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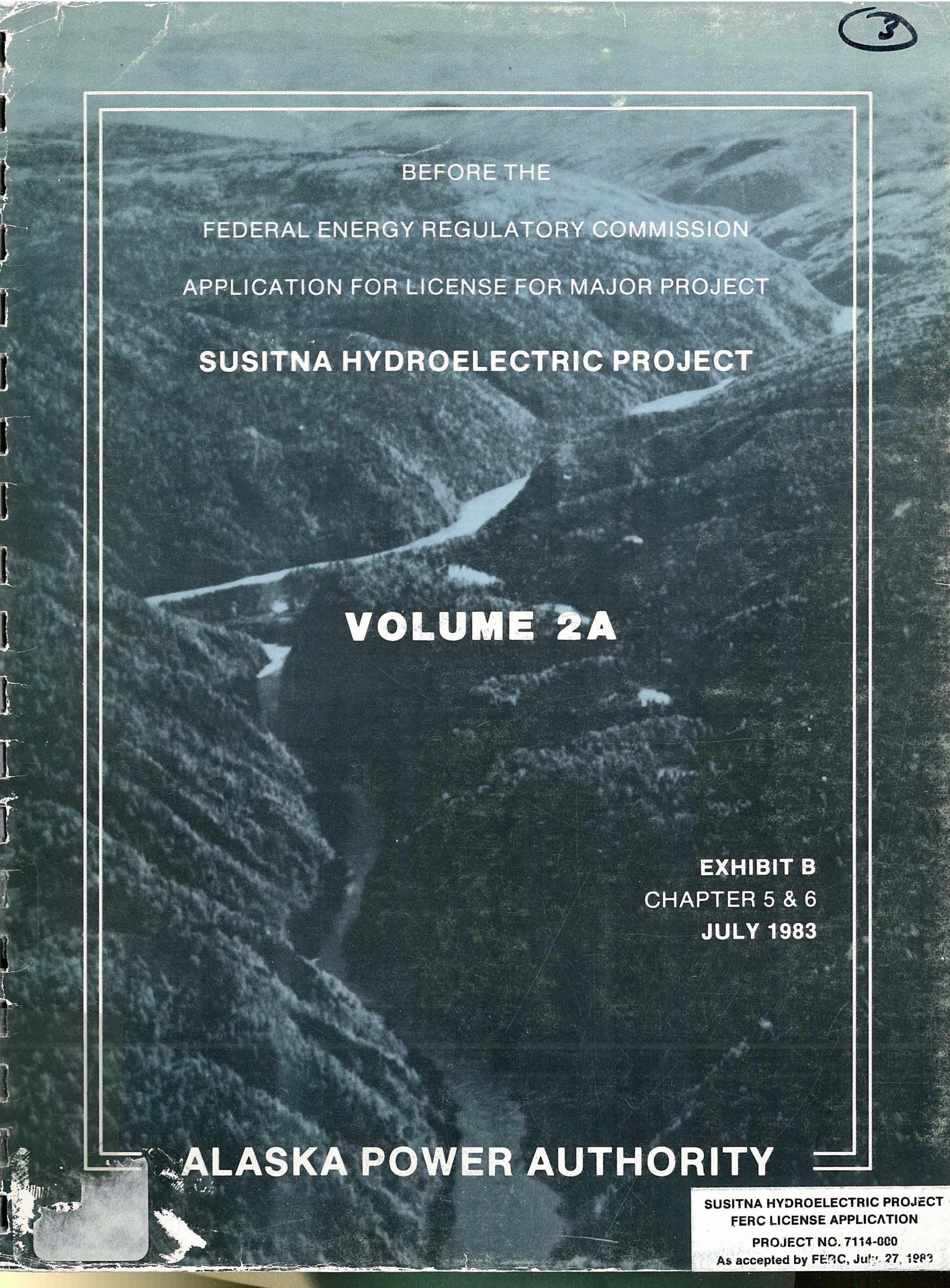

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

SUSITNA HYDROELECTRIC PROJECT

VOLUME 2A

EXHIBIT B
CHAPTER 5 & 6
JULY 1983

ALASKA POWER AUTHORITY

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5 - STATEMENT OF POWER NEEDS AND UTILIZATION

5.1 - Introduction

Electric power demand forecasts have been developed for the Railbelt market that will be served by the Susitna Project. The forecasts begin from the year 1983 and extend to 2010, a period during which the resources of the Susitna Project will be developed.

The magnitude of the future power demand depends on a number of factors, the primary one being the future price of oil which affects the revenue to the state and the state's economic activity. To account for a range of world oil price projections, varying demand forecasts are developed.

In addition to world oil price, the influence of energy conservation and the relative costs of alternative forms of energy are also important and have been factored into the forecast. Other factors affecting the forecast demand have also been included in the analysis.

The following sections present the existing electric power demand and supply situation, the basic approach used to develop the forecasts, the variables and assumptions in the forecasts, and finally the results of the forecasts and their significance.

Section 5.2 describes the electric power system in the Railbelt, including utility load characteristics, conservation programs and electricity rates. Section 5.3 presents the methodology for making the forecasts. The section describes the four computer-based models that were utilized in preparing the economic and electric energy forecasts and the generation expansion plan for meeting the loads. Section 5.4 presents the oil price scenarios forming bases for the forecasts, the other key variables involved in producing the forecasts, the results of the forecasts, and the impact of world oil prices on the forecasts. Section 5.5 summarizes the planned utilization of the power from the Susitna Hydroelectric Project.

Two new reference reports have been prepared to provide technical documentation of two of the three computer models that were developed and utilized in the derivation of the forecasts. The Man-in-the-Arctic Program (MAP) Model Technical Documentation Report provides a complete explanation of the economic forecasting model. The Railbelt Electricity Demand (RED) Model Documentation Report provides similar information for the load forecasting model.

5.2 Description of the Railbelt Electric Systems

In this section, a description of the Railbelt electric systems is presented. First, a general description is given about the interconnected Railbelt market and the electric utilities serving the market. Next, the characteristics of the loads, electricity rates and the conservation programs are discussed. Finally, historical data covering Railbelt electricity demands and regional economic factors are presented.

(a) The Interconnected Railbelt Market

The Railbelt region, shown in Figure B.77, contains two important electrical load centers: the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area. These two load centers will comprise the interconnected Railbelt market when the intertie currently under construction by the Alaska Power Authority is completed. The Glennallen-Valdez load center is part of the Railbelt region but is not planned to be interconnected nor to be served by the Susitna Project. It is therefore excluded from discussions in this report.

The existing transmission system of the Anchorage-Cook Inlet area extends north to Willow and consists of a network of 115-kV and 138-kV lines with interconnection to Palmer. The Fairbanks-Tanana system extends south to Healy over a 138-kV line. The intertie is being built by the Alaska Power Authority to connect Willow and Healy and will operate initially at 138-kV. The existing transmission system in the Railbelt region is illustrated in Figure B.78.

(i) The Electric Utilities and Other Suppliers

- Anchorage-Cook Inlet Area

The Anchorage-Cook Inlet area has two municipal utilities, three rural electric cooperative associations (REAs), a Federal Power Administration, and two military installations, as follows:

. Municipality of Anchorage-Municipal Light & Power Department (AMLP)
. Chugach Electric Association, Inc. (CEA)
. Homer Electric Association, Inc. (HEA)
. Matanuska Electric Association, Inc. (MEA)
. Alaska Power Administration (APAd)
. Elmendorf AFB - Military
. Fort Richardson - Military

All of these organizations, with the exception of MEA, have electrical generating facilities. MEA buys its power from CEA. HEA and SES have relatively small generating facilities that are used for standby operation. They also purchase power from CEA.

AMLP and CEA are the two principal utilities servicing the Anchorage-Cook Inlet area. AMLP serves most areas within the City of Anchorage except for some sections served by CEA. AMLP also serves the Anchorage International Airport, and provides electricial energy to Elmendorf AFB and Fort Richardson on a non-firm basis. The customers and associated sales in 1982 are listed below. Residential sales represented slightly over one fourth of total commercial sales. Its most important load is the downtown business and commercial district.

Customer Class	Number	Energy Sales (MWh)
Residential	14,745	129,010
Commercial	3,229	474,344
Street Lighting	---	7,663
Total	17,974	611,017

CEA serves certain urban and most suburban sections of Anchorage. In addition, CEA serves customers at Kenai Lake, Moose Pass, Whittier, Beluga and Hope. CEA also provides bulk power to AMLP, CEA's residential load is greater than its commercial and industrial loads. Furthermore, CEA's average commercial customer is consistently smaller than that of AMLP. Its 1982 sales are presented below:

Customer Class	Number	Energy Sales (MWh)
Residential	46,560	546,736
Commercial & Industrial (50 kVA or less)	4,519	161,290
Commercial & Industrial (over 50 kVA)	359	214,679
Public St. & Hwy. Lighting	26	5,216
Sales for Resale	3	702,357
Total	51,467	1,630,278

HEA, MEA and SES provide electricity service to their customers by purchases from CEA. In 1982, HEA, MEA, and SES purchased about 347, 326, and 30 GWh of electrical energy respectively. HEA serves the City of Homer and other customers on the Kenai peninsula. MEA has a service area encompassing the Matanuska Valley and related areas; SES serves the City of Seward. These areas are depicted in Figure B.78.

The Alaska Power Administration provides wholesale power (firm and secondary) to MEA, CEA, and AMLP. These utilities are interconnected with the Alaska Power Administration on 115-kV lines owned by the Administration. Fort Richardson and Elmendorf AFB supply their own needs. Their electrical requirements in 1982 were approximately 70 and 87 GWh respectively. Both bases have non-firm power agreements with AMLP. Fort Richardson has recently entered into a new contract with AMLP to purchase about 30 GWh on an interruptable basis.

- <u>Fairbanks - Tanana Valley Area</u>

The Fairbanks-Tanana Valley area is currently served by a REA cooperative and a municipal utility. In addition, a university and three military installations have their own electric systems, as follows:

. Fairbanks Municipal Utilities System (FMUS)
. Golden Valley Electric Association, Inc. (GVEA)
. University of Alaska, Fairbanks
. Eielson AFB - Military
. Fort Greeley - Military
. Fort Wainwright - Military

Golden Valley Electric Association, Inc. and Fairbanks Municipal Utilities System own and operate generation, transmission, and distribution facilities. The University and military bases maintain their own generation and distribution facilities. Fort Wainwright is interconnected with GVEA and FMUS and is providing both utilities with economy energy.

FMUS serves an area bounded by the city limits of Fairbanks, except for several residential subdivisions recently annexed by the city. The Chena River flows through the northern part of the service area with Fort Wainwright Military Reservation providing a border on the east. The downtown business district lies in the northeast corner of the FMUS service area along the south bank of the Chena River. There is an industrial area which is contained in part within the City of Fairbanks. The north bank of the Chena River provides the southern boundary of this industrial area. In addition to serving its own customers, FMUS provides economy energy to Golden Valley Electric Association. The 1982 sales of FMUS are set forth below:

Customer Class	Number	Energy Sales (MWh)
Residential	4663	27,758
Commercial	1050	68,695
Government	144	27,923
Street Lighting	--	4,911
GVEA	1	33,479
Total	5858	162,766

The commercial customers are significant in number but more importantly also in terms of total energy sales. The residential and government sectors had about the same level of energy sales in 1982.

GVEA serves Fairbanks North Star Borough including portions of the City of Fairbanks not served by FMUS, the City of North Pole, the communities of Fox and Ester, and the two military bases - Eielson Air Force Base and Fort Wainwright. Other major communities within its service area include the Cities of Nenana, Healy, Clear, Anderson and Rex. In 1982, GVEA sales were as follows:

Customer Class	Number	Energy Sales (MWh)
Residential	16,176	150,487
Commercial & Industrial (50 kVA or less)	1,859	43,195
Commercial & Industrial (over 50 kVA)	233	129,394
Public St. & Hwy. Lighting	9	328
Sales for Resale	1	9,534
Total	18,278	332,939

The University of Alaska at Fairbanks, Fort Wainwright and Eielson AFB generate their own electrical requirements. At the present time, Fort Wainwright supplies all of Fort Greeley's electricity needs by GVEA wheeling the power on their transmission lines. Fort Wainwright provides economy energy to FMUS and GVEA from coal-fired units. In 1982, Fort Wainwright had net generation of about 80 GWh and Eielson AFB generated about 59 GWh of electricity.

- Other Suppliers

Several major industrial companies in the Railbelt provide their own electric power supply. During 1981, in the Anchorage-Cook Inlet area, such generation accounted for nearly 130 GWh. The major industrial self suppliers are located in HEA's service area. The main industrial firms with operations in Kenai include Union Oil of California, Phillips Petroleum Company, Chevron U.S.A., Inc., and Tesoro-Alaskan Petroleum Corp.

In 1981, the most recent year for which data are available, industrial sources of self generation in the Fairbanks-Tanana Valley area did not produce any electricity.

(ii) The Existing Electric Supply Situation

Because electricity must compete with alternative fuels in the market place, a brief discussion of the consumption and supply of energy in total is provided for an overall setting.

- Total Energy Consumption and Supply

The State of Alaska is a major consumer of energy resources. In 1981, Alaska's total energy input was about 543 trillion Btu. Of that total, 273 trillion Btu were consumed; about 184 trillion Btus were exported; and the remainder was lost in refining, electric generating, and processing activities. The largest share of the input was accounted for by crude oil input to refineries (44%) followed by natural gas (37%) and imported petroleum products (15%). Coal, hydro, and wood resource inputs accounted for the residual 4 percent of total energy input.

The 1981 energy consumption for Alaska and the Railbelt are summarized in Table B.69. The total energy consumption for the Railbelt area was 236 trillion Btu in 1981. In 1981, Railbelt per capita consumption was about 752 million Btu, which is approximately 5 percent greater than the average Alaskan per capita consumption.

The Railbelt region accounts for almost 78 percent of the total energy consumption in the State of Alaska. Table B.70 provides a breakdown of energy consumption by fuel type for various sectors of the state economy. The transportation sector which relies almost entirely on fuel oil is the most energy intensive sector. Besides transportation, the industrial and utility sectors are major energy consumers.

Fuel oil represents the most important energy source followed by natural gas. In the industrial, utility, and commercial public sectors, natural gas consumption accounts for over 50 percent of each sector's total consumption. Natural gas consumption in the residential sector is sightly less than that of fuel oil.

Other fuels are coal and wood which are of lesser importance. Coal is used by electric utilities and military bases, whereas wood is used in the residential sector.

- <u>Electric Energy Supply</u>

The Anchorage-Cook Inlet area is almost entirely dependent on natural gas to generate electricity. About 92 percent of the total capacity is provided by gas-fired units. The remaining are hydroelectric units (5 percent) and oil-fired diesel units (3 percent). Table B.71 presents the total generating capacity of the Anchorage-Cook Inlet utilities, the two military installations and the industrial sector.

For the Fairbanks-Tanana Valley area, the total generating capacity of the utilities, the three military installations and industrial self suppliers by type of units are presented in Table B.72. A large portion of the total installed capacity consists of oil-fired combustion turbines (57 percent) and coal steam turbine (30 percent). The remaining capacity is provided by diesel units. The proposed transmission intertie between Anchorage and Fairbanks will allow Fairbanks utilities to purchase relatively inexpensive power fueled by natural gas from Anchorage. It will also allow both load centers to take advantage of the additional peaking capacity available in the Fairbanks area to provide greater reliability.

Table B.73 provides a complete list of generating plants of the Railbelt area.

(b) Railbelt Electric Utilities

(i) Utility Load Characteristics

This section presents monthly peak and energy demand, hourly load data for a typical week in April, August, and December, and an analysis of load diversity between the two load centers.

- Monthly Peak and Energy Demand

Table B.74 presents monthly distributions of peak and energy demand for the period 1976-1982 for the two load centers in the total Railbelt area. Figure B.79 shows a graph of the 1982 monthly load for each load center.

Both regions have winter peaks, occurring normally in December, and sometimes in January or February. The peak demand is lowest during the months of May through August, and the ratio of summer to winter peaks varies between 0.55 and 0.65. Although monthly peak demand varies from year to year mainly due to weather conditions, Table B.74 shows that the pattern has remained relatively constant during the period 1976-1982.

As denoted by the data in Table B.74, the monthly distribution of energy demand has also remained about the same for the period 1976-1982 and both regions have a similar distribution. The winter months, November through February, had an average monthly demand of about 10 percent of the total annual energy. The summer months, June through August, had an average monthly demand of about 6.7 percent of the total annual energy. These results were compared with an earlier study (Woodward Clyde, 1980) based on data through 1978, and found to be consistent. As part of that study, a forecast of the monthly distribution of peak demand was done. Table B.75 summarizes those results, which have been used in the generation expansion studies described in Exhibit D.

- Daily Load Profiles

Figure B.80 presents graphs of the hourly load data for a typical week in April, August, and December 1982. The data from individual utilities were combined to produce representative load curves for each load center and the total Railbelt area. The following three paragraphs describe the weekly load profiles.

In April, there is usually a morning peak between 7 and 9 a.m., and an evening peak between 6 and 8 p.m. The evening peak is usually greater than the morning peak. The night load is about 70 percent of the daily load. The average daily load factor is about 85 percent.

In August, the load begins to rise from about 7 a.m., it continues to increase until 11-12 a.m., when it reaches a peak and decreases slowly to about midnight and then drops off sharply. The night load is about 55-60 percent of the daily peak load. The average daily load factor is about 82 percent.

In December, there is usually a morning peak between 6 and 9 a.m., and an evening peak between 4 and 7 p.m. The evening peak is usually about 10 percent greater than the morning peak. The night load is about 65 percent of the daily peak load. The average daily load factor is about 85 percent.

Table B.76 presents typical average weekday and weekend daily load duration for the months of April, August, and December. These data were taken from the Woodward-Clyde study (Woodward-Clyde, 1980), and found to be consistent with the 1982 data. Similar load duration data were computed for the remaining months. These data have been used in the generation expansion studies described in Exhibit D.

- <u>Railbelt Load Diversity</u>

A system load diversity analysis was done for the peak day in Fairbanks which was December 29, 1981 and the peak day in Anchorage of January 6, 1982. The peak coincident and non-coincident loads were collected from all generating sources and the load diversity was calculated based on the data. Table B.77 shows the hourly load demand for these two peak days. The diversity measure in the total Railbelt was about 0.98. The basic conclusion of the analysis is that the total coincident peak load for the Railbelt would probably be within three percent of the total non-coincident peak demand. For the expansion plans analysis, the Railbelt peak demand is considered to be the sum of the projected peak demand of the two load centers.

(ii) Electricity Rates

Electric utility companies in the Railbelt have their tariffs approved by the Alaska Public Utilities Commission or another regulatory body with jurisdiction over electric rates. Tables B.78 and B.79 present the current residential and commercial rates for the main utilities of the Anchorage-Cook Inlet area and Fairbanks-Tanana Valley area.

Electric rates are considerably less in the Anchorage-Cook Inlet area than in the Fairbanks-Tanana Valley area. The average residential cost per kWh is approximately 5¢/kWh in the Anchorage-Cook Inlet area, and 8¢/kWh and 10¢/kWh for FMUS and GVEA respectively in the Fairbanks-Tanana Valley area. The lower rates in Anchorage-Cook Inlet can be explained by the relatively low cost natural gas supply used for electric generation. The relatively high rates in Fairbanks-Tanana are a result of considerable oil-fired generation. A description of these rates is presented in the following paragraphs.

- Anchorage Municipal Light and Power (AMLP)

  AMLP tariff for residential service and general service-small customers comprises a fixed monthly customer charge and a flat energy charge per kWh. The general service-large customers schedule has a monthly demand charge in addition to a fixed customer charge and a flat energy charge rate. In addition, AMLP has an experimental program for time-of-day rates for customers dependent on electric space heating.

- Chugach Electric Association, Inc., (CEA)

  CEA has tariffs for retail customers that reflect a declining block rate structure. The residential and small commercial customers schedules provide for a monthly rate in cents per kWh which declines with increasing blocks of electricity consumption. CEA's schedule for large commercial and industrial customers contains a demand charge as well as an energy charge which declines in relation to increasing electric consumption per kW of billing demand.

  CEA has other tariff schedules for retail customer classes such as churches and schools. CEA has a wholesale electric power and energy contract with HEA, MEA, and SES. In addition, CEA has a rate schedule for intertie with AMLP which contains a flat energy charge and certain commitment and start/stop charges.

- Fairbanks Municipal Utilities System (FMUS)

  In the Fairbanks-Tanana Valley area, FMUS has residential, all electric, and general service rate schedules which reflect declining rates as energy consumption increases in blocks. For general service customers with demand blocks of 15 kW or greater, there is (in addition to an energy charge) a monthly minimum charge per meter based on a fixed dollar amount times the highest demand reading of the preceding 11 months or times the estimated maximum demand of the first year, whichever is greater.

- Golden Valley Electric Association, Inc. (GVEA)

  GVEA has a residential schedule with an energy charge for the first 500 kWh and a lower charge for each kWh over 500 kWh of consumption. There is a separate schedule for general service customers depending on their kW demand. For GVEA's general service customers with electrical demand not exceeding 50 kW, there is only a decreasing energy charge associated with three increasing blocks of consumption. General service customers with loads exceeding 25 kW have a schedule which provides for a fixed demand charge per kW plus declining energy charges in correspondence with four increasing consumption blocks.

- Other Electric Utilities

  The remaining electric utilities have tariff schedules which differ in specific details but are similar in structure to those of the larger Railbelt electric utilities. The average residential cost per kWh for the larger utilities in the Anchorage-Cook Inlet area would tend to be less than that charged by the other smaller utilities in the area.

(iii) Conservation and Rate Structure Programs

This section presents conservation and rate structure programs initiated by the electric utilities and government agencies. The effects of these existing programs have been incorporated in the forecasting methodology which is described in Section 5.3.

The utilities have various programs aimed at supplying information to the public concerning the dollar savings associated with electricity conservation. In general, the utilities rely on market forces; however, they promote consumer recognition of those forces. Examples of conservation and rate structure programs introduced by AMLP and GVEA, are described.

- <u>The Anchorage Municipal Light and Power (AMLP) Program</u>

The AMLP program addresses electricity conservation in both residential and institutional settings. It is a formal conservation program mandated by the Powerplant and Industrial Fuel Use Act of 1978 (FUA). The AMLP program is designed to achieve a 10% reduction in electricity consumption. To achieve this level of conservation, AMLP provides information on available state and city programs to its consumers. Additionally, it has programs to:

Distribute hot water flow restrictors;
Insulate 1000 electric hot water heaters;
Heat the city water supply, increasing the temperature by 15°F (decreasing the thermal needs of hot water heaters); and
Convert two of its boiler feedwater pumps from electricity to steam.
Convert city street lights from mercury vapor lamps to high pressure sodium lamps; and
Convert the transmission system from 34.5 kV to 115 kV.

AMLP also supplies educational materials to its customers along with "Forget-me-not" stickers for light switches. The utility has a full time energy engineer devoted to energy conservation program development.

The projected impacts of specific energy conservation programs are detailed in Table B.80 for the period 1981-1987. The greatest impact will occur as a result of street light conversion, transmission line conversion, and power plant boiler feed pump conversion. By 1987, these programs are expected to provide 25,000 MWh of electricity conservation, or 72% of the total programmatic energy conservation. In the case of conversion to new sodium lights, the record shows that AMLP installed 96 kw by the end of 1980, an additional 8 kW in 1981, 16.6 kW in 1982, and 14.3 kW of additional sodium lights in 1983 to date.

In addition to these conservation programs, AMLP has also projected conservation due to price-induced effects. Table B.81 presents the projections. About 60 percent comes from price-induced conservation. After 1983, the rate of increase in conservation is expected to decline sharply, and price-induced conservation will be the principal contributor.

- The Golden Valley Electric Association, Inc. (GVEA) Program

GVEA has an energy conservation program based on a plan established pursuant to REA regulations. The utility employs an Energy Use Advisor who:

Performs advisory (non-quantitative) audits;
counsels customers on an individual basis on means to conserve electricity;
Provides group presentations and panel discussions; and
Provides printed material, including press releases and publications.

GVEA also eliminated its special incentive rate for all electric homes, and placed a moratorium on electric home hook-ups in 1977. It has given out flow restrictors. It has prepared displays and presentations for the Fairbanks Home Show and the Tanana Valley State Fair. It coordinates its programs with the state and other programs.

The efforts of GVEA, combined with price increases and other socioeconomic phenomena, produced a conservation effect as shown in Table B.82. Although much of the decline in average consumption can be attributed to conversions from electric heat to some other fuels, part of the reduction is the direct result of conservation. The data show a reduction from 17,332 kWh/house/yr in 1975 to a level of 9,080 kWh/house/yr in 1981. Table B.82 also shows a moderate upturn in electricity consumption per household in 1982, indicating that the practical limit of conservation may have been reached in the GVEA system.

Currently, GVEA's load management program is directed toward commercial consumers. A significant lower rate schedule is available to commercial customers whose demand is maintained at less than 50 kW. Larger power customers are advised on ways to manage their electrical load to minimize demands. In addition, seasonal rates are available to those large consumers who significantly reduce their demand during the winter peak season. A program is underway to identify customers who operate large interruptible loads during periods of system peak demand. Various methods of residential load management are under study, but none appears cost effective at this time other than voluntary consumer response to education programs.

- Other Utility Programs

  Other utilities have programs similar to the ones described above. For example, FMUS has two main programs aimed at electric conservation and reducing the consumers' electric bill. FMUS placed an advertisement in a local newspaper about energy conservation and offered to provide a free booklet on the topic. Also, FMUS plans to advertise the availability of a "Energy Teller" device to allow the customer to determine the direct cost of using a given appliance. These instruments are expected to be available for free loan for a period of up to two weeks.

- Other Conservation Programs

  There are several efforts, both public and private, under way throughout the State of Alaska. The two main programs that affect the Railbelt area are described in the following paragraphs.

  The State Program. The Conservation Section of the Division of Energy and Power Development (DEPD) is responsible for the administration of the United States Department of Energy's low-income weatherization program. This program has involved the following activities:

  Training of energy auditors;

  Performance of residential energy audits, which are physical inspections including measurements of heat loss;

  Providing grants of up to $300/household, or loans, for energy conservation improvements based upon the audit;

  Providing retrofit (e.g. insulation, weatherization) for low income homes.

  The key to the program is the audit, which is performed by private contractors. The forms employed are designed to show savings that can be achieved in the first year, the seventh year, and the tenth year after energy conservation measures have been implemented. The savings demonstrated provide the basis for qualifying for a grant or loan. The audits focus on major conservation opportunities such as insulation and reduction of infiltration (e.g., by weather stripping, caulking, and storm window application).

The DEPD program achieved a significant level of penetration into the conservation marketplace. Penetration in the state as a whole achieved 24%; and in the combined load centers of Anchorage and Fairbanks it also achieved 24%. Market penetration is computed by taking the ratio of audits relative to the total number of homes in various regions: Kenai Peninsula, Anchorage, Matanuska-Susitna, Fairbanks, Southeast Fairbanks, and regional total. It is useful to note that the audit program was more effective in high cost energy areas (e.g., Fairbanks) indicating that public participation was based upon market forces to some extent.

The DEPD program is currently being phased out, except for low income family assistance, particularly in the Bush Communities where it is estimated that 13% of the homes will be treated in the next three years. Educational programs will continue.

The City of Anchorage Program. The City of Anchorage Program is operated by the Energy Coordinator for the City of Anchorage. This program also involves audits, weatherization, and educational efforts. Based on walk-through audits performed on city buildings and schools, detailed audits have been performed.

The city's weatherization program is available to low income families and provides grants of up to $1600 for materials and incidental repairs. Labor is supplied from the comprehensive Employment Training Act (CETA) program. However, this program is being phased out.

The educational program has involved working with realtors, bankers, contractors and businessmen. It also has involved informal contacts with commercial building maintenance personnel. Finally, it has involved contacts with the general public.

(c) Historical Data for the Market Area

Available economic and electric power data for the State of Alaska and the Railbelt are summarized in Table B.83. The table shows the rapid growth that has occurred in the state's and the Railbelt's population, economy, and use of electric power. The growth has been especially rapid during the last decade.

Between 1960 and 1982, employment in the Railbelt grew from 94,300 to 231,984, an increase of 146 percent, or an average of 4.2 percent per year. The number of households in the Railbelt grew at a faster rate during this period, an average of 4.9 percent per year, reflecting the nationwide trend toward fewer persons per household. Much of the population and economic growth that occurred during this period is attributable to the tremendous increase in state petroleum revenues and general fund expenditures. State petroleum revenues grew from only $4.2 million in 1960 to $3.57 billion in 1982, mainly due to the discovery and development of petroleum on Alaska's North Slope. Between 1960 and 1982 state general fund expenditures rose from less than $100 million per year to $4.6 billion. Figure B.81 illustrates the historical growth in population, showing the growth rate for each five year period from 1960 to 1980.

Consumption of electric energy in the Railbelt has risen significantly faster than the rate of economic growth. Between 1965 and 1982 total energy generation rose from 467 Gwh to 2,934 GWh, a five-fold increase, or an average of 11.4 percent per year. Figure B.82 illustrates the historical growth in net generation, showing the growth rate for each five year period from 1965 to 1980.

Tables B.84 and B.85 present monthly electric power use and peak demand during the period 1976 to 1982 for the Anchorage and Fairbanks load centers. These tables show that while there has been a steady rise in the use of electric energy and in peak demand, there has been considerable variation in monthly energy use and peak demand from one year to the next, mostly due to different weather conditions in the Railbelt. Table B.86 gives the net annual generation of each Railbelt utility between 1976 and 1982.

5.3 - Forecasting Methodology

This section presents the methodological framework used for the forecasts of economic conditions and electricity demand in the Railbelt. The first subsection discusses the effect of world oil prices on power market forecasts. Next, the models used for forecasting purposes are identified and fully explained. Finally, model validation is discussed for the economic model (MAP) and electricity demand model (RED).

(a) The Effect of World Oil Prices on the Need for Power

World oil prices affect the need for electric power in the Railbelt in four basic ways, each of which is explicitly taken into account in forecasting energy demands.

First, higher world oil prices produce higher levels of petroleum revenues to the State of Alaska, mainly through production taxes and royalty payments that are tied directly to the market price of petroleum. Because of the importance of state revenues and spending to the Alaskan economy, changes in the world price of oil have a significant effect on general economic conditions and the growth in electricity demand.

Second, world oil prices impact the cost of power generation. Since much of the electricity used in the Railbelt is generated using fossil fuels, the price of electricity to the consumer will be affected by the world price of oil. As long as fossil fuels fire a substantial portion of the Railbelt's generation facilities, higher world oil prices will lead to higher electricity prices, decreasing the overall demand for electricity. This factor has been considered in the forecasts of electric demands. The same factor has also been integrated in the economic analyses associated with determining the most cost effective generation expansion program for meeting the Railbelt's future electric power demand, which in turn determines the future cost of electricity.

Third, world oil prices affect the degree to which oil and other fossil fuels may be substituted for electricity in certain applications. Inter-fuel substitution and its effect on the demand for electricity was explicitly considered in the load forecasting analysis for the Susitna Hydroelectric Project.

The fourth effect that world oil prices has on the need for power occurs through the influence that petroleum prices have on the profitability of exploration and development of petroleum reserves as well as other energy resources in Alaska. Higher world oil prices provide an incentive for higher levels of oil exploration and development, which in turn leads to higher levels of employment and gross output in the petroleum sector as well as support sectors such as transportation, construction, and services. The economic development and population growth associated with such activity increases electric power demands in the Railbelt as well as other parts of Alaska.

The following sections describe in some detail the ways in which world oil prices and other factors were considered in the economic and load forecasting analyses and generation expansion planning.

(b) Forecasting Models

(i) Model Overview

Four computer-based and functionally interrelated models were used in projecting the market for electric power in the Railbelt and evaluating alternative generation plans for meeting electric power demands. First, a model entitled PETREV, operated by the Alaska Department of Revenue, was utilized to project state revenues from petroleum production based on alternative future petroleum prices. The revenue projections from PETREV and numerous other economic and demographic data were then used by the Man-in-the-Arctic Program (MAP) Model to project economic conditions, including population, employment, and households, for the Railbelt. The economic projections, along with electric power and use information, electricity demand elasticity functions, and other electric power data then served as input to the RED Model to predict electric energy and peak loads in the Railbelt by load center. Finally, the Optimized Generation Planning (OGP) model was used to develop the most cost effective generation plans for meeting projected power requirements. The study on alternative generation expansion plans is described in detail in Exhibit D. The OGP Model is discussed in this chapter in order to describe the total conceptual approach utilized in analyzing the need for power in the Railbelt.

The relationship between the models and their principal input and output data are shown on Figure B.83 which also shows the role of financial analysis in the selection of the final generation expansion plan, also covered in Exhibit D.

Figure B.83 illustrates the parameters and variables that are common to different models and the interdependency of the models. While the planning process moves generally from the PETREV model through the MAP, RED, and OGP models, in one instance output from one model is fed back into a previous model. Electricity prices are estimated and used in the RED model to compute electric energy projections. These projections are then used by the OGP model to develop a generation expansion plan to meet projected demand and the associated cost of electricity. If there is a significant difference between the estimated and computed data, the models are rerun until the cost of supplying power is approximately equal to the price assumptions utilized in the demand model.

The following sections describe each of the four principal models, including their respective submodels and modules, key input variables and parameters, and primary output variables. Additional information on the PETREV Model is available in the quarterly issues of Petroleum Production Revenue Forecast (Alaska Department of Revenue, March

1983). Additional information on the MAP model may be found in a technical documentation report (Institute of Social and Economic Research, June 1983) which presents a detailed description of the model including a complete listing of its equations and input variables and parameters. Another technical documentation report (Battelle, June 1983) presents similarly detailed documentation of the RED model. The OGP model is a proprietary program of General Electric Company. The version used in the current study is presented in the Descriptive Handbook, Optimized Generation Planning Program, Financial Simulation Program by General Electric, March, 1983.

(ii) Petroleum Revenue Forecasting (PETREV) Model

Petroleum revenues currently constitute approximately 85 percent of total state revenues. For this reason, and because state revenues and expenditures have considerable potential variability and are important determinants of future state economic conditions, projections of the most important sources of petroleum revenues, production tax and royalties, are generated by a specialized model, PETREV, operated by the Alaska Department of Revenue (DOR). PETREV is structured to take into account the uncertainties of future oil prices and other factors associated with forecasting petroleum revenues. Using PETREV, the DOR issues updated petroleum revenue projections on a quarterly basis covering a 17 year period, using current data available on petroleum production, a range of world oil prices, tax rates, regulatory events, natural gas prices, and inflation rates.

PETREV is an economic accounting model that utilizes a probability distribution of possible values for each of the factors that affect state petroleum revenues to produce a range of possible state royalties and production taxes. The principal factors influencing the level of petroleum revenues are petroleum production rates, mainly on the North Slope, the market price of petroleum, and tax and royalty rates applicable to the wellhead value of petroleum.

Wellhead value is estimated by a netback approach whereby the costs of gathering and transporting crude oil and a quality differential value are subtracted from the market value at its destination on the West Coast or Gulf Coast of the United States. For petroleum produced on the North Slope, the source of most of the oil produced in Alaska subject to state royalties and production taxes, future wellhead value is estimated as follows. The projected world price of Saudi Arabia medium grade petroleum is adjusted by subtracting (1) the projected cost of pumping oil through the Trans Alaska Pipeline System from Prudhoe Bay to Valdez, including the pipeline tariff, (2) the projected cost of shipping the oil to refineries on the West Coast and the Gulf Coast of the United States, and (3) a projected quality differential factor representing the difference in quality between North Slope petroleum and Saudi Arabia medium grade. The result is the estimated value of petroleum at pump station #1 at Prudhoe Bay, Alaska.

Future royalties collected by the state are estimated by multiplying total projected production in barrels from state lands by the estimated per barrel price at pump station #1, subtracting field costs of production, currently approximately $.68 per barrel, and multiplying the result by .125. This amounts to a 1/8 royalty payment on oil produced after all gathering and transportation costs are met, which the State of Alaska may receive either in kind or in dollars. Future severance, or production, taxes are estimated by multiplying forecasted production, net of the 12.5 percent taken by the state as royalties, by the estimated pump station #1 price and the tax rate adjusted by an economic limit factor (ELF). The tax rate varies between 12.25 and 15 percent of net production value, depending upon the age of production wells. The economic limit factor (ELF) adjustment takes into the account declining well productivity and increased production costs. On the North Slope most production will be subject to a 15 percent severance tax rate. The average ELF for North Slope petroleum production is expected to decline from its current level of 1.0 to close to 0.6 by the year 1999. The decline in the ELF in effect lowers the tax rate to which Alaskan petroleum is subject.

A change in the market price of petroleum of a given percentage has a greater percentage impact on state petroleum revenues. This occurs because the costs of petroleum transportation and gathering and the quality differential value are relatively stable, so the wellhead price, on which state petroleum revenues are based, rises and falls almost dollar for dollar with world oil prices, producing a larger percentage effect on the wellhead value.

Due to the many uncertainties involved in forecasting revenues, the forecasting model projects a range, or frequency distribution, of state petroleum revenues by year, so that for each year a forecasted petroleum revenue figure may be selected based on a given cumulative frequency of occurrence. The model accomplishes this by iteratively selecting a set of input variable values from among alternative values and computing a petroleum revenue figure for each time period. Each projection is computed using a set of accounting equations that estimate royalties and production taxes from each state oil and gas lease for each time period. By selecting the average value of all input data the model produces an average petroleum revenue forecast.

Because of the uncertainties in projecting petroleum prices and their importance in developing alternative generation plans and load forecasts, it is necessary to examine the implications of several different world oil price projections in addition to the price projections developed by the DOR. This need is accommodated by DOR through a petroleum revenue sensitivity accounting model. This sensitivity accounting model, which is in effect a submodel of the PETREV model, utilizes the accounting equations and average values for all input variables other than world oil prices from PETREV, to compute an adjustment to PETREV's average petroleum revenue forecasts based on different assumed world oil price forecasts. By executing the sensitivity model with the alternative petroleum price projections, alternative petroleum revenue projections are developed for use in projecting state economic activity in the MAP model.

Most of the petroleum revenues are available for state expenditures for operations and capital construction. Twenty-five percent of state royalties are, by constitutional provision, deposited directly to Alaska's permanent fund.

The process of projecting state petroleum revenues and the functions of the PETREV model are presented in some detail in the quarterly report entitled "Petroleum Production Revenue Forecast." (Alaska Department of Revenue, March 1983). The petroleum revenue projections used in preparing the electric power market and economic forecasts are based on the March 1983 average expected values of all factors, including petroleum production, other than petroleum prices.

While production rates can be estimated with reasonable accuracy for the next decade because of the long lead time required to put a field into production in Alaska, higher world petroleum prices could be expected to result in higher levels of exploration and development and, by the

1990's, higher levels of production. Production rates from the North Slope, the source of most state production taxes and royalties, are projected to be approximately 1.6 million barrels per day (MMBD) in 1983, to peak at nearly 1.8 MMB/d in 1987, and to steadily decline to .7 MMBD in 1999 (Alaska Department of Revenue March 1983). The petroleum production projections assume continued production from operating fields, production from fields now being developed, and modest levels of production in the 1990's from new fields (Alaska Department of Revenue, March 1983).

(iii) Man-in-the-Arctic Program (MAP) Economic Model

The MAP model is a computer-based economic modeling system that simulates the behavior of the economy and population of the state of Alaska and each of twenty regions of the state corresponding closely to Bureau of the Census divisions. The Railbelt consists of six of those regions: Anchorage, Fairbanks, Kenai-Cook Inlet, Matanuska-Susitna, Seward, and S.E. Fairbanks. The model was originally developed in the 1970's by the Institute of Social and Economic Research of the University of Alaska, under a grant from the National Science Foundation. The model has been continually improved and updated since it was origially developed, and has been used in numerous economic analyses such as evaluations of the economic effects of alternative state fiscal policies and assessments of the economic effects of development of outer continental shelf petroleum leases. An important application of the MAP model has been in providing economic projections for developing electric demand projections. It has been used since 1980 in preparing economic projections in support of planning and design for the Susitna Hydroelectric Project.

The MAP model functions as three separate but linked sub-models, the scenario generator submodel, the economic sub-model, and the regionalization sub-model, as illustrated in Figure 84. The scenario generator sub-model enables the user to quantitatively define scenarios of development in exogenous industrial sectors; i.e., sectors whose development is basic to the economy rather than supportive. Examples of such sectors are petroleum production and other mining, the federal government, and tourism. The scenario generator sub-model also enables the user to implement assumptions concerning state revenues from petroleum production. The economic sub-model produces statewide projections of numerous economic and demographic factors based on quantitative relationships between elements of the Alaskan economy such as employment in basic industries, employment in non-basic industries, state revenues and spending, wages and salaries, gross product, the consumer price index, and population. The regionalization sub-model enables the user to disaggregate the statewide projections of population and employment to each of the 20 separate regions of the state, using data on historical and current economic conditions and assumptions concerning basic industrial development.

Each of the three MAP sub-models exists as a computer program, and each program is supported by a set of input variables and parameters. Each of these programs and the supporting input variables and parameters are discussed briefly in the following sections. Detailed information on each sub-model, including a complete model listing and the input variables and parameters used in executing the model, is provided in the MAP Model Technical Documentation Report.

- Scenario Generator Sub-Model

In order to operate the MAP model, the user must make a number of assumptions concerning the future development of basic industries in the State. Such assumptions are needed because the state economy is driven by interrelated systems of endogenous and exogenous demands for goods and services. Endogenous demands are generated by the resident population and industries that serve that population.

Exogeneous demands originate outside Alaska due to the favorable position of the state to export its minerals and other resources to other states or countries. In Alaska, exogenous demands stem from the state's natural resource base, especially petroleum, non-energy minerals, federal property, and tourist attractions. Exogenous demands lead directly to employment in basic sectors such as mining, and indirectly to employment and output in industries such as oil field services that support basic industry and industries such as housing and restaurants that support workers in basic industries and their families.

The scenario generator model permits the user to build, from among a large number of alternative basic industrial cases, economic scenarios that can be used to project economic conditions in the state of Alaska and, for purposes of the Susitna Hydroelectric Project, the Railbelt. Input data for each of the scenarios are in the form of employment projections by sector and region of the state on an annual basis over the forecast period.

The scenario generator model is also used to select the level of state petroleum revenues that should be assumed available to the state's general fund for expenditure on state government operations and capital investment. As indicated above, petroleum revenues constitute a large proportion of total state revenues which provide the basis for state expenditures, an important driving force of the Alaskan economy.

Key input and output variables and assumptions for the scenario generator are summarized in Section 5.4 of this Exhibit.

- <u>Statewide Economic Sub-Model</u>

The statewide economic model is a system of more than 1,000 simultaneous equations that individually and collectively define the quantitative relationships between economic and demographic factors in Alaska. Values for input variables come from the scenario generator, whose values can be expected to vary from one execution of the model to the next, as well as from files of other necessary exogenous data, whose values do not change across runs. Parameters, whose values are generally fixed from one model execution to the next, are provided from another input file. The equations are solved algebraically each time the model is executed to produce a unique set of values for the dependent variables, some of which are computed only incidentally as part of the mathematical process and others of which constitute projections of statewide economic conditions.

While the equations in the statewide economic model are solved as a unit each time the model is executed, they are grouped for organizational and conceptual purposes into four modules: economic module, fiscal module, population module, and household formation module, as illustrated in Figures B.84 and B.85.

The equations in the economic module express relationships between economic factors such as employment in basic industrial sectors and output and employment in support sectors. Important products from the economic module include projections of employment and payroll by industry and personal income.

The fiscal module computes state government revenues and the mix of government expenditures, which is used as input to the economic module. A separate module was created for this purpose because of the significance of state expenditures to the state's economy and the model's periodic application in estimating the economic effects of implementing alternative state fiscal policies and assuming various alternative future state revenue levels. This module plays a key role in examining the fiscal and economic effects of different future world petroleum prices and state petroleum revenue levels. Specific assumptions concerning state spending are implemented in the fiscal module as state fiscal policy parameters, which are discussed below.

The population module expresses the relationships between population and economic factors recognized as key determinants of population. Such factors include employment, labor participation rates, fertility and mortality rates, and unemployment and wage rate differentials between Alaska and the rest of the United States.

The economic, fiscal and population modules are operated simultaneously to arrive at the solution. The fourth module, household formation, is operated after the population module yields its results.

Equations in the household formation module express the relationship between the formation of households in Alaska and population by age group, sex, and race. Each age-sex cohort has its own propensity to form households which, over the last few years has generally increased. This increase is expected to continue.

- Regionalization Sub-Model

Statewide employment, population, and household projections are disaggregated by the regionalization model, the third sub-model of the MAP economic modeling system. Disaggregation is accomplished by combining statewide projections with regional industrial development data from the scenario generator model and regional parameters based on historical economic and demographic relationships between each region and the state. This process, illustrated in Figure B.86, produces projections by region or region group such as the Anchorage and Fairbanks greater metropolitan areas.

- Input Variables and Parameters

As indicated above, some input variables are factors whose values are provided by the user to the model and whose values can be expected to change from one execution of the model to the next. Parameter values are generally fixed both over time within each simulation and during the course of successive model executions.

The scenario generator model produces sixteen input variables to define the exogenous economic assumptions for each model execution:

. Agriculture Employment
. Mining Employment
. High Wage Exogenous Construction Employment
. Low Wage Exogenous Construction Employment
. High Wage Exogenous Manufacturing Employment
. Low Wage Exogenous Manufacturing Employment
. Exogenous Transportation Employment
. Fish Harvesting Employment
. Active Duty Military Employment
. Civilian Federal Employment
. State Production Tax Revenue
. State Royalty Income
. State Petroleum Lease Bonus Payment Revenue
. State Petroleum Property Tax Revenue
. State Corporate Petroleum Tax Revenue
. Tourists Entering Alaska

Of these sixteen variables, eleven are used to define discrete industrial development scenarios and are therefore region specific. The remaining five input variables are elements of state revenue forecasts. Estimates of future state petroleum revenue from state petroleum production taxes and royalties are obtained from projections generated by the Alaska Department of Revenue based, for purposes of the Susitna Hydroelectric Project, on alternative projections of world petroleum prices.

To produce economic projections in years after 1999, the last year for which petroleum revenue projections are available from the Alaska Department of Revenue, petroleum revenue forecasts were extrapolated to the year 2010 using the average annual rate of change between 1996 and 1999.

The Institute of Social and Economic Research provides corresponding estimates of future state lease bonus payments, state petroleum property taxes, and state petroleum corporate taxes. Other variables necessary to execute the MAP Model include less important exogenous factors, such as natural population growth rates, and startup values.

The regionalization model is executed using a data series for 40 exogenous variables, based on 20 state regions, and for each region, the basic sector employment and the government sector employment from the scenario generator. Total state population, households, and the ratio of support to total employment are provided by the state economic sub-model.

The MAP model utilizes three types of parameters: variable state fiscal policy parameters, stochastic parameters, and calculated, or non-stochastic, parameters.

Variable state fiscal policy parameters are used primarily in the fiscal module to represent policy options for the collection of revenues and the timing and composition of state expenditures. In general, these parameters, which may be varied to reflect alternative state fiscal policies or events were left unchanged in preparing the electric power market forecasts for the Susitna Hydroelectric Project. The most important function of these parameters is to quantitatively define state expenditure and revenue policies. In projecting economic conditions for the Susitna Hydroelectric Project, the following assumptions were made:

- o state expenditures for operations and capital improvements in 1983 dollars will rise in proportion to state population as long as revenues can support this level of expenditure; this assumption is in accordance with a 1982 amendment to the Alaska State Constitution setting a ceiling on state expenditures;

- o when revenues from existing sources cannot support expenditures at the constant real per capita level, earnings from the permanent fund will be made available for operating and capital expenditures at the expense of the Permanent Fund dividend program; as revenues decline state spending priorities shift from subsidies to capital improvements;

- o when revenues from permanent fund earnings and other sources are not sufficient to maintain expenditures at the constant real per capita level, a state personal income tax will be reimposed at its previous rate;

- o when all of these revenue sources plus accrued general fund balances are unable to support expenditures at the constant real per capita level, expenditures will be curtailed so that they will not exceed revenues.

Stochastic parameters are coefficients computed using regression analysis. They are used primarily in the economic module of the statewide economic model to express the functional relationships between economic factors such as employment, wages and salaries, wage rates, gross product, and other national and regional economic factors such as unemployment and consumer price indices. Stochastic parameters are also used in the population module to express the relationship between population migration into and out of Alaska and wage rate and unemployment level differentials.

Calculated or non-stochastic parameters are generally calculated rates or other quotients, and are used primarily in the population and household formation modules and the regionalization model. Calculated parameters include factors such as survival rates for the population by race, age group, and sex. Calculated parameters used in the regionalization model include factors such as ratio of population to residence and adjusted employment by region.

- MAP Model Output

Economic forecasts through the year 2010 were generated based on alternative petroleum price and state petroleum revenue cases and other input variables and parameters described above.

Specific MAP Model output used directly as input to the Railbelt Electricity Demand (RED) Model are the following:

- o population by load center, Greater Anchorage and Greater Fairbanks, by year 1981 through 2010;
- o total employment by load center by year;

o total households in the state by age group of head of household - 24 and under years of age, 25-29, 30-54, and over 55 - by year;

o total households by load center by year;

(iv) Railbelt Electricity Demand (RED) Model

The Railbelt Electricity Demand (RED) Model is a partial end use - econometric model that projects both electric energy and peak load demand in the Anchorage-Cook Inlet and Fairbanks-Tanana Valley load centers of the Railbelt for the period 1980-2010. The model was originally written by the Institute of Economic and Social Research (ISER) of the University of Alaska (ISER, May 1980). It was later modified and expanded by Battelle Pacific Northwest Laboratories (Battelle, December 1982, Volume VIII). The present (1983) version is a further modification and improvement, including a validation of the model performance. The results of these efforts are fully documented in the RED Documentation Report (Battelle, June 1983). A summary description of the methodology used by the RED model, and an explanation of each module of the RED model are presented in the following paragraphs. It is followed by a description of the input and output data.

The RED model is a simulation model designed to forecast annual electricity consumption for the residential; commercial, small industrial, government; large industrial; and miscellaneous end-use sectors of the two load centers of the Railbelt region. The model is made up of seven separate but interrelated modules, each of which has a discrete computing function within the model. They are the uncertainty, housing, residential consumption, business consumption, program-induced conservation, miscellaneous consumption, and peak demand modules. Figure B.87 shows the basic relationship among the seven modules.

The model may be operated probabilistically, whereby the model produces a frequency distribution of projections where each projection is based on a different, randomly selected set of input parameters. The model may also be operated on a deterministic basis whereby only one set of forecasts is produced based on a single set of input variables. When operated probabilistically, the RED model begins with the Uncertainty Module, which selects a trial set of model parameters to be used by other modules. These parameters include price elasticities, appliance saturations, end-use consumption and regional load factors. Exogenous forecasts of population, economic activity, and retail prices for fuel oil, gas and electricity are used with the trial parameters by the Residential Consumption and Business Consumption Modules to produce forecasts of electricity consumption. These forecasts, along with additional trial parameters, are used in the Program-Induced Conservation Module to simulate the effects of government programs that subsidize or mandate the market penetration of certain technologies that reduce the need for power. This program-induced component of conservation is in addition to those savings that would be achieved through normal consumer reaction to energy prices. The consumption forecasts of residential and business (commercial, small industrial, and government) sectors are then adjusted to reflect these additional savings. The revised forecasts are used to estimate future miscellaneous consumption and total sales of electricity. These forecasts and separate assumptions regarding future major industrial loads are used along with a trial system load factor to estimate peak demand.

After a complete set of projections is prepared, the model begins preparing another set by returning to the Uncertainty Module to select a new set of trial parameters. After several sets of projections have been prepared, they are formed into a frequency distribution to allow the user to determine the probability of occurrence of any given load forecast.

When only a single set of projections is needed, the model is run in certainty-equivalent mode whereby a specific default set of parameters is used and only one trial is run.

The RED model produces projections of electricity consumption by load centers and sectors at 5-year intervals. A linear interpolation is performed to obtain yearly data.

The outputs from the RED model runs are used by the Optimized Generation Planning (OGP) model to plan and dispatch electric generating capacity for each year. The remainder of this section presents a description of each module in the RED model.

- <u>Uncertainty Module</u>

  The purpose of the Uncertainty Module is to randomly select values for individual model parameters that are considered most subject to forecasting uncertainty. These parameters include the market saturations for major appliances in the residential sector; the price elasticity and substitute energy forms and cross-price elasticities of demand for electricity in the residential and business sectors; the intensity of electricity use per square foot of floor space in the business sector; and the electric system load factors for each load center.

These parameters are generated by a Monte Carlo routine, which uses information on the distribution of each parameter (such as its expected value and range) and the computer's random number generator to produce sets of parameter values. An overview of information flows within the Uncertainty Module is given in Figure B.88. Each set of generated parameters represents a "trial". By running each successive trial set of generated parameters through the rest of the modules, the model builds distributions of annual electricity consumption and peak demand. The end points of each distribution reflect the probable range of annual electric consumption and peak demand, given the level of uncertainty.

The Uncertainty Module need not be run every time RED is run. The parameter file contains "default" values of the parameters that may be used to conserve computation time.

In the current study, the RED model was used in certainty-equivalent mode for all forecasts. Sensitivity runs were performed for the reference case, using the probabilistic mode. The results are presented in Section 5.4.

- The Housing Module

The Housing Module calculates the number of households and the stock of housing by dwelling type in each load center. The Housing Module's structure is shown in Figure B.89. Using regional forecasts of households and total population, the housing module first derives a forecast of the number of households served by electricity in each load center. Next, using exogenous statewide forecasts of households headship rates and age distribution of Alaska's population, it estimates the distribution of households by age of head and size of household in each load center. Finally, it forecasts the demand for four types of housing stock: single family, mobile homes, duplexes, and multifamily units.

The supply of housing is calculated in two steps. First, the supply of each type of housing from the previous period is adjusted for demolition and compared to the demand. If demand exceeds supply, construction of additional housing begins immediately. If excess supply of a given type of housing exists, the model examines the vacancy rate in all types of houses. Each type is assumed to have a maximum vacancy rate. If this rate is exceeded, demand is first reallocated from the closest substitute housing type, then from other types. The end result is a forecast of occupied housing stock for each load center for each housing type in each forecast year. This forecast is passed to the Residential Consumption Module.

- Residential Consumption Module

The Residential Consumption Module forecasts the annual consumption of electricity in the residential sector. The Residential Consumption Module employs an end-use approach that recognizes nine major end uses of electricity, and a "small appliances" category that encompasses a large group of other end uses. They are water heaters, cooking, clothes dryers, refrigerators, freezers, dishwashers, clothes washers, and sauna-jacuzzis. Figure B.90 shows the calculations that take place in this module.

For a given forecast of occupied housing, the Residential Consumption Module first adjusts the housing stock to net out housing units not served by an electric utility. It then forecasts the residential appliance stock and the portion using electricity, stratified by the type of dwelling and vintage of the appliance. Appliance efficiency standards and average electric consumption rates are applied to that portion of the stock of each appliance using electricity and the corresponding consumption rate to derive a preliminary consumption forecast for the residential sector. Finally, the Residential Consumption Module receives exogenous forecasts of residential fuel oil, natural gas, and electricity prices, along with "trial" values of price elasticities and cross-price elasticities of demand from the Uncertainty Module. It adjusts the preliminary consumption forecast for both short- and long-run price effects on appliance use and fuel switching. The adjusted forecast is passed to the Program-Induced Conservation Module.

- Business Consumption Module

The Business Consumption Module forecasts the consumption of electricity by load center for each forecast year. Because the end uses of electricity in the commercial, small industrial, and government sectors are more diverse and less known than in the residential sector, the Business Consumption Module forecasts electrical use on an aggregate basis rather than by end use. Figure B.91 presents a flowchart of the module.

RED uses a proxy (the stock of commercial and industrial floor space) for the stock of capital equipment to forecast the derived demand for electricity. Using an exogenous forecast of regional employment, the module forecasts the regional stock of floor space. Next, econometric equations are used to predict the intensity of electricity use for a given level of floor space in the absence of any relative price changes. Finally, a price adjustment similar to that in the Residential Consumption Module is applied to derive a forecast of business electricity consumption, excluding large industrial demand, which is exogenously determined. The Business Consumption Module forecasts are passed to the Program-Induced Conservation Module.

- Program-Induced Conservation Module

Battelle developed this module for the State of Alaska, Office of the Governor (Battelle, December 1980, Volume VIII) to analyze potential large scale conservation programs that would be subsidized by the State of Alaska. This module permits explicit treatment of such government programs to foster additional market penetration of technologies and programs that reduce the demand for utility-generated electricity. The module structure is designed to incorporate assumptions on the technical performance, costs, and market penetration of electricity-saving innovations in each end use, load center, and forecast year. Figure B.92 provides a flowchart of the process employed.

The module forecasts the additional electricity savings by end use that would be produced by government programs beyond that which would be induced by market forces alone, the costs associated with these savings, and adjusted consumption in the residential and business sectors.

In the current study, this module was not used. There were several reasons: existing conservation programs are being phased out; there are many uncertainties in long term government conservation programs; and reliable data to estimate additional electricity savings beyond that which would be induced by market forces alone, is limited for the Railbelt region.

- Miscellaneous Consumption Module

  The Miscellaneous Consumption Module forecasts total miscellaneous consumption for second (recreation) homes, vacant houses, and street lighting. The module uses the forecast of residential consumption to predict electricity demand in second homes and vacant housing units. The sum of residential and business consumption is used to forecast street lighting requirements. Figure B.93 provides a flowchart of this module.

- Peak Demand Module

  The Peak Demand Module forecasts the annual peak demand for electricity. The annual peak load factors were based on an analysis of historical Railbelt load patterns. A two-stage approach using load factors is used. The unadjusted residential and business consumption, miscellaneous consumption, and load factors generated by the Uncertainty Module are used to forecast preliminary peak demand. Separate estimates of peak demand for major industrial loads are then added to compute annual peak demand for each load center. Figure B.94 provides a flowchart of this module.

- Input Data

  There are five input data files to the RED model. The RDDATA file contains output data of the MAP model, including load center population, households, and employment and state household by age group, and the real prices of fuel oil and natural gas, by load center and end-use sector.

  The RATE DAT file contains the real prices of electricity by load center and end-use sector. These prices are derived from present costs of electricity adjusted to future conditions based on the OGP results.

  The PARAMETER file contains the numerical values that describe the distributions of the parameters varied in the Uncertainty module. These variables are: housing demand coefficients; saturation rate of electrical applicances, floor space elasticities; short-term and long-term own-price and cross-price elasticities for electricity, fuel oil, and natural gas; and annual load factors.

The EXTRA DAT file contains information on the annual electrical consumption and peak demand of large industrial projects.

- Output Data

The RED output report contains various tables generated by the program. The main tables are the following:

- o Number of households for each load center, forecast year (1980, 1985, and at five year intervals to 2010), and type of housing (single family, multifamily, duplex, and mobile homes);
- o Residential appliance saturations for each load center, forecast year, and type of housing;
- o Residential use per household without price elasticity adjustments for each load center, forecast year, and appliance category (small appliance, large appliance, and space heat);
- o Business use per employee with price elasticity adjustments for each load center, and forecast year;
- o Electric energy requirements for each load center, year, and category of consumption (residential, business, miscellaneous, incremental conservation savings, large industrial, and total;
- o Peak electric requirements for each load center and year.

Output from the RED model is used as input in the OGP computer model for the purposes of analyzing alternative expansion programs.

(v) Optimized Generation Planning (OGP) MODEL

The OGP program was developed over ten years ago by General Electric Company (GE) to combine the three main elements of generation expansion planning (system reliability, operating and investment costs) and automate generation addition decision analysis. The following description of the model was extracted from GE literature and the Descriptive Handbook (GE, March 1983).

The first calculation in selecting the generating capacity to install in a future year is the reliability evaluation using either percent installed reserves or loss-of-load probability (LOLP). This answers the questions of "how much" capacity to add and "when" it should be installed. A production costing simulation is also done to determine the operating costs for the generating system with the given unit additions. Finally, an investment cost analysis of the capital costs of the unit additions is performed. The operating and investment costs help to answer the question of "what kind" of generation to add to the system. Figure B.95 outlines the procedure used by OGP to determine an optimum generation expansion plan.

The next three sections (reliability evaluation, production simulation, and investment costing) review the elements of these computations. Then, the OGP optimization procedure is described, followed by a list of the input and output files.

- Reliability Evaluation

  Historically, electric utility system planners measured generation system reliability with a percent reserves index. This planning design criterion compared the total installed generating capacity to the annual peak load demand. However, this approach proved to be a relatively insensitive indicator of system reliability, particularly when comparing alternative units whose size and forced outage rate varied.

  Since its introduction in 1946, the measure that has gradually gained widest acceptance in the industry is the "loss-of-load probability" (LOLP). The LOLP method is a probabilistic determination of the expected number of days per year on which the demand exceeds the available capacity. It factors into the reliability calculation the forced and planned outage rates of the units on the system as well as their sizes. A LOLP of 1 day in 10 years is a usual industry standard.

Computing LOLP requires an identification of all outage events possible (in a system with n units, this means 2^n events) and then a determination of the probability of each outage event. However, since LOLP is concerned with system capacity outages and not so much with particular unit outages, the probability of a given total amount of capacity on outage is calculated. Utilizing a highly efficient recursive computer technique, capacity outage tables are calculated directly from a list of unit ratings and forced outage rates.

The LOLP for a particular hour is calculated based on the demand and installed capacity for the hour. The reserves are given by capacity minus demand. On this basis, a deficiency in available capacity (i.e., loss of load) occurs if the capacity on forced outage exceeds the reserves. The probability of this happening is read directly from the cumulative outage table and is the LOLP for a single hour.

In addition to calculating the percent installed reserves, OGP can also calculate a daily LOLP (days/year). The daily LOLP is determined by summing the probabilities of not meeting the peak demand for each weekday in the year. The hourly LOLP is calculated by summing the probabilities of not meeting the load for all the hours in the year.

- Production Simulation

Once a system with sufficient generating capacity has been determined by the reliability evaluation, the fuel and related operating and maintenance (O&M) costs of the system must be calculated. OGP does this by an hourly simulation of system operation.

The program commits and dispatches generation based on economics so as to minimize costs. However, the user has the option of biasing or overriding the normal economic operation of the system. This can be accomplished in two ways. The user may specify weighting factors for various environmentally related quantities such that the program will operate those units to minimize their impact. The user may also limit, on a monthly basis, the number of hours that units may run or the amounts of different fuels that may be consumed.

The production simulation in OGP is performed in six steps: load modification based on recognition of contractual purchases and sales; conventional hydro scheduling and its associated load modification; monthly thermal unit maintenance scheduling based on planned outage rates; pumped storage hydro or other energy storage scheduling; thermal unit commitment for the remaining loads based on economics and/or environmental factors, spinning reserve rules, and unit cycling capabilities; and unit dispatch based on incremental production costs and environmental emissions. The production simulation is for a single utility system or pool. Unrestrained power transfer capability is assumed between areas or companies internal to the pool represented.

Purchases and Sales. The OGP production cost load model is an hour-by-hour model of a typical weekday and weekend day for each month, arranged in monotonically decreasing order. These hourly loads are modified to reflect the firm purchases and sales between the area being studied and entities outside that area. Each contract has associated with it a demand charge ($/kW/yr) and an energy charge ($/kWh).

Conventional Hydro Scheduling. The power and energy available from any conventional hydroelectric project used in a simulation is divided into two types: base load and peak load. The base load energy that must be produced is accounted for by subtracting a constant capacity from every hourly load in the month as shown on Figure B.96. This capacity value is referred to as the plant minimum rating. After this baseload energy is used, any remaining energy available is used for peak shaving. In such situations, the program uses the remaining capacity and energy of the hydro unit to reduce the peak loads as much as possible. If any excess energy exists at the end of a month, a user-specified maximum storage amount can be carried forward into the next month.

Thermal Unit Maintenance. On a utility system, the planned maintenance of individual units is usually performed on a monthly basis. During these periods, the units are unavailable for energy production. Maintenance scheduling is normally done so as to minimize the effect of both system reliability and system operating costs. A common strategy for scheduling maintenance, and the method used in OGP, is the levelized reserves approach. Basically, the monthly peak loads are examined throughout the year, and incremental amounts of generating capacity maintenance are scheduled to try to levelize the peak load plus capacity on maintenance throughout the year.

Increased maintenance levels which might be required during the first few years of a unit's operation are modeled using an immaturity multiplier. OGP also allows the user to annually input a predetermined maintenance schedule for units for which this information is available.

Thermal Unit Commitment. After modifications for contracts, hydro, unit maintenance, and energy storage, the remaining loads must be served by the thermal units on the system. In OGP, the units can be committed to minimize either the operating costs, as is usually done, or some combination of user specified environmental factors and operating costs. The operating costs are calculated from the fuel and variable O&M costs and input-output curve for each unit. Fixed O&M costs do not effect the order in which units are committed, but are included in the total production cost.

The unit commitment logic determines how many units will be on-line each hour and also attempts to provide an adequate level of operating reliability while minimizing the system operating costs and/or environmental emissions. The operating reliability requirement is met by committing sufficient generation to meet the load plus a user specified spinning reserve margin. Units are committed in order of their full load energy costs or emissions, starting with the least expensive.

Thermal Unit Dispatch. If a unit is committed, the unit's minimum loading level requires that its output be at that level or higher. When the final commitment has been established, each unit will be loaded to at least its minimum. Typically the sum of the minimums does not equal the load. Additional load will be served by the units' incremental loading sections. The dispatching function in the OGP production simulation loads the incremental sections of the units committed in a manner which serves the demand at minimum system fuel cost or emissions. This dispatch technique is the equal incremental cost approach.

- <u>Investment Costing</u>

  The investment cost analysis in OGP calculates the annual carrying charges for each generating unit added to the system. This is computed based on a $/kW installed cost, a kW nameplate rating, and an annual levelized fixed charge rate.

- <u>OGP Optimization Procedure</u>

  For the year under study, a reliability evaluation is performed. This determines the need for additional generating capacity. If the capacity is sufficient, the program calculates the annual production and investment costs, prints these values, and proceeds to the next year.

  If additional capacity is needed, the program will add units from a list of available additions until the reliability index is met. For each combination of units added to the system, OGP does a production simulation and investment cost calculation for the year under study. The program uses the information gained from the cost calculations to logically step through the different combinations of units to add, eliminating from consideration combinations that would produce higher annual costs than previously found. This process continues until the expansion giving the lowest annual costs is found. The selected units are added to the system, and the program proceeds to the next year of the study.

  In cases where operating cost inflation and/or time variation in unit outage rates are present, the OGP optimization logic utilizes a "look-ahead" feature. The look-ahead feature develops levelized fuel and O&M costs and mature outage rates for use in the economic evaluation. As part of the output information available, the user obtains documentation of the relative costs of all the alternatives examined. After the generating unit selection, the reliability and costing calculations are repeated for the chosen alternative so that the expansion report available for the user contains the correct annual values.

- <u>Input Data</u>

  There are two major input files to OGP: the Generation file and the Load file. The Generation file model is created for use as a data base representing the in-service and on-order generating units. For each unit, the following characteristics are described:

o Type of generator
o Unit sizes and earliest service year allowable
o Unit costs
o Fuel types and costs
o Operation and maintenance costs
o Heat rates
o Commitment minimum uptime rule
o Forced outage rates
o Planned outage rates

The Load file is specified by the user to represent peak and shape characteristics which are projected to occur for the years included in the OGP study. The user supplies the following load shape data:

o Annual peak and energy demand
o Month/annual ratios
o The 0%, 20%, 40%, and 100% points on the peak load duration curve, by month
o Typical reference weekday and weekend-day hourly ratios by month

In addition to these two input files, the user uses the Data Preparation (DP) program and the Generation Planning (GP) program to run the OGP model. The DP program is used in setting up standard tables which describe the thermal and hydro options. Included are tables for plant capital, O&M, and fuel costs, inflation patterns, planned and forced outages rates, minimum loading points, and environmental data. The GP program includes input data on loss of load probability criteria, hydro firm energy, economic parameters, and output options.

- Output Data

Output options have been designed and included in OGP to provide the user with flexibility in the level of detail and volume of documentation received. Complete output reports as well as summary outputs are available.

The output available from the OGP program includes the following information:

o Listing of the input data.
o Standard tables, as defined by the user, for various unit characteristics.

- o Listing of the unit types and sizes available for optimization and their characteristics.
- o Listing of the Load file for the study period.
- o Listing of the generating units on the system and their characteristics.
- o Year-by-year summary of the firm contracts input by the user.
- o Production simulation summaries, listing all of the generating units of the system with their energy output, fuel and O&M costs, fuel consumption, and environmental emissions. These summaries can be obtained on a monthly or annual basis, for all the decision passes or just the optimum system.
- o Summary of all the expansion alternatives, with their associated costs and reliability measures, evaluated during the optimization.
- o Summaries of the final system expansion through time and the associated costs.

(c) Model Validation

Both the MAP and RED models are used to simulate future conditions based on alternative assumptions concerning world and state economic conditions and electricity demand in the Railbelt. Measures that have been taken to ensure that both models simulate economic and electricity utilization conditions and relationships as accurately as possible are summarized below.

(i) MAP Model Validation

Validation of the MAP Model has been accomplished using two separate but interrelated techniques. First, a standard set of statistics was computed for each of the stochastic parameters used in the MAP Model equations. These statistics provide information on the expected accuracy of each coefficient and the probability that each coefficient expresses the correct relationship between variables. Second, the MAP Model was tested to determine the accuracy with which it could simulate observed historical conditions.

- Stochastic Parameter Tests

Stochastic parameters are, as indicated above, coefficients computed using regression analysis, a statistical procedure whereby the quantitative relationship between variables is estimated by one or more computed coefficients. Most of the equations in the economic module of the statewide economic model are computed using regression analysis.

In estimating coefficients using regression analysis a number of statistics are computed that indicate the accuracy of the coefficient and the overall efficiency of the equation in estimating the true value of the dependent variable. Among these statistics are t-values and correlation coefficients. They are used both in selecting the best independent variables for estimating a given dependent variable and in determining the expected accuracy of the final equation.

Correlation coefficients, t-values, and several other statistics have been computed for each stochastic equation used in the MAP Model. In each equation efforts have been made to obtain the highest possible values for these statistics in order to ensure that the model reflects actual economic relationships as accurately as possible. As a result of this effort all the coefficients used in the MAP Model have a relatively high level of statistical significance.

- Simulation of Historical Economic Conditions

Although the MAP Model has been in use since 1975, analyses conducted for the Susitna Hydroelectric Project were the first applications of the model in long range projection of economic conditions. Previous applications of the model had been in analysis of economic effects of alternative state policies. It is not possible, therefore, to test the model's projection accuracy using old forecasts. However, the model's accuracy was tested by simulating historical economic conditions by executing the model utilizing historical data and input variables. Table B.87 summarizes the results of simulation of selected historical conditions. The table shows that the MAP Model reproduces historical conditions with reasonable accuracy, in a period when significant growth and structural change occurred.

(ii) Red Model Validation

The accuracy of the RED Model was assessed by substituting historical values for the "inputs" or "drivers" of the model, and then the predicted values were compared with actual values. The historical period used in the analysis was brief because of the lack of available data for the end-use forecasting model. Complete historical data on end-use (fuel mode split, appliance saturation, end-use energy consumption, etc.) are only available for 1980. Therefore, the accuracy tests which can be performed on the model are limited. The tests were performed for the period 1980-1982.

Table B.88 summarizes the results. The 1982 results obtained from the RED Reference Case are compared to actual data from utilities. In addition, the model was run using the best estimates of 1982 economic drivers and fuel prices. These results are also shown on Table B.88, as the Backcast Case.

Even though the RED model is a long term forecasting model which uses 5-year interval inputs, it produces a forecast error of only 0.6 percent in Fairbanks and 1.7 percent in Anchorage when compared to actual data. The remaining discrepancies for the individual sectors appear related to the quality of the input data. There might also be some differences in the definition of each sector between the RED model and the utilities. However, the overall results show that the forecasts agree closely with the actual values.

5.4 Forecast of Electric Power Demand

(a) Oil Price Forecasts

Forecasting the future world price of oil is a complex task and most previous forecasts have been lacking in accuracy particularly over the last ten years when oil markets received radical upward price shocks.

Numerous forecasts of future oil prices are available and these vary in methodology used, their purpose and underlying reasoning, and the experience of the forecaster. In providing a complete review of current oil price forecasts, several forecasts are discussed below.

(i) Alaska Department of Revenue (DOR):

The DOR is the State agency responsible for forecasting State petroleum revenues for the purpose of Alaskan state budgeting and economic planning. As State revenue from petroleum production accounts for almost 90% of the State's annual budget, the forecast prepared by DOR is used to provide information to the Governor and Legislature in establishing the level of the State government's expenditures and monitoring the revenue flow during the fiscal year. To assist in this process, DOR's forecast estimates the future petroleum revenues on a monthly basis for two years, by quarters for the third year, and annually for the following fourteen years. The forecasts are updated quarterly.

In developing the revenue forecast, a number of State employees of the Office of Management and Budget, Department of Natural Resources, and DOR each develop one to ten scenarios of future world oil prices, and assign a subjective probability to each scenario. Using the Delphi method, DOR aggregates these individuals' forecasts and develops a probability density function using a computer model. The individual probability density functions are then aggregated by the model to produce a composite probability distribution of future world oil prices.

The mean or average oil price for each period is determined from the composite frequency distribution. The mean oil prices for the March 1983 quarter are summarized below and year-by-year values are presented in Table B.89.

Year(s)	Percent Change -%/yr.	Price in Final Year Period - 1983$/bbl
1983	-17.2	28.95
1984	-5.4	23.96
1985	-1.4	22.67
1986	-1.8	22.35
1987	1.3	21.95
1988-1999*	1.3	25.60

In addition to oil prices, the DOR also enters into the PETREV the probability distribution of many other variables, including North Slope production rates, which is an extremely important factor in future revenues. The model is then run to arrive at the probability distribution of future revenues. The 30% Revenue Case is used for budget, and the 50% Case is used for economic planning.

The two revenue cases mean that there is a probability of 70% (100%-30%) and 50% (100%-50%) respectively that revenues will be equal to or greater than the estimated revenues calculated for the cases.

*If the 1.3% DOR annual escalation is assumed to continue to 2040, a price of $42.48/bbl. would occur.

With each of the alternative revenue cases, (30% & 50%) there is an implicit oil price forecast which can be estimated using the PETREV model system in a reverse fashion, beginning with revenues and running the models until the associated oil prices are determined using the mean values of other variables. The implicit oil price forecasts for the 30% and 50% Revenue Cases are presented below.

Year(s)	Percent Change -%/yr. 30%	50%	Price in Final Year of period 1983$/bbl 30%	50%
1983	-21.5	-17.0	28.95	28.95
1984	-7.7	2.5	22.74	24.04
1985	-3.2	-10.5	21.00	24.63
1986	-3.9	-2.5	20.32	22.05
1987	-1.2	-0.7	19.52	21.49
1988	1.0	-0.4	19.29	21.34
1989	-6.1	-1.1	19.10	21.25
1990	-3.7	-3.4	17.93	21.01
1991	-2.0	-1.1	17.26	20.29
1992	-4.1	-4.1	16.92	20.07
1993	-1.7	-2.0	16.22	19.25
1994	-2.3	-0.5	15.94	18.86
1995	-1.5	-4.1	15.58	18.77
1996	-2.5	-0.3	15.34	18.00
1997	-0.5	-0.9	14.95	17.94
1998	-0.8	-0.6	14.88	17.78
1999*	-1.5	-1.1	14.76	17.78

(ii) Data Resources Incorporated (DRI)

DRI is a well-known forecasting organization which provides forecasts of GNP, economic indicators, and commodity prices including prices for oil, gas and coal. Extensive use is made of econometric and other computer models including special energy forecasting models such as the DRI Drilling Model, DRI Coal Model and the DRI Energy Model. Supply and demand for oil are estimated to arrive at a forecast price for oil. An example of the forecast oil production and price data that DRI develops is shown in Figure B.97.

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* If the average DOR rate of change from 1994 to 1999 is extrapolated through 2040, the forecasted prices for the 30% and 50% Revenue Cases would be $7.90/bbl. and $11.40/bbl., respectively.

DRI prepares long term forecasts of oil, natural gas, and coal prices quarterly. Their Spring 1983 forecast provides estimated future prices through 2005.** The key macro-economic assumptions behind their oil prices are that the U.S. economy will grow at an approximate 2% real rate in 1983, accelerating to a high 5.2% rate for 1984 and 4.5% for 1985. From 1985 to 1990 the growth rate will stabilize at an approximate 2.8%/yr. rate decreasing to 2.3%/yr. over the longer term, i.e. after 1990. Inflation, as measured by the Implicit Price Deflator, is assumed to be 4.7% in 1983, 5.2% in 1984, and about 6%/yr. from 1985-2000.

DRI's Base-case estimate of future oil prices (average crude acquisition price for U.S. refineries) shows prices dropping to about $25/bbl (1983$) in 1984 and then increasing at a real rate of about 6.6%/yr. from 1984-1990 to give a price of about $37/bbl in 1990. The decrease in real prices during 1983 and 1984 reflects a weak economy which strengthens rapidly during 1984 and 1985 allowing OPEC to exercise greater influence over the world oil market such that an average real rate of price increase of 6.6% can be maintained from 1985-1990. After 1990, DRI has assumed that the real rate of increase in oil prices will taper off to 4.4%/yr. for 1990 to 1995, approximately 3% from 1995-2000 and around 1.0% from 2000-2005. DRI's Base-case estimates are summarized below and presented year-by-year in Table B-89.

Year(s)	Real Rate of Price Change -%/yr.	Price in Final Year of Period-1983$/bbl
1983	-13.1	28.95
1984	7.4	25.17
1985-1990	6.5	36.99
1991-1995	4.4	45.85
1996-2000	3.1	53.43
2001-2005*	1.1	56.54

The 1983 prices listed above were determined by adjusting the 1982 prices in the following manner: (1) the 1982 prices for the years of 1984, 1990 and 2000 are increased

* DRI's forecast extends to 2005. Assuming the same DRI rate of change (1.1%) from 2001-2005 applies for 2006-2040, the 2040 price becomes $84.15/bbl in 1983 dollars.

** Data Resources, Inc. U.S. Long Term Review, Spring 1983.

by the 1983 vs GNP deflator value (4.7%) to provide prices in 1983 dollars; (2) 1983 prices for intervening years were interpolated; and (3) prices from 2000 to 2010 are extrapolated using Base Case escalation rate of 1.14%.

DRI also developed a LOWOIL and HIGHOIL price scenario stating that uncertainty over oil pricing makes it useful to examine alternative scenarios. No specific discussion was given by DRI of the economic or political forces which would underlie the LOWOIL HIGHOIL scenarios. The LOWOIL HIGHOIL forecast is:

	LOWOIL		HIGHOIL	
Years(s)	Real Rate of Price Change %/yr.	Price in Final Year of Period 1983$/bbl	Real Rate of Price Change %/yr.	Price in Final Year of Period 1983$/bbl
1983	-20.4	28.95	1.3	28.95
1984	3.5	23.04	1.3	29.32
1985-1990	3.5	28.27	7.8	46.07
1991-2000	3.8	40.84	3.8	67.01
2001-2005	1.1	43.22	1.1	70.92

(iii) Sherman H. Clark Associates (SHCA)

Sherman H. Clark Associates specializes in all phases of energy and resources economics. Clients include major oil companies, independent oil producers, independent refineries and tanker companies, state, federal and foreign government, coal companies, electric utilities and others. SHCA's experience in evaluating and projecting world economics and energy developments has resulted in the development of an extensive and detailed energy data base which is continuously updated.

SHCA prepares a detailed annual twenty-five to thirty year forecast of the worldwide supply and demand for all types of energy and estimated prices entitled Evaluation of World Energy Developments and Their Economic Significance. Figure B.98 contains an excerpt from SHCA's May 1983 forecast showing petroleum supply and consumption in the free world for 1982-2010. This illustrates the supply/demand analysis that SCHA performs to arrive at its estimates of future world oil prices.

The May 1983 SHCA forecast of world oil prices contains three scenarios to which SHCA has assigned estimated probabilities of occurrence.* These are the base case (BC), the no supply disruption (NSD), and the zero economic growth (ZEG). These scenarios are discussed in more detail below.

Base Case. In light of precedent during the 1970's, SHCA's base case envisions that a severe supply disruption will occur in the world oil market in the late 1980's, followed by production-limiting decisions of several key producing countries.

Until the supply disruption occurs, SHCA is projecting real United States economic growth at an annual rate of 3.0% and free world economic growth at 3.3%. After the disruption, growth in the U.S. will slow to 2% annually and to 2.7% annually in the free world. Prices, as measured by the Producer Price Index are projected to remain at a 2% annual rate of growth through 1983 and then increase to 5%/yr through 1988. The disruption and its resulting oil price increase will increase United States inflation to 10% annually for the period 1989-90. After 1990, the annual rate of inflation will decrease to 8% and remain at that level for the remainder of the projected period.

SHCA forecasts prices for marker crude oil FOB to remain at the existing OPEC benchmark level for marker crude of $29.00/bbl through 1985 but prices in 1983 dollars will decrease to $26.30/bbl in 1985 due to the effects of inflation. OPEC will not be able to increase the benchmark price above $29.00/bbl before 1985 because of the low average OPEC production of 18 MMBD or less which is expected from 1983-1985 versus OPEC's full production capability of around 30-32 MMBD. On the other hand, increasing world economic growth will prevent the benchmark price from dropping below $29.00/bbl.

From 1985 until the assumed disruption occurs in about 1988, the annual rate of world economic growth of 3.3% will increase the demand for OPEC oil to 20-25 MMBD which should allow OPEC to increase the benchmark price at a rate to offset the inflation rate. The real price of oil will remain at $26.30/bbl from 1985 to late 1988 when the supply disruption is assumed to occur.

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* Evaluation of World Energy Developments and Their Economic Significance, Sherman H. Clark Associates, Volume II, May 1983.

The effect of the supply disruption, stated in SHCA's own words is:*

> "In our base case, we have a supply interruption in late 1988. (Sentence omitted to improve clarity of description of supply disruption effects.) But whether in the late 1980's or after 1990, the necessary conditions include a large disruption such as total loss of Saudi capacity for a year, and either a permanent loss or a change in OPEC policy that would limit capacity available to about 20 MMBD. With 3% to 4% per year economic growth through 1988, the marker price could increase to about $40 per barrel (1983 dollars) due to the disruption, slowing economic growth thereafter to 2% per year and a rising real price would hold OPEC production about constant."

SHCA's estimate of prices from 1988 to 2040 and the reasons for those prices are summarized by the following quote:**

> "In the base case, the supply disruption in the late 1980s results in a sharp price increase and the limitation in capacity made available by OPEC causes a steady real escalation in prices that extends through 2010. Supplemental oil (and gas) supplies become partially economic by 2000 and generally economic by 2010. From 2010 to 2020 the price escalation slows to 1% per year and after 2020 there is a price plateau that could last for 20 years or perhaps indefinitely; i.e., prices are high enough to encourage all the necesssary substitution for conventional oil production."

Estimated prices for the Base-case in 1983$/bbl are summarized below and presented year-by-year in Table B.89.

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* Evaluation of World Energy Developments and Their Economic Significance, Volume II, p. I-21.

** Long-Term Outlook for Crude Oil and Fuel Oil Prices, special analysis prepared for Harza-Ebasco, May 18, 1983 and price tables of market crude in 1983 dollars provided Harza-Ebasco on May 26, 1983.

SHCA has assigned a probability of occurrence of 40% to its Base Case scenario.

Year	Real Rate of Price Change -%/yr.	Price in Final Year Period -1983$/bbl
1983	-4.6	28.95
1984	-4.7	27.61
1985-88	0.0	26.30
1988-89	52.1	40.00
1989-90	0.0	40.00
1991-2000	3.0	53.76
2001-2010	3.5	75.75
2011-2020	1.5	87.80
2021-2040	0.0	87.80

No Supply Disruption Case (NSD)

This case is the same as the base case but it is assumed that the supply disruption in the late 1980s does not occur. Economic growth after 1988 is therefore assumed to be at an annual rate of 3% in the United States slowing gradually to an annual rate of 2.5%. Economic growth in the free world will be 3.6% annually. The rate of inflation does not increase after 1988 but remains at an annual rate of 5% until after 2000. An additional assumption for this scenario is that the finding and production rate for non-OPEC crude increases above the rate assumed for the base case.

For the years 1983-1988, forecasted oil prices for the NSD scenario are the same as the base case. From 1988-2010 prices increase at a 3.0% annual rate due to the relatively high rate of world economic growth. The rate of price escalation is then assumed to taper off as the oil price approaches the price that will bring forth supplies of alternative fuels. This price occurs around 2035 to 2040.

SHCA has assigned a probability of occurrence of 35% to the NSD scenario. SHCA's estimated prices in 1983$/bbl are summarized below and presented year-by-year in Table B.89.

Year(s)	Real Rate of Price Change -%/yr.	Price in Final Year of Period-1983$/bbl
1983	-4.6	28.95
1984	-4.7	27.61
1985-88	0.0	26.30
1989-2010	3.0	50.39
2011-2020	2.5	64.48
2021-2030	1.5	74.84
2031-2040	1.0	82.66

Zero Economic Growth (ZEG). SHCA has also developed a scenario where world economic growth is zero in the United States and 0.4% in the free world through 1990. The rate of inflation would also be zero. After 1990, economic growth would increase at a vigorous rate of 4% slowing gradually to 3.2% for the United States and 4.3% slowing to 3.8% for the free world. The assumed low economic growth from 1983-1990 is based on the fact that economic growth for the years 1979-1982 was zero and on the assumption that the zero growth will continue until 1990.

Real oil prices under the scenario would decrease from the existing $29.00/bbl to $27.00/bbl toward the end of 1983 and to $21.00/bbl in 1984. A further decrease to $17.00/bbl would occur in 1985 and prices, both real and nominal (since the rate of inflation would be zero) would remain at that level through 1990 where the vigorous resumption in economic growth would allow the real price to increase slowly through 2010. The drop to $17.00/bbl through 1990 reflects a severe reduction, if not a loss, in control by OPEC over the world price of oil. SHCA has assigned a point probability of occurrence of 25% to the ZEG scenario.

SHCA's estimated prices in 1983$/bbl are summarized below. SHCA has not projected prices beyond 2010 for this scenario.

Year(s)	Real Rate of Price Change -%/yr	Price in Final Year of Period -1983$/bbl
1983	-6.9	29.00
1983 (4th quar.)	-22.2	27.00
1984		21.00
1985	-19.0	17.00
1986-1990	0	17.00
1991-2010	5.0	45.11

(iv) Other Projections

To provide a more complete range of possible future oil price scenarios and the resulting effect on the Railbelt Area demand for electrical energy, the Federal Energy Regulatory Commission has suggested that several constant price change scenarios be developed. The scenarios presented for sensitivity analysis are 2.0%/yr., 0%/yr., -1.0%/yr. and -2.0%/yr. There is no supply/demand or other type of analysis supporting these price change scenarios presented below:

	Prices in 1983$/bbl -			
Year	+2.0%	0%	-1.0%	-2.0%
1983	28.95	28.95	28.95	28.95
1990	33.25	28.95	26.98	25.13
2000	40.54	28.95	24.40	20.54
2010	49.42	28.95	22.07	16.78
2020	60.24	28.95	19.96	13.71
2030	73.43	28.95	18.05	11.20
2040	89.51	29.95	16.33	9.15

(b) Selection of Reference and Other Cases.

The estimates of future world oil prices presented above illustrate the different views and outlooks on the world economy by various forecasters. The range of forecasts are graphically displayed in Figure B.99.

To assess the impact of future oil prices on the demand for electric energy in the Railbelt, the broad range of forecasts has been analyzed and evaluated. Although it is possible that any one of the scenarios could prove to be true in the future, some would presently seem to be more probable than others. OPEC seems to be holding the line on their new benchmark price of $29.00/bbl and the United States economy is recovering from the 1981-82 recession at a stronger real rate of growth than recently predicted by many economists. The rest of the free world will probably follow the United States lead in economic growth which will increase the worldwide demand for petroleum.

In light of the foregoing, the SHCA NSD Case has been selected as the Reference Case. The SHCA NSD case presumes that OPEC will continue operating as a viable entity and will not limit production during the forecasted period. Recent trends in economic growth in the U.S. and the free world will continue at reasonable rates. Although events may affect this forecast, the Reference Case falls in the middle range of the forecasts evaluated and appears at this time to be a reasonable forecast for the purposes of this analysis.

Table B.90 identifies those forecasts which have been selected for analysis and the level of analysis to which each forecast has been carried. Ten world oil price forecasts have been used to estimate Railbelt electrical energy demand, while four of the forecasts, DOR Mean, DRI, Reference Case, and the -2%/yr. constant price change are carried through the Optimum Generation Planning (OGP) model.

(c) Variables and Assumptions Other than Oil Prices

Many variables and assumptions other than world oil prices are used in the PETREV, MAP, RED, and OGP models described in Section 5.3(b). Most of these other variables and assumptions, and representative values for the Reference Case, are listed in Tables B.91 through B.102. Input variables for each of these models are discussed in the following paragraphs.

(i) PETREV Model

State petroleum revenues from North Slope oil production are expected to account annually for between 93 and 99 percent of state petroleum royalties and production taxes during the period 1983 to 1999. Remaining royalties and production taxes will be generated by petroleum production on state lands other than on the North Slope and from production of natural gas.

Of the factors listed on Table B.91, North Slope petroleum production has the largest potential impact on state petroleum revenues, and is therefore a key variable in projecting economic conditions. Projected North Slope petroleum production is the sum of projected production from seven fields: Prudhoe Bay-Sadlerochit, Kuparuk, Milne Point, Canning River, Flaxman Island, Point Thompson, and Beaufort Sea. Currently only Prudhoe Bay-Sadlerochit and Kuparuk are producing fields. The other five fields are projected to begin production between 1987 and 1989. Production from the currently producing fields are projected to remain the main producers, accounting for an excess of 75 percent of total North Slope production in 1999 (Department of Revenue, March 1983). While production rates during the next eight to ten years can be forecasted with some degree of certainty, production rates after this period will depend on the rate of exploration and development of oil fields. Exploration rates will depend largely on the level of world petroleum prices and the demand for petroleum, but development of oil fields will depend on oil discoveries and production as well as petroleum prices and demand.

(ii) MAP Model

Table B.92 lists 10 categories of exogenous or basic employment, one measure of tourism, five categories of petroleum revenues, and five national economic parameters that are used as input to the MAP Model. These factors are the principal input variables and parameters to the MAP Model.

For purposes of projecting electric energy demand, the values of all the variables listed in Table B.92 other than petroleum revenues were left unchanged during each of the MAP Model executions. While sensitivity tests indicated that varying the value of several of these factors produced demonstrable effects on economic projections, none of these factors affected economic projections nearly to the extent that petroleum prices did, through its impact on state petroleum revenues. Based on results of the sensitivity tests discussed in Section 5.4 (f), the key input factors to the MAP Model other than petroleum revenues are: state mining employment, which includes petroleum production; state active duty military employment; tourists visiting Alaska; U. S. real wage growth rate; and price level growth rate. Employment relating to construction of the Susitna Hydroelectric Project was not tested for sensitivity. Employment in construction of electric power generating stations is considered in the larger category of construction employment.

Table B.93 summarizes the basis for selecting the values for the ten exogenous employment variables. The values for many of the variables listed in Table B.92 are taken from the MAP Model Data Base, a volume of economic and demographic data compiled and maintained by the Institute of Social and Economic Research. These data are derived from information collected by various state and federal governmental agencies, published reports, and other sources. The data are organized, adjusted, and in the case of some variables, projected to the year 2010 to meet the input requirements of the MAP Model.

(iii) RED Model

Table B.94 lists the main variables that are used in each module of the RED Model. In the Uncertainty module, the fuel price forecasts, the housing demand coefficients, the saturation of residential appliances, and the price adjustment coefficients are the main variables.

Table B.95 shows the projected customer real prices of heating fuel oil, natural gas, and electricity for the Reference Case. The heating fuel oil price forecast was derived from 1983 actual price, escalated at the same growth rate as the world oil price. The natural gas price forecast for the Anchorage-Cook Inlet area was derived from 1983 actual prices and an estimate of the weighted average price (old and new contracts) of natural gas[1]/. The new contracts were escalated at the same growth rate as the world oil price. In the Fairbanks-Tanana Valley area, a continuation of present practices of using propane for heating was assumed. The price would also escalate with world oil prices. The electricity prices were first estimated using weighted average price of natural gas and the addition of coal-fired generation in the mid 1990's. In addition, allowances to cover administrative and distribution costs were included to reflect retail prices. The prices were later adjusted to reflect the OGP results. The revised numbers are shown on Table B.95 and were used in all analyses.

Table B.96 presents the housing demand coefficients which were used in the housing demand equations for single family, multi-family, and mobile homes. Table B.97 gives an example of market saturations of appliances in single family homes for the Anchorage-Cook Inlet area, and Table B.98 presents the parameter values of the price adjustment mechanism.

For the Housing module, the two main variables are the regional household forecast, and the state households by age group. These variables are directly obtained from the MAP output file. Tables B.99, B.100, and B.101 provide detailed information on the annual consumption and growth rate of residential appliances, as well as the survival rate of the existing and new appliances.

The main variables of the Business Consumption module are the regional employment, which is an output of the MAP model, and the floor space consumption parameters. Vacant housing, second homes, and street lighting, and their expected annual consumption are the variables of the Miscellaneous module. The annual load factor for the two load centers are the main variables of the Peak Demand module.

Because the RED model is an end-use model, the appliance saturation rate based on the existing stock of appliances is a key variable. Also, the energy usage per appliance has a major effect on electricity demand. Further, the growth rate of consumption per appliance type has a significant impact on residential electricity consumption in future years. In the business sector, the projections of the demand for "floor space" and the consumption per unit of floor space are key variables. Own- and cross-price elasticities of demand have a significant impact on electricity consumption by influencing consumption behavior in both the short and long term. The own-price elasticity values that are assumed in the model determine the extent and time path of electricity price impacts on residential and commercial consumption. The cross-price elasticities show the impact on electricity consumption due to changes in the price of substitute energy resources for electricity. The own- and cross-price elasticities of demand are used to adjust electricity consumption for price induced conservation of electrical energy. The last key factor is the regional peak load factor, which is applied to the energy demand forecast to forecast peak loads. The impact of these key parameters is analyzed in Section 5.4 (f) on Sensitivity Analysis.

(iv) OGP Model

Table B.102 presents the main variables of the OGP model. The variables are: fuel costs and escalation rates, thermal and hydro plant construction costs, and the discount rate. A detailed presentation of these variables is presented in Exhibit D and Appendix D-1.

(d) Reference Case Forecast

The Reference Case forecast is based on the SHCA NSD world petroleum price forecast discussed in Sections 5.4 (a) and 5.4 (b) above. These petroleum prices served as the basis for the Reference Case state petroleum revenue forecasts, which in turn were used by the MAP Model to produce the Reference Case economic projections, which were then used by the RED Model to forecast electric energy demands. The Reference Case world petroleum price forecasts were also used to estimate future fuel prices for use in the RED and OGP models.

Table B.103 summarizes the data for the Reference Case, showing the oil price scenario and the corresponding set of 15 input and output variables over the forecast period from 1983-2010, including prices of other forms of energy, revenues, population, and employment. Table B.103 shows that in the Reference Case, Railbelt population will grow approximately 67 percent between 1983 and 2010, reaching 533,218 by the year 2010. During this same period the Railbelt's electric energy demand is forecasted to rise from 2,784 to 5,709 gigawatt-hours, a 105 percent increase. Peak demand is projected to rise from 576 to 1,187 megawatts, a 106 percent increase during the 27 year period, an average increase of 2.7 percent per year. The following sections summarize the Reference Case forecasts of state petroleum revenues, fiscal and economic conditions, and electric energy demand.

(i) State Petroleum Revenues

Table B.104 presents Reference Case projections of state petroleum revenues from each of the primary revenue sources through the year 2010. The first two columns of this table contain projected royalties and severance, or production taxes, respectively. These projections are in nominal dollars, reflecting an annual change in the consumer price index of 6.5 percent. The projections of royalties and severance taxes through the year 1999 were produced by the Department of Revenue's PETREV petroleum revenue forecasting model system, adjusted for minor differences in the future assumed rate of inflation. Projections for the years 2000 through 2010 were extrapolated using the average annual rate of change between the years 1996 through 1999.

Table B.104 also presents projections of state petroleum revenues derived from corporate income taxes, property taxes, lease bonuses, and federal shared royalties. Future revenues from these sources, estimated by the Institute of Social and Economic Research, were used along with the projections of royalties and severance taxes as input to the MAP economic model.

(ii) Fiscal and Economic Conditions

State petroleum revenues constitute a major proportion of the total funds available to the State of Alaska for expenditure on operations and capital investment, which in turn greatly affects the general level of economic activity in the state. Table B.105 presents projections of several important components of the state's fiscal structure for the Reference Case. These components include unrestricted general fund expenditures, the balance in the general fund, permanent fund dividends, state personal income tax revenues, level of outlays for subsidies, and the percentage of Permanent Fund earnings that are reinvested. The table shows that, based on the fiscal rules summarized in Section 5.3 above, dividends from the Permanent Fund continue to be disbursed through the year 1992, at which time the program is halted. A state personal income tax is reinstituted in the year 1994 in order to augment revenues. State subsidy programs are terminated after the year 1988, and reinvestment of Permanent Fund dividends ends after 1994. The subsidy programs that may be affected include, for example, mortgage subsidies, student loans and AIDA industrial development loans. Each of these measures is assumed to occur in order to permit state expenditures to grow as closely as possible in proportion to the rate of population growth, taking into account the effects of inflation. However, while these fiscal measures are assumed to be implemented, petroleum revenues are projected to continue to provide the largest share of state expenditures, accounting in the year 2010 for approximately two-thirds of total unrestricted general fund expenditures, those expenditures not funded by revenues dedicated to specific functions.

Table B.106 presents Reference Case population projections for the state, Railbelt, Anchorage-Cook Inlet area, and Fairbanks-Tanana Valley area. Railbelt population is projected to grow by approximately 67 percent between 1983 and 2010, from 320,000 to 533,000. In the Railbelt, the Anchorage area is projected to grow by 69 percent, compared to the projected growth in Fairbanks of 57 percent.

The growth of employment, shown on Table B.107, is uniformly lower than that of population. While statewide non-agricultural wage and salary employment is projected to grow by 61 percent during the next 27 years, total state employment is forecasted to increase by only 51 percent. Again the Railbelt is projected to experience a higher employment increase, rising by 61 percent, with the Anchorage area growing by 63 percent compared to 52 percent growth in the Fairbanks area.

Table B.108 presents projections of households according to state total, the Railbelt, the Anchorage area, Fairbanks area, and statewide by age of head of household. In contrast to projected employment, households are projected to increase faster than population. Statewide households are projected to increase by 72 percent by the year 2010, compared to a 75 percent increase in the Railbelt, a 78 percent rise in the Anchorage area, and a 67 percent increase in the Fairbanks area.

(iii) Electric Power Demand

The regional households projections obtained from the MAP model are used in the RED housing module to derive the number of households served by electric utilities and the number of vacant households. Tables B.109 and B.110 present the output results for the period 1980-2010. The residential module then computes the annual consumption per type of household based on the market saturation of appliances and the annual consumption per appliance.

Table B.111 summarizes the average consumption per household before and after conservation adjustment and fuel substitution. In the Anchorage area, the average consumption per household is expected to decrease from about 13,700 kWh in 1980 to 12,560 kWh in 1990, mainly due to the real increase of electricity price which will continue to cause some conversion from electric space heating to substitute fuels. After 1990, the consumption is expected to slowly increase to about 13,200 kWh in 2010, at an average annual growth rate of 0.25 percent. In the Fairbanks area, the average household consumption is expected to increase from 11,500 kWh in 1980 to 15,200 kWh in 2010, at about an average annual growth rate of 0.9 percent. This increase is due to the stabilization of electricity prices, while the price of substitute fuels are increasing. The projected consumption in year 2000 is similar to the 1975 average consumption.

The employment forecasts obtained from MAP are used in the RED Business Consumption module to derive the electric demand in the commercial-government-small industrial sector. Table B.112 summarizes the "business" use per employee projections. The consumption projections were obtained from a forecast of predicted floor space per employee, and an econometrically derived electricity consumption per square feet, which is then adjusted for price impacts. The floor space per employee is expected to increase by 10 percent in Anchorage and 15 percent in Fairbanks to approach current national average by the year 2010. As a result, in the Anchorage area, the average consumption per employee is expected to increase from about 8,400 kWh in 1980 to 11,500 kWh in 2010, at an average annual rate of 1.0 percent. In the Fairbanks area, the consumption per employee is expected to increase from 7,500 kWh in 1980 to 9,900 kWh in 2010, at an average annual growth rate of 0.9 percent.

Tables B.113 and B.115 provide a year by year projection of price-induced conservation and fuel switching for the two load centers. Tables B.114 and B.116 give a year by year breakdown of energy consumption projections for the residential, commercial-government-small industrial, miscellaneous, and large industrial sectors for the two load centers. The industrial sector includes projections of large industrial and military loads. Industrial loads were derived from estimates of industrial growth in the Kenai Peninsula. Military loads were derived from discussions with representatives at each military installation.

Finally, Table B.117 summarizes the annual peak and energy demand projections for each load center and for the total system. The annual load factor is also presented. The average annual growth rate of electricty demand is expected to slowly decrease from about 5.6 percent during the period 1980-1985 to 1.7 percent during the period 1995-2000. After 2000, the demand is expected to increase at an average annual rate of 2.3 percent until 2005, and 2.8 percent for the period 2005-2010.

(e) Other Forecasts

A broad range of world oil price forecasts has been analyzed in Section (a) and (b). The forecasts are summarized in Table B.89, and displayed in Figure B.99. In addition to the Reference Case, eight scenarios were carried through the MAP and RED models. These scenarios are the DOR-Mean, DOR-50%, DOR-30%, DRI, +2%, 0%, -1%, and -2%. The results are presented on Tables B.118 through B.125. Historical data and projections of general fund expenditures, population, households, energy demand, and peak demand are displayed in Figures B.100 through B.104 for four scenarios: DRI, Reference Case, DOR Mean, and DOR 30%. The DOR 30% and DRI forecasts are the lowest and highest scenarios, respectively. The Reference Case and DOR Mean are shown for comparison purposes.

The State General Fund Expenditures are expected to vary between 6.9 billion dollars and 26.1 billion dollars in year 2010. The Railbelt population is expected to increase from 320,000 in 1983 to 481,000 under DOR 30% and 609,000 under DRI, for the year 2010. The corresponding number of households would increase from 111,500 in 1983 to 175,000 and 223,000. The employment is expected to increase from 159,000 in 1983 to 231,500 under DOR 30%, and 300,000 under DRI, for the year 2010.

As shown on Figure B.103, the 2010 energy consumption would vary between 4,950 GWh and 6,965 GWh. The corresponding average annual growth rate over the period 1983-2010 would vary between 2.2 percent and 3.4 percent. The peak demand is expected to increase from 570 MW in 1983 to 1,026 MW under DOR 30%, and 1,450 MW under DRI, for the year 2010.

(f) Sensitivity Analyses

Sensitivity analyses for variables other than oil prices were conducted using the MAP, RED and OGP models in order to determine the extent to which forecasts are affected by varying the values of selected input variables and parameters, other than world oil prices. Some of these tests were conducted initially prior to execution of the forecasts and others were conducted during the course of the forecasts. These analyses indicated that while other factors do affect electric energy demand in the Railbelt, the effect of any one or two factors does not approach the effect that world petroleum prices has on economic conditions and electric energy demand. It was largely this finding that led to the definition of alternative energy planning scenarios based solely on alternative petroleum prices.

(i) MAP Model Sensitivity Tests

For the MAP Model, input variables subjected to sensitivity testing included ten industrial development factors, tourism in Alaska, and four national economic variable parameters. The results of the sensitivity analyses are summarized in Table B.126. The table shows that of the variables tested, projections of households are most sensitive to mining employment, which includes petroleum production, military employment, tourism, growth in real wages, and growth in the consumer price index. Sensitivity tests were also conducted using selected economic model parameters, including those relating to labor force participation rates, Federal tax rates, and population migration. Details of these tests are in the MAP Model Technical Documentation Report.

(ii) RED Model Sensitivity Tests

Sensitivity analyses were conducted for key variables, using the Uncertainly Module. These variables are (1) appliance saturations, energy consumption by appliance, growth rate of appliance consumption; (2) business consumption; (3) own price elasticity; (4) cross price elasticity; and (5) load factors. The sensitivity analyses were carried out for the Reference Case. The results are shown on Table B.127 through B.131.

Table B.127 summarizes the results obtained when parameters of the Residential Module were allowed to vary. Table B.97 presents a typical example of market saturation ranges which were used as input into the Uncertainty Module. In addition, the annual consumption per appliance and the expected growth rate of energy consumption were allowed to vary by ±20 percent. As shown on Table B.127, the results on the overall energy demand are within 3 percent of the Reference Case values.

The sensitivity analysis of the Business Sector was done by allowing the consumption rate parameter to vary while maintaining a 95 percent confidence level. This resulted in a range of values within $\pm$ 10 percent of the mean value for the Anchorage-Cook Inlet area. As shown on Table B.128, the effects on the overall energy demand are within 5 percent of the Reference Case values. Because of the lack of detailed historical data for the Fairbanks area, the range of the consumption parameter value is very large, and the results are not reliable.

Table B.129 and B.130 present the results of the own-price and cross-price elasticities variations. The values of the parameters were allowed to vary while maintaning a 95 percent confidence level. The effects on the overall energy demand are within 6 percent of the Reference Case values.

Finally, a sensitivity analysis was done for the peak demand, using the range of the annual load factors of the two load centers for the period 1970-1982. The results are presented in table B.132. For the year 2010, the peak demand would vary between 1,008 and 1,308 MW, with a Reference Case value of 1,217 MW.

(iii) OGP Model Sensitivity Tests

Sensitivity tests were also conducted for the OGP Model. The key variables other than petroleum price dependent variables which were tested are discount rate, Watana capital cost, base fuel price, and real fuel escalation. The sensitivity analyses are described in Exhibit D.

(g) Reasonableness of the RED Forecasts

In order to test the reasonableness of RED's long-term forecasts, the Reference Case was compared to three comparable long-term forecasts. The three forecasts are: forecasts by Pacific Northwest Power Planning Council (PNPPC) and Bonneville Power Administration for the Pacific Northwest, an area with large electric space heat loads and rising prices; and a forecast by Wisconsin Electric Power Company (WEPCO) for Wisconsin and Upper Michigan, an area with relatively stable electric prices, and low electric space heat penetration. The intent was to compare forecasts from areas similar to the Railbelt Region. The Pacific Northwest forecasts were selected because of the low electricity prices the region shares with the Anchorage load center, while the

Wisconsin area closely corresponds to the climate and fuel mode split exhibited in the Railbelt.

The Pacific Northwest Power Planning Council, created by an act of Congress to coordinate and direct acquisition of generation resources in the Pacific Northwest, prepared a twenty-year forecast of electricity demand in the Northwest. PNPPC modelled four alternate load growth scenarios (low, medium low, medium high, and high) for the purposes of generation planning. We chose the medium high scenario for comparison because it corresponds more closely to the economic conditions expected to occur in the Railbelt.

The Bonneville Power administration (BPA) markets all federal power in the Pacific Northwest. BPA recently completed construction of their own forecasting tools. We chose to examine BPA's medium scenario as it represents their assessment of the most probable situation.

The Wisconsin Electric Power Company markets power to Milwaukee-Kenosha-Racine Standard Metropolitan Statistical Area, plus selected counties in central and northern Wisconsin and upper Michigan. Unlike the two Pacific Northwest organizations, WEPCO markets to a service area with relatively little electric space heating. As in the southern Railbelt, the primary fuel source is natural gas, with electricity supplying only 4 to 5 percent of total energy used. Consequently, there are fewer opportunities for savings of electric energy in conservation of building heat than exist in the Pacific Northwest. In contrast to the Pacific Northwest, where annual residential electric consumption in 1980 averaged 17,260 kWh per household, and 11,000 to 13,000 in the Railbelt, WEPCO customers averaged 7,240.

The following table presents a decomposition of two commonly used consumption rates for the BPA, PNPPC, WEPCO and RED forecasts: the annual growth rate in use per employee and use per household. The RED forecasts both exhibit higher growth rates than either of the Pacific Northwest forecasts, but lower than the rates in the WEPCO forecast.

Comparison of Recent Forecasts, 1980-2000

	Average Percent Growth Rate Use Per Household	Average Percent Growth Rate Use Per Employee
Pacific Northwest Power Council	-.64	.14
Bonneville Power Administration	-.64	-.31
Wisconsin Electric Power Company	1.41	3.97
RED:		
Anchorage	-.36	1.04
Fairbanks	0.98	0.93

This is the expected relationship of the forecasts. The BPA and PNPPC forecasts assume vigorous conservation programs and rising electricity prices in a region characterized by high market penetration of electric space heat and water heat in both the residential and commercial sector. Furthermore, because Pacific Northwest electricity prices have been low historically, there are many opportunities available for cheaply saving large amounts of electricity. In contrast, the Railbelt and WEPCO regions do not have as many inexpensive opportunities to save large amounts of power, since most thermal requirements are being met with natural gas. Furthermore, the rate of increase in electricity prices is expected to remain low in the WEPCO region, reducing incentives to conserve. It is also assumed that, in WEPCO's service area, electricity would capture a high (40-60 percent) share of new residential heating appliances due to its projected cost advantage over oil and gas.

The RED forecasts occupy a middle ground, both in terms of base year consumption and in terms of the rate of increase in consumption. With moderate rates of electricity price increases and fewer inexpensive conservation opportunities, RED shows lower rates of conservation than the Pacific Northwest. In comparison with the WEPCO area, the Railbelt is expected to have a declining electric share in space heat and water heat, so the rate of increase in use per customer would be less. In addition, since Railbelt customers on the average use more electricity than WEPCO customers and are facing higher projected rates of electricity price increases, the forecasted rate of increase in the rate of electricity consumption should be lower. Based on this comparison, the results of the RED forecast seem to be consistent with what other forecasters are predicting.

(h) Comparison With Previous Forecasts

Two sets of previous forecasts have been used in the early stages of Susitna Hydroelectric Project studies in addition to the power market forecasts presented in detail in this section. In 1980, the Institute for Social and Economic Research (ISER) prepared economic and accompanying end-use electric energy demand projections for the Railbelt. These forecasts were used in several portions of the feasibility study, including the development selection study.

In 1981 and 1982, Battelle Pacific Northwest Laboratories produced a series of load forecasts for the Railbelt, as shown on Table B.132. These forecasts were developed as a part of the Railbelt Alternatives Study completed by Battelle under contract to the State of Alaska. Battelle's forecasts were based on updated economic projections prepared by ISER and some revised end-use models developed by Battelle which took into account price sensitivity and several other factors not included in the 1980 projections. The December 1981 Battelle forecasts were used in the optimization studies for the Watana and Devil Canyon developments which were completed early in 1982. The 1981 forecast reflected a projection of world oil prices of $27.45/bbl. in July 1981 to $31.45/bbl. in July 1982, with first quarter prices increasing from $36.35/bbl. to $44.65/bbl. over the next three fiscal years, and then from $53.22/bbl. in the sixth fiscal year to $157.60/bbl. in the subsequent seventeenth fiscal year.

These previous forecasts were made for three electric load centers: the Anchorage-Cook Inlet area; the Fairbanks-Tanana Valley area; and the Glennallen-Valdez area. When these studies were undertaken, it was not decided whether the Glennallen-Valdez area would be included in the intertied Railbelt electrical system. The decision was subsequently made, based on economics, that the Glennallen-Valdez area would not be initially included in the interconnected area. Therefore, the updated electric load forecasts presented herein do not consider the power requirements of this load center.

Both ISER and Battelle produced high, medium and low forecasts for use in Susitna planning studies. The medium forecast was used for determining base generation plans, with the high and low forecasts used in sensitivity analyses.

In addition to the ISER and Battelle forecasts performed for the purpose of planning the Susitna Hydroelectric Project, the Railbelt utilities annually produce forecasts for their own respective markets. The bases for these forecasts are not readily available.

Table B.132 provides a summary comparison of these previous power market forecasts under the medium scenario. While these forecasts are not precisely consistent in the definitions of the market area or in the assumptions relating to the current reference case, the comparison does provide an insight in the change in perception of future growth rates during the time that the various sets of forecasts were developed.

(i) Impact of Oil Prices on Forecasts

The world price of oil is a significant factor in the Alaskan economy. As a consequence, world oil prices influence the demand for electric energy and other forms of energy. Although oil prices are important, there are many other economic, social, and political factors which affect future Alaskan economic trends and energy requirements. For example, the anticipated higher price of gas and its limited availability in the Anchorage-Cook Inlet area will have an impact on future electricity demands and costs of power purchases.

The impact of world oil prices in conjunction with other economic causal factors on future economic conditions and electric energy and peak demands has been evaluated. A number of world oil price scenarios were used in the PETREV Model to generate various petroleum revenues projections. Because royalties and severance taxes are sensitive to changes in world oil prices, different petroleum revenue projections were obtained. The projected petroleum revenues along with specified economic development assumptions and other variables were employed in the MAP Model to project economic factors such as households, state government expenditures, and employment. These economic factors were influenced by the various oil price growth rate assumptions. Finally, electric demand forecasts were produced using the RED Model. The RED Model employed the output of the MAP Model as well as other assumptions and input data. Fuel data on electricity, natural gas, and oil prices were needed for the planning period. These data, for example, are affected by the growth rates assumed for world oil prices. An electric demand forecast was made for each world oil price scenario. This procedure resulted in the production of an electric demand forecast which incorporated all direct and indirect effects of a given timepath of world oil prices on electric demand in the Railbelt in a comprehensive and consistent manner. The range of electric demand forecast results reflects the overall impact of world oil prices as well as other key variables included in the separate models. These electric demand forecasts are presented in Section 5.4(e) above.

5.5 Project Utilization

The purpose of this section is to describe how the power generated by the Susitna Project will be utilized in the interconnected railbelt system. The discussion that follows is based on the Project's operation under the Reference Case power market forecast.

The characteristics of the combined railbelt load are discussed in Section 5.2. Daily load curves and monthly load variation are also presented in that section as Figures B.80 and B.79, respectively.

The operation of the Susitna Project as stated in Section 3.7 of this Exhibit will be as follows: the Watana development will operate as a base load project until the Devil Canyon development enters operation at which time the Devil Canyon development will operate on peak and reserve. The dependable capacity and energy production from Watana operating alone and with Devil Canyon are presented in Section 4.3 of this Exhibit. The firm and average annual energy production, and maximum dependable capacity in 2020 for the Susitna Project under the Reference Case flow regime, Regime C, are as follows:

	Watana Only	Watana Plus Devil Canyon
Average Annual Energy, GWh	3499	6934
Firm Annual Energy, GWh	2618	5451
Maximum Dependable Capacity in 2020, MW	893	1272

On-site use of the power and energy from the Project will be negligible in comparison to the Project's capability and therefore it has been assumed that all the above capacity and energy would be used in the railbelt system after deduction of transmission losses. Figure B.76 shows the dependable capacity of the project year under various flow regimes.

Although no firm sales contracts or commitments have been made by Railbelt utilities, it is anticipated that each utility's share of the project would be similar to their proportionate share of the Railbelt power market. Based on energy sales in 1982, each utility covers the following approximate percentage of the total Railbelt market:

Utility	Percentage of Railbelt Energy Sales (1982)
Chugach Electric Association	40
Anchorage Municipal Light & Power	20
Golden Valley Electric Association	10
Matanuska Electric Association	10
Fairbanks Municipal Utilities System	5
Homer Electric Association Seward Light Department	15
TOTAL	100

6 - FUTURE SUSITNA BASIN DEVELOPMENT

6 - FUTURE SUSITNA BASIN DEVELOPMENT

The Alaska Power Authority has no current plans for further development of the Watana/Devil Canyon system and no plans for further water power projects in the Susitna River basin at this time.

Development of the proposed projects would preclude further major hydroelectric development in the Susitna basin, with the exception of major storage projects in the Susitna basin headwaters. Although these types of plans have been considered in the past, they are neither active nor anticipated to be so in the foreseeable future.

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TABLES AND FIGURES

TABLE B.69

TOTAL 1981 ALASKA ENERGY CONSUMPTION

Sector	Alaska Billion Btu	Alaska (%)	Railbelt Billion Btu	Railbelt (%)
Transportation	114,672	38	88,715	38
Industrial	64,823	21	44,699	19
Utility	46,344	15	40,115	17
Military	25,847	9	25,847	11
Residential	26,571	9	19,434	8
Commercial/Public	11,913	4	10,658	5
Off-highway	13,069	4	6,430	3
Total	303,239	100	235,929	100

Note: The total electricity consumption is only reported in the utility sector.

Source: 1983 Long Term Energy Plan (Working Draft), Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska. 1983 Figure II-9 p. 11-14.

TABLE B.70

RAILBELT 1981 ENERGY CONSUMPTION BY FUEL TYPE FOR EACH SECTOR

Sector/Fuel Type	Energy Consumption Billion Btu	Percent
Transportation		
Fuel Oil	88,649	99.9
Coal	66	0.1
Total	88,715	100.0
Industrial		
Fuel Oil	13,264	28.3
Natural Gas	31,435	67.1
Electricity	2,130	4.6
Total	46,829	100.0
Utility		
Fuel Oil	2,152	5.9
Natural Gas	29,652	73.9
Coal	5,407	13.5
Hydro	2,904	7.2
Total	40,115	100.0
Military		
Fuel Oil	15,364	55.8
Natural Gas	4,590	16.7
Coal	5,893	21.4
Electricity	1,690	6.1
Total	27,537	100.0
Residential		
Fuel Oil	9,647	41.6
Natural Gas	8,109	35.0
Coal	140	0.6
Wood	1,561	6.7
Electricity	3,745	16.1
Total	23,202	100.0
Commercial/Public		
Fuel Oil	2,256	15.6
Natural Gas	7,333	50.5
Coal	1,069	7.4
Electricity	3,842	26.5
	14,500	100.0

Note: Electricity consumption is reported in the utility sector, and also in the other sectors.

Source: 1983 Long Term Energy Plan (Working Draft), Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska. Appendix S, Table S-2.

TABLE B.71

INSTALLED CAPACITY OF ANCHORAGE-COOK INLET AREA-1982

	HYDRO	OIL	NATURAL GAS		
	Hydro	Diesel	Combustion Turbine	Steam Turbine	Total
Utilities					
Alaska Power Administration	30.0	0	0	0	30.0
Anchorage Municipal Light and Power	0	0	311.6	0	311.6
Chugach Electric Associaton	15.0	0	448.5	0	463.5
Homer Electric Association	0	2.6	0	0	2.6
Matanuska Electric Association	0	0.9	0	0	0.9
Seward Electric Association	0	5.5	0	0	5.5
Total	45.0	9.0	760.1	0	814.1
Military Installations					
Elmendorf AFB	0	2.1	0	31.5	33.6
Fort Richardson	0	7.2	0	18.0	25.2
Subtotal	0	9.3	0	49.5	58.8
Industrial Installations					
Subtotal	0	9.6	16.0	0	25.6*
Total	45.0	27.9	776.1	49.5	898.5

*Figure is for 1981, latest year that data was available.

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities and Planned Additions for the Railbelt Region of Alaska, Volume VI, September, 1982; Alaska Power Administration 1983; updated by Harza-Ebasco Susitna Joint Venture, 1983.

TABLE B.72

INSTALLED CAPACITY OF THE FAIRBANKS-TANANA VALLEY AREA-1982

	OIL	HYDRO	COAL		
	Diesel	Hydro	Combustion Turbine	Steam Turbine	Total
Utilities					
Fairbanks Municipal Utility System	8.4	0	30.1	30.0	68.5
Golden Valley Electric Association	23.8	0	172.8	25.0	221.6
University of Alaska	5.6	0	0	13.0	18.6
Subtotal	37.8	0	202.9	68.0	308.7
Military Installations					
Eielson AFB	0	0	0	15.0	15.0
Fort Greeley	5.5	0	0	0	5.5
Fort Wainwright	0	0	0	22.0	22.0
Subtotal	5.5	0	0	37.0	42.5
Industrial Installations					
Subtotal	2.8	0	0	0	2.8*
Total	46.1	0	202.9	105.0	354.0

* Figure is for 1981, latest year that data was available.

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities And Planned Additions for the Railbelt Region of Alaska, Volume VI, September 1982; Alaska Power Administration 1983; updated by Harza-Ebasco Susitna Joint Venture, 1983.

TABLE B.73 (Sheet 1 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Alaska Power Administration			
Eklutna[a]	H	--	1955	30.0	--	--
			Anchorage Municipal Light and Power			
Station #1[b]						
Unit #1	SCCT	NG/O	1962	14.0	16.3	14,000
Unit #2	SCCT	NG/O	1964	14.0	16.3	14,000
Unit #3	SCCT	NG/O	1968	18.0	18.0	14,000
Unit #4	SCCT	NG/O	1972	28.5	32.0	12,500
Diesel 1[c]	D	O	1962	1.1	1.1	10,500
Diesel 2[c]	D	O	1962	1.1	1.1	10,500
Station #2[d]						
Unit #5	SCCT	O	1974	32.3	40.0	12,500
Unit #6	CCST	--	1979	33.0	33.0	--
Unit #7	SCCT	O	1980	73.6	90.0	11,000
Unit #8	SCCT	NG/O	1982	73.6	90.0	12,500
			Chugach Electric Association			
Beluga						
Unit #1	SCCT	NG	1968	15.25	16.1	15,000
Unit #2	SCCT	NG	1968	15.25	16.1	15,000
Unit #3	RCCT	NG	1973	53.3	53.0	10,000
Unit #4[e]	SCCT	NG	1976	10.0	10.7	15,000
Unit #5	RCCT	NG	1975	58.5	58.0	10,000
Unit #6	CCCT	NG	1976	72.9	68.0	15,000
Unit #7	CCCT	NG	1977	72.9	68.0	15,000
Unit #8[f]	CCST	NG	1982	55.0	42.0	--

TABLE B.73 (Sheet 2 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Chugach Electric Association (Continued)			
Cooper Lake[g]						
Unit #1,2	H	--	1961	15.0	16.0	--
International						
Unit #1	SCCT	NG	1964	14.0	14.0	15,000
Unit #2	SCCT	NG	1965	14.0	14.0	15,000
Unit #3	SCCT	NG	1970	18.5	18.0	15,000
Bernice Lake						
Unit #1	SCCT	NG	1963	7.5	8.6	23,400
Unit #2	SCCT	NG	1972	16.5	18.9	23,400
Unit #3	SCCT	NG	1978	23.0	26.4	23,400
Unit #4	SCCT	NG	1982	23.0	26.4	12,000
Knik Arm[h]						
Unit #1	ST	NG	1952	0.5	0.5	--
Unit #2	ST	NG	1952	3.0	3.0	--
Unit #3	ST	NG	1957	3.0	3.0	--
Unit #4	ST	NG	1957	3.0	3.0	--
Unit #5	ST	NG	1957	5.0	5.0	--
			Homer Electric Association			
Kenai						
Unit #1	D	O	1979	0.9	0.9	15,000
Pt. Graham						
Unit #1	D	O	1971	0.2	0.2	15,000
Seldovia[i]						
Unit #1	D	O	1952	0.3	0.3	15,000
Unit #2	D	O	1964	0.6	0.6	15,000
Unit #3	D	O	1970	0.6	0.6	15,000

TABLE B.73 (Sheet 3 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Matanuska Electric Association			
Talkeetna						
Unit #1	D	0	1967	0.9	0.9	15,000
			Seward Electric System			
SES[j]						
Unit #1	D	0	1965	1.5	1.5	15,000
Unit #2	D	0	1965	1.5	1.5	15,000
Unit #3	D	0	1965	2.5	2.5	15,000
			Military Installations - Anchorage Area			
Elmendorf AFB						
Total Diesel	D	0	1952	2.1	--	10,500
Total ST	ST	NG	1952	31.5	--	12,000
Fort Richardson						
Total Diesel[c]	D	0	1952	7.2	--	10,500
Total ST[i]	ST	NG	1952	18.0	--	20,000
			Golden Valley Electric Association			
Healy Coal	ST	Coal	1967	64.7	65.0	13,200
Healy Diesel[c]	D	0	1967	64.7	65.0	10,500
North Pole						
Unit #1	SCCT	0	1976	64.7	65.0	14,000
Unit #2	SCCT	0	1977	64.7	65.0	14,000
Zendher						
GT1	SCCT	0	1971	18.4	18.4	15,000
GT2	SCCT	0	1972	17.4	17.4	15,000
GT3	SCCT	0	1975	2.8	3.5	15,000
GT4	SCCT	0	1975	2.8	3.5	15,000
Combined Diesel	D	0	1960-70	21.0	21.0	10,500

TABLE B.73 (Sheet 4 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
University of Alaska - Fairbanks						
S1	ST	Coal	--	1.50	1.50	12,000
S2	ST	Coal	1980	1.50	1.50	12,000
S3	ST	Coal	--	10.0	10.0	12,000
D1	D	0	--	2.8	2.8	10,500
D2	D	0	--	2.8	2.8	20,500
Fairbanks Municipal Utilities System						
Chena						
Unit #1	ST	Coal	1954	5.0	5.0	18,000
Unit #2	ST	Coal	1952	2.5	2.5	22,000
Unit #3	ST	Coal	1952	1.5	1.5	22,000
Unit #4	SCCT	0	1963	5.3	7.0	15,000
Unit #5	ST	Coal	1970	21.0	21.0	13,320
Unit #6	SCCT	0	1976	23.1	28.8	15,000
Diesel #1	D	0	1967	2.8	2.8	12,150
Diesel #2	D	0	1968	2.8	2.8	12,150
Diesel #3	D	0	1968	2.8	2.8	12,150
Military Installations - Fairbanks						
Eielson AFB						
S1, S2	ST	0	1953	2.50	--	--
S3, S4	ST	0	1953	6.25	--	--
Fort Greeley						
D1, D2, D3[i]	D	0	--	3.0	--	10,500
D4, D5[i]	D	0	--	2.5	--	10,500
Ft. Wainwright[j]						
S1, S2, S3, S4	ST	Coal	1953	20	--	20,000
S5[i]	ST	Coal	1953	2	--	--

TABLE B.73 (Sheet 5 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Legend

H	-	Hydro
D	-	Diesel
SCCT	-	Simple cycle combustion turbine
RCCT	-	Regenerstive cycle combustion turbine
ST	-	Steam turbine
CCCT	-	Combined cycle combustion turbine
NG	-	Natural gas
O	-	Distillate fuel oil

Notes

(a)Average annual energy production for Eklutna is approximately 148 GWh.

(b)All AMLP SCCTs are equipped to burn natural gas or oil. In normal operation they are supplied with natural gas. All units have reserve oil storage for operation in the event gas is not available.

(c)These are black-start units only. They are not included in total capacity.

(d)Units #5, 6, and 7 are designed to operate as a combined-cycle at plant. When operated in this mode, they have a generating capacity at 0°F of approximately 139 MW with a heat rate of 8500 Btu/kWh.

(e)Jet engine, not included in total capacity.

(f)Beluga Units #6, 7, and 8 operate as a combined-cycle plant. When operated in this mode, they have a generating capacity of about 178 MW with a heat rate of 8500 Btu/kWh. Thus, Units #6 and 7 are retired from "gas turbine operation" and added to "combined-cycle operations."

(g)Average annual energy production for Cooper Lake is approximately 42 GWh.

(h)Knik Arm units are old and have higher heat rates; they are not included in in total.

(i)Standby units.

(j)Cogeneration used for steam heating.

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities and Planned Addition for the Railbelt Region of Alaska, Volume VI, September, 1982; updated by Harza-Ebasco Susitna Joint Venture, 1983.

TABLE B.74 (Sheet 1 of 2)

MONTHLY DISTRIBUTION OF PEAK DEMAND

Anchorage - Cook Inlet Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)	Average 1976-1982 (%)
January	94.2	76.8	89.2	90.5	89.9	79.1	100.0	88.5
February	91.2	91.8	85.8	100.0	84.8	84.8	93.3	87.4
March	81.7	75.4	77.5	85.9	72.4	73.1	83.0	78.4
April	70.9	69.7	70.6	67.8	60.1	69.1	77.4	69.4
May	63.9	59.8	62.6	58.9	55.7	61.3	64.3	60.9
June	59.9	55.6	59.7	58.5	52.7	61.5	61.8	58.5
July	62.3	54.2	59.4	54.9	54.2	63.0	61.6	58.5
August	63.6	57.6	61.8	55.5	50.4	62.0	63.4	59.2
September	70.1	67.5	66.1	61.9	58.3	69.7	73.8	66.8
October	89.2	78.1	81.5	72.7	69.9	78.7	90.9	80.1
November	88.8	91.7	92.3	80.0	78.7	90.2	94.4	88.0
December	100.0	100.0	100.0	99.0	100.0	100.0	95.6	99.2

Fairbanks - Tanana Valley Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)	Average 1976-1982 (%)
January	100.0	74.8	100.0	88.6	99.8	85.7	100.0	92.7
February	98.6	74.3	98.8	100.0	79.0	94.6	97.0	91.8
March	81.0	73.2	85.4	80.7	73.7	73.1	86.8	79.1
April	64.2	61.9	74.0	65.1	63.3	70.2	77.1	68.0
May	54.3	51.2	60.6	56.1	58.5	69.4	71.0	60.2
June	49.2	47.9	60.4	53.5	56.8	63.9	66.6	56.9
July	53.6	46.4	57.7	55.4	58.5	62.9	65.4	57.1
August	52.4	47.3	57.7	56.5	62.3	65.5	68.5	58.6
September	59.4	55.7	65.5	59.6	63.9	70.8	73.9	64.1
October	81.3	67.4	75.5	66.3	74.2	77.4	85.8	75.4
November	83.6	87.1	89.9	71.7	79.2	83.3	94.7	84.2
December	96.3	100.0	87.2	87.0	100.0	100.0	94.4	95.0

Total Railbelt Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)	Average 1976-1982 (%)
January	96.5	76.3	93.7	90.2	91.6	80.2	100.0	89.8
February	93.9	72.4	90.8	100.0	76.4	86.5	94.0	87.7
March	82.2	74.9	81.1	84.9	72.6	73.1	83.6	78.9
April	69.9	67.8	71.9	67.3	60.6	69.3	77.4	69.2
May	62.1	57.8	63.9	58.3	56.2	62.7	65.6	60.9
June	57.8	53.8	61.4	57.5	53.4	61.9	62.6	58.3
July	60.7	52.3	60.6	55.0	51.9	63.0	62.2	57.9
August	61.4	55.2	62.6	55.7	55.6	62.6	65.3	59.8
September	68.1	64.6	67.7	61.5	59.3	69.8	73.9	66.4
October	88.1	75.5	82.4	71.4	70.6	78.5	90.3	79.5
November	88.3	90.6	94.2	78.3	78.8	89.0	94.4	87.7
December	100.0	100.0	100.0	96.6	100.0	100.0	95.4	98.9

Source: TABLES B.84 and B.85

TABLE B.74 (Sheet 2 of 2)

MONTHLY DISTRIBUTION OF ENERGY DEMAND

Anchorage - Cook Inlet Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)	Average 1976-1982 (%)
January	10.0	9.1	10.2	10.2	10.5	9.3	10.8	10.0
February	9.4	8.0	8.7	10.3	8.6	8.6	9.0	8.9
March	9.1	9.1	9.0	9.0	8.8	8.6	8.9	8.9
April	7.8	7.9	7.7	7.9	7.5	7.8	7.9	7.8
May	7.2	7.3	7.3	7.1	6.9	7.1	7.2	7.2
June	6.4	6.7	6.7	6.4	6.5	6.8	6.5	6.6
July	6.7	6.5	6.8	6.6	6.7	7.2	6.8	6.7
August	6.8	6.8	6.8	6.8	6.8	7.2	6.9	6.9
September	7.5	7.1	7.2	7.0	7.2	7.5	7.2	7.2
October	8.9	8.8	8.8	8.2	8.4	9.1	9.0	8.7
November	9.5	10.7	10.0	8.8	9.6	10.0	9.6	9.8
December	10.6	12.0	10.8	11.6	12.3	10.8	10.2	11.2

Fairbanks - Tanana Valley Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)	Average 1976-1982 (%)
January	11.9	9.9	11.2	11.0	11.3	9.5	11.0	10.8
February	11.4	8.5	9.7	11.3	8.6	9.1	9.2	9.7
March	9.4	9.7	9.6	9.5	8.6	8.6	8.9	9.2
April	7.4	7.8	7.8	7.9	7.4	8.0	7.9	7.7
May	6.4	6.7	6.9	6.7	7.0	7.3	7.2	6.9
June	5.8	6.0	6.4	6.3	6.3	6.8	6.6	6.3
July	6.0	6.0	6.5	6.6	6.8	6.8	7.0	6.5
August	6.1	6.4	6.6	6.5	6.9	6.8	7.0	6.6
September	6.7	6.5	7.0	7.0	7.3	7.6	7.3	7.1
October	8.6	8.6	8.6	8.1	8.1	8.9	8.7	8.5
November	9.1	11.1	9.5	8.4	9.2	9.4	9.3	9.4
December	11.4	12.7	10.2	10.8	12.5	11.0	10.2	11.3

Total Railbelt Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)	Average 1976-1982 (%)
January	10.4	9.3	10.4	10.4	10.6	9.3	10.8	10.2
February	9.8	8.1	8.9	10.5	8.6	8.7	9.0	9.1
March	9.1	9.3	9.1	9.1	8.8	8.6	8.9	9.0
April	7.7	7.9	7.8	7.9	7.5	7.8	7.9	7.8
May	7.1	7.2	7.2	7.1	7.0	7.1	7.2	7.1
June	6.2	6.4	6.7	6.4	6.5	6.8	6.5	6.5
July	6.6	6.4	6.8	6.6	6.7	7.1	6.9	6.7
August	6.7	6.7	6.8	6.7	6.8	7.2	6.9	6.8
September	7.3	7.0	7.1	7.0	7.2	7.5	7.2	7.2
October	8.9	8.8	8.7	8.2	8.4	9.0	9.0	8.7
November	9.5	10.8	9.8	8.7	9.5	9.9	9.6	9.7
December	10.8	12.2	10.7	11.5	12.3	10.8	10.2	11.2

Source: TABLES B.84 and B.85

TABLE B.75

PROJECTED MONTHLY DISTRIBUTION OF PEAK AND ENERGY DEMAND PERCENTAGE OF ANNUAL DEMAND

Total Railbelt Area

	1990		2000		2010		2020	
	Peak 1/ (%)	Energy 2/ (%)	Peak 1/ (%)	Energy 2/ (%)	Peak 1/ (%)	Energy 2/ (%)	Peak 2/ (%)	Energy 1/ (%)
January	91.5	10.3	91.4	10.2	91.3	10.2	91.3	10.2
February	86.6	8.9	86.5	9.0	86.4	8.8	86.4	9.0
March	78.5	9.0	78.4	8.9	78.3	8.9	78.3	8.9
April	69.5	7.7	69.6	7.6	69.6	7.7	69.6	7.7
May	63.0	7.1	63.6	7.1	63.7	7.1	63.7	7.1
June	60.3	6.5	61.7	6.6	61.9	6.6	61.9	6.6
July	59.5	6.5	60.5	6.5	60.5	6.6	60.5	6.6
August	63.2	6.9	64.4	6.9	64.3	6.9	64.3	6.9
September	68.5	7.2	69.4	7.2	69.4	7.3	69.4	7.3
October	79.0	8.7	79.4	8.7	79.3	8.7	79.3	8.7
November	92.2	9.9	92.2	9.9	92.1	9.9	92.1	9.9
December	100.0	11.2	100.0	11.1	100.0	11.2	100.0	11.2

1/Source: Woodward-Clyde, December 1980 Report, Table 3.2.11

2/Source: Results from the OGP Load Model, Reference Case Scenario

TABLE B.76

TYPICAL DAILY LOAD DURATION

SELECTED MONTHS					
WEEKDAY			WEEKDAY		
APRIL	AUGUST	DECEMBER	APRIL	AUGUST	DECEMBER
1.000	1.000	1.000	.942	.871	.945
.990	.990	.997	.917	.868	.944
.983	.988	.979	.897	.858	.927
.981	.977	.968	.882	.846	.911
.978	.970	.948	.882	.845	.893
.966	.965	.918	.880	.842	.868
.963	.959	.915	.870	.837	.862
.957	.951	.914	.867	.835	.856
.953	.948	.913	.859	.832	.854
.947	.923	.909	.851	.830	.853
.939	.890	.905	.851	.820	.843
.936	.882	.897	.838	.816	.826
.936	.873	.896	.837	.797	.818
.931	.868	.879	.827	.786	.782
.888	.834	.873	.805	.724	.775
.853	.776	.812	.753	.703	.732
.750	.747	.804	.729	.667	.724
.769	.666	.747	.724	.623	.723
.712	.657	.710	.689	.616	.680
.698	.612	.702	.673	.595	.672
.683	.590	.675	.668	.580	.661
.672	.581	.668	.667	.564	.655
.670	.581	.664	.661	.555	.648
.670	.560	.661	.650	.545	.648

Source: Woodward-Clyde, 1980.

TABLE B.77

LOAD DIVERSITY IN THE RAILBELT

Railbelt Loads - December 29, 1871

UTILITY	2PM	3PM	4PM	5PM	6PM	7PM	8PM	Non-Coincident Peak
CEA	168.55	170.7	178.7	179.4	182.1	180.8	173.2	182.1
AMLP	107	111	110	106	104	100	96	111.0
MEA	52.3	51.4	49.5	49.0	52.2	50.1	47.0	52.3
HEA	48.1	48.3	49.7	50.4	49.7	49.0	46.7	50.4
GVEA	71.8	71.8	75.4	69.1	72.9	72.2	73.2	75.4
Ft.WR.	9.5	11.0	11.7	10.2	9.5	8.8	9.5	11.7
EIELSON	10.3	10.3	10.0	10.0	10.0	10.0	10.0	10.3
U. of A.	5.8	5.8	5.6	6.0	4.9	5.3	4.4	6.0
FMUS	27.4	26.7	26.7	25.7	24.0	21.1	18.5	27.4
TOTAL	500.7	507.0	517.3	505.8	509.3	497.3	478.5	526.6

$$\text{Diversity} = \frac{\text{Coincidnet Peak}}{\text{Non-coincident Peak}} = \frac{517.3}{526.6} = .982$$

Railbelt Loads - January 6, 1982

UTILITY	2PM	3PM	4PM	5PM	6PM	7PM	8PM	Non-Coincident Peak
CEA	175	178	194	202	214	210	203	214
AMLP	109	109	117	115	116	112	107	117
MEA	66	71	71	71	73	74	74	74
HEA	57	56	60	62	62	63	61	63
GVEA	66.5	67.8	69.0	74.6	71.9	74.1	74.2	74.6
Ft.WR.	11.0	11.7	11.7	9.5	9.5	9.5	8.8	11.7
EIELSON	11.0	11.0	11.2	10.9	10.7	10.4	10.4	11.2
U. of A.	6.0	6.2	6.2	6.5	5.7	4.3	5.0	6.5
FMUS	27.4	27.2	29.7	26.2	24.0	23.5	20.4	29.7
TOTAL	528.9	538.3	569.8	577.7	586.8	580.8	563.8	601.7

$$\text{Diversity} = \frac{\text{Coincident Peak}}{\text{Non-coincident Peak}} = \frac{586.8}{601.7} = .975$$

Source: Alaska Systems Coordinating Council, April 16, 1982.

TABLE B.78

RESIDENTIAL AND COMMERCIAL ELECTRIC RATES
Anchorage-Cook Inlet Area
March 1983

Utility	Energy Used	Electric Rate: Fixed Rate	Electric Rate: Rate With Cost of Power Adjustment
Residential Rates (monthly)			
Anchorage Municipal Light & Power	Customer Charge	\$4.50	---
	Energy Charge	4.638¢/kWh	5.199¢/kWh
	Cost of 1,000 kWh	\$46.38---	\$51.99---
Chugach Electric Association, Inc.	First - 50 kWh	13.6¢/kWh	13.916¢/kWh
	Next 200 kWh	6.7¢/kWh	7.016¢/kWh
	Next 500 kWh	3.9¢/kWh	4.216¢/kWh
	Next 750 kWh	3.5¢/kWh	3.816¢/kWh
	Over 1,500 kWh	3.0¢/kWh	3.316¢/kWh
	Cost of 1,000 kWh	\$48.45	\$51.61
Commercial Rates (monthly)			
Anchorage Municipal Light & Power	Customer Charge	\$8.24	---
	Energy Charge	5.62¢/kWh	6.181¢/kWh
	Cost of 5,000 kWh	\$281.00---	\$309.05---
Chugach Electric Association, Inc.	First - 100 kWh	9.1¢/kWh	9.416¢/kWh
	Next 150 kWh	6.1¢/kWh	6.416¢/kWh
	Next 500 kWh	5.3¢/kWh	5.616¢/kWh
	Over 750 kWh	4.8¢/kWh	5.116¢/kWh
	Cost of 5,000 kWh	\$248.75	\$264.55

Sources:

1/ AMLP, Schedule II Residential Service, effective September 29, 1982.
2/ AMLP, Gas Cost Rate Adjustment, Tariff Sheet Number 101, effective March 1, 1983.
3/ CEA, Schedule No. 1, General Residential Service, (Urban Areas), effective October 26, 1982.
4/ CEA, Fuel and Purchased Power Cost Adjustment Factor, Tariff Sheets No. 91-95, effective March 7, 1983.
5/ AMLP, Schedule 21 General Service-Small, effective September 29, 1982.
6/ CEA, Schedule No. 3, Commercial Light and Power (Not exceeding 10 kw), effective October 26, 1982.

TABLE B.79

RESIDENTIAL AND COMMERCIAL ELECTRIC RATES
Fairbanks-Tanana Valley Area
March 1983

Utility	Energy Used	Electric Rate: Fixed Rate	Electric Rate: Rate With Cost of Power Adjustment*
Residential Rates	KWH	KWH	
Fairbanks Municipal Utilities System	0-100 kWh**	12.00¢/kWh**	---
	100-400 kWh	8.20¢/kWh	---
	Over 400 kWh	5.90¢/kWh	---
	Cost of 1,000 kWh	$72.00	---
Golden Valley Electric Assn.	Customer Charge***	$10.00***	$10.00***
	0-500 kWh	11.25¢/kWh	9.73¢/kWh
	Over 500 kWh	9.50¢/kWh	7.98¢/kWh
	Cost of 1,000 kWh	$113.75	$98.58
Commercial Rates			
Fairbanks Municipal Utilities System	0-100 kWh**	12.00¢/kWh**	---
	100-400 kWh	11.30¢/kWh	---
	400-1,000 kWh	9.50¢/kWh	---
	Over 1,000 kWh	7.80¢/kWh	---
	Cost of 5,000 kWh	$414.90	---
Golden Valley Electric Assn.	Customer Charge***	$20.00***	$20.00***
	0-500 kWh	15.00¢/kWh	13.48¢/kWh
	500-5,000 kWh	11.10¢/kWh	9.58¢/kWh
	Over 5,000 kWh	9.50¢/kWh	7.98¢/kWh
	Cost of 5,000 kWh	$594.50	$518.65

* Golden Valley Electric Association electric rates include a Cost of Power Adjustment Clause (CPAC) that raises or lowers the fixed electric rate quarterly to reflect changes in the cost of fuel and the cost of electricity purchased from other utilities. The CPAC for the quarter that begins with the March billing cycle lowers the price of each kWh sold by 1.517¢.

** Fairbanks Municipal Utilities System electric rates include a minimum monthly charge of $9.00 per residential customer and $12.00 per commercial customer.

*** Golden Valley Electric Association (GVEA) electric rates also include a fixed customer charge of $10.00 per residential customer and $20.00 per commercial customer. The total GVEA monthly bill is, therefore, the sum of the customer charge and the kWh usage charge.

Source: Fairbanks North Star Borough. The Energy Report, March, 1983.

TABLE B.80

ANCHORAGE MUNICIPAL LIGHT AND POWER

CUMULATIVE ENERGY CONSERVATION PROJECTIONS

Program	1981	1982	1983	1984	1985	1986	1987
	Energy Conservation in MWh						
Weatherization	586	762	938	1,114	1,290	1,466	1,641
State Programs	879	1,759	2,199	2,683	3,078	3,518	3,737
Water Flow Restrictions	200	464	464	464	464	464	464
Water Heat Injection	3,922	3,922	3,922	3,922	3,922	3,922	3,922
Hot Water Heater Wrap	NA	NA	249	249	249	249	249
Street Light Conversion	0	555	1,859	3,307	4,788	6,306	7,861
Transmission Conversion	0	0	4,119	8,732	9,256	9,811	10,399
Boiler Pump Conversion	7,148	7,148	7,148	7,148	7,148	7,148	7,148
TOTAL	12,735	14,609	20,896	27,619	30,195	32,614	35,421
Increase From Previous Year %	NA	14.7	43.0	32.2	9.3	9.8	8.6

Source: AMLP, 1983

TABLE B.81

PROGRAMMATIC VS MARKET DRIVEN ENERGY CONSERVATION
PROJECTIONS IN THE AMLP SERVICE AREA

Year	Programmatic Conservation (MWh)	(%)	Price-Induced Conservation (MWh)	(%)	Total (MW)	(%)	Increase From Previous Year (%)
1981	12,735	39.5	19,558	60.5	32,294	100	NA
1982	191,609	34.9	27,243	65.1	41,853	100	29.6
1983	20,896	37.1	35,374	62.9	56,289	100	34.4
1984	27,619	41.1	39,560	58.9	67,133	100	19.3
1985	30,195	40.4	44,536	59.6	74,730	100	11.3
1986	32,614	40.6	48,133	59.4	81,015	100	8.4
1987	35,421	41.0	50,940	59.0	86,363	100	6.6

Source: AMLP, 1983

TABLE B.82

AVERAGE ANNUAL ELECTRICITY CONSUMPTION PER HOUSEHOLD ON THE GVEA SYSTEM, 1972-1982

Year	Annual Consumption (kWh)	Percent Change
1972	13,919	+5.6
1973	14,479	+4.0
1974	15,822	+9.3
1975	17,332	+9.5
1976	15,203	-12.3
1977	14,255	-6.2
1978	11,574	-18.8
1979	10,519	-9.1
1980	9,767	-7.1
1981	9,080	-7.0
1982	9,303	+2.5

Source: GVEA, 1983

TABLE B.83 HISTORIC ECONOMIC AND ELECTRIC POWER DATA

ITEM (1)	Unit	YEAR 1960	1965	1970	1975	1980	1982
State Oil and Gas Revenues to General Fund	10^6 x $	4.2 (2)	16.3	938.6 (3)	88.3	2,262.3	3,567.3
State General Fund Expenditures		n.a.	82.7	188.6	453.3	1,172.8	4,601.9
State Population		226,200	265,200	304,700	390,000	402,000	437,175
State Employment		94,300	110,000	133,400	197,500	211,200	231,984
Railbelt Population		140,486	n.a.	199,670	n.a.	275,818	307,107
Railbelt Employment (4)		n.a.	74,100	88,500	130,400	132,000	154,033
Railbelt Households		37,062	n.a.	54,057	n.a.	94,210	106,599
Railbelt Electric (5) Energy Generation	GWh						
Anchorage		n.a.	526	885	1,451	2,365	2,709
Fairbanks		n.a.	231	433	617	647	691
Total		n.a.	757	1,318	2,068	3,012	3,400
Railbelt Peak Demand (5)	MW	n.a.	171	296	420	634	655
Railbelt Generation Capacity	MW	n.a.	n.a.	n.a.	n.a.	1,143	1,272

Sources: MAP Model Data Base; Federal Energy Regulatory Commission, Power System Statement; Alaska Power Administration, Unpublished Printouts, 1983.

(1) Annual data is not available on a consistent basis for all items listed.
(2) Figure is for 1961.
(3) This figure results from the collection of a large petroleum lease bonus.
(4) Excludes agricultural workers and self-employed.
(5) Includes electric utilities, military generation and self-supplied industrial.

TABLE B.84 MONTHLY LOAD DATA FROM ELECTRIC UTILITIES OF THE ANCHORAGE-COOK INLET AREA 1976-1982

	1976	1977	1978	1979	1980	1981	1982
NET ENERGY (MWh)[1/]							
January	161,141.5	163,477.1	197,195.3	209,274.5	221,099.0	202,340.0	264,648.0
February	151,168.2	143,889.6	167,616.7	210,332.0	181,893.5	187,783.4	220,393.7
March	146,509.1	164,983.4	173,181.4	185,059.4	185,943.1	186,765.9	216,461.3
April	126,761.1	143,022.2	149,674.5	161,606.5	156,987.2	170,237.0	192,249.0
May	117,125.5	131,440.5	141,333.2	145,917.9	146,260.9	154,246.8	176,556.1
June	103,078.8	118,039.1	129,703.3	131,699.7	136,742.5	148,192.0	158,777.1
July	108,553.9	117,770.2	132,305.2	135,651.7	141,134.1	155,776.0	167,278.6
August	110,786.5	123,445.4	132,216.7	138,170.5	143,856.5	157,135.7	168,890.9
September	121,003.0	128,232.2	138,889.5	142,352.1	152,210.2	163,671.3	175,186.4
October	144,716.2	158,886.4	169,395.0	168,032.0	177,254.6	196,922.6	220,848.4
November	154,417.2	193,630.9	191,146.6	179,280.7	202,484.4	218,191.4	234,428.6
December	172,100.4	216,793.6	209,149.0	237,780.1	259,118.5	234,472.2	250,034.5
ANNUAL	1,617,361.6	1,803,610.6	1,931,806.2	2,045,157.1	2,104,984.5	2,175,734.4	2,445,752.6
PEAK DEMAND (MW)[2/]							
January	293.1	288.4	341.3	357.8	399.4	351.8	471.7
February	283.7	269.5	328.6	395.1	337.2	377.0	440.4
March	254.0	283.0	296.6	339.5	321.9	324.9	391.5
April	220.4	261.7	270.3	268.1	266.9	307.3	365.2
May	198.8	224.6	239.8	232.7	247.7	272.5	303.6
June	186.4	208.7	228.6	231.1	234.3	273.4	291.4
July	193.9	203.3	227.4	217.1	224.2	280.1	290.6
August	197.7	216.3	236.6	219.5	240.8	275.9	298.9
September	218.0	253.3	253.1	244.8	259.2	309.7	348.4
October	277.7	293.0	312.1	287.4	310.6	349.9	429.1
November	276.2	344.1	353.2	316.2	349.7	401.3	445.2
December	311.0	375.4	382.8	391.1	444.4	444.7	450.9
ANNUAL	311.0	375.4	382.8	395.1	444.4	444.7	471.7

[1/] Includes total net generation by CEA, AMLP and APAD and sales to other utilities.
[2/] Note: includes AMLP & CEA (This equals total area except MEA purchase from APAD - 5 MW by contract.)
Source: Alaska Power Administration, unpublished printouts, 1983.

TABLE B.85 MONTHLY LOAD DATA FROM ELECTRIC UTILITIES OF THE FAIRBANKS-TANANA VALLEY AREA 1976-1982

	1976	1977	1978	1979	1980	1981	1982
				NET ENERGY (MWh)(1)			
January	55,675.0	47,753.3	52,380.1	49,177.2	50,037.5	42,057.2	53,931.0
February	53,313.3	41,115.2	45,326.6	50,532.3	38,093.0	40,303.0	45,022.0
March	43,844.4	46,759.5	45,014.9	42,322.0	38,220.1	37,927.8	43,698.0
April	34,468.6	37,698.3	36,384.6	35,415.1	32,784.8	35,262.8	38,743.0
May	29,811.4	32,446.1	32,195.9	29,781.9	30,943.3	32,286.2	35,379.0
June	27,063.7	28,787.6	29,783.1	28,091.9	28,015.3	30,163.7	32,428.0
July	28,328.5	28,921.0	30,184.2	29,743.5	30,405.5	30,264.8	34,449.0
August	28,754.2	30,765.5	30,793.2	29,058.6	30,378.0	30,301.7	34,308.0
September	31,311.0	31,474.5	32,455.1	31,404.4	32,232.7	33,661.8	35,637.0
October	40,298.2	41,307.6	40,106.7	36,280.0	36,084.3	39,271.0	42,846.1
November	42,801.7	53,609.9	44,186.7	37,400.1	40,606.1	41,647.1	45,771.0
December	53,334.5	61,015.7	47,394.9	48,370.1	55,500.7	48,820.3	49,885.0
ANNUAL	468,004.3	481,654.2	466,206.0	447,577.1	443,301.3	442,967.3	491,097.0
				PEAK DEMAND (MW)(1)			
January	101.0	87.9	95.8	89.2	95.2	79.8	94.4
February	99.6	87.3	94.7	100.7	75.4	88.1	91.6
March	81.8	86.0	81.8	81.3	70.3	68.1	82.0
April	64.9	72.7	70.9	65.6	60.4	65.4	72.8
May	54.8	60.2	58.1	56.5	55.8	64.6	67.0
June	49.7	56.3	57.9	53.9	54.2	59.5	62.9
July	54.1	54.5	55.3	55.8	55.8	58.6	61.7
August	52.9	55.6	55.3	56.9	59.4	61.0	70.7
September	60.0	65.4	62.8	60.0	61.0	65.9	69.8
October	82.1	79.2	72.3	66.8	70.8	72.1	82.1
November	84.5	102.3	86.1	72.2	75.6	77.6	89.4
December	97.3	117.5	83.5	87.6	95.4	93.1	89.1
ANNUAL	101.0	117.5	95.8	100.7	95.4	93.1	94.4

(1) Data for FMUS and GVEA including purchases.
Source: Alaska Power Administration, unpublished printout, 1983.

TABLE B.86 NET GENERATION BY ELECTRIC UTILITY
1976-1982
(GWh)

UTILITY	YEAR 1976	1977	1978	1979	1980	1981	1982
Anchorage Municipal Light & Power	444.9	420.3	443.1	473.1	486.6	485.3	579.5
Chugach Electric Asso.	1,054.5	1,179.7	1,308.6	1,401.0	1,434.1	1,467.7	1,718.4
Alaska Power Administration	118.0	203.6	180.1	171.1	184.3	222.7	147.9
Anchorage Cook Inlet Subtotal	1,617.4	1,803.6	1,931.8	2,045.2	2,105.0	2,175.7	2,445.8
Fairbanks Municipal Utility System	123.3	128.5	124.7	124.7	125.6	126.1	140.7
Golden Valley Electric Association	344.7	353.5	341.5	322.9	317.7	316.9	350.3
Fairbanks Area Sub-total	468.0	481.7	466.2	447.6	443.3	443.0	491.1
Railbelt Total	2,085.4	2,285.3	2,398.0	2,492.8	2,548.3	2,618.7	2,936.9

Note: Subtotals and total shown may differ from column totals due to rounding.

Source: Alaska Power Administration, Unpublished Printouts, 1983.

TABLE B.87

MAP MODEL VALIDATION

SIMULATION OF HISTORICAL ECONOMIC CONDITIONS

Factor	Year	Observed Value	Estimated Value	Difference	Percent Difference
Non-Agriculatural	1965	70,529	70,406	-123	-.174
Wage and Salary	1970	92,465	88,837	-3,628	-3.924
Employment	1975	161,315	154,893	-6,422	-3.981
	1980	169,609	166,281	-3,328	-1.962
Wages and Salaries	1965	721	757	36	4.9
In Alaska -	1970	1,203	1,134	-69	-5.7
$million - nominal	1975	3,413	3,408	-5	-0.1
	1980	4,220	4,083	-182	-4.3
Personal Income	1965	827	861	34	4.1
In Alaska -	1970	1,388	1,309	-79	-5.7
$million - nominal	1975	3,455	3,372	-83	-2.4
	1980	5,030	4,972	-58	-1.2

TABLE B.88

COMPARISON OF ACTUAL AND PREDICTED
ELECTRICITY CONSUMPTION FOR 1982 (GWh)

Anchorage - Cook Inlet Area

	RED Reference Case Output	RED Adjusted	Utilities Data
Residential	1059	1097	1146
Business	1018	1070	972
Others	125	123	123
Total	2202	2290	2241

Fairbanks-Tanana Valley Area

	RED Reference Case Output	RED Adjusted	Utilities Data
Residential	205	208	178
Business	242	254	269
Others	7	6	5
Total	454	468	452

Table B.89 (Sheet 1 of 2)
ALTERNATIVE PETROLEUM PRICE PROJECTIONS 1983-2010
1983 DOLLARS

	Department of Revenue Mean-4/83(1)		DRI Spring 1983(2)		Sherman Clark Base Case -4/83		Reference Case Sherman Clark NSD Case -4/83	
	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg.	$/bbl	%Chg
1983	28.95		28.95		28.95		28.95	
4	23.96	-17.2	25.17	-13.1	27.61	-4.6	27.61	-4.6
5	22.67	- 5.4	27.02	7.4	26.30	-4.7	26.30	-4.7
6	22.35	- 1.4	28.77	6.5	26.30	0.0	26.30	0.0
7	21.95	- 1.8	30.64	6.5	26.30	0.0	26.30	0.0
8	22.15	1.3	32.62	6.5	26.30	0.0	26.30	0.0
9	22.34	1.3	34.74	6.5	40.00	52.1	27.09	3.0
1990	22.55	1.3	36.99	6.5	40.00	0.0	27.90	3.0
1	22.79	1.3	38.61	4.4	41.20	3.0	28.74	3.0
2	23.04	1.3	40.31	4.4	42.44	3.0	29.60	3.0
3	23.32	1.3	42.08	4.4	43.71	3.0	30.49	3.0
4	23.63	1.3	43.92	4.4	45.02	3.0	31.40	3.0
5	23.96	1.3	45.85	4.4	46.38	3.0	32.34	3.0
6	24.31	1.3	47.27	4.4	47.77	3.0	33.31	3.0
7	24.71	1.3	48.74	3.1	49.20	3.0	34.31	3.0
8	25.14	1.3	50.26	3.1	50.68	3.0	35.34	3.0
9	25.60	1.3	51.82	3.1	52.20	3.0	36.40	3.0
2000	25.93	1.3	53.43	3.1	53.76	3.0	37.50	3.0
1	26.27	1.3	54.04	1.1	55.64	3.5	38.63	3.0
2	26.61	1.3	54.65	1.1	57.58	3.5	39.78	3.0
3	29.96	1.3	55.27	1.1	59.58	3.5	40.98	3.0
4	27.31	1.3	55.90	1.1	61.66	3.5	42.21	3.0
5	27.66	1.3	56.54	1.1	63.81	3.5	43.47	3.0
6	28.02	1.3	57.33	1.1	66.04	3.5	44.78	3.0
7	28.39	1.3	58.13	1.1	68.34	3.5	46.12	3.0
8	28.76	1.3	58.95	1.1	70.73	3.5	47.50	3.0
9	29.13	1.3	59.77	1.1	73.20	3.5	48.93	3.0
2010	29.51	1.3	60.61	1.1	75.75	3.5	50.39	3.0

(1) DOR extrapolated after 1999 at last DOR rate of 1.3%/yr.
(2) DRI extrapolated after 2005 at last DRI rate of 1.1%/yr.

TABLE B.89 (Sheet 2 of 2)
ALTERNATIVE OIL PRICE PROJECTIONS 2010-2040
1983 DOLLARS

	Department of Revenue Mean-4/83		DRI Spring 1983		Sherman Clark Base Case-4/83		Reference Case Sherman Clark NSD Case-4/83	
	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg
2010	29.51		60.61		75.75		50.39	
1	29.89	1.3	61.28	1.1	76.89	1.5	51.65	2.5
2	30.28	1.3	61.95	1.1	78.04	1.5	52.94	2.5
3	30.68	1.3	62.63	1.1	79.21	1.5	54.26	2.5
4	31.07	1.3	63.32	1.1	80.40	1.5	55.61	2.5
2015	31.48	1.3	64.02	1.1	81.60	1.5	57.00	2.5
6	31.89	1.3	64.72	1.1	82.83	1.5	58.42	2.5
7	32.30	1.3	65.43	1.1	84.07	1.5	59.88	2.5
8	32.72	1.3	66.15	1.1	85.33	1.5	61.38	2.5
9	33.15	1.3	66.88	1.1	86.61	1.5	62.91	2.5
2020	33.58	1.3	67.62	1.1	87.80	1.5	64.48	2.5
1	34.02	1.3	68.36	1.1	87.80	0.0	65.45	1.5
2	34.46	1.3	69.11	1.1	87.80	0.0	66.43	1.5
3	34.91	1.3	69.87	1.1	87.80	0.0	67.43	1.5
4	35.36	1.3	70.64	1.1	87.80	0.0	68.44	1.5
2025	35.82	1.3	71.42	1.1	87.80	0.0	69.47	1.5
6	36.76	1.3	72.20	1.1	87.80	0.0	70.51	1.5
7	36.23	1.3	73.00	1.1	87.80	0.0	71.57	1.5
8	37.72	1.3	73.80	1.1	87.80	0.0	72.64	1.5
9	38.21	1.3	74.61	1.1	87.80	0.0	73.73	1.5
2030	38.71	1.3	75.43	1.1	87.80	0.0	74.84	1.5
1	39.21	1.3	76.26	1.1	87.80	0.0	75.59	1.0
2	39.72	1.3	77.10	1.1	87.80	0.0	76.34	1.0
3	40.23	1.3	77.95	1.1	87.80	0.0	77.10	1.0
4	40.76	1.3	78.81	1.1	87.80	0.0	77.88	1.0
2035	41.29	1.3	79.68	1.1	87.80	0.0	78.65	1.0
6	41.82	1.3	80.55	1.1	87.80	0.0	79.44	1.0
7	42.36	1.3	81.44	1.1	87.80	0.0	80.23	1.0
8	42.37	1.3	82.33	1.1	87.80	0.0	81.03	1.0
9	42.92	1.3	83.24	1.1	87.80	0.0	81.84	1.0
2040	42.48	1.3	84.15	1.1	87.80	0.0	82.66	1.0

Table B.90
LEVEL OF ANALYSIS EMPLOYED WITH WORLD OIL PRICE FORECASTS

Oil Price Forecast	Model or Level of Analysis			
	DOR Petroleum Revenue (PETREV)	ISER (MAP)	Battelle Railbelt Electric Demand (RED)	General Electric Optimum Generation Planning (OGP)
DOR Mean, Spring 83	Yes	Yes	Yes	Yes
DOR 50%	From PETREV	Yes	Yes	No
DOR 30%	From PETREV	Yes	Yes	No
DRI Spring 83	Yes	Yes	Yes	Yes
DRI LOWOIL	No	No	No	No
DRI HIGHOIL	No	No	No	No
SHCA BASE CASE	No	No	No	No
Reference Case	Yes	Yes	Yes	Yes
SHCA ZEG	No	No	No	No
+2%	Yes	Yes	Yes	No
0%	Yes	Yes	Yes	No
-1%	Yes	Yes	Yes	No
2%	Yes	Yes	Yes	Yes

TABLE B.91

VARIABLES AND ASSUMPTIONS OTHER THAN OIL PRICES
PETREV MODEL

Name	Year	Reference Case Value	Source
North Slope Petroleum Production	1983	1.611 x 10^6 bbl/day	Department of Revenue
	1999	.699 x 10^6 bbl/day	Department of Revenue
State Royalty	1983	12.5%	Department of Revenue
	1999	12.5%	Department of Revenue
North Slope Production Tax Rate	1983	15%	Department of Revenue
	1999	15%	Department of Revenue
Economic Limit Factor	1983	99	Department of Revenue
	1999	585	Department of Revenue
Transportaton and Quality Differential	1983	$9.93 nominal/bbl	Department of Revenue
	1999	$13.86 nominal/bbl	Department of Revenue

TABLE B.92

VARIABLES AND ASSUMPTIONS OTHER THAN OIL PRICES
MAP MODEL

Symbol	Name	Year	Reference Case Value	Source
EMAGRI	State Agricultural Employment	1983	203 Employees	Alaska Department of Labor
		2010	704 Employees	MAP Model Data Base
MBP9	State Mining Employment	1983	9,387 Employees	Alaska Department of Labor
		2010	16,282 Employees	Institute of Social and Economic Research
EMCNX1	State High Wage Exog.Const. Emp.	1983	3,261 Employees	Institute of Social and Economic Research
		2010	1,056 Employees	Institute of Social and Economic Research
EMCNX2	State Low Wage Exog.Const.Emp.	1983	290 Employees	Institute of Social and Economic Research
		2010	0 Employees	Institute of Social and Economic Research
EMT9X	State Exog.Transportation Emp.	1983	1,552 Employees	Institute of Social and Economic Research
		2010	3,279 Employees	Institute of Social and Economic Research
EMMX1	State High Wage Manuf. Emp.	1983	0 Employees	Institute of Social and Economic Research
		2010	0 Employees	Institute of Social and Eocnomic Research
EMMX2	State Low Wage Manuf. Emp.	1983	10,433 Employees	Institute of Social and Economic Research
		2010	11,617 Employees	Institute of Social and Economic Research
EMFISH	State Fish Harveting Emp.	1983	6,421 Employees	Institute of Social and Economic Research
		2010	7,096 Employees	Institute of Social and Economic Research
EMGM	State Active Duty Military Emp.	1983	23,323 Employees	Bureau of Economic Analysis,U.S.Dept. of Comm.
		2010	23,323 Employees	Alaska Military Command
EMGC	State Civilian Federal Emp.	1983	17,989 Employees	Alaska Department of Labor
		2010	20,583 Employees	Institute of Social and Economic Research
TOURIST	Tourists Visiting Alaska	1983	730,000 Visitors	Alaska Dept. of Commerce & Economic Develop.,
		2010	2,080,000 Visitors	Division of Tourism
RPTS	State Petroleum Production Tax	1983	1,480 MM Current $	PETREV Model Output
	Revenue	2010	699 MM Current $	Institute of Social and Economic Research
RPRY	State Petroleum Royalty Revenue	1983	1,430 MM Current $	PETREV Model Output
		2010	1,592 MM Current $	Institute of Social and Economic Research
RPBS	State Bonus Payment Revenue	1983	26 MM Current $	Institute of Social and Economic Research
		2010	0 MM Current $	Institute of Social and Economic Research
RPPS	State Petroleum Property Tax	1983	149 MM Current $	Institute of Social and Economic Research
	Revenue	2010	564 MM Current $	Institute of Social and Economic Research
RTCSPX	State Petroleum Corporate Tax	1983	235 MM Current $	Institute of Social and Economic Research
		2010	1,601 MM Current $	Institute of Social and Economic Research
GGRWEVS	U. S. Real Wage Growth/Year	--	.01	Bureau of Economic Analysis, U.S.,Dept.of Comm.
UUS	U. S. Unemployment Rate	--	.06	Bureau of Economic Analysis, U.S.,Dept.of Comm.
GRDIRPU	U. S. Real Income Growth/Year	--	.015	Bureau of Economic Analysis, U.S.,Dept.of Comm.
GRUSCPI	Price Level Growth/Year	--	.065	Bureau of Economic Analysis, U.S.,Dept.of Comm.
LFPART	Labor Force Participation Rate	--	.9338	Alaska Department of Labor

TABLE B.93 (Sheet 1 of 2)

SUMMARY OF EXOGENOUS ECONOMIC ASSUMPTIONS

Exogenous Employment Assumptions

Trans-Alaska Oil Pipeline System	Operating employment remains constant at 1,500 through 2010.
Prudhoe Bay Field Employment	Construction employment developing Prudhoe Bay and Kuparuk fields peaks at 2,400 in 1983 and 1986. Operating employment remains at 2,502 through 2010 for overall North Slope production.
Upper Cook Inlet Petroleum Production	Employment declines gradually beginning in 1983 so as to reach 50 percent of the 1982 level (778) by 2010.
Tertiary Recovery of North Slope Oil	Tertiary oil recovery project utilizing North Slope natural gas occurs in early 1990s with a peak annual employment of 2,000.
OCS Exploration and Development	The current OCS five-year leasing schedule calls for 16 OCS lease sales subsequent to October 1982, including the Beaufort, Norton, and St. George Sales, which have already taken place (Sales 71, 57, and 70). Development is assumed to occur only in the Navarin Basin (1.4 billion barrels of oil) and the Beaufort Sea (6.1 billion barrels of oil). All other sales are assumed to result in exploration employment only.
Anchorage Oil Headquarters	Several oil companies establish regional headquarters in Alaska in mid-1980s.
Beluga Chuitna Coal Production	Development of 4.4 million ton/year mine for export beginning in 1994 provides total total employment of 524.
Hydroelectric Projects	Employment peaks at 725 in 1990 for construction of several state-funded hydroelectric projects around the state.
U.S. Borax Mine	The U.S. Borax mine near Ketchikan is brought into production with operating employment of 790 by 1988.
Greene Creek Mine	Production from the Greens Creek Mine on Admiralty Island results in employment of 315 people from 1986 through 1996.
Red Dog Mine	The Red Dog Mine in the Western Brooks Range reaches full production with operating employment of 448 by 1988.

TABLE B.93 (Sheet 2 of 2)

SUMMARY OF EXOGENOUS ECONOMIC ASSUMPTIONS

Exogenous Employment Assumptions (continued)

Other Mining Activity	Employment increases from a 1982 level of 5,267 at 1 percent annually.
Agriculture	Moderate state support results in expansion of agriculture to employment of 508 in 2000.
Forest and Lumber Products	Employment expands to over 3,200 by 1990 before beginning to decline gradually after 2000 to about 2,800 by 2010.
Pulp Mills	Employment declines at a rate of 1 percent per year after 1983.
Commercial Fishing-Nonbottomfish	Employment levels in fishing and fish processing remain constant at 6,323 and 7,123 respectively.
Commercial Fishing-Bottomfish	The total U.S. bottomfish catch expands at a constant rate to allowable catch in 2000, with Alaska resident harvesting employment rising to 733. Onshore processing capacity expands in the Aleutians and Kodiak census divisions to provide total resident employment of 971 by 2000.
Federal Military Employment	Employment remains constant at 23,323.
Federal Civilian Employment	Rises at 0.5 percent annual rate from 17,900 in 1982 to 20,583 by 2010.
Tourism Assumptions	Number of visitors to Alaska increases by 50,000 per year from 680,000 in 1982 to over 2 million by 2010.

TABLE B.94 (Sheet 1 of 2)

VARIABLES AND ASSUMPTIONS OTHER THAN OIL PRICES
RED MODEL

Symbol	Name	Year	Reference Case Value	Source
Uncertainty Module				
	Fuel Price Forecast	-	Table B.95	1983 Actual Data Combined with Escalation Rates
b,c,d,	Housing Demand Coefficients	-	Table B.96	Battelle, 1983, based on Goldsmith and Huskey 1980b
SAT	Saturation of Residential Appliances	-	Table B.97	Battelle Northwest End Use Survey, 1981
A,B,	Price Adjustment Coefficients	-	Table B.98	Battelle, 1983, based on Mount, Chapman & Tyrrell (1973), and other literature
Housing Module				
THH	Regional Household Forecast	1983	101,346 Households	MAP Output
		2010	189,418 Households	MAP Output
HH	State Households by Age Group	-	Table B.108	MAP Output
Residential Module				
HI	Households by Type of Dwellings	-	Table B.109	Housing Module Output
AC	Average Consumption of Appliances	-	Table B.99	Battelle-Northwest End Use Survey;
AS	Initial Stock of Appliances	-	Table B.97 & 99	Residential Energy Surveys by San Diego Gas and Electric Company and Southern California Edisosn Company;
g	Growth Stock of Appliances	-	Table B.100	King, et. al 1982; McMahon, 1983;
d	Vintage Specific Survival Rate	-	Table B.101	Goldsmith and Huskey, 1980b.
Business Consumption Module				
TEMP	Total Regional Employment	1983	152,502 Employees	MAP Output
		2010	255,974 Employees	MAP Output

TABLE B.94 (Sheet 2 of 2)

VARIABLES AND ASSUMPTIONS OTHER THAN OIL PRICES
RED MODEL

Symbol	Name	Year	Reference Case Value	Source
Program-Induced Conservation Module				
Not Used				
Miscellaneous Module				
VACHG	Vacant Housing	-	Table B.110	RED Housing Module Output
vh	Consumption per Vacant Housing	-	300 kWh	Battelle, 1983
S1	Street Lighting Consumption	-	1.0%	Battelle, 1983
sh	Proportion of Households Having a Second Home	-	2.5%	O.S. Goldsmith, ISER, personal communication
shkWh	Per Unit Second Home Consumption	-	500 kWh	O.S.Goldsmith, ISER, personal communication
Peak Demand Module				
LF	Annual Load Factor			Battelle, 1983
	Anchorage	-	55.7%	
	Fairbanks	-	50.0%	

TABLE B.95

FUEL PRICE FORECASTS USED BY RED
(1980 dollars)

Year	Anchorage - Cook Inlet Area Residential	Anchorage - Cook Inlet Area Business	Fairbanks - Tanana Valley Area Residential	Fairbanks - Tanana Valley Area Business
		Heating Fuel Oil ($/MMBtu)		
1980	7.750	7.200	7.830	7.500
1985	6.450	5.900	6.510	6.180
1990	6.840	6.290	6.910	6.580
1995	7.930	7.380	8.010	7.680
2000	9.190	8.640	9.290	8.960
2005	10.650	10.100	10.770	10.440
2010	12.350	11.800	12.480	12.150
		Natural Gas ($/MMBtu)		
1980	1.730	1.500	12.740[1]	11.290[1/]
1985	1.950	1.720	10.600	9.150
1990	2.880	2.650	11.240	9.790
1995	4.050	3.820	13.030	11.580
2000	4.290	4.060	15.110	13.660
2005	4.960	4.730	17.520	16.070
2010	5.380	5.150	20.310	18.860
		Electricity ($/kWh)		
1980	0.037	0.034	0.095	0.090
1985	0.048	0.045	0.095	0.090
1990	0.052	0.049	0.092	0.087
1995	0.058	0.055	0.094	0.089
2000	0.062	0.059	0.096	0.091
2005	0.065	0.062	0.098	0.093
2010	0.067	0.064	0.100	0.095

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[1]Propane

TABLE B.96

HOUSING DEMAND COEFFICIENTS

Single Family		Multi Family		Mobile Homes	
Variable	Value	Variable	Value	Variable	Value
BA1	-0.303	CA1	0.225	DA1	0.068
BA2	-0.175	CA2	0.086	DA2	0.039
BA4	0.080	CA4	-0.090	DA4	0.014
B2S	0.182	C2S	-0.203	D2S	0.008
B3S	0.317	C3S	-0.280	D3S	-0.020
B4S	0.380	C4S	-3.352	D4S	-0.016

Note: These coefficients were used in the housing demand equations. A detailed explanation of these equations is presented in the RED Documentation Report.

Source: Battelle, 1983, based on Goldsmith and Huskey, 1980b.

TABLE B.97

EXAMPLE OF MARKET SATURATIONS OF APPLIANCES IN SINGLE-FAMILY HOMES FOR ANCHORAGE-COOK INLET AREA

Year	Refrigerators		Freezers		Dishwashers		Clothes Washers	
	Default	Range	Default	Range	Default	Range	Default	Range
1980	99.0	--	88.3	--	78.2	--	91.7	--
1985	99.0	98-100	90.0	85-95	85.0	80-90	92.0	90-94
1990	99.0	98-100	90.0	85-95	90.0	85-95	92.5	90-95
1995	99.0	98-100	90.0	85-95	90.0	85-95	93.7	91-96
2000	99.0	98-100	90.0	85-95	90.0	85-95	95.0	92-98
2005	99.0	98-100	90.0	85-95	90.0	85-95	95.0	92-98
2010	99.0	98-100	90.0	85-95	90.0	85-95	95.0	92-98

Year	Water Heater		Clothes Dryers		Range (cooking)		Saunas Jacuzzis	
	Default	Range	Default	Range	Default	Range	Default	Range
1980	98.6	--	90.2	--	99.9	--	14.1	--
1985	98.8	95-100	91.2	88-94	100.0	99-100	16.3	13-19
1990	99.0	98-100	92.5	89-95	100.0	99-100	18.7	14-22
1995	99.0	98-100	93.7	90-96	100.0	99-100	21.0	16-26
2000	99.0	98-100	95.0	92-98	100.0	99-100	23.4	18-28
2005	99.0	98-100	95.0	92-98	100.0	99-100	25.7	20-30
2010	99.0	98-100	95.0	92-98	100.0	99-100	28.1	23-33

Note: A complete listing of market saturation data for single-family, multi-family, mobile-homes, and duplexes in Anchorage and Fairbanks is presented in the RED Documentation Report.

Source: Battelle-Northwest End Use Survey, 1981.
1980 Census of Housing
San Diego Gas and Electric Company, 1982. 1981 Residential Energy Survey.
Southern California Edison Company, 1981. 1981 Residential Electrical Appliance Saturation Survey.

TABLE B.98

PARAMETER VALUES IN RED PRICE ADJUSTMENT MECHANISM

Short-Run Elasticities	Residential Sector	Business Sector
Own-Price	-.1552 + .3304/p*	-.2925 + 2.4014/p*
Cross-Price		
Natural Gas	.0225	.0082
Oil	.01	.01
Lagged Adjustment	.8837	.8724

*Electricity prices measured in mills per kWh, 1970 dollars

Source: Battelle 1983, based on Mount, Chapman, Tyrrell (1973) and other literature surveys.

TABLE B.99

PERCENT OF APPLIANCES USING ELECTRICITY AND AVERAGE
ANNUAL ELECTRICITY CONSUMPTION, RAILBELT LOAD CENTERS, 1980

	Anchorage					Fairbanks				
	Percentage Using Electricity				Annual kWh	Perentage Using Electricity				Annual kWh
Appliance	SF	MH	DP	MF	Consumption	SF	MH	DP	MF	Consumption
Space Heat (Existing Stock)										
Single Family	16.0	NA	NA	NA	32,850	9.7	NA	NA	NA	43,380
Mobile Home	NA	0.7	NA	NA	24,570	NA	0.0	NA	NA	33,210
Duplex	NA	NA	22.8	NA	21,780	NA	NA	11.7	NA	28,710
Multi Family	NA	NA	NA	44.4	15,390	NA	NA	NA	14.8	19,080
Space Heat (New Stock										
Single Family	10.9	NA	NA	NA	32,850	9.7	NA	NA	NA	43,380
Mobile Home	NA	0.7	NA	NA	24,570	NA	0.0	NA	NA	33,210
Duplex	NA	NA	15.0	NA	21,780	NA	NA	11.7	NA	28,710
Multi Family	NA	NA	NA	25.0	15,390	NA	NA	NA	14.8	19,080
Water Heaters (Existing)	36.5	50.4	44.0	60.9	3,300	33.1	42.8	43.1	26.2	3,300
Water Heaters (New)	10.0	0.7	15.0	25.0	3,300	33.1	42.8	43.1	26.2	3.300
Clothes Dryers	84.3	88.1	81.3	86.6	1,032	96.2	94.6	94.4	100.0	1,032
Cooking Ranges	75.8	23.2	85.2	88.2	850	79.0	48.2	95.0	97.1	850
Sauna-Jacuzzis	93.5	100.0	93.7	81.8	2,000	61.8	100.0	60.8	100.0	2,000
Refrigerators	100.0	100.0	100.0	100.0	1,800	100.0	100.0	100.0	100.0	1,800
Freezers	100.0	100.0	100.0	100.0	1,342	100.0	100.0	100.0	100.0	1,342
Dishwashers	100.0	100.0	100.0	100.0	250	100.0	100.0	100.0	100.0	250
Additional										
Water Heating (Existing)	36.5	50.4	44.0	60.9	799	33.1	42.8	43.1	26.2	799
Water Heating (New)	10.0	0.7	15.0	25.0	799	33.1	42.8	43.1	26.2	799
Clothese Washers	100.0	100.0	100.0	100.0	90	100.0	100.0	100.0	100.0	90
Additional										
Water Heating (Existing)	36.5	50.4	44.0	60.9	1,202	33.1	42.8	43.1	26.2	1,202
Water Heating (New)	10.0	0.7	15.0	25.0	1,202	33.1	42.8	43.1	26.2	1,202
Miscellaneous	100.0	100.0	100.0	100.0	2,110	100.0	100.0	100.0	100.0	2,466

Source: Battelle Northwest End Use Survey, 1981
King, et al. 1982
M[illegible]ion, [illegible]83

TABLE B.100

GROWTH RATES IN ELECTRIC APPLIANCE CAPACITY AND INITIAL ANNUAL AVERAGE CONSUMPTION FOR NEW APPLIANCES

Appliance	Average Annual kWh Consumption for New Appliances (1985) Anchorage	Fairbanks	Growth Rate in Electric Capacity Post 1985 (annual)
Space Heat			
Single Family	40,000	53,000	0.005
Mobile Home	30,000	40,600	0.005
Duplex	26,600	35,100	0.005
Multi Family	18,800	23,300	0.005
Water Heaters	3,475	3,475	0.005
Clothes Dryers	1,032	1,032	0.0
Cooking Ranges	1,250	1,250	0.0
Sauna-Jacuzzis	1,750	1,750	0.0
Refrigerators	1,560	1,560	0.00
Freezers	1,550	1,550	0.00
Dishwashers	230	230	--
Additional Water Heating	740	740	0.005
Clothese Washers	70	70	0.0
Additional Water Heating	1,050	1,050	0.005
Miscellaneous Appliances	2,160	2,536	(a)

(a) Incremental growth of 50 kWh per customer in Anchorage 5-year period; 70 kWh in Fairbanks.

Source: King et al., 1982
McMahon, 1983.

TABLE B.101

PERCENT OF APPLIANCES REMAINING IN SERVICE YEARS AFTER PURCHASE

	Years					
	5	10	15	20	25	30
a. Old Appliances						
Space Heat (All)	0.90	0.80	0.6	0.3	0.1	0.0
Water Heaters	0.6	0.3	0.1	0.0	0.0	0.0
Clothes Dryers	0.8	0.6	0.3	0.1	0.0	0.0
Ranges-Cooking	0.6	0.3	0.1	0.0	0.0	0.0
Saunas-Jacuzzis	0.5	0.3	0.1	0.0	0.0	0.0
Refrigerators	0.8	0.6	0.3	0.1	0.0	0.0
Freezers	0.9	0.8	0.6	0.3	0.1	0.0
Dishwashers	0.6	0.3	0.1	0.0	0.0	0.0
Clothes Washers	0.6	0.3	0.1	0.0	0.0	0.0
b. New Appliances						
Space Heat (All)	0.89	0.73	0.56	0.42	0.3	0.1
Water Heaters	0.75	0.35	0.1	0.0	0.0	0.0
Clothes Dryers	1.00	0.75	0.35	0.1	0.0	0.0
Ranges-Cooking	0.75	0.35	0.1	0.0	0.0	0.0
Saunas-Jacuzzis	1.00	0.75	0.35	0.1	0.0	0.0
Refrigerators	1.00	0.75	0.35	0.1	0.0	0.0
Freezers	1.00	1.00	0.75	0.35	0.1	0.0
Dishwashing	0.75	0.35	0.1	0.0	0.0	0.0
Clothes Washers	0.75	0.35	0.1	0.0	0.0	0.0

Source: Battelle, 1983 based on ISER, Goldsmith and Huskey 1980b

TABLE B.102

VARIABLES AND ASSUMPTIONS OTHER THAN OIL PRICES
OGP MODEL

Name	Year	Reference Value Case	Reference
Fuel Costs - Nenana Coal	1983	1.72 $/MMBtu	Appendix D-1
- Beluga Coal	1983	1.86 $/MMBtu	Appendix D-1
- Natural Gas	1983	2.47 $/MMBtu	Appendix D-1
Fuel Escalation Rates - Nenana Coal	1984-2051	2.3 %/yr.1/	Appendix D-1
- Beluga Coal	1984-2051	1.6 %/yr.1/	Appendix D-1
- Natural Gas			
	1984-1988	Variable	Appendix D-1
	1989-2010	3.0 %/yr.	Appendix D-1
	2011-2020	2.5 %/yr.	Appendix D-1
	2021-2030	1.5 %/yr.	Appendix D-1
	2031-2051	1.0 %/yr.	Appendix D-1
Thermal Construction Cost			
Coal Steam - Nenana	1982	2107 $/kW	Exhibit D
Coal Steam - Beluga	1982	2061 $/kW	Exhibit D
Combustion Turbine	1982	627 $/kW	Exhibit D
Combined Cycle	1982	1075 $/kW	Exhibit D
Hydro Construction Cost - Watana	1982	596 x10^6$	Exhibit D
- Devil Canyon	1982	1554 x10^6$	Exhibit D
Discount Rate	1982	3.0%	Alaska Power Authority

1/ Coal price escalation assumed only to initial operating date of a over the coal-fired unit at which time there would be no real price escalation Beluga life of the unit. Average real escalation of coal prices (Nenana and combined) for period 1993-2051 is about 1%/yr.

TABLE B.103

REFERENCE CASE FORECAST

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	26.30	27.90	32.34	37.50	43.47	50.39
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	6.45	6.84	7.93	9.19	10.65	12.35
Natural Gas - Anchorage ($/MMBtu)	1.73	1.95	2.88	4.05	4.29	4.96	5.38
State Petroleum Revenues[1]/(Nom. $\$x10^6$)							
Production Taxes	1,474	1,561	2,032	1,868	1,910	2,150	2,421
Royalty Fees	1,457	1,555	2,480	2,651	3,078	3,799	4,689
State Gen. Fund Expenditures (Nom. $\$x10^6$)	3,288	3,700	5,577	7,729	9,714	13,035	17,975
State Population	457,836	490,146	554,634	608,810	644,111	686,663	744,418
State Employment	243,067	258,396	293,689	313,954	325,186	345,701	376,169
Railbelt Population	319,767	341,613	389,026	423,460	451,561	486,851	533,218
Railbelt Employment	159,147	169,197	190,883	204,668	214,542	231,584	255,974
Railbelt Total Number of Households	111,549	120,140	138,640	152,463	163,913	177,849	195,652
Railbelt Electricity Consumption (GWh)							
Anchorage	2,322	2,561	3,045	3,371	3,662	4,107	4,735
Fairbanks	481	535	691	800	880	986	1,123
Total	2,803	3,096	3,737	4,171	4,542	5,093	5,858
Railbelt Peak Demand (MW)	579	639	777	868	945	1,059	1,217

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.104

REFERENCE CASE

STATE PETROLEUM REVENUES
(MILLION $)

Year	Royalties	Severance Taxes	Corporate Income Taxes	Property Taxes	Total Including Bonuses and Federal Shared Royalties	Total to General Fund (Net of Permanent Fund Contri-bution)
1982	1530.000	1590.000	668.899	142.700	3960.199	3570.549
1983	1456.661	1473.507	233.969	148.600	3361.836	2985.396
1984	1450.305	1474.080	328.647	153.200	3441.298	3069.956
1985	1555.117	1560.529	365.362	158.000	3668.700	3272.498
1986	1724.811	1705.298	398.724	163.456	4020.278	3582.078
1987	1896.215	1857.760	438.776	169.101	4389.691	3908.677
1988	1997.731	1647.607	396.949	174.940	4245.582	3739.060
1989	2251.456	1855.795	520.004	180.981	4837.387	4267.234
1990	2480.380	2031.695	591.983	187.231	5321.348	4693.734
1991	2352.500	1857.126	668.435	193.697	5102.781	4506.898
1992	2530.291	1929.692	794.871	200.385	5487.250	4846.672
1993	2657.006	1986.190	906.959	207.305	5790.461	5117.957
1994	2742.898	2006.949	998.581	214.464	5996.891	5302.664
1995	2651.116	1868.193	1084.124	221.870	5860.301	5188.770
1996	2599.817	1737.659	1185.670	229.532	5788.676	5129.719
1997	2755.836	1856.672	1326.406	237.458	6213.367	5515.156
1998	2865.556	1887.844	1474.798	245.658	6511.852	5785.961
1999	2950.992	1865.044	1649.613	254.141	6758.785	6011.285
2000	3077.885	1909.805	1841.891	262.917	7132.496	6353.023
2001	3210.235	1955.641	2056.580	271.996	7535.449	6722.641
2002	3348.276	2002.576	2296.294	281.389	7970.531	7122.961
2003	3492.252	2050.638	2563.949	291.106	8440.941	7557.125
2004	3642.420	2099.854	2862.802	301.158	8950.230	8028.625
2005	3799.044	2150.251	3196.489	311.558	9502.340	8541.328
2006	3962.404	2201.857	3569.072	322.317	10101.640	9099.540
2007	4132.781	2254.702	3985.082	333.447	10753.010	9708.060
2008	4310.492	2308.815	4449.578	344.962	11461.840	10372.220
2009	4495.844	2364.227	4968.219	356.874	12234.160	11097.950
2010	4689.164	2420.969	5547.316	369.198	13076.640	11891.850

SOURCE: MAP MODEL OUTPUT

TABLE B.105

REFERENCE CASE

STATE GOVERNMENT FISCAL CONDITIONS
(MILLION $)

Year	Unrestricted General Fund Expenditures	General Fund Balance	Permanent Fund Dividends	State Personal Income Tax	State Subsidy Programs	Percent of Permanent Fund Earnings Reinvested
1982	4601.891	399.200	425.000	0.000	634.000	0.000
1983	3287.977	478.004	152.608	0.000	500.000	0.500
1984	3389.729	616.992	196.738	0.000	350.000	0.500
1985	3699.507	700.539	223.721	0.000	350.000	0.500
1986	4031.094	821.113	253.168	0.000	350.000	0.500
1987	4375.941	987.922	286.008	0.000	350.000	0.500
1988	4731.574	699.973	322.441	0.000	695.501	0.500
1989	5118.008	588.465	361.817	0.000	0.000	0.500
1990	5576.836	506.125	406.085	0.000	0.000	0.500
1991	5386.480	506.141	455.185	0.000	0.000	0.500
1992	5786.504	506.152	505.111	0.000	0.000	0.500
1993	6528.020	139.531	0.000	0.000	0.000	0.500
1994	6729.594	139.543	0.000	338.049	0.000	0.500
1995	7729.250	139.563	0.000	680.847	0.000	0.000
1996	7822.879	139.586	0.000	748.723	0.000	0.000
1997	8361.188	139.609	0.000	809.145	0.000	0.000
1998	8794.711	139.633	0.000	873.359	0.000	0.000
1999	9190.000	139.652	0.000	941.928	0.000	0.000
2000	9713.740	139.668	0.000	1017.188	0.000	0.000
2001	10278.270	139.691	0.000	1098.944	0.000	0.000
2002	10886.180	139.711	0.000	1188.241	0.000	0.000
2003	11545.180	139.734	0.000	1287.516	0.000	0.000
2004	12261.640	139.766	0.000	1396.169	0.000	0.000
2005	13034.660	139.789	0.000	1513.479	0.000	0.000
2006	13871.350	139.820	0.000	1640.603	0.000	0.000
2007	14777.160	139.852	0.000	1778.121	0.000	0.000
2008	15758.890	139.891	0.000	1926.802	0.000	0.000
2009	16822.770	139.934	0.000	2085.652	0.000	0.000
2010	17975.270	139.980	0.000	2257.400	0.000	0.000

SOURCE: MAP MODEL OUTPUT

TABLE B.106

REFERENCE CASE

POPULATION
(THOUSANDS)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1982	437.175	307.105	239.830	67.277
1983	457.836	319.767	251.057	68.711
1984	473.752	330.202	259.679	70.523
1985	490.146	341.613	269.300	72.313
1986	505.884	352.187	278.082	74.105
1987	517.431	359.054	283.333	75.723
1988	526.823	364.583	287.969	76.615
1989	538.532	375.007	296.794	78.213
1990	554.634	389.026	308.196	80.831
1991	560.786	393.296	311.585	81.712
1992	581.846	405.991	322.865	83.127
1993	594.848	413.788	328.521	85.268
1994	602.027	420.130	332.694	87.436
1995	608.810	423.460	335.464	87.997
1996	616.422	428.574	339.629	88.945
1997	623.782	434.617	344.561	90.057
1998	630.352	440.001	348.981	91.021
1999	636.928	445.519	353.531	91.988
2000	644.111	451.561	358.441	93.120
2001	651.362	457.835	363.501	94.335
2002	658.994	464.362	368.801	95.561
2003	667.660	471.437	374.626	96.811
2004	676.878	478.925	380.769	98.156
2005	686.663	486.851	387.267	99.584
2006	697.022	495.287	394.168	101.119
2007	707.990	504.091	401.364	102.727
2008	719.644	513.431	408.995	104.436
2009	731.592	522.970	416.755	106.216
2010	744.418	533.218	425.115	108.104

SOURCE: MAP MODEL OUTPUT

TABLE B.107

REFERENCE CASE

EMPLOYMENT
(THOUSANDS)

Year	State Non-Ag Wage and Salary	State Total	Railbelt Total	Greater Anchorage Total	Greater Fairbanks Total
1982	192.903	231.984	154.033	120.533	33.500
1983	202.237	243.067	159.147	125.221	33.927
1984	205.903	246.984	162.259	127.853	34.406
1985	216.612	258.396	169.197	133.668	35.528
1986	225.515	267.895	174.818	138.324	36.494
1987	230.833	273.581	177.412	140.345	37.067
1988	234.657	277.669	179.422	142.065	37.357
1989	240.213	283.619	184.211	146.124	38.088
1990	249.654	293.689	190.883	151.685	39.198
1991	247.908	291.844	191.360	151.958	39.402
1992	264.012	309.031	199.404	158.995	40.409
1993	266.941	312.180	202.842	161.351	41.492
1994	267.220	312.511	203.630	161.669	41.961
1995	268.534	313.954	204.668	162.466	42.202
1996	270.783	316.404	206.258	163.772	42.486
1997	272.935	318.765	208.212	165.401	42.811
1998	274.346	320.353	210.041	166.916	43.125
1999	276.144	322.374	212.025	168.580	43.445
2000	278.729	325.186	214.541	170.645	43.897
2001	281.498	328.141	217.283	172.875	44.408
2002	284.643	331.499	220.293	175.333	44.960
2003	288.727	335.859	223.703	178.156	45.546
2004	293.137	340.569	227.487	181.265	46.222
2005	297.941	345.701	231.584	184.625	46.959
2006	303.062	351.172	235.985	188.226	47.759
2007	308.504	356.989	240.639	192.025	48.614
2008	314.317	363.203	245.561	196.044	49.517
2009	320.082	369.368	250.621	200.146	50.475
2010	326.440	376.169	255.974	204.512	51.462

SOURCE: MAP MODEL OUTPUT

TABLE B.108

REFERENCE CASE

HOUSEHOLDS
(THOUSANDS)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1982	145.453	106.572	83.678	22.894
1983	153.141	111.549	88.038	23.511
1984	159.154	115.671	91.425	24.246
1985	165.299	120.140	95.165	24.974
1986	171.192	124.275	98.580	25.695
1987	175.620	127.053	100.709	26.344
1988	179.287	129.415	102.669	26.746
1989	183.738	133.365	105.994	27.371
1990	189.696	138.640	110.267	28.373
1991	192.234	140.401	111.662	28.739
1992	199.886	145.348	116.024	29.324
1993	204.788	148.405	118.253	30.152
1994	207.695	150.964	119.963	31.002
1995	210.461	152.463	121.197	31.267
1996	213.508	154.590	122.921	31.669
1997	216.470	157.052	124.921	32.131
1998	219.161	159.242	126.710	32.532
1999	221.854	161.483	128.549	32.934
2000	224.751	163.913	130.515	33.398
2001	227.670	166.423	132.532	33.891
2002	230.716	169.023	134.636	34.388
2003	234.112	171.820	136.928	34.892
2004	237.695	174.758	139.329	35.429
2005	241.468	177.849	141.853	35.996
2006	245.436	181.121	144.520	36.601
2007	249.609	184.516	147.285	37.231
2008	254.014	188.100	150.203	37.896
2009	258.519	191.748	153.162	38.586
2010	263.323	195.652	156.336	39.316

SOURCE: MAP MODEL OUTPUT

TABLE B.108 (CONTINUED)

REFERENCE CASE

STATE HOUSEHOLDS BY AGE OF HEAD
(THOUSANDS)

Year	Total	Head Younger Than 25	Head 25-29	Head 30-54	Head Older Than 54
1982	145.453	17.141	23.938	81.706	22.667
1983	153.141	18.110	25.128	86.087	23.816
1984	159.154	18.624	25.919	89.726	24.884
1985	165.299	19.085	26.763	93.487	25.964
1986	171.192	19.447	27.532	97.157	27.056
1987	175.620	19.526	27.905	100.067	28.123
1988	179.287	19.488	28.085	102.516	29.199
1989	183.738	19.617	28.486	105.290	30.345
1990	189.696	20.014	29.285	108.807	31.591
1991	192.234	19.816	29.171	110.503	32.744
1992	199.886	20.529	30.434	114.787	34.137
1993	204.788	20.725	30.930	117.672	35.462
1994	207.695	20.603	30.909	119.437	36.746
1995	210.461	20.508	30.893	121.002	38.058
1996	213.508	20.500	30.996	122.606	39.407
1997	216.470	20.504	31.114	124.079	40.772
1998	219.161	20.485	31.199	125.334	42.143
1999	221.854	20.485	31.321	126.523	43.523
2000	224.751	20.530	31.532	127.771	44.917
2001	227.670	20.583	31.773	129.000	46.313
2002	230.716	20.656	32.069	130.279	47.712
2003	234.112	20.780	32.472	131.742	49.119
2004	237.695	20.920	32.929	133.319	50.526
2005	241.468	21.077	33.435	135.024	51.932
2006	245.436	21.247	33.987	136.866	53.336
2007	249.609	21.432	34.583	138.856	54.738
2008	254.014	21.634	35.226	141.014	56.139
2009	258.519	21.833	35.878	143.272	57.536
2010	263.323	22.058	36.592	145.736	58.937

SOURCE: MAP MODEL OUTPUT

TABLE B.109

REFERENCE CASE FORECAST
NUMBER OF HOUSEHOLDS SERVED

Year	Single Family	Multifamily	Mobile Homes	Duplexes	Total
		Anchorage-Cook Inlet Area			
1980	35473	20314	8230	7486	71503
1985	46224	26204	10958	8567	91953
1990	58740	26349	13505	8460	107054
1995	64779	29931	14941	8333	117984
2000	69822	33259	16200	8022	127302
2005	75777	36378	17749	8738	138641
2010	83343	40411	19721	9649	153124
		Fairbanks-Tanana Valley Area			
1980	7220	5287	1189	1617	15313
1985	10646	5867	2130	1765	20407
1990	11728	7960	2270	2375	24332
1995	14735	7841	3330	2339	28244
2000	16528	7703	3845	2298	30374
2005	17951	8681	4220	2121	32973
2010	19675	9612	4673	2334	36284

TABLE B.110

REFERENCE CASE FORECAST
NUMBER OF VACANT HOUSEHOLDS

Year	Single Family	Multifamily	Mobile Homes	Duplexes	Total
		Anchorage-Cook Inlet Area			
1980	5089	7666	1991	1463	16209
1985	509	1496	121	292	2417
1990	646	1005	149	289	2089
1995	713	1616	164	284	2777
2000	768	1796	178	445	3187
2005	834	1964	195	288	3281
2010	917	2182	217	319	3634
		Fairbanks-Tanana Valley Area			
1980	3653	3320	986	895	8854
1985	118	2654	24	722	3518
1990	129	454	25	81	689
1995	162	448	37	80	726
2000	182	440	42	78	742
2005	197	469	46	209	921
2010	216	519	51	77	864

TABLE B.111

REFERENCE CASE FORECAST
RESIDENTIAL USE PER HOUSEHOLD

Year	Before Conservation Adjustment and Fuel Substitution: Small Appliances (kWh)	Large Appliances (kWh)	Space Heat (kWh)	Total (kWh)	After Adjustment Total (kWh)
1980	2110	6500	5089	13699	13699
1985	2160	6151	4812	13133	12829
1990	2210	6020	4584	12814	12561
1995	2260	5959	4516	12735	12644
2000	2310	5989	4454	12753	12736
2005	2360	6059	4420	12839	12938
2010	2410	6124	4444	12977	13198
		Fairbanks-Tanana Valley Area			
1980	2466	5740	3314	11519	11519
1985	2536	6179	3606	12321	12136
1990	2606	6453	3873	12932	12736
1995	2676	6667	4050	13393	13329
2000	2746	6795	4310	13852	14009
2005	2816	6839	4536	14191	14626
2010	2886	6888	4656	14430	15180

TABLE B.112

REFERENCE CASE FORECAST

BUSINESS USE PER EMPLOYEE

Year	Before Conservation Adjustment and Fuel Substitution		After Adjustments	
	Anchorage-Cook Inlet Area (kWh)	Fairbanks-Tanana Valley Area (kWh)	Anchorage-Cook Inlet Area (kWh)	Fairbanks-Tanana Valley Area (kWh)
1980	8,407	7,496	8,407	7,496
1985	9,580	7,972	9,212	7,900
1990	10,355	8,327	9,749	8,281
1995	10,918	8,662	10,078	8,665
2000	11,416	8,958	10,349	9,024
2005	12,090	9,308	10,828	9,446
2010	12,933	9,711	11,502	9,929

TABLE B.113

REFERENCE CASE FORECAST
SUMMARY OF PRICE EFFECTS
ANCHORAGE-COOK INLET AREA

	Residential Sector		Business Sector	
Year	Own-Price Reduction (GWh)	Cross-Price Reduction (GWh)	Own-Price Reduction (GWh)	Cross-Price Reduction (GWh)
1983	18.5	-1.7	28.0	1.6
1984	24.7	-2.3	37.3	2.1
1985	30.8	-2.8	46.6	2.7
1986	38.5	-10.6	58.2	-0.4
1987	46.1	-18.5	69.7	-3.4
1988	53.7	-26.3	89.3	-6.4
1989	61.4	-34.1	92.8	-9.4
1990	69.0	-41.9	104.4	-12.4
1991	115.0	-91.2	119.9	-19.1
1992	161.1	-140.5	135.5	-25.7
1993	207.1	-189.8	151.1	-32.4
1994	253.2	-239.2	166.7	-39.0
1995	299.2	-288.5	182.2	-45.7
1996	234.0	-225.0	198.3	-52.6
1997	168.8	-161.5	214.3	-59.5
1998	103.7	-98.1	230.4	-66.5
1999	38.5	-34.6	246.4	-73.4
2000	-26.7	28.8	262.4	-80.4
2001	-7.5	6.5	282.5	-90.2
2002	11.7	-15.9	302.5	-100.1
2003	30.9	-38.3	322.6	-110.0
2004	50.1	-60.6	342.6	-119.9
2005	69.2	-83.0	362.7	-129.8
2006	78.2	-95.9	388.1	-143.3
2007	87.1	-108.8	413.6	-156.9
2008	96.0	-121.7	439.1	-170.4
2009	104.9	-134.6	464.5	-183.9
2010	113.8	-147.6	490.0	-197.4

TABLE B.114

REFERENCE CASE FORECAST
BREAKDOWN OF ELECTRICITY REQUIREMENTS

Anchorage-Cook Inlet Area

Year	Residential Requirements (GWh)	Business Requirements (GWh)	Miscellaneous Requirements (GWh)	Indust./Military Requirements (GWh)	Total Requirements (GWh)
1983	1100	1089	25	108	2322
1984	1140	1160	26	116	2442
1985	1180	1231	26	124	2561
1986	1213	1281	27	138	2658
1987	1246	1330	28	151	2755
1988	1279	1380	28	165	2852
1989	1312	1429	29	178	2949
1990	1345	1479	30	192	3045
1991	1374	1510	31	195	3111
1992	1404	1542	31	198	3176
1993	1433	1574	32	202	3241
1994	1462	1606	33	205	3306
1995	1492	1637	34	208	3371
1996	1518	1663	34	214	3429
1997	1544	1689	35	220	3487
1998	1570	1714	35	226	3545
1999	1595	1740	36	232	3604
2000	1621	1766	36	238	3662
2001	1656	1813	37	245	3751
2002	1690	1859	38	252	3840
2003	1725	1906	39	259	3929
2004	1759	1953	40	266	4018
2005	1794	1999	41	273	4107
2006	1839	2070	42	282	4232
2007	1885	2140	43	290	4358
2008	1930	2211	44	298	4484
2009	1976	2281	45	307	4609
2010	2021	2352	47	315	4735

TABLE B.115

REFERENCE CASE FORECAST
SUMMARY OF PRICE EFFECTS
FAIRBANKS-TANANA VALLEY AREA

Year	Residential Sector Own-Price Reduction (GWh)	Residential Sector Cross-Price Reduction (GWh)	Business Sector Own-Price Reduction (GWh)	Business Sector Cross-Price Reduction (GWh)
1983	0.0	2.3	0.0	1.5
1984	0.0	3.0	0.0	2.1
1985	-0.2	3.8	0.0	2.6
1986	-0.4	4.2	-0.3	2.8
1987	-0.6	4.6	-0.7	2.9
1988	-0.8	5.0	-1.0	3.1
1989	-1.0	5.4	-1.4	3.3
1990	-1.0	5.8	-1.7	3.5
1991	-1.0	5.2	-1.7	3.1
1992	-1.0	4.6	-1.6	2.7
1993	-1.0	4.0	-1.6	2.2
1994	-1.0	3.4	-1.6	1.8
1995	-1.0	2.8	-1.5	1.4
1996	-0.9	1.4	-1.2	0.6
1997	-0.7	-0.1	-1.0	-0.3
1998	-0.5	-1.6	-0.7	-1.1
1999	-0.3	-3.1	-0.4	-1.9
2000	-0.2	-4.6	-0.2	-2.7
2001	0.1	-6.8	0.2	-3.9
2002	0.4	-9.0	0.8	-5.1
2003	0.7	-11.3	1.2	-6.3
2004	1.0	-13.5	1.7	-7.5
2005	1.3	-15.7	2.2	-8.6
2006	1.8	-18.7	2.8	-10.2
2007	2.2	-21.6	3.5	-11.8
2008	2.6	-24.6	4.1	-13.4
2009	3.0	-27.6	4.8	-15.0
2010	3.5	-30.5	5.5	-16.6

TABLE B.116

REFERENCE CASE FORECAST
BREAKDOWN OF ELECTRICITY REQUIREMENTS

Fairbanks-Tanana Valley Area

Year	Residential Requirements (GWh)	Business Requirements (GWh)	Miscellaneous Requirements (GWh)	Indust./Military Requirements (GWh)	Total Requirements (GWh)
1983	219	255	7	0	481
1984	233	268	7	0	508
1985	248	281	7	0	535
1986	260	289	7	10	566
1987	273	298	7	20	597
1988	285	307	7	30	629
1989	297	316	7	40	660
1990	310	325	7	50	691
1991	323	333	7	50	713
1992	336	341	7	50	735
1993	350	349	7	50	757
1994	363	357	8	50	778
1995	376	366	8	50	800
1996	386	372	8	50	816
1997	390	378	8	50	832
1998	406	384	8	50	848
1999	416	390	9	50	864
2000	426	396	9	50	880
2001	437	406	9	50	902
2002	448	415	9	50	923
2003	460	425	9	50	944
2004	471	434	10	50	965
2005	482	444	10	50	986
2006	496	457	10	50	1013
2007	510	471	10	50	1041
2008	523	484	11	50	1068
2009	537	497	11	50	1096
2010	551	511	11	50	1123

TABLE B.117

REFERENCE CASE FORECAST
PROJECTED PEAK AND ENERGY DEMAND

Year	Anchorage-Cook Inlet Area		Fairbanks-Tanana Valley Area		Total System Area		
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Load Factor (%)
1983	2322	469	481	110	2803	579	55.3
1984	2442	493	508	116	2950	609	55.3
1985	2561	517	535	122	3096	639	55.3
1986	2658	538	566	129	2334	667	55.2
1987	2755	558	597	136	3352	695	55.0
1988	2852	579	629	144	3481	722	55.0
1989	2949	599	660	151	3609	750	54.9
1990	3045	619	691	158	3737	777	54.9
1991	3111	633	713	163	3824	796	54.8
1992	3176	646	735	168	3911	814	54.8
1993	3240	659	757	173	3997	832	54.8
1994	3306	672	778	178	4084	850	54.8
1995	3371	686	800	183	4171	868	54.8
1996	3429	697	816	186	4245	884	54.8
1997	3487	709	832	190	4319	899	54.8
1998	3545	721	848	194	4394	914	54.8
1999	3604	732	864	197	4468	930	54.8
2000	3662	744	880	201	4542	945	54.8
2001	3751	762	902	206	4652	968	54.8
2002	3840	780	923	211	4762	991	54.8
2003	3929	798	944	215	4872	1013	54.9
2004	4018	816	965	220	4983	1036	54.9
2005	4107	834	986	225	5093	1059	54.9
2006	4232	859	1013	231	5246	1091	54.9
2007	4358	885	1041	238	5399	1122	54.9
2008	4484	910	1068	244	5552	1154	54.9
2009	4609	936	1096	250	5705	1186	54.9
2010	4735	961	1123	256	5858	1217	54.9

TABLE B.118

DOR-MEAN SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	22.67	22.55	23.96	25.93	27.66	29.51
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	5.97	5.94	6.31	6.83	7.29	7.78
Natural Gas - Anchorage ($/MMBtu)	1.73	1.96	2.71	3.25	3.41	3.56	3.71
State Petroleum Revenues[1]/(Nom. $\$x10^6$)							
Production Taxes	1,474	1,241	1,518	1,313	1,283	1,382	1,488
Royalty Fees	1,457	1,233	1,844	1,863	2,079	2,473	2,941
State General Fund Expenditures (Nom. $\$x10^6$)	3,288	3,100	5,080	5,834	7,182	9,424	12,677
State Population	457,836	486,247	535,300	574,869	609,944	652,063	708,243
State Employment	243,067	254,316	279,744	294,410	309,491	330,150	359,155
Railbelt Population	319,767	339,161	372,777	399,548	427,836	462,582	507,558
Railbelt Employment	159,147	166,559	179,872	191,122	203,818	220,840	244,062
Railbelt Total Number of Households	111,549	119,247	132,857	143,731	155,042	168,580	185,697
Railbelt Electricity Consumption (GWh)							
Anchorage	2,299	2,523	2,855	3,112	3,414	3,820	4,377
Fairbanks	476	527	653	737	814	906	1,023
Total	2,776	3,050	3,508	3,849	4,228	4,726	5,399
Railbelt Peak Demand (MW)	573	630	730	801	879	982	1,121

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.119

DOR 50% SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	24.63	21.01	18.77	17.70	16.79	15.93
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	6.49	5.53	4.95	4.66	4.43	4.20
Natural Gas - Anchorage ($/MMBtu)	1.73	2.00	2.63	2.81	2.71	2.63	2.56
State Petroleum Revenues[1]/ (Nom. $$\times10^6$)							
Production Taxes	1,474	1,251	1,385	969	818	744	677
Royalty Fees	1,457	1,231	1,667	1,366	1,328	1,431	1,543
State Gen. Fund Expenditures(Nom. $$\times10^6$)	3,288	3,111	4,770	4,849	5,552	6,783	8,513
State Population	457,836	486,327	533,184	563,529	593,612	631,699	684,180
State Employment	243,067	254,400	277,633	286,643	300,109	319,313	346,691
Railbelt Population	319,767	339,204	371,539	391,838	416,622	448,422	490,620
Railbelt Employment	159,147	166,610	178,556	185,903	197,460	213,403	235,394
Railbelt Total Number of Households	111,549	119,262	132,405	140,932	150,923	163,310	179,313
Railbelt Electricity Consumption (GWh)							
Anchorage	2,304	2,531	2,849	3,029	3,305	3,690	4,218
Fairbanks	476	526	645	704	760	831	925
Total	2,780	3,057	3,494	3,733	4,065	4,521	5,143
Railbelt Peak Demand (MW)	574	631	726	776	844	938	1,066

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.120

DOR 30% SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	21.00	17.93	15.58	14.53	13.46	12.46
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMbtu)	7.75	5.53	4.73	4.11	3.83	3.55	3.28
Natural Gas - Anchorage ($/MMBtu)	1.73	1.93	2.48	2.53	2.45	2.36	2.26
State Petroleum Revenues[1]/(Nom. $x10^6)							
Production Taxes	1,474	1,102	1,034	640	488	457	428
Royalty Fees	1,457	1,092	1,287	950	891	891	891
State General Fund Expenditures (Nom. $10^6)	3,288	2,796	3,961	3,890	4,400	5,426	6,890
State Population	457,836	483,812	522,041	548,379	578,103	617,487	671,471
State Employment	243,067	251,771	269,932	278,384	292,980	313,327	341,269
Railbelt Population	319,767	337,814	364,097	381,365	405,802	438,370	481,497
Railbelt Employment	159,147	165,005	173,452	180,284	192,563	209,228	231,546
Railbelt Total Number of Households	111,549	118,748	129,695	137,079	146,858	159,429	175,691
Railbelt Electricity Consumption (GWh)							
Anchorage	2,284	2,498	2,747	2,893	3,169	3,554	4,071
Fairbanks	469	516	617	667	721	789	879
Total	2,753	3,014	3,364	3,560	3,890	4,343	4,950
Railbelt Peak Demand (MW)	568	622	699	740	808	926	1,026

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.121

DRI SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	27.02	36.99	45.85	53.43	56.54	60.61
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMbtu)	7.75	7.12	9.75	12.08	14.08	14.90	15.97
Natural Gas - Anchorage ($/MMBtu)	1.73	2.03	3.45	5.10	5.75	6.01	6.36
State Petroleum Revenues[1]/(Nom. $\$x10^6$)							
Production Taxes	1,474	1,624	2,903	2,752	2,764	3,067	3,403
Royalty Fees	1,457	1,623	3,568	3,916	4,447	5,384	6,519
State General Fund Expenditures (Nom. $\$10^6$)	3,288	3,697	5,547	8,217	12,061	17,554	26,110
State Population	457,836	490,133	550,045	614,876	680,962	751,282	842,794
State Employment	243,067	258,382	289,578	320,974	352,300	386,560	433,793
Railbelt Population	319,767	341,600	383,595	428,092	478,847	535,855	609,094
Railbelt Employment	159,147	169,186	186,951	209,761	243,133	261,894	299,610
Railbelt Total Number of Households	111,549	120,136	136,764	154,096	173,690	195,554	223,283
Railbelt Electricity Consumption (GWh)							
Anchorage	2,328	2,571	3,020	3,494	4,044	4,699	5,603
Fairbanks	483	538	697	847	997	1,158	1,362
Total	2,811	3,109	3,717	4,341	5,041	5,857	6,965
Railbelt Peak Demand (MW)	580	642	773	904	1,050	1,220	1,450

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.122

+2% SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	30.12	33.25	36.72	40.54	44.76	49.42
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	7.94	8.76	9.68	10.68	11.79	13.02
Natural Gas - Anchorage ($/MMBtu)	1.73	2.03	3.19	4.26	4.59	4.95	5.34
State Petroleum Revenues[1]/ (Nom. $x10^6$)							
Production Taxes	1,474	1,897	2,515	2,120	2,024	2,127	2,236
Royalty Fees	1,457	1,894	3,079	3,008	3,261	3,762	4,340
State General Fund Expenditures (Nom. $x10^6$)	3,288	3,701	5,556	8,184	12,178	14,269	18,384
State Population	457,836	490,157	550,359	614,826	687,750	726,125	769,233
State Employment	243,067	258,407	289,800	320,801	357,377	364,115	381,154
Railbelt Population	319,767	341,622	383,836	428,017	486,242	517,048	551,279
Railbelt Employment	159,147	169,205	187,116	209,620	238,937	245,595	259,656
Railbelt Total Number of Households	111,549	120,143	136,851	154,072	176,267	188,880	202,640
Railbelt Electricity Consumption (GWh)							
Anchorage	2,353	2,613	3,062	3,548	4,203	4,506	4,957
Fairbanks	486	543	696	834	989	1,066	1,167
Total	2,839	3,156	3,758	4,382	5,192	5,573	6,124
Railbelt Peak Demand (MW)	586	652	782	912	1,081	1,159	1,273

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.123

0% SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	28.95	28.95	28.95	28.95	28.95	28.95
Energy Price Used by RED (1908$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	7.63	7.63	7.63	7.63	7.63	7.63
Natural Gas - Anchorage ($/MMBtu)	1.73	2.01	2.96	3.60	3.60	3.60	3.60
State Petroleum Revenues[1]/ (Nom. $x10^6)							
Production Taxes	1,474	1,800	2,130	1,642	1,437	1,387	1,339
Royalty Fees	1,457	1,797	2,602	2,330	2,325	2,474	2,632
State General Fund Expenditures (Nom.$x10^6)	3,288	3,701	5,539	7,542	8,367	10,140	12,632
State Population	457,836	490,154	550,151	617,971	641,432	673,537	721,159
State Employment	243,067	258,404	289,626	322,653	320,751	334,939	360,890
Railbelt Population	319,767	341,619	383,665	432,178	450,069	478,003	517,133
Railbelt Employment	159,147	169,203	186,982	211,840	211,686	224,292	245,456
Railbelt Total Number of Households	111,549	120,142	136,790	155,506	163,382	174,668	189,812
Railbelt Electricity Consumption (GWh)							
Anchorage	2,331	2,575	3,002	3,492	3,613	3,942	4,442
Fairbanks	485	542	691	830	872	946	1,051
Total	2,816	3,118	3,693	4,322	4,485	4,888	5,493
Railbelt Peak Demand (MW)	582	644	768	900	933	1,016	1,141

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.124

-1% SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	28.37	26.98	25.66	24.40	23.21	22.07
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	7.48	7.11	6.76	6.43	6.12	5.82
Natural Gas - Anchorage ($/MMBtu)	1.73	2.00	2.87	3.32	3.06	2.96	2.86
State Petroleum Revenues[1]/ (Nom. $\$x10^6$)							
Production Taxes	1,474	1,753	1,953	1,438	1,202	1,109	1,023
Royalty Fees	1,457	1,749	2,383	2,040	1,951	1,990	2,030
State General Fund Expeditures (Nom. $\$x10^6$)	3,288	3,702	5,559	6,561	7,324	8,732	10,714
State Population	457,836	490,387	551,884	601,879	626,068	658,790	706,745
State Employment	243,067	258,648	290,318	307,313	312,417	328,554	354,812
Railbelt Population	319,767	341,852	384,894	419,075	439,370	467,659	506,906
Railbelt Employment	159,147	169,404	187,470	200,363	205,960	219,881	241,205
Railbelt Total Number of Households	111,549	120,223	137,238	150,884	159,490	170,816	185,906
Railbelt Electricity Consumption (GWh)							
Anchorage	2,351	2,610	3,047	3,365	3,567	3,904	4,391
Fairbanks	485	541	689	784	833	903	999
Total	2,836	3,151	3,736	4,149	4,400	4,807	5,390
Railbelt Peak Demand (MW)	586	651	777	864	915	998	1,119

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.125

-2% SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	27.80	25.13	22.72	20.54	18.56	16.78
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	7.32	6.62	5.99	5.41	4.89	4.42
Natural Gas - Anchorage ($/MMBtu)	1.73	1.98	2.77	3.07	2.88	2.72	2.56
State Petroleum Revenues[1]/ (Nom. $\$x10^6$)							
Production Taxes	1,474	1,705	1,786	1,253	1,001	882	477
Royalty Fees	1,457	1,701	2,176	1,778	1,630	1,598	1,566
State General Fund Expenditures (Nom. $\$x10^6$)	3,288	3,700	5,536	5,953	6,521	7,660	9,285
State Population	457,836	490,151	551,818	589,214	613,390	646,708	695,204
State Employment	243,067	258,401	291,431	299,458	306,835	323,689	350,023
Railbelt Population	319,767	341,616	385,935	409,758	430,535	459,156	498,676
Railbelt Employment	159,147	169,200	188,768	194,711	202,130	216,510	237,835
Railbelt Total Number of Households	111,549	120,141	137,567	147,521	156,215	167,584	182,700
Railbelt Electricity Consumption (GWh)							
Anchorage	2,348	2,605	3,063	3,252	3,460	3,792	4,270
Fairbanks	484	540	689	756	802	866	954
Total	2,832	3,145	3,752	4,008	4,262	4,658	5,224
Railbelt Peak Demand (MW)	585	650	780	834	886	967	1,084

[1]Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

TABLE B.126

RESULTS OF MAP MODEL SENSITIVITY TESTS

Factor	Value in Year 2000		Projected Statewide Households in Year 2000		
	Low	High	Low	High	% Difference
State Agricult. Employment	160	2,000	215,436	217,352	.9
State Mining Emp.[1]	3,990	19,107	200,458	229,782	14.6
State High Wage Exog. Constr. Emp.	0	2,000	212,523	217,971	2.6
State Low Wage Exog. Constr. Emp.	0	1,000	215,119	217,579	1.1
State Exog. Trans. Emp.	1,100	2,968	214,306	217,223	1.4
State High Wage Manu. Emp.	0	486	215,824	216,610	.4
State Low Wage Manu. Emp.	8,205	16,000	210,106	220,833	5.1
State Fish Harvesting Emp.	4,536	9,192	213,557	217,744	2.0
State Active Duty Military Emp.[1]	16,892	33,000	209,936	224,575	7.0
State Civil Fed. Emp.[1]	17,800	21,719	212,372	217,962	2.6
Tourists Visiting Alaska	1,066,000	2,566,000	209,936	224,575	7.0
U.S. Real Wage Growth/Year[1]	.005	.015	211,335	223,723	5.9
U.S. Unemp. Rate	.05	.075	211,161	222,178	5.2
U.S. Real Income Growth/Year	.005	.025	215,493	216,272	.4
U.S. Price Level Growth/Year[1]	.09	.05	205,924	222,305	8.7

[1]Key Variable.

TABLE B.127

RESULTS OF RED MODEL SENSITIVITY TESTS
ON RESIDENTIAL SECTOR

TOTAL ELECTRICITY REQUIREMENTS WITHOUT LARGE INDUSTRIAL

	1990 (GWh)	2000 (GWh)	2010 (GWh)
Anchorage-Cook Inlet Area			
Maximum	2901	3510	4496
25% GE	2872	3446	4461
Mean	2856	3428	4420
50% GE	2855	3427	4421
75% GE	2838	3411	4388
Minimum	2801	3382	4294
Std Dev	23.4	24.3	46.9
Reference Case	2854	3424	4420
Fairbanks-Tanana Valley Area			
Maximum	655	849	1099
25% GE	648	835	1082
Mean	642	829	1074
50% GE	643	830	1073
75% GE	637	823	1068
Minimum	626	812	1052
Std Dev	6.9	8.2	10.3
Reference Case	641	830	1073

TABLE B.128

RESULTS OF RED MODEL SENSITIVITY TESTS
ON BUSINESS SECTOR

TOTAL ELECTRICITY REQUIREMENTS WITHOUT LARGE INDUSTRIAL

Anchorage-Cook Inlet Area	1990 (GWh)	2000 (GWh)	2010 (GWh)
Maximum	2989	3588	4642
25% GE	2920	3504	4528
Mean	2867	3440	4443
50% GE	2862	3434	4434
75% GE	2826	3391	4375
Minimum	2702	3241	4173
Std Dev	65.9	79.5	107.6
Reference Case	2854	3424	4420

Fairbanks-Tanana Valley Area

NOT APPLICABLE

TABLE B.129

RESULTS OF RED MODEL SENSITIVITY TESTS
ON OWN PRICE ELASTICITIES

TOTAL ELECTRICITY REQUIREMENTS WITHOUT LARGE INDUSTRIAL

	1990 (GWh)	2000 (GWh)	2010 (GWh)
Anchorage-Cook Inlet Area			
Maximum	2900	3533	4614
25% GE	2877	3477	4516
Mean	2846	3406	4389
50% GE	2849	3412	4400
75% GE	2817	3337	4262
Minimum	2798	3292	4187
Std Dev	31.8	74.3	130.7
Reference Case	2854	3424	4420
Fairbanks-Tanana Valley Area			
Maximum	642	830	1075
25% GE	642	830	1074
Mean	641	830	1073
50% GE	641	830	1073
75% GE	641	830	1071
Minimum	641	830	1070
Std Dev	0.4	0.150	1.5
Reference Case	641	830	1073

TABLE B.130

RESULTS OF RED MODEL SENSITIVITY TESTS
ON CROSS PRICE ELASTICITIES

TOTAL ELECTRICITY REQUIREMENTS WITHOUT LARGE INDUSTRIAL

	1990 (GWh)	2000 (GWh)	2010 (GWh)
A. Oil Cross-Price Elasticities			
Anchorage-Cook Inlet Area			
Maximum	2870	3435	4498
25% GE	2859	3428	4446
Mean	2854	3423	4417
50% GE	2855	3423	4415
75% GE	2848	3420	4393
Minimum	2837	3412	4342
Std Dev	7.5	5.6	36.1
Reference Case	2854	3424	4420
Fairbanks-Tanana Valley Area			
Maximum	645	833	1092
25% GE	643	831	1079
Mean	642	830	1072
50% GE	642	830	1072
75% GE	640	829	1067
Minimum	639	827	1054
Std Dev	1.7	1.3	8.7
Reference Case	641	830	1073
B. Gas Cross-Price Elasticities			
Anchorage-Cook Inlet Area			
Maximum	2904	3576	4688
25% GE	2872	3479	4521
Mean	2851	3418	4408
50% GE	2850	3414	4401
75% GE	2832	3359	4301
Minimum	2805	3278	4162
Std Dev	24.0	72.2	127.8
Reference Case	2854	3424	4420
Fairbanks-Tanana Valley Area			
Maximum	645	834	1094
25% GE	643	832	1080
Mean	641	830	1072
50% GE	642	830	1072
75% GE	640	829	1064
Minimum	637	827	1053
Std Dev	2.0	1.6	9.9
Reference Case	641	830	1073

TABLE B.131

RESULTS OF RED MODEL SENSITIVITY TESTS
ON ANNUAL LOAD

TOTAL ELECTRICITY REQUIREMENTS WITH LARGE INDUSTRIAL

	1990 (MW)	2000 (MW)	2010 (MW)
Anchorage-Cook Inlet Area			
Maximum	661	793	1020
25% GE	641	749	965
Mean	598	698	903
50% GE	596	702	900
75% GE	566	650	846
Minimum	522	618	800
Std Dev	42.7	52.9	69.8
Reference Case	584	701	905
Fairbanks-Tanana Valley Area			
Maximum	175	227	288
25% GE	164	211	273
Mean	151	194	245
50% GE	152	194	243
75% GE	138	177	223
Minimum	126	162	208
Std Dev	13.7	19.2	26.1
Reference Case	146	190	245

TABLE B.132

LIST OF PREVIOUS

RAILBELT PEAK AND ENERGY DEMAND FORECASTS

(MEDIUM SCENARIO)

YEAR	ISER 1980 Forecast1/ PEAK DEMAND (MW)	ISER 1980 Forecast1/ ENERGY DEMAND (GWh)	Battelle 1981 Forecast2/ PEAK DEMAND (MW)	Battelle 1981 Forecast2/ ENERGY DEMAND (GWh)	Battelle 1982 Forecast Plan 1A (w/o Susitna)3/ PEAK DEMAND (MW)	Battelle 1982 Forecast Plan 1A (w/o Susitna)3/ ENERGY DEMAND (GWh)	Battelle 1982 Forecast Plan 1B (w/ Susitna3/ PEAK DEMAND (MW)	Battelle 1982 Forecast Plan 1B (w/ Susitna3/ ENERGY DEMAND (GWh)	Battelle Revised 1982 Forecast Plan 1A4/ PEAK DEMAND (MW)	Battelle Revised 1982 Forecast Plan 1A4/ ENERGY DEMAND (GWh)	Utility 1982 Forecast5/ PEAK DEMAND (MW)	Utility 1982 Forecast5/ ENERGY DEMAND (GWh)	Utility 1983 Forecast5/ PEAK DEMAND (MW)	Utility 1983 Forecast5/ ENERGY DEMAND (GWh)
1980	510	2790	----	----	521	2551	521	2551	521	2551	----	----	----	----
1981	----	----	574	2893	----	----	----	----	----	----	----	----	----	----
1982	650	3570	687	3431	643	3136	647	3160	615	3000	769	3697	716	3531
1990	735	4030	892	4456	880	4256	924	4482	701	3391	1126	5305	940	4678
1995	934	5170	983	4922	993	4875	996	4894	791	3884	1626	7098	1167	5884
2000	1175	6430	1084	5469	1017	5033	995	4728	810	4010	2375	9067	1420	7335
2005	1380	7530	1270	6428	1092	5421	1073	5327	870	4319	NA	NA	NA	NA
2010	1635	8940	1537	7791	1259	6258	1347	6686	1003	4986	NA	NA	NA	NA

1/Table 5.6 - Acres Feasibility Report - Volume 1. Includes 30% of military loads, and excludes industrial self-supplied electricity.

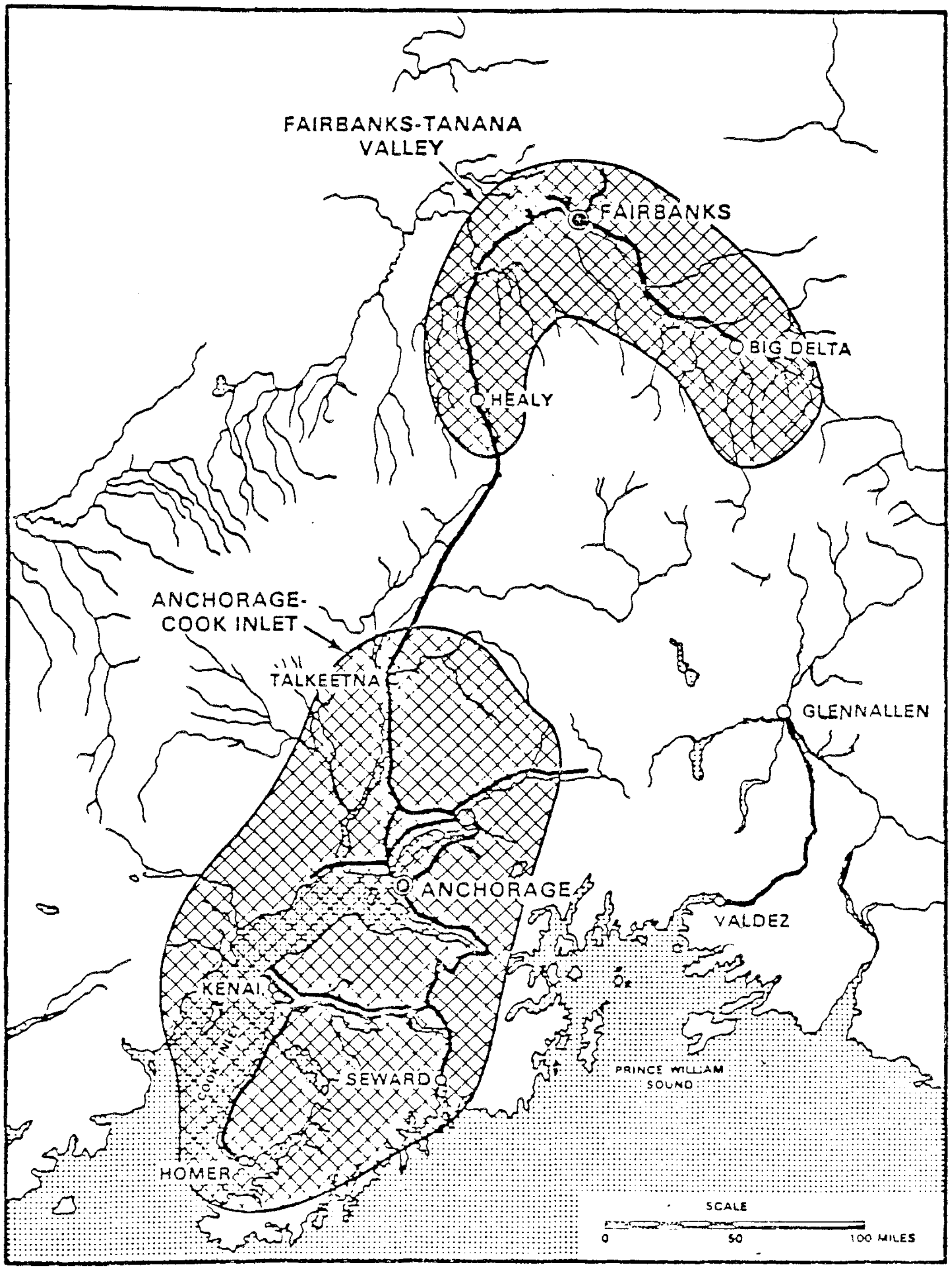
2/Table 5.7 - Acres Feasibility Report - Volume 1. Excludes military and industrial self-supplied electricity.

3/Tables B.12 and B.13 of Battelle Volume 1. Excludes military and industrial self-supplied electricity.

4/Page xv of Battelle Volume 1. Excludes military and industrial self-supplied electricity.

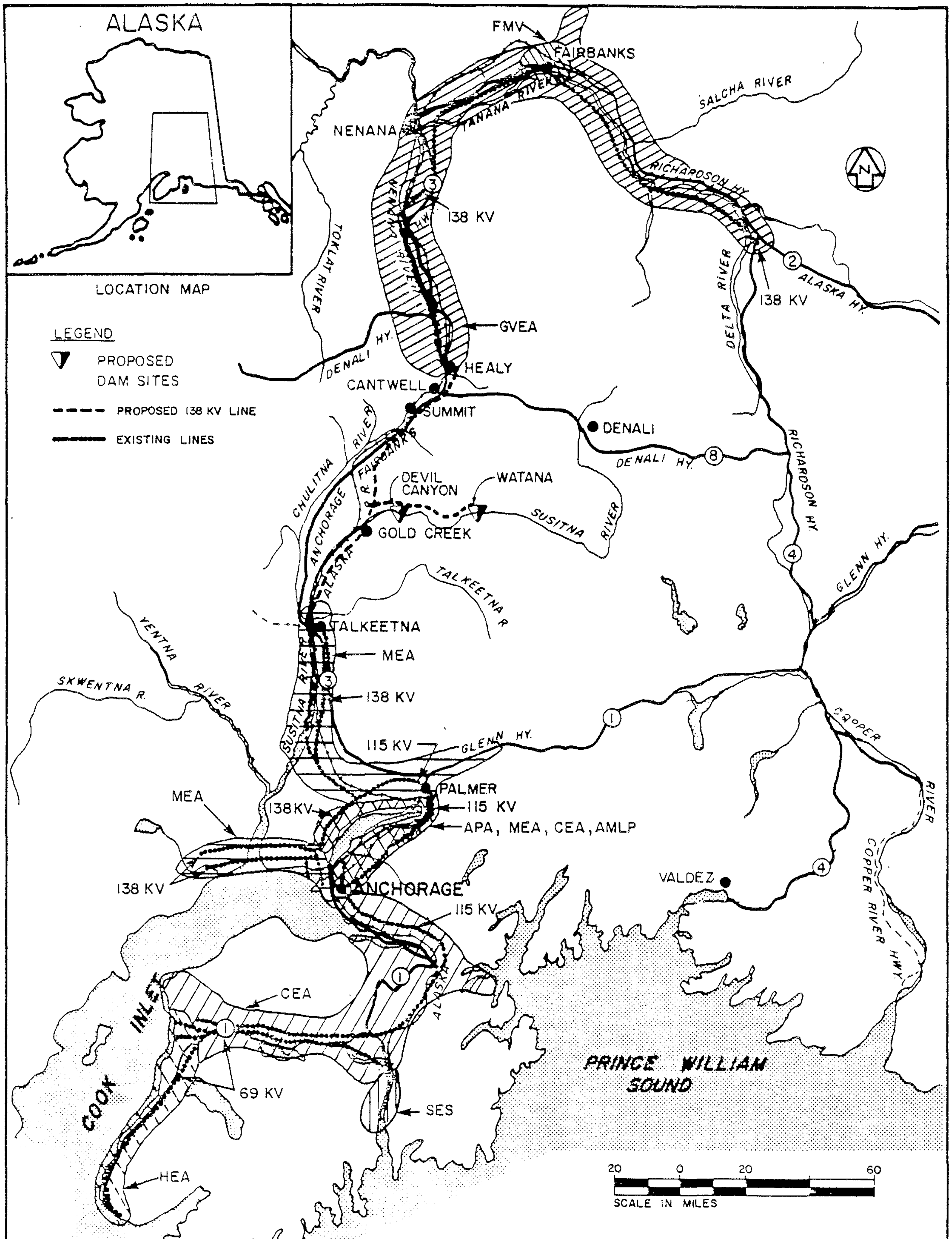
5/At plant net generation.

Note: The ISER and Battelle forecasts are for end-use demand, and should be increased by approximately 8 percent for actual at plant net generation.



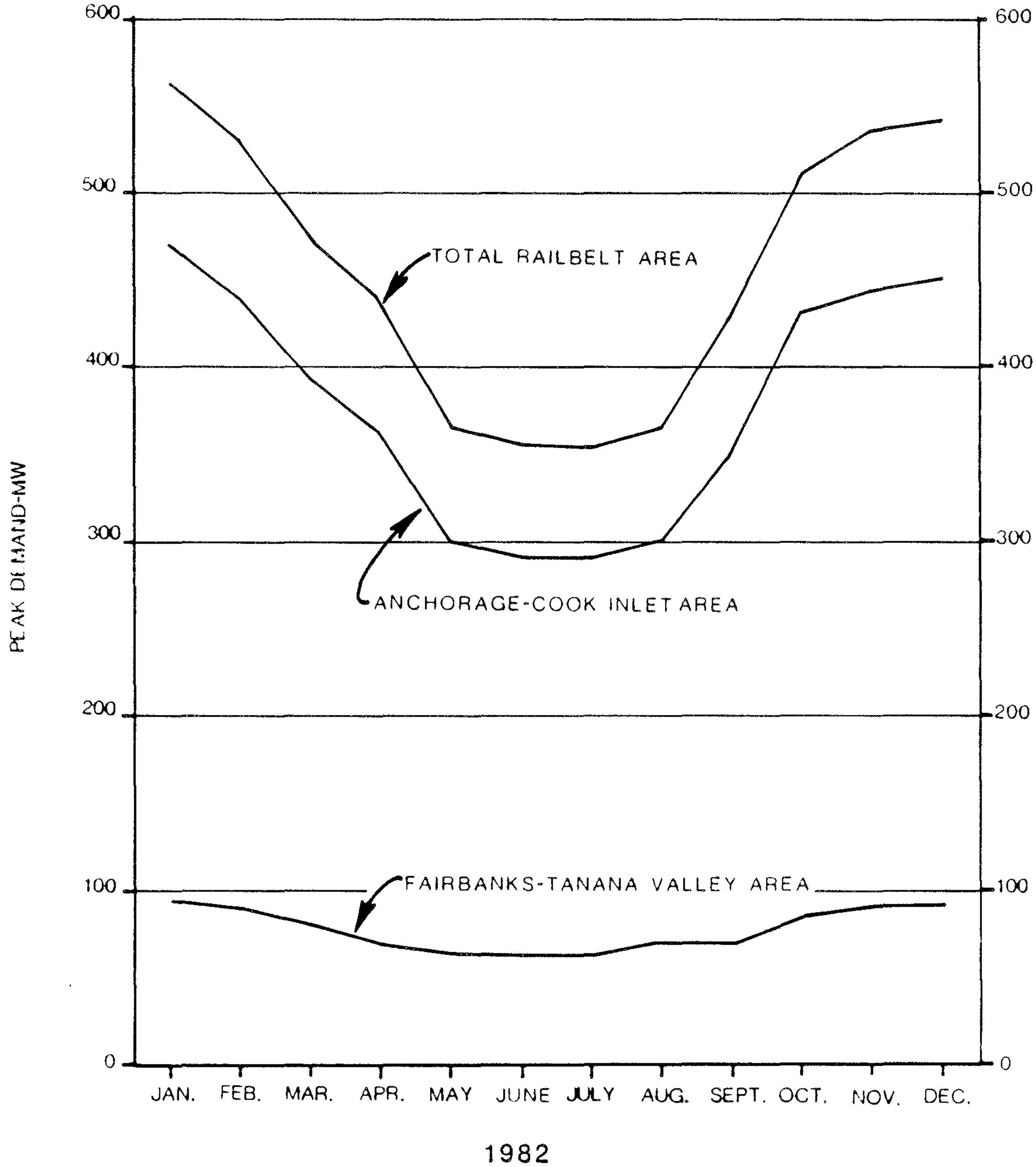
RAILBELT AREA OF ALASKA
SHOWING ELECTRICAL LOAD CENTERS

FIGURE B.77



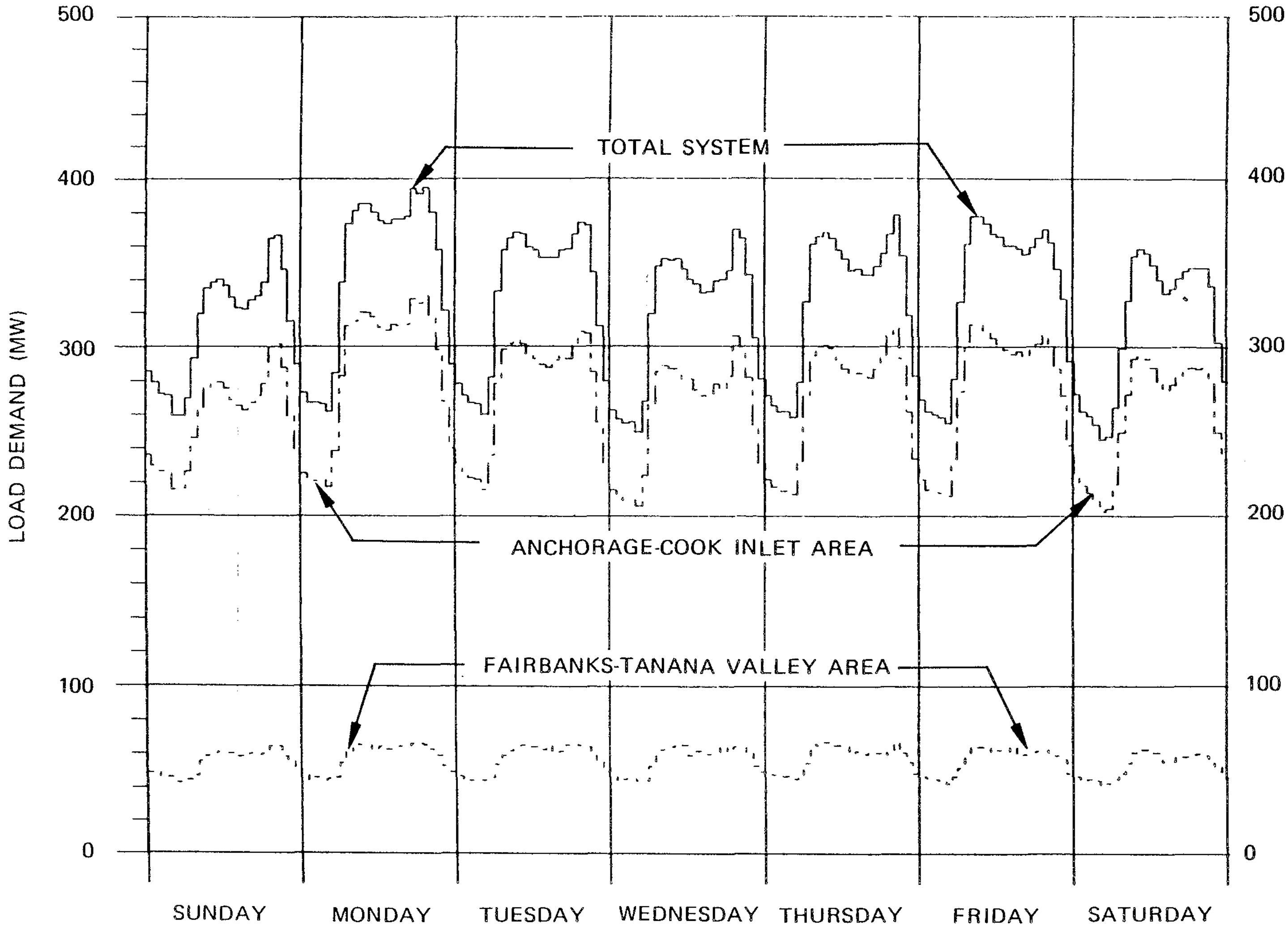
LOCATION MAP SHOWING TRANSMISSION SYSTEMS

FIGURE B.78



MONTHLY LOAD VARIATION FOR RAILBELT AREA

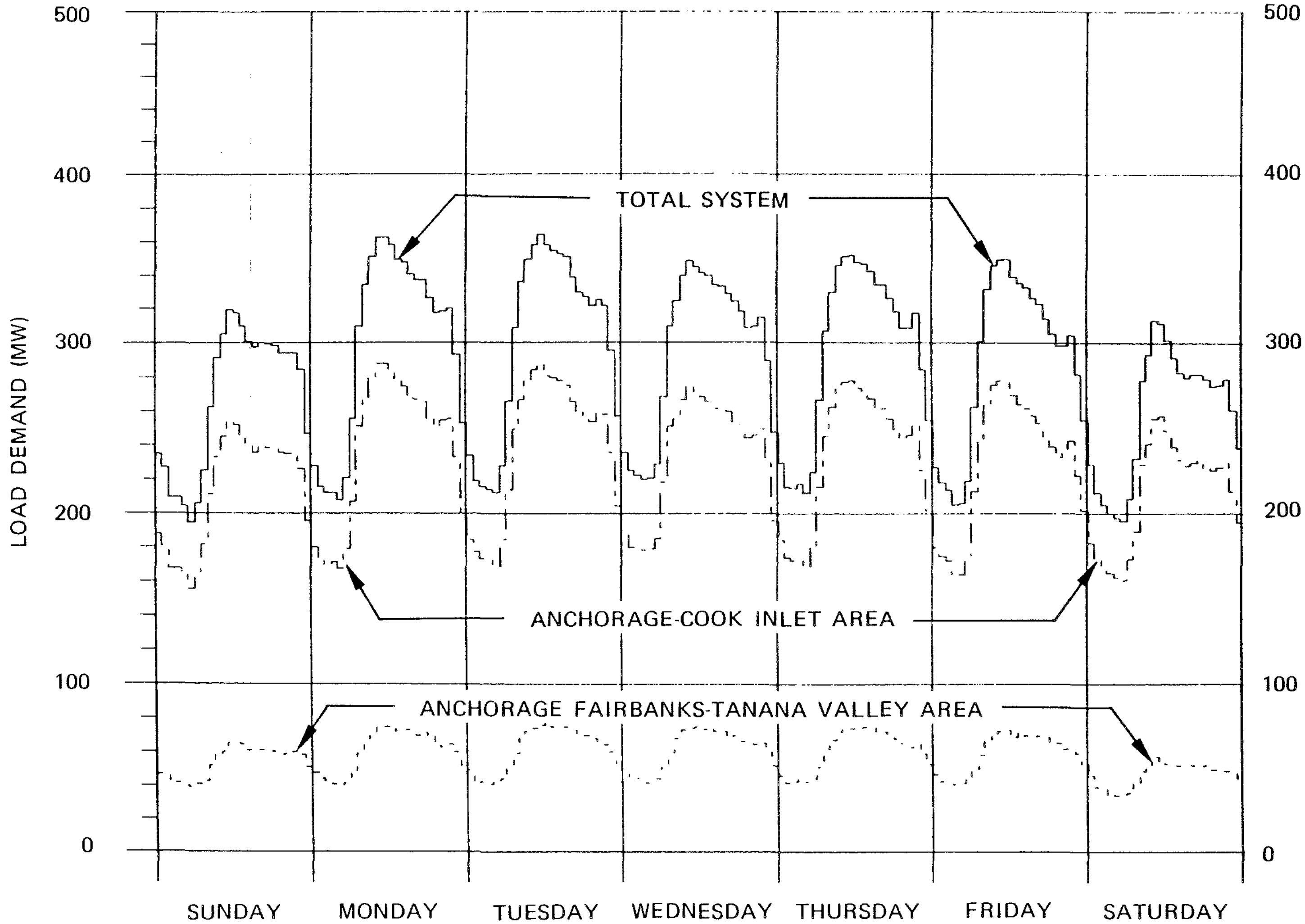
FIGURE B.79



DAILY LOAD CURVES-APRIL 1982

SHEET 1

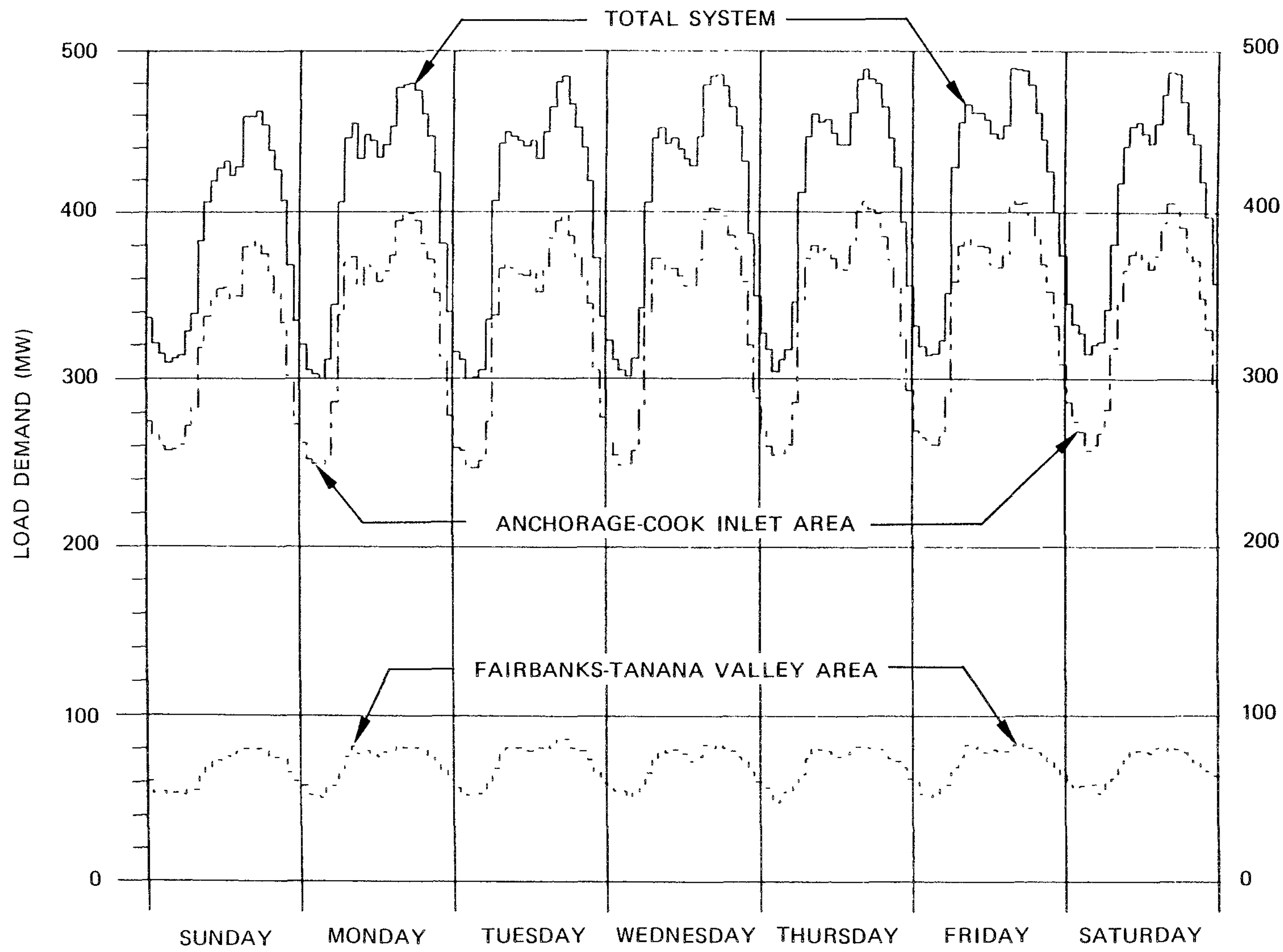
FIGURE B.80



DAILY LOAD CURVES-AUGUST 1982

SHEET 2

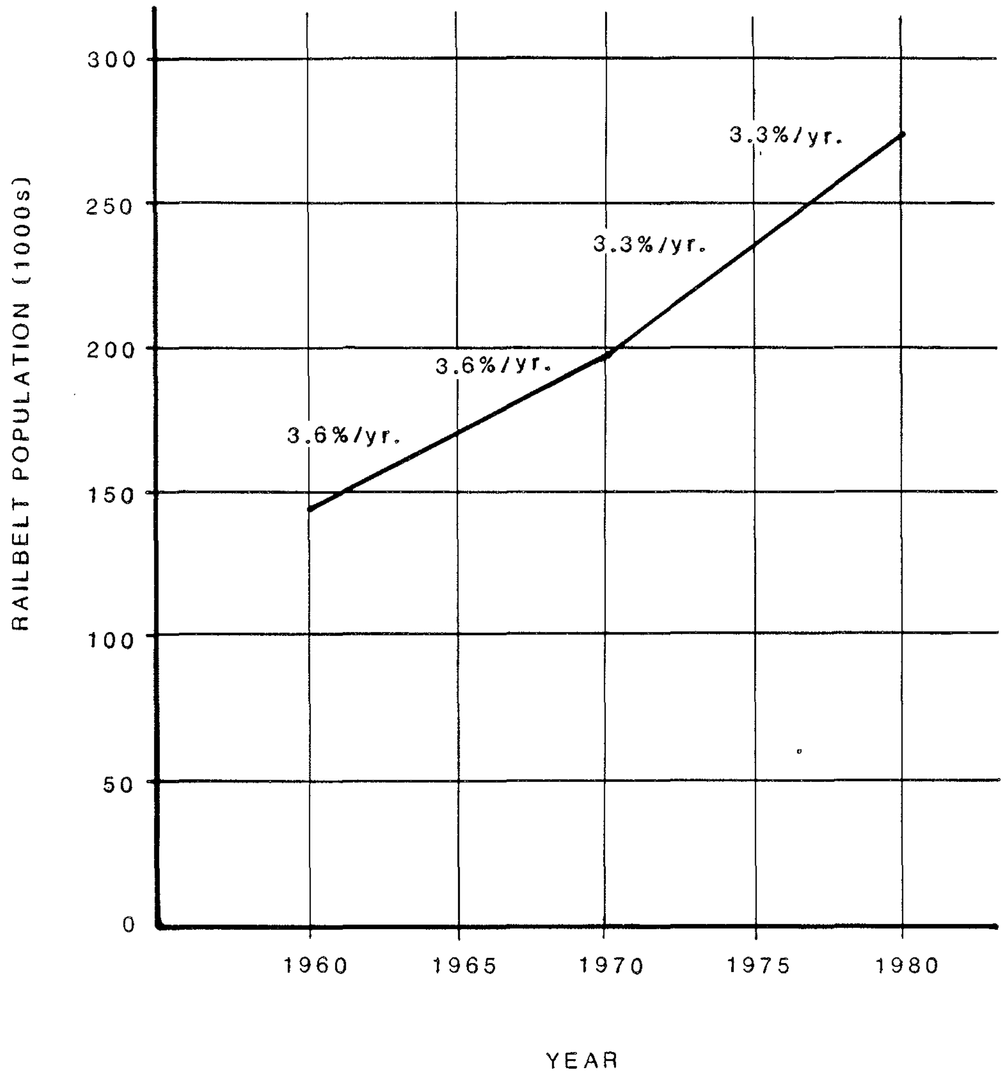
FIGURE B.80



DAILY LOAD CURVES- DECEMBER 1982

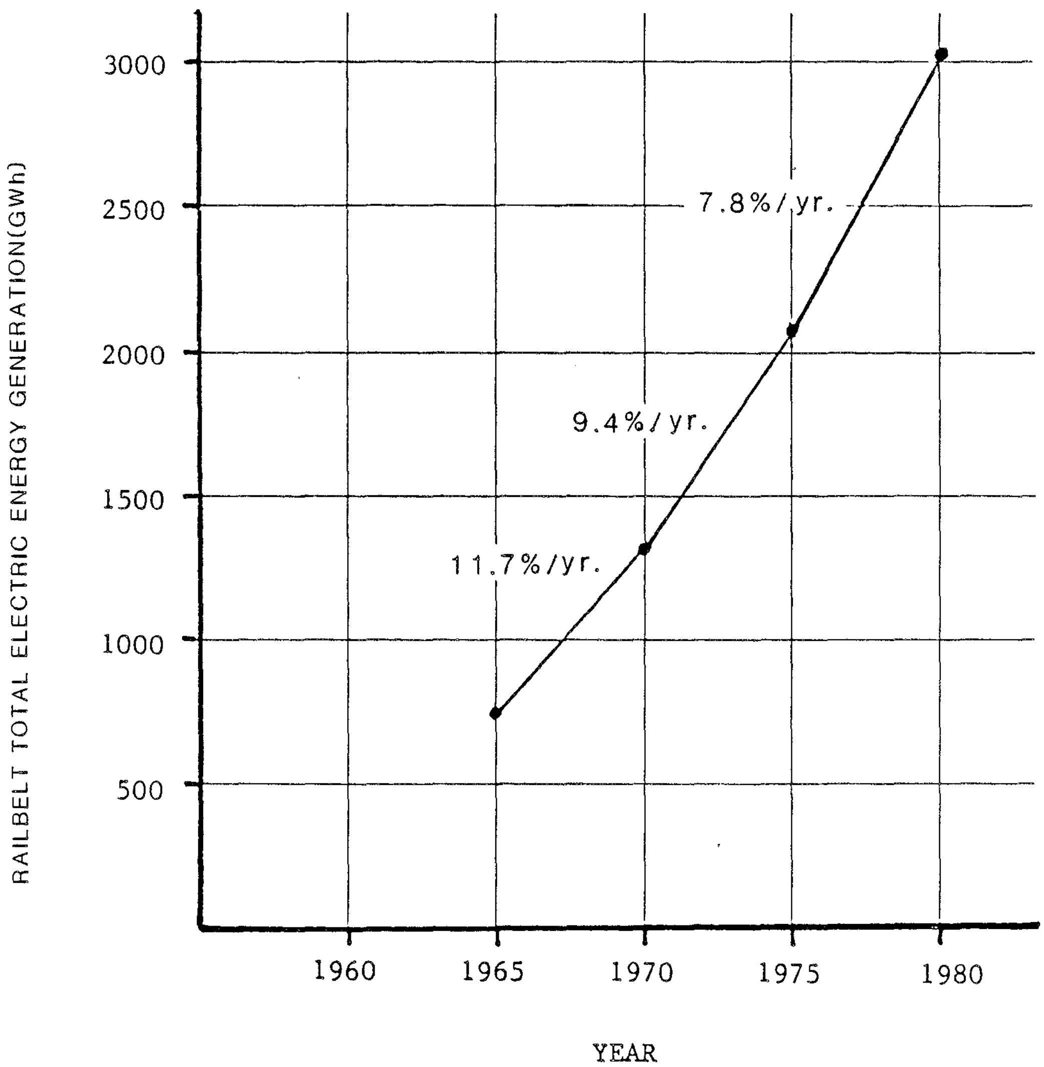
SHEET 3

FIGURE B.80



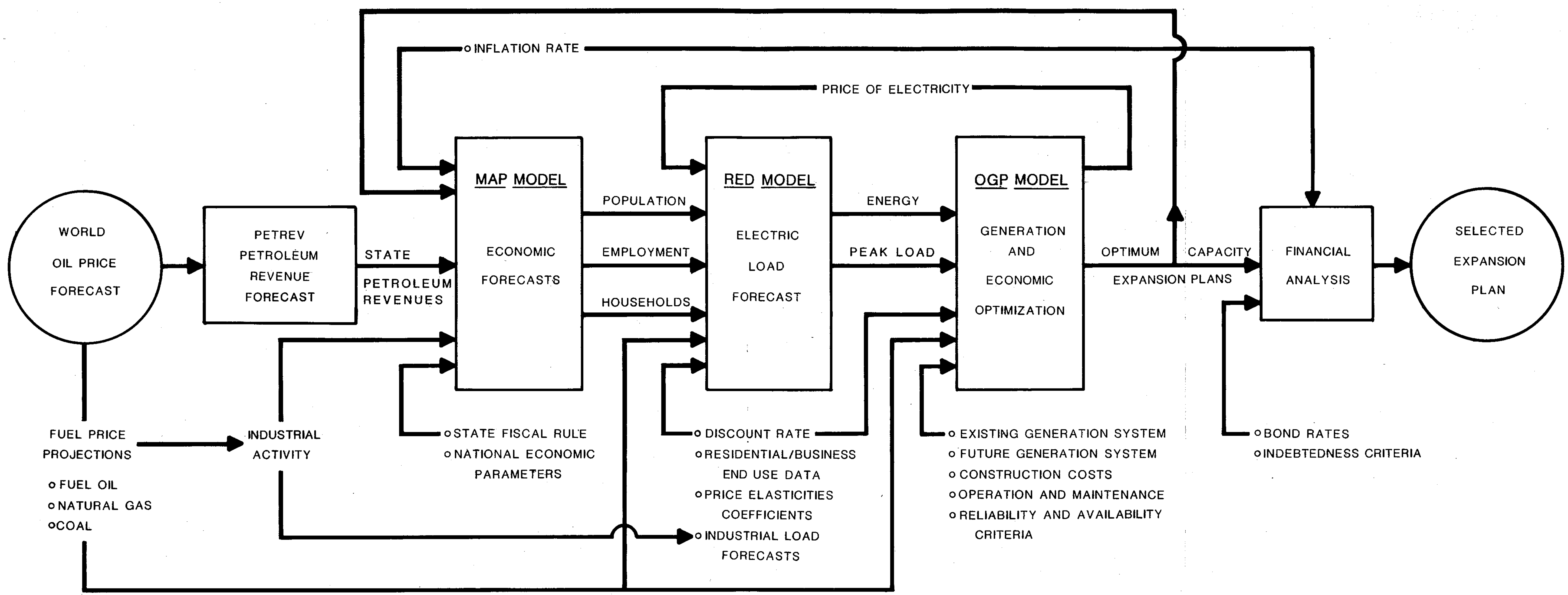
HISTORICAL POPULATION GROWTH

FIGURE B.81



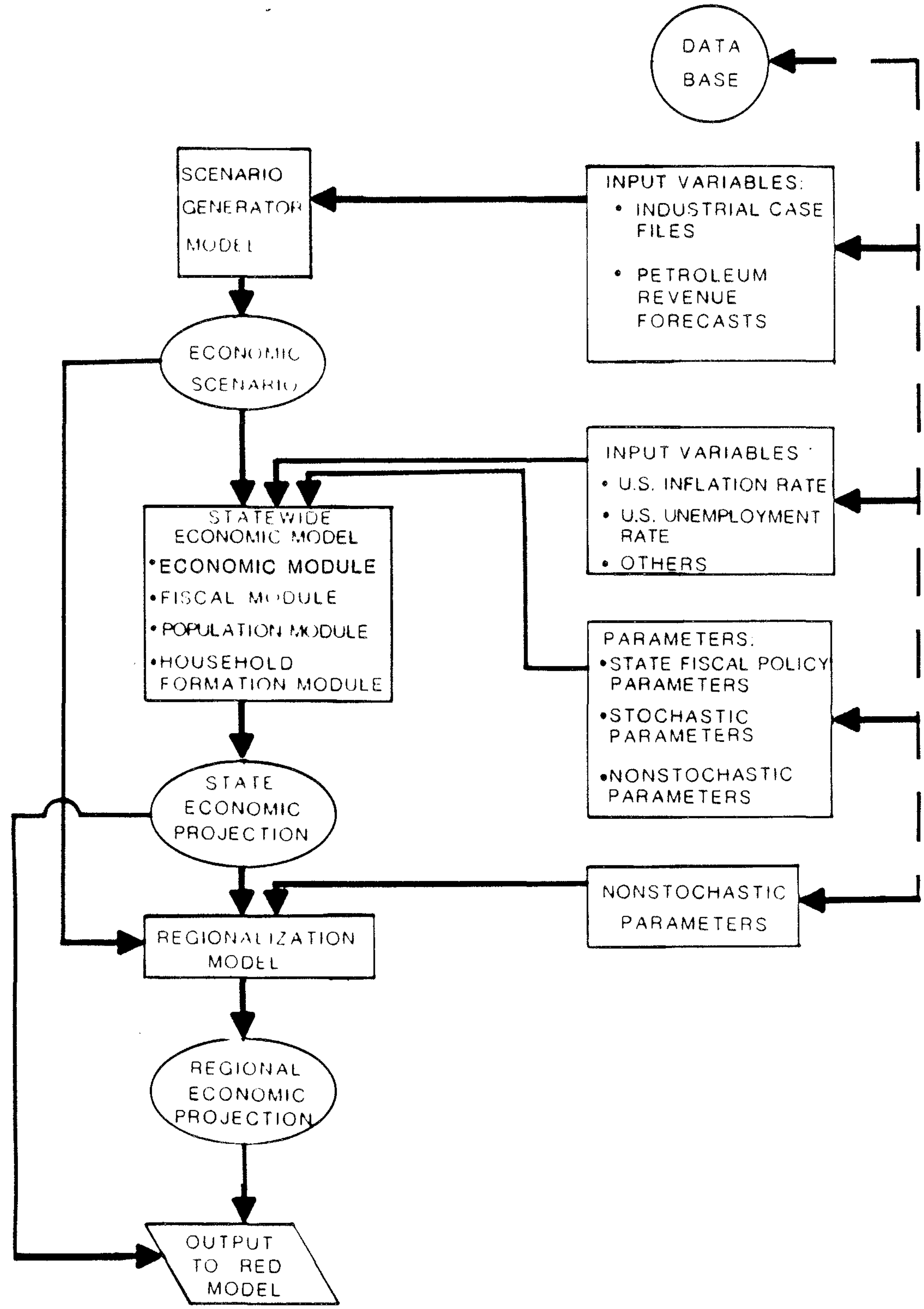
HISTORICAL GROWTH IN NET GENERATION

FIGURE B.82



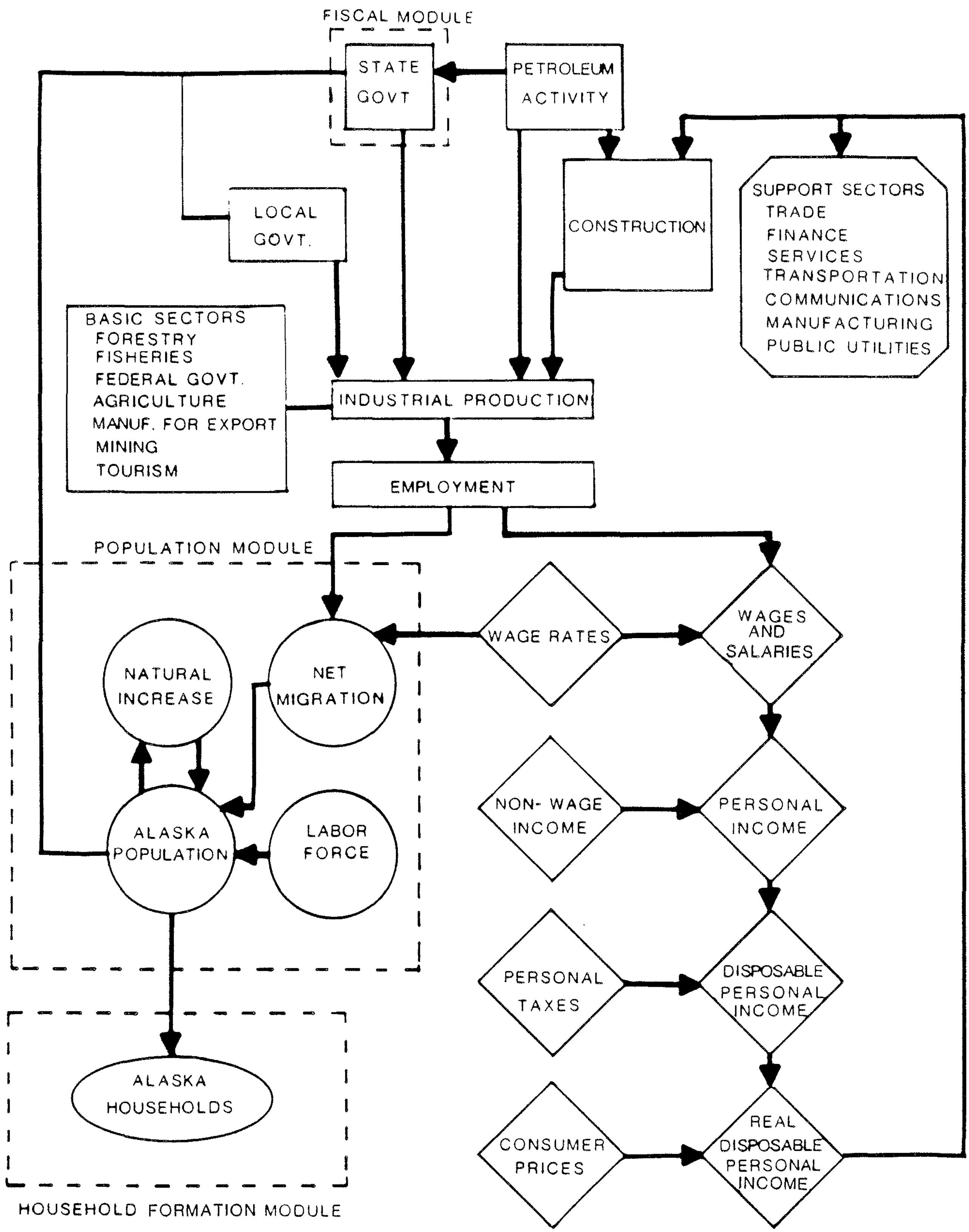
RELATIONSHIP OF PLANNING MODELS
AND INPUT DATA

FIGURE B.83



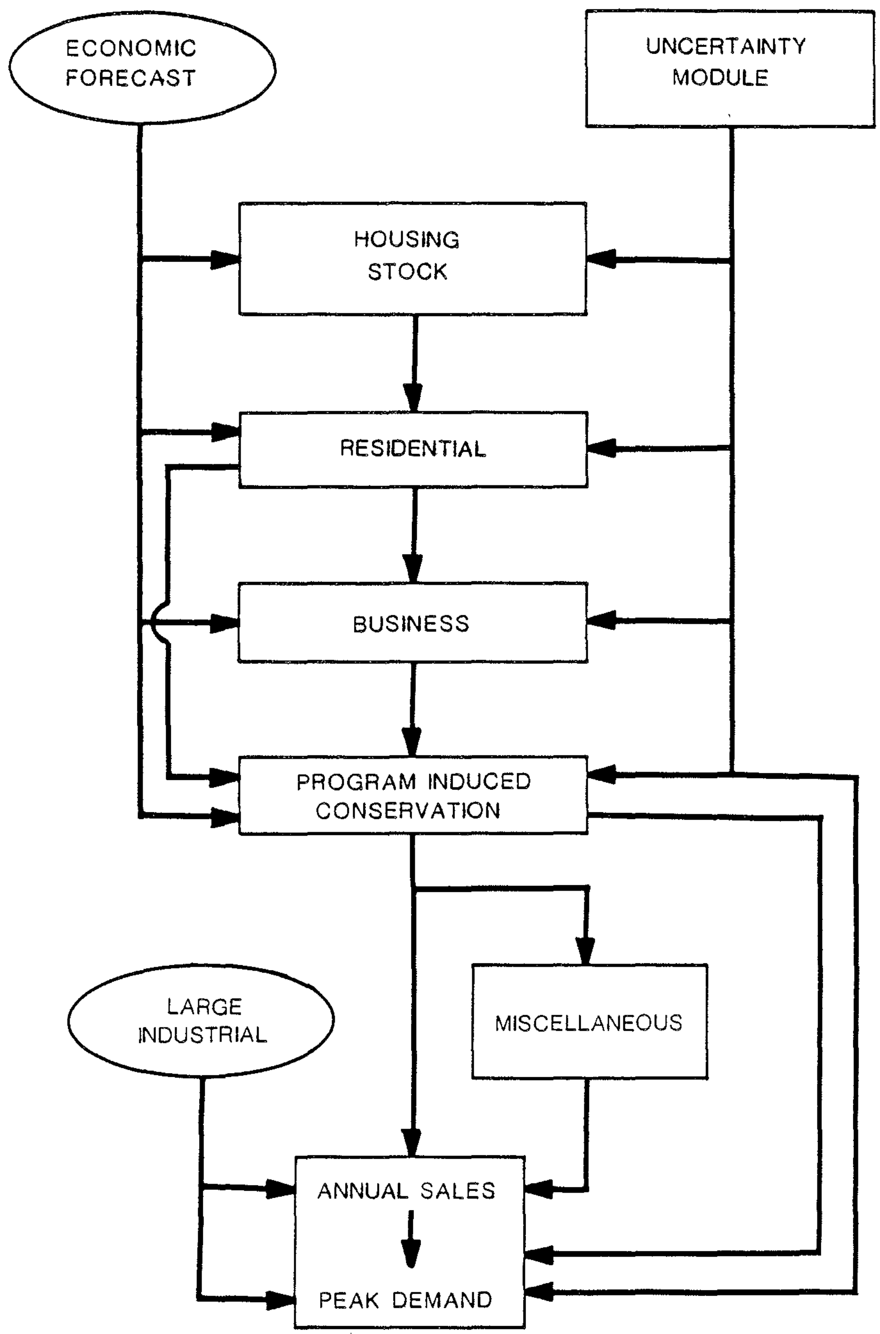
MAP MODEL SYSTEM

FIGURE B.84



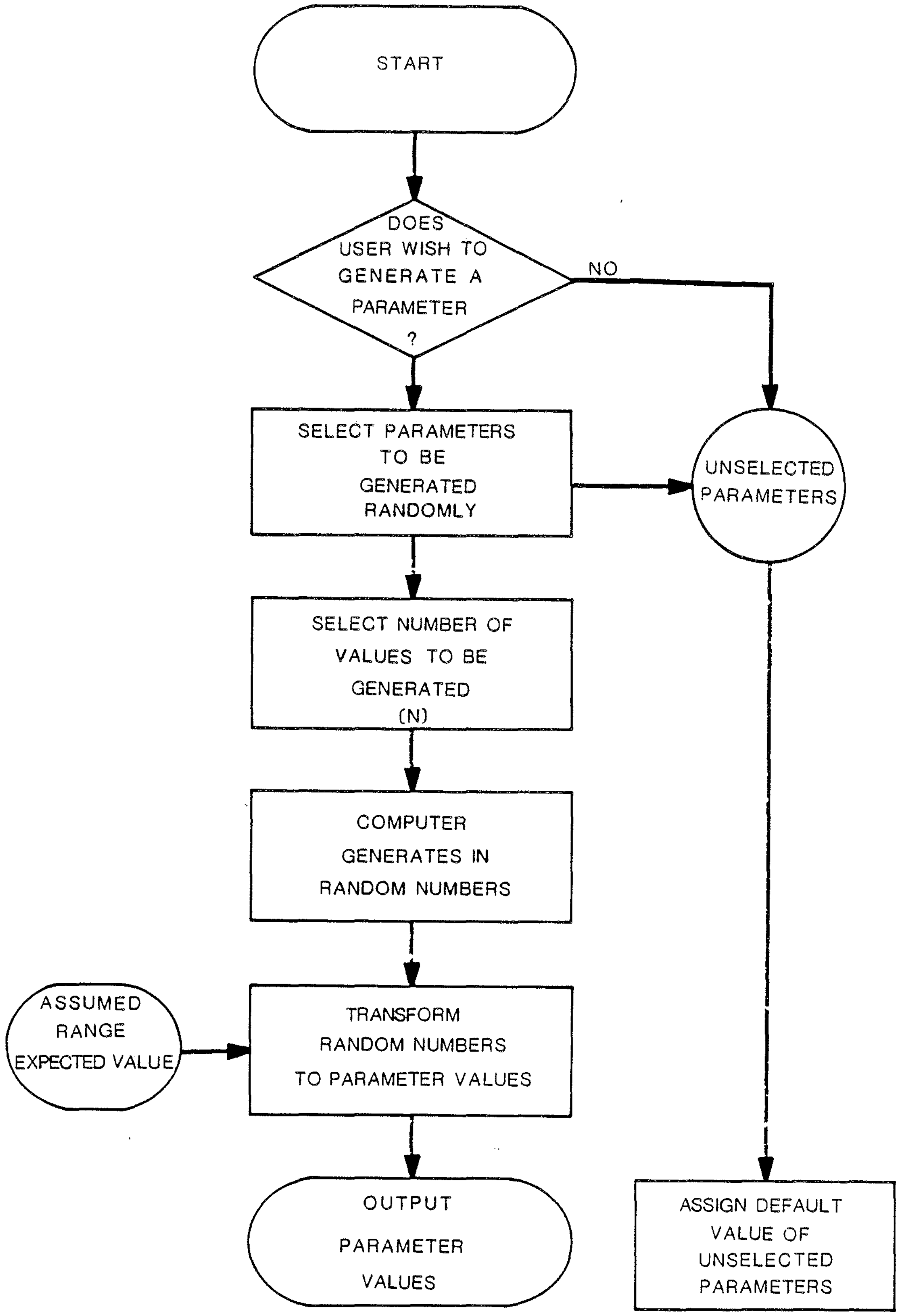
MAP ECONOMIC SUB-MODEL STRUCTURE

FIGURE B.85



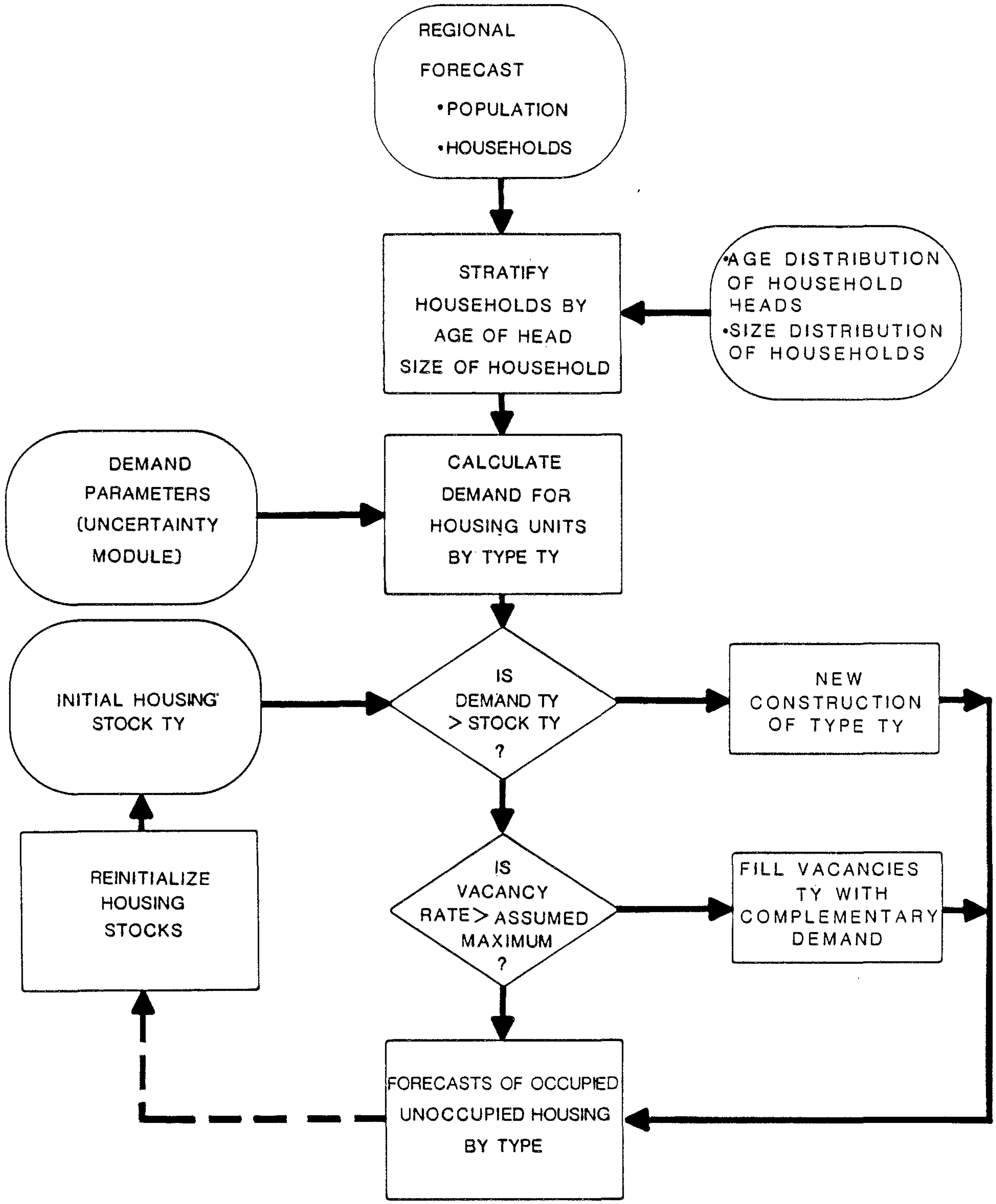
RED INFORMATION FLOWS

FIGURE B.87



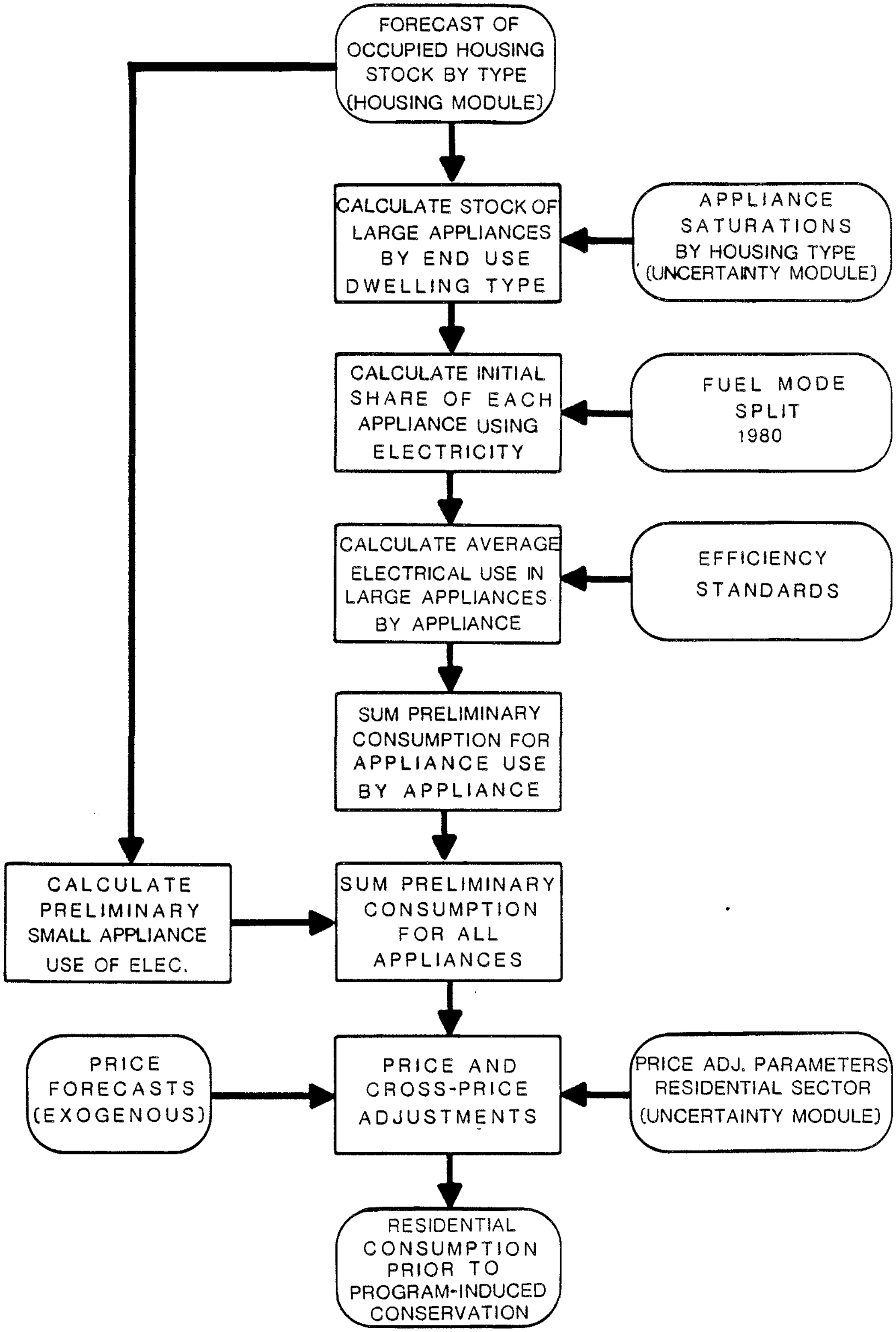
RED UNCERTAINTY MODULE

FIGURE B.88



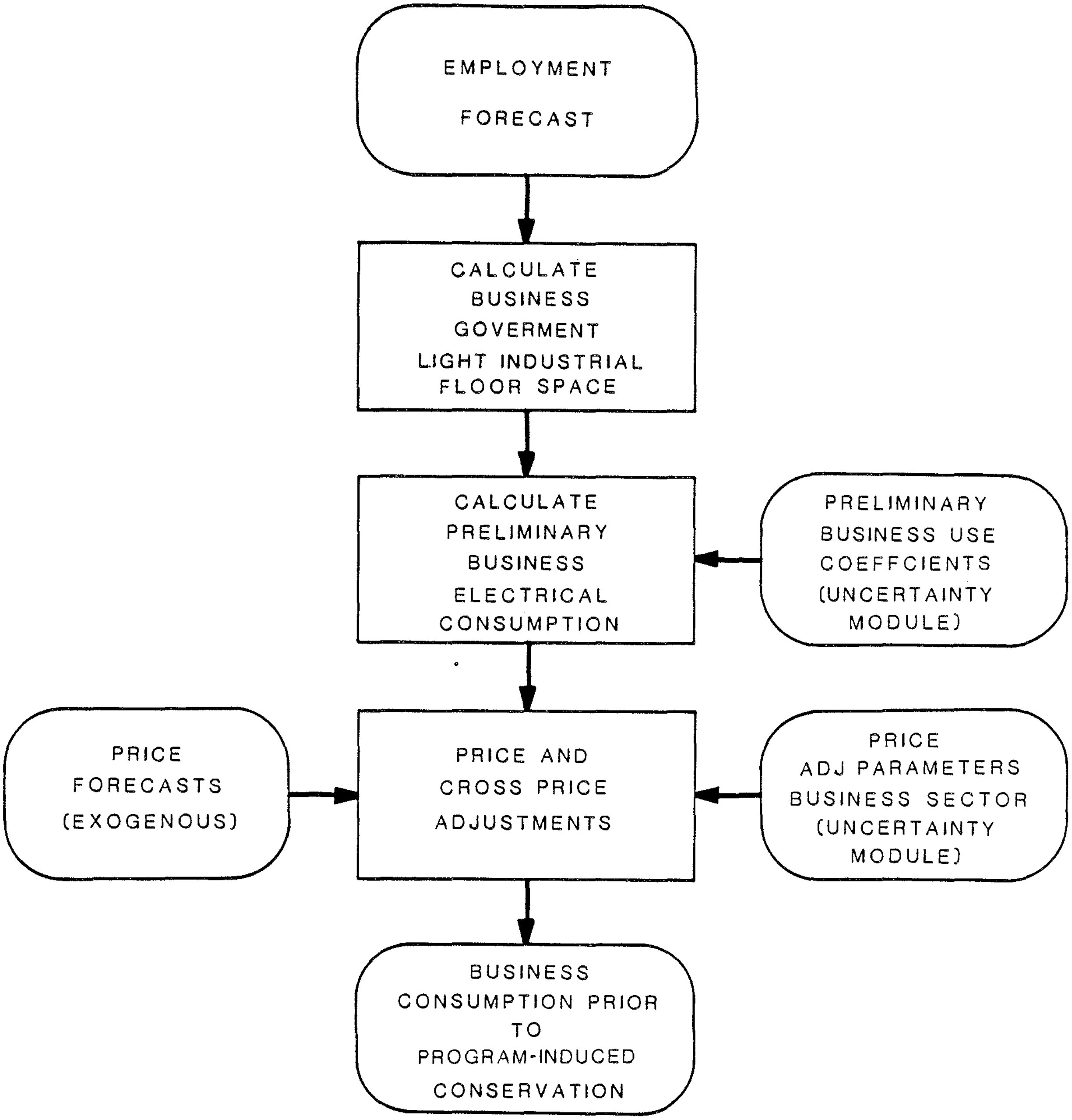
RED HOUSING MODULE

FIGURE B.89



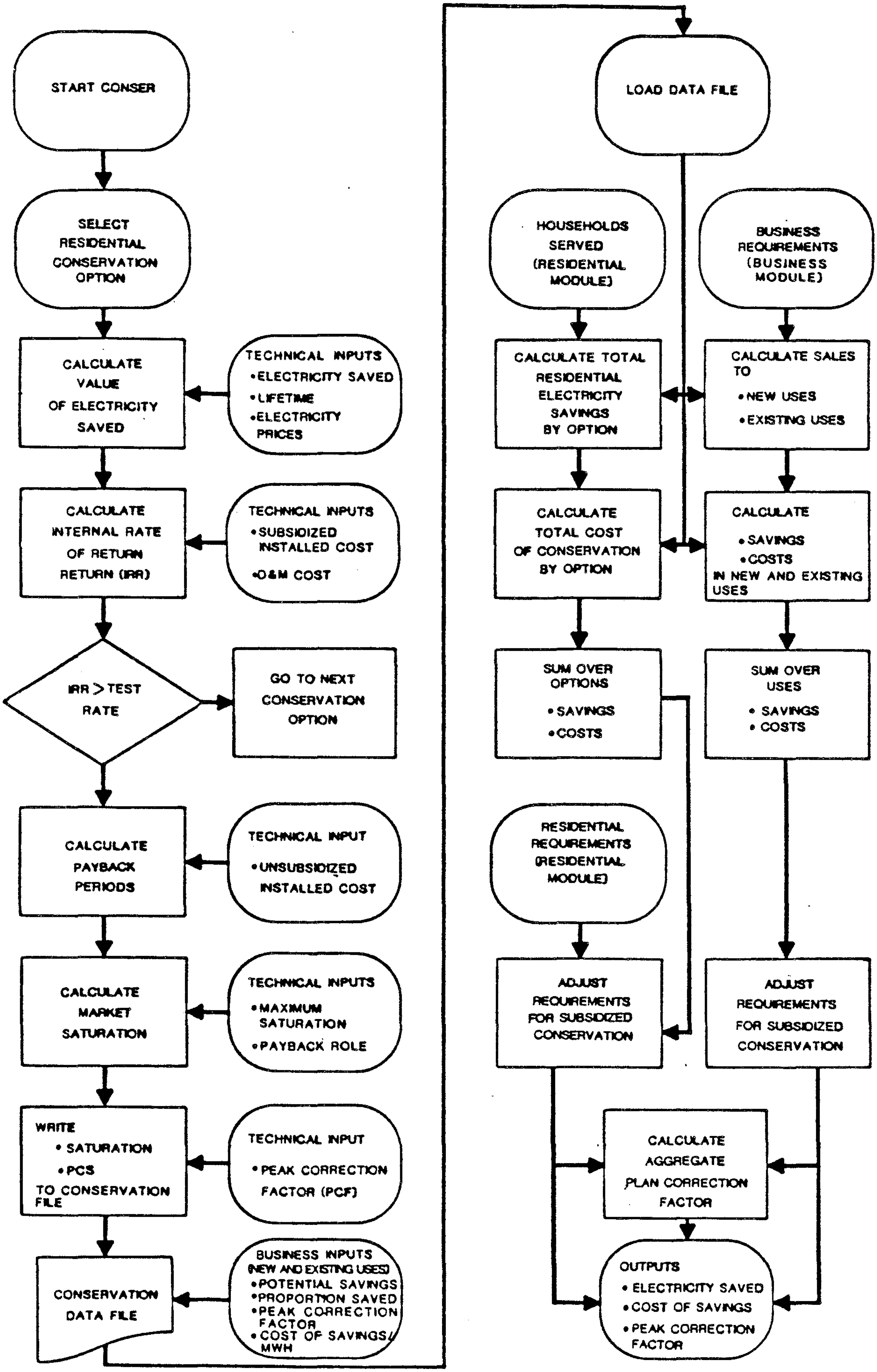
RED RESIDENTIAL CONSUMPTION MODULE

FIGURE B.90



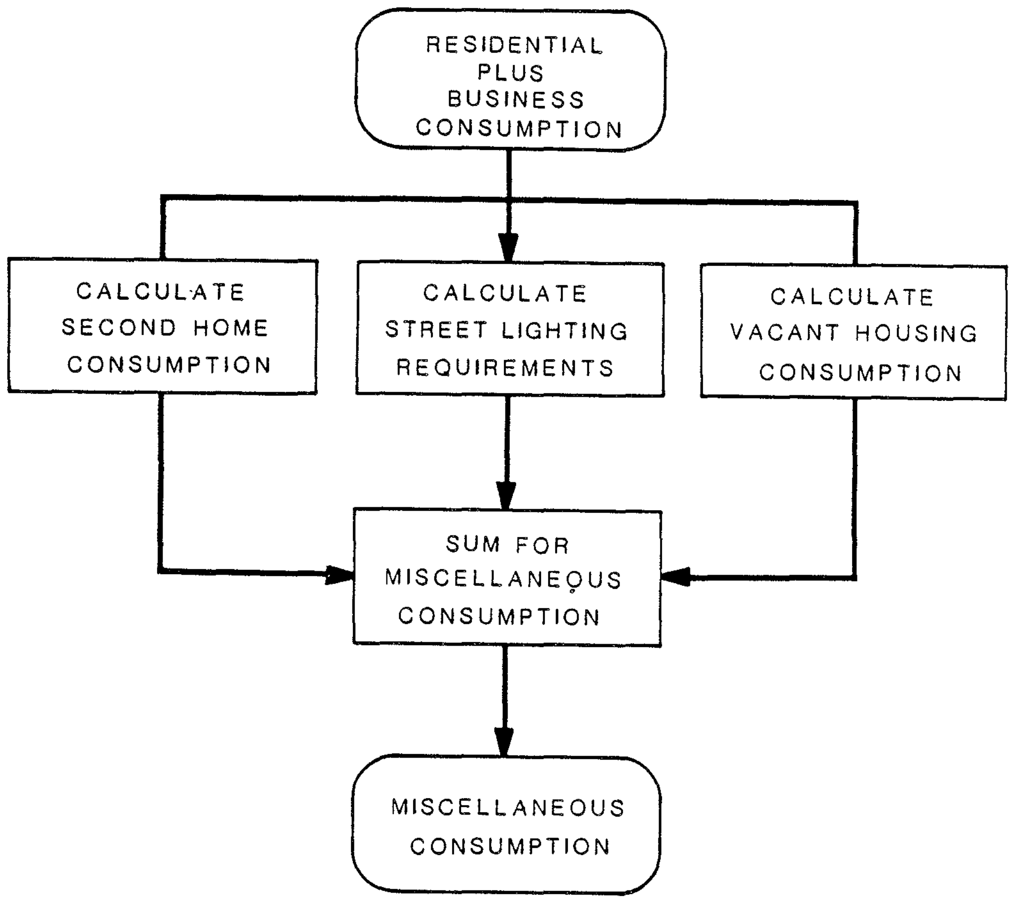
RED BUSINESS CONSUMPTION MODULE

FIGURE B.91



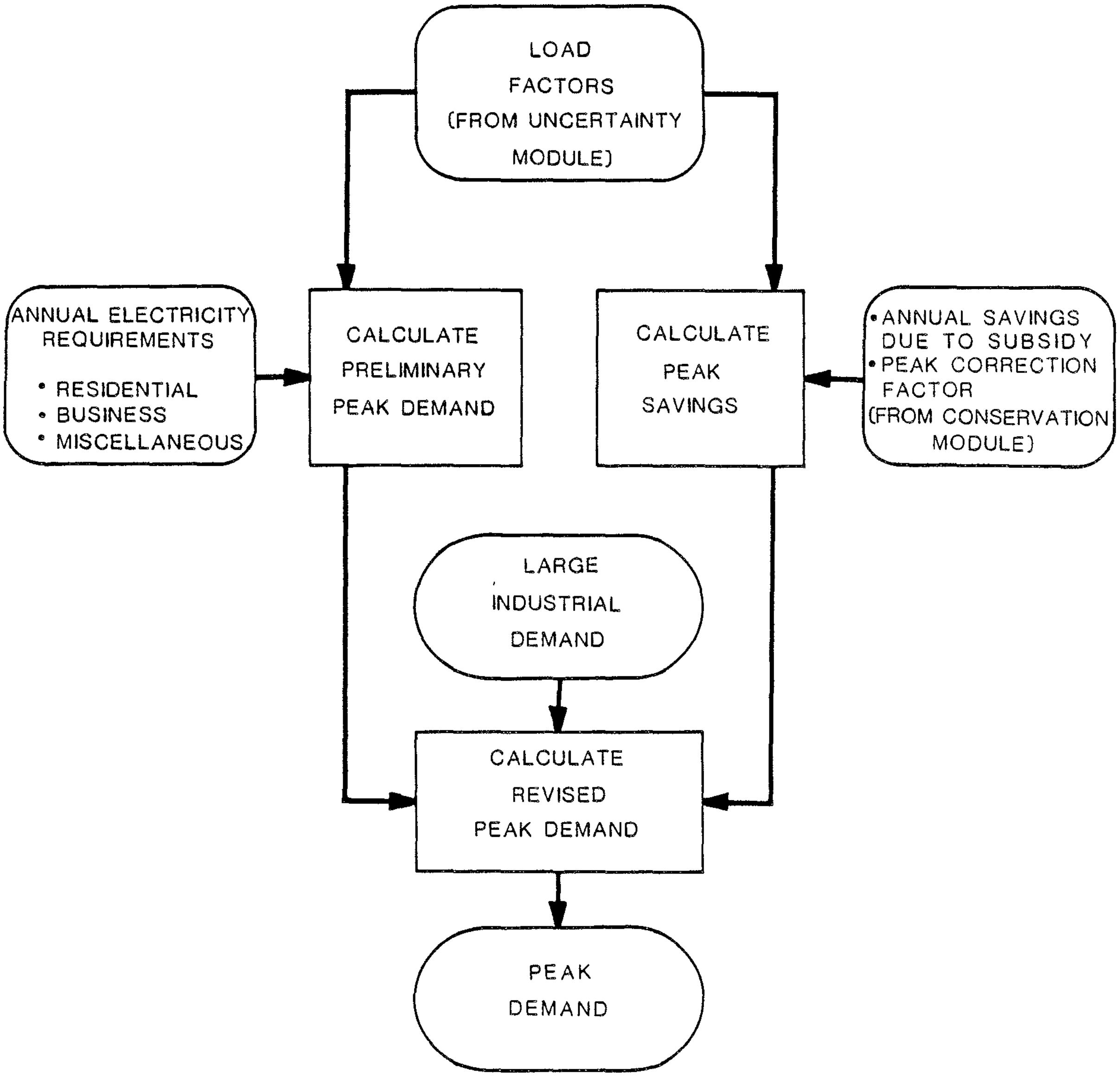
RED CONSERVATION MODULE

FIGURE B.92



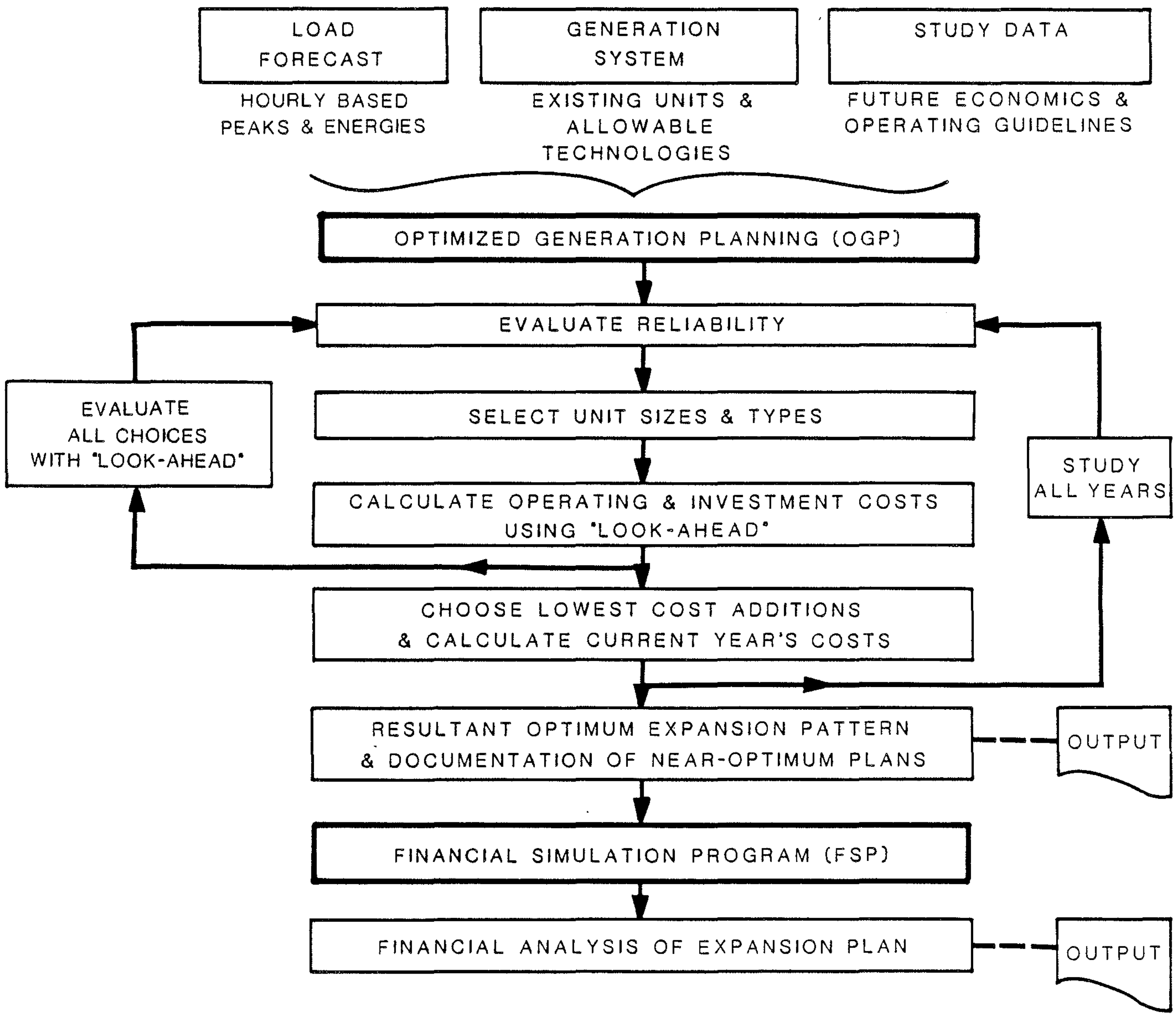
RED MISCELLANEOUS CONSUMPTION MODULE

FIGURE B.93



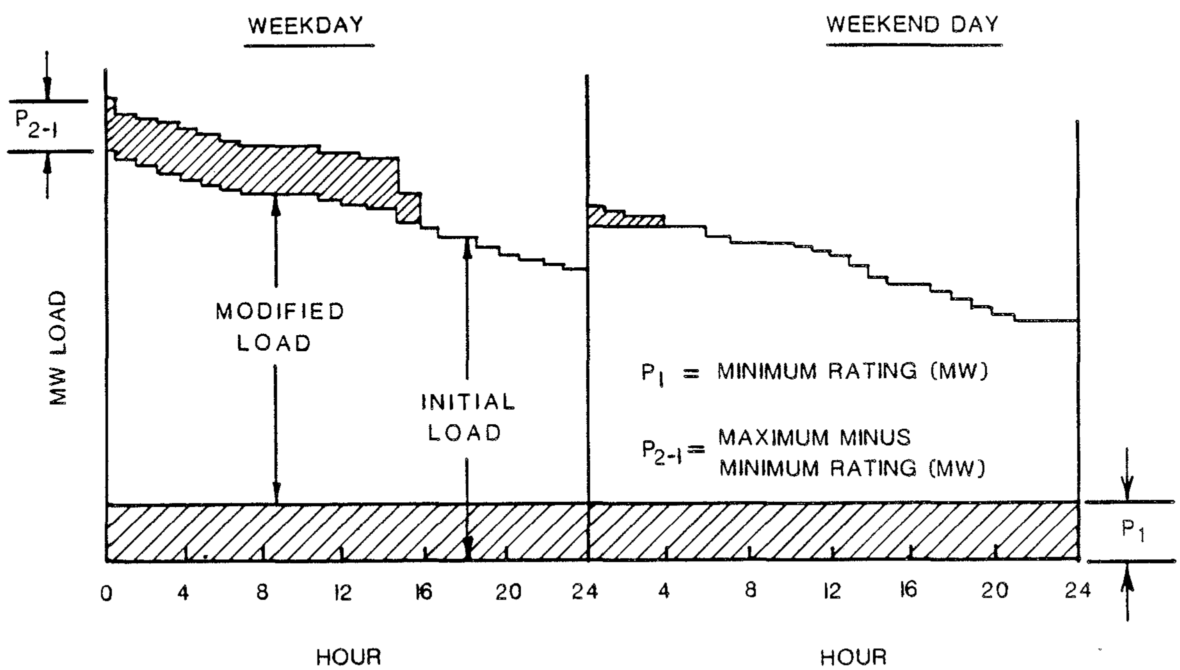
RED PEAK DEMAND MODULE

FIGURE B.94



OPTIMIZED GENERATION PLANNING (OGP) PROGRAM
INFORMATION FLOWS

FIGURE B.95



OPTIMIZED GENERATION PLANNING
EXAMPLE OF CONVENTIONAL HYDRO OPERATIONS

FIGURE B.96

	YEARS									%CH	%CH	%CH
	1981	1982	1983	1984	1985	1990	1995	2000	2005	82 TO 83	82 TO 90	90 TO 2000
REFINERS ACQUISITION COSTS ($ PER BARREL)												
Average Domestic	34.33	31.21	26.82	25.93	29.55	55.23	91.70	141.81	199.29	-14.1	7.4	9.9
Lower 48 Conventional	35.68	32.22	27.31	26.40	30.07	55.95	92.46	142.41	200.16	-15.2	7.1	9.8
Alaskan	31.60	28.84	24.81	24.09	27.57	52.48	88.67	139.56	196.16	-14.0	7.8	10.3
Shale	33.50	29.58	24.73	23.97	27.38	51.68	86.63	135.29	190.15	-16.4	7.2	10.1
Coal Liquids	39.08	34.37	28.61	27.62	31.42	58.08	95.38	145.97	205.16	-16.8	6.8	9.7
Average Imported	37.05	33.55	28.60	27.50	31.00	55.95	92.46	142.41	200.16	-14.8	6.6	9.8
Average Acquisition Cost	35.24	31.87	27.24	26.48	30.03	55.49	91.99	142.05	199.67	-14.5	7.2	9.9
REFINERS ACQUISITION COSTS (1982 DOLLARS PER BARREL)												
Average Domestic	36.38	31.22	25.61	23.55	25.39	35.16	43.65	50.95	53.89	-18.0	1.5	3.8
Lower 48 Conventional	37.82	32.22	26.08	23.97	25.83	35.62	44.02	51.16	54.13	-19.0	1.3	3.7
Alaskan	33.49	28.84	23.70	21.88	23.69	33.41	42.21	50.14	53.05	-17.8	1.9	4.1
Shale	35.50	29.58	23.61	21.77	23.52	32.91	41.24	48.61	51.42	-20.2	1.3	4.0
Coal Liquids	41.42	34.37	27.32	25.08	26.99	36.98	45.41	52.44	55.48	-20.5	0.9	3.6
Average Imported	39.27	33.55	27.31	24.97	26.63	35.62	44.02	51.16	54.13	-18.6	0.8	3.7
Average Acquisition Cost	37.35	31.87	26.02	24.04	25.80	35.33	43.79	51.03	54.00	-18.4	1.3	3.7
REFINERS ACQUISITION COSTS (1981 DOLLARS PER BARREL)												
Average Domestic	34.33	29.45	24.16	22.22	23.95	33.18	41.19	48.07	50.85	-18.0	1.5	3.8
Lower 48 Conventional	35.68	30.40	24.61	22.62	24.38	33.61	41.53	48.27	51.07	-19.0	1.3	3.7
Alaskan	31.60	27.21	22.36	20.64	22.35	31.53	39.83	47.31	50.05	-17.8	1.9	4.1
Shale	33.50	27.91	22.28	20.54	22.19	31.05	38.91	45.86	48.52	-20.2	1.3	4.0
Coal Liquids	39.08	32.43	25.78	23.66	25.47	34.90	42.84	49.48	52.35	-20.5	0.9	3.6
Average Imported	37.05	31.65	25.77	23.56	25.13	33.61	41.53	48.27	51.07	-18.6	0.8	3.7
Average Acquistion Cost	35.24	30.07	24.55	22.69	24.34	33.33	41.32	48.15	50.95	-18.4	1.3	3.7
PRODUCTION (MMBD)												
Domestic Supplies												
Lower 48 Conventional	6.96	6.98	6.93	6.86	6.81	6.72	6.65	6.42	6.08	-0.7	-0.5	-0.5
Alaskan	1.61	1.70	1.72	1.75	1.78	1.75	1.63	1.48	1.34	1.5	0.4	-1.7
Total Conventional	8.57	8.67	8.65	8.60	8.59	8.47	8.28	7.90	7.43	-0.3	-0.3	-0.7
Synthetic												
Coal Liquids	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.10	0.20	NC	NC	25.9
Shale	0.00	0.00	0.00	0.01	0.01	0.02	0.05	0.15	0.25	NC	NC	22.3
Domestic Crude	8.57	8.67	8.65	8.61	8.60	8.50	8.37	8.15	7.88	-0.3	-0.2	-0.4
Domestic NGL'S	1.61	1.54	1.54	1.54	1.54	1.30	1.14	0.91	0.74	0.2	-2.1	-3.4
Domestic Liquids	10.18	10.21	10.19	10.16	10.14	9.80	9.51	9.06	8.61	-0.2	-0.5	-0.8
Crude Exports	0.23	0.24	0.23	0.23	0.23	0.23	0.22	0.21	0.20	-3.3	-0.5	-0.9
Product Exports	0.37	0.58	0.59	0.62	0.64	0.68	0.68	0.68	0.68	1.7	2.0	0.0
Imported Supplies												
Gross												
Crude	4.41	3.29	3.99	4.28	4.43	4.88	5.11	5.45	6.20	21.5	5.1	1.1
Products	1.60	1.53	1.79	1.92	1.99	2.19	2.30	2.45	2.79	17.0	4.6	1.1
Total	6.01	4.82	5.79	6.20	6.42	7.07	7.40	7.91	8.99	20.1	4.9	1.1
Net												
Crude	4.18	3.05	3.76	4.04	4.19	4.65	4.89	5.24	6.01	23.4	5.4	1.2
Products	1.23	0.95	1.20	1.30	1.35	1.51	1.62	1.77	2.11	26.4	5.9	1.6
Total	5.41	4.00	4.97	5.35	5.54	6.16	6.50	7.02	8.11	24.1	5.6	1.3

U.S. OIL OUTLOOK
CRUDE OIL PRICES AND PRODUCTION

FIGURE B.97

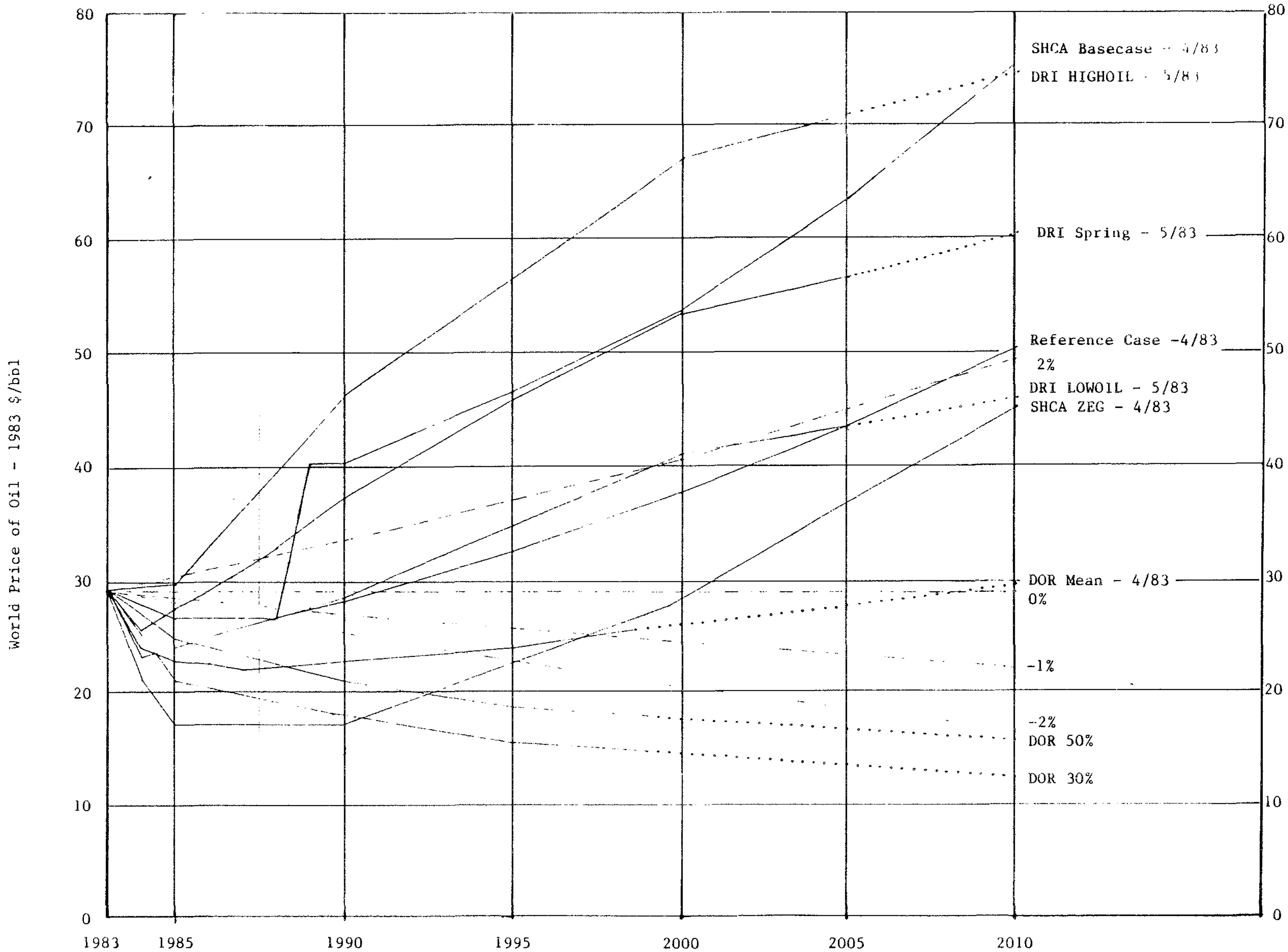
FREE WORLD PETROLEUM DEMAND AND BROAD SOURCES OF SUPPLY
(MMBD)
1982-2040

		Base Case										No Supply Disruption					
	1982	1983	1984	1985	1988	1990	2000	2010	2020	2030	2040	1990	2000	2010	2020	2030	2040
Production																	
Non-OPEC																	
Crude	19.8	20.4	20.9	21.5	22.3	22.5	21.9	20.9	17.8	14.7	11.7	21.9	26.1	28.4	24.1	19.4	14.4
NGL	2.5	2.4	2.4	2.4	2.4	2.4	2.5	2.3	2.0	1.6	1.3	2.4	2.6	2.8	2.4	1.9	1.4
Synthetic	0.3	0.3	0.4	0.5	0.6	0.6	1.7	2.5	3.3	4.0	4.5	0.6	1.5	2.1	3.0	3.8	4.5
Total Non-OPEC	22.5	23.1	23.8	24.5	25.3	25.6	26.0	25.7	23.1	20.3	17.5	24.9	30.2	33.3	29.5	25.1	20.3
OPEC																	
Crude	18.4	16.5	19.4	18.5	19.2	19.5	22.3	24.6	23.7	23.1	21.4	19.9	23.0	25.2	24.1	23.3	22.1
NGL	0.9	0.9	1.0	1.0	1.0	1.1	1.3	1.5	1.4	1.3	1.2	1.1	1.5	1.9	1.8	1.7	1.6
Synthetic	--	--	--	--	--	--	0.2	0.5	0.7	0.9	1.0	--	0.1	0.3	0.5	0.6	0.7
Total OPEC	19.3	17.5	20.4	19.4	20.2	20.5	23.8	26.6	25.8	25.3	23.6	21.0	24.6	27.4	26.4	25.6	24.4
Total production	41.8	40.6	44.2	43.9	45.5	46.1	49.8	52.3	48.9	45.6	41.1	45.9	54.8	60.7	55.9	50.7	44.7
Net imports from Sino-Soviet Bloc	1.5	1.8	1.8	1.8	1.2	1.0	1.0	1.0	0.9	0.7	0.5	1.8	1.8	1.8	1.8	1.6	1.2
Processing gain	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Increase (decrease) in stocks	(2.0)	(1.4)	0.7	0.3	0.1	0.1	0.3	0.4	(0.4)	(0.4)	(0.5)	0.2	0.5	0.6	(0.5)	(0.6)	(0.6)
Statistical difference	0.1	0.2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Consumption	45.9	44.6	45.8	46.1	47.1	47.5	51.0	53.4	50.7	47.2	42.5	48.0	56.6	62.4	58.7	53.4	47.0

Note: Details may not add to totals due to rounding.

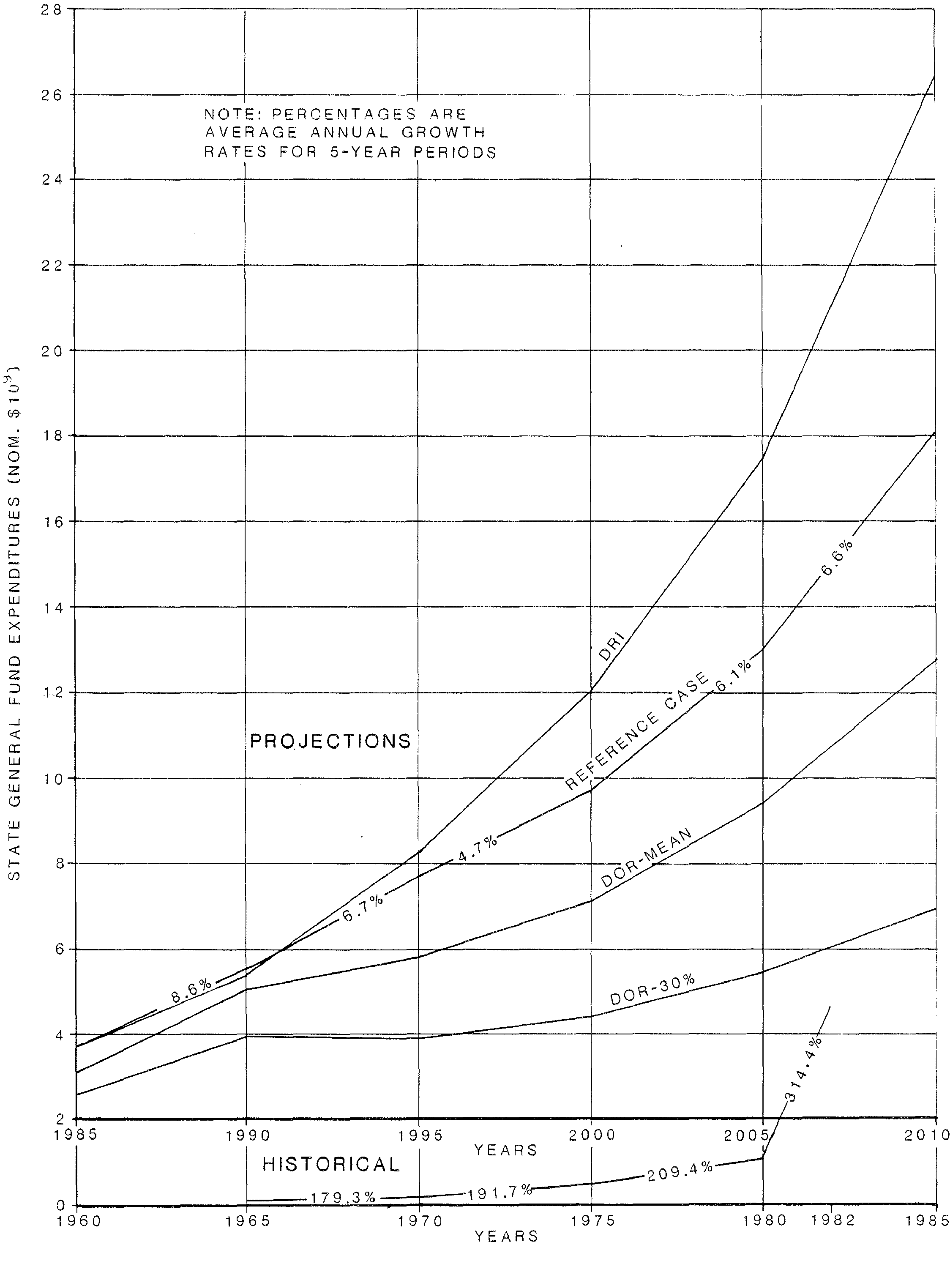
FREE WORLD PETROLEUM DEMAND AND BROAD SOURCES OF SUPPLY
(MMBD)
1982-2040

FIGURE B.98



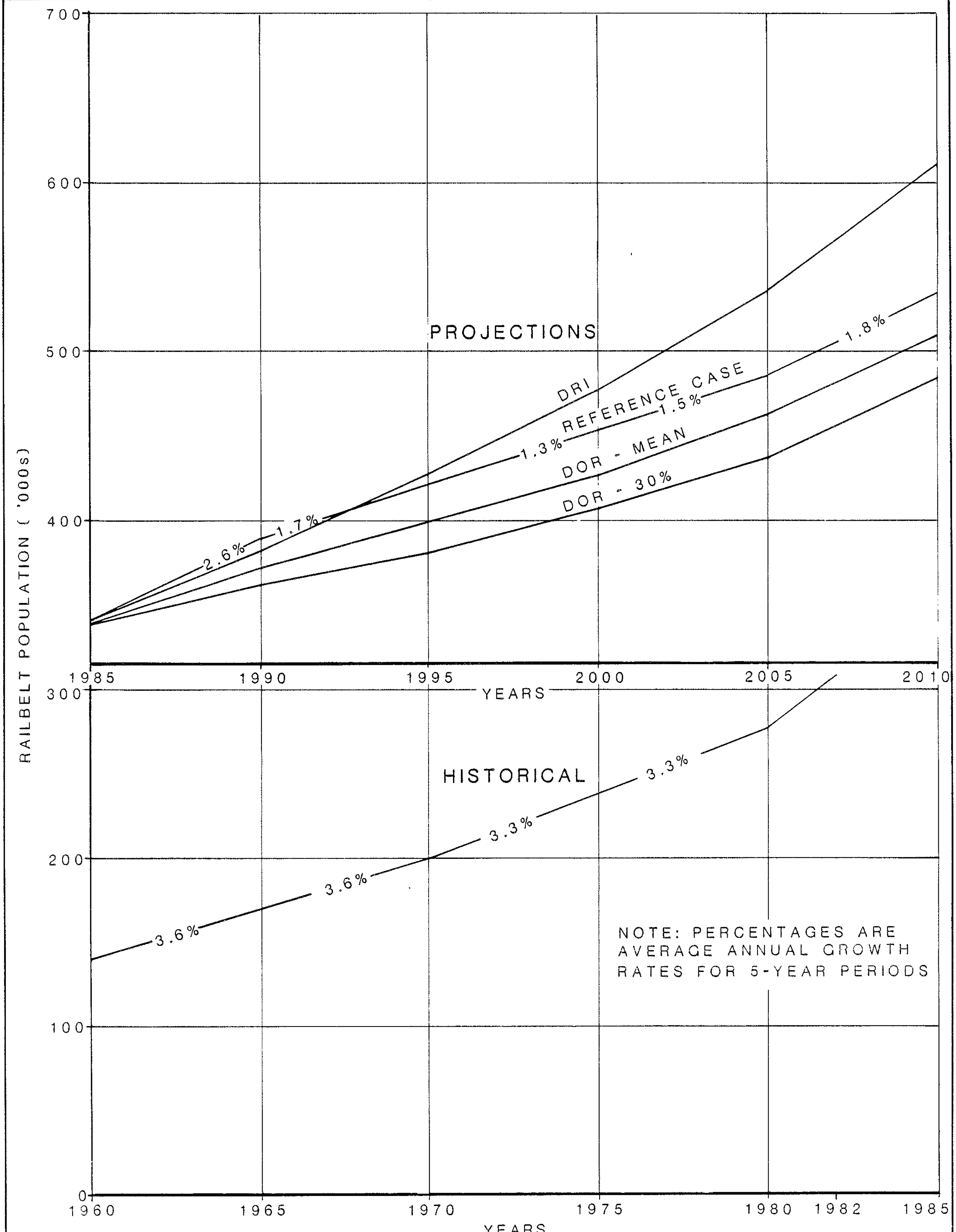
ALTERNATIVE OIL PRICE PROJECTIONS-$/bbl (1983 $)

FIGURE B.99



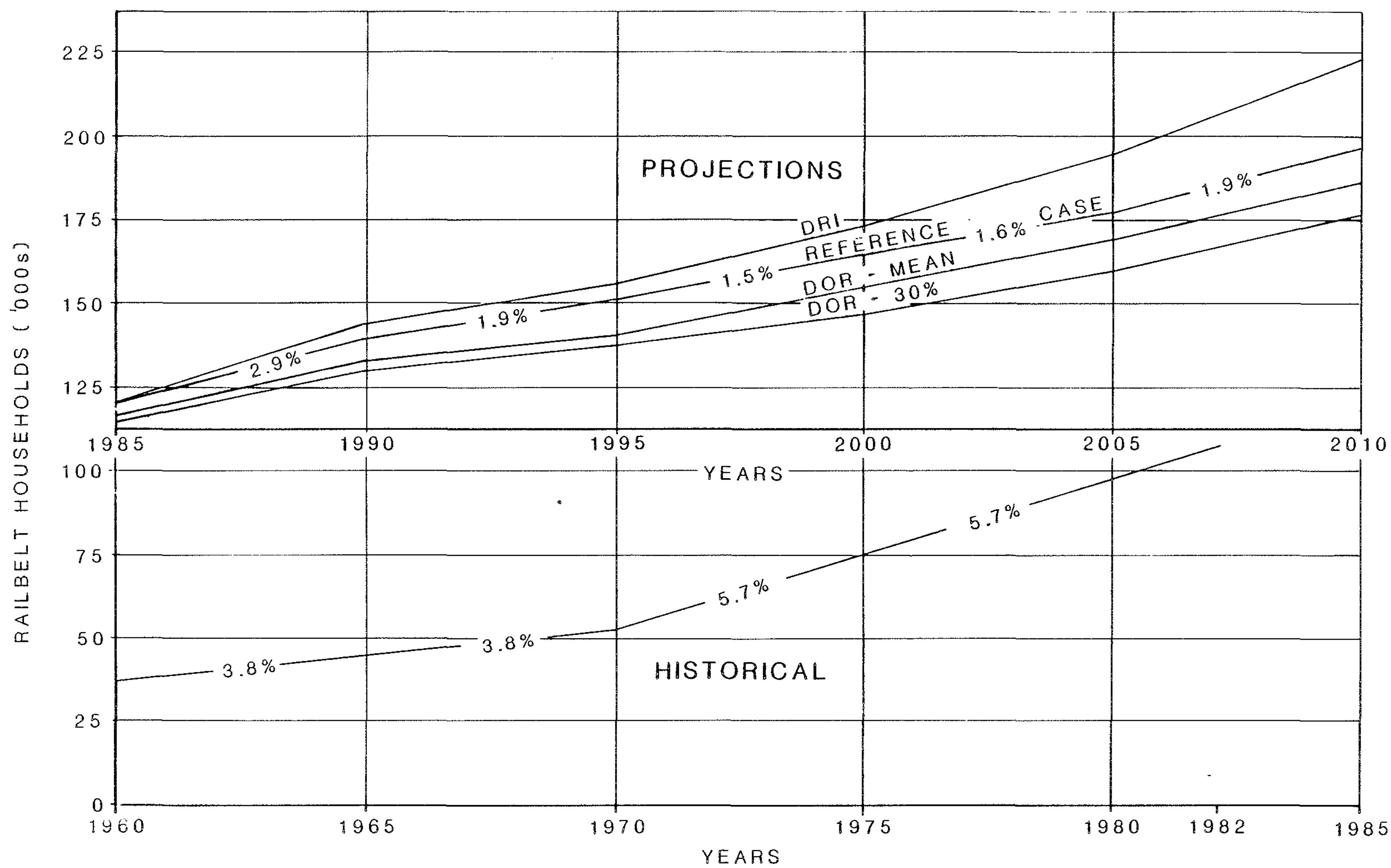
ALTERNATIVE STATE GENERAL FUND EXPENDITURE FORECASTS

FIGURE B.100



ALTERNATIVE RAILBELT POPULATION FORECASTS

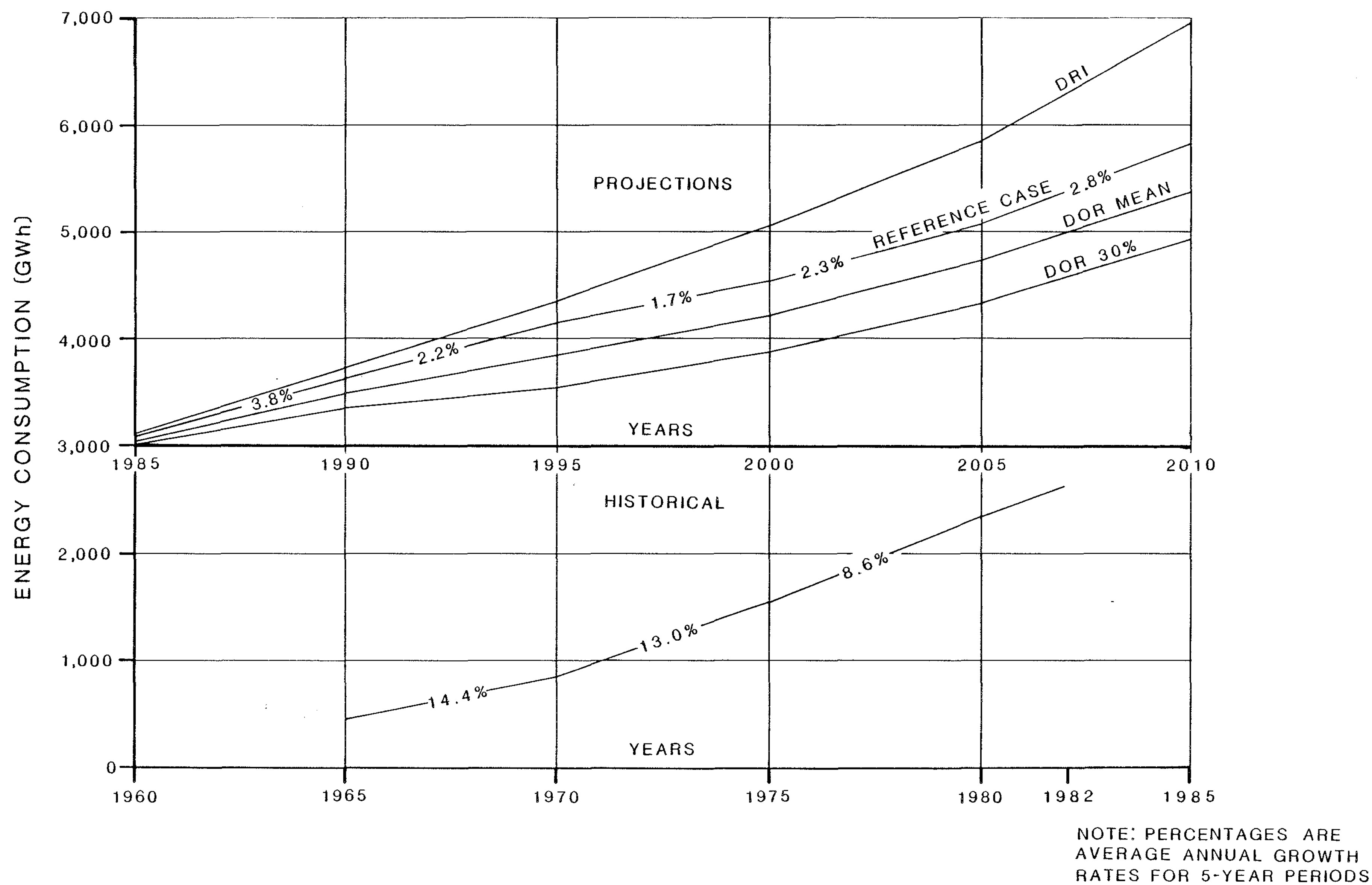
FIGURE B.101



NOTE: PERCENTAGES ARE AVERAGE ANNUAL GROWTH RATES FOR 5-YEAR PERIODS

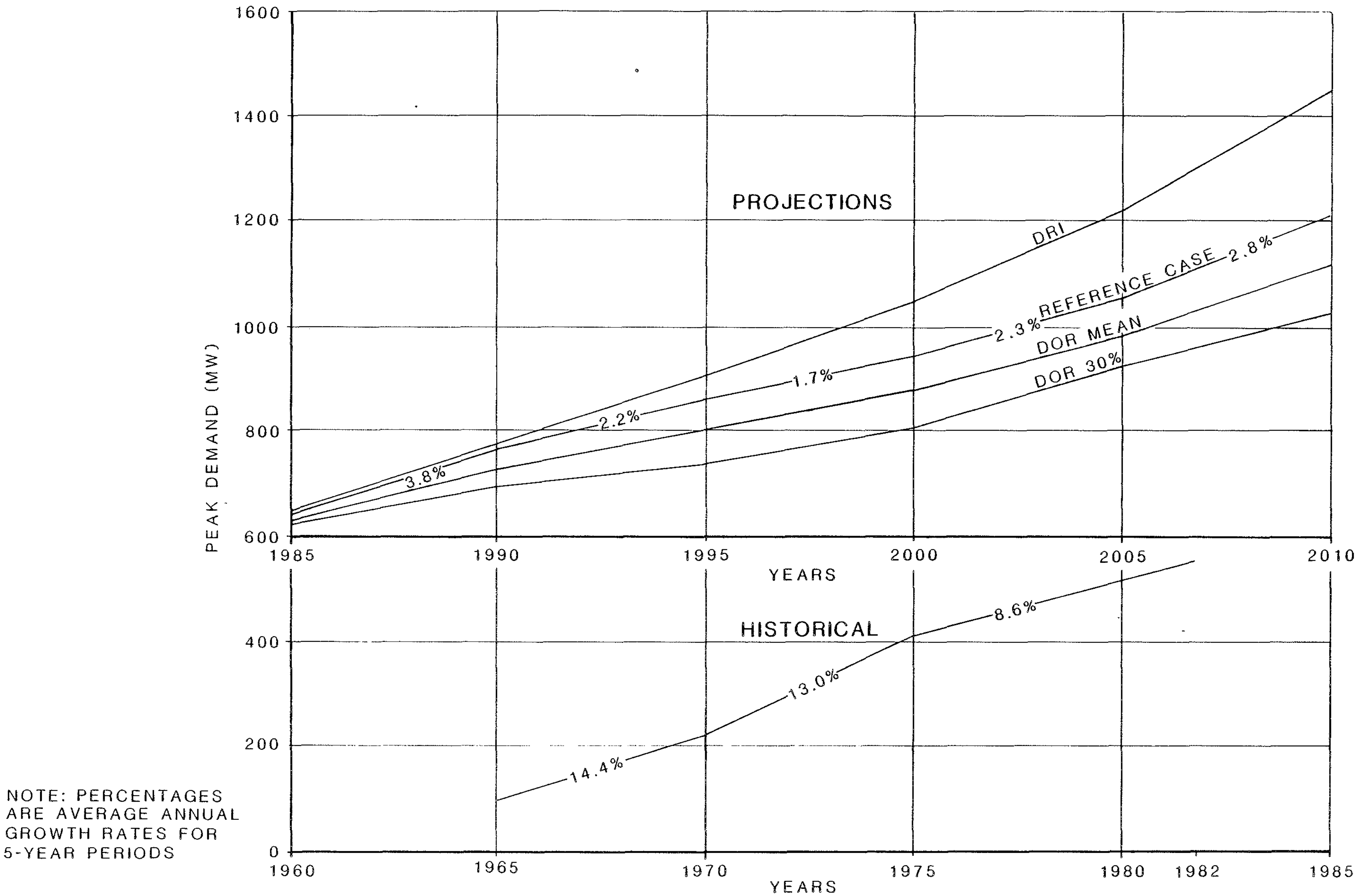
ALTERNATIVE RAILBELT HOUSEHOLDS FORECASTS

FIGURE B.102



ALTERNATIVE ELECTRIC ENERGY DEMAND FORECASTS

FIGURE B.103



ALTERNATIVE ELECTRIC PEAK DEMAND FORECASTS

FIGURE B.104