Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans

Volume I

December 1982

Prepared for the Office of the Governor
State of Alaska
Division of Policy Development and Planning
and the Governor's Policy Review Committee
under Contract 2311204417

Battelle
Pacific Northwest Laboratories

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RAILBELT ELECTRIC POWER ALTERNATIVES STUDY: EVALUATION OF RAILBELT ELECTRIC ENERGY PLANS

VOLUME I

J. J. Jacobsen
D. L. Brenchley
J. C. King
M. J. Scott
H. Harty
T. J. Secrest
F. H. Boness (Consultant)
J. E. Haggard (Consultant)

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BATTELLE
Pacific Northwest Laboratories
Richland, Washington 99352

EXECUTIVE SUMMARY

During the next 30 years - to the year 2010 - the electrical demand in the Railbelt region of Alaska is expected to increase from its present peak demand of about 520 MW to between 1000 MW if low economic growth is experienced and 1760 MW if high economic growth is experienced. This report, Volume I, analyzes alternative plans for meeting this growth in electricity demand. The project was commissioned by the State of Alaska with Battelle, Pacific Northwest Laboratories. The major effort in this project was the development of models and forecasting methodologies and associated data bases that would permit the State of Alaska to make its own forecasts to account for changing economic conditions or to evaluate different scenarios. This report illustrates the use of the models and methodologies based on economic forecasts prevalent in January 1982.[a]

The analysis included generating resources which could potentially contribute to meeting the electrical load over the time horizon of the study as well as conservation and consumer-installed small-scale generating resources. The generating resources included hydroelectric and those associated with the use of oil, gas, coal, wind, wood waste, municipal solid waste fuels, and tidal power. Nuclear plants were not considered because their size ranges do not match the load growths expected. In addition, State statutes specifically exclude nuclear energy production from the definition of power projects that can be funded through the Power Development Fund (see Power Authority Act as amended 4483.230(4)). Utility-scale solar thermal plants were not considered because of high construction costs and low capacity factor during winter peak load periods. Peat, while a potentially promising resource, was not included because of uncertainties relative to availability and cost of fuel-grade supplies in the Railbelt region.

(a) Because of recent rapidly changing forecasts of oil prices and consumption, an addendum to the Executive Summary was prepared which describes the likely effects of recent forecasts on the results in this report. Such changes were anticipated and account for the major emphasis being placed on methodology development rather than forecasting, so that the State of Alaska could readily update its forecasts as economic conditions change.

Six plans[a] were developed using different combinations of these generation and conservation options:

Plan 1A - <u>"Present Practices" Without Upper Susitna</u> - includes the addition of about 400 MW each of natural gas combined-cycle and coal steam plants, and 430 MW of hydroelectric generation.

Plan 1B - <u>"Present Practices" With Upper Susitna</u> - includes the first stage of Watana (680 MW) and Devil Canyon (600 MW) dams of the Upper Susitna Project plus some natural gas combustion turbine and gas combined-cycle capacity.

Plan 2A - <u>"High Conservation and Renewables" Without Upper Susitna</u> - emphasizes conservation renewables such as refuse-derived fuels (50 MW) and wind (175 MW), as well as six smaller hydroelectric dams (about 600 MW). Some nonrenewable resources are also required.

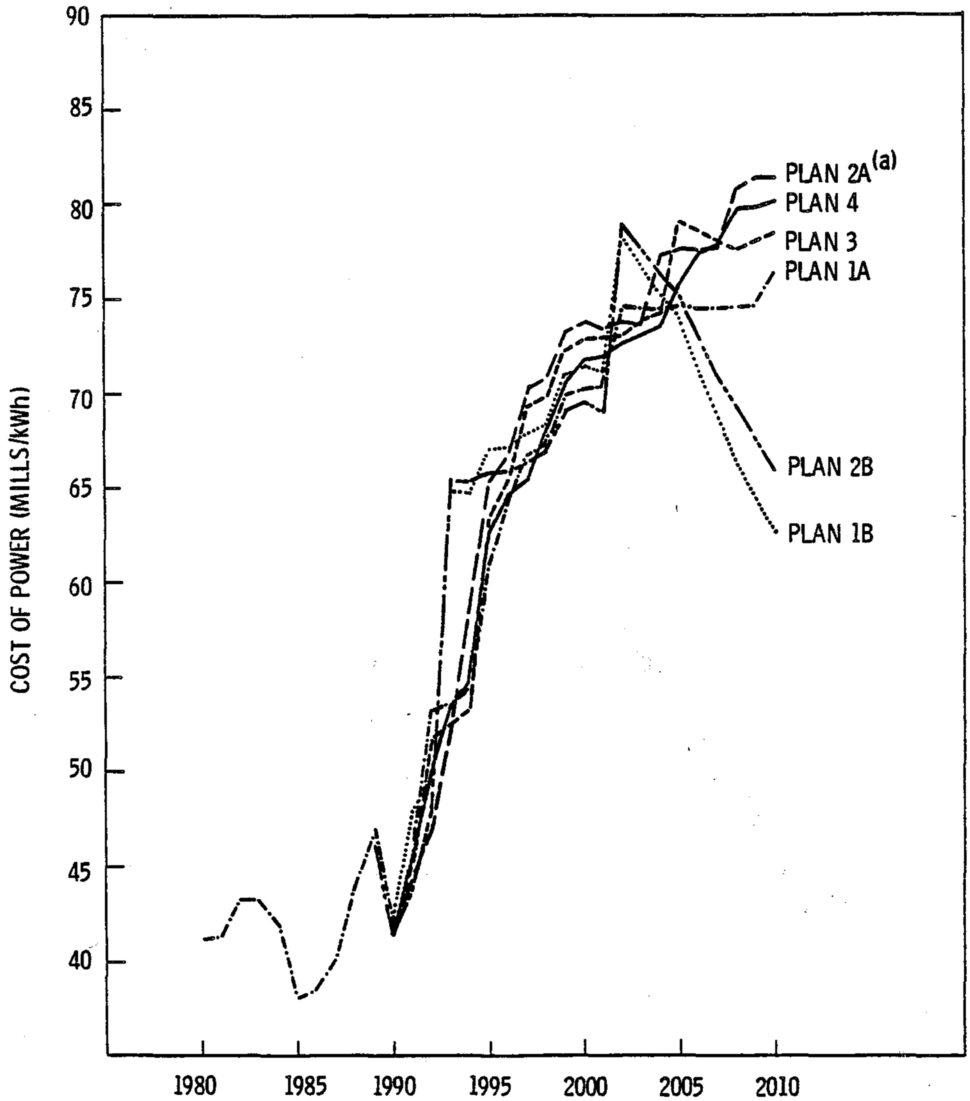
Plan 2B - <u>"High Conservation and Renewables" With Upper Susitna</u> - includes the Upper Susitna Project and lesser quantities of the other resources described in plan 2A.

Plan 3 - <u>"High Coal"</u> - is based on a transition from existing generating technologies to alternatives that directly or indirectly use coal as a fuel. It assumes that coal will be available from the Beluga area before the end of the decade. A small amount (100 MW) of hydrogeneration is developed.

Plan 4 - <u>"High Natural Gas"</u> - is based upon continued use of natural gas for generation in the Cook Inlet area, conversion to natural gas in the Fairbanks area, and the availability of North Slope gas before the end of the decade. As in Plan 3 a small amount of hydrogeneration is developed.

The annual average cost of power for the six plans is shown in the following figure. It is difficult to discern from the figure which plan has the lowest costs. It is clear, however, that the two cases which include the

(a) To assist the reader in identifying the content of each plan, a foldout sheet is included at the end of this report which contains the titles of the plans.



Comparison of Annualized Cost of Power for Railbelt Electric Energy Plans (1982 dollars)

(a) Plan 1A "Present Practices" Without Upper Susitna
1B "Present Practices" With Upper Susitna
2A "High Conservation and Renewables" Without Upper Susitna
2B "High Conservation and Renewables" With Upper Susitna
3 "High Coal"
4 "High Natural Gas"

Levelized Cost of Power for the Period 1981-2010 (mills/kWh)
(1982 Dollars)

	Low Economic Scenario	Medium Economic Scenario	High Economic Scenario
Plan 1A - "Present Practices" Without Upper Susitna	58	58	60
Plan 1B - "Present Practices" With Upper Susitna	58	58	58
Plan 2A - "High Conservation and Renewables" Without Upper Susitna	58	59	58
Plan 2B - "High Conservation and Renewables" With Upper Susitna	57	58	57
Plan 3 - "High Coal"	58	59	62
Plan 4 - "High Natural Gas"	57	59	61

Upper Susitna Project show the lowest costs after the turn of the century as they are amortized.

A second way to consider the elecrical energy costs is to express them as levelized costs (the equivalent of the present worth), and these are shown in the above table for three economic growth scenarios. Over the next 30 years there is no significant difference in the present value of the plans as measured by the levelized cost of electrical energy to the consumer, irrespective of economic growth. Energy costs range from a low of 5.7 cents/kWh to 6.2 cents (less than 5% difference).

There are several reasons for the similarity in consumer cost of power among the plans. First, given the long lead times in constructing generating facilities, all plans are virtually identical until after 1990. At the 3% discount rate used in this study, the present value of cost differences after 1990 is worth between 75% and 40% of what those differences would be if incurred today. Second, the differences in the power generating costs actually represent differences in generation and transmission costs only, but these tend to be obscured by the addition of local utility billing and distribution costs, which are assumed to be identical in all plans. Third, although there is still some difference among bus-bar energy costs of the various generating technologies included in the plans, the main generation options contained in each of the plans have fairly similar costs per kWh generated. Very high cost options were screened out in the selection of technologies to be included in the plans.

It is common in power planning to do all economic comparisons over the life of the longest-lived project. In the case of Susitna, its economic life extends to about 2050. Halting the analysis in the year 2010 would ignore the benefits of lower power costs after the year 2010 in plans containing Susitna. Assuming the relative annual costs of power for the plans remained constant from 2010 to 2050, the resulting power costs were discounted and annualized to get a levelized cost of power over the extended time horizon. These costs are shown in the following table. The differences between the plans containing the Upper Susitna project and the other plans are conservative because the annual costs of power would likely be growing in the latter cases and falling in the Susitna cases, not remaining constant as assumed.

Levelized Cost of Power for the Period 1981-2050 (mills/kWh)
(1982 Dollars)

	Low Economic Scenario	Medium Economic Scenario	High Economic Scenario
Plan 1A - "Present Practices" Without Upper Susitna	65	64	66
Plan 1B - "Present Practices" With Upper Susitna	63	59	60
Plan 2A - "High Conservation and Renewables" Without Upper Susitna	66	66	66
Plan 2B - "High Conservation and Renewables" With Upper Susitna	61	61	59
Plan 3 - "High Coal"	67	65	68
Plan 4 - "High Natural Gas"	64	66	68

There are several important assumptions underlying these results that relate to future fossil fuel prices, availability of Beluga coal, penetration of conservation options, availability of North Slope natural gas, and the capital cost of major facilities. Sensitivity analyses were performed to evaluate the importance of each assumption.

1. Fossil fuel prices were assumed to escalate at three rates above inflation: 2, 1, and 3% per year. At lower rates of escalation, those plans that rely on fossil fuels (1A, 3, and 4) are more competitive, and vice versa. The effect of continued escalation is most pronounced over the longer term and in the high economic growth scenario. Unfortunately, experts do not agree on whether fossil fuel prices will escalate faster, slower, or equal to general inflation but the general consensus appears to be that fossil fuel prices will escalate faster than general inflation over the long term.

2. The Beluga coal resource is assumed to be developed by 1988. Failure to develop that resource in this time frame would increase the power costs for Plans 1A and 3.

3. Plan 2A, and to a lesser extent Plan 2B, stresses conservation and assumes that a continuing State conservation grant program exists to encourage conservation efforts.

4. Plan 4 assumes the continued availability of Cook Inlet gas and the availability of natural gas from the North Slope by 1987. Unavailability of these resources for use in the Railbelt region would jeopardize this plan.[a]

(a) The future price of natural gas is also uncertain, for example, in the Fairbanks region. At low rates of oil price escalation, gas from the North Slope could have difficulty competing with oil in the Lower 48 states at $10.60/MMBtu (1982 dollars). If that is the case, then a netback price at the North Slope could be somewhat below the maximum legal $2.13/MMBtu assumed in the study. The minimum price would likely be $1.00 to $1.50 per MMBtu, or about 50 cents to $1.00 less than assumed. Prices below this would lead to the gas pipeline not being built. The future pipeline tariff could follow any of a number of scenarios. The likeliest is now considered to be a declining tariff that results in -4.3 percent per year change in gas prices in Fairbanks as shown in Volume VII. The study assumed the maximum wellhead price and constant real tariff. The lower price would improve the competitiveness of Plan 4 vis-a-vis the other plans.

5. Cost overruns of 20% in the Upper Susitna Project increase the present value of power cost in Plans 1B and 2B by about 5%. Similar overruns on thermal electric plants have little effect on power costs.

With the exception of capital cost overruns, the plan that is most insensitive to these assumptions is Plan 1B, which includes construction of the Upper Susitna Project. This plan provides either the lowest or nearly the lowest cost of power in all sensitivity tests over the extended time period. It is also the most resistant to inflation once it is completed. From an environmental impact standpoint, it is believed that fishery impacts can be mitigated, though dam construction can result in significant boom/bust and land-use effects.

The effect of a five-year delay in the Upper Susitna Project had little effect on levelized power costs for Plans 1B and 2B. While not specifically analyzed, the relatively small difference in power costs over the 30-year period suggests that a decision on which path to follow could be delayed for at least several years without affecting the present value of power, though the effects on annual cost of power might be significant. The effects of project delay on power costs appears worthy of continuing study. Delay might permit a clearer understanding of several technical-economic issues which could affect the power costs of the several plans. These include:

1. The re-evaluation of fossil fuel price escalation, especially for oil and gas.
2. The cost and effectiveness of conservation measures.
3. The competitivenes of advanced fossil fuel and renewable-based generating technologies.
4. The growth of electricity as an energy form compared to alternative forms of energy.
5. The resolution of air pollution issues (e.g., acid rain and CO_2) as they apply to fossil fuel uses.

With respect to institutional barriers, no Federal statutes, rules, or regulations absolutely prohibit implementing any of the plans, including the use of natural gas for generating electricity in new power plants. The Alaskan

Energy Program (as embodied in Senate Bill 25) does not preclude implementing any of the plans, with the exception of the energy conservation option, which appears to require new authorizing legislation. Some parts of the program may require court interpretation of the authorizing statute.

ADDENDUM TO EXECUTIVE SUMMARY: THE EFFECT OF LOWER OIL PRICES

The major change that has occurred since the data in the body of this report were calculated (January 1982) relates to future world petroleum prices. The range of increase of oil prices assumed in this study was 1% to 3% per year above inflation. As late as December 1981 the Alaska Petroleum Revenue Division (APRD) was projecting that the weighted average price of Prudhoe Bay-type crude oil would increase from $32.38 per barrel in 1982 to $117.56 in 1998--about an 8.4% nominal rate of increase or (given 7% inflation) about a 1.4% real price increase per year. The dramatic collapse of world oil prices in January through March of 1982 reduced nominal crude prices by between $4 and $6 per barrel and, among other things, divided oil analysts into two schools of thought--those foreseeing a stabilization of prices at about $25 per barrel and those forecasting further declines to as little as $15 per barrel. Even without substantial economic recovery in the United States and other major developed economies, it now appears that the OPEC market price has stabilized at $32 to $34 per barrel.

Industry sources now are forecasting real price increases for the 1980s ranging from minus 3.3% in constant dollars to plus 2.8%, with low-probability political crises resulting in possibly higher rates of increase (Oil and Gas Journal, May 17, 1982). The most recent APRD forecast (March 1982) for the weighted average price of Prudhoe Bay-type crudes is $29.84 per barrel in 1982 increasing to $87.95 per barrel in 1998, or about 7% per year (0% above the assumed 7% inflation). The netback wellhead price was assumed by APRD to increase annually at about 8.1% in nominal dollars (1.1% above inflation) due to market price increases and the TransAlaska Pipeline System (TAPS) tariff.

The lower starting point for oil prices and slower rate of increase now being forecast result in lower petroleum revenues for Alaska than were assumed in this study. The difference between the March and December APRD forecasts ranges from minus 8.0% for 1982 to minus 61.3% for 1998, but it could be greater since oil exploration activity and pipeline construction might be deferred or cancelled at the projected lower prices. The Alaska economy, which is heavily dependent on oil field activity and State spending, can be expected to grow at a slower rate with the lower oil prices foreseen in the new forecast. Moreover, because oil and natural gas prices would not rise as rapidly, the incentives for conservaton and for fuel switching to electricity by consumers would be reduced, possibly further reducing electricity demand beyond that projected for economic growth.

To estimate the effect of the State's revised oil price projections, calculations were made to determine whether the low-case (Case LL) government expenditures assumed in the study could be maintained with the lower State revenue projections. These calculations were made without the benefit of University of Alaska Institute of Social and Economic Research (ISER) economic models which had been used previously. The previous ISER low-case economy, population, and government expenditures forecasts were assumed. Other assumptions included:

- Petroleum revenues available for disbursement equal severance taxes plus 75% of royalties. APRD forecasts were used.
- General Fund revenues total the sum of available petroleum revenues, earnings of the General Fund and Permanent Fund, plus "other unrestricted" revenues (forecast to be about $728 million in FY 1985). This latter category includes other taxes, licenses, fees, permits, rents, intergovernmental receipts, investments, and miscellaneous. State Department of Revenue forecasts were used to FY 1982, and for subsequent years increased with inflation.
- The average balance in both the General Fund and Permanent Fund earns 10% per year throughout the forecast period.

The results of this comparison between new revenues and old expenditures to 1990 are shown in the following table. General Funds deficits occur after FY 1985. Since the State of Alaska cannot legally incur deficits at present, the level of expenditures would have to be below those previously shown in the low case. In turn, employment and population would be reduced below that in the low-case forecast.

Alaska Revised State Revenues and Low Case Expenditures
(Million $)

FY	Severance Tax Plus 75% of Royalties	General Fund Total Revenues(1)	General Fund Expenditures (Low Case)	Average General Fund Balance (2)
1982	2717.0	4292.5	3238.5	2481.1
1983	1932.0	2941.5	3539.2	1863.3
1984	2315.9	3113.4	3893.8	1090.5
1985	2695.0	3797.7	4322.9	539.8
1986	3130.8	4267.8	4913.4	-120.5
1987	3665.5	4889.9	5517.5	-627.6
1988	3759.8	5134.8	5907.3	-772.5
1989	4243.5	5708.1	6306.7	-598.6
1990	4294.8	5893.8	6789.5	-895.7

(1) May not correspond to Department of Revenues estimates because of differences in assumptions concerning General Fund expenditures (affecting the size of the balance), rate of return on General and Permanent Fund, and growth in nonpetroleum production revenues.

(2) General Fund balance is based on an assumed carryover from 1981 and earnings on the average General and Permanent Funds. It is not the sum and difference of the other columns because of carryover and fiscal calculations.

To estimate the likely size of the change, the moderate (Case MM) and low-case forecast of government employment was reduced to 40,000 persons in the Railbelt region in the years 1990 to 2000 (compared to 72,000 in the moderate case and 62,000 in the low case). Statewide government employment was reduced proportionately and the size of the Railbelt and statewide economies were re-estimated for the moderate and low-case forecasts. The revised results for the Railbelt region are summarized in the following table.

Without using the ISER econometric models it is not possible to state whether reducing government employment as assumed here would balance the State budget. However, if government employment in the Railbelt in 1990 were reduced to 40,000 and low-case government spending of $72,726 per worker for 1990 were maintained, General Fund expenditures would be about $4.5 billion in 1990. This about equals petroleum revenues for 1990, as shown in the initial table, and results in a substantial current General Fund surplus. It appears that the

Revised Year 2000 Forecast of Railbelt Employment and Population
(Thousands of Persons)

Case	Revised Government Employment	Basic Employment	Government Plus Basic	Revised Total Employment[a]	Revised Total Population[b]	Previous Total Population[c]
Moderate (MM)	40.0	56.5	96.5	178.5	385.6	484
Low (LL)	40.0	39.0	79.0	146.2	315.7	405

(a) Based on the low case ratio (1.85) of total employment to basic plus government employment.
(b) Based on the low case ratio (2.16) of population to employment.
(c) See Figure 3.3.

budget would be in approximate balance for the level of population and employment shown above.

The results indicate that reduced oil prices, through their effects on State government spending alone, could reduce Railbelt populaton by 80,000 to 100,000 persons by the end of the century. Population of the Railbelt would not reach 400,000 (in the moderate case) until about the year 2000 to 2005, instead of 1990. This could delay by about ten years when new electric generating facilities are needed.

The effect of reduced prices for oil on private sector development activity is more difficult to judge. It seems clear at this time (June 1982) that some North Slope activities will be delayed or not undertaken at all. The construction effects of the Alaska Natural Gas Transportation System (ANGTS) will be deferred until 1990 at least, and other projects such as coal or liquified natural gas (LNG) developments may experience delay or cancellation. Except for ANGTS deferral, this "future" looks very much like the low case described in the body of the report. The most likely forecast of the Railbelt economy based on present information probably lies between the revised moderate and low cases. This forecast can be expected to change as oil prices and the economy in general change.

The effect of this revised "future" on electricity consumption for the low and moderate cases is shown in the following table, given two additional

Revised Moderate and Low Case Electricity Forecasts, Railbelt

	Revised Annual Energy[a] (GWh)		Old Annual Energy (GWh)	
	Moderate	Low	Moderate	Low
1980	2551	2551	2551	2551
1985	3000	2560	3136	3028
1990	3391	3001	4256	3853
1995	3884	3164	4875	4063
2000	4010	3106	5033	3988
2005	4319	3332	5421	4278
2010	4986	3844	6258	4936

	Revised Peak Demand[b] (MW)		Old Peak Demand (MW)	
	Moderate	Low	Moderate	Low
1980	531	521	521	521
1985	615	525	643	621
1990	701	621	880	797
1995	791	652	993	837
2000	810	673	1017	815
2005	870	678	1092	870
2010	1003	780	1259	1001

(a) Revised downward based on low case annual consumption of 9.84 MWh per capita and moderate case annual consumption of 10.40 HWh per capita in the year 2000. See Appendix B, Tables B.3, B.4, B.12, and B.18. Other years consumption reduced proportionately. 1985 figures was adjusted upward judgmentally for moderate case; 1985-1995 adjusted upward for low case.
(b) Based on the ratio of peak demand to annual energy from Appendix B, Tables B.12 and B.18.

assumptions: 1) that per capita annual electricity consumption and 2) the ratio of peak demand to annual energy each year are the same as in the corresponding cases in the body of this report.

Reducing electrical load in proportion to the lowered population (as is done in the preceding table) probably overestimates electrical use, since at lower oil prices, more oil/gas and less electricity will likely be used (even though the cost of electricity generated with oil and gas decreases somewhat). The reduction in demand might be greater than that shown. However, historically, electricity demand in the Railbelt and other regions of the country has grown faster than population and might be expected to continue to do so because of rising real incomes, among other reasons. Moderate and low-case annual energy consumptions for the year 2000 based on the revised "future" and the assumptions stated above were calculated. Then the other years' figures shown in the above table were estimated on an equal proportional reduction from the corresponding case in the body of the report, but with some adjustments. The year 2010 peak demand for the moderate case decreases from 1259 MW in the old case to 1003 MW in the revised case, and for the low case from 1001 to 780. The revised moderate case does not include State spending as a major economic driver, but it does allow for private economic growth. It approximately tracks the old low case. The revised low case is about 20% less, and shows only modest growth in consumption, because neither State government growth nor private sector growth is available to stimulate consumption. The most likely case as viewed at present probably lies between the revised low and moderate cases.

The major change in the study conclusions relates to the Upper Susitna Project. A lower growth rate makes that project less attractive. While still the most resistant to inflation once it is completed, its power output would be larger than the Railbelt region could readily accommodate.

CONTENTS

FIGURES

TABLES

1.0 INTRODUCTION

One of Alaska's broad goals is to assure an adequate, long-term supply of electricity and other energy forms to its citizens and industries at the lowest cost consistent with environmental and socioeconomic considerations. Finding the "best" set of electrical generation and conservation options to meet this goal is not a simple undertaking. Many potential generation and conservation alternatives exist. Each has different costs, operating characteristics, availability, and environmental and socioeconomic impacts. The future requirements for electrical power and other energy forms are uncertain, and long lead times are often involved in increasing capacity to meet these requirements. The amount of electrical power required depends on the supply and price of other fuels as well as the extent of conservation. Electrical power alternatives cannot be analyzed outside the context of this interaction. Finally, even if a "best" solution is identified, many barriers, including institutional factors, may impede implementation.

Ultimately, the citizens and elected officials within Alaska must decide which set of electrical generation and conservation options comprise the "best" solution to the problem of assuring adequate electricity supplies in the future. The long-term consequences of committing to any one or a mix of generating alternatives may profoundly affect how the State of Alaska develops.

To assist in this planning process, the Office of the Governor, State of Alaska, Division of Policy Development and Planning and the Governor's Policy Review Committee contracted with Battelle, Pacific Northwest Laboratories to investigate potential strategies for future electric power development in the Railbelt region of Alaska. The major effort in this project was the development of models, forecasting methodologies, and data bases that would permit the State of Alaska to make its own forecasts to account for changing economic conditions and technologies. This report (Volume I of a series of seventeen reports listed in Appendix A) illustrates the use of the models and methodologies for a selected set of assumptions appropriate in late 1981 to early 1982. It is not a purpose of this report to recommend a single plan or "best" solution for the Railbelt region's electric power future. Rather it is a technical, economic, environmental and institutional analysis of a set of strategic development plans. These plans are compared with respect to cost of power, impact on the physical and human environment, and uncertainty of planning assumptions.

The Railbelt region, shown in Figure 1.1, contains three electrical load centers: the Anchorage-Cook Inlet Area, the Fairbanks-Tanana Valley area, and the Glennallen-Valdez area. The peak electrical load of these areas in 1980 was about 500 MWe. The generating capacity is comprised primarily of gas/oil-fired turbines with some coal steam and hydroelectric facilities. Because of the relatively small electrical requirements of the Glennallen-Valdez load center (~2% of the demand of the Anchorage-Cook Inlet area) it is not specifically analyzed as an individual load center, but is considered to be part of the Anchorage-Cook Inlet load center.

The study was comprised of four major tasks or activities, as illustrated in Figure 1.2:

- fuel supply and price analysis
- electrical demand forecasts
- generation and conservation alternatives evaluation
- development of electric energy themes or "futures" available to the Railbelt (Part 1), and systems integration/evaluation of electric energy plans (Part 2).

Each of the tasks contributed data and information to the final results of the project, but they also developed important results on the alternative electric generating technologies. These results are included in the reports listed in Appendix A.

The first task evaluated the price and availability of fossil fuels that could be used for electrical generation or for end-use applications, such as space or water heating, which compete with electricity. The results of this task influence the analysis-of-alternatives task and the electrical-demand forecasting task (Figure 1.2). Fuel supply and price help determine the selection of alternatives, since fuel prices often are a major determinant of the cost of power generation, and some fuels are competitors with electricity for various end applications. For example, if the price of electricity is high

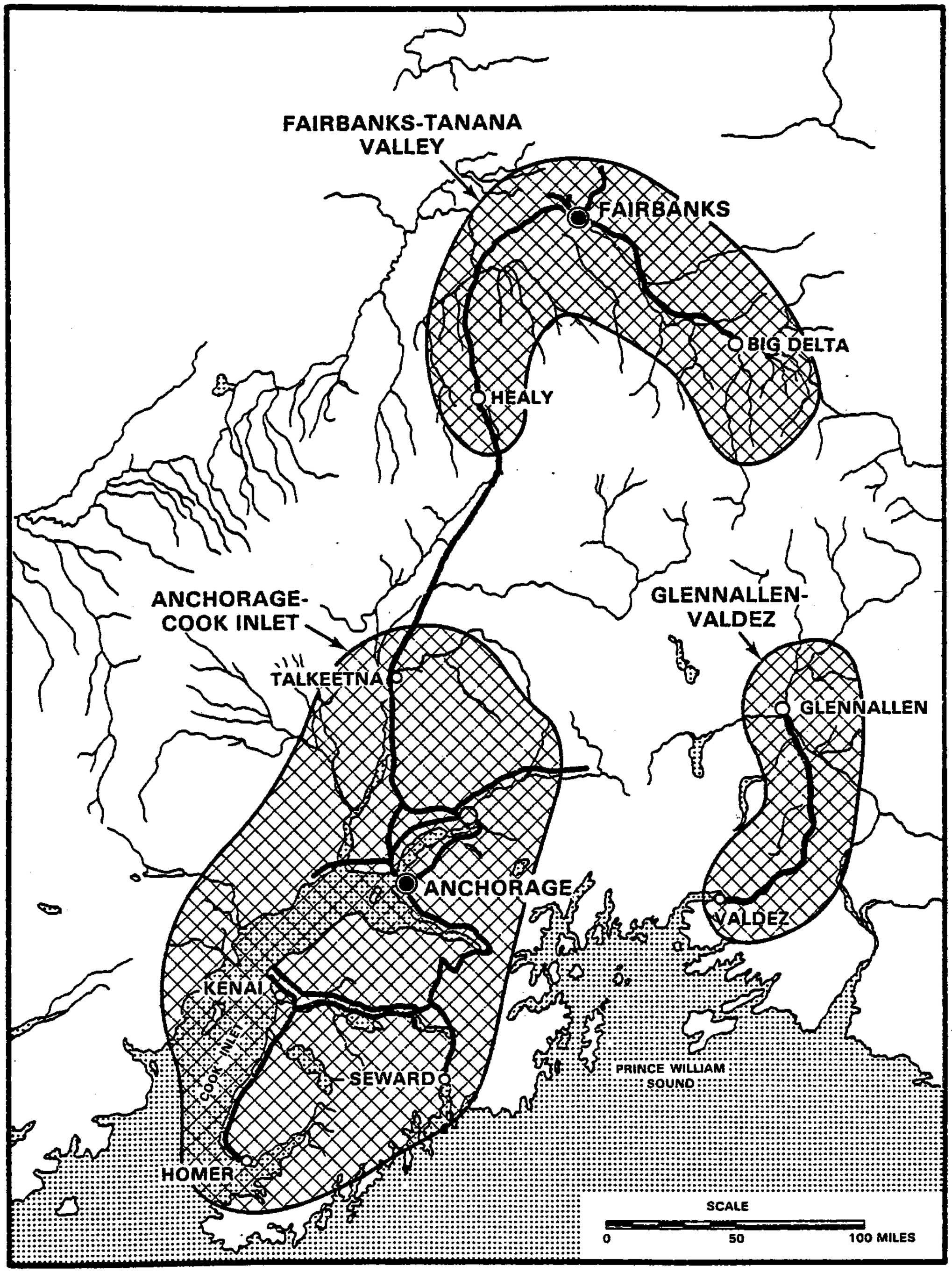


FIGURE 1.1. Railbelt Area of Alaska Showing Electrical Load Centers

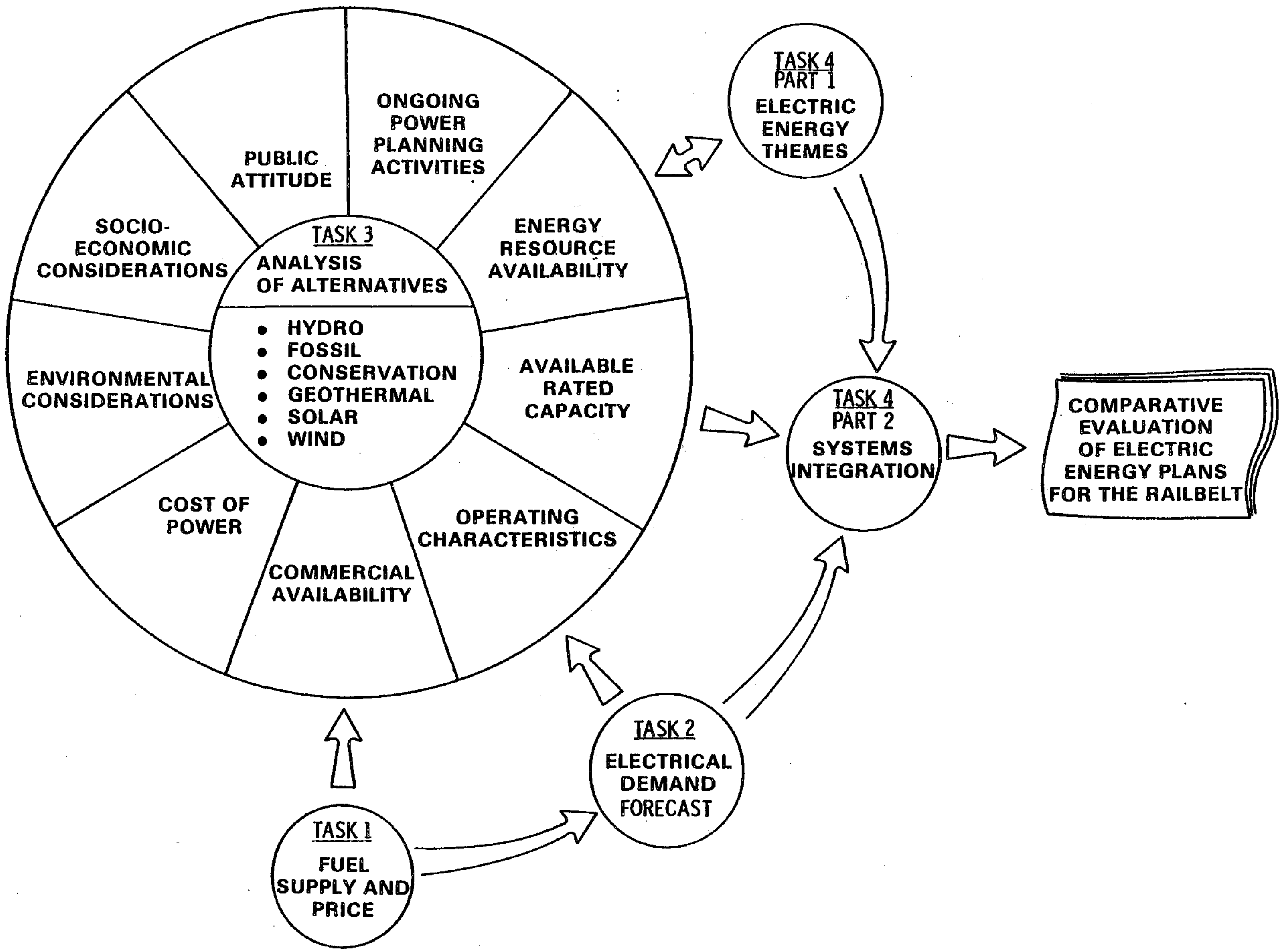


FIGURE 1.2. Study Flow Diagram

relative to the price of natural gas, then more new applications will use natural gas than if the price of electricity were low relative to the price of natural gas.

The second task, electrical-demand forecast, is important in determining both the size of generating units for the system and the number of generating units (or the total) generating capacity required.

Several generation and conservation alternatives are available to the Railbelt to meet forecasted electrical demand. The purpose of the third task was to identify electric power generation and conservation alternatives potentially applicable to the Railbelt region and to examine their feasibility, considering such factors as cost of power, environmental and socioeconomic effects, and public acceptance. Alternatives best suited to the region were then studied in depth and incorporated into one or more of the electric energy themes or plans.

The fourth task was performed in two parts. Part 1, the development of electric energy themes or plans, presents possible electric energy "futures" for the Railbelt. These plans, selected from the analysis-of-alternatives task, encompass a wide range of viable alternatives available to the region. They also include those futures currently receiving the greatest interest within the Railbelt (e.g., the Upper Susitna River Project). Each plan is defined by a set of electrical generation and conservation alternatives sufficient to meet the peak demand and annual energy requirements over the time horizon of the study (1981 to 2010). Cost-of-power analyses also are done for the 1981 to 2050 time period.

Part 2, the system integration/comparative analysis task, compared the electric energy plans. The major criteria used to evaluate and compare the plans were cost of power, environmental and socioeconomic impacts, and the susceptibility of the plan to future uncertainty in assumptions and estimates.[a]

Sections 2 through 5 of this report describe the results of each of the four tasks. The results of the comparative analysis are presented in Section 6; sensitivity analyses in Section 7; and consideration for implementing electric demand plans in Section 8.

(a) The assumptions used in this study are listed in Appendix E. Common financial premises used in this study were as follows: Cost estimates are expressed in January 1982 dollars, though costs cited in other volumes may be on other bases. Project financing was assumed to be public, at 3% (real) cost of debt, 100% debt financing. These assumptions are consistent with those used in recent studies sponsored by the Alaska Power Authority, including the Upper Susitna studies and to Cook Inlet tidal power studies.

To assist the reader in identifying the content of each plan, a foldout sheet containing the titles of the plans is included at the end of this report.

2.0 FUEL PRICE AND AVAILABILITY

One of the key components in electric power costs in the cost of fuel for generating the electricity. Some fuels are free, or essentially free, such as water for hydroelectric facilities, wind for wind turbines, and sunlight for solar generating devices. Some fuels comprise only a small part of the generating cost, such as uranium for nuclear power plants. Fossil fuels typically comprise a large fraction of generating costs. Their costs and long-term availability are very important considerations in developing a long-range electric energy supply strategy.

In this section the availability and price of fossil fuels over the forecast period 1980 to 2010 are estimated for the Railbelt region. Additional detail can be found in the Task I final report for the Railbelt Electric Power Alternatives Study (Volume VII-Fossil Fuel Availability and Price Forecasts for the Railbelt Region of Alaska).

In the assessment of fuel availability, only the in-state resource base is considered. If the fossil fuel resource is insufficient to supply Alaska's needs, the cost of transporting fuels to Alaska's markets causes in-state substitutes to become competitive. For example, the Cook Inlet natural gas resource may be inadequate to supply the needs of the southern part of the Railbelt region over the time horizon of the study, given no additional major finds. This gas could be supplemented with higher-cost liquified natural gas (LNG) imports, but then coal, oil, and North Slope gas become competitive substitutes.

When a current price for a fuel is not available, the concept of opportunity cost is used to develop the base price and forecast. This concept provides that the resource price is equal to the price that the resource will command in an alternative market, less appropriate transportation and handling costs. Alaska is familiar with this netback method of price determination, which is currently used for valuation of their royalty gas and oil resources. Table 2.1 and Figure 2.1 summarize fossil fuel availability and price faced by Alaska electric utilities for the forecast period.

The cost and availability of light water reactor fuel are not discussed because the present generation of light water reactors are too large to be incorporated in the Railbelt electrical system, and state statutes preclude nuclear power use in Alaska.

TABLE 2.1 Fossil Fuel Availability and Price

Fuel Type	Estimated Reserves	Availability	Price/MMBtu (January 1982 $)	Estimated Annual Real Escalation Rate
Coal				
Beluga/Cook Inlet	$350 \times 10^{(6)}$ tons	1988	1.48 Mine Mouth	2.1%
Nenana/Interior	$240 \times 10^{(6)}$ tons	Present	1.75 FOB Rail	2.0%
Natural Gas				
Cook Inlet[(a)]	3,900 Bcf	Present	0.86 City Gate	6.6% avg.
North Slope/Interior	21,500 Bcf	1987	5.92 City Gate[(b)]	0
Liquids	3,800 Bcf	1995		
No. 2 (Distillate) Fuel Oil	Adequate	Present	6.90 Delivered	2%
Peat	(c)	1988	(d)	1%
Municipal Solid Waste				
Anchorage	-	Present		
Fairbanks	-	Present		

(a) Volume weighted average price to Alaska Gas and Service and Chugach Electric Association.
(b) The price of North Slope gas to the interior is probably a range of prices, of which $5.92 is a maximum. It is expected to decrease over the period of this study (1981-2010) as the pipeline tariff decreases. This table shows the constant price used in calculations supporting this study. Volume VII contains the most current thinking on expected price. The net effect of the lower gas price is not expected to change electrical consumption in the Fairbanks region, (space heating would be done primarily with natural gas, even at the constant $5.92 gas price). However, the use of electricity is expected to increase somewhat in the Anchorage region under Plan 4 "High Natural Gas", since electricity generated with lower price gas might be able to compete successfully with gas at high and rising prices in Anchorage.
(c) Estimates of the peat resource in the Railbelt region are not currently available.
(d) Estimates range from 1 to 2.5 times the price of coal.

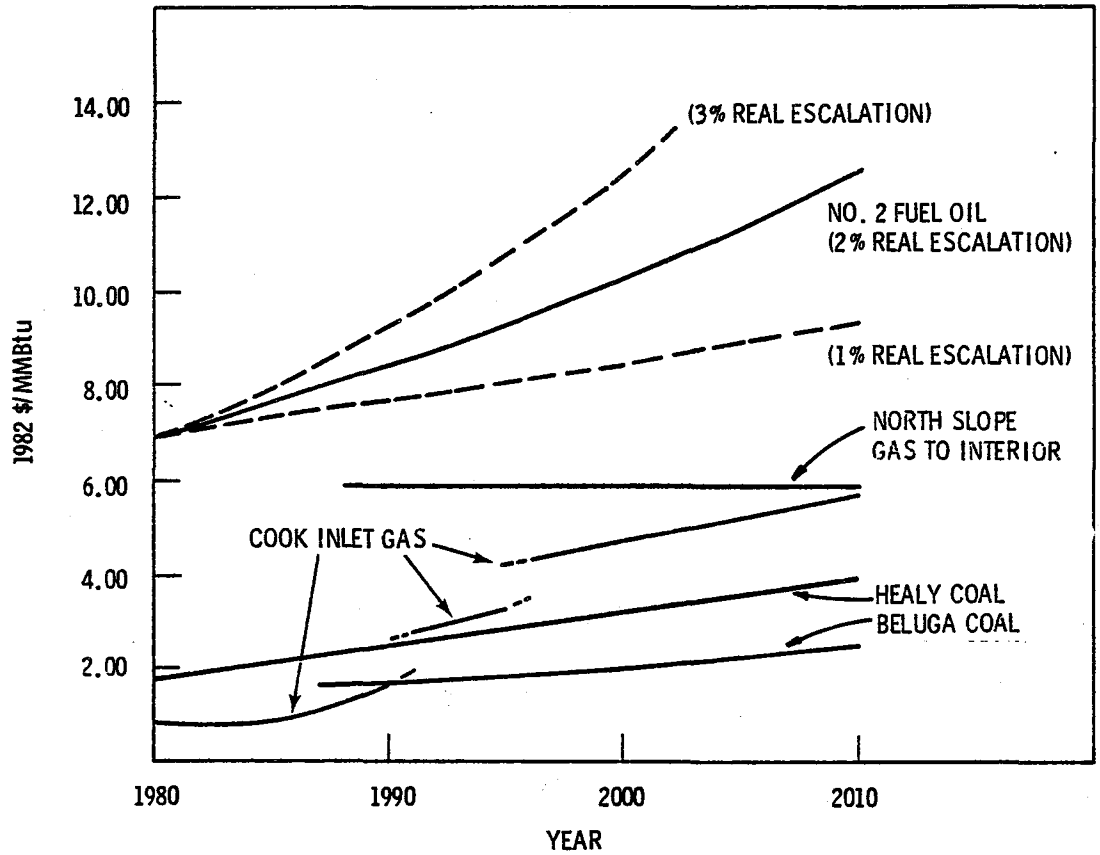


FIGURE 2.1. Projected Fuel Prices to Railbelt Utilities, 1982 $/MMBtu, 1980-2010

2.1 COOK INLET NATURAL GAS

The supply and price of Cook Inlet natural gas is the most complex of all the Railbelt fuels to analyze because contracts have established the quantity, current price, and price escalation rate for various portions of the gas, and the terms of these contracts differ. In addition, new or incremental supplies used to meet demand in excess of the contracted supply can be expected to be priced by their opportunity value, which is the net-back from liquid natural gas (LNG) sales to Japan. Determining the price for Cook Inlet gas requires a forecast of both price and quantity from each contractual source to develop the weighted average gas price for the region. The results of this forecasting is a price escalation that is not continuous over the forecast period. This uneven price escalation is evidenced in Figure 2.1 by the gas's constant price from 1980 to 1985 and its escalation over the rest of the period, with stepped increases occurring in 1990 and 1995 when major contracts expire. After 1995, the gas's price and escalation rate are determined by its opportunity value because current purchase contracts will have expired. The price of natural gas is assumed to escalate at approximately 2% faster than general inflation - the same real annual rate as for oil. Current information about Cook Inlet natural gas reserves and total demand on those reserves indicates that availability to the Alaskan market could become a major problem as early as 1990 and most certainly by the year 2000.

2.2 COAL

Two sources of coal are available to the Railbelt. One is the Usibelli mine located at Healy, the only commercial mine currently producing coal in Alaska. The second source is the Beluga coal field, which has been targeted as a potential source of supply for the Anchorage area and as an export to markets on the Pacific Rim. As discussed below, the Beluga coal field may enter production about 1988. The cost of Healy coal is assumed to escalate in real terms at the historical rate. Beluga coal is expected to escalate at the same rate as other coal supplies serving the Pacific Rim export market, or about 2.1% annually in real terms.

There is uncertainty about when the Beluga coal field will be devloped. These coal fields are now in the exploratory and predevelopment phase. They have yet to produce in significant quantity and thus, from an availability standpoint, must be considered prospective. These fields, while containing very large reserves, may require an export market for financing initial developement.

If coal-fired power generation becomes a significant factor in the Railbelt, generation capacity most likely would be added in increments of 200 or 400 MW. While mine mouth coal-fired generation stations of 400 MW or larger may be a large enough source of demand to justify opening the mine, a single 200 MW increment is a doubtful incentive, taken by itself. A firm take-or-pay contract for two million tons per year (an amount which could support 600 MW generating capacity) would be adequate incentive, as would a lesser amount, combined with firm contracts for 2 to 4 million tons of export. (The relatively large export market is needed to pay for shipping facilities.) Given the timing of additions to generation under the various plans, an export market may be a necessary precursor to the availability of Beluga coal for in-state use. While the Beluga fields could be developed for electrical generation only, the timing of such an operation would be critical (see Volume VII).

2.3 PEAT

Alaska has substantial peat reserves, although these reserves have not been comprehensively assessed. The peat resource is assumed not to be developed before Beluga coal. Although information for peat development in Alaska is lacking, a preliminary feasibility study (EKONO 1980) estimates a range of likely prices from about 1 to 2.5 times the price of coal on a Btu basis, depending upon the harvesting and processing method used. The only real escalation likely to occur is that associated with transportation and handling, set at less than 1% real annual rate.

Based upon current resource information and existing steam-electric generating technology, peat does not appear to be a competitive fuel for electrical generation in the Railbelt at present. However, because of the potential peat resources available within the area, it appears to warrant further investigation as technologies to use peat are further developed.

2.4 NATURAL GAS/INTERIOR

The North Slope reserves of natural gas are sufficient to supply the Alaska Natural Gas Transportation System (ANGTS) to capacity (2 to 2.4 Bcf/day) for the forecast period. This gas was assumed to begin flowing in 1987. If only Alaska's royalty share is diverted to serve the Fairbanks area, the supply of gas would be about 100 Bcf per year. A current estimate of the delivered price of gas to the "Lower 48" is about $10/MMBtu in 1982 dollars with the January 1982 maximum wellhead price of $2.13/MMBtu. The net-back provides a "city-gate" price to Fairbanks of about $5.92/MMBtu, declining to about $2.71 as the pipeline tariff declines. This gas is not scheduled to decontrol under existing law and escalates only with the rate of inflation, its price remains constant in real terms.

2.5 NATURAL GAS LIQUIDS/METHANOL

The delivery of natural gas liquids (NGL) to the Railbelt depends on the construction schedule for the ANGTS and the real price of crude oil. Current plans call for construction of an NGL pipeline following the ANGTS if a crude oil price in the range of $40 to $52/barrel (1982 dollars) is reached. This schedule provides for delivery of NGL in the mid to late 1990s.

Methanol production is tied closely to the ANGTS because the natural gas from that system would serve as the feedstock, but the timing of methanol production appears to be tied to petrochemical production that may accompany the NGL pipeline. Current methanol prices have been in the range of $0.90 to $1.00/gal. The net-back price at Alaska tidewater would range from $0.85 to $0.95/gal or $13.29 to $14.86/MMBtu. This price must incorporate Fairbanks city-gate price for the methane feedstock of ~$5.92/MMBtu, suggesting that production and transportation costs from Fairbanks to tidewater can be no greater than $7.34 to $8.91/MMBtu. Currently, methanol production is not cost competitive with other fuels in the "Lower 48" and is not projected to become cost competitive until after the year 2000.

2.6 FUEL OILS

Refined petroleum products are the only fuels in which Alaska is currently not self-sufficient. Alaska's royalty share of crude oil production is sufficient to meet in-state consumption at least through the year 2000, but refined products are imported because of insufficient refinery capacity. The supply of No. 2 fuel oils is not believed to be a problem through the forecast period, however. The current price of ~\$6.90/MMBtu for fuel oil is a good indicator of its current opportunity value, especially in view of the recent price decontrol on oil. Fuel oil (and crude oil) are expected to escalate at a 2% annual real rate, as shown in Table 2.1. Figure 2.1 also shows the price of No. 2 fuel oil over the forecast period for real annual escalation rates of 1% and 3%.

2.7 MUNICIPAL SOLID WASTE

The municipal solid waste (MSW), in sufficient quantities to support electricity generation, is limited to the two municipalities of Anchorage and Fairbanks. The resource has three problems: 1) limited availability, requiring MSW to be mixed with other fuels for electricity generation, 2) seasonal variations (more waste is generated in the summer than in the winter), and 3) limited storage life. However, it has two offsetting factors: 1) zero cost since there is no value placed on the waste, and disposal costs already exist to waste producers[a], and 2) escalation is expected in only transportation and handling. A limited amount of MSW-based generation appears feasible.

To summarize, coal will be the least expensive fossil fuel for electrical generation over the time span of the study, and beyond. There is an ample reserve of coal, and if the Beluga coal field is opened, it will lower the price even further. Natural gas is the next least expensive fuel. An adequate supply for Railbelt purposes depends on the availability of North Slope resources. The most expensive conventional fuel is No. 2 fuel oil. Other fuels having potential for electricity generation include peat and municipal solid waste.

(a) MSW as fuel might claim a negative price depending on the relative magnitude of collection costs and the offset disposal costs.

3.0 ANNUAL PEAK LOAD AND ENERGY REQUIREMENTS FORECASTS

The second consideration in developing the electric energy plans for the Railbelt region is a forecast of electrical demand. Forecasts typically take into account the following factors:

- future economic and population growth
- future changes in the age, size, and energy-use characteristics of households
- future growth in commercial building stock
- future price and availability of fuels that compete with electricity for such end uses as space and water heating (e.g., fuel oil, natural gas, and wood)
- application of conservation measures
- public policy actions directly affecting energy demand or the cost of power
- potentially new, large uses of electric power in industrial applications.

Since groups of these factors may interact in complex ways to produce a range of possible (but not equally plausible) forecasts, computer models were developed to determine how these factors individually and jointly affect demand estimates. The models, together with certain key assumptions concerning Alaska's economy and public policy and world prices for fossil fuels, produced forecasts of electricity demand at five-year intervals beginning 1980.

3.1 OVERVIEW OF DEMAND FORECASTING PROCESS

The electricity demand forecasting process used in this study is illustrated in Figure 3.1. It contains two steps. The first combines scenarios (economic and policy assumptions) with economic models to produce forecasts of future economic and industrial activity, population, and households in the Railbelt region. The second step combines these forecasts with data on current end uses of electricity in the residential sector, the size of the Railbelt commercial building stock, the cost and performance of

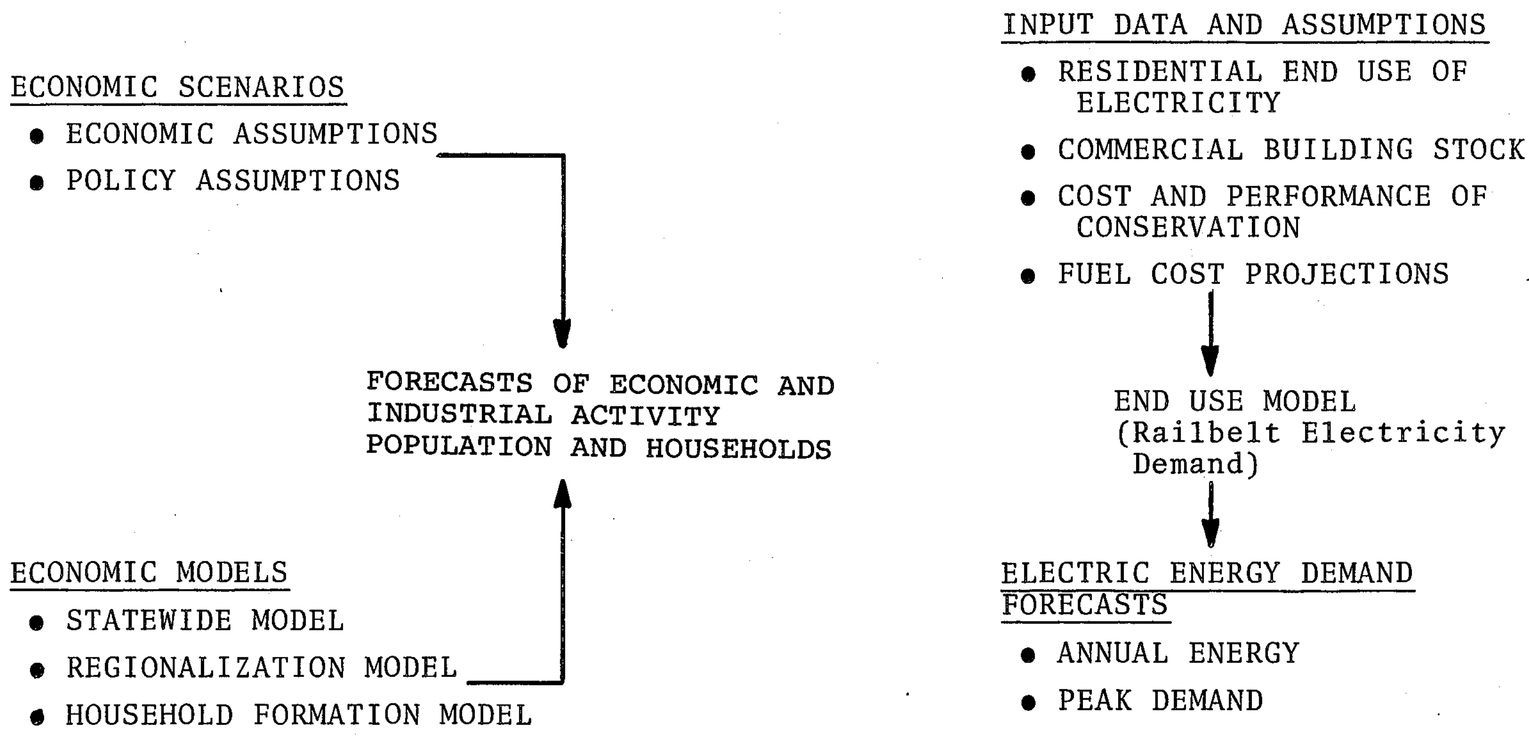


FIGURE 3.1. Electric Power Forecasting Process

conservation, assumptions concerning the future prices of electricity and other fuels, and future new uses of electricity, to produce demand forecasts.

These data and assumptions are entered into a computer-based electricity demand forecasting model called the Railbelt Electricity Demand (RED) Model.[a] The RED model generates forecasts of the amount of housing and commercial floor space (including government buildings), their energy use as affected by cost of the energy, and the proportion of energy used as electricity. Major industrial and military electrical energy demand and miscellaneous uses, such as street lighting, are estimated separately.[b] These forecasts and estimates are adjusted for energy conservation policies and combined by the model into forecasts of future annual demand for electric energy for each of the Railbelt's load centers (Figure 1.1). Annual peak loads are derived from the annual demand. The peak loads are added together and multiplied by a diversity factor (to adjust for the fact that peak loads do not coincide in time) to derive the peak demand for the Railbelt.

The projected cost of power affects these forecasts. The demand for power affects the size, number, and cost of generating facilities, which in turn affects the cost of power. Several interations through the RED model with a single set of economic assumptions and varying costs of power are required to produce a final forecast, as described in Section 6.0.

Each of the foregoing steps in the Demand Forecasting Process is described in greater detail in the following sections.

3.2 ECONOMIC SCENARIOS

The economic scenarios used to produce the demand forecasts are shown in Figure 3.2. The scenarios are characterized by combinations of assumptions concerning private economic activity and State of Alaska fiscal policy. The private economic assumptions are principally composed of assumed levels of development in Alaska's basic or export sector. (A summary of the private sector projects and growth rates is contained in Appendix B to this report.

(a) A complete description of the RED model is contained in Volume VIII.
(b) The forecasts produced for this report do not include military electrical consumption or industrial self-generated electricity because neither is assumed to be part of the electric utility load addressed in this study.

PRIVATE ECONOMIC ACTIVITY

STATE SPENDING	HIGH	MODERATE	LOW
HIGH	HH, SH		
MODERATE		MM, IM, CC	
LOW			LL

HH — HIGH ECONOMIC GROWTH, HIGH STATE SPENDING

SH — HIGH ECONOMIC GROWTH, HIGH STATE SPENDING, PLUS EXTRA INDUSTRIALIZATION PROJECTS

MM — MODERATE ECONOMIC GROWTH, MODERATE STATE SPENDING

IM — MODERATE ECONOMIC GROWTH, MODERATE STATE SPENDING, PLUS EXTRA INDUSTRIALIZATION PROJECTS

CC — MODERATE ECONOMIC GROWTH, NON-SUSTAINABLE SPENDING

LL — LOW ECONOMIC GROWTH, LOW STATE SPENDING

FIGURE 3.2. Economic Scenarios

Additional detail can be found in Goldsmith and Porter (1981), Volume IX, a report on the Railbelt economy done for this study by the University of Alaska Institute of Social and Economic Research.) The future spending of the State of Alaska is expected to be a major driving force in the Alaskan economy during the time horizon for this study (1980 to 2010). Different levels of State spending in each forecast year were assumed. The following assumptions are made for the three basic scenarios:

- High - State spending (basic operating and capital budget) grows at 1.5 times the growth rate of real per capita income in Alaska.
- Moderate - State spending grows at the same rate as real per capita income.
- Low - State spending is constant in real per capita terms (falls as a percent of real per capita income).

Combinations of private economic activity and State fiscal policy were chosen for analysis (Figure 3.2). The combinations of high economic growth and high State spending, moderate growth and spending, and low growth and spending constitute the basic scenarios. The high case (case HH) has been given a subjective probability of 0.05 to 0.10; that is, there is a 5 to 10% chance that economic growth will exceed this level. The moderate case (case MM) is given a subjective probability of 0.5. There is a 50% chance that growth will be at least this large, and a 50% chance that it will be less. The low case (case LL) is given a subjective probability of 0.9 to 0.95. There is a 90 to 95% chance that economic growth will be at least this large, with a 5 to 10% chance that it will be less.

Several additional cases were selected to test the sensitivity of the assumptions. The first two cases, Cases SH and IM, measure the effect of major industrialization projects on the Railbelt's economy, population, and electrical demand.[a] Several large industrial energy users were added to

(a) One school of thought believes that major manufacturing activity could be drawn to Alaska by the prospect of abundant and perhaps relatively inexpensive energy. Previous work by Battelle-Northwest and others (Swift et al. 1978; Dow-Shell 1981) suggests that currently this is not very likely; however an ongoing study on this specific question is being done for the State of Alaska by SRI, International.

moderate and high scenarios assuming that they would be located in the Railbelt and they purchase the bulk of their electric power from the utilities in the region. The third case (CC) assumes that State spending will not be sustained if Prudhoe Bay oil production begins to decline in the 1990s. This scenario assumes very high capital spending in the 1980s. Details on the assumptions are contained in Goldsmith and Porter (1981).

Several other sensitivity tests that did not involve changes in economic activity were also analyzed (Section 7.0). One includes the effect of a major state direct cash investment to defray part or all of the capital cost of electrical generation facilities. This has the effect of reducing the price of power to the consumer with large increases in demand. For purposes of this sensitivity test, reducing the price of power was assumed not to affect the level of economic growth. (Such price-induced economic growth may occur, but sufficient research has not been done on the question to say how large the growth response might be.) The effects of recent lower oil prices are summarized in the addendum to the Executive Summary.

3.3 ECONOMIC MODELS

The scenarios described above were analyzed by three economic models modified by the Institute of Social and Economic Research (ISER) for this study. The first was an ISER economic and population model of Alaska, usually called MAP.[a] MAP calculates statewide employment by broad sectors (basic, support, and government) and statewide population. The results from MAP are entered into a second model, a regionalization model that allocates economic growth to census division and then reaggregates the results to the Railbelt's electrical demand (load) centers. The third model (now a part of MAP) calculated the total number of households in the State for each year and for each estimate of population growth.

(a) MAP is an acronym for Man in the Arctic Program. Several key parameters in the MAP modeling framework underwent extensive testing in this study, and econometric equations of the model were re-estimated based on actual data through 1979 (and where data were available, through 1980). Details of the research conducted by ISER on the models are contained in Volume IX.

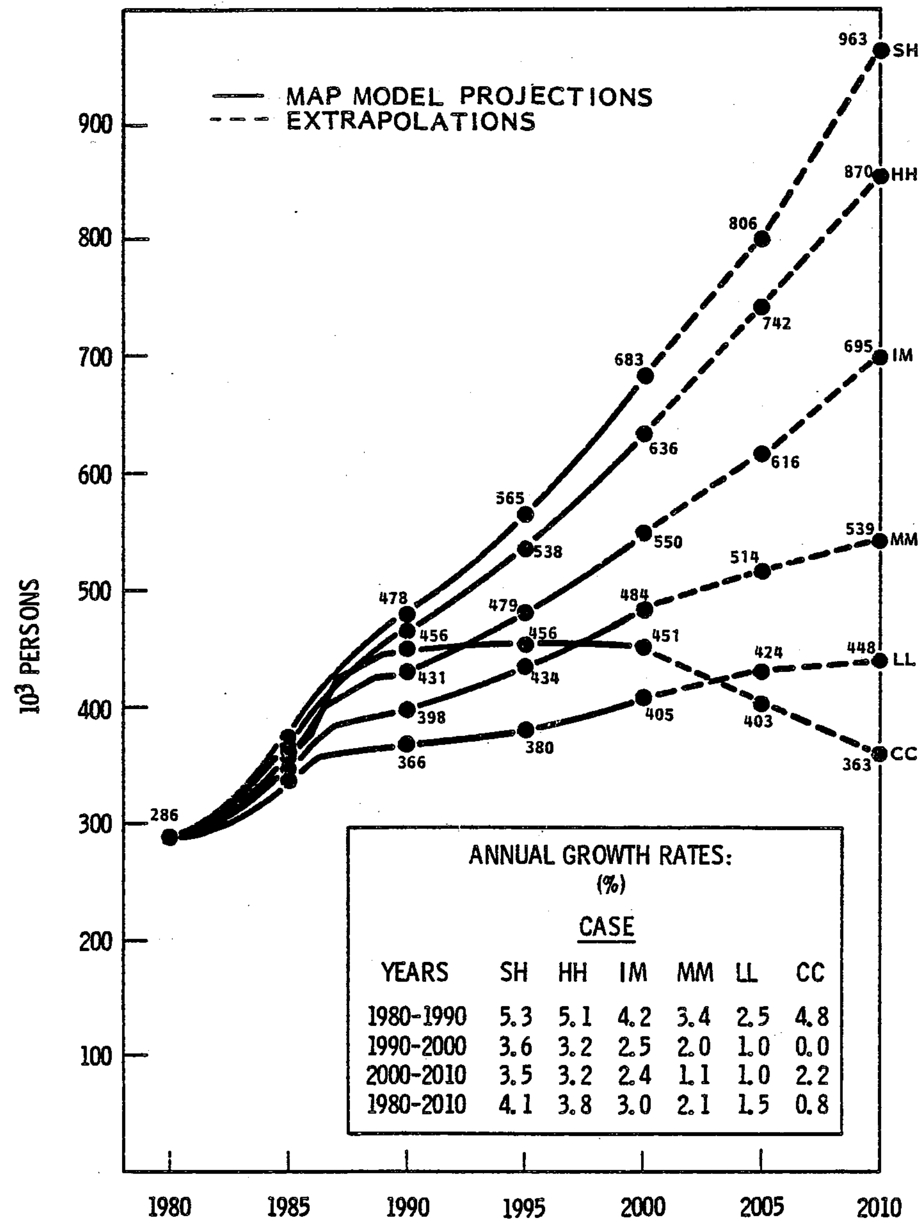
3.4 FORECASTS OF ECONOMIC AND INDUSTRIAL ACTIVITY, POPULATION AND HOUSEHOLDS

The population forecasts for the Railbelt region produced by these codes are summarized in Figure 3.3. The solid-line forecasts to the year 2000 were produced by the MAP model. The forecasts were then extrapolated to the year 2010 (dashed lines). The detailed employment, population, and household forecasts for the Railbelt and its load centers from which these projections are derived, are reported in Appendix B. Population growth rates vary considerably among cases, but most cases show decelarating growth during the period. The base case (moderate growth-moderate State spending - MM) shows an annual rate of population growth averaging 3.4% during the 1980s and 2.1% per year for the 30-year average. This compares with 3.4% in the 1970s, with 6.7% from 1970 to 1975 and 0.1% from 1975 to 1980. Railbelt population is forecast to grow from 286,000 to about 539,000. The high growth, high State spending case (HH) shows an average growth rate of 3.8%, resulting in a population of about 870,000 in year 2010. The low-low case (LL) shows 1.5% growth and a population of 448,000. The cases that include large projected industrialization add about 0.3% to 0.9% to growth rates in the high and moderate cases, respectively.

The nonsustainable spending case (CC), which is based on moderate private sector economic growth but very high initial State government spending, shows growth rates in the 1980s comparable to those in the high case. As State spending declines in the 1990s, population growth stagnates and then falls as employment declines. Population falls below the low case about year 2003 and continues downward to about the same as the 1985 level (about 363,000).

3.5 END USE MODEL (RAILBELT ELECTRICITY DEMAND MODEL)

The Railbelt Electricity Demand (RED) forecasting model was described briefly in Section 3.1. In addition to the capabilities previously described, the RED model includes a mechanism for handling uncertainty in some of the parameters, a method for explicitly including programs designed to subsidize or mandate conservation, and the ability to forecast peak electric demand by load center. The model recognizes the three load centers: Anchorage-Cook Inlet (including the Matanuska-Susitna Borough and the Kenai Peninsula);



ANNUAL GROWTH RATES: (%)

CASE

YEARS	SH	HH	IM	MM	LL	CC
1980-1990	5.3	5.1	4.2	3.4	2.5	4.8
1990-2000	3.6	3.2	2.5	2.0	1.0	0.0
2000-2010	3.5	3.2	2.4	1.1	1.0	2.2
1980-2010	4.1	3.8	3.0	2.1	1.5	0.8

FIGURE 3.3. Railbelt Population

Fairbanks-Tanana Valley and Glennallen-Valdez. It produced forecasts for each five-year period from 1980 to 2010.

The RED model operates as shown in Figure 3.4. A simulation begins with the Uncertainty Module (1) by selecting a trial set of model parameters. These parameters include demand-price elasticities, appliance saturations, housing stock demand coefficients, load factors, peak demand correction factors, and penetration rates for conservation. Exogeneous forecasts (2) of economic activity, population, and retail prices for fuel oil, gas, and electricity are used with the trial parameters to produce forecasts of housing stock (3) and electricity consumption in the residential (4) and business (5) modules. These latter forecasts, along with additional trial parameters, are used in the conservation module (6) to model the effects on consumption of subsidized conservation activities. The revised forecasts of residential and business (commercial and government) consumption are used to estimate future miscellaneous consumption (7). Assumed large industrial consumption (8) is added to produce total electricity sales (9). Finally, the initial and the revised consumption forecasts are used with a trial forecast of system load factor to estimate peak demand (10) in each load center. The model then returns to start the next trial. The model usually reaches a consistent forecast in about two iterations.

3.6 ELECTRIC ENERGY DEMAND FORECASTS

A summary of the RED model forecasts of electricity consumption and demand for the Railbelt is shown in Figures 3.5 and 3.6.[a] In the moderate case (MM), future consumption of electric energy (Figure 3.5) is forecasted to

(a) Since the supply plan chosen to generate electricity in the Railbelt can itself influence energy consumption, the forecasts in Figures 3.5 and 3.6 are based on electric energy plan 1A, which assumes the addition of about 400 MWe of gas combined-cycle and coal steam plants, and 430 MWe of hydroelectric generation. The electric energy plans are described in Section 6, and the effect of supply plans on demand in Section 7. The electricity demands for the other economic scenarios and electric energy plans are presented in Appendix B.

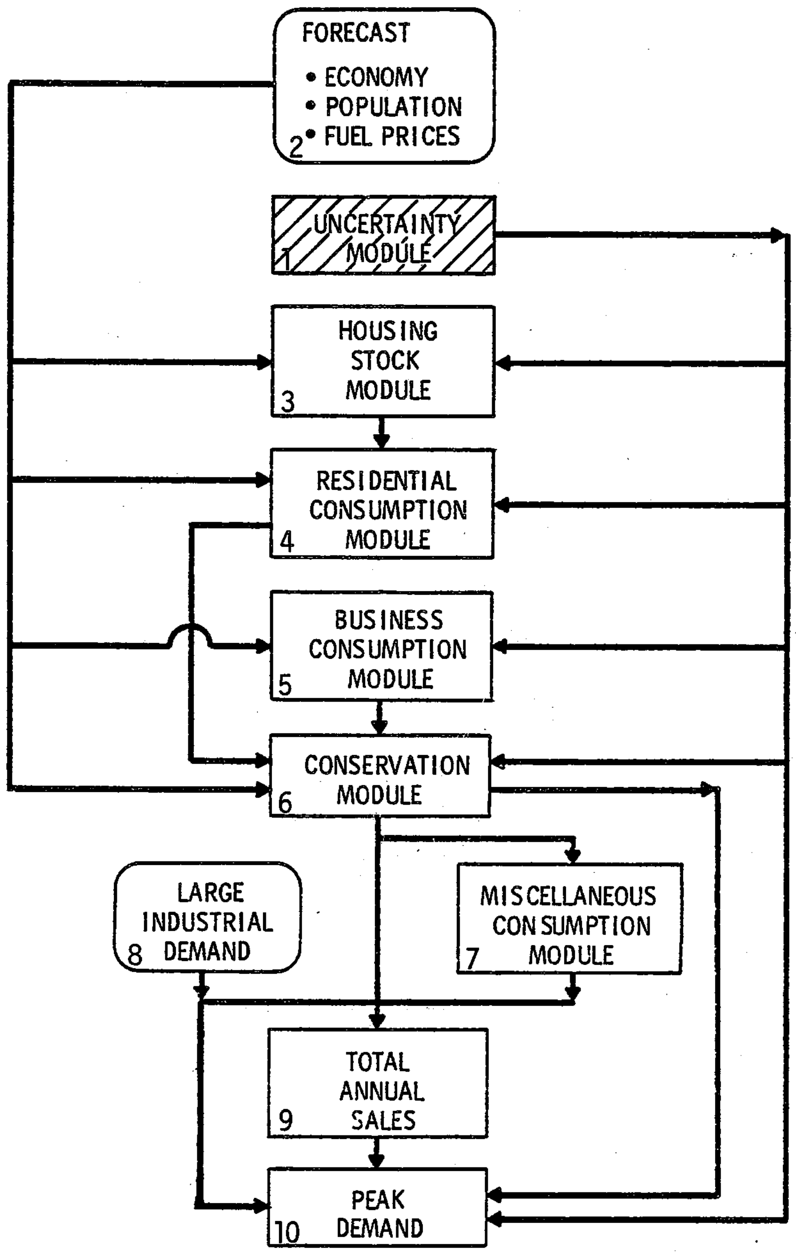


FIGURE 3.4. Railbelt Electricity Demand (RED) Model

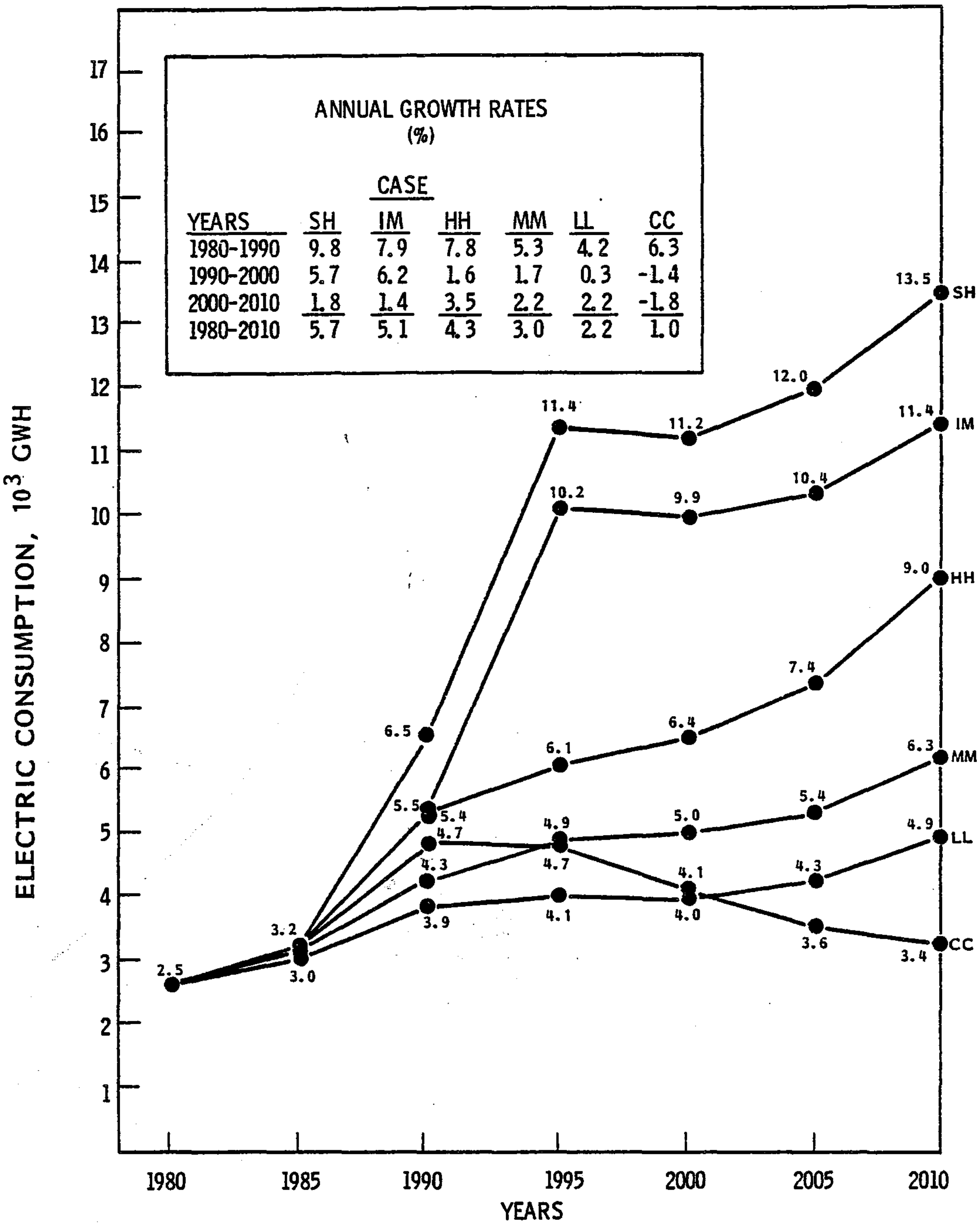


FIGURE 3.5. Railbelt Annual Electricity Consumption, 1980-2010[a]

(a) Excluding military and industrial self-supplied electricity.

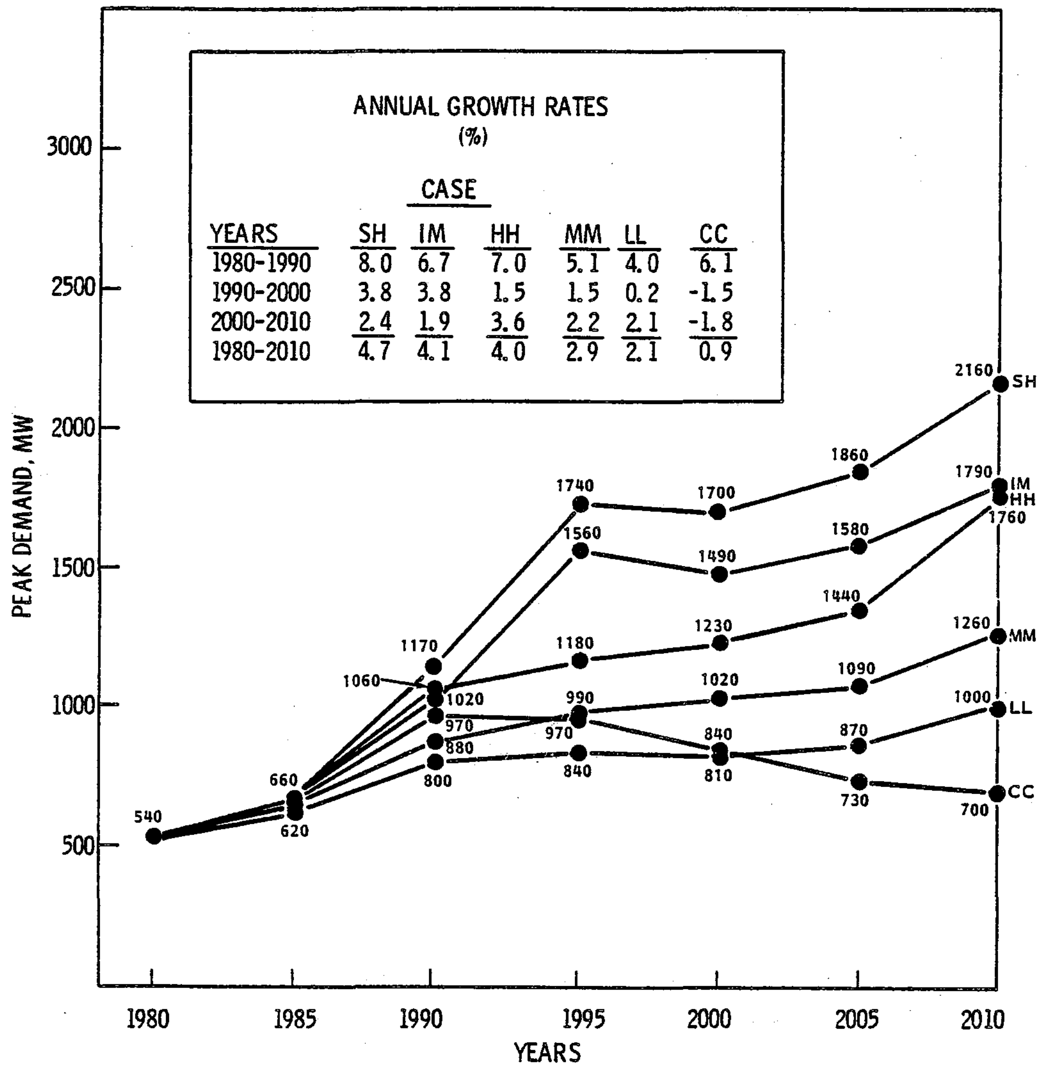


FIGURE 3.6. Railbelt Annual Peak Demand, 1980-2010[(a)]

(a) Excluding military and industrial self-supplied electricity.

average ~3.0% between 1980 and 2010, from 2500 gigawatt hours (GWh) to 6300 GWh. This results in a per capita increased use of ~0.9% per year. As previously stated, there is about a 50% probability that the growth rate will be greater for this case, and about a 50% probability that it will be less. The low (LL) case grows at 2.2% per year to 4900 GWh in year 2010. Only a 2.5% to 5% probability exists that growth in electricity use will be less than this rate.[a] The high (HH) case shows an average growth rate of 4.3% per year to 9000 GWh. There is a 95% to 97.5% probability that growth will be less.

Substantial industrialization (cases SH and IM) add 1.4 and 2.1 percentage points to the 30-year growth rates in the high and moderate cases, respectively, and result in year 2010 use that is 50% to 81% above the corresponding high and moderate cases. The near-term growth (through 1995) is very large. The industrialization scenarios are unlikely to occur, however, with projected power costs in the 60 to 80 mills/kWh range.

The unsustainable spending case (CC) shows only 1.0% average annual growth during the period, with a 1980 to 1990 rate of 6.3% and 2000 to 2010 rate of minus 1.8%. Per capita use, which grows at 0.9% in the MM case and as high as 2.1% annual in the IM case, grows in the CC case at only 0.2% annual average over the forecast period. The CC case results in demand that is about 400GWh above the MM case in 1990, but about 290 GWh per year below the MM case in the year 2010. Because the unsustainable spending (CC) case is so heavily dependent on State fiscal policy, no probability estimate is attached to it.

The peak demands for electric power are shown in Figure 3.6. The present peak demand of 540 MW increases to 1760 MW for the high case, 1260 MW for the medium case, and 1000 MW for the low case by the year 2010.[a] In the industrialization cases, SH and IM, major industrial electricity users are assumed to have constant loads, thereby contributing proportionately less to

(a) Economic growth assumed in this case is such that only a 5% to 10% probability exists that it would be lower. The LL projection forecasts median demand given the economic scenario. The probability of a forecast being below the LL line is then 0.05 to 0.10 (the probability of the economic scenario) times 0.5 (the probability of a forecast being below the median), or 0.025 to 0.005.

system peak than to annual consumption. Peak demand average growth rates in these cases are 1.0% less than annual energy growth rates. The industrialization cases result in a net increase of 400 MW over the high case (to 2160 MW) and 530 MW over the moderate case (1260 MW) in the year 2010. The unsustainable spending case (CC) again results in the lowest demand by the year 2010, a decline of 28% from 1990 demand, and 560 MW below the moderate case MM.

To summarize, the estimated growth in electric power peak demand, based on econometric modeling studies, is expected to increase from 540 MW at present to about 1260 MW in 2010, with a range of 700 to 2160 MW, depending on economic activity and State spending.

(a) The growth rates in peak demand in the three cases (HH, MM, LL) average 0.1% greater than the corresponding growth rates in annual energy demand; e.g., moderate case peak demand averages 2.9% per year. These growth rates are greater because the ratio of system peak load to annual electrical load is assumed to remain constant through the forecast period, except for specific energy conservation effects and large industrial use for which demand information was available. This assumption is replaced in Section 7, where the load factors are allowed to vary. As a part of the study, an attempt was made to determine the impact of changing energy uses on peak load. However, Railbelt utilities were unable to break out the effect of end uses in current (1981) peak demand.

4.0 ELECTRICAL ENERGY GENERATING AND CONSERVATION ALTERNATIVES

Having established the bounds of electrical generation growth in the Railbelt region to the year 2000--from the present 540 MW peak to between 700 and 2160 MW--the electric power generation and conservation alternatives were selected and analyzed. The first portion of this section describes the selection of generating alternatives, including a brief technical description, the rationale for selection, and the prototypical plants and sites used to develop the data required for assessing Railbelt electric energy plans. It concludes with a summary of cost and performance characteristics of the selected generation alternatives. The second portion describes conservation alternatives and technologies, and the rationale for their selection.

4.1 GENERATING ALTERNATIVES

The generating alternatives required for the Railbelt electric energy plans were selected by identifying a broad set of candidate technologies, constrained only by the availability of suitable resource bases in the Railbelt and the ability to place them in commercial service prior to year 2000. The candidate technologies were evaluated based on several technical, economic, environmental, and institutional considerations. Using the results of this evaluation, a set of more promising technologies was then identified. Finally, prototypical generating facilities (specific sites in the case of hydroelectric generation) were identified and analyzed in greater detail.

Resources currently used in the Railbelt for electricity generation include coal, natural gas, petroleum-derived liquids, and hydropower. Energy resources that could be developed within the planning period of this study include peat, wind power, solar energy, tidal power, geothermal, municipal solid waste fuels, and wood waste. While light water reactor fuel could be readily supplied to the Railbelt, economic considerations and state statutes preclude the use of nucler power reactors.

Candidate electric generating technologies using these resources and available for commercial order prior to year 2000 are listed in Table 4.1. The 37 generation technologies and combinations of fuel conversion-generation

TABLE 4.1. Candidate Electric Energy Generating Technologies for The Railbelt

Resource Base	Principal Sources for Railbelt	Fuel Conversion	Generation Technology	Typical Application	Availability for Commercial Order
Coal	Beluga Field, Cook Inlet Nenana Field, Healy	Crush	Direct-Fired Steam-Electric	Baseload	Currently Available
		Gasification	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload	1985-1990 1985-1990 1990-1995
		Liquefaction	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Station Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload/Cycling Baseload	1985-1990 1985-1990 1985-1990 1990-1995
Natural Gas	Cook Inlet North Slope	None	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Station Fuel-Cell - Combined-Cycle Combustion Turbine	Baseload Baseload/Cycling Baseload/Cycling Baseload Baseload/Cycling	Currently Available Currently Available 1985-1990 1990-1995 Currently Available
Petroleum	Cook Inlet North Slope	Refine to distillate and residual fractions	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Stations Fuel-Cell - Combined-Cycle Combustion Turbine Diesel Electric	Baseload Baseload/Cycling Baseload/Cycling Baseload Baseload/Cycling Baseload/Cycling	Currently Available Currently Available 1985-1990 1990-1995 Currently Available Currently Available
Peat	Kenai Peninsula Lower Susitna Valley	None	Direct-Fired Steam-Electric	Baseload	Currently Available
		Gasification	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload	1990-2000 1990-2000 1990-2000
Municipal Solid Waste	Anchorage Fairbanks	Sort & Classify	Direct-Fired Steam-Electric	Baseload[a]	Currently Available
Wood Waste	Kenai Anchorage Nenana Fairbanks	Hog	Direct-Fired Steam-Electric	Baseload[a]	Currently Available

TABLE 4.1. (contd)

Resource Base	Principal Sources for Railbelt	Fuel Conversion	Generation Technology	Typical Application	Availability for Commercial Order
Geothermal	Wrangell Mountains	--	Hot Dry Rock-Steam-Electric	Baseload	1990-2000
	Chigmit Mountains	--	Hydrothermal-Steam-Electric	Baseload	Currently Available
Hydroelectric	Kenai Mountains	--	Conventional Hydroelectric	Baseload/Cycling	Currently Available
	Alaska Range	--	Small-Scale Hydroelectric	(b)	Currently Available
			Microhydroelectric	Fuel Saver	Currently Available
Tidal Power	Cook Inlet	--	Tidal Electric	Fuel Saver	Currently Available
			Tidal Electric w/Retime	Baseload/Cycling	Currently Available
Wind	Isabell Pass	--	Large Wind Energy Systems	Fuel Saver	1985-1990
	Offshore		Small Wind Energy Systems	Fuel Saver	1985-1990
	Coastal				
Solar	Throughout Region	--	Solar Photovoltaic	Fuel Saver	1985-1990
			Solar Thermal	Fuel Saver	1995-2000
Uranium	Import	Enrichment & Fabrication	Light Water Reactors	Baseload	Currently Available

(a) Supplemental firing (e.g. with coal) would be required to support baseload operation due to cyclical fuel supply.
(b) May be baseload/cycling or fuel saver depending upon reservoir capacity.

technologies shown in the table comprised the candidate set of technologies selected for additional study.[a]

"Technology profiles" were prepared describing the technical performance and cost, environmental and socioeconomic characteristics, and potential Railbelt applications of the candidate technologies (Volume IV). The profiles were used in the analysis of the candidate technologies to determine which should be included in Railbelt electric energy plans. This selection was based on the following considerations:

- the availability and cost of energy resources
- the likely effects of minimum plant size and operational characteristics on system operation
- the economic performance of the various technologies as reflected in estimated busbar power costs
- public acceptance, both as reflected in the framework of electric energy plans within which the selection was conducted and as impacting specific technologies
- ongoing Railbelt electric power planning activities.

From this analysis[a] 13 generating technologies were selected. For each nonhydroelectric technology, a prototypical plant was defined. For the hydro-electric technologies, promising sites were selected for further study. In the following paragraphs, each of the 13 preferred technologies is briefly described, along with some of the principal reasons for its selection. Also described are the prototypical plants and hydro sites selected for further study.

4.1.1 Coal-Fired Steam-Electric Plants

Coal-fired steam-electric plants combust coal in a boiler, producing steam that is used to drive a steam turbine-generator. Coal-fired steam-electric generation was selected because it is a commercially mature and economical technology that potentially is capable of supplying all of the Railbelt's

(a) Further discussion of the selection process and technologies rejected from consideration at this stage are provided in Volume IV.

baseload electric power needs for the indefinite future. An abundance of coal in the Railbelt should be mineable at costs allowing electricity production to be economicaly competitive with all but the most favorable alternatives throughout the planning period.

The sulfur content of Railbelt coal is low. Commercially tested devices for controlling sulfur and particulate emissions to levels mandated by the Clean Air Act are available. Principal concerns using this technology are environmental impacts of coal mining, possible ambient air-quality effects of residual oxides of sulfur (SO_x), oxides of nitrogen (NO_x), and particulate emissions, long-term atmospheric buildup of CO_2 (common to all combustion-based technologies) and the long-term susceptibility of busbar power costs to inflation.

Two prototypical facilities were chosen for in-depth study: a 200-MW plant in the Beluga area that uses coal mined from the Chuitna Field; and a plant of similar capacity at Nenana that uses coal delivered by Alaska Railroad from the Nenana field at Healy. The results of the prototypical study are documented in Volume XII.

4.1.2 Coal Gasifier - Combined Cycle Plants

These plants are comprised of coal gasifiers that produce synthetic gas for combustion turbines that drive electric generators. Heat-recovery boilers use the combustion turbine exhaust heat to raise steam to drive a steam turbine-generator. These plants are expected to be commercially available in the 1985 to 1990 time frame.

These plants should use Alaskan coal resources at costs comparable to conventional coal steam-electric plants, while providing environmental and operational advantages compared to conventional plants. Environmental advantages include less waste-heat rejection and water consumption per unit for output due to higher plant efficiency. Better control of NO_x, SO_x, and particulate emission is also afforded. From an operational standpoint, these plants offer a potential for load-following operation, broadening their application to intermediate loading duty.[a] Because of superior plant

(a) However, much of the existing Railbelt capacity most likely will be available for intermediate and peak loading during the planning period.

efficiencies, coal gasifer-combined-cycle plants should be somewhat less susceptible to inflation of fuel costs than conventional steam-electric plants. Principal concerns with these plants include environmental impacts of coal mining, CO_2 production, and uncertainties in plant performance and capital cost due to the current state of technology.

A prototypical plant was selected for in-depth analysis. This 200-MW plant would be located in the Beluga area and use coal mined from the Chuitna Field. The plant would use oxygen-blown gasifiers of Shell design, producing a medium Btu synthesis gas for combustion turbine firing. The plant would be capable of load-following operation. The results of the study of the prototypical plant are described in Volume XVII.

4.1.3 Natural Gas Combustion Turbines

These plants consist of combustion turbines fired by natural gas to drive electric generators. Although of relatively low efficiency, natural gas combustion turbines serve well as peaking units in a system dominated by steam-electric plants. The short construction lead times characteristic of these units also offer opportunities to meet unexpected or temporary increases in demand. Except for production of CO_2 and potential local noise problems, these units produce minimal environmental impact. The principal economic concern is the sensitivity of these plants to escalating fuel costs.

The costs and performance of combustion turbines are well understood. However, because a major component of future Railbelt capacity additions most likely would not consist of combustion turbines, no prototype was selected for in-depth study. Analysis of this technology within the context of Railbelt electric energy plans was based on data compiled in the technology profiles (Volume IV).

4.1.4 Natural Gas - Combined-Cycle Plants

These plants consist of combustion turbines fired by natural gas to drive electric generators. Heat recovery boilers use combustion turbine-exhaust heat to raise steam to drive steam turbine generators.

Natural gas - combined-cycle plants were selected for consideration because of the current availability of low-cost natural gas in the Cook Inlet area and the possible future availability of North Slope supplies in the Railbelt (although at prices higher than those currently experienced). Combined-cycle plants are the most economical and environmentally benign method currently available to generate electric power using natural gas. The principal economic concern is the sensitivity of busbar power costs to increases in natural gas costs. The principal environmental concern is CO_2 production and possible local noise problems.

A nominal 200-MW prototypical plant was selected for further study. The plant, located in the Beluga area, would use Cook Inlet natural gas. The results of the analysis of this prototype are documented in Volume XIII.

4.1.5 Natural Gas Fuel-Cell Stations

Natural gas fuel-cell stations are expected to be available for commercial order in the 1985 to 990 period. These plants consist of a fuel conditioner to convert natural gas to hydrogen and CO_2, phosphoric acid fuel cells to produce dc power by electrolytic oxidation of hydrogen, and a power conditioner to convert the dc power output of the fuel cells to ac power. Fuel-cell stations most likely would be relatively small and sited near load centers.

Natural gas fuel-cell stations are considered for the Railbelt primarily because of their superior load-following characteristics. Plant efficiencies are likely to be far superior to combustion turbines and relatively unaffected by partial power operation. Capital costs are likely to be comparable to combustion turbines. These cost and performance characteristics should lead to significant reduction in busbar power costs and greater protection from escalation of natural gas prices compared to combustion turbines. Construction lead time should be comparable to combustion turbines. Because environmental effects most likely will be limited to CO_2 production, load-center siting will be possible and transmission losses and costs will be reduced.

No prototypical plant was selected for further study. Data for the analysis of these facilities were taken from the technology profiles (Volume IV).

4.1.6 Natural Gas Fuel-Cell - Combined-Cycle Plants

Thes plants are expected to be available in the 1990 to 1995 period. They consist of a fuel conditioner that converts natural gas to hydrogen and carbon dioxide, molten carbonate fuel cells that produce dc power by electrolytic oxidation of hydrogen, and heat recovery boilers that use waste heat from the fuel cells to raise steam for driving steam turbine-generators. A power conditioner converts the dc fuel cell output to ac power for distribution. If they attain commercial maturity as envisioned, fuel-cell combined-cycle plants should demonstrate a substantial improvement in efficiency over conventional, combustion turbine-combined-cycle plants. The reduction in fuel consumption promised by the forecasted lower heat rate of these plants could result in a baseload plant less sensitive to inflating fuel costs and less consumptive of limited fuel supplies than conventional combined-cycle plants (and may be limited to baseload operation). Likely capital costs are not well-understood, however, due to the immaturity of this technology.

Because of the early stages of development of these plants, additional study was believed to yield little additional useful information. Consequently, no prototypical plant was selected for study. Information to support analysis of Railbelt electric energy plans was drawn from the technology profiles (Volume IV).

4.1.7 Large and Intermediate-Scale Hydroelectric Plants

Substantial hydro resources are present in the Railbelt region. Much of this could be developed with large- or intermediate-scale hydroelectric plants (i.e., those larger than 15 MW). Several sites have the potential to provide power at first-year costs competitive with thermal alternatives and have the added benefit of long-term resistance to inflation. Hydroelectric options produce no atmospheric pollution or solid waste, but they can destroy or transform habitat in the area of the reservoir, impact wilderness value and associated recreational opportunities, and have negative impacts on downstream and anadromous fisheries. High capital investment costs render many sites noncompetitive with alternative sources of power.

Several large-scale hydroelectric projects were selected for consideration in Railbelt electric energy plans:

- Bradley Lake
- Chakachamna
- Upper Susitna (Watana and Devil Canyon)
- Snow
- Keetna
- Standline Lake
- Browne.

Bradley Lake was selected for consideration because of its advanced stage of planning. Information was taken primarily from its power market analysis (Alaska Power Administration 1977). The Chakachamna project is a lake tap project with relatively modest capital costs and environmental effects. The proposed project is of sufficient size (up to 1923 GWh average annual energy production) to make a significant contribution to meeting future Railbelt electric energy demand, yet not so large as to result in underutilization when operational. Data were obtained from two sources, an investigation commissioned as part of this study (Volume XIV) and the ongoing Bechtel feasibility study (Bechtel Civil and Minerals 1981). The Upper Susitna Project was selected for consideration because of its importance in the Alaska energy picture. Data were obtained from Acres American Incorporated (1981).[a]

Based on environmental and economic considerations, the Snow, Keetna, Standline Lake, and Browne hydroelectric projects were among several hydroelectric projects (along with the Chakachamna Project discussed above and the Allison Project discussed in the subsequent section) identified by Acres American (1981) as preferred hydroelectric alternatives to the Upper Susitna Project. Snow, Keetna, Strandline Lake, and Browne were selected from this set as having the most favorable costs and environmental effects. Data on the Snow, Keetna, and Strandline Lake projects were taken from the Upper Susitna Development Study (Acres American 1981). A study of the Browne project was commissioned, partly because of its estimated capacity and energy projection,

(a) Information superseding that provided in Acres American (1981) was supplied by a letter from J. D. Laurence of Acres American to J. J. Jacobsen of Battelle, Pacific Northwest Laboratories.

which was somewhat greater than the others, but also because of its apparently modest environmental impact (Volume XV).

4.1.8 Small-Scale Hydroelectric Plants

Small-scale hydroelectric plants include facilities having rated capacity of 0.1 MW to 15 MW. Several small-scale hydro sites have been identified in the Railbelt region and two currently undeveloped sites (Allison and Grant Lake) have been subject to recent feasibility studies. Although typically not as economically favorable as conventional hydro because of higher capital costs per installed kw, small-scale hydro affords similar long-term protection from inflation and may be of more appropriate size for small load centers than large projects. The environmental effects of small-scale hydro tend to be proportionally less than for conventional hydro development, especially since many of these projects are run-of-the-river or lake tap designs and do not involve development of a reservoir. Run-of-the-river projects, however, may be intermittent producers of power due to seasonal variation in streamflow.

Two small-scale hydroelectric projects were selected for consideration in Railbelt electric energy plans: the Allison hydroelectric project at Allison Lake near Valdez and the Grant Lake hydroelectric project of Seward. These two projects appear to have relatively favorable economics compared with other small hydroelectric sites and relatively minor environmental impact (each is a lake tap project). Information to support analysis of these alternatives was taken from the feasibility study recently completed on each (Corps of Engineers 1981; CH_2M-Hill 1981).

4.1.9 Microhydroelectric Systems

Microhydroelectric systems are hydroelectric installations rated at 100 kW or less. They typically consist of a water-intake structure, a penstock and turbine-generator. The units typically operate on run-of-the-stream without reservoirs. The technology is commercially available.

Microhydroelectric systems were chosen for analysis because of public interest, their renewable character and potentially modest environmental impact. Information on typical power production costs was not available when the preferred technologies were selected. Further analysis indicated that few microhydroelectric resources could be developed for less than 80 mills/kWh.

Their contribution would likely be minor. Because of the limited potential of this resource it was dropped from consideration. However, installations at certain sites, for example residences remote from distribution systems, may be justified.

4.1.10 Large Wind Energy Conversion Systems

Large wind energy conservation systems consist of machines of 100 kW capacity and greater. These systems typically would be installed in clusters in areas of favorable wind resource and would be operated as central generating units. Operation is primarily in the fuel-saving mode because of the intermittent nature of the wind resource. The technology is in the demonstration stage.

Large wind energy conversion systems were selected for several reasons. Several areas of excellent wind resource have been identified, notably in the Isabell Pass area of the Alaska Range, and in coastal locations. The winds in these areas are strongest during fall, winter, and spring months, coinciding with the winter-peaking electric load of the Railbelt. Furthermore, developing wind energy projects in the Railbelt would prove complementary to hydroelectric systems. Surplus wind-generated electricity could be readily "stored" by hydro reservoirs. Hydro operation could be used to assume loads during periods of wind insufficiency. Wind machines could provide additional energy, whereas excess installed hydro capacity could provide capacity credit. Finally, wind systems have few environmental effects with the exception of their visual presence; they appear to have widespread public support.

A prototypical large wind energy conversion system was selected for further study. The prototype consisted of a wind farm located in the Isabell Pass area comprised of ten 2.5 MW-rated capacity, Boeing MOD-2, horizontal axis wind machines. The results of the prototype studied are provided in Volume XVI.

4.1.11 Small Wind Energy Conversion Systems

Small wind energy conversion systems are small wind turbines of either horizontal or vertical axis design, rated at less than 100-kW capacity. Machines of this size would generally be installed at dispersed locations. The technology is commercially available but still developing.

Small wind energy conversion systems were selected for consideration for several reasons. Within the Railbelt, selected areas have been identified as having superior wind resource potential. The resource is renewable. Finally, power produced by these systems could be marginally economically competitive with generating facilities currently operating in the Railbelt. As previously stated, these machines operate in a fuel-saver mode because of the intermittent nature of the wind resource. Their economic performance can be analyzed only by comparing their busbar power cost to the energy cost of power they displace.

Data on small wind energy conversion systems were taken from the technology profiles (Volume IV). Analysis of this alternative indicated that 20 MW of installed capacity producing 40 GWh of electric energy annually could be economically developed at 80 mill energy costs, under the rather unlikely assumption of full penetration of the available market (all households). These machines were given parity with firm generating alternatives for cost of power comparisons. Because the potential contribution of this alternative is relatively minor to future Railbelt needs, even under the rather liberal assumptions of this analysis, the potential energy production of small wind energy conversion systems was not included in the analysis of Railbelt electric energy plans.

4.1.12 Tidal Power

Tidal power plants typically consist of a "tidal barrage" extending across a bay or inlet that has substantial tidal fluctuations. The barrage contains sluice gates to admit water behind the barrage on the incoming tide, and turbine-generator units to generate power on the outgoing tide. Tidal power is intermittently available, and requires a power system that can complement the output of the tidal plant. Hydro capacity is especialy suited for this purpose. Alternatively, energy storage facilities (pumped hydro, compressed air, storage batteries) can be used.

Tidal power was selected for consideration because of the substantial Cook Inlet tidal resource, the renewable character of this energy resource, and the substantial interest in the resource as evidenced by the recently completed first-phase assessment of Cook Inlet tidal power development (Acres American Incorporated 1981a).

The specific alternatives considered for this study were four variations on the Eagle Bay alternative recommended for further study in the Cook Inlet tidal power study preliminary assessment:

- 720-MW Eagle Bay tidal electric project without retiming
- 720-MW Eagle Bay tidal electric project with pumped storage
- 1440-MW Eagle Bay tidal electric project without retiming
- 1440-MW Eagle Bay tidal electric project with pumped storage.

Estimated production costs of a tidal power facility without retiming would be competitive with alternative sources of power, such as coal-fired power plants, if all power production could be used effectively, e.g., by a specialized industry able to accommodate to the predictable, but cyclic output of the plant. Otherwise the costs would not be competitive. Alternatively, only the portion of the power output that could be absorbed by the Railbelt power system could be used. The cost of this energy would be high relative to other power-producing options because only a fraction of the potential energy production could be used. An additional alternative would be to construct a retiming facility, such as a pumped storage plant. Due to the increased capital costs and power (pumping) losses inherent in the retiming option, busbar power costs would still be substantially greater than for nontidal generating alternatives.

4.1.13 Municipal Solid Waste (MSW) Fuel Steam Electric Plants

These plants consist of boilers, fired by the combustible fraction of municipal refuse, that produce steam for the operation of steam turbine-generators. Rated capacities typically are small due to the difficulties of transporting and storing waste, a relatively low energy density fuel. Supplemental firing by fossil fuel may be required to compensate for seasonal variation in waste production. The technology is mature, though not widely used at present.

Enough MSW appears to be available in the Anchorage and Fairbanks areas to support small MSW fuel-fired steam-electric plants if supplemental firing (using coal) were provided to compensate for seasonal fluctuations in waste availability. The cost of power from such a facility appears to be competitive, although this competitiveness depends upon receipt of waste-derived fuel at little or no cost. Advantages of disposal of municipal waste by combustion may outweigh the somewhat higher power costs of such a facility compared to coal-fired plants. The principal concerns relative to this type of plant relate to potential reliability, atmospheric emission and odor problems. Data for MSW-derived fuel steam electric plants were taken from the technology profiles (Volume IV).

Cost and performance characteristics of the alternatives discussed above are summarized in Table 4.2. Additional information on each is available in the references cited; completed tabulations of the characteristics of these alternatives are provided in Volume II.

4.2 CONSERVATION ALTERNATIVES

Two general classes of conservation measures were selected for study. The first class, residential building conservation, includes several specific measures for improving the insulation and weather tightness of residential structures. The objective of the measures is to improve the end-use efficiency of fuel used for space heating, e.g., wood, oil, natural gas, or other fuels, as well as electricity. Also include in the residential class are measures designed to improve the thermal insulation and efficiency of hot water heating systems. Again, the fuel conserved may be natural gas, oil or wood, in addition to electricity.

The second class of conservation measures considered were those involving substitution of a nonelectric fuel for electricity. Consideration was given to measures involving the substitution of a renewable resource for electricity and included passive solar space heating systems, active solar hot water and space heating systems, and wood as a residential space heating fuel.

The effects of conservation alternatives in the Railbelt region were accounted for in the Railbelt electric energy plans by assessing the effects of these measures in reducing electric demand. Technical limits on market penetration were established first. The performance and cost characteristics of promising measures then were assessed. Based on the costs and value of energy savings of the various conservation measures, the levels of adoption were then established using the demand forecasting model. Thus, the contribution of conservation measures to meet future power needs in the

TABLE 4.2. Summary of Cost and Performance Characteristics of Selected Alternatives (Jan. 1982 dollars)

Alternative	Capacity (MW)	Heat Rate (Btu/kWh)	Availability (%)	Average Annual Energy (GWh)	Capital Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)
Coal Steam-Electric (Beluga)	200	10,000	87	(f)	2090	16.70	0.6
Coal Steam-Electric (Nenana)	200	10,000	87	(f)	2150	16.70	0.6
Coal Gasifier-Combined Cycle	220	9,290	85	(f)	-	14.80	3.5
Natl. Gas Combustion Turbines	70	13,800(a)	89	(f)	730	48	(e)
Natl. Gas Combined Cycle	200	8,200(b)	85	(f)	1050	7.30	1.7
Natl. Gas Fuel Cell Stations	25	9,200	91	(f)	890	42	(e)
Natl. Gas Fuel Cell Comb. Cyc.	200	5,700	83	(f)	-	50	(e)
Bradley Lake Hydroelectric	90	-	94	347	3190	9	Nil
Chakachamna Hydroelec. (330 MW)(c)	330	-	94	1570	3860	4	Nil
Chakachamna Hydroelec. (480 MW)(d)	480	-	94	1923	2100	4	Nil
Upper Susitna (Watana I)	680	-	94	3459	4669	5	Nil
Upper Susitna (Watana II)	340	-	94	-	168	5	Nil
Upper Susitna (Devil Canyon)	600	-	94	3334	2263	5	Nil
Snow Hydroelectric	63	-	94	220	5850	7	Nil
Keetna Hydroelectric	100	-	94	395	5480	5	Nil
Strandline Lake Hydroelec.	20	-	94	85	7240	44	Nil
Browne Hydroelectric	100	-	94	430	4470	5	Nil
Allison Hydroelectic	8	-	94	37	4820	44	Nil
Grant Lake Hydroelectric	7	-	-	-	2840	44	Nil
Isabell Pass Wind Farm	25	-	36	8	2490	3.70	3.3
Refuse-Derived Fuel Steam Electric (Anchorage)	50	14,000	N/A	-	2980	140	15
Refuse-Derived Fuel Steam Electric (Fairbanks)	20	14,000	N/A	-	3320	140	15

(a) A heat rate of 12,000 Btu/kWh was used in analysis of Railbelt electric energy plans. 13,000 Btu/kWh is probably more representative of partial load operation characteristic of peaking duty.
(b) An earlier estimate of 8500 Btu/kWh was used in the analysis of Railbelt electric energy plans.
(c) Configuration selected in preliminary feasibility study (Bechtel Civil and Minerals 1981).
(d) Configuration selected in Railbelt alternatives study (Volume XIV).
(e) Variable O&M included in fixed O&M estimate.
(f) Depends on capacity factor.

347,000 MWH

520 MW
2645 GWH

Railbelt was expressed as a reduction in forecasted demand from levels of demand that might be experienced without conservation. Overviews of the conservation measures considered in the study are provided in the following paragraphs.

4.2.1 Residential Building Conservation

Building energy conservation encompasses a variety of measures for reducing the electrical load of residential structures heated with electricity. Electrically heated structures currently comprise about 21% of Anchorage households, 9% of Fairbanks households, and 1% of Glennallen-Valdez households.[a] Choice of conservation measures and resulting energy savings depend on the size and age of structure and the climatic region. The cost-effectiveness techniques on new structures include extra insulation in the ceiling (R-60), double-wall construction (R-40), heavily insulated floors (R-40), insulated doors, triple pane windows, and careful sealing and caulking to reduce air changes from 1.0 to 0.25 per hour (Barkshire 1981b). Cost-effective measures for retrofitting existing buildings include adding insulation to the floors and ceiling to bring their insulating value up to R-40 and R-60, respectively. The walls are left at current R-values because of the expense of retrofitting. Triple-glazed windows, R-8 metal insulated exterior doors, and sufficient caulking and sealing to bring air infiltration down to 0.5 air changes per hour round out the assumed improvements (Barkshire 1981b). For purposes of cost estimating, insulation is assumed to be applied by contractors, whereas glazing, caulking, and weatherstripping are applied by the owner. Energy savings of new construction improvements over standard practices are 289 Btu/hr per degree Fahrenheit below 70^{o} outside temperature for the prototypical structure. For retrofits, improvements are projected to yield 189 Btu/hr per ^{o}F.

4.2.2 Residential Passive Solar Space Heating

Passive solar space heating is accomplished by using south glazing to capture solar energy in combination with a thermal mass to store captured energy for release at night or during cloudy periods. These design features

(a) Calculations taken from a residential end-use survey conducted by Battelle-Northwest for this study (March-April 1981).

generally are combined with a thermally efficient building envelope such as those described above. Passive solar housing design in the Railbelt region has considerable potential for reducing the space heat demand of these structures. However, the homeowner's ability to use the solar resource depends on the building's location and orientation. Also, passive solar applications are generally restricted to new buildings or additions to existing structures. Retrofitting an existing structure is a relatively inefficient way to reduce heating bills (Barkshire 1981a and 1981b). A site survey of the Alternative Energy Technical Assistance program during the summer of 1981 showed about one sixth of 1200 Anchorage sites had open access to the sun the year round and thus would be candidates for effective passive solar retrofit. Preliminary study by Alaska Renewable Energy Associates indicates that from one third to one half of building sites in the Railbelt will have solar access during the heating season. Late winter and early spring are the primary months when sunlight in the Railbelt region is both needed and available in sufficient intensity to provide a net heat gain. Because sunlight is not generally available during the peak heating periods of December and January, this technology is assumed to operate in a fuel-saver mode and is given no credit for reducing peak demand.

The prototypical dwellings used for analysis of passive solar space heating were as follows. The new structure was a 1500 square foot house with 200 square feet of south-facing glass. No thermal storage was assumed. About 19.3 MW Btu annual net solar gain resulted (about 13.8 MM Btu per year more than a standard house). The prototypical solar retrofit was an 8 by 20 foot solar greenhouse, which supplied 10 to 15% of the heat required by the basic 1500 foot house used in the calculations.

Site characteristics limit penetration of passive solar space heat applications to about 35 to 50% of the new building stock, while solar greenhouses designed for heating purposes in existing buildings are expected to be limited to 10 to 15% of the existing housing stock.

(a) Although active solar space heating designs have been advanced, they did not appear to be particularly advantageous for the Railbelt and thus were not considered in this analysis.

4.2.3 Residential Active Solar Hot Water Heating [a]

Active solar technology has some potential in the Railbelt to reduce hot water heating load. The effectiveness of these systems depends upon the amount of solar radiation available and the water heating load of the household, which in turn depends on the size and characteristics of the household. Final installed costs will vary with the type of system (draindown, antifreeze, one or two tanks), as will performance (Barkshire 1981a). Prototypical new and retrofit units examined in the study assume 80 square feet of collector using Solar Roll® type technology because this appears to be the most cost effective.[a] About 50% of the annual water-heating load of a family of four can be met with such an installation, at 80 gallons per day use. The proportion of such use, which can be met by solar during the year, varies by month from near zero in November through February to about 85% in April through June.

Limitations on market penetration are expected to result from very long payback caused by high installation costs and unavailability of adequate sites. These limitations will probably hold the total market to 5 to 10% of hot water users (Barkshire 1981a).

4.2.4 Residential Wood Space Heating

Wood is already a supplementary fuel choice in many Railbelt communities. Unlike other dispersed technologies, wood-fired space heating is not resource or weather limited at this time. The analysis of wood-fired heating was done on the presumption that at maximum penetration, one fifth of the space heat required by homes heated with passive solar technology and one fifth of the space heat required by nonsolar homes would be provided by wood. This is equivalent to more than a doubling of the current market penetration of wood space heat. Inconvenience, fuel cost, and difficulty in using wood in multifamily units would deter market penetration, even at zero capital cost.[b]

(a) Solar Roll® is a trademark of Bio Energy Systems, Inc. of Ellenville, New York.
(b) Wood space heating costs are dominated by fuel costs even for the most expensive types of stoves.

Stoves are available in sizes with heating capabilities ranging from 15,000 to over 100,000 Btu/hr, with conversion efficiencies of 20 to 65%. The costs and performance characteristics used in the study are based on a high-quality airtight stove of heavy-gage steel and soapstone.

4.2.5 Cogeneration and Waste Heat Utilization

Cogeneration and use of waste heat were considered and rejected as major future sources of electric energy in the Railbelt. The most logical candidates for cogeneration in the Railbelt are the existing Kenai Peninsula and Fairbanks oil refineries, the existing (and possible future) liquefaction facilities for natural gas on the Kenai Peninsula, and the ammonia-urea fertilizer plant on the Kenai Peninsula. However, inquiries to plant managers and industry sources turned up the following information: 1) None of these large process heat users is considering cogeneration plants to sell or trade electricity to the utility grid; 2) The Dow-Shell consortium came to the conclusion that utility power would be cheaper than self-generated power in the new petrochemical plant; 3) There are severe technical problems with recovering additional high-grade heat for cogeneration turbines at LNG facilities; 4) The Fertilizer Institute was aware of no cogeneration projects in the ammonia-urea industry, even where prices for electricity are higher than Alaska's expected price. Based on these considerations, cogeneration from these sources appeared to be unlikely as a major future contributor of electric power in the Railbelt as long as the cost analysis used by the potential sponsor is based on average power costs as seen by industry and not marginal power costs as seen by electric utilities. Commercial and residential users might undertake smaller scale cogeneration.

To summarize, conservation measures for residential buildings were selected, and their performance and cost characteristics were assessed as a basis for reducing electric demand. These conservation measures and the generating technologies previously described were major inputs to developing the alternative electric energy plans for the Railbelt region. Cogeneration and waste heat utilization are unlikely sources of electric energy for the Railbelt region.

5.0 ELECTRIC ENERGY PLANS

Six plans were developed to provide a comparison of electric power development strategies for the Railbelt region. The plans were selected to encompass the full range of viable generation and conservation alternatives available to the Railbelt.[a]

Plan 1A, "Present Practices" Without Upper Susitna. Generation additions are conventional coal and/or gas-fired steam plants and other hydroelectric generation. Plan 1A is considered the base case against which the others are compared.

Plan 1B, "Present Practices" With Upper Susitna. Generation additions are primarily by the Upper Susitna Project with some gas-fired generation.

Plan 2A, "High Conservation and Renewables" Without Upper Susitna. Generation additions include six small hydroelectric dams, wind power, refuse-derived fuels, and some gasified generation.

Plan 2B, "High Conservation and Renewables" With Upper Susitna. Generation additions are primarily the Upper Susitna Project and lesser amounts of the resources of Plan 2A.

Plan 3, "High Coal". Generation additions are primarily fueled with coal either directly or indirectly.

Plan 4, "High Natural Gas". Generation additions are primarily fueled with natural gas.

Five major factors were considered when developing these plans:

- natural resources available in the Railbelt region
- current generating facilities and utility plans
- performance characteristics and availability of alternative generation technologies
- current and forecasted requirements for electricity
- input from public meetings

(a) To assist the reader in identifying the content of each plan, a foldout sheet containing the titles of the plans is included at the end of the report.

With these factors a subjective process was used to develop the electric energy plans. As noted above, the plans were developed to encompass the full range of conservation and generation alternatives available to the region rather than to select the "best" plans based upon a formal selection and evaluation process.

A major concern of the State of Alaska is whether the Upper Susitna hydroelectric project should be developed or whether other alternatives should be pursued; thus, two electric energy plans are immediately logical choices. Plan 1A does not include the Upper Susitna project, whereas Plan 1B does. The former provides the conditions for the "base case"; that is, the case against which the alternatives will be compared. Plan 1A and Plan 1B provide a direct comparison between continued development of conventional generating resources and development of conventional generating resources with the addition of the Upper Susitna project.

The public meetings held as part of this project, as well as other inputs, pointed to widespread interest in both conservation and renewable energy resources. While significant electric energy conservation will take place as a result of price increases in all of the electric energy plans, a specific plan in which conservation alternatives receive greater emphasis than in any other plan is possible. Thus, Plan 2A, High Conservation and Renewables without Upper Susitna, and Plan 2B, High Conservation and Renewables with Upper Susitna, were selected. These two plans include the conservation technologies explicitly analyzed as well as a variety of other measures that generally have low initial cost and quick payback periods. Among the unidentified conservation measures are weatherstripping, setback thermostats, water heater jackets, and energy-conserving lighting. Also assumed are price-induced conservation savings, those which change peoples' behavior patterns, such as taking shorter showers, turning off lights, and turning back thermostats. Low initial investment, quick payback conservation is assumed to be adopted as a matter of course.

To achieve the maximum contribution from conservation, the conservation program assumed in this study goes beyond this market-induced conservation. The State of Alaska is assumed to provide a grant program to residential electricity consumers to offset the initial investment cost of four technologies with higher initial cost and high energy payoff. Those four technologies are superinsulation of buildings, passive solar designs for space heating, active solar hot water heating, and wood-fired space heating. Because much less information is available about specific end uses of electricity in the business sector, the conservation supply plans relied on estimates of maximum average electrical conservation of about 35% in the business sector and corresponding estimates of minimum life cycle energy costs.[a] The initial capital cost of achieving this maximum saving was assumed to be provided by a business sector grant program so that the full savings could be realized.

Finally, the market penetration of the conservation technologies described above for the residential sector and the general measures for the business sector was estimated for market conditions without subsidies. The difference between the subsidized and unsubsidized case was the impact of the conservation supply program.

Plan 3 is based on increased use of coal. Coal is an attractive fuel for electrical generation in the Railbelt area for several reasons:

- It is abundant.
- Good, easily mined coal deposits are close to the load centers.
- The technologies for both mining and burning coal are well established.
- Projections indicate that coal will continue to be competitively priced relative to alternative fuels.

Further, an export mine will probably be developed at Beluga and thereby could provide the Cook Inlet area with a good source of coal.

Plan 4 is based on increased use of natural gas. Natural gas is currently the mainstay fuel for electric generation in the Anchorage-Cook Inlet area and may become available in the Fairbanks area if production and transmission of North Slope natural gas occurs. The major favorable attributes associated with natural gas are its relatively low environmental impact compared

(a) The basis for these assumptions is from work done in support of the Oak Ridge Laboratory commercial model (DOE 1979).

to other fossil fuels, the lower capital cost per unit of generating capacity, and the short lead time involved in making capacity additions. Natural gas is a clean and flexible fuel readily adapted to conditions of uncertain future demand.

Further, considerable known reserves of natural gas [∿3,900 billion cubic feet (BCF)] exist in the Cook Inlet region. Some of this gas is committed (or dedicated) under contract to gas and electric utilities (620 BCF), some is committed to industrial applications (ammonia and urea production), and some to export (∿730 BCF). About 980 BCF is tentatively committed to the proposed (but currently uncertain) Pacific Alaska LNG project for export to the Lower 48 states. A significant amount (∿1600 BCF) of the known reserves appears free of current commitments. However, current industrial and export uses will probably compete with the gas and electric utilities for commitment of this gas to their operations and, thus, the future price is subject to considerable uncertainty. Current reserves in the Cook Inlet do not appear sufficient to allow expanded gas use beyond 1990. Additional resources might be discovered, however.

Several assumptions were made which are common to all plans:

- Current utility plans for generating additions will proceed as planned.
- Generating units will be retired based on typical economic lifetimes.
- An interconnection between the Anchorage-Cook Inlet and Fairbanks-Tanana Valley load centers will be completed in 1984 and strengthened as necessary to allow economical power exchanges between Fairbanks and Anchorage.
- The Glennallen-Valdez load center electrical loads and generating capacity will be combined with Anchorage-Cook Inlet loads and generating capacity.
- All load centers will maintain sufficient peaking capacity to provide peak requirements in the event of interconnection failure.
- The Bradley Lake hydroelectric project will be completed and will come on-line in 1988.

The approach and rationale for the selection of the preliminary electric energy plans, as well as descriptions of the assumptions and features in each plan, are contained in Volume V.

The detailed electrical generation and conservation alternatives that were selected for each of the electric energy plans are summarized in Table 5.1.

In each plan, the costs of constructing the transmission systems to connect the various generating facilities to the intertied system are included in the analysis. For example, Plan 1A includes the costs of constructing a transmission system to connect the Chakachamna project and the coal steam-electric generating plants located at Beluga with the Anchorage-Fairbanks transmission intertie and the Anchorage-Cook Inlet transmission system. Costs also are included for the transmission facilities that are assumed to be built in conjunction with the first coal-fired steam plant added in the Beluga area. Similarly, the cost of the transmission system necessary to connect the additional generating facilities at Nenana to the intertie and the Fairbanks area is also included. In Plan 1A other generating facilities are assumed to be built near existing transmission lines, and the costs of connecting them to the transmission are ignored.

Because of the large size and location of the Upper Susitna project (included in Plans 1B and 2B), approximately midway between Anchorage and Fairbanks, a relatively extensive transmission system is required. The costs of the transmission system necessary to connect the various stages of the project with the Anchorage and Fairbanks area are included with capital costs of those stages.

While there are differences in transmission systems for Plans 3 and 4, they are sufficiently similar to the transmission system in Plan 1A that similar costs can be ascribed to them. In Plan 3 the additional coal-based generating facilities are assumed to be added in the Beluga area and in the Nenana area, allowing much the smae system to be used. In Plan 4 the additional gas generating facilities in the Anchorage area are assumed to be added in the Beluga area. The exact location for the gas-fired capacity in the Fairbanks area is not specified, but there are costs of connecting these facilities to Fairbanks and to the intertie. These are assumed to be the same as for Plan 1A.

TABLE 5.1. Summary of Electrical Energy Alternatives Included as Future Additions in Electric Energy Plans

	Electric Energy Plan[a]					
	1A	1B	2A	2B	3	4
BASE LOAD ALTERNATIVES						
Coal Steam Electric	X	X	X	X	X	
Refuse-Derived Fuel Steam Electric			X	X		
Natural Gas - Fuel-Cell Combined-Cycle						X
CYCLING ALTERNATIVES						
Coal Gasifier - Combined-Cycle					X	
Natural Gas - Fuel Cell-Stations						X
Natural Gas - Combined-Cycle	X	X	X	X		X
Natural Gas - Combustion Turbine	X	X	X	X	X	X
Bradley Lake Hydroelectric	X	X	X	X	X	X
Grant Lake Hydroelectric	X		X			
Lake Chakachamna Hydroelectric	X		X			
Upper Susitna Hydroelectric		X		X		
Allison Hydroelectric	X		X			
Browne Hydroelectric			X			
Keetna Hydroelectric			X			
Snow Hydroelectric			X			
Strandline Lake Hydroelectric			X			
FUEL SAVER (INTERMITTENT) ALTERNATIVES						
Large Wind Energy Conversion System			X	X		
ELECTRIC ENERGY SUBSTITUTES						
Passive Solar Space Heating			X	X		
Active Solar Hot Water Heating			X	X		
Wood-Fired Space Heating			X	X		
ELECTRIC ENERGY CONSERVATION						
Building Conservation			X	X		

(a) Plan 1A, "Present Practices" without Upper Susitna (Base Case)
Plan 1B, "Present Practices" with Upper Susitna
Plan 2A, "High Conservation and Renewables" without Upper Susitna
Plan 2B, "High Conservation and Renewables" with Upper Susitna
Plan 3, "High Coal"
Plan 4, "High Natural Gas"

6.0 COMPARATIVE EVALUATION OF ELECTRIC ENERGY PLANS

Having selected the alternative electric plans to be considered, the next steps were to describe them in greater detail and then evaluate their impact on the Railbelt region. A schedule of plant additions was developed; i.e., the type, size, timing, and location of each plant were specified. The schedule was developed using two computer codes: RED (described briefly in Section 3) and AREEP (described in this section). A major output of this computer analysis was the costs of electric energy for each plan, and these were compared. Qualitative evaluations of environmental and socioeconomic impacts were made for each plan. This section concludes with a qualitative evaluation of the strengths, weakness, and uncertainties of each plan.

Detailed information on generation system reliability, environmental and economic effects for each plan is presented in Appendix D. The effects of other growth scenarios can be estimated from this information.

6.1 DEVELOPMENT OF DETAILED ALTERNATIVE ENERGY PLANS

As previously stated, the demand for electricity is partially determined by the price of electricity, which is determined largely by the types and performance of the facilities used to generate electricity. Thus, electricity demand forecasts require some interaction between the demand and supply forecasting methodologies. These interactions were performed as shown in Figure 6.1 and led to a schedule of capacity additions and the present worth for each plan.

To start the process, a price of electricity is assumed as input to the electrical demand model (RED model). Using this price, as well as other input data and assumptions, the RED model produces forecasts of peak demand and annual energy consumption for the Railbelt. The AREEP model uses these forecasts of peak demand and annual energy consumption as input data and produces a schedule of plant additions to the electrical generation system, as well as price of electricity to the consumer. The resulting demand under the new price is compared to the demand with the original price assumption, and if

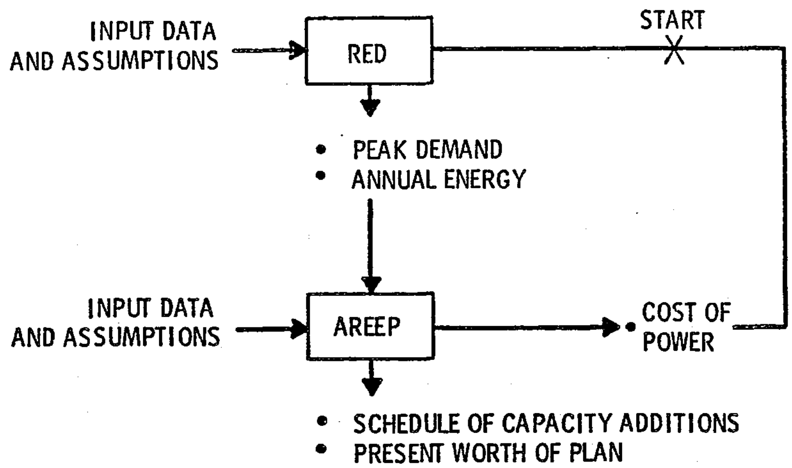


FIGURE 6.1. Electrical Demand and Supply Interactions

the two demands are relatively close, then supply and demand are said to be in equilibrium and the process is halted. If the two demands are not relatively close, the process is repeated until the demand estimates for two successive iterations for RED are relatively close.

AREEP requires capital and O&M cost data (developed in the preceding sections), financial assumptions, fuel costs, and the desired set of generation alternatives from which the model will select specific generating plants.

The general computational procedure used by AREEP to determine the price of electricity for a particular case is presented in Figure 6.2.

The first step (1) is to adjust the consumption forecast (peak demand and annual energy) developed by the RED model for transmission line losses and unaccounted energy. This adjustment determines the amont of energy that must be generated. The peak demands and annual energy from each of the three load centers are added together and a single annual load duration curve is developed for the combined Railbelt region.

The next step (2) is to develop a schedule for new additions to the generating capacity. Generating capacity additions are based upon the need to meet the forecasted annual peak demand, with allowances for line losses and reserve margin. The model accounts for retirement of existing plants. The type of generating alternative added is selected from a general set of alternatives that is input by the model operator.

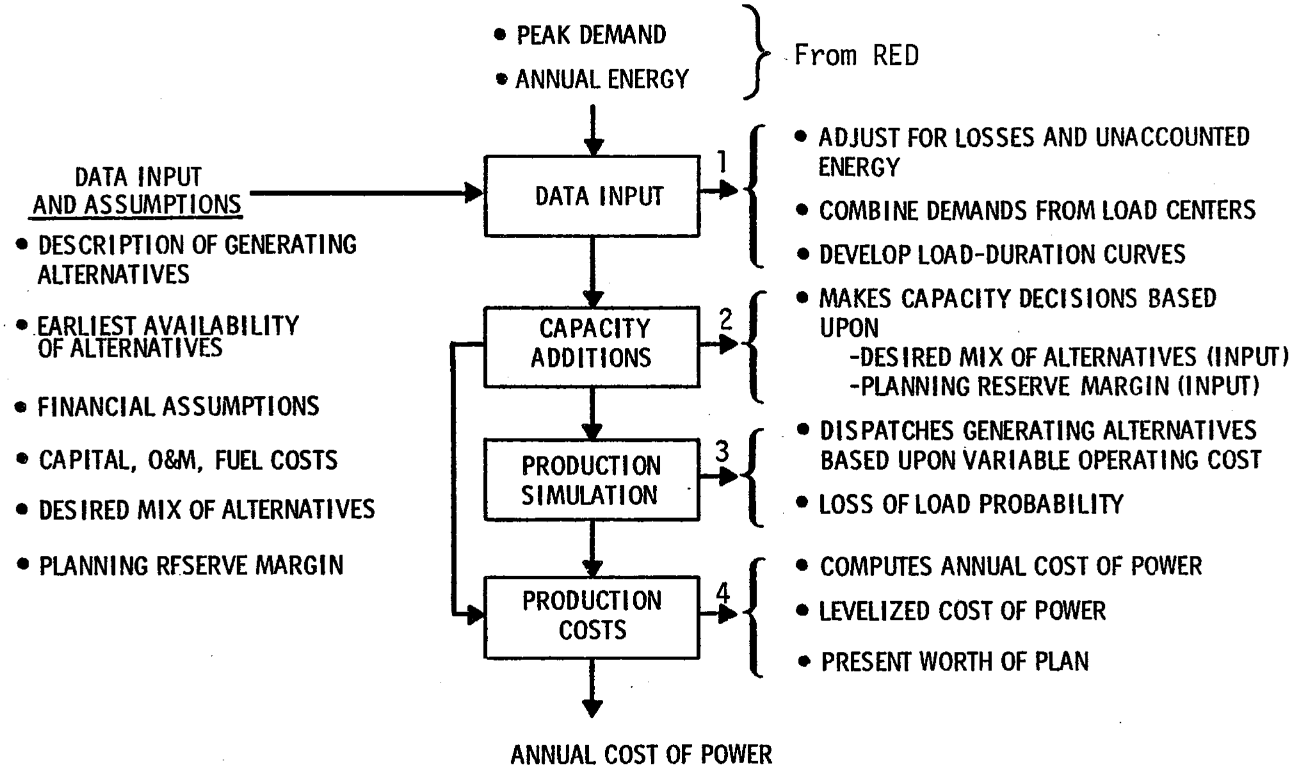


FIGURE 6.2. AREEP Diagram

Once the schedule of new plant additions is established, the capital cost and fixed cost portion of the electricity production cost can be computed. As indicated in Figure 6.2, this information is computed and used to forecast the production cost of electricity.

The next step (3) in the computational procedure is the selection of available generating alternatives to generate electricity during any particular year. The model selects the resource based upon the relative variable operating costs of the alternatives. The alternative with the lowest operating costs is selected (dispatched) first, followed by the alternatives with the next lowest variable cost. The generating alternatives are dispatched in this order until the annual energy demand is satisfied.

Finally, the information on the amount of electricity produced by each generating technology is then used to compute the annual variable costs of producing electricity for the Railbelt region (4). As Figure 6.2 shows, adding the total annual fixed costs, which were computed earlier, to the total annual variable costs produces the total annual cost of power to the consumer. The levelized cost of power[a] of the plan is then calculated from the annual costs of power over the time horizon 1980 to 2010.

6.2 DETAILED DESCRIPTIONS OF PLANS

The types of generating plants to be constructed, their size, location, and timing for each of the electric energy plans were developed in greater detail. For clarity purposes, the medium-medium (MM) economic scenario (moderate economic growth, moderate State spending) was selected as the basis for comparing the six plans.

The peak electrical demand for the Railbelt region was 540 MW in 1980. By the year 2010 the peak demand is expected to be slightly larger than double this amount (for the MM case). Capacity additions of about 1200 MW will be required to meet the load growth, to replace older units, and to provide adequate reserve margins.

6.2.1 Plan 1A "Present Practices" Without Upper Susitna

In Plan 1A 400 MW of gas combined-cycle, 400 MW of coal steam turbine, and 430 MW of hydroelectric capacity would be added during the 1981 to 2010 time period. The hydroelectric capacity includes the following projects:

- The Bradley Lake hydroelectric project (90 MW) would come on-line in 1988.
- The Chakachamna hydroelectric project (330 MW) would come on-line in 2002.
- The Allison (7 MW) and Grant Lake (7 MW) hydroelectric projects would come on-line in 1992 and 1995, respectively.

In the Anchorage-Cook Inlet area:

- Coal steam turbines (200 MW in 1992) and gas combined-cycles (178 MW in 1982 and 200 MW in 1996) would be installed to supplement the hydroelectric projects.

(a) The procedure used to compute the levelized cost of power is presented in Appendix C.

In the Fairbanks-Tanana Valley area:

- Oil combustion-turbine units would be used for peaking until retirement occurs in the mid-1990s.
- Gas combined-cycles (100 MW) each in 1991 and 2010) would be added to provide peaking generation and partly to replace oil combustion units that will be retired.
- Coal steam-electric capacity (200 MW) would be added for baseload in 1997.

During the 1981 to 1991 time period, electrical generation in Anchorage would be largely supplied by gas combustion/turbine and combined-cycle with some hydroelectric generation. During the next 20 years, generation in the Anchorage area would be largely hydroelectric with some gas combined-cycle and coal steam turbine generation.

In Fairbanks, coal steam turbine capacity would be used for generation throughout the time horizon. Oil combustion turbines would be used during the first 10 years while some gas combined-cycle capacity would be used during the remainder of the period.

6.2.2 Plan 1B "Present Practices" With Upper Susitna

In Plan 1B almost all of the additional capacity added results from the construction of the Watana (680 MW) and Devil Canyon (600 MW) dams of the Upper Susitna Project. The Watana Dam would come on-line in 1993 and the Devil Canyon Dam would come on-line in 2002. The Bradley Lake project (90 MW) would come on-line in 1988. The only other capacity added would be 70 MW of gas combustion turbine capacity and 200 MW of gas combined-cycle capacity brought on-line in 1990 and 1991, respectively, in the Anchorage area.

During the 1981 to 1992 time period, electrical generation in Anchorage would be largely by gas combustion turbines and combined-cycle capacity with some hydroelectric generation. In Fairbanks, oil combustion turbines and diesel capacity would be used until 1990-1991, and coal steam turbine until 2002 when the Devil Canyon Dam would come on-line. From 2002 until 2010 the majority of electrical generation in the Railbelt would be supplied by hydroelectric power, largely from the Upper Susitna project.

Basically, this plan is a continuation of present generating technologies with a transition to Upper Susitna hydropower as required. Additional capacity required would be supplied by conventional coal-steam turbine or combined-cycle facilities.

In the Anchorage-Cook Inlet area:

- If required by load growth, combustion turbine and gas combined-cycle capacity would be added until Upper Susitna is available.
- After the Upper Susitna Project is completed, coal-steam turbine units would be added if required by load growth.

In the Fairbanks-Tanana Valley area:

- Combustion turbine and gas combined-cycle capacity would be added as required prior to the Upper Susitna Project, and coal-steam turbine units would be added as required after the Upper Susitna Project is completed.

6.2.3 Plan 2A "High Conservation and Renewables" Without Upper Susitna

Plan 2A emphasizes conservation to reduce electrical energy demand and the use of renewable energy sources to provide for a significant portion of the electrical energy growth. A continuing State grant program is assumed that encourages the installation of conservation alternatives (passive solar space heating, active solar water heating, wood space heating, and building conservation). The conservation program is estimated to supply the equivalent of 40 to 75 MW in generating capacity.

Additional capacity required would be provided by conventional generating alternatives as in Plan 1A. The hydroelectric projects include:

- The Bradley Lake project (90 MW), the Allison project (7 MW), the Chakachamna and Grand Lake projects (337 MW), and the Keetna hydroelectric project (100 MW) would come on-line in 1988, 1991, 1995, and 2008, respectively.
- The Browne hydroelectric project (80 MW) would come on-line in 2005.

In the Anchorage-Cook Inlet area:

- A 50-MW municipal solid waste-derived fuel plant would come on-line in 1993.

- Additional generation would be supplied by natural gas combined-cycle (178 MW in 1982 and 200 MW in 1987) and combustion turbine (70 MW in each of the years 2006 and 2009.

In the Fairbanks-Tanana Valley area:

- 175 MW of large wind turbine generation would be added in the Isabell Pass area during the period 1992 to 1996.
- A 20-MW refuse-derived fuel plant will come on-line in 1994, and be supplemented with an additional 20 MW in 1996.

6.2.4 Plan 2B "High Conservation and Renewables" With Upper Susitna

Plan 2B is similar to Plan 2A except that the Upper Susitna project would be constructed. A number of the smaller dams would not be built and lesser amounts of fossil fuel-fired generation would be required. The hydroelectric projects include the following:

- The Bradley Lake project (90 MW) would come on-line in 1988.
- The first stage of Watana (680 MW) would come on-line in 1993; Devil Canyon (600 MW) in 2002.

In the Anchorage-Cook Inlet area:

- A 50 MW municipal solid waste-derived fuel plant would come on-line in 1992.

In the Fairbanks-Tanana Valley area:

- 50 MW of large wind-turbine generation would be added in the Isabell Pass area in 1992.

6.2.5 Plan 3 "High Coal"

Plan 3 assumes a transition from existing generating technologies to alternatives that use coal, directly or indirectly, as a fuel. As previously stated, coal is currently available in the Railbelt from the Healy area; it is also expected to be available from the Beluga area in 1988. This plan assumes that coal-fired generation in the Anchorage-Cook Inlet load center would be located in the Beluga area. Baseload generation for the Fairbanks area will depend on the costs of facilities located at Beluga compared to costs of facilities located in the Nenana area. With the exception of Bradley Lake (90 MW), which would come on-line in 1988, no additional hydroelectric facilities would be built.

In the Anchorage-Cook Inlet area:

- Two 200 MW coal steam turbine power plants would come on-line in 1992 and 2005.
- A 200 MW coal-gasifier combined-cycle would come on-line in 1995.
- Three 700 MW gas combustion turbines would come on-line in 1991, 2009, and 2010.

In the Fairbanks-Tanana Valley area:

- A 200 MW coal steam turbine power plant would come on-line in 1997.

6.2.6 Plan 4 "High Natural Gas"

Plan 4 is based upon continued use of natural gas for generation in the Anchorage-Cook Inlet area and a conversion to natural gas in the Fairbanks-Tanana Valley area. The key assumptions for this plan are that sufficient gas will be continually available in the Cook Inlet area in the amounts required for electrical generation, and that natural gas will be available for the Fairbanks area from the North Slope beginning in 1988. Gas-fueled alternatives in this plan include fuel-cells, gas combined-cycle, combustion turbine, and fuel-cell combined cycle. As in Plan 3, with the exception of the Bradley Lake project (90 MW), which would come on-line in 1988, no additional hydroelectric facilities would be built.

In the Anchorage-Cook Inlet area:

- A 178 MW and a 200 MW gas combined-cycle plants would come on-line in 1982 and 1998.
- A 200 MW gas fuel-cell station would come on-line in 1995.

In the Fairbanks-Tanana Valley area:

- Three 100 MW gas combined-cycle plants would come on-line in 1991, 2005, and 2006.
- Two 200 MW gas fuel-cell stations would come on-line in 1993 and 2008.

6.3 ELECTRICAL DEMAND

The peak electrical demand in all plans is very similar, ranging from 1120 MW to 1350 MW by year 2010 (Figure 6.3).

Plan 1A, the base case, results in a peak demand of about 1260 MW in the year 2010.

Plan 1B, which includes the Susitna hydroelectric project, has a higher electricity demand to the year 1995 because of the population and employment impacts of construction of this project. Since the Upper Susitna project results in a slightly higher cost of power than Plan 1A between 1993 and 2005, demand is reduced until after 2005, when a lower cost of power results in a higher demand.

Plans 3 and 4 are less sheltered from fuel price escalation than the other plans since they include a limited amount of hydroelectric capacity. While the effect of escalation is not significant compared to Plan 1A up to about the year 2000, the lower reliance on hydroelectric power in these cases increases the cost of power and reduces demand below that in Plan 1A.

As previously stated, all plans include substantial electricity conservation due to the cost of power. However, in Plans 2A and 2B the demand for electricity is reduced still further by using a grant program to cover the investment costs of the four conservation alternatives specifically analyzed in this study (building conservation, passive solar space heating, active solar water heating, and wood stoves), plus commercial conservation initiatives. The peak demand in these plans is from 100 to 140 MW less than Plans 1A and 1B.

6.4 COST OF POWER

The annualized cost of power for all of the electric energy plans is similar (Figure 6.4). The major differences in the cost of power are in the plans that include the Upper Susitna project (Plans 1B and 2B). A relatively rapid increase in the cost of power occurs in 1993 when the Watana Dam would come on-line and another rapid increase in 2002 when the Devil Canyon Dam would come on-line. However, the annualized cost of power falls rapidly beyond 2002

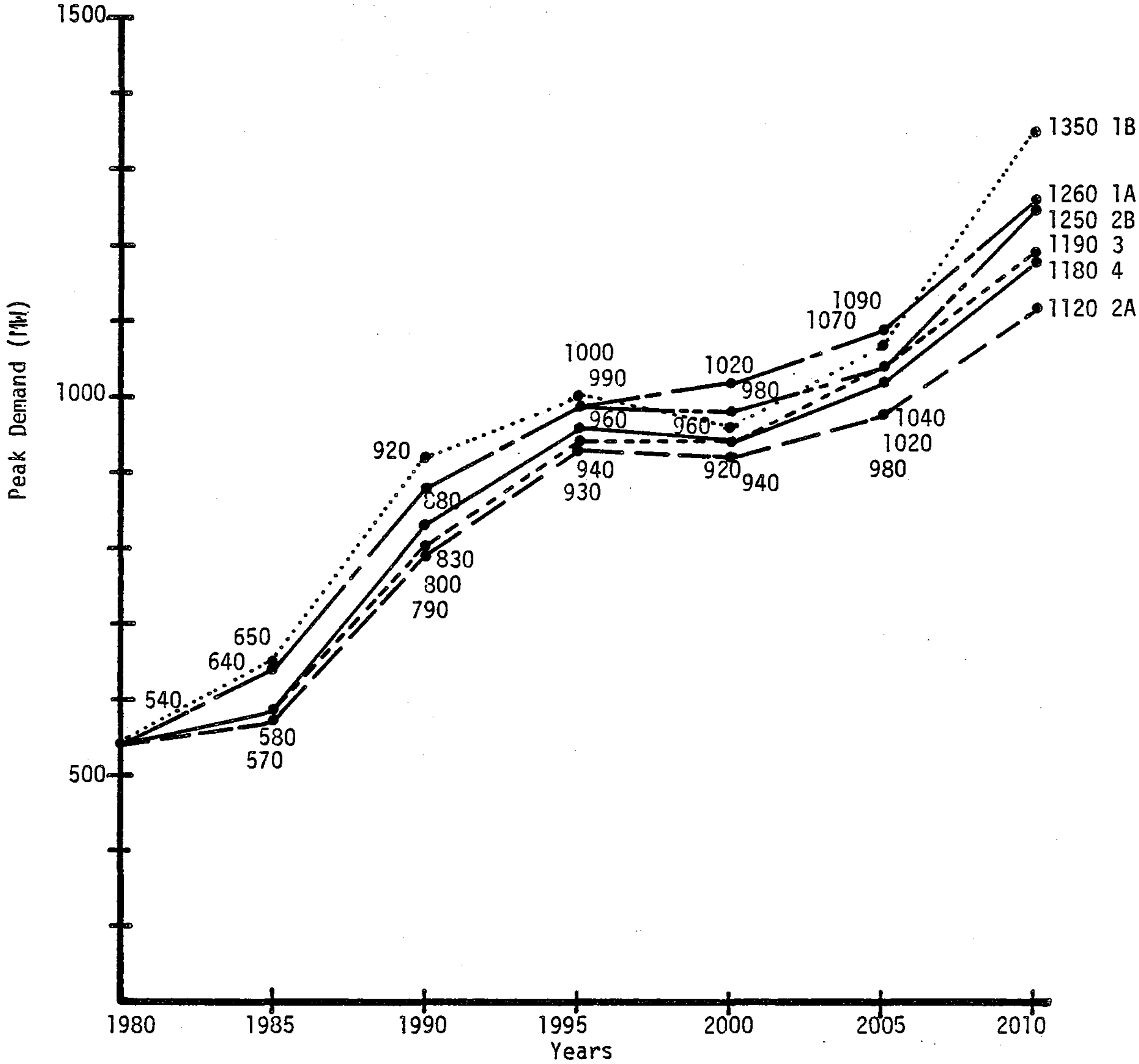


FIGURE 6.3. Peak Electrical Demands for Medium-Medium Economic Scenario

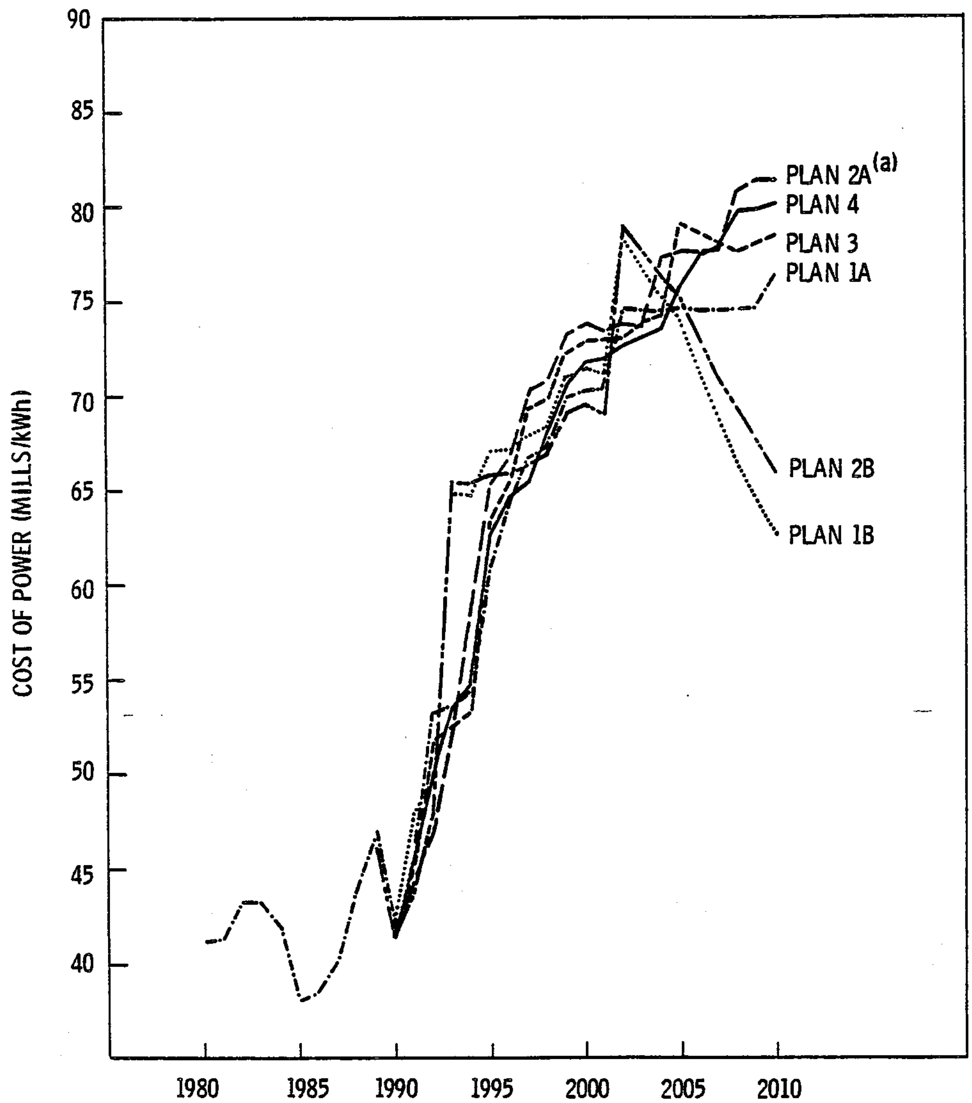


FIGURE 6.4. Comparison of Annualized Cost of Power for Railbelt Electric Energy Plans (1982 dollars)

(a) Plan 1A "Present Practices" Without Upper Susitna
1B "Present Practices" With Upper Susitna
2A "High Conservation and Renewables" Without Upper Susitna
2B "High Conservation and Renewables" With Upper Susitna
3 "High Coal"
4 "High Natural Gas"

and is significantly lower than any of the other plans by the year 2010. Plans 1A, 2A, 3, and 4, which rely on fossil fuels, all show the effects of the continued escalation of fuel prices throughout the time period to 2010.

Little difference exists in the annualized cost of power for three primary reasons:

1) As part of the selection process described earlier, generating alternatives with high generating costs were screened out from further analysis. Since the alternatives with relatively high power costs were not included in any of the plans, one would expect that the plans would have similar power costs.

2) Over much of the 1980 to 2010 time period, the electrical supply systems (and thus the costs) are the same for all plans. During the first 10 years (1980 to 1990), the same capacity additions are included in all of the plans. As a result, the costs are the same over this time period.

3) The costs presented in Figure 6.4 include distribution and utility general and administrative costs as well as generation and transmission costs. While the latter vary from plan to plan, the distribution and utility general and administrative costs are assumed proportional to the electrical consumption and, as a result, vary relatively little from plan to plan.

Choosing the plan with the lowest cost of power is difficult if only annual power costs are considered, as in Figure 6.4. For example, Plan 1A provides a lower cost of power than Plan 1B during the 1993 to 2003 time period, whereas Plan 1B has the lower cost of power from 2004 to 2010. To compare the costs of power for the various plans, unit power costs can be expressed as levelized costs. The levelized cost of power is computed by estimating a single annual payment, the present worth of which is equivalent to the present worth of the forecasted stream of annual costs.[a]

The levelized costs of power for the six plans over the two periods of analysis are presented in Table 6.1. The most striking aspect of these data is that there is essentially no difference in the levelized cost of power among the plans within each period of analysis.

(a) The procedure used to levelize the cost of power is explained in Appendix C.

TABLE 6.1. Levelized Costs of Power for Electric Energy Plans (mills/kWh)

	Period of Analysis	
	1981-2010	1981-2050
Plan 1A "Present Practices" Without Upper Susitna	58	64
Plan 1B "Present Practices" With Upper Susitna	58	59
Plan 2A "High Conservation and Renewables" Without Upper Susitna	59	66
Plan 2B "High Conservation and Renewables" With Upper Susitna	58	61
Plan 3 "High Coal"	59	65
Plan 4 "High Natural Gas"	59	66

As previously noted, an important observation from Figure 6.4 is that the plans including the Upper Susitna project have higher cost power during the 1993 to 2004 time period, but they have a lower cost power in the latter years. Since the service life of the Upper Susitna project extends beyond 2010, this difference in power costs can be expected to be maintained because Plans 1A, 2A, 3, and 4 are more reliant on fossil fuels, which are expected to continue to escalate.

To evaluate this aspect of power costs, the levelized costs were also computed for the period 1981 to 2050 (Table 6.1), assuming that no escalation will occur in fuel costs or capital replacement costs over the 2010 to 2050 time horizon (and no generating capacity is added). This assumption understates the relative advantages of the plans that include the Upper Susitna project, but it does indicate the longer-term power cost advantage of the larger hydroelectric projects.

Over the longer time horizon the plans, including the Upper Susitna project, provide the lowest cost of power. But even here the difference is only about 10%. As stated above, the assumption of no escalation in fuel and capital replacement costs does not favor the plans that rely on those fuels.

In Section 7, the effect of changes in the key assumptions leading to these results are evaluated.

6.5 POTENTIAL ENVIRONMENTAL AND SOCIOECONOMIC IMPACTS

The environmental and socioeconomic impacts were evaluated by examining the following major concerns for each plan.

- air and water quality: Do pollutants that degrade these resources for other uses exist?
- terrestrial, aquatic, and marine ecology: Will any changes that reduce the habitat and production of animal and fish life occur?
- noise, visual, and odor: Are these effects present to such an extent as to constitute a nuisance?
- health and safety: Do any effluents exist that may affect the health of workers and/or population?
- jobs in Alaska: Does this technology provide new jobs?
- boom/bust effects: Are new construction communities built and then left afterwards with impacts on existing community structure?
- land-use effects: To what extent will large areas of land be precluded for other uses by this technology?
- susceptibility to inflation: To what extent is the power cost closely tied to the cost of fuels such as coal, oil, and gas?
- spending in Alaska: Will a major portion of the total cost of this project be spent in Alaska?

The environmental and socioeconomic information has been integrated into a qualitative evaluation, summarized in Table 6.2. The six plans are listed on the vertical axis of this table, and the various environmental and socioeconomic sectors are listed on the horizontal axis. Each item has been designated with "+", "-", or "N". The "+" indicates the impact of the change is positive or desirable. The "-" indicates a negative or undesirable change. The neutral "N" means that some change may occur, but it is not perceived to be particularly desirable or undesirable.

This system of evaluation does not measure the degree of impact; that is, some "minuses" may be more detrimental than other "minuses". Thus, the fact

TABLE 6.2 Summary of Potential Environmental & Socioeconomic Impacts of Railbelt Energy Plan[(a)]

Energy Plan	Potential Environmental and Socioeconomic Impacts										
	Air Quality	Water Quality	Terrestrial Ecology	Aquatic/Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/Bust Effects	Land-Use Effects	Susceptibility to Inflation	Spending in Alaska
Plan 1A: Base Case Without Upper Susitna	-	N	N	N	-	N	+	-	-	-	N
Plan 1B: Base Case With Upper Susitna	+	N	N	N	+	+	+	-	-	N	+
Plan 2A: High Conservation & Use of Renewable Resources, Without Upper Susitna	N	N	N	N	-	+	+	-	-	N	+
Plan 2B: High Conservation & Use of Renewable Resources, With Upper Susitna	+	N	N	N	+	+	+	-	-	+	+
Plan 3: Increased Use of Coal	-	-	N	N	-	N	N	N	-	-	+
Plan 4: Increased Use of Natural Gas	+	+	+	+	+	+	N	N	N	-	-

(a) Key: + positive or desirable
- negative or undesirable
N neutral

that Plans 1A and 3 have the most negative or undesirable notations does not mean that overall they have substantially greater environmental and/or socio-economic impacts. Some perspective might be gained by recognizing that the amount of new capacity (about 1200 MW) in the Railbelt is not large for the area over which it is distributed. One might expect the major impacts to arise from the Susitna projects, which are large and concentrated. New fossil-fueled plants can be designed to reduce environmental impacts to very low levels. None of the power plants which might be added to the system are larger than 2-00 MW, apart from the Susitna project, and should not create significant socio-economic impacts. Even Susitna-size projects have been constructed elsewhere in settings that are not unlike the Railbelt region, and without unacceptable socioeconomic effects. The conclusion is that none of the plans need result in unacceptable environmental or socioeconomic impacts. A more detailed analysis of environmental and socioeconomic impacts is presented in Appendix D.

6.6 SUMMARY OF PLAN EVALUATIONS

Plan 1A: "Present Practices" Without Upper Susitna is not significantly different from past practices in the Railbelt. Jobs will result from the construction of coal plants and the Chakachamna hydroelectric project. No major problems are expected from water quality ecology, health and safety, boom/bust effects or spending outside the State.

Some impacts arising from air quality and land-use consideration are possible. From a cost-of-power standpoint, inflation effects due to fossil fuel use are possible. A potential exists for some boom/bust impacts at the Bradley Lake and Chakachamna hydroelectric projects.

A major uncertainty in this plan is whether the export coal mine at Beluga will be developed on the schedule assumed in this plan.

Plan 1B: "Present Practices" With Upper Susitna avoids impacts associated with the burning of fossil fuels; i.e., those related to air quality, visibility, health, waste disposal, etc. New jobs are created and significant spending occurs within the State. Construction of hydroelectric facilities is a well-established technology. Relatively good information is available on capital costs and environmental impacts. The plan is resistant to inflation once the Upper Susitna projects are constructed.

Significant boom/bust and land-use effects can be associated with the Upper Susitna projects. Capital costs are high. The Upper Susitna project may delay development of coal resources in the State.

Improper river flow control may be detrimental to anadromous fish species, especially salmon. Considerable experience exists in the "lower 48" states to evaluate these potential effects and proposed mitigation measures.

Plan 2A: "High Conservation and Renewables" Without Upper Susitna will create jobs and stimulate significant spending within the State. The heavy reliance on hydroelectric generation, wind generation, and natural gas minimizes the problems related to air quality, water quality, and ecology impacts. The plan is relatively insensitive to inflation effects. The Railbelt community is thoroughly involved in conservation activities with its resultant increase in energy-use awareness.

Some problems are associated with the local boom/bust effects of the six hydroelectric projects.

This plan assumes that a State conservation grant program is created and maintained. Potential health effects arising from increased indoor air pollution caused by conservation activities may need to be dealt with.

Plan 2B: "High Conservation and Renewables" With Upper Susitna has similar advantages to Plan 2A with respect to air and water quality, noise, odor and visual effects, health and safety, new jobs, and spending in the State. Relatively good information exists on capital costs and environmental impacts. Power costs will be resistant to inflation once the hydroelectric projects are constructed.

The disadvantages are similar to Plan 1B; boom/bust and land-use impacts and high capital costs are associated with the construction of the Upper Susitna project.

As with Plan 2A, this plan assumes an extensive and continuing State conservation grant program. As before, potential effects arising from increased indoor air pollution may need to be dealt with.

Plan 3: "High Coal" results in considerable spending within the State to construct coal-related facilities. It may accelerate development of coal resources in the State. No major problems are associated with health and safety or boom/bust effects.

Some potential problems could occur in such areas as air quality, water quality, visual impacts and land-use. Coal use is susceptible to inflation effects. Constraints due to the Prevention of Significant Deterioration (PSD) program air-quality regulations are possible. Incremental coal mining and reclamation activities may occur in Beluga and Nenana areas.

The development of the export coal mine at Beluga with its effect of reducing coal costs is a major uncertainty.

Plan 4: "High Natural Gas" has very little effect on the environment. No major problems are associated with boom/bust effects or land use.

Due to high technology of fuel cells and to a lesser extent gas combined-cycle units, a substantial amount of spending will occur outside of the State. Inflation effects are potentially significant because power costs are very sensitive to the price of natural gas.

The major uncertainty with this plan is that natural gas reserves in the Cook Inlet area may not be adequate for expanded generation beyond 1990 to 1995. Additional reserves will be required and their source, timing, and cost are not certain. Also, North Slope gas was assumed available at Fairbanks, and this availability is uncertain.

7.0 SENSITIVITY ANALYSIS

This section evaluates the sensitivity of the levelized cost of power to changes in several key parameters; that is, what is the effect on the cost of power if costs, projections, or schedules are incorrectly estimated. In any analysis, such as that presented in the previous section, considerable data are required to describe the systems being analyzed. If the data and procedures used in these (or any) analyses were accurate estimates of the "real world", the evaluation results would be exact, and therefore no uncertainty regarding the results would exist.

Unfortunately, some level of uncertainty is associated with all data; that is, the "correct" value for a parameter may be either larger or smaller than the value selected. For example, the capital cost of coal steam turbine generating units located in the Beluga area has been estimated to be $2090/kW, expressed in 1982 dollars. The only way to be completely certain of the capital costs of such units is to build one. Otherwise, the cost estimate has some uncertainty associated with it; that is, the correct cost estimate may be either higher or lower than the estimated $2090/kW.

Furthermore, the methods used in analyzing the plans are not exact representations but rather simplifications of the real world. Because of these two factors, the results have an uncertainty associated with them. In some cases the uncertainties are relatively small, and therefore their effects on the overall results may be relatively minor. In other cases, the uncertainties in a parameter or calculation may be relatively large, but the impact of the uncertainties on the overall results may still be relatively minor. In both of these cases, the overall effects of uncertainty could perhaps be neglected. However, in some cases the effects of the uncertainties do have a significant impact on analyses results.

Because uncertainty is associated with most data and computational procedures, it is necessary to test how changes in a parameter or an analysis would affect the results. Parameter values that are either higher or lower than the "best guess" estimate are selected and the analysis is redone to see how much the results change. If the change is significant, the results are said to be sensitive to the parameter estimate. If little change occurs, the results are said to be insensitive. The change in the results necessary for the analysis to be deemed sensitive to an input parameter varies depending upon the analysis. In some analyses, a change of 1% in the result may be quite significant, whereas in other analyses, much larger changes could be negligible.

In the context of this study, perhaps the best determination of whether the results are sensitive to a parameter is whether the ranking of the electric energy plans is changed. Many computer runs were made to estimate the sensitivity of the models to various parameters. The results of several important parameters are presented in this section, including fuel price escalation rates, forecasted demand, capital cost estimates, and generation efficiency. In general, the levelized costs of power changed by less than 5% in all the sensitivity tests. The most sensitive estimate analyzed is the Upper Susitna capital cost estimates (in Plan 1B and 2B) with variations of about plus or minus 9% in electrical energy costs. Based upon these analyses, the following general conclusions can be drawn regarding the relative costs of the various plans.

<u>Plan 1A: "Present Practices" Without Upper Susitna</u> has relatively stable levelized costs of power among the various sensitivity tests. Generally, Plan 1A is neither the highest nor lowest cost. The costs are stable because this plan includes a more diverse mix of supply options than the other plans. Rapidly increasing demand during the 1981 to 2010 time period causes its cost to be relatively high.

<u>Plan 1B: "Present Practices" With Upper Susitna</u> has relatively low power costs over the 1981 to 2010 time period, except for the case assuming higher than anticipated capital costs for the Upper Susitna Project. Also, this plan provides either the lowest or nearly the lowest cost of power in all sensitivity tests over the extended time period. It does relatively less well in cases with lower demand growth.

<u>Plan 2A: "High Conservation and Renewables" Without Upper Susitna</u> has relatively high power costs in most cases because of the plan's reliance upon hydroelectric projects that have high capital costs relative to the Upper Susitna Project, and because it does not have lower cost fossil fuel alternatives as an option. This plan has the highest cost of power in the case where electrical demand increases rapidly after 1990.

Plan 2B: "High Conservation and Renewables" With Upper Susitna has much the same behavior as Plan 1B, since both include the Upper Susitna Project. It has slightly higher costs of power than Plan 1B over the extended time horizon.

Plan 3: "High Coal" generally produces relatively high costs of power over the 1981 to 2050 time period. As expected, it is more attractive in the case of lower fuel price escalations.

Plan 4: "High Natural Gas" behaves similarly to Plan 3. It provides the lowest cost of power over the 1981 to 2010 time period for lower escalation rates and for reduced demand beyond 1995. It is one of the higher cost alternatives over the extended time horizon.

7.1 UNCERTAINTY IN FOSSIL FUEL PRICE ESCALATION

Although a considerable effort was made in this study to forecast the future prices and availability of fossil fuels and electricity in the Railbelt region, these forecasts are subject to a high degree of uncertainty. International political events affecting both the prices of oil and coal, national policies affecting the pricing and delivery of natural gas and oil, and national and state policies affecting both the prices of electricity and energy conservation create the uncertainties. Also, because economic behavior of individuals, businesses, and government in response to future fuel price changes must be extrapolated from past behavior, the degree of substitution among fuels and the degree of energy conservation are also uncertain.

7.1.1 Effects of Uncertainty in Fossil Fuel Price Escalation on Cost of Power

As discussed in Section 2, a long-term world oil price escalation rate 2% faster than inflation is assumed over the study's time horizon. The escalation of natural gas and oil with respect to general inflation is a subject on which there is little agreement. Some believe that escalation rates in the range of 1 to 3% over the time period covered by this report (to year 2010) are realistic; others believe that the experience of the past year or two will prevail, and there will be no net escalation results in a doubling of cost in 35 years, roughly the time period covered by this study (1% has a doubling period of 70 years; 3% about 23 years). A limited resource such as natural gas and oil in a growing economy has considerable price leverage. In a stagnant economy such as the world has experienced over the past year or two, a limited resource has much less leverage.

In this series of sensitivity tests, world oil prices are assumed to escalate at rates of 1% and 3% to evaluate the effects of lower and higher fuel price escalation rates on the cost of power and electricity demand. Because other fossil fuel price escalation rates are assumed to be linked to world oil prices, the long-term escalation rates of other fuel prices are modified to be consistent with the price of oil. In Table 7.1 the levelized costs of power for the 1% and 3% fuel price escalation rates are compared with the costs of power for the 2% fuel price escalation rate case (presented in Section 6.0).

TABLE 7.1 Effect of Alternate Fossil Fuel Escalation Rates on Levelized Cost of Power (mills/kWh)

	Base Case 2% Escalation		1% Escalation		3% Escalation	
	1981-2010	1981-2050	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	56	61	60	67
Plan 1B	58	59	57	61	57	58
Plan 2A	59	66	57	64	61	69
Plan 2B	58	61	58	63	57	58
Plan 3	59	65	58	62	62	71
Plan 4	59	66	55	62	61	68

In the 1% real escalation rate case, levelized power costs generally dropped in the cases using relatively high amounts of fossil fuels for generation (Plan 1A, 3, and 4) over both periods of analysis. This drop reflected the reduced cost of generation. The plans using relatively less fossil fuels for generation (Plans 1B, 2A, and 2B) have a slight cost reduction over the 1981-2010 time period, but show a slight increase in power costs over the longer time period. This increase occurs because the price of fossil fuels relative to electricity gradually decreases, causing consumers to switch fuels. This switch reduces demand for electricity, which slightly increases the cost of electricity over the longer time period for these plans. The impacts of lower and higher fuel price escalation on the demand for electricity are discussed later.

A 1% fuel price escalation rate reduces the relative advantage of the plans that include the Upper Susitna project. If fuel escalation rates were further reduced, the relative advantage of those plans would be reduced further.

In the case assuming a 3% escalation rate in fuel prices, power costs significantly increased in those plans using relatively high amounts of fossil fuels and decreased in the plans less reliant on fossil fuel for generation. In the cases using relatively large amounts of fossil fuel for generation, the higher costs of fuel increased the cost of generation. In the plans less reliant on fossil fuels, the costs declined because the price of electricity declined relative to fossil fuels. This decline caused a switch to electricity, which increased demand. The increased demand, in turn, reduced the costs. (The consumer reaction to changes in relative prices is discussed in greater detail in Section 7.1.3.)

7.1.2 Effects of Uncertainty in Fossil Fuel Prices on Demand for Electricity

The effects of the alternative fossil fuel price escalation rates on the peak demand for electricity in the year 2010 are presented in Table 7.2.

TABLE 7.2 Effect of Alternate Fossil Fuel Price Escalation Rates on Peak Electricity Demand in 2010 (MW)

	Peak Demand (MW)		
	Base Case 2% Escalation	1% Escalation	3% Escalation
Plan 1A	1260	1160	1310
Plan 1B	1350	1160	1560
Plan 2A	1130	1040	1160
Plan 2B	1250	1050	1450
Plan 3	1190	1130	1200
Plan 4	1220	1180	1260

For the 1% fuel escalation rate case, the plans that rely relatively heavily upon fossil fuels (Plans 1A, 3, and 4) generally show a slight decline in demand, whereas those less dependent upon fossil fuels show a more significant decline. In the former cases, both electricity and fossil fuel prices are lower than in Plan 1A, causing the overall energy demand for both fossil fuels and electricity to increase. However, the effects of fuel switching away from electricity appears to outweigh the overall energy demand effects of lower electricity prices.

The plans that are less reliant on fossil fuels (Plans 1B, 2A, and 2B) show a larger decline in demand. In these cases, the price of fossil fuels decreases relative to the price of electricity because the price of electricity is not heavily influenced by the drop in fossil fuel prices. This relative price advantage of fossil fuels causes fuel switching to take place away from electricity and toward fossil fuels.

In the 3% fuel escalation case the demand for electricity goes up in all cases for the same reasons it declined in the previous case. In these cases the price of electricity goes down relative to fossil fuels, causing fuel switching to electricity. Again, the greatest amount of fuel switching takes place in those cases that are less reliant on fossil fuels.

7.1.3 Consumer Reaction to Changes in the Price of Electricity Relative to Other Forms of Energy

The effects of fuel and electricity price changes depend on consumer reactions to the changes. These reactions were summarized in the RED model in a set of short- and long-run demand "elasticities" for electricity. An elasticity is the ratio of two percentage changes. Own-price elasticity is the percentage change in quantity of electricity demanded divided by a given percentage change in the price of electricity. Cross-price elasticity is the percentage change in quantity demanded of electricity for a given percentage change in the prices for substitute fuels such as natural gas and oil. The own-price and cross-price elasticities of demand are usually larger the longer the period of time over which the consumer has to react to a given change in prices. The consumer is able to make more costly changes in fuel-using equipment over the longer time period.

For example, Figure 7.1 shows the effect of price changes in the base case. In the figure, the line marked "No Price Effects" shows what the forecast electricity demand would have been had real prices of electricity, fuel oil, and natural gas remained constant over the forecast period, and if present trends in sizes of buildings and appliances had continued. However, the actual forecast assumes that the price of electricity more than doubles in 1982 dollars in Anchorage, while in Fairbanks it first falls by 50%, then slowly rises again to its 1980 value. Fuel oil about doubles in price over the forecast period in both areas, while natural gas quadruples in price in

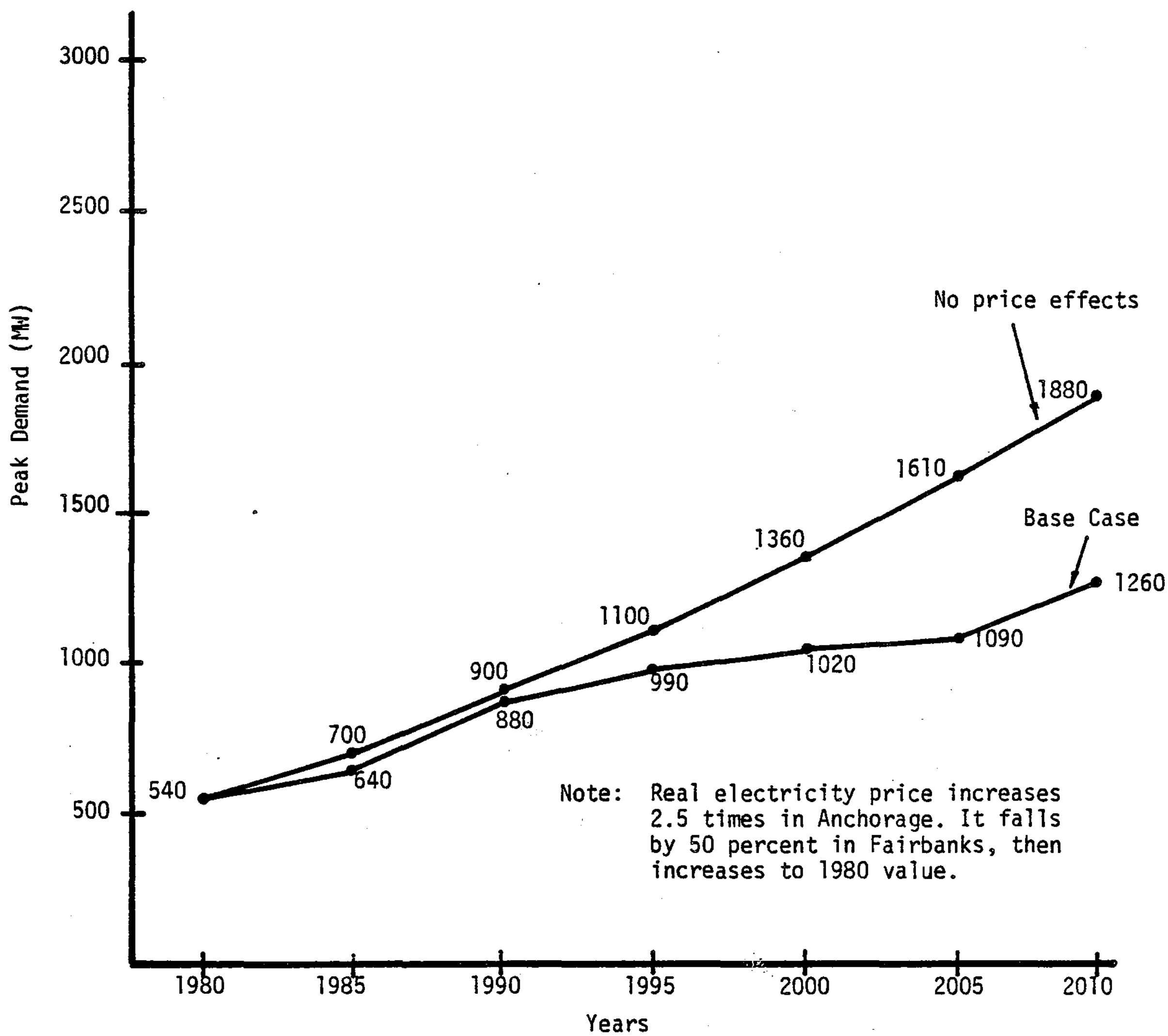


FIGURE 7.1. Effect of Energy Price Changes on Electricity Demand

Anchorage and falls by 50% or more in Fairbanks. With such significant price changes in the cost of energy and significant changes in the relative prices of fuels, actual forecasted electricity demand is considerably reduced from the value it would have had, had there been no changes in price. This is shown as the line "Base Case" in Figure 7.1. The difference is substantial by the year 2010--about 620 MW--and represents price-induced conservation and fuel switching.

The RED model relies on price elasticities derived from a review of econometric estimates of demand for electricity in the United States to forecast the effects of fuel price changes on the demand for electricity. The "best guess" elasticities used when the model is run in its certain mode (default values) are shown in Table 7.3.

Because various sources estimated the elasticities in different contexts, using a variety of data sets, and producing different estimates, the RED model

TABLE 7.3. Default Values Used in the RED Model

Sector	Short-Run (1 Year) Elasticity Percentage Change in Electricity Demanded for a One Percent Increase in the Price of: Electricity	Fuel Oil	Natural Gas
Residential	-.15	.01	.05
Business	-.30	.03	.05
	Long-Run (7 Year) Elasticity Percentage Change in Electricity Demanded for a One Percent Increase in the Price of: Electricity	**Fuel Oil**	**Natural Gas**
Residential	-1.50	.13	.50
Business	-1.00	.20	.30
	Load Factors Electricity	**Fuel Oil**	**Natural Gas**
All Sectors Combined	.5573	.4899	.5216

Source: Volume VIII -Railbelt Electricity Demand (Red) Model Specifications also contains a range of values for elasticities that can be selected randomly by the model's Monte Carlo routine. As consumers change their uses of electricity in response to changing energy prices, the pattern of use during the year also will change. Very little data are available to quantitatively link the changes in the pattern of electrical energy use in Alaska to changes in the ratio of average annual load to peak demand when relative prices change. To reflect this uncertainty in the ratio of average annual load to peak demand - the so-called "load factor" - the RED model allows the annual load factor to vary. The historic average in each load center is used as the load factor when the model is run in its certainty-equivalent mode. In each load center, the load factor is allowed to range from the highest to the lowest value recorded for any utility in the load center during the 1970s. The assumed range of elasticities and load factors for each load center are shown in Table 7.4.

TABLE 7.4 Range of Elasticities of Demand and Load Factors Used in the RED Model

Sector	Short-Run (1 Year) Elasticity Percentage Change in Electricity Demanded for a One Percent Increase in the Price of:		
	Electricity	Fuel Oil	Natural Gas
Residential	-.08 to -0.54	.01 to .03	.05 to .10
Business	-.20 to -.54	.01 to .05	.01 to .10

	Long-Run (7 Year) Elasticity Percentage Change in Electricity Demanded for a One Percent Increase in the Price of:		
	Electricity	Fuel Oil	Natural Gas
Residential	-1.02 to -2.00	.05 to .21	.17 to .81
Business	-.87 to -1.36	.15 to .31	.18 to .41

	Load Factors		
	Electricity	Fuel Oil	Natural Gas
All Sectors Combined	.492 to .634	.416 to .591	.454 to .612

Source: Volume VIII-Railbelt Electricity Demand (Red) Model Specifications

Figure 7.2 shows the effect on peak demand of allowing price elasticities and load factors to vary. The shaded zones on the figure are the 50% "confidence intervals" for the high, medium, and low economic scenarios combined with the Plan 1A and 2% world oil price escalation. The probability is 25% that it is lower than the lower bound in each case and 25% that it is higher than the upper bound. The probability is therefore 50% that the true value lies between those values. As Figure 7.2 shows, the peak demand's central value for year 2010 is 1280 MW, with a 50% probability of lying between 1150 and 1400 MW. Using the default value for elasticity of demand and load factors in the moderate case, demand was 1260 MW. The figures differ for Monte Carlo and certainty-equivalent cases because only 20 iterations were performed to generate the distributions in Figure 7.2. Increasing the number of iterations to 100 reduces the mean demand to 1260 MW. In the figure shown, 1280 MW is the median demand. The figure indicates that a reasonable rule-of-thumb for the forecasts is that, given the economic scenario, the forecast demand is the central (default) value, plus or minus about 100 MW with 50% confidence. If higher confidence levels were required, the confidence interval would widen somewhat. Therefore, as Figure 7.2 shows, the forecast cases are virtually indistinguishable until late in the forecast period because of uncertainty concerning consumer response to energy prices.

7.2 UNCERTAINTY IN ELECTRICITY DEMAND FORECASTS

7.2.1 High-High Economic Scenario

As discussed in Section 3, electrical demand forecasts were made for six economic scenarios. The analysis and discussion presented in Section 6 assumed the medium or base case, load growth scenario (MM, medium economic growth and medium state spending). In this section the effects of higher load forecasts on the levelized cost of power are presented and discussed. The analysis was conducted for the high economic scenario (HH, high economic growth and high state spending). The peak demand and annual energy consumption for the year 2010 for the medium (base case) and high economic scenario are presented in Table 7.5

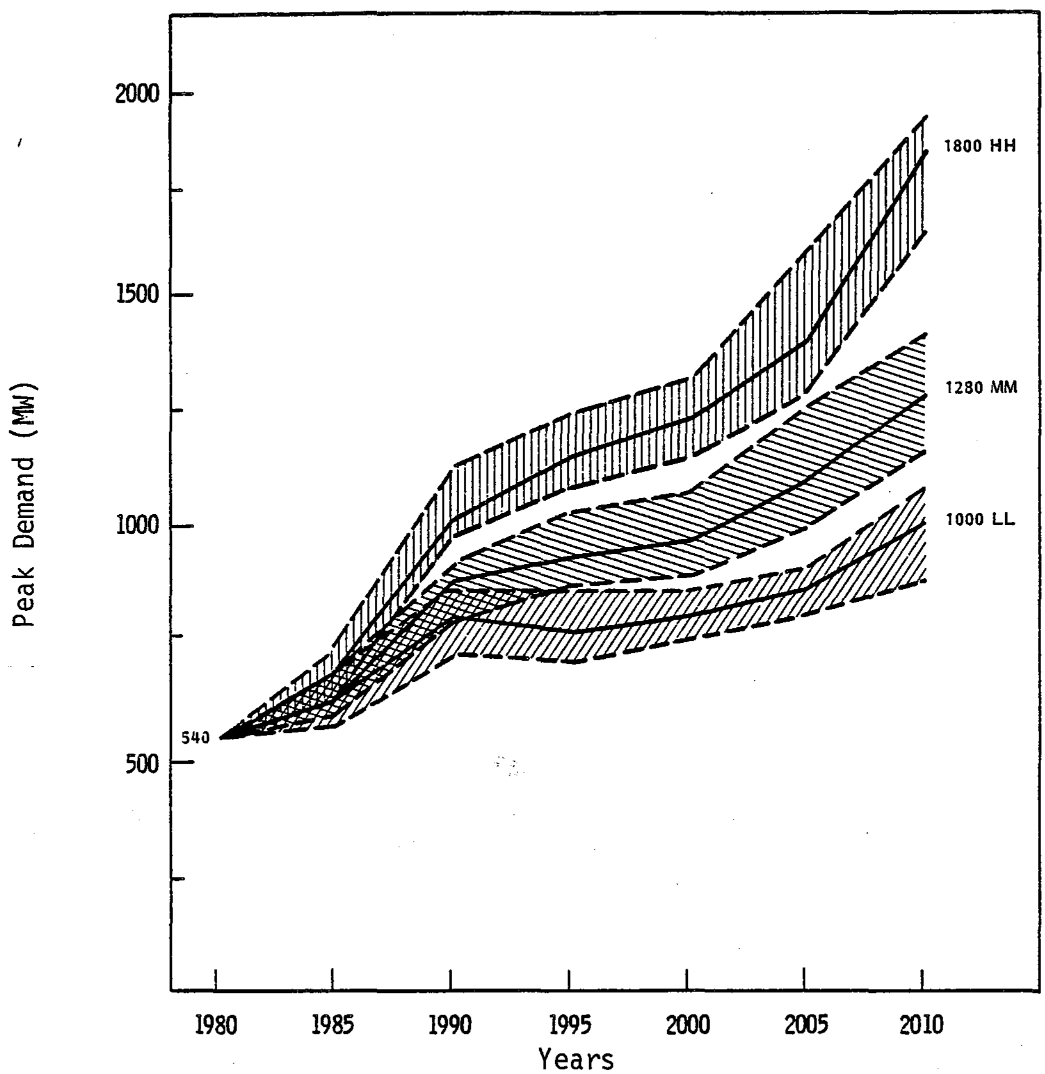


FIGURE 7.2. Sensitivity Test of Peak Demand: Monte Carlo Simulation with Varying Price Elasticities and Load Factors[a]

(a) Shaded areas equal 50% confidence intervals.

TABLE 7.5 Peak Demand and Annual Energy Use in 2010 for the Medium and High Economic Scenarios

	Base Case Medium Economic Scenario		High Economic Scenario	
	Peak (MW)	Annual Energy (GWH)	Peak (MW)	Annual Energy (GWH)
Plan 1A	1260	6260	1760	9010
Plan 1B	1350	6690	1890	9630
Plan 2A	1130	5520	1510	7650
Plan 2B	1250	6100	1820	9160
Plan 3	1190	5910	1610	8280
Plan 4	1220	6060	1650	8470

The levelized costs of power for each plan for the medium economic scenario are compared to the levelized costs of power for the high economic scenario in Table 7.6 for the time periods 1981 to 2010 and 1981 to 2050.

TABLE 7.6 Levelized Costs of Power for Medium and High Economic Growth Scenarios (mills/Kwh)

	Base Case Medium Economic Scenario		High Economic Scenario	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	60	66
Plan 1B	58	59	58	60
Plan 2A	59	66	58	66
Plan 2B	58	61	57	59
Plan 3	59	65	62	68
Plan 4	59	66	61	68

As shown in Table 7.6, in the high economic scenario Plan 2B has the lowest levelized cost of power over both periods of analysis (57 mills/kWh over the 1981-2010 time period and 59 mills/kWh over the 1981-2050 time period). Plans 1B and 2A both yield 58 mill/kWh power over the 1980-2050 time horizon.

However, over the extended time horizon Plan 1B gives a cost of power of 60 mills/kWh compared with 66 mills/kWh for Plan 2A. Plans 1A, 3, and 4 all have higher costs of power over both time horizons. This analysis indicates that the plans including the Upper Susitna project become more attractive for higher electrical energy demands.

7.2.2 Low-Low Economic Scenario

In this sensitivity test, the effects of lower forecasted electrical demand on the levelized costs of power are evaluated for each of the electric energy plans. For this comparison the low private economic growth and low state spending economic scenario is used. The peak demand annual energy forecasted for the year 2010 for the medium and low economic scenarios is presented in Table 7.7.

TABLE 7.7 Peak Demand and Annual Energy in 2010 for Medium and Low Economic Scenarios

	Base Case Medium Economic Scenario		High Economic Scenario	
	Peak (MW)	Annual Energy (GWH)	Peak (MW)	Annual Energy (GWH)
Plan 1A	1260	6260	1000	4940
Plan 1B	1350	6690	990	4880
Plan 2A	1130	5520	920	4490
Plan 2B	1250	6100	980	4760
Plan 3	1190	5910	960	4730
Plan 4	1220	6060	1010	4980

The low economic scenario results in a 20% decrease in annual energy use and a similar decrease in peak demand.

The levelized costs of power for the medium and the low economic scenarios are presented in Table 7.8 for the two periods of analysis, 1981-2010 and 1981-2050.

TABLE 7.8 Levelized Costs of Power for Medium and Low Economic Growth Scenarios (mills/Kwh)

	Base Case Medium Economic Scenario		Low Economic Scenario	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	65
Plan 1B	58	59	58	63
Plan 2A	59	66	58	66
Plan 2B	58	61	57	61
Plan 3	59	65	58	67
Plan 4	59	66	57	64

For the low economic forecast and 30-year time frame, the lowest levelized costs of power result from Plans 2B and 4 (57 mills/kWh). Plans 1A, 1B, 2A and 3 have slightly higher costs of power (58 mills/kWh). Over the longer time period Plans 1B and 2B have slightly lower costs. Plan 1B, including Upper Susitna, is the most adversely affected by low growth, while Plan 4 is most favorably affected.

7.2.3 Effects of Electrical Load Growth Higher and Lower Than Forecasted After 1990

As mentioned earlier there is a relatively large amount of uncertainty regarding growth in electrical demand in the Railbelt. Unforeseen events may cause damage to be significantly higher or lower than expected. Factors contributing to this uncertainty include the following:

1. The uncertainty in world crude oil prices. Crude oil prices affect electrical demand in the Railbelt in two ways. Firstly, since the State is heavily dependent upon royalty and severance tax revenues from the North Slope oil fields, lower world oil prices reduce State revenue which, in turn, reduces the amount of money available to be expended in the State. Since state government spending accounts for a relatively large amount of total expenditures in Alaska, world crude oil prices have a major impact on economic growth in the State.

Secondly, since fuel oil and other fossil fuels compete with electricity in many end uses such as space heating, water heating and cooking, and since all fossil fuel prices tend to be influenced by world crude oil prices, crude oil prices affect the decision by the consumer on which energy source to use. If fossil fuel prices are low relative to electricity prices, then consumers will tend to use more fossil fuels and less electricity. Conversely, if fossil fuel prices are high relative to electricity prices, then consumers will tend to use more electricity and less fossil fuels.

2. The uncertainty in large private economic development projects. Construction of large private development projects such as the ANGTS pipeline can have relatively large impact on population and employment and as a result can significantly influence electrical demand.

Perhaps the best strategy to deal with such uncertainty is to retain as much flexibility as possible when planning future electrical generation additions. Policies on strategies can be designed to reduce the risk of having either too much or too little generating capacity at any point in time. Such policies are also referred to as hedging strategies.

The key to maintaining maximum flexibility in electric power planning is to add generating facilities that are relatively small and have short licensing and construction times. However, in most cases, long-term electricity generation costs from generating technologies available in small units and having short construction periods is higher than generation costs from technologies available in larger sizes with longer construction periods. (Examples of generating technologies available in small units with relatively short construction periods include combustion turbine and combined-cycle units. While historically these technologies have offered low generation costs in the Anchorage area because of the availability of low cost natural gas, this situation is not expected to continue in the future. Examples of technologies available in large sizes with longer construction periods include coal-fired steam-electric units and large hydroelectric facilities.) These considerations lead to trade-offs between generally lower cost generation technologies that require longer lead times but that reduce flexibility to respond to changes in demand, and generally higher cost generation technologies that allow shorter lead times and thus provide more flexibility in planning.

In the context of the present power planning situation in the Railbelt with the relatively high amount of uncertainty associated with future load growth in the region, consideration of hedging strategies tends to favor generating technologies that have relatively short construction periods and that can be added in relatively small units. Therefore, technologies such as combustion turbine units and other small technologies would be attractive compared to technologies such as large hydroelectric projects or coal-fired steam turbine generation.

Because of the relatively large size of the Upper Susitna project (600 MW for the first stage of Watana), the feasibility of this project must be carefully evaluated with respect to the considerations of hedging strategies outlined above.

To evaluate the impact of incorrect initial forecasts of demand on cost of power, two cases were examined. The first case assumes that the state begins to build for demand that never materializes because of post-1990 events. The second case assumes that post-1990 demand is initially underestimated, and shorter term solutions (at higher cost) must be formed to meet higher demand.

7.2.4 Load Growth Begins as Projected in the Medium Economic Growth Scenario but Levels Off After 1990

In this case electrical demand is assumed to grow as projected in the base case medium-medium (MM) economic scenario but levels off and declines slightly beyond 1990. This case is similar to the load growth in the nonsustainable spending scenario (CC). The electrical demand for this case is shown in Figure 7.3, and the levelized costs of power are given in Table 7.9.

TABLE 7.9 Levelized Costs of Power for Reduction in Electrical Demand after 1990 (mills/kWh)

	Base Case Medium Economic Scenario		Reduced Growth Scenario	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	67
Plan 1B	58	59	59	67
Plan 2A	59	66	58	67
Plan 2B	58	61	60	69
Plan 3	59	65	59	70
Plan 4	59	66	57	66

As shown in Table 7.9, the reduced demand has relatively little impact on the levelized costs of power over the 1981 to 2010 time period. Over the longer time period the costs of power of all the plans go up; however, the costs of power for Plans 1B and 2B, which include the Upper Susitna Project, go up more than the costs of power for the other plans. This increase results because the Watana Dam is build and comes on-line in 1993, about the time when the demand begins to taper off. The Devil Canyon Dam is not built in either Plan 1B or 2B in this test.

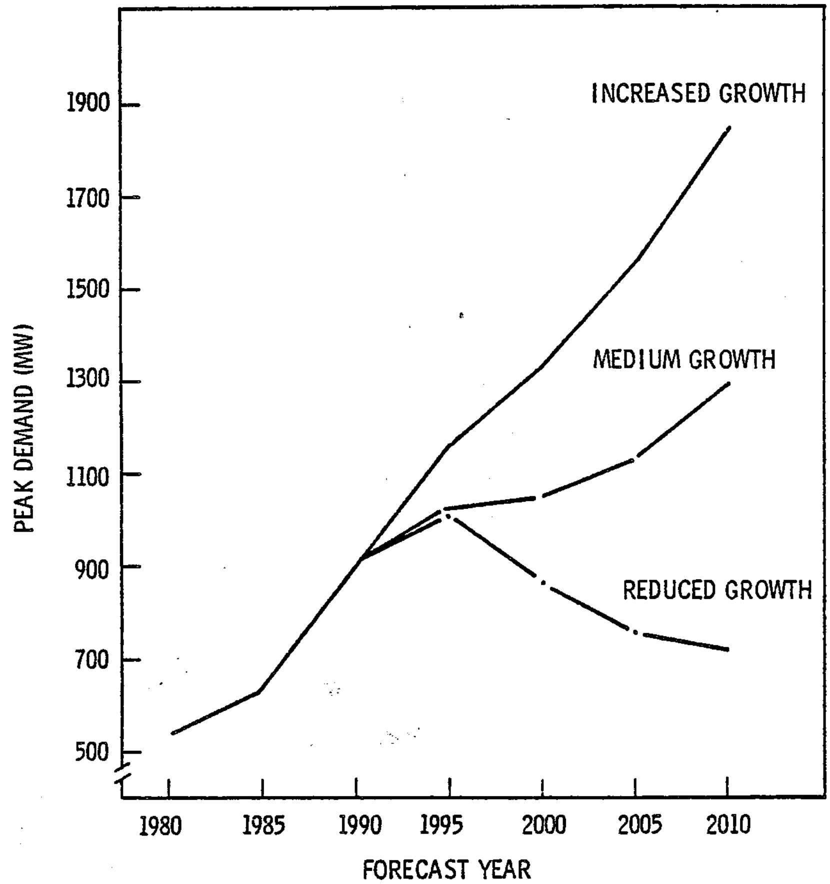


FIGURE 7.3. Electrical Load Growth for Increased and Reduced Growth Beyond 1990

7.2.5 Load Growth Begins As Projected in the Medium Economic Growth Scenario but Increases After 1990

In this sensitivity test the electrical demand is assumed to grow as projected in the base case medium-medium economic scenario but increases after

1990. Demand increases are assumed to be same as the industrialization case by 2010. The electrical demand for this case is shown in Figure 7.3 and the levelized costs of power for this case are shown for the two periods in Table 7.10.

TABLE 7.10 Levelized Costs of Power for Increase in Electrical Demand After 1990 (mills/kWh)

	Base Case Medium Economic Scenario		Increased Growth Scenario	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	66	74
Plan 1B	58	59	63	68
Plan 2A	59	66	71	80
Plan 2B	58	61	62	67
Plan 3	59	65	69	79
Plan 4	59	66	68	78

In the increased growth scenario the costs of power increase substantially in both time periods. The cases including the Upper Susitna projects (1B and 2B) provide the lowest cost of power in both time periods.

7.3 UNCERTAINTY IN COST AND AVAILABILITY OF MAJOR ALTERNATIVES

7.3.1 Capital Cost of Upper Susitna Project-20% Lower and Higher Than Estimated

The large size and capital intensive nature of the Upper Susitna project makes the capital cost estimates for this project an important determinant of the overall power costs within the region. The capital cost estimates for the Upper Susitna Project were developed by Acres American Incorporated (1981b) as part of the Susitna hydroelectric project feasibility study and are presented in Section 4.

To evaluate the possible effects of lower and higher capital costs, sensitivity tests were done assuming that the capital costs of the project are 20% lower and 20% higher than shown. Because the Upper Susitna project is included only in Plans 1B and 2B, only those cases were rerun. The results of these sensitivity tests are presented in Table 7.11 for the periods 1981-2010 and 1981-2050.

TABLE 7.11 Levelized Costs of Power for Upper Susitna - Capital Costs 20% Lower and Higher Than Estimated (mills/kWh)

	Base Case		20% Lower		20% Higher	
	1981-2010	1981-2050	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	64	58	64
Plan 1B	58	59	54	54	61	64
Plan 2A	59	66	59	66	59	66
Plan 2B	58	61	54	55	62	66
Plan 3	59	65	59	65	59	65
Plan 4	59	66	59	66	59	66

The levelized costs of power are relatively sensitive to the changes in these capital cost estimates. If the capital costs are 20% lower than estimated, Plans 1B and 2B provide significantly lower power costs than the other plans in both periods of analysis (especially in the 1981-2050 time period). If the capital costs are 20% higher than estimated, Plans 1B and 2B become relatively high-cost plans relative to other plans in the 1981-2010 time period and about equal over the longer time period.

7.3.2 Capital Cost of Coal Steam-Electric Power Capital Costs - 20% Higher and Lower Than Estimated

Capital costs were estimated for 200-MW coal-fired steam-electric power plants located in both the Beluga and Nenana areas. As presented in Section 4, these costs are $2070/kW for a plant located at Beluga and $2150/kW for a plant located at Nenana. New coal steam-electric plants are included in Plans 1A and 3. The results of these sensitivity tests are presented in Table 7.12 for the two periods of analysis, 1981 to 2010 and 1981 to 2050.

TABLE 7.12 Levelized Costs of Power for Coal Steam Turbine Plant - Capital Costs 20% Lower and Higher Than Estimated (mills/kWh)

	Base Case		20% Lower		20% Higher	
	1981-2010	1981-2050	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	57	62	59	65
Plan 1B	58	59	58	59	58	59
Plan 2A	59	66	59	66	59	66
Plan 2B	58	61	58	61	58	61
Plan 3	59	65	57	63	60	67
Plan 4	59	66	59	66	59	66

As shown in Table 7.12, the effects of higher and lower coal plant capital costs have little effect on the relative costs of the various plans.

7.3.3 Penetration of Conservation Alternatives Higher and Lower Than Estimated

In this case the maximum penetration of conservation alternatives was increased and decreased by 20% to test their impact on the cost of power. The conservation alternatives included in this plan are building conservation, passive solar space heating, active solar hot water heating, and wood-fired space heating. To test the sensitivity of subsidized conservation on the cost of power, the number of installations of all conservation options was simultaneously increased or decreased by 20%. The subsidized market was not allowed to exceed 100% of households in any case. However, if the decreased amount fell below the level of conservation predicted with no subsidies, the nonsubsidized market penetration rate was also decreased by 20% to permit the lower number. Because these alternatives are dealt with explicitly only in cases 2A and 2B, only those cases were rerun. The results are shown in Table 7.13 for the two periods of analysis.

TABLE 7.13 Levelized Costs of Power for Penetration of Conservation Alternatives 20% Higher and Lower Than Estimated (mills/kWh)

	Base Case		20% Lower		20% Higher	
	1981-2010	1981-2050	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	64	58	64
Plan 1B	58	59	58	59	58	59
Plan 2A	59	66	60	68	59	65
Plan 2B	58	61	59	62	57	60
Plan 3	59	65	59	65	59	65
Plan 4	59	66	59	66	59	66

As shown in Table 7.13, changes in the penetration rates have relatively little effect on the cost of power. In general, lower penetration rates tend to increase the costs of power, whereas higher penetration rates tend to decrease cost of power. This situation reflects the fact that the conservation alternatives analyzed in the study generally cost less per kWh saved than the cost of generation and delivery displaced by the conservation alternatives.

7.3.4 Effects of Increased Thermal Generating Efficiency

One of the factors that influences the cost of generating electricity using fossil fuels is the heat rate. The heat rate is a measure of the efficiency with which a generating unit converts Btus of fuel into kWhs of electricity. As newer materials and designs for thermal generating plants are developed, the heat rates for these plants are expected to go down; i.e., they are expected to become more efficient. In this test the heat rates for new thermal options added after 1980 were lowered, as shown in Table 7.14, to reflect such improvements in performance. Because some of this added capacity is already under construction or on order, these assumptions may overstate the overall savings that result from lowered heat rates.

TABLE 7.14 Assumed Improvements in Heat Rates (Btu/kWh)

Generating Alternative	Base Case Heat Rate	Improved Heat Rate
Combustion Turbine	12,200	10,000
Combined Cycle	8,500	8,000
Coal Steam Turbine	10,000	9,500
Fuel Cells	9,200	8,500
Coal Gasification Combined-Cycle	9,300	8,700

The effects of these improvements were evaluated in Plans 3 and 4 and presented in Table 7.15 for the two periods of analysis.

TABLE 7.15 Levelized Costs of Power for Lowered Heat Rates in Thermal Generation (mills/kWh)

	Base Case		Improved Heat Rates	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	64
Plan 1B	58	59	58	59
Plan 2A	59	66	59	66
Plan 2B	58	61	58	61
Plan 3	59	65	58	64
Plan 4	59	66	56	63

As shown, these changes in thermal efficiency make Plan 4 the lowest cost alternative over the shorter time period. However, the effects of these changes are relatively small. The longer-term ranking of Plans is virtually unaffected.

7.3.5 Impact of Using Fuel-Cell Combined-Cycle Generation Rather Than Fuel-Cell Stations

Because the number of alternative generating technologies that can be included in any single model run is limited, the fuel-cell combined-cycle alternative was not included in Plan 4. To test the effect of this technology on the cost of power, the fuel-cell was replaced with the fuel-cell combined-cycle alternative in one test. Although the fuel-cell combined-cycle has a higher capital cost than fuel-cell station, the combined-cycle operates more efficiently. The impact on the levelized cost of power of this sensitivity test is shown in Table 7.16 for the two periods of analysis.

TABLE 7.16 Levelized Costs of Power for Using Fuel-Cell Combined-Cycle Units Rather Than Fuel-Cell Stations - Plan 4 (mills/kWh)

	Base Case		Fuel-Cell Combined-Cycle	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	64
Plan 1B	58	59	58	59
Plan 2A	59	66	59	66
Plan 2B	58	61	58	61
Plan 3	59	65	59	65
Plan 4	59	66	61	69

As shown, the levelized cost of power increases if fuel-cell combined-cycle units are used. The increase in efficiency does not offset the increase in capital cost.

7.3.6 Impact of 50% Higher Fuel-Cell Station and Coal-Gasifier Combined-Cycle Capital Costs

In general, the cost of emerging technologies tends to be higher when they become commercially available than initially estimated. To test the impact of such possible increases, the capital cost of fuel-cell stations and coal-gasifier combined-cycle alternatives was increased by 50%. Plan 3 includes coal-gasifier combined-cycle facilities and Plan 4 includes fuel-cell stations. The results of these tests are presented in Table 7.17 for the two periods of analysis. These capital cost increases raise the levelized cost of power by 1 to 2 mills in both time periods.

TABLE 7.17 Levelized Costs of Power for Increased Capital Cost of Fuel-Cell Stations and Coal-Gasifier Combined-Cycle (mills/kWh)

	Base Case		Increased Capital Cost	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	64
Plan 1B	58	59	58	58
Plan 2A	59	66	59	66
Plan 2B	58	61	58	61
Plan 3	59	65	61	67
Plan 4	59	66	59	67

7.3.7 Capital Cost of Chakachamna Hydroelectric - 20% Lower and Higher Than Estimated

The Lake Chakachamna project is a relatively large hydroelectric project that would be located on the west side of Cook Inlet. It is a key alternative included in Plans 1A and 2A. Two cost estimates have recently been prepared on two different concepts of developing the project. As part of this study, a cost estimate was prepared for a project with a peak capacity of 480 MW. The total cost of this concept is \$1.01 billion or \$2100/kW. In another project being conducted for the Alaska Power Authority, a preliminary cost of \$3860/kW was estimated for a 330-MW project (excluding transmission costs). The capacity in the 330-MW concept was reduced to allow minimum stream flow in the Chakachamna River to maintain the fish runs existing in the river. The 330-MW project concept was used in this report since the 330-MW concept reflects more research concerning the possible environmental impacts of the projects.

However, to test the impact of the lower capital cost estimate on the cost of power, a sensitivity test was run assuming that the total project cost was \$1.01 billion for a capacity of 330-MW (\$3060/kW). This estimate is 21% lower than the Bechtel estimate for the same project. Another sensitivity test was performed by increasing the capital cost of the project by 20%. The results of these tests are shown in Table 7.18 for the two periods of analysis.

TABLE 7.18 Levelized Costs of Power for Chakachamna, Capital Costs 20% Lower and Higher Than Estimated (mills/kWh)

	Base Case		Lower Capital Cost		Higher Capital Cost	
	1981-2010	1981-2050	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	57	62	59	65
Plan 1B	58	59	58	59	58	59
Plan 2A	59	66	57	64	60	68
Plan 2B	58	61	58	61	58	61
Plan 3	59	65	59	65	59	65
Plan 4	59	66	59	66	59	66

The changes in the capital costs of the Chakachamna project have a relatively small impact on the levelized cost of power over both time horizons. Little change occurs in the relative ranking of the plans in either the lower or higher capital cost test.

7.3.8 Use of Healy Coal in the Anchorage Area

The development of the Beluga coal field is uncertain at this time. Because development of this coal field is a key assumption in several electric energy plans, this uncertainty must be recognized and taken into account in the decision process. One possible alternative to using Beluga coal at minemouth plants is to transport coal via the Alaska Railroad from the Healy area to steam-electric plants located in the greater Anchorage area. This option would be quite different in several ways from the concept of using Beluga coal at minemouth generating stations (e.g., there would be differneces in environmental impacts). In this sensitivity test the only difference is assumed to be the price of coal, which is assumed to be the price at Healy plus transportation costs to Anchorage. Sensitivity analyses were run for Plans 1A and 3. The impacts of this assumption are shown in Table 7.19 for the two periods of analysis.

TABLE 7.19 Levelized Costs of Power Assuming Healy Coal is Used in Anchorage Area (mills/kWh)

	Base Case		Healy Coal in Anchorage	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	59	65
Plan 1B	58	59	58	59
Plan 2A	59	66	59	66
Plan 2B	58	61	58	61
Plan 3	59	65	61	68
Plan 4	59	66	59	66

As shown, this test indicates that the levelized cost of power would increase by 1 to 2 mills/kWh over the 1981 to 2010 period and by 1 to 3 mills/kWh over the longer time period.

7.3.9 Delay in Upper Susitna Project from 1993 to 1998

For large construction projects, such as the Upper Susitna, the possibility of delays always exists. To test the potential impact of delays on the cost of power, runs were made assuming that Watana does not come on-line until 1998. Devil Canyon was assumed not to come on-line within the time horizon. The effects of this delay for plans 1B and 2B are presented in Table 7.20 for the two periods of analysis.

TABLE 7.20 Levelized Costs of Power Assuming Watana Dam Delayed Until 1998 (mills/kWh)

	Base Case		Delay in Watana	
	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	64	58	64
Plan 1B	58	59	59	64
Plan 2A	59	66	57	63
Plan 2B	58	61	58	63
Plan 3	59	65	59	65
Plan 4	59	66	59	66

Delaying the Upper Susitna project by 5 years and providing short construction time generation alternatives in the interim has relatively little impact on the levelized cost of power over the 1981 to 2010 time period. The delay slightly increases the costs of power over the 1981 to 2050 period.

7.4 EFFECTS ON ELECTRICITY DEMAND OF STATE SUBSIDIES TO COVER CAPITAL COSTS OF NEW GENERATING FACILITIES

As discussed in Section 8, the State of Alaska has the legal framework in place to provide subsidies and/or loans to finance electrical generation projects. If the State does not require market rate of return on these funds, the cost of power from projects financed this way would be lower than if capital costs were fully recovered. One potential major impact of reduced costs of power would be an increase in the demand for electricity. Two sensitivity runs were made assuming that extreme forms of a policy were implemented: the State was assumed a) to pay the capital costs for all new generating facilities and b) not to require any capital recovery in electric energy Plans 1A and 1B. Only recovery of operating and maintenance costs were assumed to be required.

The levelized cost of power and peak demand for the medium economic scenario and the no-capital-recovery assumption are presented in Table 7.21.

TABLE 7.21 Levelized Cost of Power and Peak Demand Assuming No Capital Recovery (mills/kWh)

	Medium Economic Scenario		No-Capital-Cost Recovery	
	Levelized Cost of Power 1981-2010	Peak Demand 2010 (MW)	Levelized Cost of Power 1981-2010	Peak Demand 2010 (MW)
Plan 1A	58	1260	42	2302
Plan 1B	58	1350	36	2964

As the table shows, the resulting very low price of power to the consumer causes large-scale fuel switching to electricity and few incentives to conserve in existing uses. Demand in the year 2010 increases by about 1.8 times in Plan 1A and by about 2.2 times in Plan 1B. A greater increase occurs in Plan 1B because the costs of power from hydroelectric facilities consist almost entirely of capital charges that are now absorbed by the State in these cases.

The real financial resources the state must spend to generate the power in the no-capital-recovery case are higher than the 42 or 36 mills shown, although the consumer sees only the 42 or 36 mill charge. These real resource costs most likely will be higher than the 58 mills in the unsubsidized case because demand is higher and will require that some higher cost generating capacity be built.

These sensitivity tests indicate the State's influence over demand for electricity with capital subsidy policies. Less ambitious approaches requiring either repayment of the capital costs or some positive rate of return will tend to force the demand and prices in Table 7.21 toward the base case.

7.5 SENSITIVITY TEST IMPLICATIONS

To summarize the effects of the sensitivity tests, it may be useful to distinguish between a change in absolute power costs and a change in the ranking of the plans. For example, the unexpected reduced growth scenario had little effect on absolute power costs for most plans, but moved the high natural gas plan from near last place to first place. On the other hand, an unexpected increase in demand after 1990 sharply increased the absolute costs of all plans with very little effect on ranking. Capital cost overruns on Susitna both adversely affected absolute costs of plans that included Susitna and dropped plans that included Susitna from first place to last. The effects of the two experiements with fuel price escalation were less profound, both in absolute and relative terms. However, with the exception of unexpectedly high demand none of the changes in either absolute power costs or ranking of plans over the 1980 to 2010 time period can be considered large, since changes in absolute levels of costs were 2 to 3 mills per kWh, and rank was determined by a spread of 2 to 3 mills. Only over the extended time period were the results more profoundly influenced, with plans that included Susitna more adversely affected by capital cost overruns and the high natural gas plan helped the most by low demand. This suggests that individual events' impacts on power costs, by themselves, do not clearly favor one plan over another. While combinations of events damaging or favoring the case for certain plans are possible, one should carefully consider the combined probabilities of those events before deciding which alternative truly has the lowest power costs.

8.0 CONSIDERATIONS FOR IMPLEMENTATING ELECTRIC ENERGY PLANS

When this study was started, the intended purpose of this section of the report was to identify "institutional constraints" that might prevent implementation of any of the electric energy plans. This section also was to include recommendations for legislation that would facilitate implementation of a preferred electric energy plan. However, with the passage of Senate Bill 25 during the 1981 state legislative session, the approach was changed. SB 25 amended substantially the institutional framework previously in place and established a new set of standards that must be followed by the Alaska Power Authority (APA) before undertaking construction of a power generating facility.

In this section the electric energy plans are evaluated in light of this legislation and the following subjects are discussed: 1) a review of federal legislation to determine if any federal statutes are preventing the state from undertaking any of the electric energy plans; 2) a brief review of the history of the planning and implementation of power generation, transmission and distribution in Alaska, with particular attention to the State's involvement in these areas; and 3) a review of the recently enacted state statute to determine if the electric energy plans can be implemented under it.

8.1 FEDERAL CONSTRAINTS

No federal statutes, rules or regulations absolutely prohibit implementation of any of the alternatives discussed in this report. The closest thing to a federal constraint upon state implementation may be the Fuel Use and Power Plant Act (FUA) of 1978, which initially might be perceived as a bar to using natural gas for generating electricity in new power plants. However, a more extensive analysis indicates that FUA is not an absolute bar, but rather only a legal obstacle that must be negotiated if the State chooses to pursue a natural gas alternative such as Plan 4. This situation is true for several reasons. First, the general proscription against using natural gas has several exceptions. Most likely one or more of these exceptions will be applicable to power generation in Alaska and therefore FUA would not be the absolute constraint it appears to be. Second, FUA may be amended or repealed in the near future because of changing attitudes towards natural gas availability for power generation and the general effort to reduce regulation on the natural gas industry. If the FUA is not repealed or amended, and if none of the exceptions ultimately could apply, FUA would be a bar to the natural gas alternative. However, the application for an exception must be developed and pursued before this situation can be determined. A more complete discussion of FUA implications relative to specific technologies is contained in Volume IV.

Certain environmental laws also could impose a constraint. For example, air-quality standards might prevent adoption of the increased coal-use alternative. Again, however, before this constraint can be determined a substantial amount of baseline data and engineering design work must be accomplished. At this stage in the analysis of that alternative, the more reasonable conclusion is that environmental standards can be met and that such standards do not pose a constraint that absolutely cannot be satisfied. Under special or unique circumstances, other environmental laws likewise could prevent implementation of a particular option. For example, dam construction was halted on a major hydro project in Tennessee following the discovery of a species of fish protected by the Endangered Species Act. However, complete and detailed studies must be completed before such unique events can be predicted to preclude one or more of the alternatives.

8.2 A HISTORICAL PERSPECTIVE OF POWER PLANNING IN ALASKA

In Alaska, state involvement in planning and directly providing generating capacity and transmission facilities is a new undertaking. Prior to 1976, planning and construction of facilities were performed either by the individual municipal or cooperative utility, or by various federal government agencies. For example, the Alaska Power Administration (now within the U.S. Department of Energy) has owned and operated the Eklutna hydroelectric project since 1955. Chugach Electric Association has planned and assumed responsibility for both constructing hydroelectric projects such as Cooper Lake (1961) and installing gas-fired generating capacity, as well as the transmission and distribution systems associated with these projects. Other local utilities also assumed responsibility for constructing facilities and conducting various feasibility studies. Federal agencies also undertook a variety of feasibility and planning studies.

In the mid seventies, however, these factors began to give way to other forces. Project costs escalated significantly. Additionally, state revenues were rising. In 1976 these forces resulted in passage of a bill creating the Alaska Power Authority. The legislative findings and declaration of purpose in the enabling legislation reveal the broad purposes and objectives that the legislation sought to address.

Lack of direct state involvement in the first fifteen years after statehood can be explained by several factors. Perhaps most significantly is that little need for such involvement was perceived. Another major factor was that the local utilities were able to plan and manage the projects they required. Furthermore, federal funds were available and state funds were not.

Legislative Finding and Policy

(a) The legislature finds, determines and declares that

(1) there exist numerous potential hydroelectric and fossil fuel generating sites in the state;

(2) the establishment of power projects at these sites is necessary to supply lower cost power to the state's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumers of the state, as well as to supply existing or future industrial needs;

(3) the achievement of the goals of lower consumer power costs and long-term economic growth and of establishing, operating and development power projects in the state will be accelerated and facilitated by the creation of an instrumentality of the state with powers to incur debt for constructing, and with powers to operate, power projects.

(b) It is declared to be the policy of the state, in the interests of promoting the general welfare of all the people of the state, and public purposes, to reduce consumer power costs and otherwise to encourage the long-term economic growth of the state, including the development of its natural resources, through the establishment of power projects by creating the public corporation with powers, duties and functions as provided in this chapter (Sec.1 Ch/ 278 SLA 1976).

To accomplish its objectives the Power Authority was given broad powers, including the power to issue bonds, to enter into contracts for the construction, acquisition, operation and maintenance of power projects, and to transmit and sell such power. It was also authorized to conduct feasibility studies for hydroelectric and fossil fuel power generating projects.

The same legislation that created the Power Authority also created the Power Project Revolving Loan fund. The Power Authority administered this fund, which was set up as a "trust fund" to make loans to municipal or public utilities for feasibility studies, preconstruction engineering and design, and construction of hydroelectric and fossil fuel plants. For example, in 1977 $1.6 million was appropriated for the Green Lake Hydroelectric project at Sitka and $540,000 was appropriated to the Power Project Revolving Loan Fund. Through the fund, loans also could be made to cities, boroughs, village corporations, village councils and nonprofit marketing cooperatives for meeting their "energy requirements."

In 1978 the legislature significantly amended its 1976 legislation. The findings were changed to state that the legislature's policy was to foster power projects to supply power at "the lowest reasonable cost . . .," whereas the earlier findings had referred only to "lower cost" power. The provision relating to pricing of power was amended to make certain that the prices at which power was sold covered the "full cost of the electricity and services..."

In 1978 the legislature also adopted resolutions approving the sale of $300,000,000 in revenue bonds for constructing a coal-fired electric generating plant at Healy and authorizing the Power Authority to incur indebtedness ($25,000,000) for Phase I studies for the Susitna Hydroelectric Project. Additionally, the state Senate adopted a resolution directing its Special Committee on the Permanent Fund to investigate the use of money from the permanent fund as a source of revenues for financing hydroelectric projects.

In 1979 the legislature adopted two resolutions related to power. One asked the Army Corps of Engineers to use funds from the Small Hydroelectric Plants program to investigate the feasibility of small-scale hydroelectric projects in rural Alaska as an alternative to the high cost of deisel-generated electricity. The other resolution approved issuance of $120 million in revenue bonds for the Terror Lake Hydroelectric project and $20 million for the Solomon Gulch project.

The 1980 session of the legislature passed substantial legislation relating to the Power Authority. Approximately $50 million was appropriated for some 35 projects. The major appropriations were $15 million for the Tyee Lake project at Wrangell and an $18 million loan for the Swan Lake project. Most other projects received funds ranging from ∿$40,000 to ∿$2 million.

In addition to these direct appropriations, two resolutions authorized the issuance of a variety of revenue bonds. The revenues from those bonds would be used for constructing or acquiring generating facilities or for financing expansion of distributions systems by local utilities. The revenues used included the following:

- $70 million toward construction of the Tyee Lake project
- $120 million for the Swan Lake project
- $110 million for waste heat power generation facilities to be constructed by Golden Valley Electric Association
- $15 million to finance the Lake Elva (Dillingham) project
- $30 million for the Bear Lake project (Prince of Wales Island)
- lesser amounts for Homer Electric Association, Naknek Electric Association, Matanuska Electric Association, Glacier Highway Electric Association and Cordova Electric Association.

In addition to this legislation relating to funding, two bills were passed that again amended substantially the legislation creating the Power Authority. The first bill was a major piece of legislation on the general subject of energy. One part of this bill contained the provisions relating to amendment of the Power Authority statute. These amendments gave the Power Authority the power to recommend power project financing through the use of general obligation bonds--a financing approach that earlier legislation had not contemplated. This bill also amended substantially the provisions creating the Power Project Revolving Loan Fund. One change converted the fund from a revolving loan fund to a direct loan program, with funds for loans appropriated by the legislature to the fund and revenues from repayment deposited in the state's General Fund rather than in the Power Project Fund. The purposes for which loans could be granted were expanded. A provision that permitted the Power Authority to make unsecured loans in some instances also was added. The right to forgive loans was transferred from the Power Authority to the legislature itself.

A new section was added requiring the Authority to undertake reconnaissance studies to identify power alternatives for communities. Under this addition reconnaissance studies must be reviewed by the Division of Budget and Management and submitted to the legislature. The Susitna Hydroelectric project was addressed directly in subsequent 1980 legislation.

In 1981 the legislature again passed electric power legislation, known as SB 25 and SB 26. The legislation, discussed in Section .3, relates to the Power Authority.

The above discussion is not intended as either a comprehensive review of history of electrical power planning and development in the State of Alaska or a detailed review of the legislation relating to the Power Authority. Nonetheless, several relevant observations can be drawn. First, involvement by legislative and executive branches of the state government in the planning, analysis, financing, and direct ownership of power generation and distribution facilities is a recent phenomenon. Second, although recently involved, the State has clearly assumed a major role in these activities. It has preempted significantly most other efforts by federal agencies and by individual utilities. Third, almost yearly the state's involvement has been expanding significantly, in terms of dollar volume, complexity, and geographic area. Fourth, the specific means and parameters that define that involvement have changed frequently.

These observations suggest that the analysis of the 1981 legislation and its impact upon alternative energy projects, which follows, must be viewed with some skepticism. Most likely, these laws will be changed before either the Susitna Project or some alternative can be implemented. Furthermore, because the State's involvement has been so fluid, if an alternative is perceived publicly as preferable to the Susitna Project, the alternative most likely could be implemented directly by changes in the current statutes.

Federal, state, or local governments have become involved in the construction and ownership of power generating facilities for four general reasons. First, government involvement in the decision making process and ownership of production facilities may be appropriate where market imperfections prevent a utility from building the generating capacity it needs to meet demand. Such imperfections do exist in the capital markets and also may be caused by regulatory risks. To address such imperfections, the simplest approach is for the government to make available to the utility a grant or loan to provide a direct source of capital. Normally, the government entity would not have to take over the decision making process or own the facility simply to correct capital market imperfections.

A second reason for government involvement is to give recognition to "externalities" that result in public benefits but which are not factored into an individual utility's decision making process. Many projects undertaken by the federal government are justified on this basis. For example, construction of Tennessee Valley Authority dams was undertaken when public sentiment viewed the creation of construction jobs as a public benefit in itself. In this instance, the government was willing to spend money to put people to work on a construction project even if a private entity was not willing to build the project. For dams built in the West, the externalities that constitute public benefits justifying the expenditure of public dollars include making water available for irrigation and for protection against flooding. Although a private utility might not chose construction of a hydroelectric plant if cheaper energy sources are available, the hydroelectric plant may be the "best" plant when consideration is given to the additional public benefits it creates.

A third reason for government involvement is the decision to effect income transfers through the distribution and consumption of power. If the government wishes to subsidize the consumption of power, it may construct a plant and sell the power below its free market price. The result will be a subsidy to electricity users. Such a subsidy can result in income transfer either to end-use consumers, to the utility distribution companies, or to both.

A fourth reason for government intervention in the decision making or production production process is simply to alter the free market result for political or policy reasons. Thus, if a private utility will generate electricity using methods "A" and "B" and the government prefers methods "C" and "D", it can intervene to ensure use of methods "C" and "D." The government's preference for "C" and "D" might result from objectives already discussed (such as income redistribution) or it might be the result of noneconomic objective. For one example, a noneconomic objective might be the desire to create a local market for coal. If this were a government objective, the government might wish to encourage coal-fired power generation even if that method was not the least-cost method.

8.3 THE CURRENT STATUTORY FRAMEWORK IN ALASKA

The legal authority for the state to implement the electric energy plans is contained in the recently adopted legislation that revises the legislation creating the Alaska Power Authority. The provisions creating the Alaskan Energy Program, A.S. 44.83.380 et seq (SB 25), are especially important. This statute creates a fund, the revenues of which may be used for, among other things, reconnaisance, feasibility and construction of power projects (including all related costs of such construction). The fund may not be used for operation and maintenance which, as discussed below, creates a significant bias in planning. Before the revenues can be used for constructing a project, the project must satisfy the following conditions:

1. The project must be economically feasible and after construction must be able to provide revenue sufficient to return annually to the State five percent (5%) of the amount that the Power Authority has spent from the fund for the project.

2. The project must provide the lowest reasonable power cost to the utility in the market area for the estimated life of the power project, whether operated by itself or in conjunction with other power projects in the market area.

3. The project must operate either on renewable energy resources such as hydroelectric, wind, biomass, geothermal, tidal, solar, temperature differentials of the ocean, or coal, peat, waste heat, or fossil fuel.

4. The project must be approved by the legislature and funds appropriated by the legislature.

Because these limitations are defined primarily in economic and political terms and not in terms of engineering or hardware, the statute appears to have enough flexibility to permit the Power Authority to adopt any of the four alternative electric energy plans, provided that the plan meets the tests of the statute. The exception to this conclusion is the plan option that requires large expenditures for conservation of electrical energy. The statute appears to contemplate construction of facilities that will generate electricity. The statute may be interpreted so that certain types of conservation programs could be classified as "projects;" however, this approach is doubtful. Implementating the conservation option appears to require new authorizing legislation.

Although the requirements of A.S. 44.83.384 et seq. do not preclude implementing any of the energy option plans (except perhaps conservation as mentioned above), the circumstances under which the requirements dictate a particular option as the only authorized option cannot be determined with certainty. Lack of certainty results because the requirements are too general and sometimes contradictory to judge definitively how the courts will interpret the statute.

The relationship between the requirements set forth in A.S. 44.83.384 (conditions 1-3 above) and the requirement of legislative approval contained in A.S. 44.83.380 is not clear. Legislative approval appears to be a separate, independent requirement and therefore should not be sufficient to authorize construction of a project that does not also satisfy the requirements of A.S. 44.83.384. On the other hand, the legislative approval must be in accordance with A.S. 44.83.185, which requires passage of a law authorizing the project. Most likely the legislation authorizing approval will either make explicit or implied amendments, or if necessary, repeal the requirements of A.S. 44.83.384 as to the project the legislation authorizes. If the legislature takes this action, then any of the options are possible if it is approved by enactment of a law. While this analysis seems logical, it renders the requirements of A.S. 44.83.384 illusory, and for that reason, a court might conclude that a project is not properly before the legislature for approval until the requirements of A.S. 44.83.384 are met.

Application of the standards set forth in the statutes requires interpretation by the Power Authority. For example, the requirement that a project "be able to provide revenue sufficient to return annually to the State five percent (5%) of the amount that the (Power Authority) has spent from the fund. . ." is ambiguous. If this requirement is interpreted to mean that a project <u>must</u> return five percent (5%) of the amount spent, almost no project could qualify because the price the Power Authority charges for power pursuant to section .490 expressly excludes capital recovery. This provision must mean that five percent (5%) would be returned if a full price is charged. However, even this interpretation raises questions. What price and demand assumptions should be made to determine if the project meets the requirement? Is it realistic that a project large enough to meet demand at a low price will also be able to sell enough power at a much higher price to return five percent (5%) per year? What rate of return should be assumed for invested capital? Also, if the State has a 100% equity position in the project, this requirement necessarily implies a 20-year amortization of the project.

The statute requires that a project must provide the lowest price by itself <u>and</u> when operated in conjunction with other power projects in the market area. However, a project may be lowest in only one situation, not both. All of these uncertainties are problems that are frequently encountered and handled by planners and engineers when making decisions about future generating additions. Once assumptions are made about market area, future demand, project lifetime and other parameters, conclusions can be drawn about which project will provide the "lowest" cost. In the current statute uncertainty exists, however, because it authorizes projects only when certain criteria, such as "lowest cost," are met. It does not provide guidance on the assumptions that are to be used when arriving at the final determination.

Because the statutory requirements are technical and require the Power Authority in determining whether they are met, its determination should be final unless a court finds that no reasonable basis exists for the their finding. This standard maximizes the Power Authority's flexibility to evaluate alternatives, but does not give the Power Authority complete freedom to select whatever option it wants. If the option or base case is not justified in terms of the statutory requirements, interpreted in a reasonable manner, the option or base case could not be implemented under the existing statute.

In the statute, other provisions that seemingly are unrelated to the statutory standards create bias in favor of a particular generation option. Because the Power Authority obtains the needed funds for a project from the legislature and because the project is expected to be subsidized partially with General Fund revenues, no direct market accountability exists for whatever option the Power Authority undertakes. On the other hand, the Power Authority, as an agency of the state, must be accountable to the legislature, the governor and the people of the state and, to the extent this political accountability is a direct substitute for market accountability, the Power Authority can be expected to seek out the least-cost approach just as a private utility would. Conversely, if the least-cost objective conflicts with other political objectives, the Power Authority may seek to accommodate both the economic and political goals to the maximum extent feasible.

Section .490(b)(2) of SB 25 states that if the legislature has not appropriated $5 billion to the fund, the wholesale power rate shall be the higher of either 10% of the amount the Power Authority has invested in power projects or the amount of revenues necessary to pay operation and maintenance (O&M) costs plus debt service plus safety inspections. If O&M costs, debt service and safety inspections are less than 10% of investment, which is quite likely, then purchasing utilities will want the legislature to appropriate the $5 billion to satisfy the condition contained in (b)(2) since they then will avoid the risk of the higher wholesale power costs. To meet the $5 billion appropriation requirement, the legislature will have to select those power projects and energy options that have the greatest initial capital cost. Of the option plans identified in this study, only those including construction of

Susitna appear to meet that requirement. The purchasing utilities can be expected to work aggressively, in their own self interest, to persuade the Power Authority to choose an energy option that includes construction of Susitna, even if Susitna is not the least-cost approach.

The pricing provision also creates a second kind of bias. Assuming the legislature does appropriate $5 billion, the wholesale price the Power Authority charges to purchasers is a function of O&M costs, safety inspections and the financing approach used by the Power Authority. Under this provision, the price to the purchasing utilities will be lowest for those projects having lowest O&M and safety inspection costs, regardless of capital cost, when the project is funded by direct appropriation. If the least-cost approach is one that includes projects with higher overall long-term O&M costs but less initial capital investment, the least-cost approach will not be favored by the purchasing utilities because it results in greater power costs to them (and less cost to the State). This bias in favor of the facility with the lowest O&M is significant when considering alternatives. Those facilities, such as hydroelectric projects, with high initial capital investment but low O&M costs, will be favored by purchasing utilities because the capital costs are subsidized by the State but O&M costs are not. On the other hand, projects, such coal-fired plants, which have lower front end costs but higher O&M costs, might be the least-cost project (in present dollars) but will not be favored by the purchasing utilities because it could result in higher cost power to them and to their customers because the State subsidy will be less.

The extent to which the statute's pricing provisions create, for the purchasing utilities, objectives that conflict with the criteria contained in other parts of the statute cannot be known until additional economic analyses of the options are undertaken. Likewise, the extent to which the Power Authority's analysis will be directly or indirectly inflenced by the desires of purchasing utilities is unknown. Note that the Power Authority is required to average prices statewide for all projects. This requirement means that all purchasing utilities, not just Railbelt utilities, will be impacted by the Power Authority's decisions. All utilities which do, or may, purchase power from the Power Authority, therefore, will have the same objectives of preferring those projects that receive maximum State subsidy whether they purchase power from a particular project or not.

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REFERENCES

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APPENDIX A

SUPPORTING REPORTS
RAILBELT ELECTRIC POWER ALTERNATIVES STUDY

Volume I	-	Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans
Volume II	-	Selection of Electric Energy Generation Alternatives for Consideration in Railbelt Electric Energy Plans
Volume III	-	Executive Summary - Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska
Volume IV	-	Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska
Volume V	-	Preliminary Railbelt Electric Energy Plans
Volume VI	-	Existing Generating Facilities and Planned Additions for the Railbelt Region of Alaska
Volume VII	-	Fossil Fuel Availability and Price Forecasts for the Railbelt Region of Alaska
Volume VIII	-	Railbelt Electricity Demand (RED) Model Specifications
Volume VIII	-	Appendix - RED Model User's Guide
Volume IX	-	Alaska Economic Projections for Estimating Electricity Requirements for the Railbelt
Volume X	-	Community Meeting Public Input for the Railbelt Electric Power Alternatives Study
Volume XI	-	Over/Under (AREEP Version) Model User's Manual
Volume XII	-	Coal-Fired Steam-Electric Power Plant Alternatives for the Railbelt Region of Alaska
Volume XIII	-	Natural Gas-Fired Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska
Volume XIV	-	Chakachamna Hydroelectric Alternative for the Railbelt Region of Alaska
Volume XV	-	Browne Hydroelectric Alternative for the Railbelt Region of Alaska
Volume XVI	-	Wind Energy Alternative for the Railbelt Region of Alaska
Volume XVII	-	Coal-Gasification Combined Cycle Power Plant Alternative for the Railbelt Region of Alaska

APPENDIX B

DEMAND ASSUMPTIONS AND FORECASTS

APPENDIX B
DEMAND ASSUMPTIONS AND FORECASTS

This appendix contains tables summarizing electrical demand assumptions and results for the three Railbelt load centers - Anchorage and vicinity, Fairbanks and vicinity, and Glennallen-Valdez. The demand totals include only utility-provided energy at the consumer level. Military consumption, self-supplied industrial electricity, and residential and commercial consumption of electrical power by small users not connected to utilities are excluded. Line losses and spinning reserve requirements are considered part of supply requirements, but are not shown as part of demand.

The appendix is organized as follows. Table B.1 summarizes the assumptions used to generate forecasts of the Railbelt's economy and population for use in the MAP model. Table B.2 summarizes the assumptions used in the study for large industrial demand. Tables B.3 through B.11 show the forecasts of total employment and population for each load center used throughout the study. Tables B.12 through B.37 show total energy and peak demand forecasts for each load center for each combination of economic growth and supply plan analyzed in the study.[a] Finally, Tables B.38 to B.49 summarize the impact of 1% and 3% growth in fossil-fuel prices above inflation as a sensitivity test of the base case fuel escalation rate of 2%.

(a) The sum of peak demands for the three load centers will exceed that for the Railbelt because the peak loads are assumed not to coincide. A diversity factor of .971 is multiplied times the sum of the load center peak demands to derive Railbelt peak demand.

TABLE B.1. Assumptions Used in Railbelt Power Alternatives Study

Industry	Project(s)	Assumption	Low Case[a]	Moderate Case[b]	High Case[c]	Industrialization Case[d]	Superhigh Case[e]
Agriculture		Various levels of development depending on State & Federal policies, combined with market conditions	Slow decline in activity	Employment growth at 8% annual rate	Major agricultrual developments; 16% annual growth	Employment growth at 8% annual rate	Major agricultural developments; 16% annual growth
Fisheries		Constant employment in existing fishery. Development of bottom fishing to replace foreign fishing in 200 mine limit varies.	No development	50% replacement	100% replacement	50% replacement	100% replacement
Oil, Gas and Mining	Trans-Alaska Pipeline	Construction of 4 additional pumping stations	Yes	Yes	Yes	Yes	Yes
	Northwest Gas Pipeline	Construction of natural gas pipeline from Prudhoe Bay and associated facilities 1983-87	Yes	Yes	Yes	Yes	Yes
	Prudhoe Bay Oil and Gas	Production from existing and newly developed fields resulting in increased permanent employment	Yes	Yes	Yes	Yes	Yes
	Upper Cook Inlet Oil and Gas	Declining employment in oil production offset by employment growth in gas production	Yes	Yes	Yes	Yes	Yes
	National Petroleum Reserve in Alaska	Development & production from 5 oil fields and construction of of 525 miles of pipeline	Exploration but no develment	Slow development	Rapid development	Slow development	Rapid development
	Outer Continental Shelf (OCS) petroleum and gas	Exploration, develement & production based on current OCS lease schedule with additional sales after 1985	Beaufort Sea production; no sales after 1985; 1 billion bbl discovered	3 lease sales after 1985; 7 billion bbl discovered & developed	7 lease sales after 1985; 17 billion bbl discovered & developed	3 lease sales after 1985; 7 billion bbl discovered & developed	7 lease sales after 1985; 17 billion bbl discovered & developed
	Coal Development	Development of Beluga coal reserves for export and synfuel production	No	Eventual production of 4.4 million tons per year	Eventual production of 11 million tons per year	Eventual production of 4.4 million tons per year	Eventual production of 11 million tons per year

TABLE B.1. (contd)

Industry	Project(s)	Assumption	Low Case[a]	Moderate Case[b]	High Case[c]	Industrialization Case[d]	Superhigh Case[e]
	U.S. Borax	Development of mining operation by 1993	No	No	Yes	No	Yes
	Other Mining	Hardrock and other petroleum activities	Constant at current levels	1% annual growth of employment	2% annual growth of employment	1% annual growth of employment	2% annual growth of employment
Manufacturing	Aluminum Smelting	180,000 ton smelter	No	No	No	Yes	Yes
	Synfuels	Construction and manufacturing by 1990	No	No	No	Yes	Yes
	Petroleum Refining	Construction of 100,000 barrel per day refinery at Valdez	No	Yes	Yes	Yes	Yes
	Pacific LNG Project	Development of liquid natural gas project in the Anchorage area between 1985-87	No	Yes	Yes	Yes	Yes
	Petrochemicals	Development of a project similar in concept the Dow-Shell proposal	No	No	Phase 1	Phase 1 & Phase II	Phase 1 & Phase II
	Food Processing	Development based on and correspondent to growth of fisheries	Grows to accommodate growth in fishing industry.				
	Timber, Lumber, Pulp	Expansion to accommodate annual cut of 960 million to 1.3 billion board feet by 2000	960 million board feet	960 million board feet	1.3 billion board feet	960 million board feet	1.3 billion board feet
	Manufacturing for Local Alaskan Use	Expansion of existing production as well as new manufacturing as a proportion of total employment	1% of total employment	2% of total employment	3% of total employment	5% of total employment	5% of total employment
Government	State Capital Move	State capital move to Willow beginning in 1983	No	No	Yes	No	Yes
	Federal Government	Increases in civilian employment; military remains constant	Growth at rate of 0.5%	Same as low	Growth rate of 1% annually	Growth at historical rate of 0.5%	Growth at of 1% annually

TABLE B.1. (contd)

Industry	Project(s)	Assumption	Low Case[a]	Moderate Case[b]	High Case[c]	Industrialization Case[d]	Superhigh Case[e]
	State Government[f]	Spending grows with population, prices and incomes	Per capita spending unchanged	Per capita spending increases at same rate as per capita income	Per capita spending increases at same rate as per capita income	Per capita spending increases at same rate as per capita income	Per capita spending increases at same rate as per capita income
Tourism		Annual growth rate of tourism employment	2%	4%	6%	4%	6%

(a) Has 90-95% probability that actual developments will equal or exceed this projection
(b) Has 50% probability that actual developments will equal or exceed this projection
(c) Has 5-10% probability that actual developments will equal or exceed this projection
(d) Same as moderate case with addition of a series of industrial developments: 1) petrochemical developments; 2) aluminum; 3) synfuels; and 4) local manufacturing
(e) Same as high case plus: 1) petrochemical; 2) synfuels; 3) aluminum; and 4) local manufacturing.
(f) In the unsustainable spending case, private sector assumptions in the moderate case are maintained. State Revenues are reduced to the levels predicted in October 1981 by the Department of Revenue. Operating expenditures grow by the same rule as in the moderate case. Capital expenditures are assumed to equal 90% of the accumulated General Fund balance in the 1980's, equalling $5 billion per year by 1990. Operating and capital expenditures are thereafter limited by the exhaustion of the General Fund balances with the decline in oil revenues. After 1997, capital expenditures are financed at a reduced level of $200 million per year, entirely out of borrowing.

Sources: Volume IX.

TABLE B.2. Large Industrial Additional Sales and Peak Demand

Forecast Year	Anchorage Probability .75 Peak MW	Anchorage .75 Sales GWH	Anchorage .5 Peak MW	Anchorage .5 Sales GWH	Anchorage .25 Peak MW	Anchorage .25 Sales GWH	Glennallen-Valdez Probability .75 Peak MW	Glennallen-Valdez .75 Sales GWH	Glennallen-Valdez .5 Peak MW	Glennallen-Valdez .5 Sales GWH	Glennallen-Valdez .25 Peak MW	Glennallen-Valdez .25 Sales GWH
Medium Economic Scenario (MM)												
1990	0	0	0	0	0	0	0	0	7.75	33.05	15.5	66.1
1995	5	43.8	13.5	118.25	22	196.7	0	0	7.75	33.05	15.5	66.1
Accelerated Industrial Development Economic Scenario (IM)												
1990	0	0	125	1095	250	2190	0	0	7.75	33.05	15.5	66.1
1995	245	2103.8	428.5	3699.75	612	5273.7	245	2146	252.75	2179.05	260.5	2212.1
High Economic Scenario (HH)												
1990	0	0	0	0	0	0	75	648	82.75	681.05	90.5	714.1
1995	5	43.8	13.5	118.25	22	196.7	75	648	82.75	681.05	90.5	714.1
Superhigh Economic Scenario (SH)												
1990	0	0	125	1095	250	2190	75	648	82.75	681.05	90.5	714.1
1995	245	2103.8	428.5	3689.75	612	5273.7	320	2794	327.75	2827.05	335.5	2860.1

Note: Fairbanks has zero large project demand in all cases. Low scenario has zero large project demand for all areas.
The figures for 1980 and 1985 are zero, whereas the 1995-2010 numbers will remain at the 1995 level.

Table B.3. Population and Total Employment, Medium Scenario Without Susitna

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218564	93936	58671	23300	8100	2691	285335	119927
1985	264424	122621	75785	34015	12539	4450	352748	161086
1990	306886	141906	77969	35053	13144	4602	397999	181561
1995	335010	151398	83911	37168	14430	4933	433351	193499
2000	374779	171546	92804	42168	16103	5547	483686	219261
2005	398115	186172	99351	45637	17112	6031	514578	237840
2010	417505	205017	103957	50203	17957	6635	539419	261855

Table B.4. Population and Total Employment, Low Scenario Without Susitna

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218913	93645	58926	23292	8095	2677	285934	119614
1985	253808	114303	75945	32778	9340	3197	339093	150278
1990	282101	122593	74100	30612	10581	3474	366782	156679
1995	292968	123311	76736	30664	11103	3526	380807	157501
2000	312575	132422	81012	32763	11776	3742	405363	168927
2005	327848	139991	84521	34497	12414	3929	424783	178417
2010	346001	148836	88557	36512	13114	4141	447672	189489

Table B.5. Population and Total Employment, High Scenario Without Susitna

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218482	94426	58530	23376	8101	2705	285113	120507
1985	275788	130809	76292	35982	17320	6418	369400	173209
1990	358872	180554	86056	43966	22016	8508	466944	233028
1995	413988	205937	99293	50680	24579	9321	537860	265938
2000	491123	245945	117976	61841	27843	10610	636942	318396
2005	572944	285692	138009	72878	31339	11786	742292	370356
2010	672846	335270	162136	86901	35307	13199	870289	435370

Table B.6. Population and Total Employment, Medium Scenario With Susitna

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218564	93936	58671	23300	8100	2691	285335	119927
1985	268115	124260	75237	34069	12442	4453	355794	162782
1990	336799	155615	75677	36505	12679	4733	425155	196853
1995	354350	160211	84271	38456	14386	5041	453007	203708
2000	383049	174255	94050	42683	16272	5589	493371	222527
2005	420595	190667	103938	45498	18290	6003	542823	242168
2010	457904	207822	115608	49180	20667	6519	594179	263521

Table B.7. Population and Total Employment, Low Scenario With Susitna

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218913	93645	58926	23292	8095	2677	285934	119614
1985	257584	115916	75319	32819	9262	3200	342165	151935
1990	311233	134943	70789	31648	10092	3566	392114	170157
1995	311340	131141	76471	31698	11023	3610	398834	166449
2000	320716	135274	82209	33340	11942	3794	414867	172408
2005	327736	141290	87859	34598	12883	3938	428478	179826
2010	334379	146616	94485	36081	13973	4105	442837	186802

Table B.8. Population and Total Employment, High Scenario With Susitna

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218482	94426	58530	23376	8101	2705	285113	120507
1985	279346	132446	75807	36042	17194	6421	372347	174909
1990	388802	195619	84987	45902	21378	8686	495167	250207
1995	435592	217122	100815	52678	24606	9513	561013	279313
2000	502335	250680	120081	62943	28166	10715	650582	324338
2005	571444	289582	142268	73121	32275	11826	745987	374529
2010	651904	334113	169023	85749	37000	13141	857927	433003

Table B.9. Population and Total Employment, Nonsustainable Government Spending

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218564	93936	58671	23300	8100	2691	285335	119927
1985	272705	128927	77518	35570	12578	4528	362801	169025
1990	351654	175499	88789	43872	14008	5216	454451	224587
1995	353143	159188	88122	39094	15060	5118	456325	203400
2000	350448	144939	85749	34508	15430	4846	451627	184293
2005	313275	129565	74838	30117	14930	4689	403043	164371
2010	282679	116911	65793	26477	14335	4502	362807	147890

Table B.10. Population and Total Employment, Industrialization scenario

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218614	94048	58714	23350	8092	2691	285420	120089
1985	267427	125943	77072	35380	17311	6259	361810	167582
1990	324973	156423	82221	39259	24106	8846	431300	204528
1995	363129	170487	90410	42769	26178	9399	479717	222655
2000	417435	199128	104453	51006	27944	10122	549832	260256
2005	469011	221905	116505	56724	30279	10815	615795	289444
2010	531132	250652	131586	64656	32651	11593	695369	326901

Table B.11. Population and Total Employment, Superhigh Economic Scenario

Year	Anchorage-Cook Inlet Pop.	Anchorage-Cook Inlet Empl.	Fairbanks-Tanana Valley Pop.	Fairbanks-Tanana Valley Empl.	Glennallen-Valdez Pop.	Glennallen-Valdez Empl.	Total Railbelt Pop.	Total Railbelt Empl.
1980	218510	94489	58554	23405	8097	2705	285161	120599
1985	276860	131646	76731	36331	17287	6420	370878	174397
1990	366002	185893	88100	45886	24533	9617	478635	241396
1995	433643	219292	103946	54769	27649	10730	565238	284791
2000	524260	268112	127396	69247	30961	12103	682617	349462
2005	623899	319180	149238	83859	33837	13091	806974	416130
2010	747245	383833	178311	103084	37241	14359	962797	501276

Table B.12. Peak Demand and Annual Energy, Medium Economic Scenario, Plan 1A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	496	2424	155	665	10	47	643	3136
1990	616	3009	269	1155	21	93	880	4256
1995	728	3608	270	1157	25	110	993	4875
2000	811	4011	208	893	29	130	1017	5033
2005	906	4477	185	793	34	151	1092	5421
2010	1073	5288	185	794	39	175	1259	6258

Table B.13. Peak Demand and Annual Energy, Medium Economic Scenario, Plan 1B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	502	2450	154	662	10	47	647	3160
1990	667	3254	265	1136	21	92	924	4482
1995	737	3651	264	1133	25	110	996	4894
2000	760	3763	195	835	29	130	955	4728
2005	888	4387	183	786	34	155	1073	5327
2010	1140	5617	206	883	41	186	1347	6686

Table B.14. Peak Demand and Annual Energy, Medium Economic Scenario, Plan 2A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	437	2075	143	605	10	46	573	2726
1990	532	2522	262	1121	21	92	791	3734
1995	672	3287	264	1134	25	110	933	4530
2000	724	3533	196	841	29	130	921	4503
2005	802	3909	173	742	34	151	979	4802
2010	946	4604	173	744	39	175	1125	5523

Table B.15. Peak Demand and Annual Energy, Medium Economic Scenario, Plan 2B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	442	2099	142	602	10	46	577	2746
1990	579	2741	258	1105	21	91	832	3937
1995	703	3438	267	1144	25	110	966	4692
2000	735	3590	200	857	29	130	936	4576
2005	848	4130	187	800	34	155	1038	5085
2010	1041	5056	201	860	41	185	1245	6101

Table B.16. Peak Demand and Annual Energy. Medium Economic Scenario, Plan 3

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	496	2424	155	665	10	47	643	3136
1990	616	3009	269	1155	21	93	880	4256
1995	720	3569	267	1146	25	110	983	4826
2000	781	3865	200	858	29	130	981	4853
2005	862	4262	175	753	34	151	1040	5166
2010	1012	4991	173	744	39	175	1188	5910

Table B.17. Peak Demand and Annual Energy. Medium Economic Scenario, Plan 4

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	496	2424	155	666	10	47	643	3136
1990	616	3007	269	1156	21	93	880	4256
1995	722	3578	268	1148	25	110	985	4837
2000	792	3921	203	869	29	130	994	4919
2005	884	4369	180	771	34	151	1066	5291
2010	1038	5120	179	767	39	175	1219	6062

Table B.18. Peak Demand and Annual Energy. Low Economic Scenario, Plan 1A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2027	114	488	9	39	522	2554
1985	476	2325	154	661	9	42	621	3028
1990	557	2721	251	1078	12	54	797	3853
1995	609	2971	239	1023	15	69	837	4063
2000	647	3157	174	746	18	84	815	3988
2005	721	3520	153	655	22	102	870	4278
2010	852	4157	153	655	27	124	1001	4936

Table B.19. Peak Demand and Annual Energy, Low Economic Scenario, Plan 1B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2027	114	488	9	39	522	2554
1985	482	2353	153	657	9	42	626	3052
1990	610	2978	245	1051	12	54	841	4083
1995	629	3070	236	1012	15	69	854	4150
2000	609	2971	163	700	19	85	767	3756
2005	668	3261	146	627	23	104	812	3991
2010	831	4055	162	696	28	128	991	4878

Table B.20. Peak Demand and Annual Energy. Low Economic Scenario, Plan 2A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2027	114	488	9	39	522	2554
1985	419	1988	142	600	9	41	553	2629
1990	478	2269	243	1040	12	54	712	3362
1995	565	2717	235	1008	15	68	791	3793
2000	604	2908	173	740	18	84	772	3732
2005	674	3244	153	654	22	102	825	4000
2010	775	3724	149	638	27	124	923	4486

Table B.21. Peak Demand and Annual Energy, Low Economic Scenario, Plan 2B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2027	114	488	9	39	522	2554
1985	424	2013	141	597	9	41	557	2651
1990	525	2486	237	1016	12	53	751	3554
1995	591	2846	235	1008	15	68	816	3922
2000	587	2824	167	718	19	85	750	3627
2005	646	3109	151	647	23	104	796	3859
2010	811	3905	169	726	28	127	979	4758

Table B.22. Peak Demand and Annual Energy, Low Economic Scenario, Plan 3

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2027	114	488	9	39	522	2554
1985	476	2325	154	661	9	42	621	3028
1990	557	2721	251	1078	12	54	797	3853
1995	618	3018	242	1038	15	69	850	4125
2000	675	3293	182	781	18	84	850	4158
2005	723	3530	154	659	22	102	873	4291
2010	815	3981	146	627	27	124	960	4732

Table B.23. Peak Demand and Annual Energy. Low Economic Scenario, Plan 4

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2027	114	488	9	39	522	2554
1985	476	2325	154	661	9	42	621	3028
1990	557	2721	251	1078	12	54	797	3853
1995	610	2978	239	1026	15	69	839	4073
2000	657	3206	177	758	18	84	827	4048
2005	739	3607	157	674	22	102	892	4383
2010	859	4194	154	662	27	124	1010	4980

Table B.24. Peak Demand and Annual Energy, High Economic Scenario, Plan 1A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	515	2512	157	671	12	55	663	3238
1990	696	3400	293	1257	100	758	1057	5414
1995	811	4012	294	1264	105	782	1175	6058
2000	922	4552	237	1015	111	808	1232	6375
2005	1133	5585	235	1009	118	840	1443	7434
2010	1425	7008	262	1122	126	881	1760	9011

Table B.25. Peak Demand and Annual Energy, High Economic Scenario, Plan 1B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	520	2536	156	668	12	55	667	3259
1990	744	3630	292	1252	99	757	1102	5639
1995	831	4107	298	1278	105	782	1198	6168
2000	872	4311	226	971	111	809	1174	6092
2005	1081	5332	233	1000	118	844	1391	7175
2010	1513	7440	303	1300	128	887	1888	9627

Table B.26. Peak Demand and Annual Energy, High Economic Scenario, Plan 2A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	454	2153	144	610	12	53	592	2816
1990	608	2880	286	1223	99	757	964	4860
1995	764	3724	294	1261	105	781	1129	5767
2000	814	3960	220	944	111	808	1112	5711
2005	962	4669	211	902	118	840	1253	6411
2010	1195	5783	230	984	126	880	1506	7647

Table B.27. Peak Demand and Annual Energy, High Economic Scenario, Plan 2B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	458	2175	144	607	12	53	596	2835
1990	648	3069	285	1219	99	755	1002	5043
1995	793	3864	301	1291	105	782	1164	5937
2000	840	4090	231	990	111	809	1148	5888
2005	1036	5031	238	1018	118	843	1352	6892
2010	1438	6964	305	1305	128	887	1816	9156

Table B.28. Peak Demand and Annual Energy, High Economic Scenario, Plan 3

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	515	2512	156	671	12	55	663	3237
1990	697	3403	293	1255	100	758	1058	5416
1995	810	4007	294	1262	105	782	1174	6052
2000	892	4408	229	984	111	808	1196	6201
2005	1040	5128	215	920	118	840	1332	6889
2010	1297	6386	236	1011	126	881	1611	8278

Table B.29. Peak Demand and Annual Energy, High Economic Scenario, Plan 4

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	515	2512	156	671	12	55	663	3237
1990	697	3401	292	1254	100	758	1057	5413
1995	804	3975	292	1252	105	782	1165	6009
2000	887	4382	227	973	111	808	1189	6163
2005	1076	5305	223	955	118	840	1375	7100
2010	1330	6545	243	1041	126	881	1650	8467

Table B.30. Peak Demand and Annual Energy. Nonsustainable Government Spending, Plan 1A

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	505	2466	156	671	10	47	652	3184
1990	691	3373	299	1281	14	62	974	4716
1995	713	3482	273	1170	17	79	974	4730
2000	664	3242	180	772	21	94	839	4108
2005	600	2930	129	552	24	108	731	3590
2010	584	2851	106	456	27	124	697	3431

Table B.31. Peak Demand and Annual Energy, Nonsustainable Government Spending, Plan 1B

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	506	2469	157	673	10	47	653	3189
1990	694	3390	301	1290	14	62	979	4741
1995	703	3434	270	1160	17	79	962	4672
2000	618	3017	168	719	21	94	783	3830
2005	543	2651	117	500	24	108	663	3259
2010	523	2551	95	407	27	124	626	3082

Table B.32. Peak Demand and Annual Energy, Industrialization Scenario, Plan 1A

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	501	2447	157	672	12	55	650	3174
1990	755	4170	272	1169	25	114	1022	5453
1995	1084	6890	247	1060	276	2284	1560	10235
2000	1081	6874	172	737	281	2306	1489	9917
2005	1181	7361	156	668	287	2334	1576	10363
2010	1382	8343	169	726	294	2367	1791	11436

Table B.33. Peak Demand and Annual Energy, Industrialization Scenario, Plan 1B

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	501	2446	157	671	12	55	650	3172
1990	756	4175	273	1171	25	114	1023	5459
1995	1083	6882	247	1061	276	2284	1559	10227
2000	1065	6797	167	717	281	2306	1469	9820
2005	1200	7457	159	682	287	2334	1598	10472
2010	1503	8934	192	823	294	2367	1931	12124

Table B.34. Peak Demand and Annual Energy, Superhigh Economic Scenario, Plan 1A

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	516	2518	157	672	12	55	665	3245
1990	814	4460	290	1244	101	763	1170	6467
1995	1163	7275	273	1172	352	2936	1736	11382
2000	1191	7413	203	873	358	2963	1701	11249
2005	1354	8205	196	840	364	2994	1858	12039
2010	1624	9527	223	956	373	3034	2156	13516

Table B.35. Peak Demand and Annual Energy, Superhigh Economic Scenario, Plan 1B

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2025	113	486	9	39	521	2550
1985	516	2518	157	672	12	55	665	3245
1990	820	4489	292	1251	101	763	1177	6503
1995	1171	7314	277	1187	352	2936	1747	11437
2000	1166	7291	196	841	358	2963	1670	11095
2005	1356	8214	195	837	364	2994	1859	12046
2010	1739	10089	245	1052	373	3034	2289	14174

Table B.36. Peak Demand and Annual Energy. No Capital Recovery, Plan 1A

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	511	2495	160	687	10	47	662	3229
1990	693	3385	307	1317	21	93	991	4795
1995	897	4433	338	1449	25	110	1223	5993
2000	1185	5836	312	1339	29	130	1482	7305
2005	1519	7466	322	1380	34	151	1819	8997
2010	1971	9675	361	1550	39	175	2302	11401

Table B.37. Peak Demand and Annual Energy. No Capital Recovery, Plan 1B

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	511	2495	160	688	10	47	662	3230
1990	699	3412	311	1334	21	93	1001	4839
1995	971	4793	366	1571	25	110	1322	6475
2000	1464	7197	393	1684	29	130	1830	9012
2005	1928	9463	416	1787	34	151	2308	11400
2010	2538	12442	477	2048	39	175	2965	14665

Table B.38. Peak Demand and Annual Energy, Low Fuel Prices, Plan 1A

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	498	2430	156	667	10	47	644	3144
1990	634	3093	278	1191	21	91	904	4375
1995	758	3753	289	1240	24	107	1040	5100
2000	784	3879	210	901	27	122	991	4902
2005	848	4192	185	793	31	139	1033	5124
2010	981	4842	183	786	35	157	1164	5785

Table B.39. Peak Demand and Annual Energy, Low Fuel Prices, Plan 1B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	503	2457	155	664	10	47	649	3168
1990	686	3346	273	1172	20	90	951	4609
1995	786	3889	290	1243	24	107	1067	5238
2000	777	3846	210	900	27	123	985	4870
2005	830	4105	184	789	32	142	1015	5037
2010	968	4780	190	815	37	166	1160	5761

Table B.40. Peak Demand and Annual Energy, Low Fuel Prices, Plan 2A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	438	2079	144	606	10	46	574	2731
1990	545	2584	269	1153	20	90	810	3827
1995	702	3430	284	1217	24	106	980	4753
2000	707	3450	201	860	27	122	908	4433
2005	752	3666	174	744	31	139	928	4549
2010	863	4201	172	736	35	157	1038	5094

Table B.41. Peak Demand and Annual Energy, Low Fuel Prices, Plan 2B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	443	2104	143	604	10	46	579	2753
1990	598	2834	268	1146	20	90	860	4069
1995	757	3698	295	1266	24	106	1045	5070
2000	734	3582	209	898	27	123	942	4603
2005	769	3749	181	777	32	142	954	4668
2010	867	4217	181	775	37	166	1053	5158

Table B.42. Peak Demand and Annual Energy. Low Fuel Prices, Plan 3

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	498	2431	156	668	10	47	645	3146
1990	634	3093	278	1191	21	91	905	4375
1995	754	3733	287	1232	24	107	1034	5072
2000	759	3757	204	874	27	122	961	4753
2005	792	3917	171	733	31	139	965	4789
2010	955	4713	178	762	35	157	1133	5632

Table B.43. Peak Demand and Annual Energy. Low Fuel Prices, Plan 4

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	498	2430	156	667	10	47	644	3144
1990	634	3093	278	1191	21	91	904	4375
1995	765	3785	291	1250	24	107	1048	5141
2000	805	3983	216	928	27	122	1018	5033
2005	870	4300	190	815	31	139	1059	5254
2010	990	4886	186	798	35	157	1176	5841

Table B.44. Peak Demand and Annual Energy. High Fuel Prices, Plan 1A

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		Glennallen-Valdez		Total Railbelt	
Year	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)	Peak (MW)	Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	498	2432	156	668	10	47	645	3147
1990	641	3127	279	1195	21	94	913	4417
1995	793	3922	289	1239	26	114	1075	5275
2000	848	4191	209	896	31	138	1056	5225
2005	942	4653	183	786	36	164	1128	5602
2010	1126	5549	182	783	43	196	1312	6527

Table B.45. Peak Demand and Annual Energy, High Fuel Prices, Plan 1B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	504	2459	155	665	10	47	649	3171
1990	693	3383	274	1175	21	93	959	4652
1995	814	4027	287	1233	26	114	1094	5374
2000	830	4103	205	881	31	138	1035	5122
2005	978	4826	192	826	37	168	1173	5820
2010	1330	6547	228	979	46	208	1558	7734

Table B.46. Peak Demand and Annual Energy, High Fuel Prices, Plan 2A

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	438	2081	144	607	10	46	575	2734
1990	552	2618	270	1158	21	93	819	3869
1995	736	3593	284	1219	26	114	1015	4926
2000	759	3702	198	847	31	138	958	4687
2005	826	4024	170	728	36	164	1002	4916
2010	979	4761	168	721	43	195	1156	5677

Table B.47. Peak Demand and Annual Energy, High Fuel Prices, Plan 2B

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	444	2106	143	604	10	46	579	2756
1990	602	2850	268	1146	21	92	864	4088
1995	781	3815	292	1252	25	114	1067	5180
2000	809	3948	213	911	31	138	1022	4997
2005	936	4553	197	844	37	168	1136	5566
2010	1227	5953	223	956	46	207	1452	7116

Table B.48. Peak Demand and Annual Energy. High Fuel Prices, Plan 3

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	498	2432	156	668	10	47	645	3147
1990	641	3129	278	1194	21	94	913	4417
1995	787	3894	287	1231	26	114	1068	5240
2000	807	3992	199	854	31	138	1007	4983
2005	861	4256	166	712	36	164	1032	5131
2010	1031	5084	166	712	43	196	1204	5991

Table B.49. Peak Demand and Annual Energy. High Fuel Prices, Plan 4

Year	Anchorage-Cook Inlet Peak (MW)	Anchorage-Cook Inlet Sales (GWh)	Fairbanks-Tanana Valley Peak (MW)	Fairbanks-Tanana Valley Sales (GWh)	Glennallen-Valdez Peak (MW)	Glennallen-Valdez Sales (GWh)	Total Railbelt Peak (MW)	Total Railbelt Sales (GWh)
1980	415	2026	113	487	9	39	521	2551
1985	498	2432	156	668	10	47	645	3147
1990	640	3125	278	1193	21	94	912	4412
1995	787	3893	287	1230	26	114	1067	5237
2000	824	4077	203	871	31	138	1028	5086
2005	898	4436	174	747	36	164	1076	5347
2010	1076	5303	173	743	43	196	1254	6241

APPENDIX C

LEVELIZED COST OF POWER

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LEVELIZED COST OF POWER

In this report the levelized cost of power is used to compare the costs of power from the various electric energy plans. The levelized cost of power is computed by estimating a single level annual payment, which would be equivalent to the present worth, given assumptions about the time value of money. The procedure used to levelize the cost of power is explained in this appendix. The relationship between the annual cost of power and the levelized cost of power over a certain time horizon is shown in Figure C.1.

The total capital costs for a particular power plan (assuming no generating facility or additions or retirements for this example) are fixed by the initial financing and are typically constant over the life of the facility. Operation and maintenance and fuel costs typically increase over time as affected by inflation and as real fuel price increases. As a result, the annual cost of power progressively increases over time.

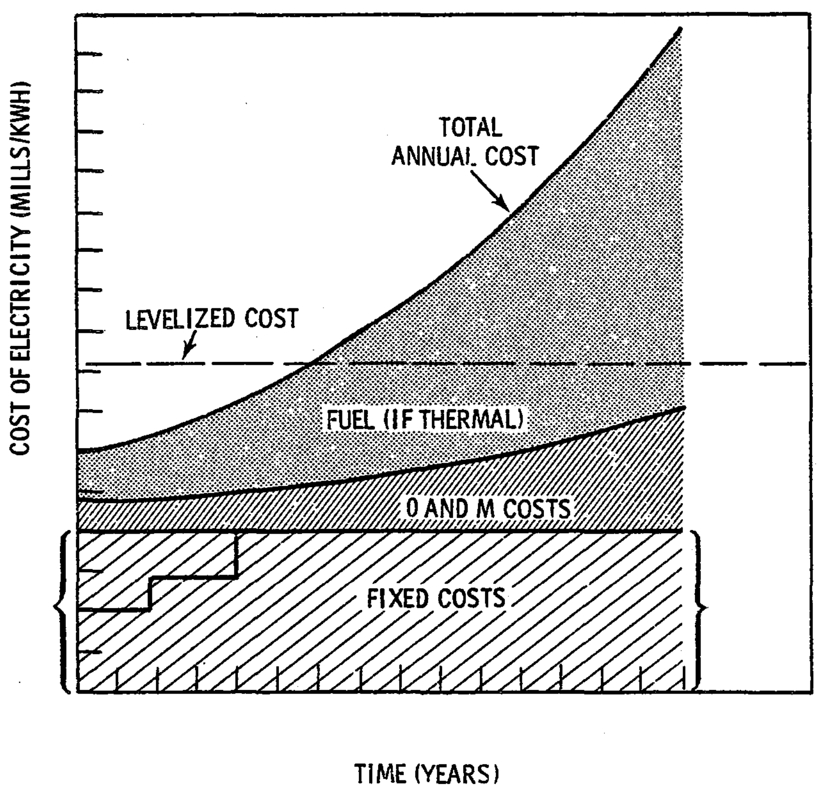

FIGURE C.1. Annual Cost of Power and Total Levelized Cost

Figure C.2 illustrates the use of the levelized cost of power to select the alternative with the lower power cost. Alternative A represents a plan with lower initial annual costs of power but with high annual costs of power in later years. Alternative B represents a plan with higher initial costs of power but with lower costs of power in later years. Without the use of a present worth analysis, the selection of the lower cost plan would be unclear. Initially, Plan A looks more attractive, whereas alternative B looks more attractive in later years. Using levelized costs, however, Plan B is clearly the lower cost plan over the time horizon.

As indicated in the report, the time horizon for this study extends from 1980 to 2010. However, because the economic lifetime of the Upper Susitna project (assumed to be 50 years) will extend beyond 2010, a longer time period was also used in the evaluation to compare the costs of power. The longer time period runs from 1980 to 2050 and roughly corresponds to the economic life of the Upper Susitna project.

The methodology used to compute the levelized cost of power over the 1980-2050 time period is represented graphically in Figure C.3. In Figure C.3 typical annual costs of power computed using the AREEP model are presented for the 1980-2010 time period. The case represented by the dashed line has slightly higher power costs over the 1993-2000 time period but lower costs over the 2002-2010 time period. This case corresponds to the cases including the Upper Susitna project. The case represented by the solid line corresponds to cases not including the Upper Susitna project such as Plans 1A or 3.

To compute the levelized cost of power over the extended 1980-2050 time period, the annual costs of power from 2010 to 2050 were assumed to be the same as in 2010 and constant over the time period.

This method does not account for replacement costs of thermal generation changes in electrical demand or possible escalation in fuel costs over the 2010-2050 time period. While it would be desirable to include these factors in the analysis, it would require detailed analyses over the entire 1980-2050 time horizon. The decision to compute and include the levelized costs over the 1980-2050 time period was not made until late in the project when it became clear that there was not going to be any clear price difference among the various plans over the 1980-2010 time horizon.

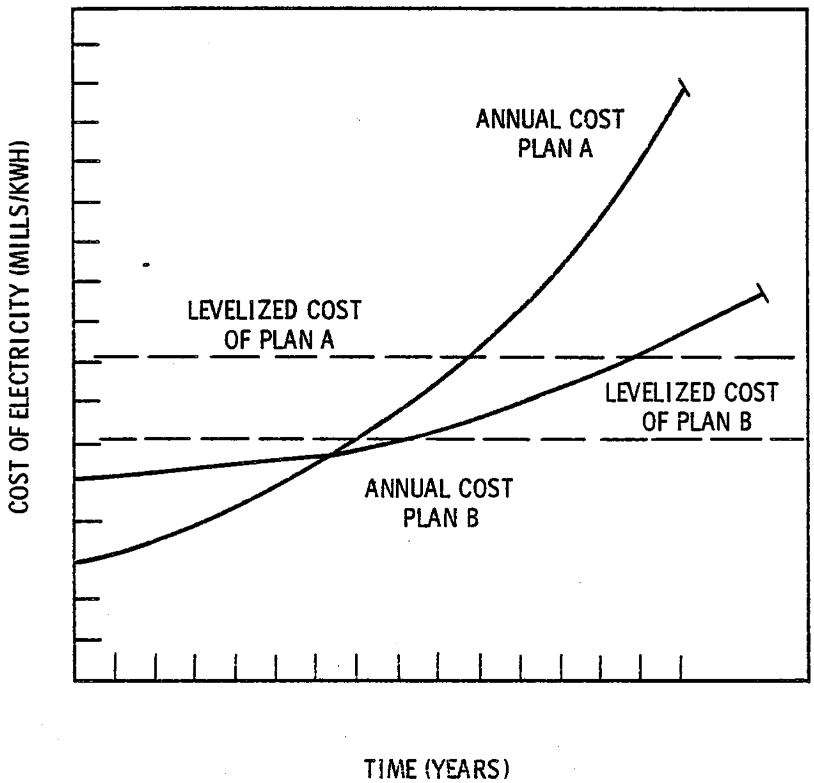

FIGURE C.2. Use of Levelized Cost to Select Lowest Life Cycle-Cost Plan(a)

(a) See Volume IV, Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska, Appendix C, for a general discussion of levelized cost. For specific calculational procedures, see Volume XI, Over/Under (AREEP Version) Model User's Manual.

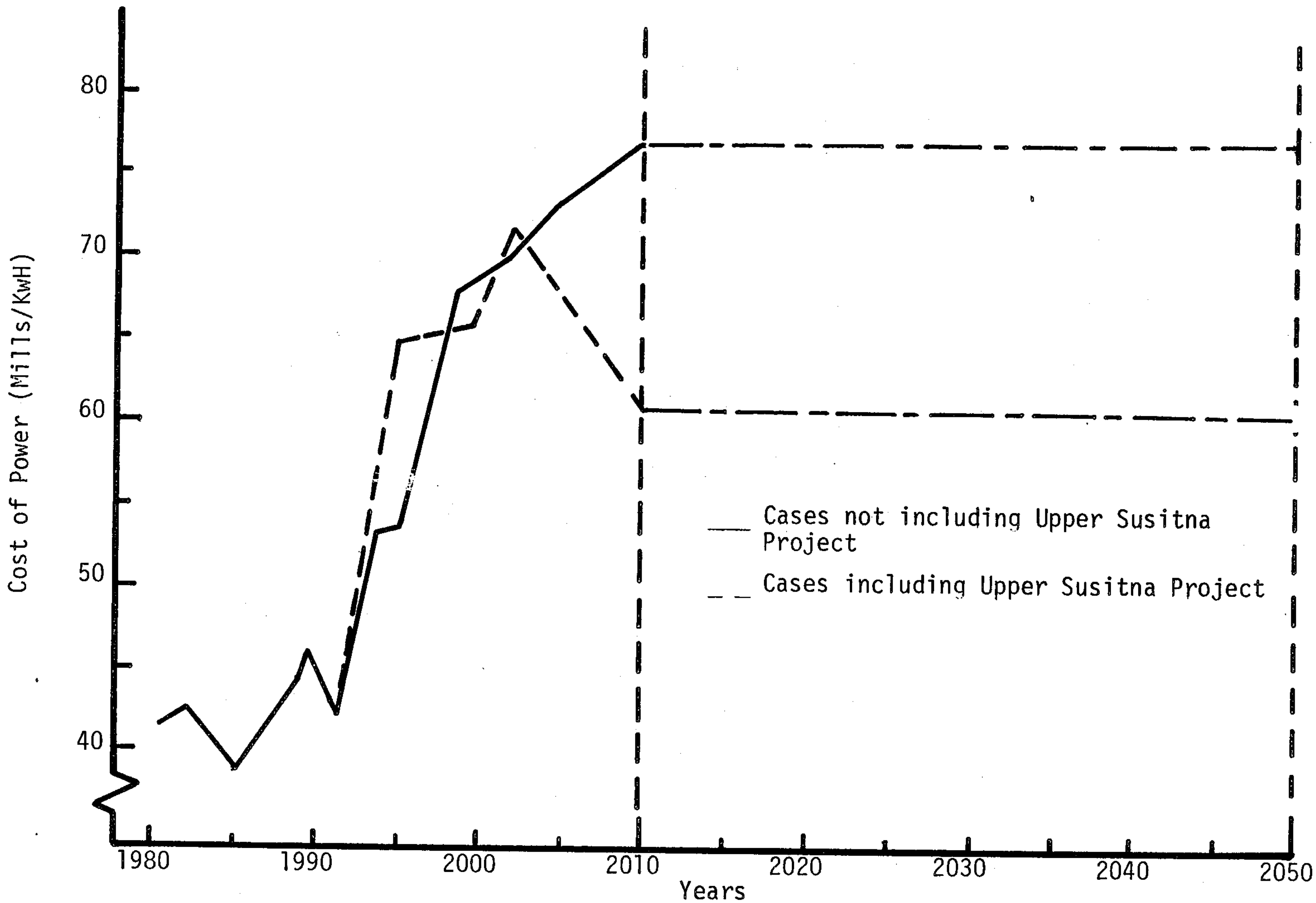

FIGURE C.3. Levelized Cost Methodology for 2010-2050 Time Period

APPENDIX D

DETAILED DESCRIPTION OF RAILBELT ELECTRIC ENERGY PLANS

APPENDIX D

DETAILED DESCRIPTION OF RAILBELT ELECTRIC ENERGY PLANS

Appendix D contains a more detailed description of the electric energy plans. In addition to a brief summary of the major features of each plan and its potential impacts, the generation system reliability, and the environmental and socioeconomic considerations are discussed in detail.

D.1 PLAN 1A: "PRESENT PRACTICES" WITHOUT UPPER SUSITNA

Plan 1A and 1B are both based on a transition from existing generating technologies to alternative conventional generating technologies.

The following are the primary generating alternatives included in Plan 1A:

- combustion turbines (gas or distillate)
- combined-cycle (gas or distillate)
- hydroelectric (other than Upper Susitna)
- conventional cost steam-electric

Hydroelectric plants include the following:

- the Bradley Lake hydroelectric project, which comes on-line in 1988
- the Chakachamna hydroelectric project, which comes on-line in 2002
- the Grant Lake project, which comes on-line in 1995
- the Allison hydroelectric project, which come on-line in 1992

Other generating capacity includes the following:

Anchorage - Cook Inlet

- Coal steam turbines and gas combined-cycles are installed as necessary to supplement the hydroelectric projects.

Fairbanks - Tanana Valley

- Oil combustion-turbine units are used for peaking until retirement.
- Gas combined-cycles are added to provide peaking generation when existing oil combustion units are retired.
- Coal steam-electric capacity is added for baseload.

D.1.1 Capacity and Generation for Plan 1A

In Plan 1A 400 MW of gas combined-cycle, 400 MW of coal steam turbine, and 430 MW of hydroelectric capacity are added during the 1981 to 2010 time span. Table D.1 shows the existing capacity in 1980 and the capacity additions (positive numbers) and retirements (negative numbers). Table D.2 shows the amount of electricity generated by each of the generating alternatives during the 1981 to 2010 time period.

As shown, during the 1981 to 1991 time period, electrical generation in Anchorage is largely supplied by gas combustion, turbine and combined-cycle with some hydroelectric generation. During the later 20 years, generation in the Anchorage area is largely hydroelectric with some gas-combined cycle and coal steam turbine generation.

In Fairbanks, coal steam turbine capacity is used for generation throughout the time horizon. Oil combustion turbine capacity is used during the first 10 years while some gas combined cycle capacity is used during the latter period.

D.1.2 Generation System Reliability

The loss-of-load probability (LOLP) is an indication of the reliability of an electrical generation system. The LOLP indicates the probability that an electrical generating system will not be able to meet the electrical demand. The LOLP is expressed as the number of times a generation system will not be able to meet demand over a specified time period. For example, a LOLP of one day in 10 years indicates that the system would not meet load one time in 10 years. A LOLP of one day in 10 years is a relatively common design goal in the U.S.

An indirect method of measuring system reliability is the reserve margin. The reserve margin indicates the amount of generating capacity an electrical generating system has in excess of the annual peak demand. Extra capacity is required to allow the system to meet the peak demand in the event of scheduled or unscheduled outages of certain generating units. A system with a peak demand of 1000 MW and a total generating capacity of 1200 MW would have a reserve margin of 20%. In general, a higher reserve margin indicates a greater amount of system reliability.

TABLE D.1. Existing Capacity (1980) and Capacity Additions and Retirements (1981-2010) - Plan 1A (MW)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley			
Year	Gas Combustion Turbine	Gas Combined-Cycle	Coal Steam Turbine	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Gas Combined-Cycle	Hydroelectric
1980	461	139	0	266	69	0	46 (Eklutna & Cooper Lake)
1981	0	0	0	0	0	0	12 (Solomon Gulch)
1982	-20	178	0	0	0	0	0
1983	0	0	0	-8	0	0	0
1984	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0
1986	0	0	0	-1	0	0	0
1987	0	0	0	-8	-4	0	0
1988	0	0	0	-6	0	0	90 (Bradley Lake)
1989	0	0	0	0	-5	0	0
1990	0	0	0	0	0	0	0
1991	0	0	0	-18	0	100	0
1992	-16	0	200	-19	0	0	7 (Allison)
1993	-9	0	0	0	0	0	0
1994	-30	0	0	0	0	0	0
1995	-14	0	0	-33	0	0	7 (Grant Lake)
1996	0	200	0	-102	0	0	0
1997	0	0	0	-65	200	0	0
1998	-50	0	0	0	0	0	0
1999	0	0	0	0	0	0	0
2000	-18	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	-51	0	0	0	-25	0	330 (Chakachamna)
2003	-53	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	-58	0	0	0	-21	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	-26	0	0	0	0	0	0
2009	0	0	0	0	0	0	0
2010	0	0	0	0	0	100	0

TABLE D.2. Electricity Demand and Generation by Type of Capacity - Plan 1A (GWh)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley			
Year	Gas Combustion Turbine	Gas Combined-Cycle	Coal Steam Turbine	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Gas Combined-Cycle	Hydroelectric
1981	2017	46	0	27	537	0	254
1982	765	1386	0	66	537	0	254
1983	839	1400	0	104	537	0	254
1984	941	1386	0	143	537	0	254
1985	409	2265	0	0	458	0	254
1986	1345	1465	0	27	537	0	254
1987	1440	1505	0	133	537	0	254
1988	1244	1445	0	238	537	0	648
1989	1355	1469	0	386	496	0	648
1990	998	2490	0	3	457	0	648
1991	1878	1655	0	1	496	51	648
1992	749	1429	1578	0	427	2	679
1993	858	1438	1584	0	436	3	679
1994	965	1428	1611	0	443	5	679
1995	91	2162	1611	0	496	197	710
1996	10	2444	1611	0	496	29	710
1997	1	995	1611	0	2013	3	710
1998	1	1024	1611	0	2019	4	710
1999	1	1057	1611	0	2020	4	710
2000	1	1085	1611	0	2026	4	710
2001	1	1159	1611	0	2034	5	710
2002	0	169	1611	0	1668	0	2155
2003	0	182	1611	0	1738	0	2155
2004	0	196	1611	0	1809	0	2155
2005	0	372	1611	0	1716	1	2155
2006	0	547	1611	0	1722	1	2155
2007	0	722	1611	0	1727	1	2155
2008	0	899	1611	0	1730	2	2155
2009	1	1059	1611	0	1732	20	2155
2010	0	1225	1611	0	1734	33	2155

The AREEP model adds capacity such that the reserve margin never drops below a selected value. The model then computes the resulting LOLP. Several model runs were made to insure that when analyses are done with AREEP, the reserve margin would yield a LOLP of about one day in 10 years. Different electric energy plans and electrical demands slightly change the reserve margin required to maintain a LOLP of about one day in 10 years. In most cases a planning reserve margin of between 34% to 32% yielded a LOLP of about one day in 10 years during most of the time horizon. As shown by the typical results presented in Figure D.1, there is little effect on the cost of power of alternative reserve margins within this range (EPRI 1978). For the results presented in this report, a planning reserve margin of 30% was used in all cases.

D.1.3 Environmental Considerations of Plan 1A

The hallmark of Plan 1A is the increased use of fossil fuels (coal and gas) to produce electricity. The main environmental impacts are therefore associated with the combustion gases, waste products and cooling water required to operate the plants. In addition, the potential impacts of the 90-MW Bradley Lake and 330-MW Chakachamna hydroelectric facilities must be considered.

This section discusses some of the general environmental concerns of Plan 1A. Specific impacts of this plan are discussed.

Air Pollutants

Several kinds of air pollutants are normally emitted by fuel-burning power plants. These include particulate matter, sulfur dioxide (SO_2), nitrogen oxides, carbon monoxide, unburned hydrocarbons, water vapor, noise, and odors.

Particulate matter consists of finely divided solid material in the air. Fuel combustion power plants produce particulate matter in the form of unburned carbon and noncombustible minerals. Particulate matter is emitted in large quantities if high-efficiency control equipment is not used. Particulates are removed from flue gas by electrostatic precipitators or fabric filters (baghouses). These precipitators or filters are routinely required, however, and collection efficiencies can be very high (in excess of 99%).

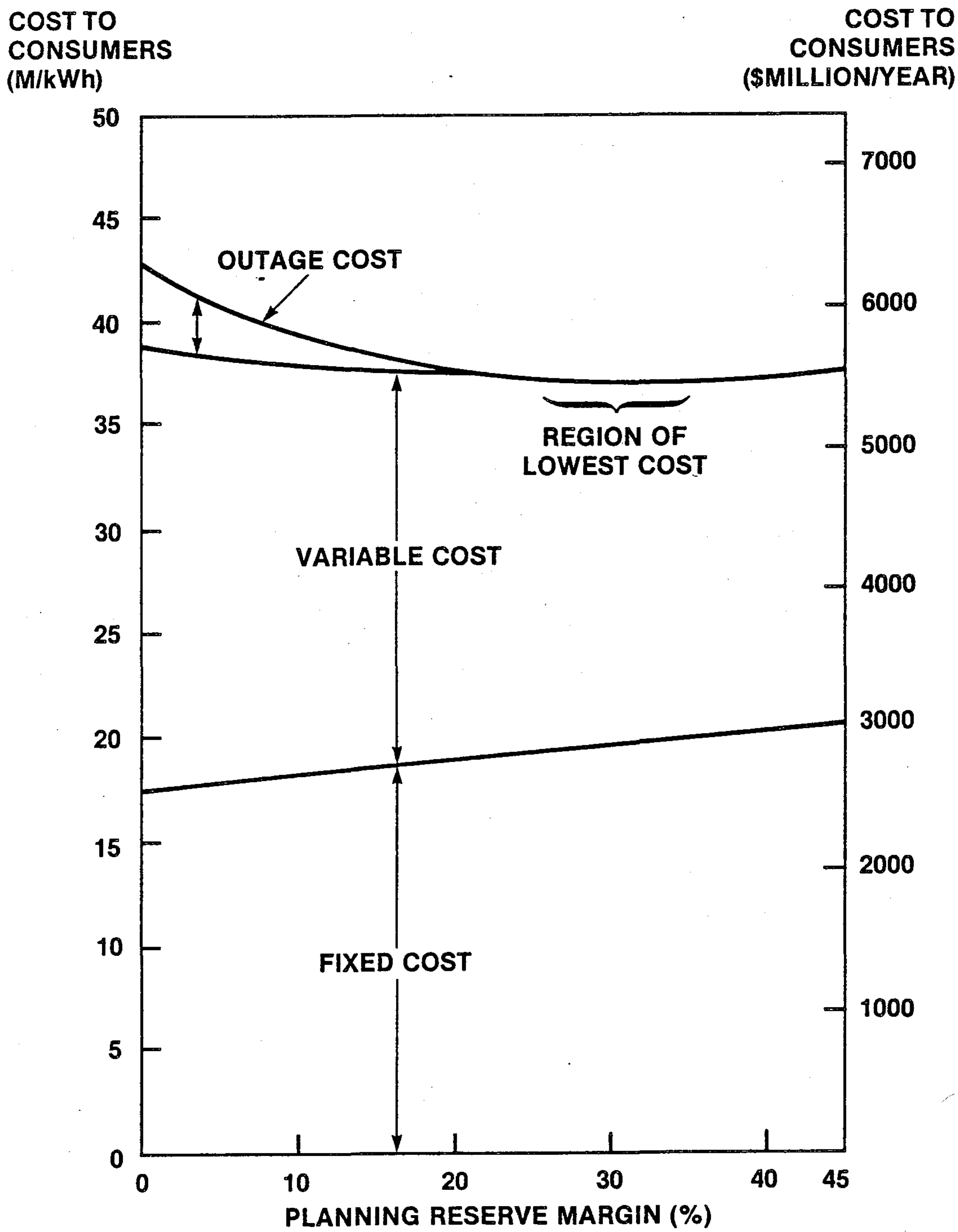

FIGURE D.1. Typical Costs for Alternative Reserve Margins (EPRI 1978, p. 6-11)

Sulfur dioxide is a gaseous air pollutant that is emitted during combustion of fuels that contain sulfur. Sulfur dioxide, like particulate matter, has been identified as being harmful to human health, and it appears to be particularly serious when combined with high concentrations of particulate matter.

Nitrogen oxides (NO_2 and NO, primarily) are gaseous air pollutants that form as a result of high-temperature combustion or oxidation of fuel-bound nitrogen. Nitrogen oxides damage plants and play an important role in photochemical smog. Fuel combustion plants and automobiles are significant contributors to these emissions.

Pollution control technology for nitrogen oxides has developed more slowly than for most other air pollutants. Lack of chemical reactivity between NO_x and conventional scrubbing compounds is the main difficulty. Thus, current control strategies focus on control of NO_x production. Principal strategies include control of combustion temperatures (lower combustion temperatures retard formation of NO_x) and control of combustion air supplies to minimize introduction of excess air (containing 78% nitrogen).

Carbon monoxide (CO) emissions result from incomplete combustion of carbon-containing compounds. Generally, high CO emissions result from poor combustion conditions and can be reduced by using appropriate firing techniques. However, CO emissions can never be eliminated completely, even if the most modern combustion techniques and clean fuels are used. CO emissons are regulated under the Clean Air Act because of their toxic effect on humans and animals.

Plumes of condensed water vapor come from wet cooling towers and combustion cases. When it is cold, the plumes are particularly long because the ambient air can hold little added moisture. Formation of these plumes is particularly hazardous during "fogging" conditions when a high wind speed causes the plume to travel along the ground. During freezing conditions, such plumes may lead to ice formation on nearby roads and structures. Dry cooling towers can be used to reduce fogging and icing.

The SO_2 and NO_x emissions from major fuel-burning facilities have been related to the occurrence of acid rainfall downwind of major industrial areas. Congress may soon enact laws to restrict these emissions because of the effects of acid rain. The theoretical framework for explaining acid rain formation, the acidification of lakes, the effects on soils, vegetation, wildlife and structures, and the tracing of problems to specific source emissions is not yet fully understood. Much research is in progress, and recent research indicates that some remote areas of the western United States have been affected by acid rain.

Emissions from Power Plants

Combustion Turbines. One of the primary siting constraints of the combustion turbine technology is environmental. The exhaust from combustion turbines typically contains oxides of sulfur (SO_x) as well as NO_x. These constituents comprise the main pollutants of greatest regulatory concern. CO, unburned hydrocarbons, and particulate matter can also be present. The quantity of each particular contaminant emitted is a function of the size of the machine, the manufacturer, the type of fuel burned, and the extent to which emission control techniques are used. The suitability of a particular site will depend upon the degree to which these contaminants can be controlled.

Combined Cycle. Like the simple-cycle combustion turbine plant, a combined-cycle plant has siting constraints related to air emissions. In addition, the combined-cycle plant has further constraints imposed by the steam cycle, which requires water for condenser cooling and boiler make-up. However, because the combustion turbine portion of the total combined-cycle plant (approximately two thirds) requires essentially no cooling water, water requirements are much less than a similar sized, conventional steam-electric plant. Air-quality impacts are similar to those associated with combustion turbines.

Coal-Fired Power Plants. Coal-fired power plants generate large quantities of solid waste derived from both the combustion process (fly ash and bottom ash) and from atmospheric emissions (flue-gas desulfurization wastes). These wastes require more extensive environmental monitoring and waste characterization studies, and generally more sophisticated treatment technologies than other steam-cycle technologies. Water resource impacts associated with these solid wastes are generally mitigated through appropriate plant siting and a water, wastewater, and solid waste management program.

The combustion of large amounts of coal leads to a potentially significant deterioration of the surrounding air quality. The major pollutants include particulate matter, SO_x and NO_x. Federal New Source Performance Standards govern these emissions.

Other significant effects from coal-fired steam plants are associated with water supply and wastewater discharge requirements. Water withdrawal may result in impingement and entrainment of aquatic organisms. Chemical and thermal discharges may produce acute or chronic effects to organisms living in the discharge plume area. Thermal discharges can also cause lethal thermal shock for some organisms in the Railbelt region.

Many potentially suitable development areas for coal-fired plants border important aquatic resource areas (salmon in streams like the Copper and Susitna Rivers and other marine fish and shellfish in Cook Inlet); plants located in these areas would have to be designed to mitigate effects on these resources. The greatest impact on the terrestrial biota is the loss or alteration of habitat due to the large amounts of land required for both construction and operation. These land requirements are generally greater than those for other types of fossil-fueled power plants.

Other impacts to the terrestrial ecology could result from gaseous and particulate air emissions, fuel or waste storage discharges, human disturbance, and the power plant facilities themselves. Biological impacts are best mitigated by siting plants away from important wildlife areas and by implementing appropriate pollution control procedures. Although certain impacts can be controlled, land losses are irreplaceable.

Air-Quality Regulations

In 1970 the federal Clean Air Act established the national strategy in air pollution control. The Act established New Source Performance Standards (NSPS) for new stationary sources, including fuel combustion facilities. Levels of acceptable ambient air quality (National Ambient Air Quality Standards) were also established, and the regulations were promulgated to maintain these standards or to reduce pollution levels where the standards were exceeded.

New source performance standards (NSPS) have been promulgated for coal-fired steam-electric power plants and for combustion turbines. In addition, any combustion facility designed to burn coal or coal mixtures is subject to the coal-fired power plant standards.

Major changes were made to the Clean Air Act in 1977 when the Prevention of Significant Deterioration (PSD) program was added by Congress. The PSD program has established limits of acceptable deterioration in existing ambient air quality, SO_2 and total suspend particulates (TSP) throughout the United States. Pristine areas of national significance, called Class I areas, were set aside with very small increments in allowable deterioration. The remainder of the country was allowed a greater level of deterioration.

The PSD program, currently administered by the U.S. Environmental Protection Agency (EPA), applies to SO_2 and suspended particulates. In the near future, PSD control over other major pollutants, including NO_x, CO, oxidants, and hydrocarbons may be promulgated. Obtaining a PSD permit represents one of the largest single obstacles to constructing a major fuel-burning facility.

Water Quality Effects

Hydroelectric Facilities. A hydroelectric facility can have several hydroelectric impacts because of its physical configuration and operation. The most obvious impact is the creation of an impoundment. The change from a flowing-water to a still-water environment is a fundamental modification of the hydrologic system. Development of the reservoir also increases evaporation and groundwater seepage. Both of these phenomena increase water losses to the watershed. In the low-runoff regions of the Railbelt area, these losses, if substantial, could incur significant impacts by reducing downstream flow, especially during the summer months.

Important hydrologic impacts are also associated with operating a hydroelectric plant. Large daily fluctuations in river flow can result when hydropower is used for peaking power or when it closely follows load. If the fluctuations are too large and rapid, adverse impacts to aquatic biota can occur, and for the more accessible small river projects, they can be hazardous to downstream recreationists. On a seasonal time scale, the reservoir level can vary greatly, again having the potential for adverse impacts to aquatic biota and for making the reservoir unattractive for recreation (especially when the reservoir is low). The reservoir can be operated to have positive impacts by attenuating flood flows and thereby helping to prevent flood damage to property downstream. By augmenting low river flows, the reservoir can improve water quality and aquatic habitat. Because many rivers in the Railbelt region exhibit wide natural flow variations, attenuation can be a significant positive impact.

Reservoir operation primarily impacts four parameters in terms of water quality: temperature, dissolved oxygen (DO), total dissolved gases, and suspended sediment. Adverse impacts from temperature and DO can occur during the summer months when the reservoir is stratified. The large water surface area of the reservoir allows the upper layer of water to be heated to temperatures higher than those experienced in the natural free-flowing river. If all water released from the reservoir is from the upper layer of water, elevated river-water temperatures downstream can result, causing adverse impacts on aquatic biota (especially cold water fish). If all water released from the reservoir is from the lower layer of water, the DO in the river will be depressed until it can be replenished by natural reaeration. Intake structures can be designed to take water from different levels in the reservoir to help avoid some of these impacts.

If the water released from the reservoir goes over the spillway, gas supersaturation sometimes occurs. Because of the turbulent nature of the water as it falls over the spillway, atmospheric gases (nitrogen and oxygen) are entrained. If these gases are carried to depth (e.g., in a deep plunge pool), the gases are readily dissolved and the water becomes supersaturated relative to surface conditions. This situation can result in injury or mortality to aquatic organisms, particularly fish. The effects are most pronounced in organisms that inhabit shallow areas or surface levels. Supersaturation can be minimized by various spillway designs and operating measures.

As water flows into a reservoir, its velocity is reduced, and it deposits much of its suspended sediment. Therefore, when the water is released from the reservoir, it is relatively free of sediment load. A potential exists, then, for this water to initiate scour downstream to re-establish equilibrium between the erosive energy of the flowing water and its sediment loads. Given that many of the Railbelt rivers are glacier-fed with very high suspended sediment loads, sediment deposition and downstream scouring will be important siting considerations. Scour can also occur near the outlet works and spillway of the hydropower plant if the water is discharged with a high velocity. The latter scour problem can be mitigated by proper engineering design.

Hydroelectric projects alter the streamflow characteristics and water quality of streams. These changes result in corresponding changes in the aquatic biota. Although impacts occur on all levels of the food chain, the impacts on fish are usually of most concern. Potential major effects in the Railbelt that will be most difficult to mitigate include the following:

1. loss of spawning areas above and below the dam
2. loss of rearing habitat
3. reduced or limited upstream access to migrating fish
4. increased mortalities and altered timing of downstream migrating fish.

Construction activities can result in elevated stream turbidity levels and gravel loss, and expanded public fishing in the area from increased access. Other potentially significant impacts could include altered nutrient movement, which could affect primary production; flow pattern changes, which can modify species composition; and temperature regime alteration, which could affect the timing of fish migration and spawning, and insect and fish emergence. Competition and predation among and within species may also be changed.

Mitigative procedures are possible for many impacts and are frequently incorporated into the design of the facility. Fish hatcheries are commonly used to replace losses in spawning habitat. Screening or diversion structures are used to direct fish away from critical areas. Depending on the height of dam and the availability of spawning areas upstream of the created reservoir, fish ladders are frequently incorporated into the design. Controlled release of water (including both flow and temperature regulation by discharging from various depths in the reservoir) can be used to improve environmental conditions during spawning, rearing, and migration.

<u>Steam-Electric Plants</u>. The construction and operation of steam-electric plants have three potential areas of impacts on aquatic ecosystems: water

quality effects from construction stormwater runoff, water withdrawal for power plant use, and process water discharge. The degree of each potential impact depends on the plant's size, location, and operating characteristics.

Construction area runoff can increase turbidity and siltation in receiving waters adjacent to site construction. For inland waters where steam-cycle facilities could potentially be sited, the main effect of this siltation could be the destruction of these productive aquatic ecosystems. Spawning areas could be eliminated by inundating gravel with fine sediment particles that smother eggs or inhabit fry emergence (especially for salmonids); benthic organisms could be smothered and light penetration reduced, thereby inhibiting the growth of aquatic plants. Salmon, trout, char, grayling, burbot, sheefish, and whitefish species, which are common in many of the major rivers of the Railbelt region, could be affected.

The impact from construction runoff depends on the efficiency of erosion control measures and location of the site. Potential problems in both the fresh and marine waters can be minimized or eliminated by implementing appropriate site runoff and erosion control measures, such as runoff collection systems, settling ponds, and other runoff treatment facilities.

Withdrawing water in significant amounts from inland streams can alter flow patterns and reduce aquatic habitat downstream. These effects may be partially offset by the amount of water discharged, if both the intake and discharge are on the same body of water. The loss of habitat is highly dependent on the size, type, and location of the steam plant.

Attraction of organisms to thermal discharges may interfere with normal migration patterns. A particular concern is that marine organisms are attracted and become acclimated to a heated discharge from a once-through cooling water system, which is then interrupted or stopped; the almost instantaneous temperature change back to ambient levels can result in thermal shock and subsequent mortalities to these organisms. Proper plant siting and cooling system design could reduce or eliminate thermal impacts. With other factors constant, the plant that uses the most water would have the greatest impact.

The chemical composition of the intake water is altered during its passage through the steam plant. Changes in the composition generally depend on the specific steam cycle and its capacity, but chemical additions include the following:

1. chemicals, such as chlorine, added to control biological fouling and deposit of materials on cooling system components
2. constituents of the intake water concentrated during recirculation through evaporative cooling systems
3. corrosion products from structural components of the cooling system.

Other potential pollutants from steam cycles include low pH, high metal concentrations, biochemical oxygen demand, radionuclides, and petroleum products. When discharged in sufficent quantity, these can cause immediate impacts such as death of organisms or long-term changes in the aquatic ecosystem. Of particular concern would be the effects on the commercial and recreationally important fish and shellfish species that reside in both the fresh and marine systems of the Railbelt region.

Some effluents, like heavy metals and radionuclides, could have negative effects far from the site of their initial discharge, whereas others like low pH and biological oxygen demand (BOD) will have the most impact close to the discharge. Some of these effluents would have less impact on marine systems than on fresh water systems. Total dissolved solids (TDS) can be especially high in geothermal plants. High TDS would have little effect on the marine environment because TDS is already much higher in seawater than in fresh water. Low pH discharges would be more easily neutralized in the marine systems. Most other discharges could have negative effects on both fresh water and marine systems, but the marine environment's much larger area for dilution more easily reduces impacts.

Ecological Effects

Steam-electric and hydroelectric energy projects require large amounts of land. The amount of land required varies with the energy-producing capacity of a plant. Because hydroelectric plant requirements generally exceed those of other energy types, an important impact is the inundation of large areas of wildlife habitat.

Impacts from hydroelectric energy projects result not only from inundation of land but also from the operation of the dam and the dam itself. Inundation of flood plains, marshes, and other important wildlife habitat can negatively affect big game animals, aquatic furbearers, waterfowl, shorebirds, and raptors. Big game animals can be impacted by loss of seasonal ranges and interruption of migratory routes. Winter ranges in particular are critical habitats for migratory big game animals. The flood control provided by dams may significantly reduce the extent of wetland habitats resulting from the elimination of seasonal inundation of large areas downstream of dam sites. This factor may significantly impact moose and other wetland species. Aquatic furbearers can be adversely affected by the loss of habitats. Correspondingly, waterfowl and shorebird nesting, loafing, and feeding areas can be eliminated by the flooding of these habitats. The re-establishment of high-quality habitats is generally prevented by the constantly fluctuating water levels of plant operation. Fluctuating water levels can also destroy trees and other natural structures used by birds for perching, nesting, and roosting sites. Birds and bears can further be impacted by the loss of fish if fish passage is prevented or reduced by the dam.

Steam-electric and hydroelectric projects located in remote areas cause other impacts. Access roads to remote locations cause extensive disturbance to wildlife. Not only will habitat be replaced by roads, but isolated wildlife populations will be adversely affected by increased human activity and numbers. These impacts could result in disturbance of wilderness species like grizzly bears. Also, other wildlife could be impacted from increased hunting pressure, poaching, and road kills. The magnitude of these and other potential impacts will depend on the wildlife population densities at each specific site.

Mitigative measures could be taken to relieve some wildlife impacts resulting from dam developments. The habitats flooded by a reservoir would be largely irreplaceable. However, other habitats, such as islands used by waterfowl for nesting, could be created by placing spoils or channels in the affected area. Trees and other natural features used by raptors could be retained instead of removed as is usually done prior to inundation. Whereas these relief measures are somewhat specific, wildlife impacts, in general, can be minimized by selecting only those sites where wildlife disturbances would be the least.

D.1.4 Socioeconomic Considerations of Plan 1A

This section covers the general socioeconomic concerns of Plan 1A.

Combustion Turbines. Because of the relatively small workforce and acreage requirements for combustion turbine development, impacts can be expected to vary more with location than with plant scale. The absence of major siting constraints allows flexibility in locating a combustion-turbine facility. Construction of a 170-MW plant would require 30 persons for a period of 9 months. To minimize impacts, combustion turbines should not be sited in very small towns, although installing a construction workcamp would lessen the demand for housing and public services. Primary plant sites would be Anchorage, Soldatna, and Fairbanks. Secondary sites would include Kenai, Seward, Wasilla, Palmer, and North Pole.

Since a combustion turbine is a capital-intensive facility, 20% of the project expenditures would be invested within Alaska, while 80% would be spent outside Alaska.

Combined Cycle. Construction of a 200-MW combined-cycle plant requires 45 persons for a period of 2 years. The operating and maintenance requirements would be approximately 15 persons. Since the construction work force is relatively small, impacts should vary more with site location than with plant capacity. Severe construction-related impacts could occur in very small communities along the distribution pipeline or railroad where the infrastructure is insufficient to meet new demands. These impacts can be lessened by siting a combined-cycle plant in a community with a population greater than 500. Primary sites would include Anchorage, Fairbanks, and Soldatna. Secondary locations adjacent to the railroad or major highway corridor include Kenai, Seward, Wasilla, Palmer, and North Pole.

Since combined cycle is a capital-intensive technology, the largest portion of expenditures outside the region would be attributed to equipment. Approximately 70% of the project expenditures would be spent in the lower 48 states, while 30% would be spent within the Railbelt.

Steam Electric. The construction and operation of a coal-fired plant has the potential to seriously affect smaller communities and cause a boom/bust cycle. These effects are due to the remoteness of prospective sites. The magnitude of these impacts is a function of plant scale. A major contributing factor to this relationship is the variation in size of the construction work force with plant size. Construction times, exclusive of licensing and permitting, will vary according to the size, type of equipment, and external factors such as weather and labor force. Construction schedules for coal-fired plants in the Railbelt will vary depending upon whether the boiler is field-erected. A 200-MW plant requires 3 to 5 years to construct.

Impacts would be most severe at the Beluga coal fields since the surrounding communities are small and transportation facilities are poorly developed. Power plant components would most likely be shipped by barge and then transported overland to the site. Secondary impacts would be caused by the construction of haul roads. The largest community in the area is Tyonek, an Alaskan native village with a population of 239. The influx of a construction work force would disrupt the social structure of a community of this size. The construction of a work camp would not substantially reduce these impacts.

Impacts from developing a plant along the railroad corridor would depend on a plant scale. Existing communities may be able to accommodate the requirements for constructing a 10- to 30-MW plant, but would be severely affected by a large-scale plant.

The flow of capital expenditures both outside and within Alaska is expected to balance for a 200-MW coal-fired steam-electric plant. The flow of operating and maintenance expenditures is expected to be 10% spent outside the region and the balance spent in the region.

Hydroelectric. The construction and operation of a large hydroelectric plant has a high potential to cause a boom/bust cycle, but a small-scale project will have a minor to moderate impact on community infrastructure. The primary reason large projects will create adverse effects is the remoteness of the sites. The sites are located at or near communities with a population of less than 500. An in-migration of 250 to 1,000 workers, depending on the scale of plant in the range of 100 to 1,000 MW, would be necessary for construction.

In these remote communities, the population could more than quadruple. The installation of a construction camp would not reduce the impacts on the social and economic structure of a community.

A small-scale hydro project may be compatible with remote communities. For example, a 2.5-MW project would require a construction workforce of 25. The length of construction time would be 2 years in comparison to 5 to 10 years for completion of a large-scale project.

The expenditures that flow out of the region account for investment in equipment and supervisory personnel. For a large-scale project, a larger proportion of the expenditures is attributed to civil costs. Approximately 35% of an investment in a large project would be made outside the region, whereas 65% would be made within the Railbelt. Sixty-five percent of the investment in a small-scale hydro project would be made in the lower 48 states, whereas 35% would be contained within the Railbelt. The breakdown of operating and maintenance expenditures for a hydroelectric project would be ~11% spent outside the Railbelt and ~89% spent within the region.

D.1.5 Integration of Potential Impacts

The overall environmental and socioeconomic impacts of Plan 1A are presented in Table D.3. The impacts mainly are minor to moderate. However, the following points represent prominent concerns:

1. air-quality impacts of coal-fired units
2. boom-bust impacts of coal and hydroelectric projects
3. water-quality and ecological impacts of construction and operation.

Air-Quality Impacts of Coal-Fired Units

The increased use of coal-fired steam turbines will require large amounts of land. The major facilities that will alter the landscape include smokestacks, cooling towers, coal stockpiles, the boiler plant, and the ash ponds. Of course, the smokestack and cooling tower plumes will be highly visible, especially in the winter months. The combustion emissions will contribute to decreased visibility. Also, locating the fossil fuel power plants such that their plumes do not violate the PSD air quality regulations may be a problem.

TABLE D.3. Integration of Potential Environmental & Socioeconomic Impacts for Plan 1A

Energy Facilities Added	Air Quality	Water Quality	Terrestrial Ecology	Aquatic/Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/Bust Effects	Land-Use Effects	Susceptibility to Inflation	Spending in Alaska (% Total)
	Potential Environmental and Socioeconomic Impacts										
Anchorage-Cook Inlet											
Gas Turbine Combustion	2	1	1	1	2	1	1	1	2	3	20
Combined Cycle	2	2	2	2	2	1	2	2	3	3	30
Coal-Fired Steam Turbine	3	2	2	2	3	2	2	2	3	3	40
Fairbanks-Tanana Valley											
Coal-Fired Steam Turbine	3	2	2	2	3	2	3	2	3	3	40
Gas Turbine Combustion	2	1	1	1	2	1	1	1	2	3	20
Hydroelectric											
Bradley Lake	1	2	2	2	2	1	3	3	3	1	65
Chakachamna	1	2	2	2	2	1	3	3	3	1	65
Allison	1	2	2	2	1	1	2	2	2	1	35
Grant Lake	1	2	2	2	1	1	2	2	2	1	35

Rating Scale: 1 - minor
2 - moderate
3 - significant

Two permanent Class I (Pristine Air) areas, Denali National Park and the pre-1980 areas of the Tuxedni Wildlife Refuge, are in or near the Railbelt region. The new National Parks and Wildlife Preserves have not been included in the original designation, but the state may designate additional Class I areas in the future. New major facilities located near Class I areas must not cause a violation of the PSD increment. This requirement presents a significant constraint to developing nearby facilities.

A potentially important aspect of the PSD program to developing electric power generation in the Railbelt region is that Denali National Park (Mt. McKinley National Park prior to passage of the 1980 Alaska Lands Act) is Class I, and it lies close to Alaska's only operating coal mine and the existing coal-fired electric generating unit (25 MWe) at Healy. Although the PSD program does not affect existing units, an expanded coal-burning facility at Healy would have to comply with Class I PSD increment for SO_2 and suspended particulates. Because of this regulation, any coal plants in the Fairbanks-Tanana Valley are assumed to be located in the Nenana area. Decisions to permit increased air pollution near Class I areas can only be made after careful evaluation of all the consequences of such a decision. Furthermore, Congress required that Class I areas must be protected from impairment of visibility resulting from man-made air pollution. The impact of visibility requirements on Class I areas is not yet fully known.

Based on information on emissions and regulations, several general conclusions can be drawn that bear on the siting of major fuel-burning facilities. First, these facilities should be located well away from Class I areas. A minimum distance would probably be 20 miles, but each case should be carefully analyzed to reliably choose a site. The forthcoming visibility regulations may require a greater distance. Also, because of regulatory constraints, any of these facilities should be located well away from the non-attainment areas surrounding Anchorage and Fairbanks. In addition, the major fuel-burning facilities should be located away from large hills and outside of narrow valleys or other topographically enclosed areas. Facilities should be developed in open, well-ventilated sites in which atmospheric dispersion conditions will contribute to minimizing impacts on air quality.

Many acceptable sites should exist for coal-fired power plants in the Beluga, Kenai, Susitna, and Nenana areas and near the available coal fields. Since Alaska coal is generally low in sulfur content, the siting constraints will be less stringent than those normally encountered in the eastern United States. Generally, emissions from natural gas combustion are of less significance, and the siting of such facilities is therefore less critical. For this study, the coal plants in Anchorage-Cook are assigned to be in Beluga and near Nenana in the Fairbanks-Tanana Valley.

An initial assessment indicates that Alaskan lakes are not so sensitive to acid rain as lakes in eastern Canada and the northeastern United States. Furthermore, the total emissions into the Alaskan environment are much less than emissions from industrialized areas of the midwest and northeastern United States. In Alaska acid rainfall most likely never will present problems similar to those in the eastern portion of the continent. Currently no basis exists for assessing the impacts of acid rainfall that might develop because of increased fuel combustion in Alaska.

Boom/Bust Impacts of Coal and Hydroelectric Projects

The construction activities for the larger coal-fired steam-turbine units and the Bradley Lake and Chakachamna hydroelectric facilities will require substantial labor forces. For the more remote areas, the population could quadruple. In these situations, installing a construction camp would not reduce the impacts on the social and economic structure of the community.

Water-Quality and Ecological Impacts of Construction and Operation

Both the coal-fired steam turbine units and the hydroelectric facilities will significantly alter water quality and the surrounding habitat for wildlife. For example, the configuration of the Chakachamna hydroelectric project will have some significant, irreversible impacts on the local water resources. Creation of the power tunnel, together with the concrete overflow structure, will greatly reduce flows in the Chakachatna River. In addition, the lake will be subject to significant fluctuations in elevation, perhaps as much as 180 feet. The McArthur River will experience an increase in flow, corresponding roughly to the loss in the Chakachatna River. Should the water qualities of the lake and McArthur River differ significantly, the river will experience a change in water quality as well. Parameters most likely to experience a change include temperature, dissolved oxygen, total dissolved gases, and suspended sediment.

During the design phase, actions can be taken to reduce the impacts on fish and wildlife. For example, a prime alternative for the Chakachatna project provides for flow from the lake into the Chakachamna River to maintain minimum flow requirements. This trade-off means a reduction in capacity from 400 MW to 330 MW and a 16% increase in the subsequent cost of power. But even with this increase, the cost of power is significantly less than the most competitive coal-fired power plant.

Potential aquatic ecological impacts of hydropower project construction on Chakachamna Lake center on lake level fluctuations as a result of reservoir drawdown (exposure of fish spawn and elimination of spawning habitat) and possible entrainment and impingement problems (fish eggs, larvae, and food organisms) associated with diversion of lakewater through the generators. Potential aquatic ecological impacts to the lake inlet streams may result from decreased lake access due to reservoir drawdown during certain periods of the year.

The primary inlet to the lake, the Chilligan River, serves as a spawning area for red (sockeye) salmon. Known spawning areas for Chinook (King) and pink (humpback) salmon exist in the lower tributaries of the Chakachatna (lake outlet) and McArthur Rivers. The McArthur River will receive the tailrace flows from the project. The annual adult escapement for these species is unknown, as is their contribution to the Cook Inlet runs. Lake trout are resident within Lake Chakachamna; Dolly Varden (Arctic char), whitefish, and rainbow trout are present in the lower tributaries of the Chakachatna and McArthur Rivers. Nonsalmonid fish species that probably are found within project area waters include sculpins, blackfish, and northern pike. Most likely all of the above species will be disturbed because of the project.

Aquatic impacts on the Chakachatna and McArthur Rivers will be the most severe due to potential changes in existing flow regimes. For example, the design will essentially dewater the upper Chakachatna River and divert the lake outflow via a tunnel to the McArthur River. This scenario will most likely eliminate fish access to the upper Chakachatna River and Chakachamna Lake and will alter the existing flow regimes and chemical makeup of the McArthur River, thus potentially altering fish production in that river as well.

The primary potential wildlife impacts of hydroelectric development in the project area will be from river level fluctuations and habitat loss. River level fluctuation may change the character of the riverine vegetation, which is used by moose in the winter, and marshes, which are used by waterfowl during the spring, summer, and fall. Changes in the river level may also affect the fish populations used by brown and black bear and habitat used by beaver. Unexpected drawdown will expose beaver-inhabited lodges to predation.

The hydroelectric facilities and access roads will eliminate some wildlife habitat and open up the project area to increased hunting pressure. Whereas increased hunting is detrimental to some populations, it is beneficial to others and provides additional hunting opportunity to Alaskans. Increased access and the associated use by people will also create more poaching and human/bear conflicts. The Chakachamna project will impact wildlife in two river drainages. However, wildlife impacts resulting from alteration of Lake Chakachamna are expected to be small.

D.2 PLAN 1B: "PRESENT PRACTICES" WITH UPPER SUSITNA

This plan is based upon a continuation of present generating technologies with a transition to Upper Susitna hydropower as required. Any additional capacity required is to be supplied by conventional coal-steam turbine or combined-cycle facilities.

Hydroelectric plants include the following:

- The Lake project which comes on-line in 1988
- The Upper Susitna Project: Watana (680 MW) which comes on-line in 1993; Devil Canyon (600 MW) which comes on-line in 2002.

Other generating capacity includes the following:

Anchorage-Cook Inlet

- If required by load growth, combustion turbine and combined capacity is added to fill in until Upper Susitna is available.

- If required by load growth, coal-steam turbine units are added after the Upper Susitna project is completed.

Fairbanks-Tanana Valley

- If necessary, combustion turbine and combined cycle capacity is added to fill in until the Upper Susitna project is available.
- If necessary, coal-steam turbine units are added after the Upper Susitna project is completed.

D.2.1 Capacity and Generation for Plan 1B

As shown in Table D.4, almost all the additional capacity added in this plan is the first stage of Watana (680 MW) and Devil Canyon (600 MW) dams of the Upper Susitna project. The Watana dam comes on-line in 1993 and the Devil Canyon dam comes on-line in 2002. The only other capacity added is 70 MW of gas combustion turbine capacity and 200 MW of gas combined-cycle capacity brought on-line in 1990 and 1991, respectively, in the Anchorage area.

As shown in Table D.5, during the 1981-1992 time period, electrical generation in Anchorage is largely by gas combustion turbines and combined-cycle capacity, with some hydroelectric generation. In Fairbanks, oil combustion turbines and diesel capacity are used until 1990-91, whereas coal steam turbine continues to be used to a significant amount until 2002 when the Devil Canyon dam comes on-line. From 2002 until 2010 the majority of electrical generation in the Railbelt is supplied by hydroelectric power, largely from the Upper Susitna project.

D.2.2 Environmental Considerations of Plan 1B

The principle environmental considerations for this plan are associated with the development of the Upper Susitna River, with dams at Watana and Devil Canyon. In this section, descriptions of ambient biological and vegetation conditions are presented.

Fisheries. The Susitna Basin is inhabited by resident and anadromous fish. The anadromous group includes five species of Pacific salmon: sockeye (red), coho (silver), chinook (king), pink (humpback), and chum (dog) salmon. Dolly Varden are also present in the lower Susitna Basin with both resident and

TABLE D.4. Existing Capacity (1980) and Capacity Additions and Retirements (MW) (1981-2010) - Plan 1B

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		
Year	Gas Combustion Turbine	Gas Combined-Cycle	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Hydroelectric
1980	461	139	266	69	46 (Eklutna & Cooper Lake)
1981	0	0	0	0	12 (Solomon Gulch)
1982	-20	178	0	0	0
1983	0	0	-8	0	0
1984	0	0	0	0	0
1985	0	0	0	0	0
1986	0	0	-1	0	0
1987	0	0	-8	-4	0
1988	0	0	-6	0	90 (Bradley Lake)
1989	0	0	0	-5	0
1990	70	0	0	0	0
1991	0	200	-18	0	0
1992	-16	0	-19	0	0
1993	-9	0	0	0	680 (Watana)
1994	-30	0	0	0	0
1995	-14	0	-33	0	7 (Grant Lake)
1996	0	0	-102	0	0
1997	0	0	-65	0	0
1998	-50	0	0	0	0
1999	0	0	0	0	0
2000	-18	0	0	0	0
2001	0	0	0	0	0
2002	-51	0	0	-25	600 (Devil Canyon)
2003	-53	0	0	0	0
2004	0	0	0	0	0
2005	-58	0	0	-21	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	-26	0	0	0	0
2009	0	0	0	0	0
2010	0	0	0	0	0

TABLE D.5. Electrical Generation by Type of Capacity - Plan 1B (GWh)

	Anchorage-Cook Inlet		Fairbanks-Tanana Valley		
Year	Gas Combustion Turbine	Gas Combined Cycle	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Hydroelectric
1981	2021	46	26	537	254
1982	773	1389	64	537	254
1983	851	1403	102	537	254
1984	958	1389	140	537	254
1985	425	2275	0	455	254
1986	1403	1482	20	537	254
1987	1528	1541	123	537	254
1988	1391	1470	226	537	648
1989	1529	1515	370	496	648
1990	1234	2494	2	468	648
1991	1945	1855	0	496	648
1992	1969	1928	1	496	648
1993	1	1022	0	11	4103
1994	2	1110	0	19	4103
1995	0	733	0	496	4103
1996	0	688	0	496	4103
1997	0	643	0	496	4103
1998	0	597	0	496	4103
1999	0	553	0	496	4103
2000	0	508	0	496	4103
2001	0	626	0	496	4103
2002	0	0	0	0	5349
2003	0	0	0	23	5436
2004	0	0	0	0	5611
2005	0	0	0	0	5698
2006	0	0	0	1	5961
2007	0	0	0	5	6224
2008	0	0	0	9	6487
2009	0	0	0	14	6750
2010	0	0	0	18	7013

anadromous populations. Anadromous smelt are known to run up the Susitna River as far as the Deshka River about 40 miles from Cook Inlet.

Salmon are known to migrate up the Susitna River to spawn in tributary streams. Surveys to date indicate that salmon are unable to migrate through Devil Canyon into the Upper Susitna River Basin. To varying degrees spawning is also known to occur in freshwater sloughs and side channels. Principal resident fish in the basin include grayling, rainbow trout, lake trout, whitefish, sucker, sculpin, burbot and Dolly Varden.

Because the Susitna is a glacially fed stream, the waters are silt laden during the summer months. This condition tends to restrict sport fishing to clear water tributaries and to areas in the Susitna near the mouth of these tributaries.

In the Upper Susitna Basin grayling populations occur at the mouths and in the upper sections of clear water tributaries. Between Devil Canyon and the Oshetna Rivers most tributaries are too steep to support significant fish populations. Many terrace and upland lakes in the area support lake trout and grayling populations.

<u>Big Game</u>. The project area is known to support species of caribou, moose, bear, wolves, wolverine and Dall sheep.

The Nelchina caribou herd, which occupies a range of ∿20,000 square miles in southcentral Alaska, has been important to hunters because of its size and proximity to population centers. The herd has been studied continuously since 1948. The population declined from a high of ∿71,000 in 1962 to a low of between 6,500 and 8,100 animals in 1972. From October 1980 estimates, the Nelchina caribou herd contained ∿18,500 animals.

The proposed impoundments would inundate a very small portion of apparent low-quality caribou habitat. Concern has been expressed that the impoundments and associated development might serve as barriers to caribou movement, increase mortality, decrease use of nearby areas and tend to isolate subherds.

Moose are distributed throughout the Upper Susitna Basin. Studies to date suggest that the areas to be inundated are used by moose primarily during the winter and spring. The loss of their habitat could reduce the moose population for the area. The areas do not appear to be important for calving or breeding purposes; however, they do provide a winter range that could be critical during severe winters. In addition to direct losses, displaced moose could create a lower capacity for the animals in surrounding areas.

Black and brown bear populations near the proposed reservoirs appear to be healthy and productive. Brown bears occur throughout the study area, whereas black bears appear largely confined to a finger of forested habitat along the Susitna River.

The proposed impoundments are likely to have little impact on the availability of adequate brown bear den sites; however, the extent and utility of habitats used in the spring following emergence from the dens may be reduced. Approximately 70 brown bears inhabit the 3,500-square-mile study area.

Black bear distribution appears to be largely confined to or near the forests found near the Susitna River and the major tributaries. The forest habitat appears to be used the most in the early spring. In late summer black bears tend to move into the more open shrublands adjacent to the spruce forest because of the greater prevalence of berries in these areas.

Five known and four to five suspected wolf packs have been identified in the Upper Susitna Basin. Project impacts on wolves could occur indirectly due to reduction in prey density, particularly moose. Temporary increases could occur in the project area due to displacement of prey from the impoundment areas. Direct inundation of den and rendezvous sites may decrease wolf densities. Potential increased hunting and trapping pressure could also increase wolf mortality.

Wolverines are found throughout the study area, although they show a preference towards upland shrub habitats on southerly and westerly slopes. Potential impacts would relate to direct loss of habitat, construction disturbance and increased competition for prey.

Dall sheep are known to occupy all portions of the Upper Susitna River Basin, which contains extensive areas of habitat above the 4,000 foot elevation. Three such areas near the project area include the Portage-Tusena Creek drainages, the Watana Creek Hills and Mount Watana. Since Dall sheep are usually found at elevations above 3,000 feet, impacts will likely be restricted to potential indirect disturbance from construction activities and access.

Furbearers. Furbearers in the Upper Susitna Basin include red fox, coyote, lynx, mink, pine marten, river otter, short-tailed weasel, least weasel, muskrat and beaver. Direct inundation, construction activities and access can be expected generally to have minimal impact on these species.

Birds and Nongame Mammals. One hundred and fifteen species of birds were recorded in the study area during the 1980 field season. The most abundant species were Scaup and Common Redpoll. Ten active raptor/raven nests have been recorded and of these, two Bald Eagle nests and at least four Golden Eagle nests would be flooded by the proposed reservoirs, as would about three currently inactive raptor/raven nest sites. Preliminary observations indicate a low population of waterbirds on the lakes in the region; however, Trumpeter Swans nest on several lakes between the Oshetna and Tyone Rivers.

Flooding would destroy a large percentage of the riparian cliff habitat and forest habitats upriver of Devil Canyon dam. Raptors and ravens using the cliffs could be expected to find alternative nesting sites in the surrounding mountains, and the forest inhabitants are relatively common breeders in forests in adjacent regions. Lesser amounts of lowland meadows and fluvial shorelines and alluvia, each important to a few species, will also be lost. None of the water bodies that appear to be important to waterfowl will be flooded, nor will the important prey species of the upland tundra areas be affected. Impacts of other types of habitat alteration will depend on the type of alteration. Potential impacts can be lessened by avoiding sensitive areas for construction sites.

In the project area, thirteen small mammal species were found during 1980, and the presence of three others was suspected. During the fall survey, red-backed voles and masked shrews were the most abundant species trapped, and these, plus the dusky shrew, appeared to be habitat generalists, occupying a wide range of vegetation types. Meadow voles and pygmy shrews were least abundant and the most restricted in their habitat use; the former were found only in meadows and the latter in forests.

Vegetation. The Susitna River drains parts of the Alaska Range on the north and parts of the Talkeetna Mountains on the south. Many areas along the east-west portion of the river, between the confluences of Portage Creek and the Oshetna River, are steep and covered with conifer, deciduous and mixed conifer, and deciduous forests. Flat benches occur at the tops of these banks and usually contain low shrub or woodland conifer communities. Low mountains rise from these benches and contain sedge-grass tundra and mat and cushion tundra.

The Devil Canyon and Watana reservoirs will inundate a total of 44,729 acres of vegetation. The access road or railroad will destroy an additional 371 to 741 acres of vegetation, which is roughly equal to 0.02% of the vegetation in the entire basin. The primary vegetation types to be affected are mat and cushion tundra, sedge-grass tundra, birch shrubland and woodland spruce.

Land Use. Existing land use in the Susitna area is characterized by broad expanses of open wilderness areas. Those areas where development has occurred often include small clusters of several cabins or other residences. Many single-cabin settlements are located throughout the basin. Most of the existing structures are related to historical development of the area, initially involving hunting, mining, and trapping and later guiding activities associated with hunting and to a lesser extent fishing. Today a few lodges can be found, mostly used by hunters and other recreationalists. Many lakes in the area also included small clusters of private year-round or recreational cabins.

Perhaps the most significant use activity for the past 40 years has been the study of the Susitna River for potential hydro development. Hunting, boating, and other forms of recreation are also important uses. Numerous trails throughout the basin are used by dog sled, snowmobile and all-terrain vehicles. Air use is significant for many lakes, providing landing areas for planes on floats.

D.2.3 Socioeconomic Considerations of Plan 1B

The construction and operation of the Watana and Devil Canyon dams have the potential for both positive and adverse socioeconomic effects. The positive effects will be employment opportunities and revenues that will be generated by the project and which will stimulate growth of the local economy in the short term and, in the long term, will contribute to the expansion of the regional economy. The adverse effect is the in-migration of temporary workers to a community, potentially causing a boom/bust cycle.

The primary effect of a boom/bust cycle is a temporarily expanded population with insufficient infrastructure to support the new demands. The in-migration of workers to a community will have an impact on land availability, housing supply, commercial establishments, electric energy availability, roads, public services such as schools, hospitals, and police force, and public facilities such as water supply and domestic waste treatment facilities. The magnitude of these impacts will depend on the population of the area, the size of the construction work force, and the duration of the construction period. The bust occurs with the out-migration of a large construction work force, which leaves the community with abandoned housing and facilities.

The magnitude of the boom/bust cycle is determined by the duration of the construction and the relative size of the work force to the community. A construction force of a thousand or more workers will be required for a period of 5 to 10 years for the Upper Susitna project. Yet, as revealed by the 1981 Census, only 18,000 people or 6% of the State's population lives in the Matanuska-Susitna Burough where the project is located. This area is already experiencing rapid growth because its southern part is influenced by the Anchorage labor market. The 1970 population of the Matanuska-Susitna Burough was 6,500. Smaller cities along the Railbelt, especially Talkeetna, would be directly impacted by the Upper Susitna project, whereas Fairbanks and Anchorage would be less affected due to their size and distance from the project area. While much of the work force may be drawn from the Fairbanks and Anchorage labor market areas, they most likely will not be commuting the distance involved. Installing a construction camp would not substantially reduce the social and economic impacts in the community.

The secondary effect of the construction may be the growth of the local and regional economies. The increase in the number of permanent residents will cause the introduction of new businesses and jobs to the community. This effect may be perceived as either positive or negative, depending on individual points of view. The expenditures on capital and labor during both the construction and operation phases will increase regional income as well as local income. Increased regional income would be caused by the expansion of construction firms and related industries. A parameter of expansion of the regional economy is flow of expenditures within the region and can be measured in terms of percentage.

The expenditures that flow out of the region account for investment in equipment and supervisory personnel. For a large-scale project, such as the Upper Susitna, a larger proportion of the expenditures is attributed to civil costs. Approximately 35% of an investment in a large project would be made outside the region, while 65% would be made within the Railbelt. The breakdown of operating and maintenance expenditures for the project would be ~11% spent outside the Railbelt and ~89% spent within the region.

D.2.4 Integration of Potential Environmental and Socioeconomic Impacts for Plan 1B

The integration of potential environmental and socioeconomic impacts are presented in Table D.6. The impacts are directly related to nature of this plan; that is, future demands for electricity are largely met by developing the Upper Susitna project, and thereby precluding the use of other alternatives such as coal-fired steam-turbine power plants. In this plan, concerns related to air pollution are almost nonexistent because all existing oil combustion turbines, diesels and coal steam turbine units in Fairbanks are phased out. In Anchorage, a substantial amount of the existing gas combustion turbine capacity is phased out and only 70 MW of new capacity is added; however, about 400 MW of gas combined-cycle capacity is added. Even with this, in 2010 the amount of electricity derived from fossil-fuel resources would be less than it is today. The principle integrated impacts of this plan are, therefore, related to the construction and operation of Bradley Lake, Watana and Devil Canyon hydroelectric projects. Therefore, the main concerns are 1) changes in water quality and subsequent impact on fisheries, 2) loss of habitat area for animals, and 3) the boom/bust impacts of construction.

TABLE D.6. Integration of Potential Environmental & Socioeconomic Impacts for Plan 1B

Energy Facilities Added	Potential Environmental and Socioeconomic Impacts										
	Air Quality	Water Quality	Terrestrial Ecology	Aquatic/Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/Bust Effects	Land-Use Effects	Susceptibility to Inflation	Spending in Alaska (% Total)
Anchorage-Cook Inlet											
Gas Turbine Combustion	2	1	1	1	2	1	1	1	1	3	20
Gas Combined Cycle	2	1	2	2	2	1	2	1	2	3	30
Hydroelectric											
Grant Lake	1	2	2	2	1	1	2	2	2	1	35
Bradley Lake	1	2	2	2	1	1	3	3	3	1	65
Watana	1	2	2	2	1	1	3	3	3	1	65
Devil Canyon	1	2	2	2	1	1	3	3	3	1	65

Rating Scale: 1 - minor
2 - moderate
3 - significant

D.3 PLAN 2A: HIGH CONSERVATION AND RENEWABLES WITHOUT UPPER SUSITNA

Plan 2A emphasizes the use of conservation to reduce electrical energy demand, as well as the use of renewable energy sources such as refuse-derived fuel and wind. Increasing levels of conservation are included for each load center and they are assumed to be encouraged through state grant programs.

Under this plan, conservation and alternatives relying on renewable resources, excluding the Upper Susitna project, will be developed to the maximum extent feasible. Additional capacity required will be provided by conventional generating alternatives as in Plan 1A.

Hydroelectric plants include the following:

- the Bradley Lake project, which comes on-line in 1988
- the Allison project, which comes on-line in 1991
- the Chakachamna and Grant Lake projects, which come on-line in 1995
- the Keetna hydroelectric project, which comes on-line in 2008
- the Browne hydroelectric project, which comes on-line in 1995.

Other generating capacity includes the following:

Anchorage-Cook Inlet

- A 50-MW refuse-derived fuel plant is added in 1993.
- Additional generation is supplied by natural gas combined-cycle and combustion turbine.
- A state grant program to encourage the installation of conservation alternatives (passive solar space heating, active solar water heating, wood space heating, and building conservation) exists for 1981 onward.

Fairbanks-Tanana Valley

- A 100 MW of large wind turbine generation is added in the Isabell Pass area.
- A 20-MW refuse-derived fuel plant is added in 1994.
- A state grant program to encourage the installation of conservation alternatives exists.

D.3.1 Capacity and Generation for Plan 2A

As shown in Table D.7, this plan is highly reliant on hydroelectric and other renewable generating resources. The amount of reduction in the peak load due to a conservation grant program is shown in the last column. As shown, the reduction varies between 40 MW and 60 MW, depending upon the year.

The electrical production for each of the generating capacities in the plan is shown in Table D.8.

7.4.2 Environmental Considerations of Plan 2A

Technologies used in this plan and not included in earlier plans are refuse-derived fuel and wind turbine generators. In addition, Allison, Brown and Snow and hydroelectric projects are used, as well as several energy conservation methods.

Refuse-Derived Fuel

Refuse-fuel plants are distinct from fossil fuel-fired units in that maximum plant capacities are achieved at much lower power ratings in refuse-fuel plants. Also, refuse-fuel plants have specialized fuel handling requirements. The generally accepted limits for refuse-fired power plants are ~5 to 60 MW. The moisture content of the fuel, as well as the scale of operation, introduces thermal inefficiencies into the power plant system. In both Anchorage's and Fairbanks' refuse-derived fuel plants, supplemental firing with coal is required to compensate for seasonal fluctuations in refuse availability.

Siting and Fuel Requirements. Siting requirements are dictated by the condition of the fuel, location of the fuel source, and the cycle employed. Because the fuel is high in moisture content and low in bulk density, economical transport distances do not exceed 50 miles. The power plants are thus typically sited at, or near the fuel source. Sites must be accessible to all-weather highways since biomass fuels are usually transported by truck. Approximately 4 trucks per hour would be required for a 50-MW plant.

While proximity to the fuel source may be considered most limiting, sites also must be accessible to water for process and cooling purposes. Land area requirements are a function of scale, extent of fuel storage, and other design

TABLE D.7. Existing Capacity (1980) and Capacity Additions and Retirements (1981-2010) - Plan 2A (MW)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley					
Year	Gas Combustion Turbine	Gas Combined-Cycle	Refuse-Derived Fuel	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Wind Turbine Generators	Refuse-Derived Fuel	Total Hydroelectric	Total Conservation Due to Subsidy
1980	461	139	0	266	69	0	0	46 (Eklutna & Cooper Lake)	0
1981	0	0	0	0	0	0	0	12 (Soloman Gulch)	13
1982	-20	178	0	0	0	0	0	0	26
1983	0	0	0	-8	0	0	0	0	39
1984	0	0	0	0	0	0	0	0	52
1985	0	0	0	0	0	0	0	0	65
1986	0	0	0	-1	0	0	0	0	67
1987	0	0	0	-8	-4	0	0	0	69
1988	0	0	0	-6	0	0	0	90 (Bradley Lake)	71
1989	0	0	0	0	-5	0	0	0	73
1990	0	0	0	0	0	0	0	0	75
1991	0	0	0	-18	0	0	0	7 (Allison)	68
1992	-16	0	0	-19	0	25	0	0	62
993	-9	0	50	0	0	25	0	0	56
1994	-30	0	0	0	0	50	20	0	49
1995	-14	0	0	-33	0	0	0	337 (Grant Lake & Chakachamna)	43
1996	0	0	0	-102	0	75	20	0	43
1997	0	200	0	-65	0	0	0	0	44
1998	-50	0	0	0	0	0	0	0	44
1999	0	0	0	0	0	0	0	0	45
2000	-18	0	0	0	0	0	0	0	45
2001	0	0	0	0	0	0	0	0	47
2002	-51	0	0	0	-25	0	0	0	48
2003	-53	0	0	0	0	0	0	0	50
2004	0	0	0	0	0	0	0	0	51
2005	-58	0	0	0	-21	0	0	80 (Brown)	53
2006	70	0	0	0	0	0	0	0	55
2007	0	0	0	0	0	0	0	0	57
2008	0	0	0	0	0	0	0	100 (Keetna)	54
2009	70	0	0	0	0	0	0	0	61
2010	0	0	0	0	0	0	0	0	63

TABLE D.8. Electrical Generation by Type of Capacity - Plan 2A (GWh)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley					
Year	Gas Combustion Turbine	Gas Combined-Cycle	Refuse-Derived Fuel	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Wind-Turbine Generators	Refuse-Derived Fuel	Total Hydroelectric	Total Conservation Due to Subsidy
1981	1936	35	0	14	537	0	0	254	77
1982	636	1364	0	39	537	0	0	254	155
1983	652	1359	0	65	537	0	0	254	233
1984	673	1351	0	90	537	0	0	254	310
1985	195	2101	0	0	393	0	0	254	378
1986	995	1406	0	0	504	0	0	254	401
1987	1090	1417	0	78	537	0	0	254	414
1988	824	1394	0	189	537	0	0	648	427
1989	918	1405	0	342	496	0	0	648	440
1990	495	2466	0	0	416	0	0	648	453
1991	1532	1489	0	0	496	0	0	677	415
1992	1594	1509	0	1	496	0	0	677	377
1993	1360	1441	394	0	487	85	0	677	339
1994	1216	1436	394	0	476	171	158	677	302
1995	9	1317	394	0	496	342	158	2153	264
1996	8	1311	394	0	492	342	158	2153	268
1997	1	1313	394	0	496	342	158	2153	272
1998	1	1307	394	0	496	342	158	2153	275
1999	1	1300	394	0	496	342	158	2153	279
2000	1	1294	394	0	496	342	158	2153	283
2001	1	1376	394	0	496	342	158	2153	292
2002	2	1662	394	0	289	342	158	2153	300
2003	2	1743	394	0	289	342	158	2153	309
2004	3	1823	394	0	289	342	158	2153	317
2005	2	1685	394	0	124	342	158	2539	325
2006	3	1823	394	0	124	342	158	2539	338
2007	4	1960	394	0	124	342	158	2539	350
2008	3	1776	394	0	124	342	158	2863	363
2009	4	1913	394	0	124	342	158	2863	375
2010	5	2051	394	0	124	342	158	2863	387

parameters. A 50-MW plant would require 50 acres of land. This large area is needed to accommodate fuel-receiving facilities, fuel-storage piles, materials handling and preparation systems, boilers, feedwater treatment systems, turbine generators, and associated pollution control systems for such activities as stack gas cleaning and ash disposal. Also, because of the refuse, substantial buffer zones may be required.

Power Plant Characteristics and Emissions. The core of the power plant is the boiler and the turbine generator. However, like the coal-fired power plant, ancillary systems exist for fuel receiving, storage and processing, for stack gas cleanup, bottom and fly ash handling and condenser cooling purposes. Fuel processing equipment is particularly critical if spreader-stocker firing is used. Metallic and other noncombustible objects must be removed from the fuel. Preferably, municipal waste will be shredded and classified to minimize contamination by metals and glass objects. Combustion with minimal fuel preparation, while practical in some cases, results in less efficient operation of the equipment.

Potentially significant impacts from refuse plants are similar to other steam-cycle plants and result from 1) the water withdrawal and effluent discharge, 2) atmospheric emissions of particulate matter, NO_x, SO_x and others, 3) disposal of solid waste and ash, and 4) ecological effects.

The major impact affecting the terrestrial biota and resulting from refuse-fired power plants is the loss or modification of habitat. Land requirements for refuse-fired plants are similar to those of coal-fired plants and are generally greater than those for other steam-cycle power plants on an acres-per-MW basis. The primary locations of refuse-fired power plants in the Railbelt region are adjacent to lands that contain seasonal ranges of moose, waterfowl and other animals. Impacts on these animal populations will depend on the characteristics of the specific site and the densities of the wildlife populations in the site area. Because of the relatively small plant capacities involved, however, impacts should be minimized through the plant siting process.

Wind Energy

Until the mid-1930s wind energy supplied a significant amount of energy to rural areas. With the advent of the Rural Electrification Administration and the abundance of oil and coal, wind energy ceased to be competitive with other power alternatives. Renewed interest in the development of wind resources has occurred, however, as fuel costs have risen and have increased the cost of power from competing technologies.

This alternative consists of large wind energy conversion systems (wind turbines) configured as a wind farm, located in the Isabell Pass wind resource area. The wind farm consists of ten 2.5-MW horizontal axis wind turbines, for a total 25-MW rated capacity.

Wind turbine generators located at Isabell Pass would have small impacts on the atmospheric or meteorological conditions around the site. The impacts relate to small microclimatic changes and interference with electromagnetic wave transmission through the atmosphere. No effects on air quality are generated.

Wind turbines extract energy from the atmosphere and, therefore, have the potential of causing slight modifications to the surrounding climate. Wind speeds will be slightly reduced at surface levels and to a distance equivalent to 5 rotor diameters, which would be $\sim$1500 feet for a single 2.5-MW facility. Small modifications in precipitation patterns may be expected, but total rainfall over a wide area will not be impacted. Nearby temperatures, evaporation, snowfall, and snow drift patterns will be affected only slightly. The microclimatic impacts will be qualitatively similar to those noted around large isolated trees or tall structures.

The rotation of the turbine blades may interfere with television, radio, and microwave transmission. Interference has been noted within 0.6 miles (1 km) of relatively small wind turbines. This distance is expected to be greater for the relatively large 2.5 MW machines considered in this study. The nature of the interference depends on signal frequencies, blade rotation rate, number of blades, and wind turbine design. A judicious siting strategy could help to avoid these impacts if they seem to be a problem.

Stream siltation effects from site and road construction are the only potential impacts associated with wind-energy technology since process water is not required. Silt in streams may adversely affect feeding and spawning of fish, particularly salmonids, which are common in the Railbelt region. These potential problems can be avoided by proper construction techniques and should not be significant unless extremely large wind farms are developed.

Wind-powered energy requires varying amounts of land area for development. The area required will depend on the number, spacing, and type of wind-powered unit. This requirement can range from ~2 acres for a 2.5-MW generating unit to 100 square miles for numerous units generating up to 1000 MW. Because of operational requirements for persistent high-velocity winds, these developments may be established in remote areas.

Because of the land requirements involved and the potentially remote siting locations, the greatest impact resulting from wind-energy projects on terrestrial biota would be loss or disturbance of habitat. Wind-generating structures can furthermore impact migratory birds by increasing the risk of collision-related injury or death. Other potential impacts include low-frequency noise emanating from the generators and modification of local atmospheric conditions from air the turbulence created by the rotating blades. The impacts of these latter disturbances on wildlife, however, are presently unclear.

Hydroelectric

The environmental considerations associated with hydroelectric projects such as Allison, Brown, Keetna, Grant Lake, Snow, Bradley Lake and Chakachamna are all similar and previously described in Section D.1.3.

Conservation

In this plan, the State of Alaska is assumed to provide grants to those homeowners who wish to implement high-cost conservation techniques. In the absence of a subsidy program, a substantial amount of electrical conservation would exist because of increases in electricity and fossil fuel prices. Through grants to homeowners Plan 2A increases this situation by "investing" in additional conservation that reduces the consumer's investment cost (but not his operating and maintenance costs) to zero for selected high-investment homeowner energy-saving technologies. At the prices of power projected in these supply plans, consumers are assumed to undertake on their own such low-investment, high-payoff strategies as set-back thermostats, water heater blankets, storm windows, weatherstripping, etc. The specific techniques for which grants are assumed to be available are superinsulation, passive solar heating, active solar hot water heating and wood-fired space heating. The subsidies bring the housing stock electric-use efficiency up to technical and market limits imposed by siting considerations, operating costs, and consumer convenience.

The limits on market penetration of the four residential high-investment technologies are assumed to be affected in the following way. For superinsulation, the price-induced market penetration is substantial - 50% of the total housing stock (and a much higher percentage of new homes). The payback period is already very short for conservation and is only slightly reduced by grant programs. Market penetration is increased to 55% by subsidies. Passive solar is restricted in the existing housing stock by siting and architectual considerations, and in the new housing stock by building sites. However, the long payback period in the nonsubsidized case implies that a state grant program would increase market penetration from about zero to up to 33% of the whole housing market (more in new houses). Active solar hot water heating has very long paybacks, but siting and technical considerations are expected to restrict the market penetration to ~10% of all households. Wood stoves are already very popular as supplemental heat. Payback periods are quite long; however, if the wood fuel must be purchased at $80 to $90 a cord, this will be a fair market test of the technology. Because fuel costs are important, a grants program is expected to have little <u>incremental</u> impact on use of wood stoves as primary heating units. An estimated equivalent of 20% of all households would heat exclusively with wood, but none would do this because of the subsidy.

Little is known about commercial electrical uses in the Railbelt. Based on investment and engineering calculations contained in the Oak Ridge National Laboratories' commercial energy model (DOE 1979), commercial electrical use was estimated to be reduced in the commercial sector by ~35% on the average. In the absence of subsidies, ~69% penetration is assumed. With grants, this is increased to 100% penetration, and 35% full technical savings are achieved. Table D.9 shows the estimated number of homes using these techniques in the year 2010.

TABLE E.9 Estimated Number of Homes Using the Conservation Techniques

	Super Insulation	Passive Solar Space Heating	Active Hot Water Heat
Anchorage	8,384	54,498	16,769
Fairbanks	1,975	12,835	3,949
Glennallen/Valdez	368	2,389	735

Superinsulation. This includes several measures such as specialized construction techniques for floor and foundations systems, wall systems, roof systems, windows and doors, plus movable insulation such as shudders and a wide range of measures to reduce air infiltration. Caulking and weatherstripping plus air-to-air heat exchangers are features commonly included. All of these measures reduce the direct loss of thermal energy from the home.

Passive Solar Space Heating. In the purest sense, passive solar uses no mechanical means such as fans or pumps to distribute heat from the sun into the living space. It relies on a combination of a thermally efficient building envelope to contain heat, south glazing to capture solar energy, some form of thermal mass to store this energy for release at night or during cloudy periods, and design techniques to distribute heat by convection. Essentially, the building is the system.

Environmental impacts from passive solar technologies are minimal, almost nonexistent. No traceable air or water pollution has been recorded in dispersed application. For the environment solar is almost ideally benign fuel source.

The potential detriments of solar on the environment center on two factors: aesthetics and reflected glare. Aesthetic appeal is, of course, subjective, and not quantifiable. It is, however, an important factor. Since the concept of passive solar centers on the building and its components, the designers must ensure an aesthetically pleasing structure. Many examples of passive solar buildings throughout the United States are considered "ugly" by their critics. On the other hand, just as many or more examples of successful installations can be found. Entire solar subdivisions such as those in the city of Davis, California, are both pleasing to look at and pleasant to live in. Passive solar housing does not have to look different from the more "traditional" buildings, except for the expanse of south-facing glass.

Reflected glare off south glazing is a potential problem in solar application. The extent of the problem in the Railbelt is not known at this point. Glare is more prevalent when the sun strikes the glazing at an acute angle; i.e., the less perpendicular the sun's rays to the collector surface, the more glare encountered. During the winter, vertical glass will not cause excessive glare problems. In the summer proper design of the roof overhangs will ensure that enough glass is shaded to alleviate most glare. During the spring and fall the phenomenon could cause problems to passing motorists and pedestrians. The small number of solar system installations in the Railbelt region precludes answers to these potential problems at this time.

Consumer safety poses no real problem with passive solar. Because most systems are simple and benign, danger to the consumer is far less than a central fuel-fired furnace system, for example. Workers certainly face higher percentage of danger when installing systems, but potential injury and death are limited to those risks that the worker might encounter in standard construction.

Active Solar Water Heating. "Active" solar systems require auxiliary pumping energy to function properly. These systems differ from "passive" solar energy application, which requires very little or no auxiliary energy. Active solar energy use is an accepted technology; thousands of systems have been installed throughout the United States.

Three varieties of dispersed active solar systems are currently available for use in Alaska: liquid-based flat-plate collector systems for space heating, liquid-based flat-plate collector systems for hot water heating, and hot-air systems for space heating.

The high cost of initial investment seems to preclude solar energy use for space heating but for heating water it is feasible in the Railbelt. On an annual average, $\sim$50% of the hot water needs can be met by active solar collectors.

D.3.3 Socioeconomic Considerations for Plan 2A

The socioeconomic considerations for this plan stem from a wide range of activities, including construction of fossil power plants, use of refuse as a fuel, wind energy, hydroelectric facilities and energy conservation techniques which include insulation, passive solar heating, and active solar hot water heating.

Refuse Fuel

Impacts of refuse-fired plants will vary among the primary locations identified, as well as with scale. For Anchorage 50-MW and for Fairbanks 20-MW plants can be constructed with minimal impacts to the social and economic structure of those communities. The construction staff of 65 could come from the regional labor force, reducing or eliminating the need to transfer workers from other areas of the Railbelt to these sites.

The breakdown of capital expenditures is expected to be 60% outside the Railbelt and 40% within the region. Expenditures due to a large capital investment will be offset by an Alaskan labor force. Approximately 10% of the operating and maintenance expenditures would be spent outside the Railbelt region.

Wind Systems

A wind turbine requires a small construction work force of 10 to 15 persons, no operating work force, and minimal maintenance requirements. In comparison to the other fuel-saver techologies, wind power would create very few demands on community infrastructure. Installing a 100-MW wind farm would require a construction work force of ∿60 over a period of a few years. The peak work force would be ∿140. The addition of incremental capacity to the system would permit a test period during which necessary design and siting modifications could be made. The impacts of constructing a wind farm on small communities may be significant due to the increase in work force size and length of construction period. However, the impacts should decrease as the population of the communities near the site increases.

The cost breakdown for a wind turbine investment is based on the assumption that the monitoring field work, site preparation, and installation would be performed by Alaskan labor and that all components would be imported from outside manufacturers. Therefore, ~80% of the capital expenditures would be sent outside the region and 20% would remain within Alaska. The allocation of operating and maintenance expenditures would be 15% spent outside the Railbelt and 85% within the region. The high percentage of costs allocated to outside maintenance would be offset to some extent by the small requirements for supplies.

Hydroelectric

See Section D.3.4 for a description of the socioeconomic considerations associated with hydroelectric power facilities.

Conservation

Passive Solar. Virtually no work on capital costs for passive solar has been done in the Railbelt, mainly because so few system actually have been installed. In addition, most solar buildings in the region rely on heavy insulation and efficient thermal envelopes to first reduce heat load, and often, differentiating between costs for solar and those general building costs is difficult. Preliminary studies show an increase in a range of 6% to 10% above normal construction costs for a passive solar, superinsulated home.

Passive solar will create jobs and new capital ventures at a local as well as at a regional level. Because the skills required to design and install systems are relatively straightforward if standard materials and techniques are used, most likely the needed human resource exists in the region. If pursued on a fairly widespread scale, the potential for long-lasting jobs in new and existing businesses is promising.

An increase in employment and business at the regional level would very likely result in an increase in the amount of capital staying in the region, further providing economic benefits outside the construction sector. Certainly the extra income available to the consumer by reduced fuel expenditures will find its way into the region's economy. Whereas an in-depth economic analysis cannot be done until the degree of penetration of the solar technologies in the marketplace can be better assessed, preliminary study and common sense indicate that solar will have a positive impact on the economy.

D.3.4 Integration of Potential Environmental and Socioeconomic Impacts for Plan 2A

The integration of potential environmental and socioeconomic impacts for Plan 2A is presented in Table D.10. The potential impacts on air quality, water quality, and ecology are moderate, and the use of refuse-derived fuel at plants in Anchorage and Fairbanks is not a major concern because the plants are of fairly small capacity compared to typical fossil fuel plants.

The construction of hydroelectric projects at Bradley Lake, Browne, Chakachamna and Snow present the jobs and boom/bust impacts associated with hydroelectric construction projects. The local labor markets in Anchorage and Fairbanks will be able to handle the demands created by conservation activities such as construction of refuse-power facilities.

This plan would create a moderate demand for jobs, require a substantial portion of spending within Alaska and yet, due to the emphasis on conservation activities and use of hydroelectric facilities, a great inflation effect from the rising cost of fuel would not result.

D.4 PLAN 2B: HIGH CONSERVATION AND USE OF RENEWABLE RESOURCES WITH UPPER SUSITNA

Plan 2B is similar to Plan 2A except that the Upper Susitna project is built. The other hydroelectric facility to be built is the Bradley Lake project, which comes on-line in 1988.

Other generating capacity includes the following:

Anchorage-Cook Inlet

- A 50-MW refuse-derived fuel plant comes on-line in 1992.

Fairbanks-Tanana Valley

- Wind-energy resources in the Isabell Pass area are developed (50 MW).

D.4.1 Capacity and Generation for Plan 2B

The capacity additions and retirements for Plan 2B are shown in Table D.11, and the electrical generation for each of these capacities is shown in Table D.12. In general, the capacity additions and electrical generation are

TABLE D.10. Integration of Potential Environmental & Socioeconomic Impacts for Plan 2A

Energy Facilities Added	Potential Environmental and Socioeconomic Impacts: Air Quality	Water Quality	Terrestrial Ecology	Aquatic/Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/Bust Effects	Land-Use Effects	Susceptibility to Inflation	Spending in Alaska (% Total)
Anchorage-Cook Inlet											
Gas Turbine Combustion	2	1	1	1	2	1	1	1	2	3	20
Gas Combined Cycle	2	2	2	2	2	1	2	1	3	3	30
Refuse Derived Fuel	3	2	2	2	3	2	2	1	2	1	40
Fairbanks-Tanana Valley											
Wind Turbine Generators	1	1	2	1	2	1	1	1	2	1	20
Refuse Derived Fuel	3	2	2	2	3	2	2	1	2	1	40
Hydroelectric											
Allison	1	2	2	2	1	1	2	2	2	1	35
Bradley Lake	1	2	2	2	2	1	3	3	3	1	65
Grant Lake	1	2	2	2	1	1	2	2	2	1	35
Brown	1	2	2	2	2	1	3	3	3	1	65
Keetna	1	2	2	2	2	1	3	3	3	1	65
Chakachamna	1	2	2	2	2	1	3	3	3	1	65
Snow	1	2	2	2	2	1	3	3	3	1	65
Conservation[a]	2	1	2	1	2	2	3	1	1	1	80-90

Rating Scale: 1 - minor
2 - moderate
3 - significant

(a) Includes building conservation, passive solar heating, and active solar hot water heating.

TABLE D.11. Existing Capacity (1980) and Capacity Additions and Retirements (1981-2010) - Plan 2B (MW)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley				
Year	Gas Combustion Turbine	Gas Combined-Cycle	Municipal Solid Waste	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Wind-Turbine Generators	Total Hydroelectric	Total Conservation Due to Subsidy
1980	461	139	0	266	69	0	46 (Eklutna & Cooper Lake)	0
1981	0	0	0	0	0	0	12 (Solomon Gulch)	13
1982	-20	178	0	0	0	0	0	26
1983	0	0	0	-8	0	0	0	39
1984	0	0	0	0	0	0	0	52
1985	0	0	0	0	0	0	0	65
1986	0	0	0	-1	0	0	0	68
1987	0	0	0	-8	-4	0	0	71
1988	0	0	0	-6	0	0	90 (Bradley Lake)	74
1989	0	0	0	0	-5	0	0	77
1990	0	0	0	0	0	0	0	79
1991	0	0	0	-18	0	0	0	72
1992	-16	0	50	-19	0	50	0	65
1993	-9	0	0	0	0	0	680 (Watana)	58
1994	-30	0	0	0	0	0	0	51
1995	-14	0	0	-33	0	0	0	44
1996	0	0	0	-102	0	0	0	44
1997	0	0	0	-65	0	0	0	45
1998	-50	0	0	0	0	0	0	45
1999	0	0	0	0	0	0	0	45
2000	-18	0	0	0	0	0	0	45
2001	0	0	0	0	0	0	0	47
2002	-51	0	0	0	-25	0	600 (Devil Canyon)	49
2003	-53	0	0	0	0	0	0	51
2004	0	0	0	0	0	0	0	52
2005	-58	0	0	0	-21	0	0	54
2006	0	0	0	0	0	0	0	57
2007	0	0	0	0	0	0	0	59
2008	-26	0	0	0	0	0	0	62
2009	0	0	0	0	0	0	0	65
2010	0	0	0	0	0	0	0	68

TABLE D.12. Electrical Generation by Type of Capacity - Plan 2B (GWh)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley				
Year	Gas Combustion Turbine	Gas Combined-Cycle	Municipal Solid Waste	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Wind Turbine Generators	Total Hydroelectric	Total Conservation Due to Subsidy
1981	1955	36	0	13	537	0	254	78
1982	641	1366	0	37	537	0	254	156
1983	662	1362	0	62	537	0	254	234
1984	685	1354	0	86	537	0	254	311
1985	202	2114	0	0	388	0	254	389
1986	1045	1413	0	0	494	0	254	408
1987	1169	1423	0	64	537	0	254	427
1988	943	1408	0	171	537	0	648	446
1989	1068	1425	0	319	496	0	648	465
1990	654	2474	0	1	424	0	648	484
1991	1689	1537	0	2	496	0	648	441
1992	1350	1484	394	1	496	171	648	398
1993	0	95	394	0	0	171	4103	355
1994	0	214	394	0	0	171	4103	312
1995	0	44	394	0	320	171	4103	269
1996	0	42	394	0	299	171	4103	272
1997	0	40	394	0	279	171	4103	274
1998	0	38	394	0	259	171	4103	277
1999	0	31	394	0	248	171	4103	279
2000	0	29	394	0	231	171	4103	281
2001	0	43	394	0	311	171	4103	292
2002	0	0	0	0	0	19	5098	303
2003	0	0	0	0	0	18	5273	313
2004	0	0	0	0	0	17	5361	324
2005	0	0	0	0	0	16	5448	334
2006	0	0	0	0	0	9	5624	351
2007	0	0	0	0	0	33	5800	368
2008	0	0	0	0	0	30	6063	385
2009	0	0	0	0	0	5	6239	402
2010	0	0	0	0	0	20	6415	419

similar to Plan 2A except that the Watana and Devil Canyon dams are added in Plan 2B, replacing several of hydroelectric projects added in Plan 2A.

D.4.2 Environmental and Socioeconomic Considerations for Plan 2B

The main environmental and socioeconomic considerations for Plan 2B stem from 1) the development of the Upper Susitna dams at Watana and Devil Canyon, 2) construction of Bradley Lake dam, 3) construction of a refuse plant and gas combined plant in Anchorage, 4) construction of a wind-turbine generator in Fairbanks and 5) the implementation of energy conservation measures, including insulation, passive solar space heating, and active solar hot water heating. These considerations have been presented previously in the following sections: Bradley Lake in Sections D.2.3 and D.2.4; Watana and Devil Canyon in Sections D.3.2 and D.3.3; and Refuse-Derived Fuel, Wind-Turbine Generators, and Conservation in Sections D.4.2 and D.4.3.

An important feature of Plan 2B is that after 1982 no more fossil-fuel electrical-generating capacity is added and most of the existing gas, oil, coal and diesel electric capacity is phased out by 2010. The penetration of conservation activity for this plan is given in Table D.13; these estimates differ from Plan 2A because the penetration is determined by the cost of power, which is different for the two plans.

TABLE D.13. The Estimated Number of Homes Using the Conservation Techniques in the Year 2010

	Super Insulation	Passive Solar Space Heating	Active Hot Water Heating
Anchorage	9,211	59,872	18,422
Fairbanks	2,213	14,385	4,426
Glennallen/Valdez	423	2,750	846

D.4.3 Integration of Potential Environmental and Socioeconomic Impacts for Plan 2B

The integrated potential environmental and socioeconomic impacts of Plan 2B are presented in Table D.14. The air-quality and water-quality impacts for this plan are low to moderate. With the use of the Upper Susitna projects

TABLE D.14. Integration of Potential Environmental & Socioeconomic Impacts for Plan 2B

Energy Facilities Added	Potential Environmental and Socioeconomic Impacts: Air Quality	Water Quality	Terrestrial Ecology	Aquatic/ Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/ Bust Effects	Land-Use Effects	Susceptibility to Inflation	Spending in Alaska (% Total)
Anchorage-Cook Inlet											
Gas Combined Cycle	2	2	2	2	2	1	2	1	3	3	20
Refuse-Derived Fuel	3	2	2	2	3	2	2	1	3	1	40
Fairbanks-Tanana Valley											
Wind Turbine Generator	1	1	2	1	2	1	1	1	2	1	20
Hydroelectric											
Bradley Lake	1	2	2	2	1	1	3	3	3	1	65
Watana	1	2	2	2	1	1	3	3	3	1	65
Devil Canyon	1	2	2	2	1	1	3	3	3	1	65
Conservation[(a)]	2	1	2	1	2	2	3	1	1	1	80-90

Rating Scale: 1 - minor
2 - moderate
3 - significant

(a) Includes building conservation, passive solar heating, and active solar hot water heating.

at Watana and Devil Canyon, almost all fossil-fuel plants, including gas combination turbines, coal steam turbines, oil combustion turbines and diesel electric units, are phased out. These projects would represent a significant amount of spending within the state and inflation impacts would be low because the fossil-fuel use is phased out and replaced by hydroelectric.

The main environmental and socioeconomic concerns for this plan stem from the potential for large land-use and boom/bust effects. Significant labor forces will be necessary to build the dams. However, in this plan the construction of the Watana and Devil Canyon dams are separated by nine years, which would tend to distribute the boom/bust effects over a time period of about 15 years.

D.5 PLAN 3: INCREASED USE OF COAL

This plan is based on a transition from existing generating technologies to alternatives that either directly or indirectly use coal as a fuel. All new generation is either coal-fired steam turbines or combined-cycle units using coal-based synthetic fuels. In the Railbelt, coal is currently available from the Healy area; it is also expected to be available from the Beluga area in 1988. This plan assumes that coal-fired generation in the Anchorage-Cook Inlet load center will be located at the Beluga area. Baseload generation for the Fairbanks area depends on the costs of facilities located in the Nenana area. With the exception of Bradley Lake, no additional hydroelectric facilities are built.

D.5.1 Capacity and Generation for Plan 3

The capacity additions and retirements for this plan are shown in Table D.15. The generation by type of capacity is shown in Table D.16.

D.5.2 Environmental Considerations for Plan 3

In Plan 3 the main environmental consideration that has not been addressed in previous plans is the use of coal-gasifier combined-cycle technology. This consideration is the focus of this section. The following energy facilities are a part of this plan, but their environmental considerations have been discussed in a previous section: Gas Combustion Turbine, Gas Combined-Cycle, Coal Steam Turbine, and Bradley Lake Hydroelectric in Section D.2.3.

TABLE D.15. Existing Capacity (1980) and Capacity Additions and Retirements (1981-2010) - Plan 3 (MW)

	Anchorage-Cook Inlet				Fairbanks-Tanana Valley		
Year	Gas Combustion Turbine	Gas Combined-Cycle	Coal Steam Turbine	Coal Gasifier Combined Cycle	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Total Hydroelectric
1980	461	139	0	0	266	69	46 (Eklutna & Cooper Lake)
1981	0	0	0	0	0	0	12 (Solomon Gulch)
1982	-20	178	0	0	0	0	0
1983	0	0	0	0	-8	0	0
1984	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0
1986	0	0	0	0	-1	0	0
1987	0	0	0	0	-8	-4	0
1988	0	0	0	0	-6	0	90 (Bradley Lake)
1989	0	0	0	0	0	-5	0
1990	0	0	0	0	0	0	0
1991	70	0	0	0	-18	0	0
1992	-16	0	200	0	-19	0	0
1993	-9	0	0	0	0	0	0
1994	-30	0	0	0	0	0	0
1995	-14	0	0	200	-33	0	0
1996	0	0	0	0	-102	0	0
1997	0	0	0	0	-65	200	0
1998	-50	0	0	0	0	0	0
1999	0	0	0	0	0	0	0
2000	-18	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	-51	0	0	0	0	-25	0
2003	17	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	-58	0	200	0	0	-21	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	-26	0	0	0	0	0	0
2009	70	0	0	0	0	0	0
2010	70	0	0	0	0	0	0

TABLE D.16. Electrical Generation by Type of Capacity - Plan 3 (Gwh)

Year	Anchorage-Cook Inlet: Gas Combustion Turbine	Anchorage-Cook Inlet: Gas Combined-Cycle	Anchorage-Cook Inlet: Coal Steam Turbine	Anchorage-Cook Inlet: Coal Gasifier Combined-Cycle	Fairbanks-Tanana Valley: Oil Combustion Turbine & Diesel	Fairbanks-Tanana Valley: Coal Steam Turbine	Total Hydroelectric
1981	2017	46	0	0	27	537	254
1982	766	1386	0	0	66	537	254
1983	840	1400	0	0	105	537	254
1984	942	1386	0	0	143	537	254
1985	411	2266	0	0	0	459	254
1986	1347	1465	0	0	28	537	254
1987	1433	1506	0	0	134	537	254
1988	1248	1445	0	0	240	537	648
1989	1358	1471	0	0	387	496	648
1990	1005	2490	0	0	3	457	648
1991	1934	1660	0	0	1	496	648
1992	787	1431	1580	0	0	428	648
1993	902	1440	1584	0	0	436	648
1994	1015	1430	1611	0	0	442	648
1995	52	1028	1611	1506	0	435	648
1996	55	1043	1611	1509	0	437	648
1997	5	195	1611	1506	0	1356	648
1998	5	196	1611	1509	0	1370	648
1999	6	199	1611	1511	0	1385	648
2000	6	202	1611	1512	0	1399	648
2001	7	213	1611	1511	0	1428	648
2002	11	251	1611	1514	0	1420	648
2003	11	259	1611	1514	0	1448	648
2004	12	279	1611	1517	0	1462	648
2005	2	68	3199	1219	0	431	648
2006	2	97	3207	1264	0	532	648
2007	3	131	3211	1294	0	647	648
2008	4	164	3215	1326	0	760	648
2009	7	197	3218	1354	0	877	648
2010	10	231	3220	1379	0	997	648

Synthetic fuels processes such as oil shale and tar sands exist for other hydrocarbons, but coal is the logical choice for Alaska because of the large reserves in the Beluga coal fields and other coal deposits in the Railbelt region. The principles used to produce synthetic fuels from coal are conceptually simple and varied, depending upon the products sought. Coal is a heterogeneous solid substance with hydrogen/carbon (H/C) ratios of about 0.5 to 0.8. To convert coal to gaseous or liquid fuels, the H/C ratio is increased dramatically by carbon removal (pyrolysis, coking), hydrogen addition (direct hydrogenation), or total reformation (indirect liquefaction through the production and reaction of synthesis gas, a mixture of carbon monoxide (CO) and H_2). Simultaneously, the coal molecule is fragmented into smaller units. Coal gasification systems employing these principles produce low Btu gas (e.g., 150 Btu/ft^3), medium Btu gas (e.g., 350 Btu/ft^3), and high Btu gas or substitute natural gas (e.g., 900-1000 Btu/ft^3). Coal gasification plants are, for the most part, large petrochemical-like complexes.

Land requirements for the plants must provide 30 to 90 days coal storage, the primary facility itself, ancillary facilities such as an on-site power plant and/or a cryogenic oxygen separation plant, and product storage. The site must have transportation facilities for moving coal to the facility if mine-mouth sites are not available and for transporting the product from the facility.

The site must have access to copious quantities of water for process, cooling, and other requirements. Water serves as a source of hydrogen for altering the H/C ratio in the water gas shift reaction. Water also is the sink for waste heat.

Water-quality problems can arise from leaching and surface runoff from coal storage. These impacts are similar to those of a coal-fired steam-electric facility. Other concerns include the disposal of ash from the gasifier and the steam plant.

Coal gasification creates the potential for large amounts of emissions into the atmosphere. These emissions are similar to those associated with conventional combustion processes and include primarily particulate matter, sulfur oxides, nitrogen oxides, hydrocarbons, and carbon monoxide. In addition, emissions similar to those from a coal-fired boiler can come from the steam plant.

The effects most difficult to mitigate from a coal gasification plant are similar to those from steam-cycle facilities because they are associated with water supply and wastewater discharge requirements. In addition, the large land-area requirement could impose large construction runoff effects. Water withdrawal is associated with impingement and entrainment of aquatic organisms. Chemical and thermal discharges may have acute or chronic effects on organisms living in the discharge plume area. Thermal discharges can also cause lethal thermal shock effects in the Railbelt region when the discharge is stopped. The degree of these impacts will depend on many factors, such as the location of the intake and discharge structure in the water body, the chemical composition of the water supply source and discharged effluent, the plant's water and wastewater management plan, and the type and quantity of aquatic organisms present in the receiving water. In general, however, the magnitude of impacts can be related to a plant's makeup water requirements.

The major impact affecting the terrestrial biota and resulting from a coal gasification plant is the loss of habitat. The plants require land areas that are two to five times that of coal-fired plants for a given energy-generating capacity. The gasification plant, electrical generating facility, and support facilities can occupy ∿1000 to 3000 acres. In addition, the work force needed to support this facility will create further disturbances to local terrestrial ecosystems.

Terrestrial impacts can also result from the release of harmful air emissions. These impacts will be similar to those of gas- and oil-fired plants. While sulfur and nitrogen oxides are generally retained as a plant product, particulates and other pollutants are released into the environment. Such particulates can have adverse effects on local soils, vegetation, and animals.

D.5.3 Socioeconomic Considerations for Plan 3

The main socioeconomic considerations related to Plan 3 are associated with the use of fossil-fuel facilities. Most of these considerations, gas-turbine combustion, gas combined-cycle, coal steam turbine, and Bradley Lake hydroelectric, were discussed in Section D.2.4.

In this section the socioeconomic concerns for coal gasification are presented. The socioeconomic impacts are difficult to predict because no U.S. experience exists from which to extrapolate employment levels. Due to the large scale of these plants, however, the construction work force requirements can be assumed to be at least equal to that of a large coal-fired power plant. The work force requirements for mining the coal would increase the impacts of a gasification plant by an order of magnitude of at least two. If the product is used on-site, then the cumulative impacts of a coal mine, gasification plant, and on-site power plant would be significant.

The construction and operation of a gasification plant (including the coal mine and power plant) would cause a permanent boom due to the large cumulative operating work force requirements. Whereas the construction work force would be substantially larger than the operating staff, the impacts caused by the out-migration of the construction work force would not be as great as the initial boom. These effects would be caused by the large scale and intensity of a plant development and the remoteness of sites.

Socioeconomic impacts would be severe at all potential sites, including the Beluga and Healy area. The communities near all these coal fields are small in population. At the Beluga site, power plant components would most likely be shipped by barge and then transported over land to the site. Therefore, secondary impacts would be caused by the construction of haul roads. The largest community in the Beluga area, Tyonek, is an Alaskan native village with a population of 239. The influx of a construction work force would disrupt the social structure of the community. Communities near the Nenana would be severely impacted by the siting of a synthetic fuels plant as well. All of these communities are very small, with population sizes of less than 500. Installing a construction camp would not substantially reduce the impacts in these communities.

D.5.4 Integration of Potential Environmental and Socioeconomic Impacts for Plan 3

The integrated environmental and socioeconomic impacts for Plan 3 are presented in Table D.17. The main impacts are associated with the increased use of coal. Environmental concerns include degradation of air quality and, as discussed in Section D.2.2, compliance with the current PSD regulations can be a problem. The power plants are not aesthetically attractive and the plumes from the smokestacks and cooling towers contribute to reduced visibility.

The addition of coal-based power facilities is distributed fairly evenly throughout the time period. The Anchorage and Fairbanks labor markets will probably be able to handle the job demands for construction and, therefore, a significant boom/bust impact is not expected. Note that with the increased dependency on coal, the potential for inflation effects is significant.

D.6 PLAN 4: "HIGH NATURAL GAS"

This plan is based upon continued use of natural gas for generation in the Cook Inlet area and a conversion to natural gas in the Fairbanks area. The key assumption in this plan is that sufficient gas will be available in the Cook Inlet area to allow utilities to continue to use it for electrical generation. Natural gas also is assumed to be available for the Fairbanks area from the North Slope beginning in 1988. Possible generating alternatives to be included in this plan include fuel-cells, combined-cycle, combustion turbine, and fuel-cell combined-cycle. The only hydroelectric project is the Bradley Lake project, which comes on-line in 1988.

D.6.1 Capacity and Generation for Plan 4

The capacity additions and retirements for this plan are shown in Table D.18. The generation by type of capacity is shown in Table D.19.

D.6.2 Environmental and Socioeconomic Considerations for Plan 4

For Plan 4 the main environmental consideration that has not been addressed in previous plans is the use of gas fuel-cell combined-cycle technology. This consideration will be the focus in this section. The following energy facilities are a part of this plan but were previously

TABLE D.17. Integration of Potential Environmental & Socioeconomic Impacts for Plan 3

Energy Facilities Added	Potential Environmental and Socioeconomic Impacts									
	Air Quality	Water Quality	Terrestrial Ecology	Aquatic/Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/Bust Effects	Land-Use Effects	Susceptibility to Inflation	Spending in Alaska (% Total)
Anchorage-Cook Inlet											
Gas Turbine Combustion	2	1	1	1	2	1	1	1	2	3	20
Gas Combined Cycle	2	2	2	2	2	1	2	2	3	3	30
Coal-Fired Steam Turbine	3	2	2	2	3	2	2	2	3	3	40
Coal Gasifier Combined Cycle	3	2	2	2	3	2	2	2	3	3	
Fairbanks-Tanana Valley											
Coal-Fired Steam-Turbine	3	2	2	2	3	2	2	2	3	3	40
Hydroelectric											
Bradley Lake	1	2	2	2	1	1	3	3	3	1	65

Rating Scale: 1 - minor
2 - moderate
3 - significant

TABLE D.18. Existing Capacity (1980) and Capacity Additions and Retirements (1981-2010) - Plan 4 (MW)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley				
Year	Gas Combustion Turbine	Gas Combined-Cycle	Gas Fuel-Cell Stations	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Gas Combined-Cycle	Gas Fuel-Cell Stations	Total Hydroelectric
1980	461	139	0	266	69	0	0	46 (Eklutna & Copper Lake)
1981	0	0	0	0	0	0	0	12 (Solomon Gulch)
1982	-20	178	0	0	0	0	0	0
1983	0	0	0	-8	0	0	0	0
1984	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0
1986	0	0	0	-1	0	0	0	0
1987	0	0	0	-8	-4	0	0	0
1988	0	0	0	-6	0	0	0	90 (Bradley Lake)
1989	0	0	0	0	-5	0	0	0
1990	0	0	0	0	0	0	0	0
1991	0	0	0	-18	0	100	0	0
1992	-16	0	0	-19	0	0	0	0
1993	-9	0	0	0	0	0	200	0
1994	-30	0	0	0	0	0	0	0
1995	-14	0	200	-33	0	0	0	0
1996	0	0	0	-102	0	0	0	0
1997	0	0	0	-65	0	0	0	0
1998	-50	200	0	0	0	0	0	0
1999	0	0	0	0	0	0	0	0
2000	-18	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0
2002	-51	0	0	0	-25	0	0	0
2003	-53	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0
2005	-58	0	0	0	-21	100	0	0
2006	0	0	0	0	0	100	0	0
2007	0	0	0	0	0	0	0	0
2008	-26	0	0	0	0	0	200	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0

TABLE D.19. Electrical Generation by Type of Capacity - Plan 4 (GWH)

	Anchorage-Cook Inlet			Fairbanks-Tanana Valley				
Year	Gas Combustion Turbine	Gas Combined-Cycle	Gas Fuel-Cell Stations	Oil Combustion Turbine & Diesel	Coal Steam Turbine	Gas Combined-Cycle	Gas Fuel-Cell Stations	Total Hydroelectric
1981	2007	44	0	26	537	0	0	254
1982	747	1382	0	63	537	0	0	254
1983	811	1394	0	100	537	0	0	254
1984	903	1378	0	137	537	0	0	254
1985	368	2250	0	0	452	0	0	254
1986	1264	1446	0	11	537	0	0	254
1987	1324	1467	0	108	537	0	0	254
1988	1080	1420	0	204	537	0	0	648
1989	1159	1434	0	342	537	0	0	648
1990	696	2481	0	1	496	0	0	648
1991	1685	1528	0	1	440	3	0	648
1992	1777	1528	0	0	496	1	0	648
1993	1781	1615	0	0	496	4	48	648
1994	1754	1731	0	0	496	8	84	648
1995	144	3434	1611	0	496	30	263	648
1996	14	1964	1611	0	496	29	267	648
1997	14	1973	1611	0	496	34	272	648
1998	13	1982	1611	0	496	4	36	648
1999	13	1992	1611	0	496	4	37	648
2000	15	2002	1611	0	496	4	38	648
2001	15	2025	1611	0	496	5	46	648
2002	7	2248	1611	0	289	9	74	648
2003	1	2271	1611	0	289	10	85	648
2004	1	2293	1611	0	289	12	98	648
2005	1	2296	1611	0	124	21	667	648
2006	1	2341	1611	0	124	30	773	648
2007	1	2374	1611	0	124	39	883	648
2008	2	2398	1611	0	124	9	1240	648
2009	2	1283	1611	0	124	13	2886	648
2010	0	1293	1611	0	124	18	2910	648

discussed in the sections indicated: gas combined-cycle and Bradley Lake hydroelectric in Sections D.2.3 and D.2.4.

Environmental Consideration. Fuel cells represent a technology that is approaching commercialization and, therefore, should be considered in Alaska. The fuel cell is fundamentally comprised of two electrodes, (an anode and a cathode), separated by an electrolyte. Electrical energy is produced by the cell when fuel and oxygen are electrochemically combined in the electrolyte. The fuel and oxygen must be in the gaseous form, but the electrolyte may be an aqueous acid such as phosphoric acid.

A complete fuel-cell plant typically consists of a fuel processor, a fuel-cell section, and electrical equipment. The fuel processor converts natural gas into hydrogen and clears the gas before it goes to the fuel cell.

The basic electrochemical process in the fuel-cell system is the combination of hydrogen gas and oxygen to form water. Since the fuel-cell system is hot while operating, ranging from approximately 20^{o} to $1200^{o}C$ depending upon the electrolyte, product water will experience elevated temperatures. A 10-MW plant would produce about 27,000 gal/day. This product water can either be discharged from the plant, or if in the form of steam, used either to drive a conventional steam turbine in a bottoming cycle or to reform the hydrocarbon fuel in the fuel processor. Additional makeup water may also be used to maximize the use of the reject heat in producing steam. The quantity, however, would be very design specific. Regardless of the specific facility application, an appropriate water and wastewater management plan incorporating suitable waste-heat rejection technologies must be implemented to ensure that thermal discharges comply with pertinent receiving stream standards.

Gaseous emissions from the operation of fuel cells are very low when compared to alternative methods that use combustion techniques. Sulfur and nitrogen will be gasified, not oxidized, and can easily be recovered from process streams. Fuels that are essentially free of such pollutants, such as hydrogen or natural gas, will not lead to any pollutant emissions. Carbon dioxide and water vapor will be formed in large quantities, similar to that associated with combustion. However, no detectable environmental impacts will be associated with these emissions. Because of the high efficiences of fuel cells and the ease of controlling potential pollutants, fuel cells represent a dramatic improvement in air-quality impacts over combustion technologies.

The impacts of fuel-cell energy systems on terrestrial biota are relatively slight since the air pollution potential is very low and small land areas are required ($\sim$one acre for a 5-MW facility). Noise and other potential disturbance factors are also relatively low. Furthermore, these plants will be sited within or adjacent to developed areas where access road requirements are minimal.

Socioeconomic Considerations. Sites for fuel-cell plants should be constrained by the population size of the community since construction work force requirements are relatively large and may cause significant impacts in very small and small communities. Approximately 90 persons would be required for a period of less than 1 year to construct a 10-MW plant. Impacts would be minor to moderate in Anchorage, Fairbanks, Soldotna, Kenai, Valdez, Wasilla, and Palmer.

Capital expenditures that would flow out of the region due to development of a fuel-cell facility would include investment in high-technology equipment. An expected 80% of the project expenditures would be made outside the region, whereas 20% would be spent within the Railbelt. The allocation of operating and maintenance expenditures spent outside the Railbelt is expected to be $\sim$10%.

Advantages of fuel-cell stations include highly competitive energy costs, short design and construction lead time, very favorable environmental characteristics and favorable public acceptance (the latter largely because of lack of adverse environmental effects). Use of local siting should minimize transmission losses. Additionally, the units, being modular in nature, should be insensitive to economics of scale; this combined with short lead time would allow capacity increases to closely follow demand. The units may be operated in either a baseload or load-following mode; unit efficiencies remain high at partial power operation.

D.6.3 Integration of Potential Environmental and Socioeconomic Impacts for Plan 4

The integrated environmental and socioeconomic impacts are presented in Table D.20. The air-quality, water-quality, ecological and health impacts of

TABLE D.20. Integration of Potential Environmental & Socioeconomic Impacts for Plan 4

	Potential Environmental and Socioeconomic Impacts										
Energy Facilities Added	Air Quality	Water Quality	Terrestrial Ecology	Aquatic/ Marine Ecology	Noise, Visual & Odor	Health and Safety	Jobs in Alaska	Boom/ Bust Effects	Land Use Effects	Susceptibility to Inflation	Spending in Alaska (% Total)
Anchorage-Cook Inlet											
Gas Combined Cycle	2	2	2	2	2	1	2	2	3	3	30
Gas Fuel Cell Stations	1	1	2	2	2	1	2	2	1	3	20
Fairbanks-Tanana Valley											
Gas Combined Cycle	2	2	2	2	2	1	2	2	3	3	30
Gas Fuel Cell Stations	1	1	2	2	2	1	2	2	1	3	20
Hydroelectric											
Bradley Lake	1	2	2	2	1	1	3	3	3	1	65

Impact Rating Scale: 1 - minor
2 - moderate
3 - significant

this plan are low to moderate due to the use of hydroelectric and natural gas power facilities. Furthermore, gas turbine combustion, oil turbine combustion and diesel electric units are phased out. Bradley Lake is the only new hydroelectric project used and, thus, local boom/bust impacts will be associated with its construction.

Compared to the previous plans, this plan represents a large amount of spending outside of the state. This situation is caused mainly by the "high technology" aspects of fuel-cell systems and, to a lesser extent, a similar situation exists for gas combined-cycle units. The increased use of natural gas would make inflation effects significant.

APPENDIX E

LIST OF ASSUMPTIONS

APPENDIX E

LIST OF ASSUMPTIONS

GENERAL ECONOMIC ASSUMPTIONS

1. Rate of Inflation - 0%
2. Real Interest Rate (Cost of Capital) - 3.0%
3. Consumer Discount Rate - 3.0%

FUEL PRICE ESCALATION RATES

1. Escalation in World Crude Oil Prices - 2.0%
2. Escalation in Fuel Oil in Alaska - 2.0%
3. Escalation in Healy Coal Prices Delivered to Nenana - 2.0%
4. Escalation in Beluga Coal Prices - 2.1%
5. Escalation in Cook Inlet Natural Gas Prices Beyond 1995 - 2.0%
6. Escalation in North Slope Natural Gas Prices - 0%

FUEL AVAILABILITY ASSUMPTIONS

1. North Slope natural gas is available via ANGTS at Fairbanks by 1987.
2. A large-scale coal export mine (5 million tons per year) is developed in the Beluga area, making coal available for electrical generation. Without such a development, coal will not be available from Beluga.
3. The current reserves of natural gas in the Cook Inlet will not be sufficient to support expanded gas-fired generation beyond 1990-1995. Additional reserves will be available to allow expanded gas-fired generation beyond 1995.

ECONOMIC SCENARIO AND ELECTRICAL DEMAND ASSUMPTIONS

This is a summary only. Full details are in Volume IX.

Medium Economic Scenario

1. Alaska private basic sector employment, 1980-2000 - See Appendix B. Appropriate average growth rate: 3.2%.

2. State government budget average real growth rate, 1980 to 2000 - 1.0 times real income growth.[a]

3. Railbelt basic sector employment average growth rate, 1980 to 2000 - 3.7%

4. Inflation rate, 1980 to 2000 - 6.9%

5. Alaska average household size falls from 3.086 (1980) to 2.657 (2000).

6. Railbelt population average growth rate, 1980 to 2000 - 2.7%

7. Resulting employment and population trends extrapolated to 2010.

Low Economic Scenario

1. Alaska private basic sector employment growth, 1980 to 2000 - See Appendix B. Approximate average growth rate: 1.6%

2. State government budget average real growth rate, 1980 to 2000 - Constant real per capita.[a]

3. Railbelt basic sector employment average growth rate, 1980 to 2000 - 1.9%

4. Inflation rate, 1980 to 2000 - 7.2%

5. Alaska average household size falls from 3.086 (1980) to 2.660 (2000)

6. Railbelt population average growth rate, 1980 to 2000 - 1.8%

7. Resulting employment and population trends extrapolated to 2010.

High Economic Scenario

1. Alaska private basic sector employment growth, 1980 to 2000 - See Appendix B. Approximate average real growth rate: 5.5%

2. State government budget average real growth rate, 1980 to 2000 - 1.5 times real income growth.[a]

3. Railbelt basic sector employment average growth rate, 1980 to 2000 - 6.3%

4. Inflation rate, 1980 to 2000 - 6.7%

(a) Basic operating and capital budget. Excludes some items such as debt service and special capital project funds. See Volume IX for details.

5. Alaska average household size falls from 3.086 (1980) to 2.655 (2000).

6. Railbelt population average growth rate 1980 to 2000 - 4.1%

7. Resulting employment and populaton trends extrapolated to 2010.

FIXED CHARGE RATES ASSUMPTIONS

The fixed charge rates cover the capital cost recovery for the generating facilities. The fixed charge rates represent the annual costs required to cover the initial capital cost of a capital cost item (such as generating facility). The fixed charge rate depends upon the economic lifetime of the item and the cost of capital. For the economic lifetimes presented above, a 3% cost of capital and an annual insurance cost equal to .25% of the initial capital costs, the following fixed charge rates are used:

Fixed Charge Rates (%)

	Project Life			
	20 years	30 years	40 years	50 years
Cost of Capital	3.00	3.00	3.00	3.00
Sinking Fund	3.72	2.10	1.65	0.89
Insurance	0.25	0.25	0.25	0.25
	6.97	5.35	4.90	3.99

COMMON ASSUMPTIONS TO ALL ELECTRIC ENERGY PLANS

1. Current utility plans for generating system additions proceed as planned. The Bradley Lake hydroelectric project is built and comes on-line in 1988.

2. Existing generating units are retired based on assumed economic lifetimes.

3. The electrical transmission interconnection between Anchorage and Fairbanks is completed in 1984 and strengthened as necessary to allow economical power exchanges between Fairbanks and Anchorage.

4. The Glennallen-Valdez load center electrical loads and generating capacity are combined with Anchorage-Cook Inlet loads and generating capacity.

GENERATING CAPACITY COST ESCALATION ASSUMPTIONS (1981 TO 2010)

1. Variable O&M Costs Escalation - 2.0%
2. Fixed O&M Costs Escalation - 2.0%
3. Capital Cost Escalation - 1.4%

PLANNING RESERVE MARGIN & LOSS ASSUMPTIONS

1. Planning Reserve Margin - 30%
2. Loss and Unaccounted Energy - 8%

Plan	1A	"Present Practices" Without Upper Susitna
	1B	"Present Practices" With Upper Susitna
	2A	"High Conservation and Renewables" Without Upper Susitna
	2B	"High Conservation and Renewables" With Upper Susitna
	3	"High Coal"
	4	"High Natural Gas"