE
      IF (DEBUG) WRITE (5,5045) DT(J,1),T,CMD(I,J,1),EXT(I,J,1),
      *      DOE(I,J,1),A24(I,J),DOEA(I,J)
      IF (MORE) GO TO 145
C     * END OF DATA
      ENDFILE 7
      REWIND 7
C
C     ** READ DATA FOR CROSS-CORRELATION
259  CONTINUE
      J=0
260  J=J+1
      READ (7) IDATE,HOUR,NVV,VAR(1,J),VAR(2,J),(VAR(I+2,J),I=1,NVV)
      IF (EOF,7) 300,260
C
C     **CHECK FOR CORRESPONDING TIME ON INSOLATION (WEATHER) TAPE
300  N = J-1
      NN = NVV + 2
C     * STORE SQRT(AUTCCORRELATION) IN SIGMA ARRAY
      DO 302 L=1,NN
      DO 301 K=1,N
301  AUTO(K)=VAR(L,K)
      CALL CROSS(AUTO,AUTO,N,1,R,S)
      SIGMA(L)=SQRT(R(1))
302  CONTINUE

```





```

SUBROUTINE WBAN(DAY,HR,FLG,SWITCH,T,NN,NV,V1,V2,V3,V4,V5)
C
* INTEGER          CARD(400),    DAY,          DEW,
*                  DRY,          DIE,          FILE,
*                  FLG,          HR,          RECD,
*                  T,           TME,         TSRAD,
*                  WIND,        Y,          YMD
* LOGICAL          SWITCH,       SWITCH
C
SWITCH = .TRUE.    FOR WEATHER DATA
SWITCH = .FALSE.   FOR INSOLATION DATA
C
IF (DAY.NE.0) GO TO 50
C
INITIALIZATION
NN=25
OTE=0
TME=0
FILE=1
RECD=1
REWIND T
* FILE POSITIONING
C 5 IF (FILE.EQ.HR) GO TO 20
10 BUFFER IN (T,0) (CARD(1),CARD(8))
IF (UNITP(T)) 10,15,10
15 FILE=FILE+1
GO TO 10
C * RECORD POSITIONING
20 IF (RECD.GE.FLG) RETURN
25 IPAR=0
30 BUFFER IN (T,0) (CARD(1),CARD(8))
IF (UNITP(T)) 40,45,35
35 IPAR=IPAR+1
IF (IPAR.GE.5) GO TO 40
BACKSPACE T
GO TO 30
40 RECD=RECD+1
GO TO 20
45 RETURN
C
RETRIEVE DATA
C 50 Y = DAY.AND.00000000777700000000B
MD = MXIFT(DAY,24).AND.00000000000777777777B
YMD=Y+MD
C * FIND DATE
55 IF (OTE-YMD) 90,60,110
C * FIND TIME
60 IF (TME-HR) 65,120,110
C * READ NEXT RECORD
65 IPAR=0
70 BUFFER IN (T,0) (CARD(1),CARD(400))
IF (UNITP(T)) 95,80,75

```

```

C 75  ** PARITY ERROR
      IPAR=IPAR+1
      IF (IPAR.GE.5) GO TO 85
      BACKSPACE T
      GO TO 70
C 80  ** END OF FILE
      FLG=3
      FILE=FILE+1
      RETURN
C 85  ** RECORD ACCEPTABLE
      LNT=LENGTH(T)
      NN=-1
      90  NN=NN+1
      95  IF (SWTCH) 95,100
          IF (NN.GE.9) GO TO 65
          DECODE (80,1020,CARD(8*NN+1)) DTE,TME,DEW,WIND,DRY
          GO TO 105
      100 IF (NN.GE.23) GO TO 65
          DECODE (130,1030,CARD(13*NN+1)) DTE,TME,TSRAD,NIRAD,DRY,DEW,WIND
      105 IF ((DTE.AND.77000B).EQ.55000B) DTE=DTE-22000
          IF ((DTE.AND.770000000B).EQ.550000000B) DTE=DTE-220000000B
          GO TO 55
C 110 * DATA UNAVAILABLE
      FLG=2
      WRITE (5,4100) DTE,YMD,TME,HR
      RETURN
C 120 * DATA FOUND
      FLG=1
      V4=1.
      V5=1.
C 130 ** DEW POINT (DEGREES F TO DEGREES C)
      SWITCH=(DEW.AND.7700000B).EQ.3000000B
      IF (SWTCH) DEW=DEW+300000B
      DECODE (10,2010,DEW) WORD
      IF (SWTCH) 130,140
      130 V1=5.*(WORD-32.)/9.
          GO TO 150
      140 V1=WORD
      150 IF (SWTCH) V1=-V1
C 155 ** WIND VELOCITY (KNOTS TO METERS/SEC)
      SWITCH=(WIND.AND.77000B).EQ.30000B
      IF (SWTCH) WIND=WIND+3000B
      DECODE (10,2020,WIND) WORD
      IF (SWTCH) WORD=WORD+100.
          IF (SWTCH) 160,170
      160 V2=.5144431335*WORD
          GO TO 180
      170 V2=WORD
C 180 ** DRY BULB TEMPERATURE (DEGREES F TO DEGREES C)
      SWITCH=(DRY.AND.7700000B).EQ.3000000B
      IF (SWTCH) DRY=DRY+30000B
      DECODE (10,2010,DRY) WORD

```

```

190 IF (SWTCH) 190,200
    V3=5.*(WORD-32.)/9.
    RETURN
200 V3=WORD
C   **TOTAL SOLAR RADIATION (KILOWATTS/METER**2)
    SWTCH = (TSRAD.AND.77000000B).EQ.30000000B
    IF (SWTCH) TSRAD = TSRAD + 30000000B
    DECODE (10,1040,TSRAD) WORD
    IF (SWTCH) WORD = WORD + 10000.
    V4 = WORD
C   **NORMAL INCIDENCE RADIATION (KILOWATTS/METER**2)
    SWTCH = (NIRAD.AND.77000000B).EQ.30000000B
    IF (SWTCH) NIRAD = NIRAD + 30000000B
    DECODE (10,1050,NIRAD) WORD
    IF (SWTCH) WORD = WORD + 1000.
    V5 = WORD
    RETURN
C
1010 FORMAT(8A10)
1020 FORMAT(5X,F6,I2,22X,R3,2X,R2,4X,R3)
1030 FORMAT(5X,R6,I2,R4,12X,R3,19X,2R3,22X,R2)
1040 FORMAT(6X,F4.3)
1050 FORMAT(7X,F3.2)
2010 FORMAT(7X,F3.0)
2020 FORMAT(8X,F2.0)
3200 FORMAT(* DTE,TME*/2021)
4000 FORMAT(4021/4021)
4100 FORMAT(* DTE,YMD,TME,HR*/4021)
    END

```

C-15

```

SUBROUTINE JULIAN(MO,DA,YR,JD)
INTEGER      DA,      MTAB(12),      YR
DATA         59,      90,      120,
*           151,      181,      212,
*           243,      273,      304,
*           334/
JD=MTAB(MO)+DA
IF ((YR-4*(YR/4).EQ.0).AND.(MO.GE.3)) JD=JD+1
RETURN
C
ENTRY MMDDYY
ID=JD
IF ((YR-4*(YR/4).EQ.0).AND.(JD.GT.59)) ID=ID-1
DO 10 I=2,12
IF (ID.GT.MTAB(I)) GO TO 10
MO=I-1
GO TO 20
10 CONTINUE
MO=12
20 DA=ID-MTAB(MO)
IF ((MO.EQ.2).AND.(ID.NE.JD)) DA=29
RETURN
END

```

C-16

```

* PROGRAM WISDM (INPUT, OUTPUT, TAPES=INPUT, TAPE6=OUTPUT, TAPE1,
  TAPE2, TAPE10)
CCCCCCCC
* * * * *
READS DEMAND DATA AND WEATHER INSOLATION DATA AND MERGES
THE SPECIFIC ITEMS
* * * * *
* DIMENSION      DEMND(24),          BUFW(313),          WORD(50),
*                FILE(20),          OTA(50),          BUFO(54),
*                OBUF(1)
*
* NAMELIST /INPT/      NWRDS,      WORD,      NYEARS,      FILE,
*                    NPRINT,      IEND
*
* INTEGER          FILE,      WORD,      OBUF
*
* EQUIVALENCE      (OBUF, BUFO)
*
* BUFW(313)=10H
*/INITIALIZE COUNTERS
FILE COUNTER FOR INSOLATION DATA TAPE
IEND=0
IFILE=0
5 READ(5, INPT)
*
* COUNTER FOR LINE PRINT
IPRINT=NPRINT
WRITE(6, 7000)
7000 FORMAT(1H1, 20X, *WEATHER INSOLATION AND POWER DEMAND DATA MERGE*//)
*
* TIME=0.
* NUMBER OF WORDS IN RECORD ON OUTPUT TAPE
IF (NWRDS.NE.0) GO TO 15
DO 10 J=1, 48
WORD(J)=J
10 CONTINUE
NWRDS=48
*
* 15 NWDSF=NWRDS+4
DO 100 I=1, NYEARS
*
* C C C
* POSITION TO CORRECT FILE ON INSOLATION DATA TAPE
20 IFILE=IFILE+1
IF (IFILE.EQ.FILE(I)) GO TO 40
BUFFER IN(2, 0) (BUFW(1), BUFW(312))
30 IF (UNITP(2)) 30, 20, 30

```

```

C
C   READ RECORD ON DEMAND DATA TAPE
40  READ(1,9000) DDATE,(DEMND(J),J=1,12)
9000 FORMAT(A6,14X,12F5)
    IF (EOF,1) 100,45
45  READ(1,9010) IDAY,(DEMND(J),J=13,24)
9010 FORMAT(16X,I3,1X,12F5)

C
C   BUFFER IN DATA ON INSOLATION TAPE
    BUFFER IN(2,0) (BUFW(1),BUFW(312))
    IF (UNITP(2)) 50,100,50

C
C   DECODE INSOLATION DATA
50  DO 80 J=1,24

C
    NW=(J-1)*13+1
    DECODE(130,8000,BUFW(NW)) DTA
8000 * FORMAT(A5,3I2,F2,F4.3,F2,F3.2,F2,A1,2X,2A1,F3.2,1X,F2,A1,1X,2F2,
    F3,7F1,2F3,3A1,A3,2A1,A3,3A1,A3,3A1,A3,2F2,F4,29X,2F4,I5)

C
    TIME=TIME+1.
    BUFO(1)=TIME
    BUFO(2)=DDATE
    OBUF(3)=IDAY
    EUFO(4)=DEMND(J)

C
C   PICK UP REQUESTED DATA OFF OF INSOLATION TAPE
    DO 60 K=1,NWRDS
    N=WORD(K)
    BUFO(4+K)=DTA(N)
60  CONTINUE

C
C   BUFFER OUT(10,1) (BUFO(1),EUFO(NWDSF))
    IF (UNITP(10)) 70,70,70

C
70  IPRINT=IPRINT+1
    IF (IPRINT.LT.NPRINT) GO TO 80
    IPRINT=0
    WRITE(6,8010) TIME,DDATE,IDAY,DEMND(J),(BUFO(K),K=5,NWDSF)
8010 FORMAT(/F10.0,1X,A6,1X,I3,1X,F5,(/E021))

C
80  CONTINUE
    GO TO 40

C
100 CONTINUE

C
C   IF (IEND.EQ.0) GO TO 5
    REWIND 10
C

```

STOP 77

```
*/INPUT (I) NUMBER OF DATA ITEMS TO BE SELECTED OUT OF
NWRDS DATA FRAME
WORD (I) ARRAY OF WORD NUMBERS TO CORRESPOND TO POSITION
IN INSOLATION DATA FRAME
NYEARS (I) VARIABLE DEFINES NUMBER OF YEARS TO PROCESS
FILE (I) ARRAY (NYEARS IN LENGTH) OF PHYSICAL FILE NUMBERS
TO PROCESS ON INSOLATION TAPE
NPRINT (I) VARIABLE TO REGULATE PRINTOUT. PROGRAM WILL
PRINT EVERY NTH FRAME
IEND (I) VARIABLE TO END PROGRAM. USER MUST SET TO ANYTHING
OTHER THAN 0
```

```
THE FOLLOWING DEFINES THE WORD NUMBER OF DATA ON THE
INSOLATION TAPE
NO 1 = STATION NUMBER CHAR 1-5
2 = YEAR 6-7
3 = MONTH 8-9
4 = DAY 10-11
5 = HOUR LST 12-13
6 = TOTAL SOLAR RADIATION 14-17
7 = SOLAR ELEVATION 18-19
8 = EXTRA-TERRESTRIAL RADIATION 20-22
9 = SUNSHINE 23-24
10 = SNOW COVER 25
11 = ESTIMATED TOTAL INSOLATION FLAG 28
12 = ESTIMATED NORMAL INCIDENCE INSOLATION FLAG 29
13 = NORMAL INCIDENCE RADIATION 30-32
14 = SOLAR WEEK 34-35
15 = OPAQUE SKY COVER 36
16 = SOLAR HOUR 38-39
17 = PERCENT OF POSSIBLE RADIATION 40-41
18 = VISIBILITY 42-44
19 = LIQUID PRECIPITATION 45
20 = LIQUID PRECIPITATION 46
21 = FROZEN PRECIPITATION 47
22 = FROZEN PRECIPITATION 48
23 = FROZEN PRECIPITATION 49
24 = OBSTRUCTIONS TO VISION 50
25 = OBSTRUCTIONS TO VISION 51
26 = DRY BULB 52-54
27 = DEW POINT TEMPERATURE 55-57
28 = TOTAL CLOUDS AND OBSCURING PHENOMENA 58
29 = AMOUNT OF LOWEST LAYER 59
30 = TYPE OF CLOUD LOWEST LAYER 60
31 = HEIGHT OF LOWEST LAYER 61-63
32 = AMOUNT OF SECOND LAYER 64
33 = TYPE OF SECOND LAYER 65
34 = HEIGHT OF SECOND LAYER 66-68
35 = SUMMATION AMOUNT AT SECOND LAYER 69
```

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CCCCCCCC

36=	AMCUNT OF THIRD LAYER	70
37=	TYPE OF THIRC LAYER	71
38=	HEIGHT OF THIRC LAYER	72-74
39=	SUMMATION AMCUNT AT THIRO LAYER	75
40=	AMCUNT CF FOURTH LAYER	76
41=	TYPE OF FOURTH LAYER	77
42=	HEIGHT OF FOURTH LAYER	78-80
43=	WIND DIRECTION	81-82
44=	WIND SPEED	83-84
45=	STATION PRESSURE	85-88
46=	SOLAR DECLINATIONS	118-121
47=	SOLAR AZIMUTH	122-125
48=	JULIAN DAY	126-130
	END	

C-20