Selection of Electric Energy Generation Alternatives for Consideration in Railbelt Electric Energy Plans

Volume II

December 1982

Prepared for the Office of the Governor
State of Alaska
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SELECTION OF ELECTRIC ENERGY GENERATION ALTERNATIVES FOR CONSIDERATION IN RAILBELT ELECTRIC ENERGY PLANS

Volume II

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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

SUMMARY

A major task of the Railbelt Electric Power Alternatives Study was to identify electric power generating alternatives that are potentially applicable to the Railbelt region and to examine their technical and economic feasibility and environmental and socioeconomic effects. Technologies that appear best suited for future application in the region were subject to additional study and incorporated into alternative electric power plans for the Railbelt region (Volume I). This report describes the selection of these alternatives.

A set of alternatives was selected for consideration in each of the four Railbelt Electric Energy Plans. The four plans included the Present Practices Plan,[a] the High Conservation and Renewables Plan, the High Natural Gas plan and the High Coal Plan.

The selection of alternatives for each plan was based on the following considerations:

- energy resource availability
- available unit sizes of candidate alternatives
- operating characteristics of candidate alternatives
- commercial availability of candidate alternatives
- estimated cost of power from candidate alternatives
- likely environmental effects of candidate alternatives
- public acceptance
- on-going studies of specific alternatives.

Alternatives selected for each plan are listed in Table S.1.

(a) Known as the "Base Case" in Volume V.

TABLE S.1 Alternatives Selected for Each Plan

Alternative	Plan: Present Practice	High Renewable	High Coal	High Natural Gas
Coal Steam Electric	X	X	X	
Coal Gasification - Combined-Cycle			X	
Natural Gas Combined-Cycle	X	X	X	X
Natural Gas Combustion Turbines	X		X	
Natural Gas Fuel Cell Stations				X
Natural Gas Fuel Cell - Combined-Cycle				X
Natural Gas Cogeneration				X
Distillate Combined-Cycle Retrofit	X	X		
Distillate Fuel Cell Station				X
Diesel Electric	X	X	X	X
Bradley Lake Hydro	X	X	X	X
Grant Lake Hydro	X	X	X	X
Chakachamna Hydro	X	X	X	X
Allison Hydro	X	X	X	X
Browne Hydro		X		
Snow Hydro		X		
Keetna Hydro		X		
Strandline Lake Hydro		X		
Refuse Fired Steam Electric		X		
Large Wind Energy Conversion Systems		X		
Tidal Power		X		
Upper Susitna	X[a]	X[a]		

(a) Assessed as specific variations to the Present Practices and High Renewables plans.

TABLE OF CONTENTS

FIGURES

TABLES

1.0 INTRODUCTION

The Railbelt region of Alaska, as defined in this project, includes Anchorage, Fairbanks, the Kenai Peninsula and the Valdez-Glennallen areas. The region has a total population of approximately 260,000, about two-thirds of the state's population. Currently installed generating capacity for the region is approximately 1080 MWe (Volume VI).

A variety of energy resources is potentially available for producing electric power in the Railbelt. Those currently used include natural gas, coal, petroleum-derived fuels (distillate and residual oils), and hydropower. Several additional resources, including peat, refuse-derived fuel, geothermal power, wind, solar and tidal power, offer potential as future sources of electric power. Numerous technologies are currently available to generate electric power from these resources. Additional technologies, currently under development, will become available in the future for producing electricity from these resources.

To date several organizations, including the Corps of Engineers, the Alaska Power Administration, the Alaska Power Authority, the Institute of Social and Economic Research, and the existing Railbelt utilities have engaged in various aspects of electric power planning. Several individual proposals for electric power development are currently under study, including the Upper Susitna hydroelectric project (Devil Canyon and Watana Dams) (Acres American 1981b), Cook Inlet tidal power development (Acres American 1981a), the Bradley Lake hydroelectric project, the Grant Lake hydroelectric project (CH_2M-Hill 1980), the Allison hydroelectric project (U.S. Army Corps of Engineers 1981) and the Chakachamna hydroelectric project (Bechtel 1981). To date, however, no comprehensive electric power plan has been prepared for the Railbelt region.

The State of Alaska, Office of the Governor, contracted with Battelle-Northwest to perform a Railbelt Electric Power Alternatives Study. A major objective of this study was to develop and analyze alternative long-range plans for electrical energy development for the Railbelt region. These plans will be used as the basis for recommendations to the Governor and Legislature for Railbelt electric power development, including whether the state should concentrate its efforts on developing the hydroelectric potential of the Susitna River or pursue other alternatives.

Because of the variety of potential electric generating options available to the Railbelt, one of the study's major tasks was to identify electric power generating alternatives potentially applicable to the Railbelt region and to examine their technical and economic feasibility and prospective environmental and socioeconomic effects. Those alternatives that appear best suited for future application to the region were studied further and were incorporated into one or more electric power plans that were developed and assessed as part of this project (Volume I).

The procedure used to select generating alternatives for inclusion in the Railbelt electric energy plans is shown in Figure 1.1. A broad set of potential alternatives was first defined. These were screened for technical feasibility in the Railbelt region and for commercial availability by year 2000. This screening process and the resulting set of candidate alternatives are described in Volume IV. The technical performance, fuel and siting requirements, costs, environmental and socioeconomic effects and potential Railbelt applications of each candidate alternative was assessed. The resulting technical profiles are provided in Volume IV.

Using the information developed in the technical profiles, a set of preferred alternatives was identified. The selection of these preferred alternatives is the subject of this volume. The preferred alternatives were then divided into two groups to determine whether additional information should be compiled on each prior to incorporation into the electric energy plans. One group consisted of alternatives for which substantial information was available on the cost and performance of the alternatives in the Railbelt. This group included alternatives for which feasibility or engineering studies had been recently performed, as well as alternatives for which cost and performance characteristics are well documented in the resource profiles. Key cost and performance characteristics of these alternatives were compiled into technical data sheets (Appendix A).

The second group of alternatives consisted of alternatives for which cost and performance characteristics were less well understood. Individual

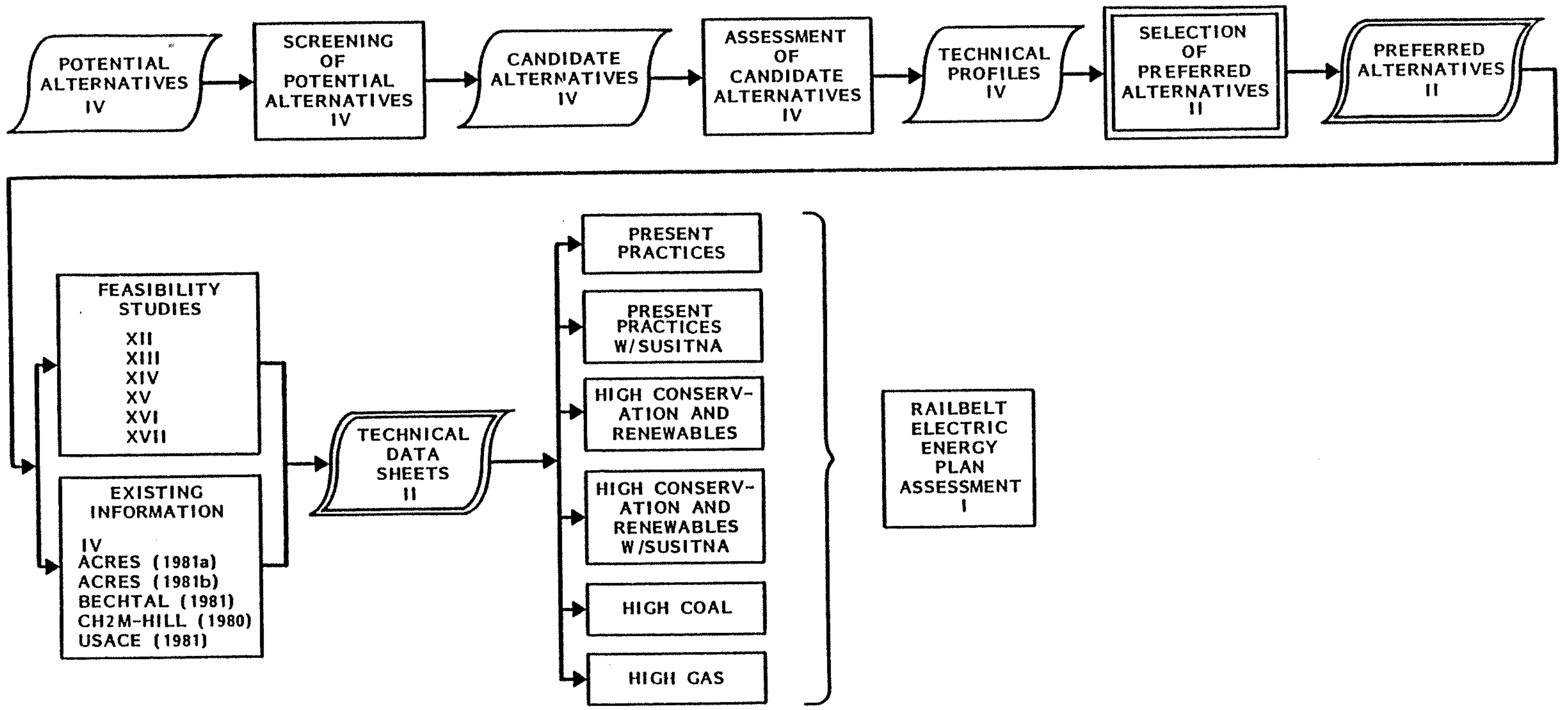

FIGURE 1.1. Procedure Used to Select Generating Alternatives for Inclusion in the Railbelt Electric Energy Plans

feasibility studies were performed on these alternatives (Volumes XII through XVII). Key cost and performance data were extracted from these feasibility studies and compiled on technical data sheets. The technical data sheets (included as Appendix A to this report) were used as the source of generating alternative cost and performance information for operation of the capacity addition model (AREEP, Volume XI) used to assess the six Railbelt electric energy plans considered in the study (Volumes V and I).

This report consists of four chapters following this introduction and a major appendix. The second chapter includes an overview of the candidate electric power generating alternatives potentially applicable to the Railbelt region. Chapter 3.0 contains a discussion of the approach to the selection process. Chapter 4.0 discusses the selection of alternatives and the merits of individual candidates. Chapter 5.0, Conclusion, includes the list of alternatives selected for consideration in the development of Railbelt electric power plans. Also included is a discussion of the approaches taken to develop additional information on the alternatives required to compare alternative Railbelt electric energy plans. This volume concludes with an appendix of technical data sheets on the preferred generating and conservation alternatives selected for consideration in the Railbelt electric power plans.

2.0 THE CANDIDATE ALTERNATIVES

Candidate electric generating alternatives were selected based on two considerations: 1) energy resources available in the Railbelt and 2) generating technologies using these resources likely to be available for commercial order by year 2000. Year 2000 was selected as a cut-off date because technologies becoming available for commercial order beyond year 2000 would not significantly contribute to meeting the Railbelt's electric energy demand before the end of the planning period (2010). Moreover, uncertainties in the introduction date, technical performance and cost of technologies becoming available beyond 2000 are so great that plans based on their use would be highly speculative at best.

Primary energy resources available or potentially available in the Railbelt in sufficient quantity to support electric power generation are listed in Table 2.1. In addition to the indigenous resources listed in Table 2.1, fabricated nuclear fuel could be imported from manufacturers in the "lower 48" states.

Twenty electrical generating technologies using these resources were identified as currently available or forecasted to be available for commercial order by year 2000. These are listed in Table 2.2. Discussion of these technologies is provided in Volume IV.

The 38 specific electric energy alternatives listed in Table 2.3 are combinations of energy resources and generating technologies that could be used to produce electric power based on energy resources available in the Railbelt region. This table also indicates when these alternatives would be available for service in the Railbelt region. The estimated earliest in-service dates consider availability of the technology for commercial order; design, construction and licensing lead times; and availability of fuels.

TABLE 2.1. Energy Resources Available in the Railbelt Region

Resource	Principal Sources	Primary Transportation Options[a]
Coal	Beluga Field (north of Cook Inlet)	Barge or collier transport to tidewater locations
	Nenana Field (Healy)	Alaska Railroad
Natural gas	Cook Inlet Fields and Kenai Peninsula	Natural gas pipelines to Anchorage
	North Slope Fields	Proposed North Slope natural gas pipeline to Fairbanks and through Tanana Valley. Proposed liquefaction of North Slope gas with LNG pipeline transport to Fairbanks and Anchorage
Petroleum products	Cook Inlet Fields, Cook Inlet and Kenai Peninsula, refined at Kenai	Product pipeline to Anchorage; rail or truck tanker transport; barge (to tidewater locations)
	North Slope Fields, refined at North Pole	Rail or truck tanker transport
Peat	Kenai Peninsula	Truck Transport
	Lower Susitna Valley	Alaska Railroad; truck transport
	Tanana Valley	Alaska Railroad; truck transport
Municipal Refuse	Anchorage	Truck transport; railroad; barge (to tidewater locations)
	Fairbanks	Truck transport; Alaska Railroad
Wood Residue	Kenai/Soldatna	Truck transport
	Anchorage area	Truck transport; Alaska Railroad
	Nenana area	Truck transport; Alaska Railroad
	Fairbanks area	Truck transport; Alaska Railroad
Geothermal Energy	Wrangell Mountains	Transport generally not feasible
	Chigmit Mountains	Transport generally not feasible
Hydro	Kenai Mountains	
	Chigmit Mountains	Transport not feasible
	Susitna River system	
	Nenana River system	
	Other Locations	
Tidal power	Cook Inlet	Not applicable
Wind	Isabell Pass area	Not applicable
	Offshore	Not applicable
Solar	Throughout region	Not applicable

(a) Transportation options available for synthetic fuels derived from coal, peat, wood residue or refuse-derived fuel not included.

TABLE 2.2. Energy Conversion, Generation and Storage Technologies Available for Commercial Order by Year 2000

Technology	Typical Application	Estimated Availability for Commercial Order
Coal-Fired Steam-Electric	Baseload Generation	Currently available
Gas or Distillate-Fired Steam-Electric	Baseload Generation	Currently available
Biomass[a] or Peat-Fired Steam-Electric	Baseload Generation	Currently available
Nuclear Light Water Reactor	Baseload Generation	Currently available
Geothermal Steam Electric	Baseload Generation	1990-2000[b]
Molten Carbonate Fuel Cells	Baseload Generation	1990-1995
Combined-Cycle	Baseload Load-Following Generation	Currently available
Combustion Turbines	Baseload Load-Following or Resource Generation	Currently available
Diesel Generators	Baseload Load-Following or Resource Generation	Currently available
Hydroelectric	Baseload Load-Following Generation	Currently available
Phosphoric Acid Fuel Cells	Baseload or Cycling Generation	1985-1990
Tidal Electric	Fuel-Saver Generation	Currently available
Wind Energy Systems	Fuel-Saver Generation	1985-1990
Solar Photovoltaic	Fuel-Saver Generation	1985-1990[c]
Microhydro[d]	Fuel-Saver Generation	Currently available
Solar Thermal	Fuel-Saver Generation	1995-2000
Coal Gasification	Fuel Synthesis	1985-1990
Coal Liquefication	Fuel Synthesis	1985-1990
Peat Gasification	Fuel Synthesis	1990-2000
Pumped Hydroelectric	Energy Storage	Currently available
Compressed Air Storage	Energy Storage	Currently available
Storage Batteries	Energy Storage	1985-1990

(a) Wood residue or municipal waste.
(b) Dates given are for hot dry rock technology applicable to Railbelt geothermal resources as currently understood. Hydrothermal technology is currently available.
(c) Photovoltaic technology is currently available though not cost competitive with other technologies. Dates given are estimates for low-cost large arrays.
(d) Microhydroelectric units are generally defined as those of 0.1 MW capacity or less.

TABLE 2.3. Electric Energy Alternatives Available to the Railbelt Region

Resource	Alternative	Typical Application	Estimated Earliest In-Service Date
Coal	Coal Steam-Electric	Baseload	1989
	Coal Gasification - Combined-Cycle	Baseload or Load Following	1991
	Coal Gasification - Fuel Cell Combined-Cycle	Baseload	1995
Peat	Peat Steam-Electric	Baseload	1990
	Peat Gasification - Combined-Cycle	Baseload or Load Following	1995-2000
	Peat Gasification - Fuel Cell Combined-Cycle	Baseload	1995-2000
Natural Gas	Natural Gas Combustion Turbine	Baseload or Load Following	1984
	Natural Gas Combined-Cycle	Baseload or Load Following	1985
	Natural Gas Fuel Cell Stations	Baseload or Load Following	1987
	Natural Gas Steam-Electric	Baseload	1988
	Natural Gas Fuel Cell Combined-Cycle	Baseload	1995
Fuel Oil	Distillate Combustion Turbine	Baseload, Load Following, or Reserve	1984
	Diesel Electric	Baseload, Load Following, or Reserve	1984
	Distillate Combustion-Cycle	Baseload or Load Following	1985
	Distillate Fuel Cell Stations	Baseload or Load Following	1987
	Distillate Steam-Electric	Baseload	1988

TABLE 2.3. (contd)

	Distillate Fuel Cell Combined-Cycle	Baseload	1995
Geothermal	Geothermal Steam-Electric	Baseload	1995-2000
Biomass	Wood Residue/Municipal Refuse Steam-Electric	Baseload	1987
Hydro	Grant Lake Hydroelectric	Baseload or Load Following	1988
	Bradley Lake Hydroelectric	Baseload or Load Following	1988
	Devil Canyon Hydroelectric	Baseload or Load Following	1993
	Watana Hydroelectric	Baseload or Load Following	1993
	Snow Hydroelectric	Baseload or Load Following	1990-1995
	Tustumena Hydroelectric	Baseload or Load Following	1990-1995
	Allison Hydroelectric	Baseload or Load Following	1990
	Strandline Lake Hydroelectric	Baseload or Load Following	1990-1995
	Bruskasna Hydroelectric	Baseload or Load Following	1990-1995
	Silver Lake Hydroelectric	Baseload or Load Following	1990-1995
	Cache Hydroelectric	Baseload or Load Following	1990-1995
	Johnson Hydroelectric	Baseload or Load Following	1990-1995
	Browne Hydroelectric	Baseload or Load Following	1990-1995
	Tokachitna Hydroelectric	Baseload or Load Following	1990-1995
	Talkeetna II Hydroelectric	Baseload or Load Following	1990-1995
	Hicks Hydroelectric	Baseload or Load Following	1990-1995

TABLE 2.3. (contd)

	Lane Hydroelectric	Baseload or Load Following	1990-1995
	Chakachamna Hydroelectric	Baseload or Load Following	1990
	Lower Chulitna Hydroelectric	Baseload or Load Following	1990-1995
	Microhydroelectric	Fuel Saver	1984
Tidal	Cook Inlet Tidal Power Project	Fuel Saver[a]	2000-2005
Wind	Large Wind Energy Conversion Systems	Fuel Saver[a]	1990
	Small Wind Energy Conversion Systems	Fuel Saver	1984
Solar	Solar Photovoltaic Stations	Fuel Saver[a]	1995
	Solar Thermal Electric	Fuel Saver[a]	2000
Nuclear	Nuclear Steam-Electric	Baseload	1994

(a) Could be baseload or cycling if coupled with energy storage.

3.0 APPROACH TO THE SELECTION OF ALTERNATIVES

The selection of alternatives for the Railbelt electric energy plans was based on planning themes established for the preliminary Railbelt electric energy plans (Volume V) and a set of specific criteria that were considered to be important in selecting generating alternatives for further consideration.

This chapter first reviews the four planning themes selected for Railbelt electric energy plans. Following this is a discussion of criteria pertinent to the comparison and selection of alternatives to be considered within each planning theme.

3.1 RAILBELT ELECTRIC ENERGY PLANNING THEMES

Four basic Railbelt electric energy plans were developed for comparison in this study. Each represents an "energy future" that appears possible for the Railbelt. The plans were developed to represent a range of reasonable conservation and generation alternatives available to the region, including the alternatives that are currently receiving the greatest interest within the region.

A set of planning objectives was developed to serve as the basic framework for developing the Railbelt electric energy plans. The planning objectives were based on cited objectives of the State of Alaska (State of Alaska 1980), current utility planning practice, and responses received from a public participation effort conducted in conjunction with this study (Volume X). The objectives included the following: 1) plans should endeavor to minimize the cost of power; 2) one or more plans should emphasize conservation and the use of renewable resources; 3) plans should endeavor to minimize adverse environmental effects, including effects on fish and wildlife habitat, air-quality effects, aesthetic effects and health and safety effects; 4) each project under active consideration should be incorporated in one or more plans; and 5) plans should incorporate a realistic extension of current Railbelt electric power utility characteristics and planning. Based on these objectives, the following Railbelt Electric Energy Plans were developed and assessed (Volume I):

PLAN 1: PRESENT PRACTICES. This plan would involve continued development of generating capacity consistent with current trends. Two cases are considered:

A. no development of the Upper Susitna project
B. eventual development of the Upper Susitna project.

Plan 2: HIGH CONSERVATON AND USE OF RENEWABLE RESOURCES. This plan would emphasize the development of generating capacity based on renewable resources plus tempering of demand by promotion of conservation alternatives. As in Plan 1, two cases are considered:

A. no development of the Upper Susitna Project
B. eventual development of the Upper Susitna Project.

PLAN 3: HIGH COAL. This plan would involve a transition from current generating practice to a substantial use of coal as a primary energy resource.

PLAN 4: HIGH NATURAL GAS. This plan would involve continued use of natural gas as a primary energy resource in the Cook Inlet area and possible conversion to natural gas use in the Fairbanks area. As natural gas supplies were depleted, eventual transition to other energy resources may be required.

3.2 SELECTION CRITERIA

Several criteria weighed in the selection of electric power generating alternatives for consideration in the development and analysis of a given Railbelt electric energy plan. These criteria include the following:

- the availability of suitable energy resources
- available plant sizes
- operating characteristics
- commercial availability
- estimated cost of power
- likely environmental and socioeconomic effects
- public acceptance
- on-going electric power planning activities.

These issues are discussed below.

Resource Availability

The primary energy resources currently used for power production in the Railbelt include coal, natural gas, petroleum-derived liquids and hydro power. Energy resources that are not currently used but could be developed for the generation of electric power include peat, tidal power, wind, solar energy, municipal refuse and wood residue. Nuclear fuel could be imported to the Railbelt if desired. Important considerations in the use of energy resources include abundance, transportability and cost. Each of the resources cited above appears to be available in sufficient quantities to potentially support utility-scale generating facilities. Some of the renewable resources are available only cyclically or intermittently and cannot be stored in their "as-received" forms. These resources, which include wind, solar and tidal resources, must be used when received or converted to a storable form of energy.

The transportability of the various resources controls the potential locations of power-generating facilities based on these resources. Renewable resources, with the exception of wood residue and municipal refuse, are not transportable and must be used onsite. Coal is economically transported in the quantities used by typical coal-fired power plants only by barge or rail. Natural gas and petroleum products may be readily transported in bulk quantities using pipeline. The transportability of Railbelt energy resources is summarized in Table 2.1.

Finally, the cost of energy resources is an important factor in determining the cost of power produced by the associated generating alternatives. For example, over the lifetime of a coal-fired generating plant located in the Railbelt, approximately 40% of the cost of power generated by the plant is attributable to fuel cost. Because fuel is purchased throughout the lifetime of the plant, it affects the sensitivity of the alternative to inflation.

Available Plant Sizes

Certain alternatives are available only in large plant sizes. Construction of generating alternatives having large unit sizes compared to electrical demand in the Railbelt may not be desirable for several reasons. First, development of a unit having large rated capacity in comparison with demand may result in surplus capacity for a prolonged period following initial plant operation. This will increase power production costs. Secondly, development of a system consisting of relatively few large units may reduce system reliability and may require greater reserve capacity to provide an acceptably low loss-of-load probability, again increasing costs. Finally, provision of large baseload units in a small system with substantial seasonal peaking may require additional load-following capacity to be installed or the baseload units to be operated in a less efficient cycling mode.

Operating Characteristics

Inherent operating characteristics of alternatives govern their application to electric energy systems. Of particular significance are the load-following characteristics of power plants. Three typical load-following characteristics are recognized: baseload, peaking (load following) and fuel saver.

Baseload plants provide large amounts of power at a steady production rate, generally at a relatively low cost. Certain generating alternatives are best suited to steady-state operation. Examples include most steam-electric facilities (coal, gas, oil, nuclear, and geothermal). These plants are generally operated in a baseload mode for much of their lives. As this type of plant ages and lower cost alternatives become available for baseload service, they may be shifted to intermediate cycling operation to meet seasonal peak demands, often at a sacrifice of operating efficiency. An additional and important factor motivating the use of certain alternatives as baseload alternatives is the ratio of fixed to variable costs. Alternatives having high fixed and low variable costs may be economical only if operated at or near maximum capacity. This is true of nuclear, geothermal and many hydroelectric facilities.

Peaking (load-following) plants are capable of rapid adjustment of power level to meet demand. In addition, these alternatives often have relatively low fixed costs compared to variable costs. For these reasons, these alternatives are used for load following to meet daily or seasonal peaks. Most alternatives capable of load following are technically capable of being used in baseload operation as well. Low conversion efficiencies or high fuel costs of these alternatives may, however, render them undesirable baseload service.

Fuel-saver alternatives are available intermittently. These include alternatives relying on solar, wind or tidal power. Alternatives based on these resources typically operate in a "fuel-saver" mode. Because the fuel for these alternatives is essentially free, their variable costs of operation are less than baseload plants. Thus, when available, they generally operate at baseload capacity, thus saving variable costs of the baseload or cycling plants being displaced. Energy-storage devices may be installed in conjunction with alternatives based on intermittent resources to store any surplus energy produced during daily low load periods and to shift power output of these devices to the peak load periods of the day. Thus equipped, these plants are capable of offsetting the variable costs of peaking facility operation (generally greater than the variable costs of baseload facilities).

Energy-storage technologies may be used in conjunction with fuel-saver options, as discussed above. Alternatively, energy-storage options may be charged using low cost power from baseload alternatives, then discharged to meet peak power demands. This type of operation is especially desirable in systems having a high daily load factor.[a] Because of the high capacity (fixed) costs of storage options, they can generally be economically justified only for meeting short duration (e.g. daily) peaks.

A final operational consideration is startup capability. Rapid startup capability is needed for emergency reserve units. Certain generating alternatives are slow to bring on-line, notably the steam-electric technologies. Other technologies, including hydroelectric facilities, combustion turbines, and diesel generators can be brought on-line quickly from a cold start and thus serve well as emergency reserve capacity.

Generating alternatives having baseload and cycling capability must be provided in any electric power system. Reserve capacity is also required, either as normally operating units with surplus capacity or as units dedicated

(a) Load factor is the ratio of peak load to baseload. Baseload is the minimum system load during a given period of time.

to reserve service. Fuel-saver plants may be desirable, if a good fuel-saver resource is available and if the variable costs of baseload or peaking plants are relatively high. Energy storage facilities may be useful to utilities characterized by high daily load factors.

Commercial Availability

The time frame of Railbelt Electric Power Planning Study is a 30-year planning period extending from 1980 to 2010. During this period, several electric power production technologies currently in the development or demonstration stage most likely will attain commercial maturity. Examples of such technologies include synthetic fuels production from coal or peat, fuel cells, advanced combustion turbines, and solar thermal and photovoltaic devices. Although generally not presently competitive with conventional generating alternatives, and in many cases not fully developed, some of these advanced technologies may be competitive within the planning period. With the exception of the Present Practices plan, which considers proven technologies only, the potential desirability of advanced technologies is considered at the time they are anticipated to be available for commercial operation.

Cost of Power

The power costs used for selection of alternatives is busbar power cost based on the net revenue requirement of alternatives. The net revenue requirement includes recovery of capital costs, fixed and variable operating and maintenance expenses, fuel costs, and return on investment. The net revenue requirements used in this report for comparison of alternatives are levelized lifetime unit costs of power, expressed in 1980 dollars.[a] Use of levelized lifetime costs for cost comparison provides a way of comparing alternatives that may have quite different cost profiles over their operating lives. For example, use of levelized costs permits comparison of a hydroelectric facility having a fairly uniform power cost throughout its operating life with a distillate-fired generating plant subject to increases in fuel and operating costs. Levelized costs, however, can be misleading as they

(a) Note that the costs cited in the technical data sheets of Appendix A are in January 1982 dollars to conform to the convention established for comparison of Railbelt electric energy plans (Volume I).

do not correspond with the actual power costs to be expected early in plant life, except for facilities such as hydroelectric plants, which are not greatly subject to escalation or general inflation. For most alternatives levelized costs will be greater than first-year power costs. Further discussion of net revenue requirements and levelized costing methodology is provided in Volume IV.

The cost comparisons drawn in this document are largely independent of application of alternatives in the power system in which they may be installed. It is important to recognize that complete cost comparison of electric power generating alternatives should consider the value of the alternative to the system. For example, a fuel-saver alternative is worth more to a system having baseload capacity using expensive fuel (for example, distillate) than to a system having baseload capacity using relatively low cost fuel, such as coal. As a second example, a hydroelectric facility having substantial installed capacity but relatively low annual energy production capability may be worth more to a utility needing reserve capacity than to a utility having abundant reserve capacity. The costs of alternatives in a systems context were compared during the analysis of Railbelt electric energy plans (Volume I).

Environmental and Socioeconomic Effects

If equipped with appropriate environmental controls, each of the alternatives of Table 2.3 is capable of complying with current environmental standards applicable to Railbelt installations. Moreover, none of the alternatives are thought to result in profound environmental or socioeconomic effects of regional consequence. Some of the alternatives, such as those requiring mining of coal or peat and certain hydroelectric alternatives, are likely, however, to result in local impacts of considerable significance. Consideration of environmental and socioeconomic effects beyond those controlled by state and federal regulations is important in the selection of alternatives for future application in the Railbelt, as evidenced by the high level of public interest in the environmental ramifications of the proposed Upper Susitna Project.

Public Attitudes

A survey of public preferences of electric power system planning objectives and electric energy supply and conservation alternatives was conducted in conjunction with this study (Volume X). The objectives of this survey were to gain understanding of public attitudes relative to electric power system planning objectives and to obtain measures of citizen attitudes on issues relating to the selection of electric power supply and conservation alternatives. Responses to the questions on planning objectives were used in developing the overall framework of the preliminary Railbelt electric energy plans, as discussed in Volume V.

Ongoing Electric Power Planning Activities

An appraisal of future electric power conditions in the Railbelt must recognize effects of current planning activities, if implemented. Recent power-related planning studies in the Railbelt region include the Anchorage-Fairbanks electric intertie study, the Upper Susitna hydroelectric study, the Bradley Lake hydroelectric study, the Grant Lake hydroelectric study, the Chakachamna hydroelectric study, the Cook Inlet tidal project study, and various power-related resource development studies. These latter studies include the North Slope natural gas pipeline, the Pacific Alaska Liquified Natural Gas (LNG) development, the Dow-Shell petrochemical study, and studies relating to development of the Beluga coal field. In general, any project for which planning is in progress was included in one or more electric energy plans, as appropriate.

4.0 SELECTION OF ALTERNATIVES

The purpose of this chapter is to discuss the selection of electric power generating alternatives for inclusion in the four Railbelt electric plans. Candidate alternatives were first organized into groups corresponding to the four Railbelt electric energy planning themes. The alternatives were compared based on the planning criteria discussed in the previous chapter, and a set of preferred alternatives was selected for inclusion in each of the four plans.

4.1 PRESENT PRACTICES PLAN

Candidate alternatives for the Present Practices plan included those based on demonstrated technologies with emphasis on energy resources and technologies currently in use in the Railbelt. Resources considered included coal, natural gas, fuel oil, hydro, and nuclear. Conversion technologies included combustion turbines, combined-cycle plants, direct-fired steam-electric plants, hydroelectric plants, and light water reactors. Future use of these technologies for electric power production in the Railbelt would minimize risk from the perspective of technology and resource development. Costs and performance of these technologies are relatively well understood compared to developing technologies. The principal uncertainties relative to use of these technologies include the licensing and construction lead times of large-scale coal, nuclear and hydroelectric projects, global environmental impacts of combustion-based technologies and long-term operational reliability of light water reactors.

The relative costs of energy production using the Present Practices alternatives are given in Figures 4.1 through 4.4. Plotted in Figure 4.1 are levelized lifetime energy costs for fossil fuel alternatives available to the Anchorage load center, brought on-line at various times during the planning period. Similar costs are presented in Figure 4.2 for hydroelectric alternatives available to the Anchorage load center. Costs of nonhydroelectric resources are calculated using a 65% capacity factor; hydroelectric costs are based on forecasted annual average energy production.

Electrical interconnection of the Anchorage and Fairbanks load centers was assumed for this study. However, additional generating capacity could be

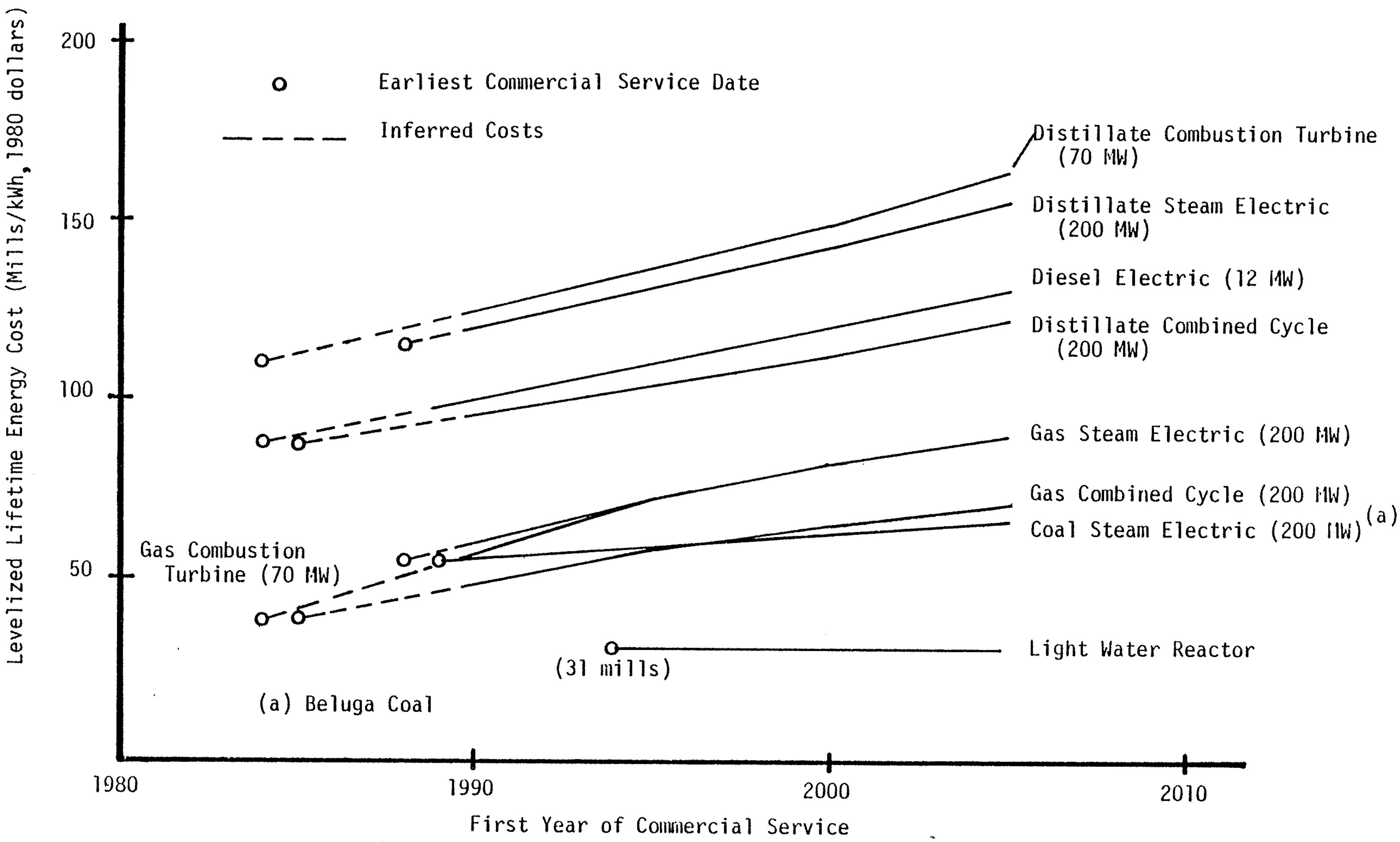

FIGURE 4.1. Cost and Availability of Fossil-Fired Present Practice Alternatives for the Anchorage Load Center

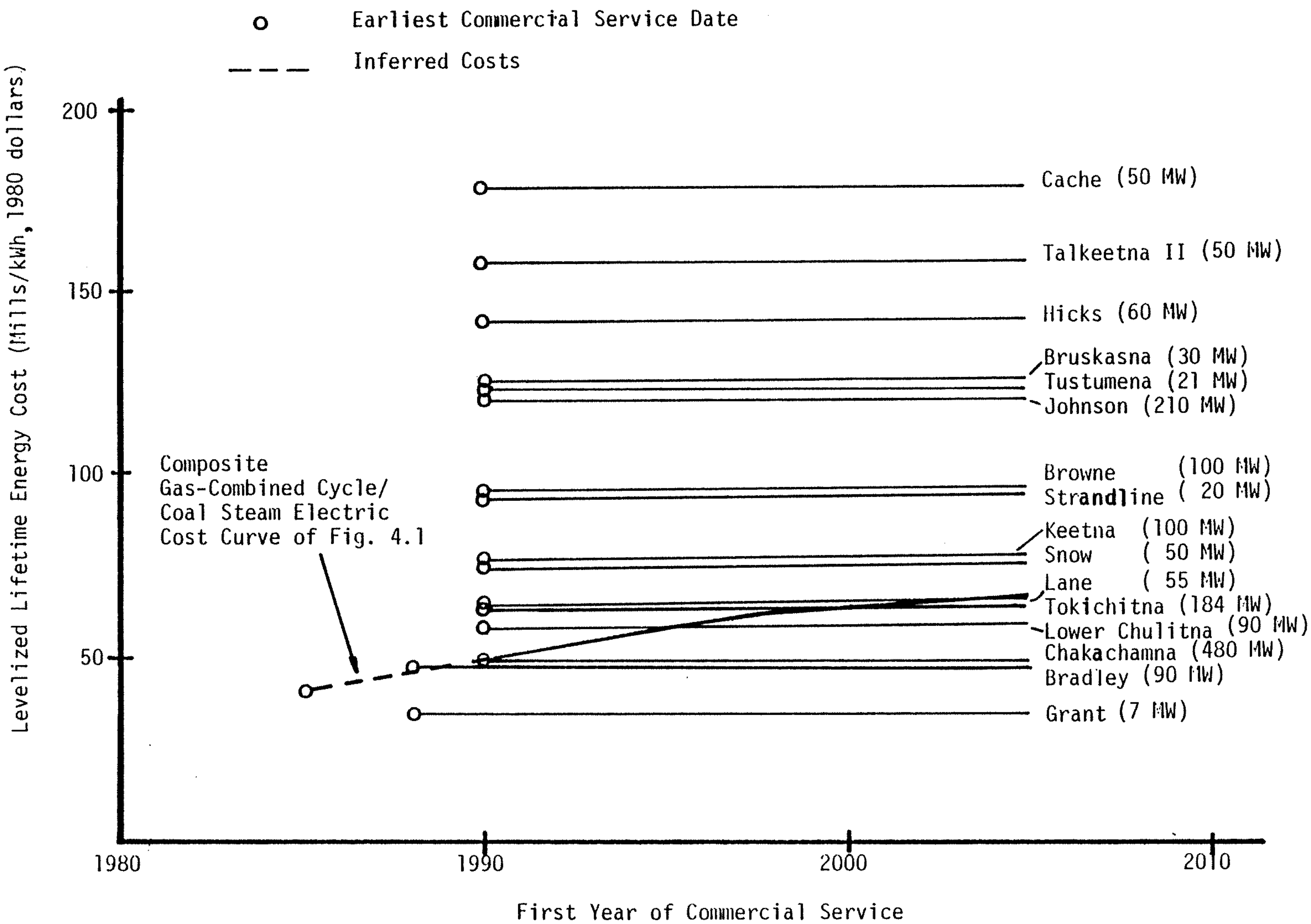

FIGURE 4.2. Cost and Availability of Hydroelectric Alternatives for the Anchorage Load Center

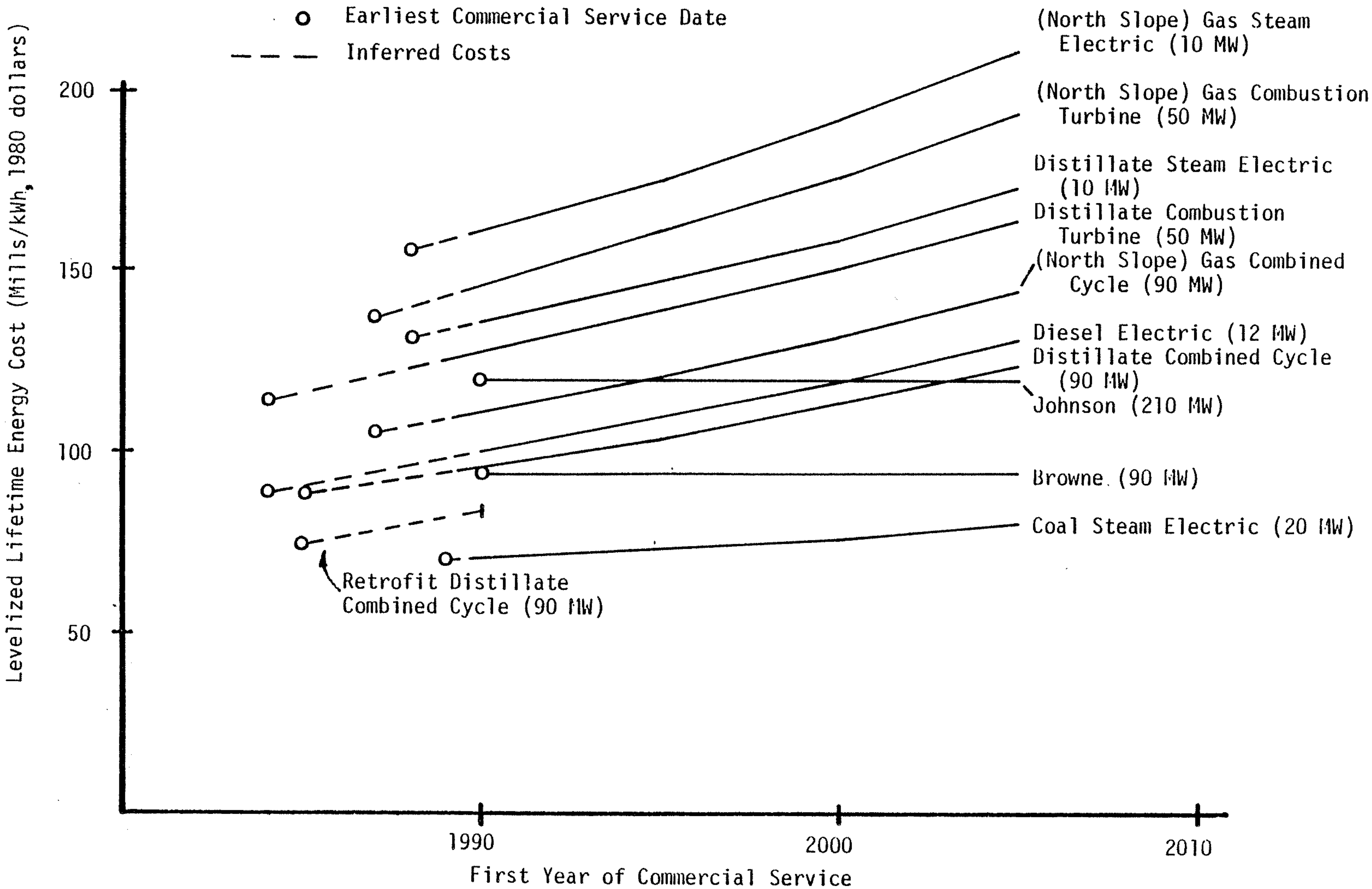

FIGURE 4.3. Cost and Availability of Present Practice Alternatives for the Fairbanks Load Center

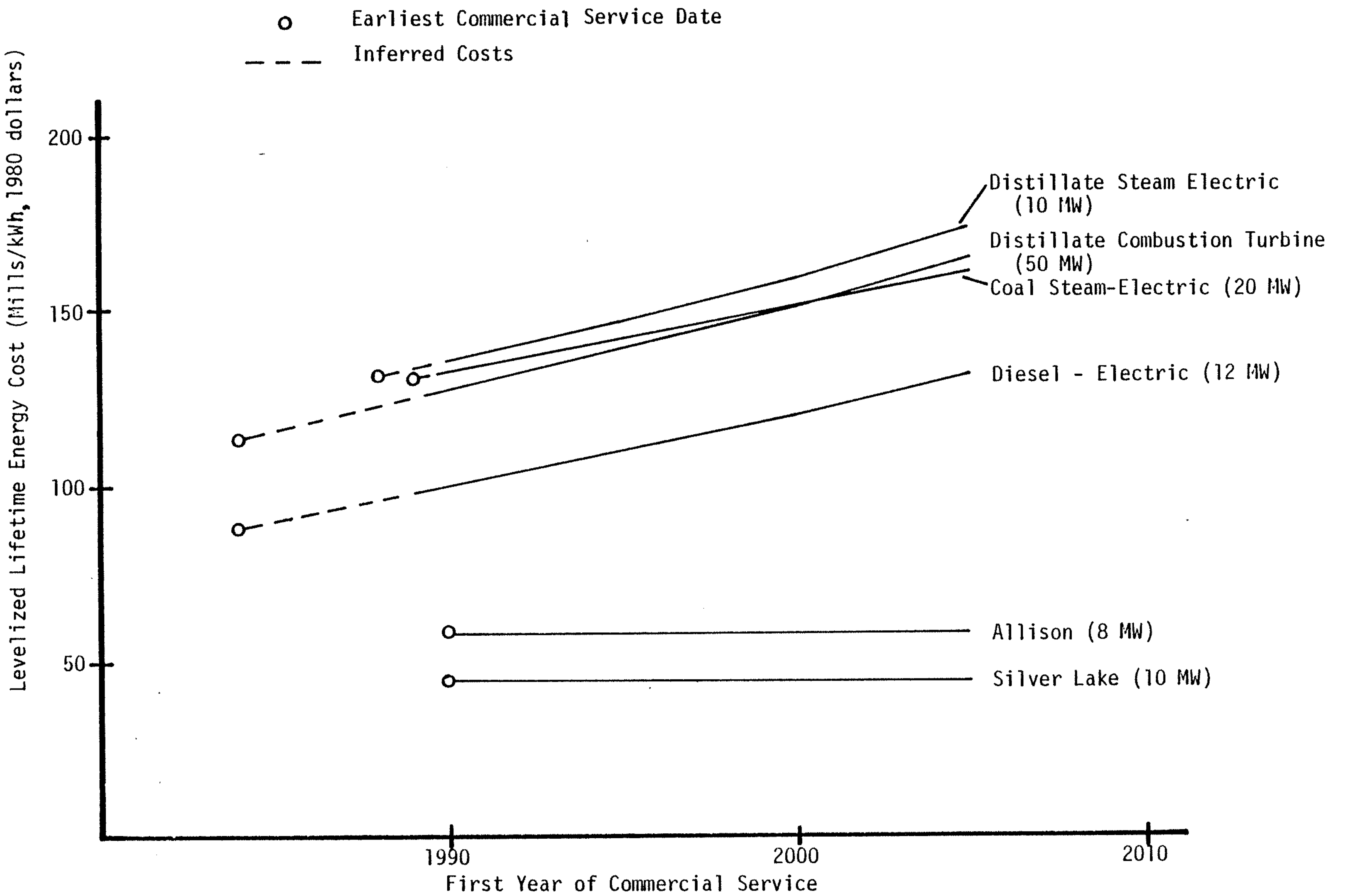

FIGURE 4.4. Cost and Availability of Present Practice Alternatives for the Glennallen-Valdez Load Center

required in the Fairbanks load center if the Fairbanks load increased beyond intertie capacity, if it is needed for reliability. The costs of Present Practices alternatives available to meet prospective needs within the Fairbanks load center are shown in Figure 4.3.

Finally, the Copper River Valley is electrically independent of the other load centers. Future capacity needs in this subregion could be met by constructing a transmission tie from the Anchorage load center, or by developing generating capacity within the Copper River subregion. The costs of Present Practices alternatives available to this subregion are shown on Figure 4.4. (Costs in Figures 4.1 through 4.10 before 1990 are inferred or extrapolated.)

Not shown in Figures 4.1 through 4.4 are the Watana or Devil Canyon dams of the Upper Susitna project. These alternatives were included and a specific variation of the Present Practices plan was separately assessed.

The principal criteria used for selecting alternatives for consideration in the Present Practices plan included availability of the energy resource, availability and maturity of generating technologies and cost effectiveness. Also considered were the prospective environmental effects of technologies.

Anchorage Load Center

Alternatives available to the Anchorage load center in the near-term (present to 1990) include combustion turbines and combined-cycle plants, firing either fuel oil or natural gas; steam-electric plants, firing coal, fuel oil or natural gas; and the Bradley Lake and Grant Lake hydroelectric projects.

Of the available alternatives, natural gas combined-cycle power plants are the most cost-effective alternative available in the near-term with large potential for capacity expansion (1000MW) relative to the current installed capacity (711 MW) of the Anchorage load center. Natural gas combined-cycle plants are a mature technology currently in use in the Railbelt with flexible operating characteristics (both baseload and load-following operation are feasible) and modest environmental effects. Because of these favorable characteristics and because of the potential need for capacity and energy in advance of or in addition to that potentially provided by the hydro plants available in the near-term, natural gas fixed combined-cycle plants will be considered for use in the Present Practices plan.

Development of natural gas combined-cycle capacity for baseload operation would require an exemption from the Fuels Use Act. If such an exemption cannot be obtained, the next most cost-effective alternative having large developable capacity in comparison with current Railbelt requirements is coal steam-electric plants. Environmental impacts of these plants are more severe than for natural gas-fired facilities; however, mining impacts would likely be incremental only as coal would be supplied from the existing Healy mine, or from Beluga mines opened to supply an export market. Estimated energy costs of coal plants include allowance for emission controls meeting current federal standards. Use of these controls should not result in significant regional impact, although questions remain concerning global effects of CO_2 and residual SO_x emissions.

Alternatives available in the near-term and having greater cost-effectiveness than new natural gas combined-cycle plants include the Bradley Lake and Grant Lake hydro projects. The 90 MW Bradley Lake project has been authorized and will thus be included in the Present Practices plan (as well as the other plans).

The proposed Grant Lake hydro project is a small (7.3 MW) lake-tap project at Grant Lake, north of Seward. The level of Grant Lake would be raised by use of main dams and cofferdams, and the flow of Grant Creek diverted through a conveyance pipe and penstocks to a powerhouse at Trail Lake. The principal environmental impact would be dewatering Grant Creek, destroying the anadromous fishery of this stream. Mitigation potential exists, either by locating the powerhouse on lower Grant Creek or by developing new spawning sites elsewhere. Because of the apparently favorable economics of this project and because mitigation of environmental impacts appears to be possible, consideration of the Grant Lake project in the Present Practices plan is recommended.

Alternatives available to the Anchorage load center in the mid-term (1990 to 2000) include, in addition to the alternatives available in the near-term, light water reactor plants, and several hydroelectric projects (Figure 4.2).

During the first part of the mid-term period, the most cost-effective alternative with large potential for capacity expansion continues to be natural gas-fired combined-cycle plants; however, by 1994, a light water reactor could be in-service with estimated busbar energy cost of 31 mills/kWh (if the output of the plant were fully used).[a] This alternative is not, however, recommended for consideration in the Present Practices plan primarily because the smallest available unit size (800 MW) approximates the current combined capacity of the Anchorage and Fairbanks load centers (926 MW). A single unit of this size would be inappropriate for the Railbelt due to reliability and scheduled outage reserve requirements. In addition, existing Alaska statutes do not permit the use of state funds for promoting of nuclear electric generating plants. For these reasons and because of the general public opposition to the nuclear alternative, further consideration of light water reactors is not recommended.

Alternatives that are more cost effective than natural gas combined-cycle or coal steam-electric plants during the mid-term period include the Chakachamna and Lower Chulitna hydroelectric projects. The proposed Chakachamna project is a transmountain diversion hydroelectric project drawing upon Lake Chakachamna, northwest of Cook Inlet about 85 miles west of Anchorage. Proposed installed capacity ranges from 330 to 480 MW depending upon the minimum flow to be retained in the natural lake outlet stream, the Chakachatna River. The principal environmental impact of the project would be potential disruption or destruction of the anadromous fishery of the Chakachatna River. This impact can be mitigated by retaining Chakachatna flow. This, however, would reduce the capacity and energy available from the project (330 MW capacity/1446 GWh annual firm energy vs. 480 MW/1845 GWh). Because of the potential cost effectiveness of this project and because environmental effects can potentially be lessoned, it is recommended for inclusion in the Present Practices plan.

The Lower Chulitna project is a proposed dam and reservoir hydroelectric project located on the Chulitna River north of Talkeetna. The potential capacity of this project has been estimated as 90 MW, producing 394 GWh annually. Levelized life-cycle costs, based on very preliminary estimates, appear to be competitive with natural gas combined-cycle plants about 1995. Environmental impacts are potentially severe, including blockage of anadromous fish runs of the Chulitna and inclusion of the site within an area considered

(a) See Figure 4.1 for the estimated busbar cost of a natural gas-fired combined-cycle plant.

for wilderness designation. Because of the apparently significant environmental impacts of this project, it is not recommended for consideration in the Present Practices plan.

Alternatives available to the Anchorage load center in the long-term (2000 to 2010) under the Present Practices plan are essentially similar to those available during earlier periods. Coal steam-electric plants remain the most cost-effective option having the potential for large capacity in relation to potential electrical demand. Because of forecasted escalation in coal prices, two additional hydroelectric projects, the Tokichitna project and the Lane project, become more cost effective than coal.

The Tokichitna project is a proposed high dam and reservoir located on the Chulitna River above the Lower Chulitna site. The potential capacity of the site is estimated to be 184 MW with annual firm energy production of 806 GWh. Based on very preliminary information, the busbar energy cost is estimated to be 64 mills/kWh. The principal environmental impact would be blockage of the anadromous fish run of the Chulitna River; in addition, the project borders a primitive area. Because of the potential impact on anadromous fisheries and the insignificant cost advantage compared to coal steam electric plants, this project is not recommended for consideration in the Present Practices plan.

The Lane project is a proposed high dam and reservoir located on the Susitna River north of Talkeetna. The potential capacity of the site is 240 MW with annual firm energy production of 1052 GWh. Estimated busbar energy cost is 65 mills/kWh, based on very preliminary information. The principal environmental effects would be blockage of the anadromous fish runs of this section of the Susitna River. Because of this potential impact, and the insignificant cost advantage of this project compared to coal steam-electric plants, the project is not recommended for inclusion in the Present Practices plan.

By 2000, the existing combustion turbine plant in the Anchorage load center will have reached retirement age. Construction of additional combined-cycle plants and hydroelectric facilities by this time should provide capacity for meeting peak load. If, however, additional peaking capacity is required, or if capacity having short lead time is needed, combustion turbines using natural gas appear to be the most cost-effective demonstrated technology throughout the planning period.

Fairbanks Load Center

The Fairbanks load center is assumed to be electrically interconnected with the Anchorage load center in the assessment of electric energy plans. Moreover, the Fairbanks load center is presently characterized by surplus capacity and high operating costs due to the extensive use of fuel oil for electric power generation. However, additional generating capacity may be required for the Fairbanks load center to meet load requirements in excess of combined intertie and installed capability, or to meet reserve requirements.

Alternatives available to Fairbanks in the near-term include combustion turbine, combined-cycle diesel, electric and steam-electric plants fired with fuel oil and retrofit of existing combustion turbines for combined-cycle operation. North Slope gas may become available as early as 1987 and could be used to fuel combustion turbine, combined-cycle or steam-electric plants. However, as indicated in Figure 4.3, at forecasted prices North Slope gas does not appear to be competitive with continued use of fuel oil. Also available late in the near-term period would be additional steam-electric plants using Nenana coal.

An attractive alternative for obtaining additional power at Fairbanks during the near-term is retrofit of the existing Golden Valley Electric Association North Pole combustion turbines for combined-cycle operation. Busbar power costs of a combined-cycle retrofit to existing combustion turbines are estimated to be 86 mills/kWh in 1990. The incremental environmental impacts of such a plant would be relatively minor. Moreover, the resulting plant could be adapted to natural gas operation if North Slope natural gas prices became competitive with fuel oil. Because of the age of the North Pole turbines, this alternative would not be feasible much beyond 1990.

Additional coal steam-electric capacity based on Nenana (Healy) coal could be brought on-line late in the near-term period. Costs of even a small plant, as shown in Figure 4.3, are more competitive than any other alternative available to Fairbanks, including the combined-cycle retrofit. Construction of the Anchorage-Fairbanks intertie would make larger units feasible, further reducing energy costs. Incremental environmental effects would be minor since the Healy mine is currently in operation, and the plant would include full air emission controls as required by federal standards.

During the mid-term, two hydroelectric alternatives become available to Fairbanks - the Johnson project on the Tanana River and the Browne project on the Nenana River. Neither is economically competitive with the coal steam-electric alternative.

No additional alternatives become available in the long-term, and coal steam electric plants remain as the most cost-effective alternative for Fairbanks.

By 2000, the existing combustion turbine capacity of the Fairbanks load center will have reached retirement age. At this time additional low capital cost capacity may be required for peaking, load-following and reserve applications. The most cost-effective alternative for these applications appears to be diesel-electric units. Consequently, these will be considered in the Present Practices plan.

Glennallen-Valdez Load Center

The Glennallen-Valdez load center may remain electrically independent of the Anchorage load center throughout the planning period. The costs of alternatives available to the Glennallen-Valdez load center are shown in Figure 4.4. Available in the near-term are the Solomon Gulch hydro project (12 MW) (under construction and not plotted in Figure 4.4), distillate oil-fired combustion turbines and diesel-electric plants, and small fuel oil or coal-fired steam-electric plants. The most cost-effective alternative available in the near-term (following the Solomon Gulch project) would be diesel-electric plants.

Alternatives available in the mid- and long-term include the Allison and Silver Lake hydroelectric projects and various alternatives fired by fossil fuels.

The Allison project is a proposed lake-tap hydroelectric project located on Allison Creek near Valdez. Installed capacity would be 8 MW, with an annual firm energy production of 32.2 GWh. Estimated busbar power cost is 58 mills/kWh. The potential impact on the Allison Creek anadromous fishery would be alleviated by tailrace discharge to Allison Creek during critical periods. Because of the cost effectiveness and modest potential environmental impact of this project, it is recommended for consideration in the Present Practices Plan.

The Silver Lake project is a proposed lake-tap hydroelectric project located at Silver Lake near Valdez. This site was selected by Acres American as a potential alternative to the proposed Upper Susitna Project (Acres American 1981b) on the basis of potential environmental impacts (rated "good") and cost. Busbar power costs, based on very preliminary information, were estimated for this study to be 46 mills/kWh, competitive with other options for the Copper River Valley. However, a Corps of Engineers feasibility study of power for the Copper River Valley (USACE 1981) rejected Silver Lake in favor of the Allison hydro project and pressure-reducing turbines on the Trans-Alaska Pipeline descent. Further study of the Silver Lake project within the scope of this project was not believed warranted due to its relatively minor potential contribution in the context of the Railbelt as a whole. Because of the uncertain information available on the Silver Lake project, it was not selected for consideration in the Railbelt electric power plans. Further assessment of the potential role of the Silver Lake project and pressure-reducing turbines within the Copper River load center may be justified.

A summary of the generating alternatives recommended for inclusion in the Present Practices plan is provided in Table 4.1.

4.2 HIGH CONSERVATION AND RENEWABLES PLAN

The candidate alternatives for the High Conservation and Renewables plan ("High Renewables") are those based on geothermal, hydro, biomass, solar, wind and tidal energy resources. The technology for power generation using these resources is well demonstrated for hydro, and less so for biomass, wind, and tidal resources. Technologies for using solar and the hot dry rock geothermal resources that are believed to be characteristic of the Railbelt are in the early stages of development or demonstration. Because the amount of power available at reasonable cost from renewable resources using proven technology (hydro) is relatively finite, cost-effective nonrenewable resources were also considered in the selection set of alternatives for the High Renewables plan.

TABLE 4.1 Alternatives Recommended for Consideration in the Present Practices Plan

Period	Load Center		
	Anchorage	Fairbanks	Glennallen-Valdez
Near-Term (Present-1990)	Grant Lake Hydro	Coal Steam Electric	Solomon Gulch Hydro
	Bradley Lake Hydro	Retrofit Distillate Combined Cycle	Diesel-Electric
	Natural Gas Combined Cycle		
	Coal Steam Electric		
Mid-Term (1990-2000)	Renewable Options not Developed in Near-Term		
	Chakachamna Hydro	Coal Steam Electric	Allison Hydro
	Natural Gas Combined Cycle		
	Coal Steam Electric		Diesel-Electric
Long-Term (2000-2010)	Renewable Options not Developed Earlier	Coal Steam Electric	Allison Hydro[a]
		Diesel-Electric	Diesel-Electric
	Coal Steam Electric		
	Natural Gas Combustion Turbines		

(a) If not developed in the mid-term.

The cost and availability of renewable generating alternatives to the Railbelt is shown in Figures 4.2, 4.5, 4.6 and 4.7. Nonhydro renewables available to the Anchorage load center are shown in Figure 4.5. Also shown in Figure 4.5 are the levelized lifetime costs of natural gas-fired combined-cycle plants - a possible supplement to renewable-based resources in the Anchorage load center if sufficient renewable resources cannot be developed to meet forecasted demand. Shown in Figure 4.2 are the costs of hydroelectric resources available to the Anchorage load center during the planning period. Not shown are the Watana and Devil Canyon dams of the Upper Susitna hydroelectric project, as these alternatives will be included in a variation of the High Conservation and Renewables plan to be separately assessed. Provided in Figure 4.6 are the costs of renewable alternatives available to the Fairbanks load center during the planning period. Finally, Figure 4.7 shows the renewable resources available to the Copper River load center.

In the selection of alternatives for consideration in the High Renewables plan, emphasis is placed upon the renewable character, environmental compatibility and cost effectiveness of alternatives, in accordance with the philosophy underlying this plan. Because of the somewhat limited availability of renewable resources using proven technology on possible future Railbelt electric demand, "backup" alternatives based on nonrenewable resources were also chosen for consideration. These latter alternatives can also typically be brought into service earlier than many of the renewable alternatives and thus could provide power, if needed, in the near-term period prior to the availability of longer lead time renewable alternatives. The primary criteria used for selecting the backup nonrenewable resources were environmental compatibility and cost effectiveness.

Anchorage Load Center

Nonhydroelectric renewables available to the Anchorage load center in the near-term (present to 1990) include small wind energy conversion systems and a steam-electric plant fired by municipal refuse. Hydroelectric alternatives include microhydro plants and the Grant Lake hydro project (Figures 4.5 and 4.6). The 90 MW Bradley Lake hydro project is authorized and will be included in the High Renewables plan.

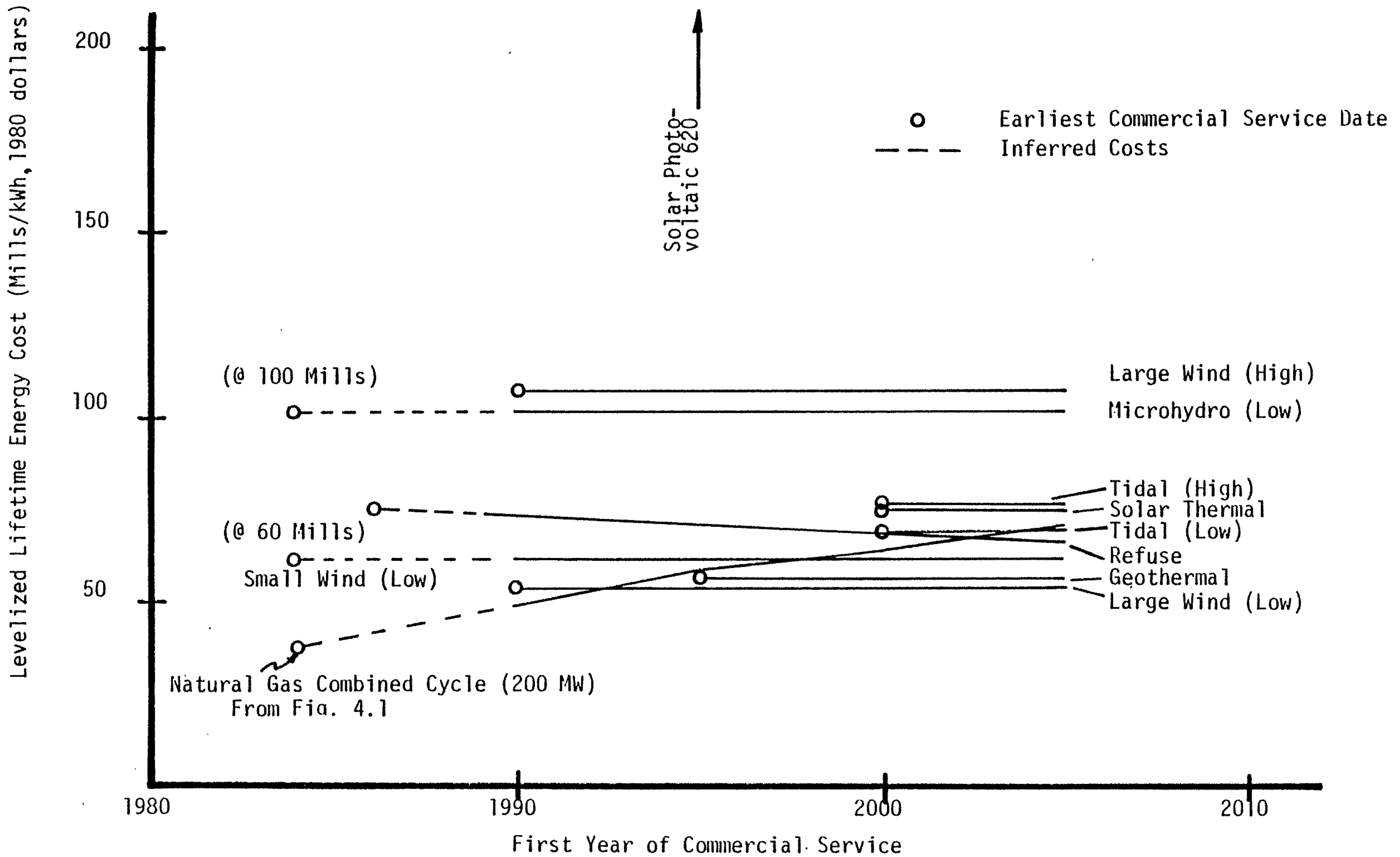

FIGURE 4.5. Cost and Availability of Non-Hydro Renewable Alternatives for the Anchorage Load Center

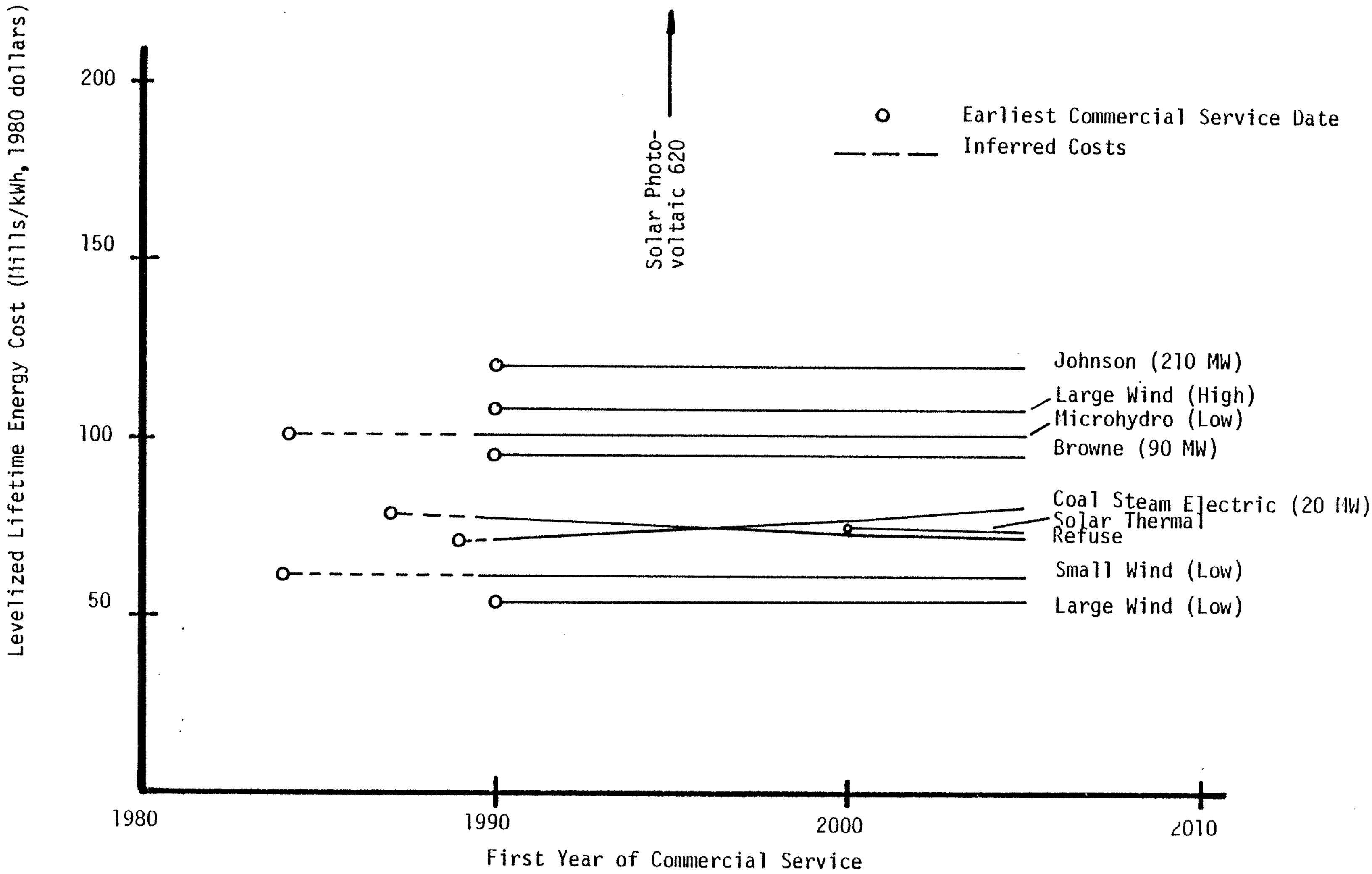

FIGURE 4.6. Cost and Availability of Renewable Alternatives for the Fairbanks Load Center

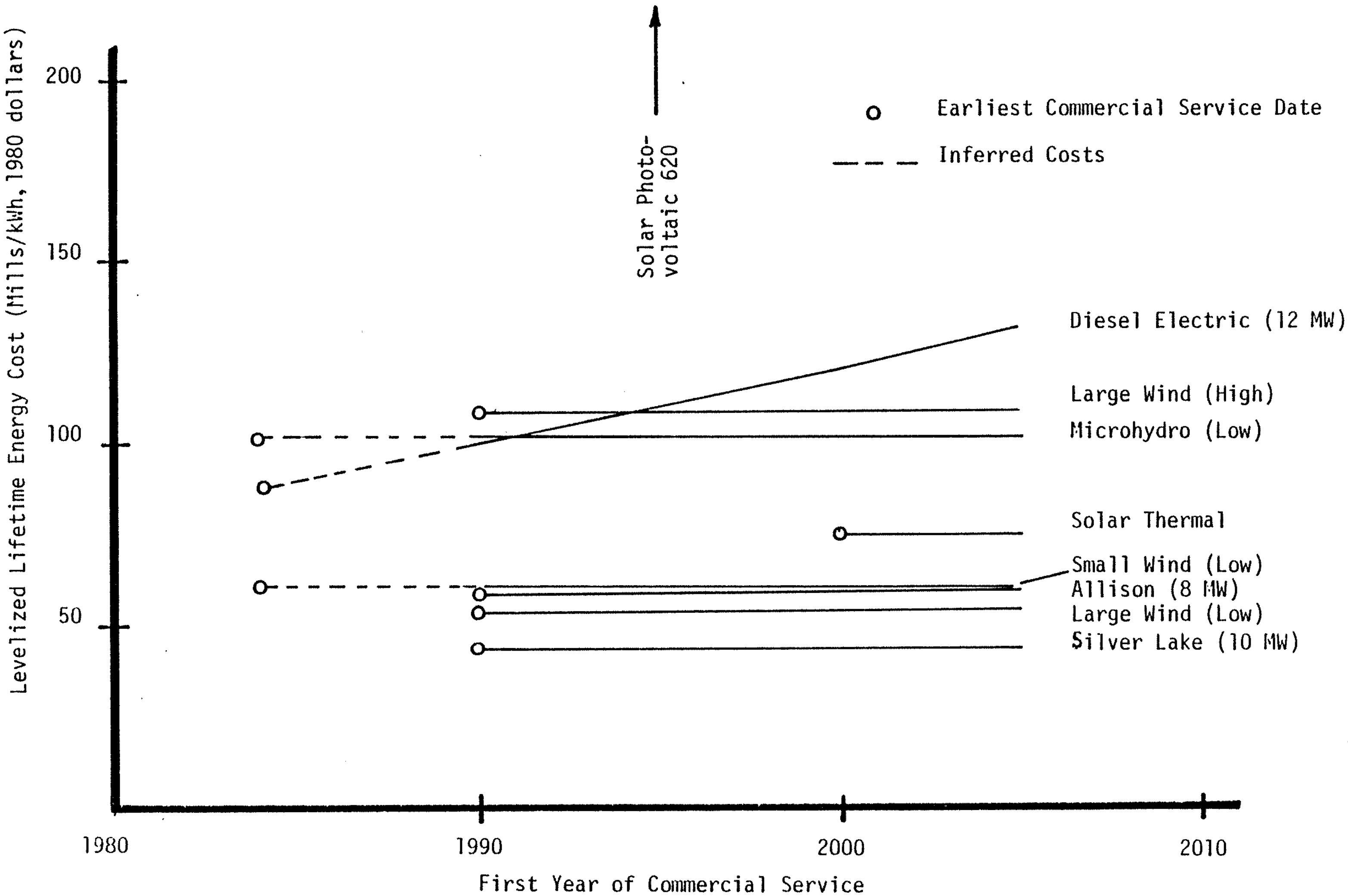

FIGURE 4.7. Cost and Availability of Renewable Alternatives for the Glennallen-Valdez Load Center

The 7.2 MW Grant Lake project, discussed in the preceeding section, is economically competitive with other renewable alternatives and will be included in the High Renewables plan.

No microhydro capacity is anticipated to be available at energy costs less than 100 mills/kWh. Thus, this alternative will not be included in the High Renewables plan. At no point during the planning period does microhydro appear to become competitive with other major sources of energy (Figure 4.5). Further study of the microhydro alternative should receive low priority.

Approximately 28 MW of installed small wind capacity, producing 71 GWh annual energy is estimated to be available in the Anchorage load center. This would be a dispersed resource with development largely dependent upon individual initiative. This would be a significant constraint to development, perhaps limiting penetration of small wind to 10% of potential installations. Because the resulting capacity is less than 5 MW and not significant in the context of overall Railbelt electric energy plans, the potential contribution of small wind was excluded from the High Renewables plan. The more favorable small wind sites, however, appear to become economically competitive with least-cost thermal resources during the 1990s (Figure 4.5). Further study of the potential of this option is therefore recommended.

Sufficient municipal waste is forecasted to be available from the Anchorage metropolitan area to support a steam-electric plant of approximately 50-MW installed capacity producing approximately 285 GWh of energy. Supplemental firing with wood residue and coal would be required until 2010 when forecasted municipal refuse production rates would be sufficient to fully fire a plant of this size. Estimated energy costs (Figure 4.5) decrease over time as supplemental fuel requirements decline; further reduction in energy production costs could be achieved by imposition of refuse tipping fees. Because the estimated costs of power of refuse-fired steam-electric plants lie within the range established for consideration in the High Renewables plan, this alternative will be considered in that plan. Constraints possibly restricting development of this alternative include its cost effectiveness relative to other methods of refuse disposal, operational reliability, public acceptance and atmospheric emissions.

The capacity and energy available from renewable resources selected for the High Renewables plan in the near-term is 147 MW and 619 GWh, respectively. Additional energy may be required. If so, natural gas combined-cycle plants are the most cost-effective nonrenewable alternative available to the Anchorage load center in the near-term. Coal steam-electric plants would be the next most cost-effective thermal option if Fuel Use Act exemptions could not be obtained for baseload application of natural gas.

Renewable alternatives available to the Anchorage load center in the mid-term (1990 to 2000) include (in addition to alternatives available in the near-term) large wind energy conversion systems, solar photovoltaic systems, geothermal, and the Chakachamna, Lower Chulitna, Tokichitna, Lane, Snow, Keetna, Strandline Lake, Browne, Johnson, Tustumena, Bruskasna, Hicks, Tulkeetna II and Cache hydro sites (Figure 4.2).

Large wind energy conversion systems, probably similar to the DOE Mod-2 wind turbines currently being tested at Goodnoe Hills, Washington, could be available for commercial operation in the Railbelt by 1990. A promising wind resource in the area of Isabell Pass south of Big Delta has estimated annual average wind power density of 400 to 2000 watts/m^2 at large wind turbine hub height. Of additional significance is the seasonality of this wind resource. Average wind power is greatest in fall, winter and spring, corresponding with peak electrical load.

Estimated busbar cost of power from large wind turbines ranges from 54 to 100 mills/kWh, depending upon the quality of the wind resource. This cost compares favorably with other renewable (and conventional) alternatives available in 1990 and beyond. However, questions relating to the appropriate capacity credit to be granted wind machines do not make it possible for this cost to be directly compared to the busbar energy cost of alternatives having firm capacity. Because of the promising wind resource of the Railbelt and favorable environmental effects of wind machines, they will be considered in the development of the High Renewables plan. Constraints potentially impacting the development of this alternative include the technology's reliability, especially under cold climate conditions, and its cost effectiveness in the power system context.

If current prospects for future cost reductions in the manufacture of large-scale solar photovoltaic arrays materialize, this alternative will have the potential for producing power at costs competitive with other renewable alternatives, even considering the seasonal limitations on sunlight of Railbelt latitudes. However, current costs of production remain very high (greater than 600 mills/kWh) and the projected cost reductions rely on major breakthroughs in production methods or cell efficiency. Moreover, seasonal correlation of photovoltaic production with load would be unfavorable. Because of the great uncertainty regarding future photovoltaic capital costs, the limited information regarding solar insolation in the Railbelt, and the unfavorable correlation of photovoltaic production with load, this alternative is not recommended for further consideration within the scope of this study. Future study may be warranted if significant reduction in photovoltaic costs materialize.

Geothermal resources possibly suitable for generation of electric power are known to exist near Mt. Drumm in the Wrangell Mountains and at several locations in the Chigmit Mountains. These resources are thought to be hot dry rock resources, although hydrothermal resources may be present. Information on the quantity or quality of these resources is insufficient to support estimates of the amount or cost of power, or the environmental effects likely to result from development of these resources. Because of the lack of information on the resource and the immaturity of hot dry rock technology, the geothermal alternative is not recommended for further consideration in this study. Because the estimated cost of power for geothermal power appears to be potentially competitive with other alternatives, further study of Railbelt geothermal resources is recommended.

Because of its cost effectiveness and potentially modest environmental impacts, the Chakachamna hydroelectric project will be considered in the High Renewables plan. Further discussion of this alternative appears in Section 4.1 of this report.

For reasons discussed in Section 4.1, the Lower Chulitna, Tokichitna and Lane hydroelectric projects are not recommended for consideration in the High Renewables plan.

The Snow project is a proposed high dam and reservoir located on the Snow River north of Seward. Installed capacity would be approximately 50 MW with estimated annual firm energy production of 278 GWh. The project could be in-service in the 1990 to 1995 period. Estimated busbar power costs are 74 mills/kWh. The principal environmental impact would be potential conflict with a proposed ecological reserve at this site. Because of the cost effectiveness of this project relative to other renewable resources and its potentially modest environmental impact, it will be considered in the High Renewables plan.

The Keetna/Talkeetna-II/Cache projects on the Talkeetna River are being considered as a system. The total installed capacity of the three dams would be approximately 200 MW (100 MW for Keetna, and 50 MW each for Cache and Talkeetna II). Annual firm energy production is estimated to be 759 GWh (324 GWh for Keetna, 220 GWh for Cache and 215 GWh for Talkeetna II). These projects could be in-service in the 1990 to 1995 period. Estimated busbar energy costs are 77 mills for Keetna, 179 mills for Cache and 158 mills for Talkeetna II. Environmental impacts could potentially be significant, including blockage of the anadromous fish runs of the Talkeetna River and impacts on primitive lands. It is thought, however, that development of the three sites on one river would result in a more favorable project than equivalent capacity developed on separate streams because of improved economic potential of the integrated project and better downstream regulation (Acres American 1981b). The most cost effective of the three sites, Keetna, was selected for consideration in the High Renewables plan. Additional capacity, if needed, could be obtained at little environmental impact by developing the remaining two sites.

The proposed Strandline Lake project would consist of a diversion structure and powerhouse located on the Beluga River northeast of Cook Inlet. Installed capacity would be 20 MW and annual firm energy production would be 81 GWh. Estimated busbar power costs are 94 mills/kWh. The potential environmental impact of this project appears to be minor, consisting principally of possible effects upon scenic and primitive lands. Because of energy costs within the 100 mill constraint established for the High Renewables plan and because of potentially minor environmental effects, Strandline Lake was selected for consideration in the High Renewables plan.

The Browne project is a proposed dam and reservoir on the Nenana River north of Healy. Installed capacity would be approximately 100 MW, annual firm energy 385 GWh. Estimated busbar energy cost is 95 mills/kWh. Potential environmental impacts appear to be minor. Delivery of energy from this project to the Anchorage load center would require completion of the Anchorage-Fairbanks intertie. This project was selected for consideration in the High Renewables plan due to its potentially modest environmental impact, fair cost-effectiveness and location near the Fairbanks load center.

The four remaining hydroelectric projects, Johnson, Tustumena, Bruskasna, and Hicks have estimated energy costs significantly higher than the 100 mills/kWh cutoff chosen for the High Renewables plan. Additional power, if required, could be supplied by natural gas-based thermal resources.

Additional renewable resources becoming available to the Anchorage load center in the long-term (2000 to 2010) include Cook Inlet tidal and solar thermal.

A variety of tidal-electric power plants for Cook Inlet were assessed in the Acres American study of this resource (Acres American 1981a). One site, Eagle Bay, was recommended for further study. Two site designs were proposed, one of 720-MW installed capacity producing 2050 GWh annual energy (with re-timing), and one of 1440-MW installed capacity producing 3200 GWh of annual energy (with retiming). Estimated energy costs are 70 mills/kWh for the smaller facility and 73 mills/kWh for the larger facility. The facility could greatly affect the tidal patterns and marine ecology of Knik Arm. Because of the current interest in this alternative, the Cook Inlet Tidal project was considered in the High Renewables plan

Forecasted production costs of solar-thermal plants are competitive with other renewable resources. Energy production from these plants would be intermittant unless energy storage were provided. In addition,coincidence of seasonal production to load is poor for the Railbelt. For these reasons and because of current uncertainty regarding the cost, availability and performance of solar-thermal plants, this alternative was not considered.

The Fairbanks Load Center

Renewable alternatives available to the Fairbanks load center are shown in Figure 4.6. Where available, renewable alternatives chosen for the Anchorage load center were also selected for the Fairbanks load center. These included large wind energy conversion systems, refuse-fired steam-electric plants, and the Browne hydroelectric project. No microhydro power appears to be available at costs less than 100 mills/kWh, and small wind potential at 100 mills/kWh or less is less than one MW, assuming a 10% penetration. These alternatives were consequently not included. If demand is greater than available renewable resources, retrofit of the North Pole combustion turbines for combined-cycle operation, followed by coal steam-electric plants, are the most cost-effective options for Fairbanks.[a] Additional peaking or reserve requirements would be met by most cost effectively using diesel-electric plants.

Glennallen-Valdez Load Center

With the exception of large wind energy systems, the alternatives available to the Glennallen-Valdez load center for the High Renewables plan are those available for the Present Practices plan (Figure 4.7).

A summary of the generating alternatives recommended for inclusion in the High Renewables plan is provided in Table 4.2.

4.3 THE HIGH COAL PLAN ALTERNATIVES

Because of the abundance of the coal resource, its potential for development for export markets, the forecasted relatively low cost of fuel on a Btu basis and the prospects for substantial improvement in operational flexibility and environmental characteristics of coal-based technologies, examining the possibility of emphasizing coal use for future electric power development in the Railbelt was thought to be appropriate.

In the selection of alternatives for the High Coal plan, emphasis was placed upon the use of coal or peat resources, cost effectiveness, and adoption of advanced coal combustion technologies promising fewer environmental effects

(a) The combustion turbine retrofit would likely not be feasible after 1990 due to the age of the North Pole units.

TABLE 4.2 Summary of Alternatives Recommended for Consideration in the High Conservation and Renewables Plan

Period	Load Center		
	Anchorage	Fairbanks	Glennallen-Valdez
Near-Term (Present-1990)	Grant Lake Hydro Bradley Lake Hydro Natural Gas Combined-Cycle Coal Steam-Electric	Retrofit Distillate Combined-Cycle Coal Steam-Electric Refuse Steam-Electric	Solomon Gulch Hydro Diesel-Electric
Mid-Term (1990-2000)	Renewable Options not Developed in Near-Term Chakachamna Hydro Large Wind Snow Hydro Keetna Hydro Strandline Lake Hydro Browne Hydro Natural Gas Combined-Cycle Coal Steam-Electric	Renewable Options not Developed in Near-Term Browne Hydro Large Wind Coal Steam-Electric	Allison Hydro Large Wind Diesel-Electric
Long-Term (2000-2010)	Renewable Options not Developed Earlier Cook Inlet Tidal Coal Steam-Electric	Renewable Options not Developed Earlier Coal Steam-Electric Diesel-Electric	Renewable Options not Developed Earlier Diesel-Electric

and greater operating flexibility than conventional coal-based technologies. Using advanced coal-based technologies may lesson concern for the environmental effects of coal use expressed in the opinion surveys conducted in conjunction with this study (Volume X). Additional benefit may be gained from the increased operating flexibility promised by technologies using coal gasification. These alternatives may provide load-following characteristics superior to conventional coal steam-electric plants, reducing or eliminating the need for natural gas or distillate-fired combustion turbine or diesel load-following units.

Incorporating advanced technologies into the High Coal plan introduces uncertainty relative to the availability of these technologies for commercial order. Therefore, the technologies currently available to meet forecasted demand should be considered in case the availability of advanced technologies does not materialize as forecasted.

The High Coal plan most likely will rely upon alternatives selected for the Present Practices plan for the near-term (Present to 1990), primarily due to the long lead time requirements for coal-based technology. The only coal-based option potentially available prior to 1990 would be conventional coal-fired steam-electric plants. Given a 1982 decision to proceed, this type of plant could be in commercial service by 1989.

Other coal-based options, currently under development, could become available in the mid-term (1990 to 2000). These include coal gasifier combined-cycle plants (1990) and coal gasifier fuel cell combined-cycle plants (1994). Peat-based alternatives were also considered for the "High Coal" plan. Most advanced are direct-fired steam-electric plants using peat as fuel. This type of plant is in commercial service in Europe and the Soviet Union and could be available for commercial operation in the Railbelt by 1990.

No additional coal-based generation technologies are expected to become available for commercial operation during the long-term period (2000 to 2010).

Anchorage Load Center

The estimated energy costs and time of availability of alternatives available to the Anchorage and the Fairbanks load centers for the High Coal plan are shown in Figure 4.8. With the exception of coal steam-electric plants, the costs shown are based on use of Nenana coal. If Beluga coal becomes available, energy costs would be two to three mills/kW lower, as evidenced by the cost curves for coal steam-electric plants. Note that estimated costs for coal gasifier combined-cycle plants and coal gasifier fuel cell combined-cycle plants are essentially identical. The gasifier combined-cycle plant, however, should become available for service in 1991, five years prior to the gasifier fuel cell combined-cycle alternative.

Coal steam-electric is the only coal-based alternative available to the Anchorage load center in the near-term period. If additional resources are required prior to the 1989 earliest availability of new coal-steam electric capacity, the noncoal alternatives selected for the Present Practices plan are recommended for consideration in the High Coal plan. These include the Bradley Lake and Grant Lake hydro projects and natural gas fired combined-cycle plants (see Section 4.1 for discussion of these alternatives). These noncoal alternatives would also provide good load-following characteristics complementary to coal-steam plants.

If coal is emphasized as a primary energy resource, coal steam-electric plants most likely will be considerably larger than those currently in use in the Railbelt, perhaps 200 MWe in rated capacity. Operation would be baseload. The Nenana or Beluga fields would be the most likely source of coal; plant sites would be mine mouth if Beluga coal is used or along the Alaska Railroad if Nenana coal is used. Location of a large plant at Healy may not be feasible because of the proximity of the Denali National Park Class 1 nondegradation area. Because the coal steam-electric alternative is the sole coal-fired alternative available prior to the 1990 to 1995 period and because estimated power costs are competitive in comparison with other technologies available during this period (see Table 4.2), this alternative was considered in the High Coal plan.

Becoming available in the mid-term would be coal gasifier combined-cycle plants, coal gasifier fuel cell combined-cycle plants and peat-fired steam-electric plants.

Coal gasification combined-cycle plants would use low or medium Btu synthesis gas obtained from coal gasification to drive an integrated combustion

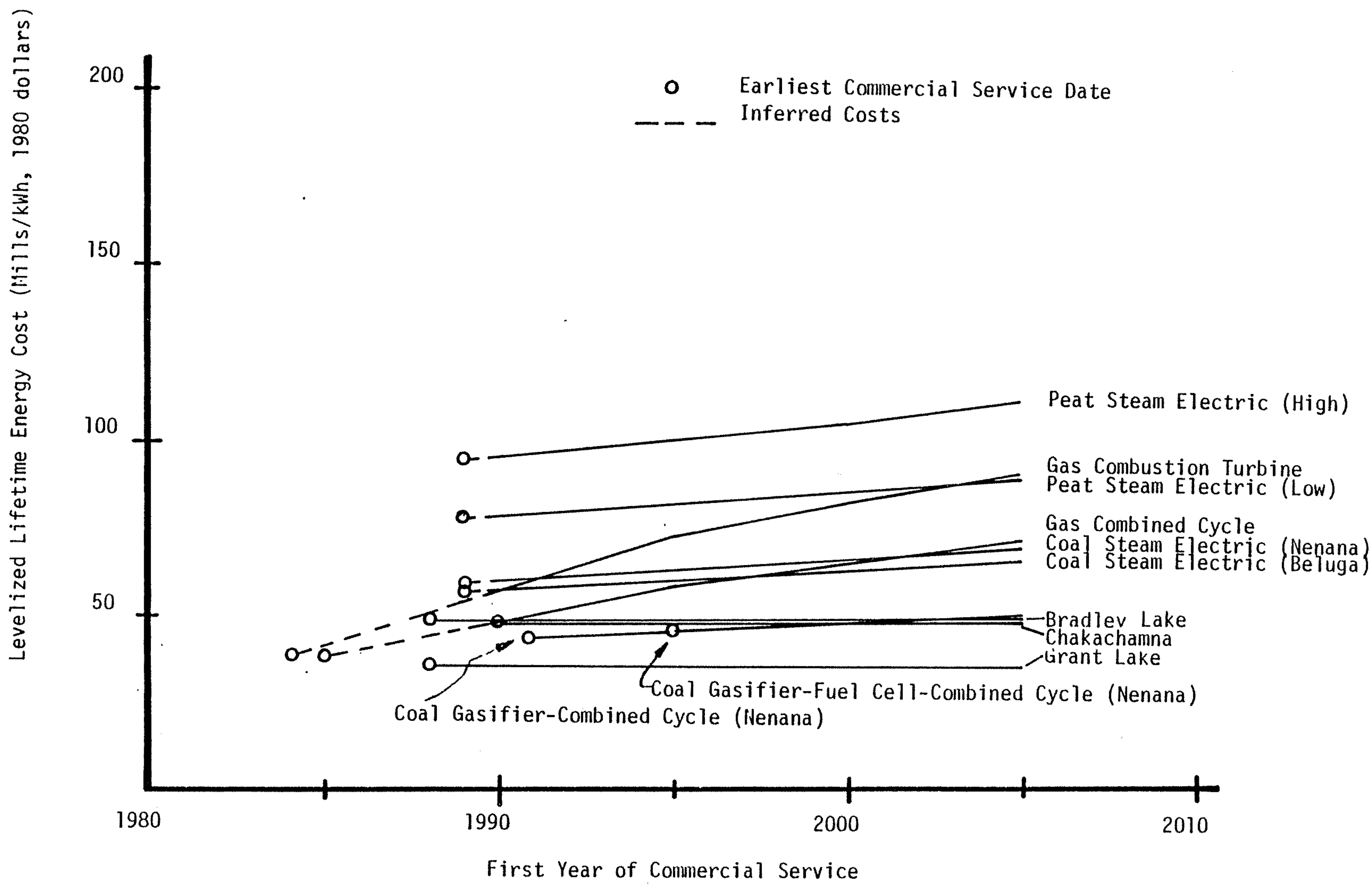

FIGURE 4.8. Cost and Availability of High Coal Plan for the Anchorage/Fairbanks Load Center

turbine combined-cycle plant. These plants would use either Beluga or Nenana coal and would likely be located at mine mouth if Beluga coal is used or along the Alaska Railroad if Nenana coal is used. A Cook Inlet location would be preferred if surplus synthesis gas were to be converted into an exportable energy product, such as methanol. Surplus production from an Interior plant might be used to produce a synthetic natural gas for space heating. Plant sizes would likely be 200 MWe or larger. Several gasification processes are currently under development, including Lurgi fixed bed, British Gas Corporation (BGC) slagger, Texaco pressurized slurry feed and Combustion Engineering atmospheric-pressure entrained flow. Recent studies sponsored by EPRI have indicated that gasifier combined-cycle units might function satisfactorily as load-following units. Entrained flow gasifiers appear to be particularly suitable for load-following duty.

Gasification-based power plants offer environmental advantages in comparison with conventional direct-fired steam-electric plants. Sulfur and particulate removal occurs in the product gas stream - a more benign environment than that faced by flue gas cleanup processes. This allows for more effective and less costly cleanup and results in a cleaner exhaust gas. Heat rejection is lower than for steam-electric plants because of the lower heat rates of combined-cycle plants.

Because of the favorable cost of power estimates, flexibility, and superior operational environmental characteristics potentially offered by integrated gasifier combined-cycle plants, this alternative was considered in the High Coal plan.

The coal gasifier fuel cell combined-cycle plant would consist of coal gasifiers integrated with molten carbonate fuel cells. Reject heat would be captured in waste heat recovery boilers. Because the fuel cell is an electrochemical energy conversion device, it is free from the thermodynamic limitations of the Carnot cycle. Moreover, because "combustion" is limited to the oxidation of hydrogen, the cells produce no oxides of nitrogen. Potential advantages of fuel cell use include enhanced conversion efficiency and reduced environmental emissions.

The fuel cells contemplated in this alternative are of the molten carbonate type, a design that operates at higher temperatures (600 to 800°C) than phosphoric acid cells (70 to 175^{o}C). The elevated temperature regime of the molten carbonate cells should allow the coupling of waste heat boilers to the fuel cell section of the plant, further increasing overall conversion efficiency and reducing heat rejection requirements. Anticipated heat rates of these plants are about 7100 Btu/kWh, compared to rates of 7900 to 8500 Btu/kWh for "conventional" integrated gasifier combined-cycle plants. Molten carbonate cells are in an early stage of development, and the availability of plants using these cells for commercial operation is not anticipated until the mid 1990s. Current versions of molten carbonate fuel cells are susceptable to damage from thermal cycling. This may limit power plants using molten carbonate fuel cells for baseload operation.

Despite the favorable heat rates forecasted for coal gasifier combined-cycle power plants, the estimated electric energy costs for these plants do not appear to be significantly lower than for the integrated gasifier combined-cycle plant described above. This is due to the relatively low cost of Railbelt coal and the greater capital costs forecast for gasifier fuel cell combined-cycle plants. Coal gasifier fuel cell combined-cycle plants are not recommended for further consideration because of the lack of clear cost-of-power advantages, relatively minor environmental advantages and more limited operational flexibility in comparison with coal gasifier combined-cycle power plants in the High Coal plan.

In the United States, peat lands are estimated to cover 52.6 million acres, making the United States second only to the Soviet Union in peat land area. Approximately 51% of the U.S. resources are located in Alaska. The characteristics and extent of fuel-grade peat resources are, however, poorly understood at present and have only recently begun to be investigated. The better peat resources appear to be located in the Anchorage load center.

Peat can be used to generate electricity either by direct-firing in steam-electric plants or by gasification and firing in combined-cycle plants. Direct-fired steam-electric plants using peat as fuel could be available for commercial operation in the Railbelt as early as 1990.

Although the quantity of fuel-grade peat in the Railbelt is not presently defined, it appears that sufficient resources are present to support electric energy generation. At current costs, however, peat-based generation does not appear to be cost competitive with coal (Figure 4.3). For this reason, and because the quantity of available peat resource and processing requirements are not well-understood, peat-based generation was included in the Railbelt electric energy plans. However, because a substantial peat resource capable of supporting electric power generation appears to be present within the Railbelt, this resource should be explored further.

The Chakachamna hydroelectric project becomes cost competitive with conventional coal steam electric plants in the mid-term and is recommended for development if the more cost-effective advanced coal-based technologies do not become available for commercial order as anticipated.

Additional coal-based electric power generation options beyond those discussed above are not expected to become available for commercial application in the Railbelt in the long-term period. The Chakachamna hydroelectric project becomes cost competitive with advanced coal-based technologies in the long-term and is recommended for development at this time if not developed earlier.

Sufficient combustion turbine capacity from existing turbines will be available until well into the mid-term period to provide peak load-following complementary to baseload coal plants. Following the retirement of existing combustion turbines, load following could be provided by new natural gas combustion turbines, hydro, or coal gasifier combined-cycle plants. The capital costs of the latter may be sufficiently great to warrant baseload application only. If these advanced technologies do not become available for commercial order as expected, natural gas combustion turbines could provide load following, peaking and reserve capacity.

Fairbanks Load Center

The coal-based alternatives available to the Fairbanks load center are essentially the same as those available to the Anchorage load center. Nenana coal would be used in lieu of Beluga coal, resulting in slightly higher busbar energy costs (Figure 4.7). Construction of the Anchorage-Fairbanks intertie is assumed, allowing construction of plants in the 200-MW unit size range. Peat is found in the Fairbanks-Tanana Valley area. The quality and quantity of the resource is poorly understood but appears to be inferior to the peat resources of the Anchorage-Cook Inlet area.

Because of the current surplus of capacity in the Fairbanks load center, it is unlikely that additional capacity would be required prior to the 1989 availability of new coal capacity. Should new capacity be required prior to this time, alternatives similar to those selected for the Present Practices plan (Section 4.1) would be appropriate. These include distillate combined-cycle retrofit and diesel-electric. Load-following, peaking and reserve capacity requirements in the mid-term and long-term appear to be most economically met by diesel units (Section 4.1).

Glennallen-Valdez Load Center

Coal resources, although present near the Glennallen-Valdez area, are more limited and inferior to those of the Beluga and Nenana fields. Coal, if used for electric power generation would likely be imported from one of these fields, resulting in energy costs substantially greater than for competing alternatives (Figure 4.4). Electrical demand in this load center is insufficient to support more advanced and efficient coal conversion technologies. The peat resource of the area is insufficiently known to permit estimates to be made of availability and cost of peat-based electricity generation. Therefore, the High Coal alternatives recommended for the Copper River Valley load center are those selected for the Present Practices plan. Additional investigation of the peat resources of the area might be desirable to establish the potential for electric power generation.

A summary of the generating alternatives recommended for inclusion in the High Coal plan is provided in Table 4.3.

4.4 HIGH NATURAL GAS

Natural gas is used to fuel 655 MW of the 983 MW of generating capacity presently installed in the Railbelt (Volume VI). All gas-fired capacity is located in the Cook Inlet area, as gas is not presently available to the Fairbanks or to the Copper River Valley load centers.

Where available, natural gas has been an economical choice for power generation. Supplies have been abundant and prices low, largely due to limited natural gas export capability. Environmentally, as well as economically, gas has proven to be an attractive resource for electric power production.

TABLE 4.3 Alternatives Recommended for Inclusion in the High Coal Plan

Period	Load Center		
	Anchorage	Fairbanks	Glennallen-Valdez
Near-Term (Present-1990)	Grant Lake Hydro Bradley Lake Hydro Natural Gas Combined-Cycle Coal Steam-Electric	Coal Steam-Electric Retrofit Distillate Combined-Cycle	Solomon Gulch Hydro Diesel-Electric
Mid-Term (1990-2000)	Hydro Alternatives not Developed in Near-Term Coal Steam Electric Coal Gasifier - Combined-Cycle Chakachamna Hydro	Coal Steam-Electric Coal Gasifier Combined-Cycle	Allison Hydro Diesel Electric
Long-Term (2000-2010)	Hydro Alternatives not Developed Earlier Coal Steam-Electric Natural Gas Combustion Turbines	Coal Steam-Electric Coal Gasifier Combined-Cycle Diesel-Electric	Allison Hydro[a] Diesel Electric

(a) If not developed in the mid-term.

Extraction of the resource produces few environmental effects; air emissions are low in compounds of sulfur and particulates; and water consumption of the combustion turbines and combined-cycle units predominately used for electric power production is typically low. The combined-cycle technology currently used for electricity production using natural gas is mature, inexpensive, reliable and efficient.

Because of the compelling economic, technical and environmental characteristics of electric power generation using natural gas, it was thought appropriate to develop a Railbelt electric energy plan based on continued reliance upon this energy resource. Additional motivation for a natural gas plan included the generally favorable public perception of natural gas-based electricity generation (Volume X) and the prospect of future availability of emerging and advanced generating alternatives using natural gas, which promise efficiencies and environmental effects superior to technologies currently in use.

Continued use of natural gas for electric power generation is not without potential problems. Principal among these is the future availability and price of gas. Natural gas prices have traditionally been low and supplies abundant in the Cook Inlet area, chiefly due to the lack of a significant export market. However, without additional discoveries, the availability of Cook Inlet reserves will be constrained within the planning period (Volume VII). To forestall future price increases and constraints on gas availability, proposals have been advanced for state purchase of a block of Cook Inlet gas reserves to ensure continued availability of gas for electricity production and direct heating applications.

Ultimately, and perhaps within the planning period, a shift to other resources for electricity generation would be required. At this time two options are available: 1) development of conventional and advanced technologies based on renewable resources, or 2) development of conventional and advanced technologies based on the use of coal or peat. These options are represented by the High Renewables and High Coal plans, respectively. A High Natural Gas plan may thus be viewed as an interim plan, ultimately leading to an energy plan based on resources of greater availability. However, the High Natural Gas plan may be the option of least environmental and economic cost as advanced renewable or coal-based technologies of superior economic and environmental characteristics are developed.

A second factor impacting a "High Natural Gas" electric energy plan is geographic restrictions on natural gas availability. The resource is currently found in Cook Inlet and on the North Slope. A distribution system provides Cook Inlet gas to the Anchorage metropolitan area; however, Cook Inlet gas is not available to the Fairbanks or to the Copper River Valley load centers. The proposed North Slope natural gas pipeline, primarily intended to transport North Slope gas to the Lower 48 States, would pass through the Tanana Valley, making gas available to the Fairbanks load center. Unlike the Trans-Alaska pipeline, the gas pipeline would continue southeast along the Alaska highway and would not enter the Copper River Valley. Pipeline gas is likely to remain unavailable to the Copper River Valley during the planning period.

The North Slope gas pipeline may be completed to Fairbanks as early as 1987. Fairbanks gas prices, however, are forecasted to be substantially greater than distillate on an equivalent Btu basis (Volume VII). Since similar technologies are used to generate electricity with the two fuels, distillate would continue to be the cost-effective fuel choice at Fairbanks. The estimated future cost of either distillate or natural gas-based generation at Fairbanks is sufficiently higher than natural gas generation at Anchorage to suggest that natural gas-based electricity could be most cost effectively supplied to Fairbanks via the proposed Anchorage-Fairbanks, intertie. The High Natural Gas plan will thus focus on continued use of gas at Anchorage, transmission of gas-based electricity from Anchorage to Fairbanks,and use of the most cost-effective available alternatives in the Copper River Valley. Emphasis will be placed on emerging and advanced technologies promising enhanced conversion efficiencies of available natural gas supplies. With the exception of coal, nonnatural gas technologies will be incorporated where cost effective.

The final factor impacting the High Natural Gas plan is the constraint upon natural gas usage for electricity generation presented by the Fuels Use Act. Exemption to the Act may be available, as discussed in Volumes I and IV.

Anchorage Load Center

"Conventional" natural gas alternatives available in the Anchorage load center in the near-term (present to 1990) include combustion turbines, combined-cycle plants, and steam-electric power plants. Advanced technologies using natural gas include fuel cells and cogeneration steam topping plants. Economically competitive hydro alternatives include the Grant Lake, Chakachamna and Bradley Lake projects (Figure 4.9).

Natural gas combined-cycle plants are the least cost, mature technology offering the potential for large-scale, near-term capacity expansion relative to the Railbelt demand. Due to modular design, combined-cycle plants also offer the flexibility of operation under all load conditions plus high reliability. This alternative thus establishes the upper bound of cost effectiveness in the near-term. Alternatives of equal or greater potential for cost effectiveness in the near-term include cogeneration, fuel cell stations and the Grant Lake hydro project.

Although not as cost effective in the near-term as natural gas combined-cycle plants, construction of the Bradley Lake hydro project has been authorized; hence, Bradley Lake will be included in the High Natural Gas plan.

Where opportunity exists for use of by-product steam, natural gas-fired cogeneration plants are the most cost-effective alternatives in the near-term. The estimated energy costs shown in Figure 4.9 are based on a steam topping cycle. This type of plant would consist of a natural gas-fired boiler producing steam used to drive a steam turbine-generator. Exhaust steam from the turbine, rather than being condensed as in a conventional steam-electric power plant, is used for process or space heating. Other cogeneration plant configurations include combustion turbine and diesel generation topping cycles and in the future, perhaps fuel cell topping plants. The configuration selected depends upon specific applications. While steam topping cycles are suited for many industrial applications, diesel-electric plants may be better suited for building cogeneration installations.

Because of its apparent cost effectiveness well into the mid-term (Figure 4.9), natural gas-based cogeneration is recommended for consideration for the High Natural Gas plan. The industrial, commercial and multifamily residential end-use sectors each offer potential opportunities for cogeneration

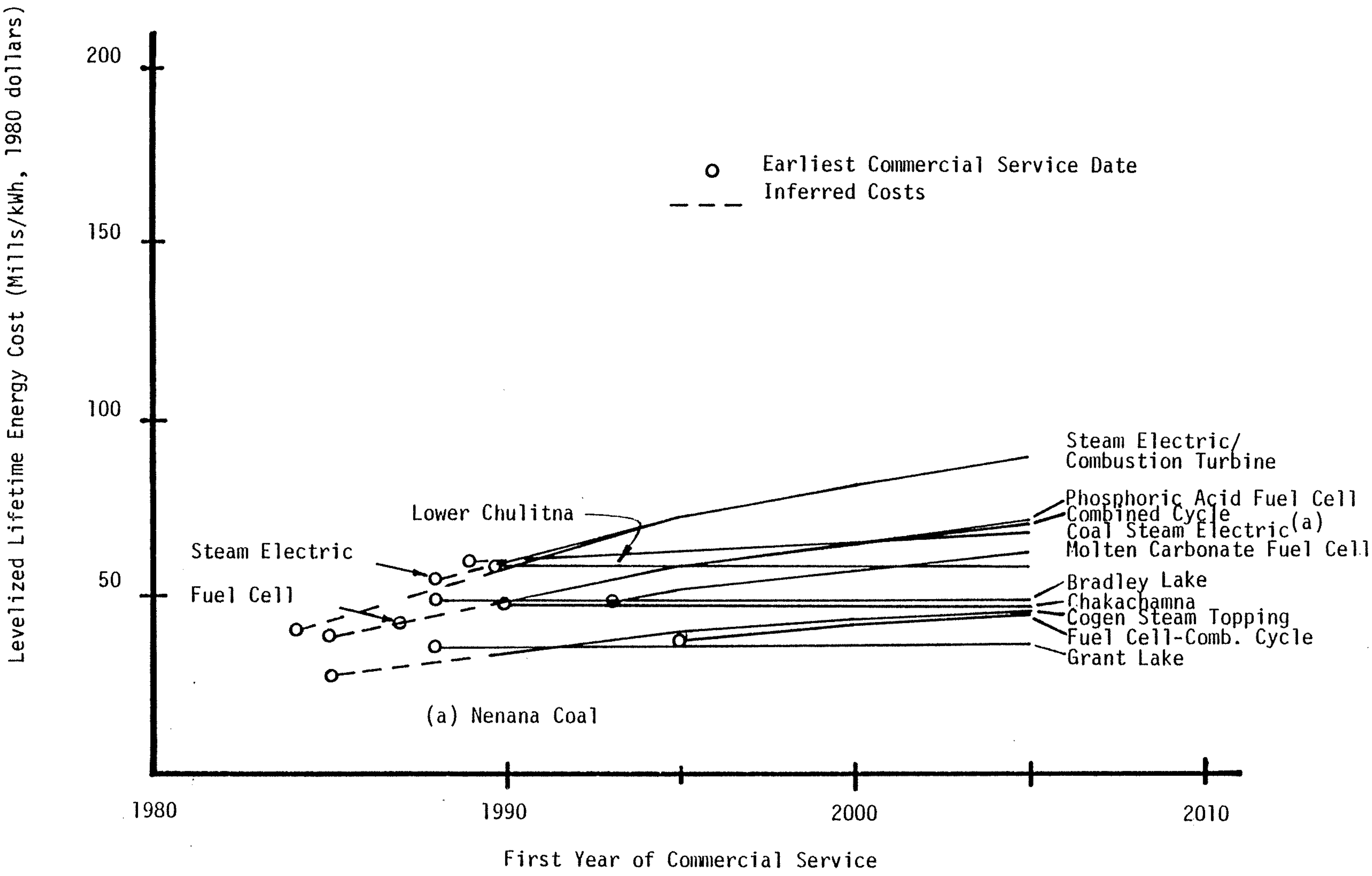

FIGURE 4.9. Cost and Availability of Conventional and Advanced Natural Gas Alternatives for the Anchorage Load Center

applications. This potential is, however, imperfectly understood at present. Because of the diversity of potential applications and potential sponsors, cogeneration costs are only approximated by the estimates depicted in Figure 4.9. It is likely, moreover, that much cogeneration would be developed under provision of PURPA, resulting in a cost equivalent to the avoided power cost. Because of these uncertainties, this alternative was not specifically incorporated into the High Natural Gas plan. Because of its apparent cost effectiveness in comparison with all but the lowest cost hydro alternatives, it is recommended that the potential for cogeneration receive further study.

Fuel cell stations based on the use of phosphoric acid fuel cells are an emerging technology forecasted to become generally available for commercial order about 1984, with subsequent availability for commercial service in 1987. Demonstration units are currently undergoing testing for both cogeneration and noncogeneration applications. The costs of Figure 4.9 are predicated on the production of commercial quantities of fuel cells. Whether these production levels will be achieved in the near-term is uncertain. The low energy production costs of fuel cells are attributable to forecasted low capital costs and high conversion efficiency. In addition to these attributes, the fuel cell stations should have highly desirable environmental qualities and short design and construction lead time. 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. For these reasons fuel cell stations were considered in the High Natural Gas plan.

The 7-MW Grant Lake hydro project (described in Section 4.1) is anticipated to produce power at lower cost than the most cost-effective natural gas alternatives having large-scale capability for expansion (combined-cycle plants and fuel cells) and therefore was considered in the High Natural Gas plan.

Combined-cycle plants remain the most cost-effective currently mature natural gas-based alternative in the mid-term (1990 to 2000). New alternatives of equal or greater cost effectiveness during this period include molten carbonate fuel cell stations, fuel cell combined-cycle plants, and the Chakachamna hydro project. The Lower Chulitna project, though economically competitive with natural gas combined-cycle plants during this period, is not included in the High Natural Gas plan because of its potential impact upon anadromous fisheries.

Molten carbonate fuel cells are a second generation fuel cell, currently in an earlier stage of development than the phosphoric acid cell. The molten carbonate cell will offer a higher conversion efficiency than the phosphoric acid cell and will likely supersede use of the phosphoric acid cell except for load-following applications for which the phosphoric acid cell appears to be better[a] suited. In addition to having a higher conversion efficiency than phosphoric acid cells, the molten carbonate cell operates at much higher temperatures. Reject heat could be used to raise steam in heat recovery boilers to drive steam turbine-generators. The resulting fuel cell combined-cycle plant could operate at efficiencies of nearly 60%. Limited natural gas supplies would be more efficiently used and energy costs lowered, depending upon the capital costs of the fuel cell combined-cycle plant.

Fuel cell stations using molten carbonate fuel cells are anticipated to become available for commercial service about 1993. Because the capital costs of the two types of cells are expected to be similar, and the efficiencies of molten carbonate cells higher, the molten carbonate cells most likely would supersede the phosphoric acid cells except in applications involving frequent changes in load.

Because molten carbonate cells operate at a much higher temperature than phosphoric acid cells, they appear to be suitable for operation as the topping cycle of a combined-cycle plant. Heat recovery boilers and steam turbines would comprise the bottoming cycle. Combined plant efficiencies as high as 60% are expected to result in lower costs of power, if capital costs are comparable. Natural gas supplies would also be significantly extended. These plants should exhibit very favorable environmental characteristics because the by-products of operation would be only CO_2 and water. Given a 1990

(a) The molten carbonate cells appear to be subject to damage under cycling conditions.

availability for order, such plants may be in operation by 1995. Because of their early stage of development, the costs of these plants are not well understood at present; however, because of their potentially attractive economic and environmental character, natural gas, fuel cell combined-cycle plants were considered in the High Natural Gas plan.

The Chakachamna hydroelectric project could be available for service by 1990. It is economically competitive with natural gas alternatives available at this time, although less cost effective than fuel cell combined-cycle plants forecasted to becoming available in 1995. Because it is economically competitive with natural gas combined-cycle plants, it was considered in the High Natural Gas plan.

Additional natural gas technologies are not foreseen as becoming available in the long-term period (2000-2010). Limitations on the availability of natural gas at this time may require development of renewable or coal resource-based generation as in the High Renewables or High Coal plans.

Fairbanks Load Center

The cost and availability of natural gas resources for the Fairbanks load center are shown in Figure 4.10. Available natural gas-fired options using mature technology include combined-cycle plants, steam-electric plants and combustion turbines. Options using advanced technology include phosphoric acid and molten carbonate fuel cells and fuel cell combined-cycle plants. Also included in Figure 4.10 is the Browne hydro project, which becomes cost competitive with the most cost-effective North Slope natural gas alternative (fuel cell combined-cycle plants) in the long-term period. Shown in Figure 4.10 for comparative purposes are the cost and availability information for distillate combined-cycle plants and combined-cycle plants fired with Cook Inlet natural gas.

Because of persistently lower forecasts of distillate prices on equivalent Btu basis, at no point during the planning period do alternatives fired by North Slope natural gas appear to be cost effective with equivalent technologies supplied by distillate. For example, the costs of equivalent combined-cycle plants fired by distillate oil and by North Slope gas are plotted in Figure 4.10. Costs of the natural gas plant are about 16% greater

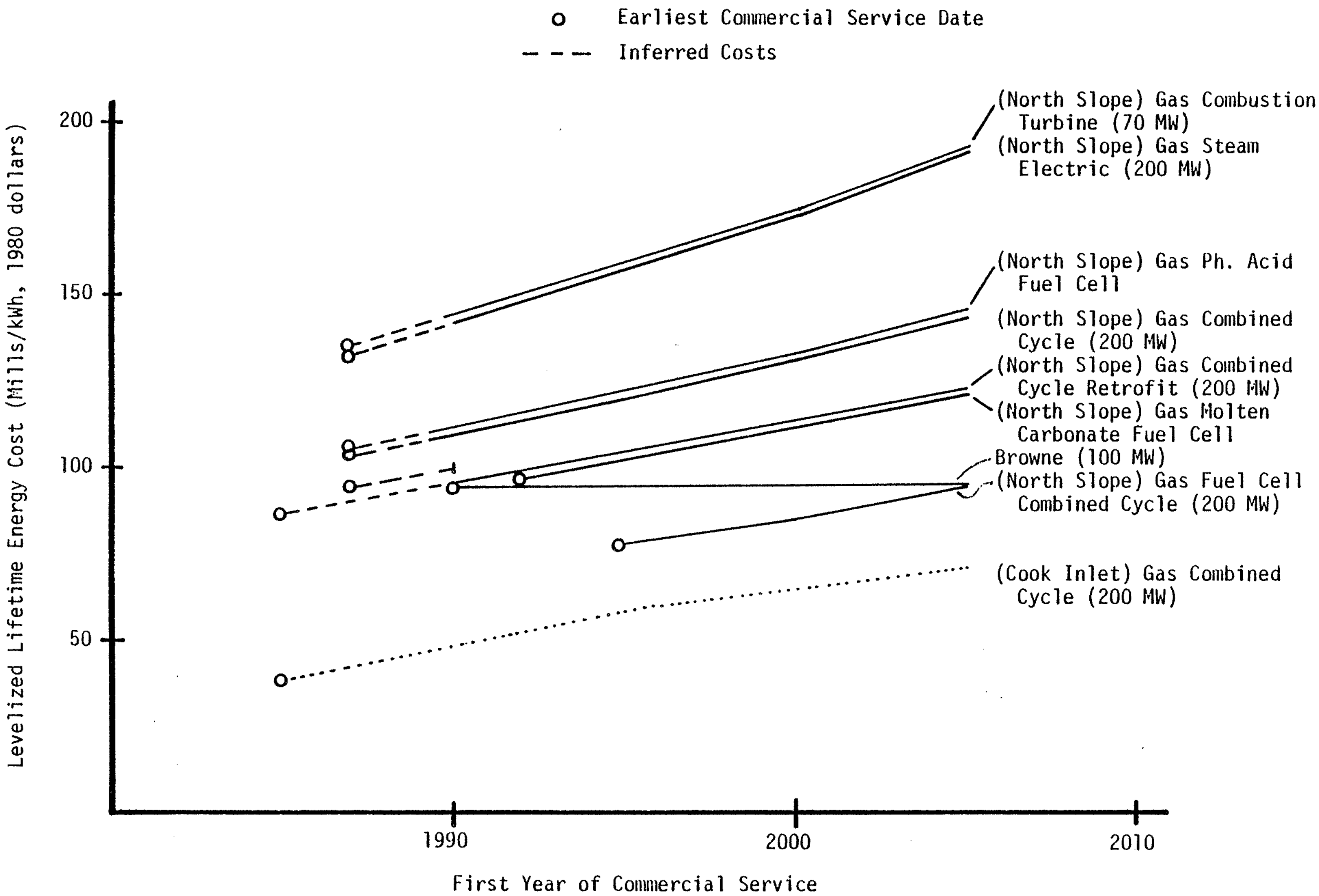

FIGURE 4.10. Cost and Availability of Natural Gas Alternatives for the Fairbanks Load Center

throughout the planning period. Because most technologies using natural gas are adaptable to operation using distillate fuel oil, the use of North Slope gas for electricity generation would not be economically competitive with distillate fuel oil during the planning period, based on current fuel price forecasts.

An alternative source of electricity based on natural gas usage would be generating plants located in the Cook Inlet region using Cook Inlet gas. Power would be transmitted to Fairbanks via the intertie. The busbar cost of a combined-cycle plant using Cook Inlet gas is plotted in Figure 4.10. The estimated cost of this option is 49 mills/kWh in 1990, compared to 95 mills/kWh for distillate combined-cycle plants and 110 mills/kWh for North Slope gas combined-cycle plants. The cost savings appear to be more than sufficient to justify transmission of power from the Cook Inlet area to Fairbanks if a High Natural Gas plan is adopted.

Because baseload power for the Fairbanks area under a High Natural Gas plan appears to be most economically obtained from Anchorage, generating resource requirements for the Fairbanks areas under the High Natural Gas plan are limited to those required for peaking or reliability considerations. From a purely cost-effectiveness standpoint, these should be based on the use of distillate fuel oil. Candidate alternatives for reserve and peaking duty are those having good load-following characteristics and low capital costs. These include combustion turbines, phosphoric acid fuel cells and diesel electric plants. The levelized lifecycle costs for these three types of plants, fired with distillate fuel oil, for four different in-service dates, are shown below.

	Levelized Cost of Energy Under Peaking Duty for In-Service Dates Shown (mills/kWh, 1980 dollars)(a)			
Alternative	1990	1995	2000	2005
Diesel Electric (12 MW)	173	182	192	203
Phosphoric Acid Fuel Cell Station(b)	192	201	210	220
Combustion Turbine (70 MW)	204	215	228	242

(a) 10% capacity factor
(b) Unit costs are relatively insensitive to plant capacity.

Diesel electric units appear to be consistently more cost effective throughout the planning period and were recommended for inclusion in the High Natural Gas plan for peaking and reserve duty at Fairbanks.

Fuel cell stations were also recommended for consideration in the High Natural Gas plan. Because fuel cell technology is not fully developed, estimated costs for this technology are less certain than for turbines or diesels.[a] Fuel cell plants may provide better fuel switching capability than diesel electric units. The capability is further reason to incorporate fuel cells into the High Natural Gas plan.

Glennallen-Valdez Load Center

Because natural gas is not expected to be available in the Glennallen-Valdez load center during the planning period, the alternatives available to Glennallen-Valdez are basically those selected under the Present Practices plan. In conformance with the philosophy underlying the High Natural Gas plan relative to advanced technologies, the cost effectiveness of advanced technologies suitable for the Glennallen-Valdez area was also examined.

Advanced technologies suitable for the Glennallen-Valdez load center are those available in small unit sizes and capable of operating on distillate fuel oil. These include fuel cell stations using phosphoric acid fuel cells and fuel cell stations using molten carbonate fuel cells. A cost comparison of these alternatives with mature technologies suitable for use in the Glennallen-Valdez area is provided below.

Fuel cell stations, especially those based on molten carbonate fuel cells are clearly more cost effective than conventional alternatives under the assumed operating conditions. Prior to the availability of fuel cells, diesel electric units are the most cost-effective nonrenewable option for the Glennallen-Valdez area.

A summary of the generating alternatives recommended for inclusion in the High Natural Gas plan is provided in Table 4.4.

(a) Past experience has indicated that the actual cost of new technologies when commercially available is typically higher than that estimated during development.

Alternative	Levelized Cost of Energy Under General Service for In-Service Dates Shown (mills/kWh, 1980 dollars)(a)			
	1990	1995	2000	2005
Phosphoric Acid Fuel Cell Station (b)	97	106	115	125
Cell Station (b)	NA	90	97	106
Diesel Electric (12 MW)	100	110	120	131
Combustion Turbine (50 MW)	127	139	151	166

NA = Not Available
(a) 65% capacity factor
(b) Unit costs relatively insenstive to size.

TABLE 4.4 Alternatives Recommended for inclusion in the High Natural Gas Plan

Period	Load Center: Anchorage	Load Center: Fairbanks	Load Center: Glennallen-Valdez
Near-Term (Present-1990)	Combined-Cycle Cogeneration Bradley Lake Fuel Cell Stations Grant Lake	Diesel-Electric Fuel Cell Stations(a) Combined-Cycle(b) Cogeneration(b)	Solomon Gulch Hydro Diesel-Electric Fuel Cell Stations(a)
Mid-Term (1990-2000)	Combined-Cycle Cogeneration Fuel Cell Stations Fuel Cell Combined-Cycle Chakachamna Hydro not Developed in Near-Term	Diesel-Electric Fuel Cell Stations(a) Combined-Cycle(b) Cogeneration(b) Fuel Cell Combined-Cycle(b)	Allison Hydro Fuel Cell Stations(a)
Long-Term (2000-2010)	Cogeneration Fuel Cell Stations Fuel Cell-Combined Cycle Hydro not Developed in Earlier Periods Note(d)	Diesel-Electric Fuel Cell Stations(a) Cogeneration(b) Fuel Cell Combined-Cycle(b) Note(d)	Allison Hydro(c) Fuel Cell Stations(a) Note(d)

(a) Using distillate fuel oil.
(b) Imported baseload power from Cook Inlet appears to be more cost effective than local use of North Slope natural gas.
(c) If not developed in earlier periods.
(d) Additional nonnatural gas resources maybe required during the long-term period due to possible depletion of Cook Inlet natural gas supplies.

5.0 CONCLUSION

Twenty-two electric power generating alternatives were selected for consideration in the development of Railbelt electric energy plans. The alternatives are shown in Table 5.1. The second column of the table lists the Railbelt electric energy plans for which use of each alternative will be considered. Consideration of alternatives is not technically limited to the plans shown and combinations other than those indicated may be investigated.

A description of the "typical" Railbelt facility to be considered in the development of more detailed information on each alternative is provided in the third column of Table 5.1. The plant sizes, locations and fuel sources shown are considered to be the most likely for these technologies. Some flexibility will exist for scaling costs and performance information to other plant sizes, locations and fuel sources.

In the right hand column of Table 5.1 are listed the principal sources of cost, performance and environmental information for analysis of the selected alternatives. Information sources are of three general types. First, information was obtained from feasibility studies where these existed. These included the Upper Susitna, Allison, Bradley Lake, and Grant Lake hydroelectric projects, and the Cook Inlet Tidal project.

Second, in-depth "Task 3B" studies were prepared on alternatives generally meeting the following criteria: 1) having the potential for significantly contributing to future Railbelt generating capacity; 2) not currently existing in the Railbelt or for which significant Railbelt experience in likely future configurations or sizes does not exist; and, 3) sufficiently mature to allow significant information to be developed beyond the existing technology profile. These alternatives include coal steam-electric, coal gasifier-combined cycle, natural gas fuel cell stations, the Chakachamna, hydroelectric project,[a] the Browne hydroelectric project and large wind energy conversion systems.

(a) A separate feasibility study of the Chakachamna hydroelectric project was initiated by the Alaska Power Authority following the selection of this project for Task 3B study. Both references are included in Table 5.1.

Finally, further study on certain alternatives was limited to a review and update of the existing technical profiles (Volume IV) with consideration of likely plant sizes, locations and fuel sources. These alternatives generally include those for which a good understanding of Railbelt cost and performance exists, or those that do not appear to have the potential to significantly contribute to meeting demand in the context of total load center demand.

Further study, beyond the scope of this project, is recommended for several options. Most promising are cogeneration applications, especially those using natural gas. Also promising, based on very preliminary estimates of the cost of power, is geothermal generation. The Railbelt geothermal resource, however, is not sufficiently well understood to permit estimates of availability to be made. Moreover, the resource appears to be of the hot dry rock type for which conversion technology is not developed. Additional exploration of the resource potential appears prudent, however. Finally, the peat resources of the Railbelt appear to warrant additional study to determine their potential for electric power generation. Current estimates of the cost of peat-based generation are based on very preliminary information and could change given better understanding of the resource.

The performance and economic characteristics of each alternative used in the assessment of the Railbelt Electric Energy plans are provided in the technical data sheets of Appendix A.

TABLE 5.1 Alternatives Selected for Consideration in Railbelt Electric Energy Plans

Alternative	Applicable Plan(a)	Nominal Railbelt Plant	Source of Planning Information
Coal Steam-Electric	I,II,III	200-MW pulverized coal-fired power plant. Two locations considered - Beluga and Nenana.	Task 3B Study (Volume XII)
Coal Gasification - Combined-Cycle	III	200-MW integrated gasifier combined-cycle power plant; gasifier dedicated to power plant operation. Located at Beluga, supplied with Beluga coal.	Task 3B Study (Volume XVII)
Natural Gas Combined-Cycle	I,II,III,IV	200-MW natural gas-fired combined-cycle power plant located at Beluga, supplied with Cook Inlet gas.	Task 3B Study (Volume XIII)
Natural Gas Combustion Turbines	I,III	70-MW natural gas-fired combustion turbine. Cook Inlet location, supplied with Cook Inlet gas.	Technology Profile (Volume IV)
Natural Gas Fuel Cell Station	IV	25-MW fuel cell station with phosphoric acid fuel cells. Located in Cook Inlet area, supplied with Cook Inlet natural gas.	Technology Profile (Volume IV)
Natural Gas Fuel Cell Combined-Cycle	IV	200-MW natural gas fuel cell combined-cycle plant using molten carbonate fuel cells. Located in Cook Inlet area, supplied with Cook Inlet natural gas.	Technology Profile (Volume IV)

TABLE 5.1. (contd)

Alternative	Applicable Plan(a)	Nominal Railbelt Plant	Source of Planning Information
Natural Gas Steam Topping Cogeneration Plant	IV	Insufficient cost and information available to permit incorporation of this alternative into Railbelt electric energy plans.	Further study recommended
Distillate Combined-Cycle Retrofit	I,II	Retrofit of Golden Valley Electric Association North Pole combustion turbines for combined-cycle operation.(b)	Technology Profile (Volume IV)
Distillate Fuel Cell Station	IV	25-MW fuel cell station with phosphoric acid fuel cells. Located in Glenn-allen-Valdez area.	Technology Profile (Volume IV)
Diesel Electric	I,II,III,IV	12-MW diesel electric plant. Located either in Fairbanks or Glennallen-Valdez load centers.	Technology Profile (Volume IV)
Bradley Lake	I,II,III,IV	90-MW Bradley Lake hydro project	Alaska Power Administration 1977
Grant Lake	I,II,III,IV	7-MW Grant Lake hydro project	CH_2M-Hill 1981
Chakachamna	I,II,III,IV	330/480 MW Chakachamna hydro project	Task 3B Study (Volume XIV)(c)
Allison	I,II,III,IV	8-MW Allison hydro project	U.S. Army Corps of Engineers 1981

TABLE 5.1. (contd)

Alternative	Applicable Plan(a)	Nominal Railbelt Plant	Source of Planning Information
Browne	II	100-MW Browne hydro project	Task 3B Study (Volume XV)
Snow	II	50-MW Snow hydro project	Acres American Inc., 1981b
Keetna	II	100-MW Keetna hydro project	Acres American Inc., 1981b
Strandline Lake	II	20-MW Strandline hydro project	Acres American Inc., 1981b
Refuse-Fired Steam-Electric	II	50-MW refuse-fired steam-electric plant at Anchorage 20-MW refuse-fired steam-electric plant at Fairbanks	Technology Profiles (Volume IV)
Large Wind Energy Conversion Systems	II	25-MW wind farm consisting of 10 2.5-MW units - located near Isabell Pass	Task 3B Study (Volume XVI)
Tidal Power	II	720-MW tidal electric power plant or Knik Arm at Eagle Bay	Acres American 1981a
Upper Susitna	I(d),II(d)	The Upper Susitna hydroelectric project consisting of the two-stage Watana dam (680 MW plus a 340-MW expansion) and the 600-MW Devil Canyon dam.	Acres American 1981b

(a) Plan I - Present Practice
Plan II - High Conservation and Renewables
Plan III - High Coal
Plan IV - High Natural Gas
(b) Additional capacity was not required in the Fairbanks load center until the North Pole units were 15 years of age, beyond the point in life at which retrofit was considered feasible.
(c) Later supplemented with Bechtel Civil and Minerals, 1981 (330 MW alternative).
(d) Separate version of Plans I and II, were assessed specifically incorporating the Upper Susitna project.

APPENDIX A

TECHNICAL DATA SHEETS FOR ELECTRIC ENERGY GENERATION AND CONSERVATION OPTIONS

APPENDIX A

TECHNICAL DATA SHEETS FOR ELECTRIC ENERGY GENERATION AND CONSERVATION OPTIONS

The purpose of this appendix is to provide in one location the technical performance and cost data used in the AREEP capacity addition model for new generating options and in the demand forecasting models for conservation options.

Each generating and conservation option is summarized on one technical data sheet. Each sheet consists of a general description of the option, followed by tabulated technical performance, schedule, fuel and cost data. Also provided are references to source documents from which the information on the data sheets was taken.

The information on many generating and conservation options was taken from Volume IV of this series of reports, Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska. Costs given in Volume IV are expressed in 1980 dollars. Costs used in the AREEP model are in January 1982 dollars. The methods of escalating Volume IV costs to January 1982 are documented in the appropriate technical data sheets. Separate data sheets are provided for fuel price and escalation information common to several options.

TECHNICAL DATA SHEET 1.0

COAL-FIRED STEAM-ELECTRIC POWER PLANTS[(a)]

Two pulverized coal-fired steam-electric power plants were considered. The first plant would be a 200-MW nominal capacity pulverized coal-fired steam-electric station located in the Beluga area on the northeast side of Cook Inlet. The plant would be of conventional design, using dry lime slurry flue-gas desulphurization (FGD) scrubbers, baghouse particulate removal and wet/dry mechanical draft cooling towers. The facility would be supplied with Beluga coal by truck or conveyor from the mine mouth. Power would be supplied to Anchorage-Fairbanks intertie by a 345-kV tie line, approximately 75 miles in length and terminating in a substation at Willow.

The second plant would be a 200-MW nominal capacity pulverized coal-fired steam-electric plant located in the Nenana area, southwest of Fairbanks. This plant also would be of conventional design, using dry lime slurry FGD scrubbers, baghouse particulate removal and wet/dry mechanical draft cooling towers. The facility would be supplied with coal from the Nenana field at Healy via the Alaska Railroad. Power would be supplied at Nenana, at 138 kV if supply to Fairbanks is intended, and at 345 kV if supply to Anchorage is intended.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	200
Size Range for Which Data Are Generally Valid (MW)	150-250
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Large relative to prospective demand
Typical Operation	Baseload
Heat Rate (Btu/kWh)	10,000
Forced Outage Rate (%)	4.8 (150 MW) 5.7 (200 MW) 6.6 (250 MW)

(a) All data in this data sheet are taken from Volume XII unless otherwise indicated.

Scheduled Outage Rate (%)	8
Equivalent Availability (%)	88 (150 MW) 87 (200 MW) 86 (250 MW)

SCHEDULE

Availability for Order	Current
Preconstruction Studies and Licensing (years)	3
Construction (years)	4
Startup (years)	0.25
Earliest Commercial Service	1989[a]
Plant Life (years)	35

FUEL

Heating Value (Btu/lb)	8000

COST DATA

Estimated Costs (January 1982)

	Beluga	Nenana
Overnight Capital ($/kW)[b]	2051	2110
Working Capital ($/kW)[c]	34	41
Fixed O&M ($/kW/yr)	16.71	16.71
Variable O&M (mills/kWh)	0.6	0.6
Fuel ($/MMBtu)	See Table 26.1	

(a) 1982 decision to proceed.
(b) Does not include land or land rights, client charges, taxes or transmission costs beyond the substation or switchyard.
(c) Includes 90-day coal pile plus one month O&M.

Payout Schedule

Year	Beluga Station $	Beluga Station %	Nenana Station $	Nenana Station %
1	72,006,000	17.6	76,920,600	18.2
2	119,372,000	29.1	121,283,000	28.8
3	121,096,000	29.5	126,740,000	30.1
4	97,687,000	23.8	96,622,200	22.9

Escalation Factors (%/Year, 1981-2010)

	Beluga	Nenana
Capital	See Table 25.1	
O&M	See Table 25.2	
Fuel	See Table 26.1	

Economics of Scale — Negligible in 150-250 MW range

TECHNICAL DATA SHEET 2.0

INTEGRATED COAL GASIFIER COMBINED-CYCLE POWER PLANTS[a]

The proposed plant would consist of coal gasifiers producing a medium Btu synthetic fuel gas. The synthetic fuel gas would be used to drive a combined-cycle power plant of 220-MW nominal capacity. The prototypical plant selected for study would be located in the Beluga area northwest of Cook Inlet and would use coal from the proposed Chuitna Field surface mines. Alternatively, plants of the proposed design could be sited along the Alaska Railroad and could use coal from the Usibelli mine at Healy.

Pulverized coal would be supplied to high-pressure, oxygen-blown, entrained-flow gasifiers of Shell design to produce a medium Btu synthesis gas. The raw product gas would be passed through particulate removal cyclones and then would be directed to gas coolers that contribute saturated steam to the steam bottoming cycle. Gas exiting from the gas cooler would be passed through a quench scrubbing column and then a sulfur removal section consisting of a COS conversion unit and a H_2S absorber unit.

Clean gas would be supplied to two combustion turbine-generators rated at 74.5 MW each. Exhaust from the combustion turbines would be directed to heat recovery steam generators that would produce superheated steam for a 100-MW steam turbine-generator plus auxiliary steam at lower pressures for in-plant use. Waste heat would be rejected by a wet/dry mechanical draft cooling tower.

Power would be transmitted to a substation at Willow on the proposed Anchorage-Fairbanks intertie by a single circuit 345-kV line ∿75 miles in length.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	220
Size Range for Which Data Are Generally Valid (MW)	150-250
Capacity Credit	Full

(a) All data in this data sheet are taken from Volume XVII unless otherwise indicated.

Capacity Limit in Railbelt (MW)	Large relative to prospective demand
Typical Operation	Baseload/Load Following
Heat Rate (Btu/kWh)	9290
Forced Outage Rate (%)	8
Scheduled Outage Rate (%)	7
Equivalent Availability (%)	7

SCHEDULE

Availability for Order	1985
Preconstruction Studies and Licensing (years)	3[a]
Construction (years)	2.5
Startup (years)	1/3
Earliest Commercial Service	1991
Plant Life (years)	25

FUEL

Heating Value (Btu/lb)	8000

COST DATA

Estimated Costs (January 1982)

	Beluga
Overnight Capital (\$/kW)[b]	3280
Working Capital (\$/kW)[d]	65
Fixed O&M (\$/kW/yr)	16.87
Variable O&M (mills/kWh)	0.7
Fuel (\$/MMBtu)	See Table 26.1

(a) Estimated based on pulverized coal steam-electric plant of similar capacity.
(b) Does not include land or land rights, client charges, taxes or transmission costs beyond the substation or switchyard.
(c) Costs for a Nenana location were not separately estimated.
(d) 90-day coal pile plus 30-day O&M costs. Assumes 1990 coal prices.

Payout Schedule

Year	10^6 \$	%
1	167.2	23
2	331.8	46
3	223.6	31

Escalation Factors (%/Year, 1981-2010)

	Beluga	Nenana
Capital	See Table 25.1	
O&M	See Table 25.2	
Fuel	See Table 26.1	

Economics of Scale

Capital	Can be realized by using larger component sizes; however, this is not documented.
Fixed O&M	Can be realized by using larger component sizes; however, this is not documented.
Variable O&M	Not documented
Fuel	Not documented

TECHNICAL DATA SHEET 3.0

NATURAL GAS COMBUSTION TURBINE POWER PLANTS[a]

Natural gas combustion power plants consist of a combustion turbine driving an electric generator. A typical plant consists of an air compressor, a combustor section, the gas turbine unit, an electric generator, and appurtenant facilities. Combustion turbines can also be fired with distillate or residual oil for emergency operation in case of gas supply failure.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	70
Size Range for Which Data Are Generally Valid (MW)	50-100
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	∿1000[b]
Typical Operation	Load Following (Peaking)[c]
Heat Rate (Btu/kWh @ HHV)	13,800[d]
Forced Outage Rate (%)	8
Scheduled Outage Rate (%)	3.2
Equivalent Availability (%)	89.1

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	1

(a) All data in this data sheet are taken from Volume IV unless otherwise indicated.
(b) Using Cook Inlet gas.
(c) Currently in use throughout the Railbelt in baseload and load-following service; future installations would likely be used primarily in peaking duty.
(d) Current technology under average duty. Advanced machines may have average annual heat rates of 12,400 Btu/kWh.

Construction (years)	1
Startup (years)	<1
Earliest Commercial Service	1984
Plant Life (years)	20

FUEL

Heating Value (Btu/lb)	21,500

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	638[a]
Working Capital ($/kW)	88[b]
Fixed O&M ($/kW/yr)	48[c]
Variable O&M (mills/kWh)	(Included in Fixed O&M)
Fuel ($/MMBtu)	See Table 26.1

Payout Schedule — One Shot

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2
Fuel	See Table 26.1

Economics of Scale — No information available.

(a) Based on costs reported in Volume IV escalated to January 1981 using Handy Whitman index; line 30 then escalated to January 1982 using annual inflation rate of 9% plus 1981 capital cost escalator of Table 25.1.
(b) Includes 30-day emergency distillate supply (1990 prices) and 30-day O&M costs.
(c) Escalated to January 1981 using Handy Whitman index, line 1; then escalated to January 1982 using 9% annual rate of inflation plus 1981 O&M escalator from Table 25.1.

TECHNICAL DATA SHEET 4.0

NATURAL GAS-FIRED COMBINED-CYCLE PLANT[(a)]

The proposed plant would be a conventional combined-cycle power plant of 200-MW nominal rated capacity, located in the Beluga area northwest of Cook Inlet. Natural gas to fire the plant would be taken from the Cook Inlet natural gas fields. The plant would consist of gas compressors and fuel forwarding facilities, two combustion turbine units driving generators rated at 75 MW each, a heat recovery steam generator operating from combustion turbine exhaust and a steam turbine driving a generator rated at 59 MW. A wet/dry mechanical draft cooling tower would be provided for waste heat rejection. Power would be transmitted by 345 kV single circuit line to a substation located near Willow on the proposed Anchorage-Fairbanks intertie.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	200
Size Range for Which Data Are Generally Valid (MW)	200-300
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	~1000[(b)]
Typical Operation	Baseload
Heat Rate (Btu/kWh)	8200
Forced Outage Rate (%)	8
Scheduled Outage Rate (%)	7
Equivalent Availability (%)	85

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	3
Construction (years)	3
Startup (years)	1/4
Earliest Commercial Service	1988
Plant Life (years)	25

(a) All data in this data sheet are taken from Volume XIII unless otherwise indicated.
(b) Using Cook Inlet gas.

FUEL

Heating Value (Btu/lb)	21,500

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	1001[a]
Working Capital ($/kW)	52[b]
Fixed O&M ($/kW/yr)	7.25
Variable O&M (mills/kWh)	1.7
Fuel ($/MMBtu)	See Table 26.1

Payout Schedule[c]

Year	10^6 $	%
1	51.5	26
2	102.2	51
3	46.5	23

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2
Fuel	See Table 26.1

Economics of Scale

Capital	Can be realized through use of large component sizes, but not documented.
Fixed O&M	Can be realized through use of larger component sizes, but not documented.
Variable O&M	Not documented
Fuel	Not documented

(a) Does not include land or land rights, owner costs, or transmission costs beyond the substation.
(b) Includes 30-day emergency distillate supply (1990 prices) plus 30-day O&M costs.
(c) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 5.0

NATURAL GAS FUEL CELL STATIONS[(a)]

Fuel cell stations would be relatively small (5 to 25 MW), dispersed generating plants consisting of phosphoric acid fuel cells supplied with a hydrogen-rich fuel reformed from natural gas. A typical station would consist of a fuel conditioner, which converts the natural gas fuel to hydrogen and carbon dioxide; phosphoric acid fuel cells, which generate DC power by electrolytic oxidation of hydrogen; a power conditioner, which converts the DC fuel cell output to AC power for distribution; and appurtenant facilities.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	25
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	~1000[(b)]
Typical Operation	Baseload or Load Following
Heat Rate (Btu/kWh)	9200
Forced Outage Rate (%)	6
Scheduled Outage Rate (%)	4
Equivalent Availability (%)	91

SCHEDULE

Availability for Order	1985
Preconstruction Studies and Licensing (years)	1
Construction (years)	1
Startup (years)	<1
Earliest Commercial Service	1987
Plant Life (years)	20

(a) All data in this data sheet are taken from Volume IV unless otherwise indicated.
(b) Assuming use of Cook Inlet gas.

FUEL

Heating Value (Btu/lb, HHV)	21,500

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	830[a]
Working Capital ($/kW)	60[b]
Fixed O&M ($/kW/yr)	42[c]
Variable O&M (mills/kWh)	(Included in Fixed O&M)
Fuel ($/MMBtu)	See Table 26.1

Payout Schedule — One Shot

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2
Fuel	See Table 26.1

Economics of Scale — No information available.

(a) Escalated to January 1981 using Handy Whitman index, line 30; escalated to January 1982 using 9% annual rate of inflation plus 1981 capital cost escalator of Table 25.1.
(b) Includes 30-day emergency distillate supply (1990 prices) and 30-day O&M costs.
(c) Midpoint value of Volume IV (35 $/kW/yr) escalated to January 1981 using Handy Whitman index; line 1 then escalated to January 1982 using 9% annual rate of inflation plus 1981 O&M escalator from Table 25.1.

TECHNICAL DATA SHEET 6.0

NATURAL GAS FUEL CELL COMBINED-CYCLE POWER PLANTS[a]

Natural gas fuel cell combined-cycle power plants would be relatively large (∿200 MW), central generating stations consisting of molten carbonate fuel cells, with waste heat recovery boilers driving a steam turbine-generator. A typical plant would include a fuel conditioner to convert natural gas to hydrogen and carbon dioxide; molten carbonate fuel cells producing DC power by electrolytic oxidation of hydrogen; heat recovery boilers using reject heat from fuel-cell operation to raise steam; a turbine-generator driven by steam from the heat recovery boiler; a power conditioner to convert the DC fuel cell output to AC power; and appurtenant facilities.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	200
Size Range for Which Data Are Generally Valid (MW)	Not known
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	∿1000[b]
Typical Operation	Baseload
Heat Rate (Btu/kWh)	5700
Forced Outage Rate (%)	4
Scheduled Outage Rate (%)	11
Equivalent Availability (%)	83

SCHEDULE

Availability for Order	1990
Preconstruction Studies and Licensing (years)	3
Construction (years)	3
Startup (years)	1/2
Earliest Commercial Service	1996
Plant Life (years)	25

(a) All data in this data sheet are taken from Volume IV unless otherwise indicated.
(b) Assuming use of Cook Inlet gas.

FUEL

Heating Value (Btu/lb)	21,500

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	2000
Working Capital ($/kW)	39[a]
Fixed O&M ($/kW/yr)	50
Variable O&M (mills/kWh)	Included in Fixed O&M
Fuel ($/MMBtu)	See Table 26.1

Payout Schedule[b]

Year	10^6 $	%
1	100	25
2	200	50
3	100	25

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2
Fuel	See Table 26.1

Economics of Scale — No information available.

(a) Includes 30-day emergency distillate supply (1990 prices) and 30-day O&M costs.
(b) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 7.0

BRADLEY LAKE HYDROELECTRIC PROJECT[a]

The proposed Bradley Lake hydroelectric project would be located at Bradley Lake near Homer, Alaska, at the head of Kachemak Bay. The project would use Bradley Lake as a reservoir, with the natural water supply of the lake supplemented by diversion of North Banks Creek into Bradley Lake. A concrete gravity dam would raise the elevation of the lake to 1170 feet from its natural elevation of 1090 feet. A power tunnel, tapping the lake, would convey water to an underground powerhouse located near tidewater. The preferred plan involves installation of 90-MW capacity, although 60- and 135-MW alternatives have been investigated.[b]

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	90
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/cycling
Forced Outage Rate (%)	5[c]
Scheduled Outage Rate (%)	1.5[d]
Annual Firm Energy (GWh)	315[b]
Average Annual Energy (GWh)	347[b]
Equivalent Capacity Factor (%)	44.0

(a) All data in this data sheet are taken from Alaska Power Administration (APA) (1977) unless otherwise indicated.
(b) Reported in a telephone conversation with John Denniger of the Alaska Power Administration.
(c) Based on estimates prepared for the Chakachamna Hydroelectric project, Volume XIV.
(d) Estimate.

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	2[a]
Construction (years)	6[b]
Startup (years)	<1[a]
Earliest Commercial Service	1990
Plant Life (years)	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	3184[c]
Working Capital ($/kW)	1[d]
Fixed O&M ($/kW/yr)	9[e]
Variable O&M (mills/kWh)	None

Payout Schedule[f]

Year	$	%
1	20,070,000	7.0
2	51,600,000	18.0
3	71,660,000	25.0
4	71,660,000	25.0
5	51,600,000	18.0
6	20,070,000	7.0

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale	Not Applicable

(a) Estimate.
(b) Inferred from APA (1977).
(c) Corps of Engineers January 1981 estimate (2900 $/kW), escalated to January 1982 using weighted escalation rates of Table 25.1 plus 9% general inflation rate.
(d) Based on 30-day O&M costs.
(e) Estimate of APA (1977), escalated to January 1981 using Handy Whitman index; escalated to January 1982 as in (c) above.
(f) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 8.0

GRANT LAKE HYDROELECTRIC PROJECT[a]

The proposed Grant Lake hydroelectric project would use Grant Lake as a reservoir. Grant Lake is about 25 miles north of Seward and east of the Seward-Anchorage Highway. The project would consist of a main and a saddle dam, a low-pressure water conveyance pipe, a surge tank, a penstock and an aboveground powerhouse of 7.3-MW installed capacity. Water would be drawn from Grant Lake at an elevation of 705 to 740 feet and discharged to Upper Trail Lake on the Trail River at 472 feet elevation. The aboveground concrete powerhouse, located on Trail Lake, would be equipped with two turbine-generators rated at 3640 kW each with a total installed capacity of 7250 kW. The tailrace would discharge to Upper Train Lake.

TECHNICAL PERFORMANCE DATA

Installed Capacity (MW)	7.3
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/Cycling
Forced Outage Rate (%)	5
Scheduled Outage Rate (%)	1.5
Equivalent Availability (%)	94
Annual Firm Energy (GWh)	19
Average Annual Energy (GWh)	27
Equivalent Capacity Factor (%)	42.2

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	2

(a) All data in this data sheet are based on CH_2M-Hill (1980) unless otherwise indicated.

Construction (years)	2
Startup (years)	<<1
Earliest Commercial Service	1986
Plant Life (years)	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	2838[a]
Working Capital ($/kW)	4[b]
Fixed O&M ($/kW/yr)	44
Variable O&M (mills/kWh)	None

Payout Schedule[c]

Year	$	%
1	10,360,000	50.0
2	10,360,000	50.0

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale	Not Applicable

(a) CH_2M-Hill capital costs escalated from January 1980 to January 1981 using Handy Whitman index. Costs escalated from January 1981 to January 1982 using weighted escalation rates of Table 25.1 plus 9% general inflation rate.
(b) Based on 30-day O&M costs.
(c) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 9.0

ALLISON HYDROELECTRIC PROJECT[a]

The proposed Allison hydroelectric project would be located on Allison Lake and Allison Creek, which discharges to Valdez Inlet near the Port of Valdez. The proposed project would use Allison Lake as a reservoir and would consist of a power tunnel, penstock and an aboveground powerhouse. The 10,200-foot power tunnel would tap Allison Lake and lead to the penstock. The penstock would drop to the powerhouse, located near the discharge of Allison Creek to Valdez Inlet. The project would have an installed capacity of 8 MW. A dual tailrace would be provided, allowing discharge to Allison Creek during warm seasons to protect the Allison Creek anadromous fishery.

TECHNICAL PERFORMANCE DATA

Installed Capacity (MW)	8
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/Cycling
Forced Outage Rate (%)	5[b]
Scheduled Outage Rate (%)	1.5[c]
Equivalent Availability (%)	94
Annual Firm Energy (GWh)	32.2
Average Annual Energy (GWh)	37.3
Equivalent Capacity Factor (%)	53.2

(a) Unless otherwise specified, all data in this data sheet are based on a 1982 telephone conversation with Loren Baxter from the U.S. Army Corps of Engineers in Anchorage, Alaska.
(b) Based on estimates prepared for the Chakachamna hydroelectric project, Volume XIV.
(c) Estimate.

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	2[c]
Construction (years)	4
Startup (years)	<<1
Earliest Commercial Service	1988
Plant Life (years)	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	4817[a]
Working Capital ($/kW)	4[b]
Fixed O&M ($/kW/yr)	44[c]
Variable O&M (mills/kWh)	None

Payout Schedule[d]

Year	$	%
1	5,785,000	15.0
2	13,500,000	35.0
3	13,500,000	35.0
4	5,785,000	15.0

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale	Not Applicable

(a) Corps of Engineers October 1980 estimate (4288 $/kW), escalated to January 1981 using Handy Whitman index. Costs escalated from January 1981 to January 1982 using escalation rates of Table 25.1 plus 9% general inflation rate.
(b) Based on 30-day O&M costs.
(c) Based on Grant Lake estimate (CH_2M-Hill 1981).
(d) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 10.0

CHAKACHAMNA HYDROELECTRIC PROJECT[a]

The proposed Chakachamna hydroelectric project would be a transmountain diversion project located near Chakachamna Lake, which is northwest of Cook Inlet and about 85 air miles west of Anchorage. Chakachamna Lake, with an average natural water level of 1083 ft, would be used as a storage reservoir for the project. Other facilities would include a power tunnel, surge tank, power shaft, penstock, powerhouse and appurtenant structures. The 26-ft diameter power tunnel, 10.8 miles in length, would extend in a southeasterly direction from a water intake structure with an invert elevation of 894 ft to a surge tank located to the north bank of the McArthur River. An 80-ft-diameter, 500-ft-high surge tank would be excavated in rock at the downstream end of the power tunnel. A 26-ft diameter vertical power shaft would extend from the bottom of the surge tank to the powerhouse elevation ($\sim$185 ft). From the base of the power shaft, a steel penstock would lead to a surface powerhouse on the north bank of the McArthur River. Four turbogenerator units of 480-MW total installed capacity would be provided. The 185-ft tailrace elevation would provide a net average head of 875 ft. Power would be transmitted over a 230-kW double circuit line, $\sim$115 miles in length, to Anchorage.[b]

TECHNICAL PERFORMANCE DATA

	Ebasco (1982)	Bechtel (1981)
Installed Capacity (MW)	480	330
Size Range for Which Data Are Generally Valid (MW)	Not Applicable	Not Applicable
Capacity Credit	Full	Full
Capacity Limit in Railbelt (MW)	Not Applicable	Not Applicable
Typical Operation	Baseload/Cycling	

(a) All data in this data sheet are taken from Volume XIV unless otherwise indicated.
(b) The above description is taken from Volume XIV. The design proposed by Bechtel (1981) differs primarily in that water would continue to be discharged to the Chakachatna River to support anadromous fish passage. This results in a reduction in firm and average power output, installed capacity, and power tunnel diameter.

Forced Outage Rate (%)	5	Not Applicable
Scheduled Outage Rate (%)	1.5	Not Applicable
Equivalent Availability (%)	94	Not Applicable
Annual Firm Energy (GWh)	1845	1446
Average Annual Energy (GWh)	1923	1570
Equivalent Capacity Factor (%)	45.7	54.3

SCHEDULE

Availability for Order	Available	Available
Preconstruction Studies and Licensing (years)	4	2.5
Construction (years)	5	6
Startup (years)	1/2	1/2
Earliest Commercial Service	1991	1991
Plant Life (years)	50	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	2100[a]	3860[a]
Working Capital ($/kW)	Nil	Nil
Fixed O&M ($/kW/yr)	4	Not Applicable
Variable O&M (mills/kWh)	Nil	Not Applicable

Payout Schedule

	Ebasco Proposal[b]		Bechtel Proposal[c]	
Year	10^6 $	%	10^6 $	%
1	111.7	11	89.1	7
2	128.0	13	229.3	18
3	170.7	17	318.5	25
4	375.3	37	318.5	25
5	224.5	22	229.3	18
6	--	--	89.1	7

(a) Does not include land or land rights, owner's cost or transmission system.
(b) Volume XIV.
(c) Based on Phung (1978) weak sinusoidal payout schedule.

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale — Not Applicable

TECHNICAL DATA SHEET 11.0

SNOW HYDROELECTRIC PROJECT[a]

The proposed Snow hydroelectric project would lie on the Snow River, which is about 15 miles north of Seward and east of the Anchorage-Seward highway. An earth-fill dam approximately 200 ft in height would be constructed across the Snow River about 2 miles east of the Anchorage-Seward highway. This construction would form a storage reservoir with a normal maximum water level of 1190 ft. A power tunnel would lead from an intake structure adjacent to the main dam to a surge shaft approximately 7000 ft west of the main dam. A penstock tunnel would lead an additional 2000 ft to a 50-MW installed capacity underground powerhouse. A subsurface/surface tailrace would discharge to the Snow River at a tailwater elevation of 500 ft slightly upstream of the junction of the south fork of the Snow River (Acres American 1981b).

TECHNICAL PERFORMANCE DATA

Installed Capacity (MW)	50
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/Cycling
Forced Outage Rate (%)	5[b]
Scheduled Outage Rate (%)	12.5[c]
Equivalent Availability (%)	94
Annual Firm Energy (GWh)	278[d]
Average Annual Energy (GWh)	220
Equivalent Capacity Factor (%)	50

(a) All data in this data sheet are taken from Acres American (1981b) unless otherwise indicated.
(b) Based on estimates prepared for the Chakachamna hydroelectric project, Volume XIV.
(c) Estimate.
(d) Alaska Power Administration 1980.

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	2[a]
Construction (years)	5[a]
Startup (years)	<<1[a]
Earliest Commercial Service	1989
Plant Life (years)	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	5849[b]
Working Capital ($/kW)	1[c]
Fixed O&M ($/kW/yr)	7[d]
Variable O&M (mills/kWh)	None

Payout Schedule[e]

Year	$	%
1	29,300,000	10.0
2	73,100,000	25.0
3	87,800,000	30.0
4	73,100,000	25.0
5	29,300,000	10.0

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale	Not Applicable

(a) Estimates.
(b) Acres American (1981b) estimate (5092 $/kW) in July 1980 dollars, escalated to January 1981 using Handy-Whitman index; escalated to January 1982 using 9% annual rate of inflation plus 0.8% real escalation (Table 25.1).
(c) Based on 30-day O&M costs.
(d) Based on estimates prepared for Browne hydroelectric project (Volume XV). with powerhouse O&M (assumed to constitute 50% of O&M costs) taken at 50% of Browne costs.
(e) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 12.0

STRANDLINE LAKE HYDROELECTRIC PROJECT[(a)]

The proposed Strandline Lake hydroelectric project would consist of a diversion structure and powerhouse of 20-MW installed capacity on the Beluga River, which is northeast of Cook Inlet.

TECHNICAL PERFORMANCE DATA

Installed Capacity (MW)	20
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/Cycling
Forced Outage Rate (%)	5[(b)]
Scheduled Outage Rate (%)	1.5[(c)]
Equivalent Availability (%)	94
Annual Firm Energy (GWh)	81
Average Annual Energy (GWh)	85
Equivalent Capacity Factor (%)	99

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	2[(c)]
Construction (years)	4[(d)]
Startup (years)	< 1
Earliest Commercial Service	1988
Plant Life (years)	50

(a) All data in this data sheet are taken from Volume IV unless otherwise indicated.
(b) Based upon estimates prepared for the Chakachamna hydroelectric project, Volume XIV.
(c) Estimate.
(d) Estimate based on Allison hydroelectric project (see Technical Data Sheet 9.0).

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	7240[a]
Working Capital ($/kW)	4[b]
Fixed O&M ($/kW/yr)	44[c]
Variable O&M (mills/kWh)	None

Payout Schedule[d]

Year	$	%
1	21,700,000	15.0
2	50,700,000	35.0
3	50,700,000	35.0
4	21,700,000	15.0

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale Not Applicable

(a) Acres American (1981b) estimate (6300 $/kW) in July 1980 dollars, escalated to January 1981 using Handy Whitman index; escalated January 1982 using 9% annual rate of inflation plus 0.8% real escalation (weighted capital cost escalation (60% material and equipment 40% labor) from Table 25.1.
(b) Based on 30-day O&M costs.
(c) Based on Grant Lake estimate. See Technical Data Sheet 8.0.
(d) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 13.0

KEETNA HYDROELECTRIC PROJECT[a]

The proposed Keetna hydroelectric project would be located on the Talkeetna River several miles east of the community of Talkeetna upstream of the confluence of the Sheep River. This project has been proposed as part of an integrated system project that includes the proposed Cache and Talkeetna-2 hydroelectric facilities located upstream. The Keetna project would consist of an earthfill dam approximately 350-ft high and 1200 ft in length. The resulting reservoir would have a normal maximum water level of about 945 ft. The tailwater elevation of 615 ft would result in a maximum gross head of 330 ft. A separate rock cut channel, a spillway control structure and a spillway would be provided. An intake and power tunnel would lead to a penstock dropping to an aboveground powerhouse of 100-MW installed capacity.

TECHNICAL PERFORMANCE DATA

Installed Capacity (MW)	100
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/Cycling
Forced Outage Rate (%)	5[b]
Scheduled Outage Rate (%)	1.5[c]
Equivalent Availability (%)	94
Annual Firm Energy (GWh)	324
Average Annual Energy (GWh)	395
Equivalent Capacity Factor (%)	45

(a) All data in this data sheet are taken from Acres American (1981b) unless otherwise indicated.
(b) Based upon estimates prepared for the Browne hydroelectric project (Technical Data Sheet 14.0).
(c) Estimate.

SCHEDULE[a]

Availability for Order	Available
Preconstruction Studies and Licensing (years)	4
Construction (years)	4.5
Startup (years)	~1/2
Earliest Commercial Service	1991
Plant Life (years)	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	5476[b]
Working Capital ($/kW)	<1[c]
Fixed O&M ($/kW/yr)	5[d]
Variable O&M (mills/kWh)	Negligible

Payout Schedule[e]

Year	10^6 $	%
1	54.8	10.0
2	137.0	25.0
3	164.0	30.0
4	137.0	25.0
5	54.8	10.0

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale	Not Applicable

(a) Based upon estimates prepared for the Browne hydroelectric project (Technical Data Sheet 14.0).
(b) Acres American (1981b) estimate in July 1980 dollars (4767 $/kW), escalated to January 1981 using Handy Whitman index, line 22; escalated to January 1982 using 9% annual inflation rate plus 0.8% real escalation.
(c) Based on 30-day O&M costs.
(d) Based on Browne hydroelectric project (Technical Data Sheet 14.0).
(e) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 14.0

BROWNE HYDROELECTRIC PROJECT[a]

The proposed Browne hydroelectric project would be located on the Nenana River approximately two miles downstream of the Alaska Railroad siding of Browne, which is approximately 65 air miles southwest of Fairbanks. The proposed project would consist of a dam, spillway, reservoir, aboveground powerhouse and appurtenant structures. A zoned earth and rockfill dam is proposed, 200 ft in height and 3000 ft long. A reservoir would be formed with maximum pool elevation of 975 ft extending 11 miles south of the damsite. The average tailwater elevation of 780 ft would provide a maximum gross head of 195 ft and an average operating head of 170 ft. A spillway would be provided at the left abutment of the dam. A water intake would be constructed in the right abutment of the dam. A water intake would be constructed in the right abutment at an invert elevation of 850 ft. A high-pressure power tunnel would convey water to the penstock, which would drop to the abovegound powerhouse located on the right bank downstream of the dam. Four turbogenerators of 100-MW total rated capacity would be provided. 138 kV transmission lines would lead to the proposed Anchorage-Fairbanks intertie.

TECHNICAL PERFORMANCE DATA

Installed Capacity (MW)	100
Size Range for Which Data Are Generally Valid (MW)	Not Applicable
Capacity Credit	Full
Capacity Limit in Railbelt (MW)	Not Applicable
Typical Operation	Baseload/Cycling
Forced Outage Rate (%)	5
Scheduled Outage Rate (%)	1.5
Equivalent Availability (%)	94
Annual Firm Energy (GWh/yr)	298

(a) All data in this data sheet are taken from Volume XV unless otherwise indicated.

Average Annual Energy (GWh)	430
Equivalent Capacity Factor (%)	48

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	4
Construction (years)	4-1/2
Startup (years)	∿1/2
Earliest Commercial Service	1991
Plant Life (years)	50

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	4470
Working Capital ($/kW)	<1(a)
Fixed O&M ($/kW/yr)	5
Variable O&M (mills/kWh)	Negligible

Payout Schedule (b)

Year	10^6 $	%
1	69.4	16
2	97.5	22
3	126.0	28
4	115.9	26
5	41.9	9

Escalation Factors (%/Year, 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

(a) Based on 30-day O&M costs.
(b) Based on Phung (1978 weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 15.0

UPPER SUSITNA HYDROELECTRIC PROJECT[a]

The Upper Susitna hydroelectric project would consist of two major hydroelectric dam and reservoir facilities located on the Upper Susitna River. The Watana Dam and reservoir would be located near Watana Creek approximately 35 miles east of the Alaska Railroad (Gold Creek). The proposed dam would be rockfill with an impervious core with a crest elevation of 2225 ft and a length of 5400 ft. Maximum height above the foundation would be about 880 ft. A small saddle dam would be located above the right abutment. A spillway with crest elevation of 2115 ft would be located on the right bank. A water intake would be provided upstream of the left abutment and would lead to four penstocks, which would convey water to an underground powerhouse below the left abutment. Initial plans called for four turbine generators of 200 MW each to be istalled in two stages; however, revised plans call for a total of 1020 MW of installed capacity installed in two stages of 680 MW and 340 MW. A tailrace tunnel would discharge to the river downstream of the dam.[b]

The Devil Canyon Dam and reservoir would be located in Devil Canyon approximately 10 miles northeast of Gold Creek. A proposed dam would be a thin arch concrete structure with an overall height of 650 ft, a crest elevation of 1420 ft and a crest length of 1230 ft. A small saddle dam would be constructed on the left abutment. A main gate-controlled spillway would be located on the right abutment and a secondary gated spillway in the center section of the dam. An emergency spillway with fusible plug would be located in the right of the saddle dam. A water intake would be located upstream of the right abutment; four concrete penstocks would lead to an underground powerhouse below the right abutment. Initial plans called for 400 MW of installed capacity; however, revised plans call for 600-MW of installed capacity.[b] Draft tubes would discharge to a tailrace tunnel discharging downsteam.

(a) All information in this data sheet is taken from Acres American (1981b) unless otherwise indicated.
(b) Obtained from a letter: J.D. Lawrence, Acres American, Inc., to J.J. Jacobsen of Battelle, Pacific Northwest Laboratories, December 22, 1981.

The Devil Canyon Dam would be constructed to follow the Watana Dam, which would provide for sufficient storage capacity to allow optimal operation of Devil Canyon. Prior to completion of Devil Canyon, a small re-regulating dam would be constructed at the Devil Canyon site. Power would be transmitted from the development by up to four 345-kV lines connecting to the proposed Anchorage-Fairbanks intertie at Gold Creek.

TECHNICAL PERFORMANCE DATA

	Watana 1st Stage	Watana 2nd Stage	Devil Canyon
Installed Capacity (MW)	680[a]	340[a]	600[a]
Size Range for Which Data Are Generally Valid (MW)		Not Applicable	
Capacity Credit (MW)	680	340	600
Capacity Limit in Railbelt (MW)		Not Applicable	
Typical Operation		Baseload/Cycling	
Forced Outage Rate (%)	5[b]	5[b]	5[b]
Scheduled Outage Rate (%)	1-1/2[b]	1-1/2[b]	1-1/2[b]
Equivalent Availability (%)	94[b]	94[b]	94[b]
Annual Firm Energy (GWh)	2631[a]	0	2763[a]
Annual Average Energy (GWh)	3459[a]	0[a]	3334[a]
Equivalent Capacity Factor (%)	58	0	63

SCHEDULE

	Watana 1st Stage	Watana 2nd Stage	Devil Canyon
Availability for Order	Available	Available	Available
Preconstruction Studies and Licensing (years)	3	(c)	(c)
Construction (years)	8	2	8
Startup (years)	1/4	1/2	1
Earliest Commercial Service	1993	1995	1996
Plant Life	50	50	50

(a) Obtained from a letter: J.D. Lawrence, Aces American, Inc., to J.J. Jacobsen of Battelle, Pacific Northwest Laboratories, December 22, 1981.
(b) Typical, taken from Volume XIV.
(c) Schedules for 2nd stage of Watana and Devil Canyon depend upon completion of Watana access.

COST DATA

Estimated Costs (January 1982)

	Watana 1st Stage	Watana 2nd Stage	Devil Canyon
Overnight Capital ($/KW)[a]	4669	168	2263
Working Capital ($/kW)	Nil	Nil	Nil
Fixed O&M ($/kW/yr)	5[b]	5[b]	5[b]
Variable O&M	Nil	Nil	Nil

Payout Schedule[c]

	Watana 1st Stage		Watana 2nd Stage		Devil Canyon	
Year	10^6 $	%	10^6 $	%	10^6 %	%
1	127	4	29	50	95	7
2	239	11	29	50	571	18
3	508	16	--	--	794	25
4	603	19	--	--	794	25
5	603	19	--	--	571	18
6	508	16	--	--	95	7
7	349	11	--	--	---	--
8	127	4	--	--	---	--

Escalation Factors (%/year 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2
Economics of Scale	Not Applicable

(a) Transmission costs are excluded.
(b) Battelle estimate.
(c) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 16.0

MICROHYDROELECTRIC PLANTS[a]

Microhydroelectric projects are typically defined as hydroelectric projects of less than 100-kW (0.1-MW) installed capacity (Noyes 1980). A typical microhydroelectric facility includes a water intake structure, a penstock, a turbine-genertor unit, and a powerhouse. A dam and storage reservoir may be used in some installations; however, many microhydro installations operate on run-of-the-stream. Off-grid installation may provide for energy storage, generally in the form of lead-acid storage batteries. On-grid installations will require a reversing meter, circuit breaker and disconnect. For most of the utility-connected installtions, the utility line at primary distribution voltage will have to be brought to the immediate vicinity of the microhydro generator, with connection to be made via a distribution transformer.

TECHNICAL PERFORMANCE

Installed Capacity (typical) (MW)	0.05
Size Range for Which Data Are Generally Valid (MW)	0.001 to 0.1
Capacity Credit	None
Capacity Limit in Railbelt (MW)	See Table 16.1
Typical Operation	Fuel Saver
Forced Outage Rate (%)	Variable
Scheduled Outage Rate (%)	Variable
Annual Firm Energy (GWh)	None
Average Annual Energy (GWh)	0.26[b]
Typical Capacity Factor (%)	60 to 100

(a) Data in this data sheet are taken from Volume IV unless otherwise indicated.
(b) Based on capacity factor of 60%, which was the low end of 60% to 100% range suggested in Alward, Eisenbart and Volkman (1979). Selected due to presumed significant reduction in stream flow during cold seasons.

TABLE 16.1. Estimated Economic Limits to Microhydroelectric Development in the Railbelt

Cost of Power ($/kWh)	Anchorage Load Center: Installed Capacity (MW)	Anchorage Load Center: Energy (GWh)	Fairbanks Load Center: Installed Capacity (MW)	Fairbanks Load Center: Energy (GWh)	Glennallen Load Center: Installed Capacity (MW)	Glennallen Load Center: Energy (GWh)	Total: Installed Capacity (MW)	Total: Energy (GWh)
0.09	--	--	--	--	--	--	--	--
0.10	<1	1	<1	<1	1	1	<1	2
0.15	1	8	<1	<1	1	6	2	14
0.20	3	14	<1	<1	2	11	5	25
0.25	4	21	<1	1	3	17	7	39
0.30	5	27	<1	1	4	22	9	50

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	1 to 2[a]
Construction (years)	≤1
Startup (years)	<1
Earliest Commercial Service	1983
Plant Life (years)	20

COST DATA

Estimated Costs (January 1982)

	Low	High
Overnight Capital ($/kW)		
Local Plant	5,000	29,000
Remote Plant[b]	12,000	36,000
Working Capital ($/kW)[c]		
Local Plant	6	48
Remote Plant	20	59
Fixed O&M ($/kW/yr)		
Local Plant	75	580
Remote Plant	240	720
Variable O&M (mills/kWh)	Negligible	

Payout Schedule	One shot
Escalation Factors	
Capital	See Table 25.1
O&M	See Table 25.2
Economics of Scale	No information available.

(a) Upper end of range is based on typical small-scale (15 MW) hydro project schedule (Corps of Engineers 1979).
(b) Five miles of transmission line and access road required.
(c) Based on 30-day O&M cost.

TECHNICAL DATA SHEET 17.0

COOK INLET TIDAL ELECTRIC PROJECT[a]

Tidal electric power plants typically consist of a barrier (barrage) across a bay or inlet that is subject to high tides. Intake (sluice) gates are provided to admit water on incoming tides; horizontal axis turbine-generators are provided to generate power as the outgoing tide drops below the level of water retained behind the tidal barrage. Appurtenant structures may include substations, transmission lines, navigational locks and vehicular crossing facilities.

Examination of candidate sites in Cook Inlet resulted in the recommendation of a potential site at Eagle Bay on Knik Arm for further study (Acres American 1981a). The proposed Eagle Bay installation would consist of a tidal barrage extending across Knik Arm at the narrowing of the channel above Eagle and Goose Bays. The barrage would consist of an access dike from shoreside to the location of the first powerhouse unit; 60 powerhouse modules, each containing a bulb turbine-generator unit of 24-MW rated capacity for a total of 1440-MW of rated capacity; 36 sluiceway modules, and a closure dike to the far shore. A substation and 230-kV or 345-kV transmission tie would be provided. A vehicular causeway would be optional. An alternative (720-MW) design would use 30 turbine-generators.

Pumped storage capacity could be used to retime energy derived from tidal power. Complementary pumped storage retiming projects were considered for each Eagle Bay tidal electric project alternative.

(a) All data in this data sheet are taken from Acres American (1981a) unless otherwise indicated.

TECHNICAL PERFORMANCE DATA

	720-MW Plant		1440-MW Plant	
	Tidal Facility	Retiming Facility	Tidal Facility	Retiming Facility
Installed Capacity (MW)	720	450[a]	1440	1200[a]
Size Range for Which Data Are Generally Valid	NA	NA	NA	NA
Capacity Credit (MW)	None	225[b]	None	600[b]
Capacity Limit in Railbelt (MW)	NA	NA	NA	NA
Typical Operation	Intermittent	Baseload	Intermittent	Baseload
Forced Outage Rate (%)[c]	5	5	5	5
Scheduled Outage Rate (%)[c]	1.5	1.5	1.5	1.5
Equivalent Availability (%)[c]	94	94	94	94
Annual Raw Energy (GWh)	2300	---	4000	---
Annual Usable Energy (GWh)	1530[d,e]	2050[e,f]	1600[d,f]	3200[e,f]
Equivalent Capacity Factor (%)[g]	24.3	32.5	12.7	25.4

NA = Not Applicable
(a) Installed pumping capacity.
(b) Installed generating capacity. Value shown for 720-MW alternative is an assumption.
(c) Outage data taken from Volume XV.
(d) Approximately 10% of total system load could be directly absorbed without retiming. These figures therefore vary with future system load.
(e) Estimated, given Acres American (1981a) data on fraction of usable energy and pumped storage efficiency.
(f) Total usable energy includes direct and retimed contribution.
(g) Based on tidal plant installed capacity.

SCHEDULE

	720-MW Plant		1440-MW Plant	
	Tidal Facility	Retiming Facility	Tidal Facility	Retiming Facility
Availability for Order	Available	Available	Available	Available
Preconstruction Studies and Licensing (years)	7	4[a]	7	4[a]
Construction (years)	11	4[b]	11	5[b]
Startup (years)		(Included in construction)		
Earliest Commercial Service	2000	2000[d]	2000	2000[d]
Plant Life	50	50	50	50

COST DATA[e]

Estimated Costs (January 1982)

	720-MW Plant		1440-MW Plant	
	Tidal Facility	Retiming Facility	Tidal Facility	Retiming Facility
Overnight Capital ($/kWh)[f]	3710	1150[g]	2690	1150[g]
Working Capital ($/kWh)[h]	Nil	Nil	Nil	Nil
Fixed O&M	22.20	10.60	16.20	10.60
Variable O&M (mills/kWh)		(Included in Fixed O&M)		

(a) Assumption.
(b) Pumped storage data from Volume IV.
(c) Construction period for 720-MW alternative is assumed to be comparable to 1440-MW alternative.
(d) Pumped storage projects are assumed to be timed to come on-line with associated tidal power facility.
(e) Costs were provided in June 1981 dollars in original report (Acres American 1981a). All costs have been escalated to January 1982 dollars using 9% annual rate of inflation plus the 1981 capital cost escalator from Table 25.1.
(f) Does not include land or land rights, causeway or transmission facilities. Owner's costs included.
(g) Based on kW of pumping capacity.
(h) Includes 30-day O&M costs.

Payout Schedule[a]

	720-MW Alternative				1440-MW Alternative			
	No Retiming		With Retiming		No Retiming		With Retiming	
Year	$10^{(6)}$\$	%	$10^{(6)}$\$	%	$10^{(6)}$\$	%	$10^{(6)}$\$	%
1	107	4	107	3	154	4	155	3
2	214	8	214	7	310	8	310	6
3	294	11	294	9	426	11	426	8
4	347	13	347	11	504	13	504	10
5	374	14	374	12	542	14	542	10
6	374	14	374	12	542	14	542	10
7	374	14	374	12	542	14	680	13
8	347	13	425	13	504	13	849	16
9	294	11	475	15	426	11	840	16
10	214	8	395	12	310	8	655	12
11	107	4	184	6	154	4	293	6

Escalation Factors (%/year 1981-2010)

Capital	See Table 25.1
O&M	See Table 25.2

Economics of Scale — As provided in 720-MW and 1440-MW estimates.

(a) Based on Phung (1978) weak sinusoidal payout schedule.

TECHNICAL DATA SHEET 18.0

LARGE WIND ENERGY CONVERSION SYSTEMS[a]

Large wind energy conversion systems would consist of several multimegawatt wind turbines configured as a wind farm. The prototypical system examined in this study consists of ten 2.5-MW MOD-2, horizontal axis wind turbines, arrayed in an integrated wind farm in the Isabell Pass area south of Big Delta. In addition to the wind turbines, the prototypical wind farm includes control, maintenance, substation and transmission facilities. Power transmission from the prototypical site would be by a 138-kV single-circuit line to the existing GVEA line at Fort Churchill and upgrading of the existing 15.8/24.4-kV Fort Churchill-Fairbanks line to 138 kV. Additional areas of favorable wind resource are found in the Railbelt, and several wind farms of the configuration examined in the prototype could be constructed.

TECHNICAL PERFORMANCE DATA

Nominal Plant Size (MW)	25
Size Range or Which Data Are Generally Valid (MW)	Multiple Wind Farms of 25 MW each
Capacity Credit	None
Capacity Limit in Railbelt (MW)	100 - 1000[b]
Typical Operation	Intermittent Baseload (fuel saver)
Forced Outage Rate (%)	6
Scheduled Outage Rate (%)	5
Equivalent Availability	89
Average Annual Energy	7.8
Equivalent Capacity Factor (%)	35.5

(a) All data in this data sheet are taken from Volume XVI unless otherwise indicated.
(b) Possibly limited to lower levels because of system stability considerations.

SCHEDULE

Availability for Order	1985[a]
Preconstruction Studies and Licensing (years)	2[b]
Construction (years)	1-3/4
Startup (years)	1/4
Earliest Commercial Service	1988[c]
Plant Life (years)	30

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	2490[d]
Working Capital ($/kW)	<1[e]
Fixed O&M ($/kW/yr)	3.68
Variable O&M (mills/kWh)	3.3

Payout Schedule[f]

Year	$10^{(6)}$$	%
1	13.5	21.8
2	48.7	78.2

Escalation Factors (%/year 1981 - 2010)

Capital	See Table 25.1
O&M	0

(a) EPRI (1979).
(b) Allows one year for site selection and one year of site monitoring. Additional monitoring may be desirable.
(c) Assumes site monitoring and licensing commences after commercial availability is announced.
(d) Does not include land or land rights, owner's costs or transmission costs beyond the plant switchyard.
(e) Includes 30-day O&M cost.
(f) Based on Phung (1978) sinusoidal payout schedule.

Economics of Scale

Capital	• none for additional wind farms at other sites • shared transmission costs for up to 80-MW capacity at Isabell Pass area • shared maintenance, control system, access and substation costs for additional machines at proposed site
O&M	• some fixed O&M economies would result from additional capacity in Isabell Pass area.

TECHNICAL DATA SHEET 19.0

SMALL WIND ENERGY CONVERISON SYSTEMS[a]

Small wind energy conversion systems (SWECS) are wind turbines rated at 100 kW or less, of horizontal or vertical axis design. Machines currently in production range in size from 0.1 to 37 kW. Typically, the siting of these machines would be dispersed, at the individual residence, commercial, industrial, or small community level.

SWECS may be operated independently of a utility grid or interfaced with the grid. Only grid-connected installations are considered in this study.

TECHNICAL PERFORMANCE

Nominal Plant Size (MW)	0.0005 to 0.1
Size Range for Which Data are Generally Valid (MW)	0.005 to 0.1 unless noted
Capacity Credit	None
Capacity Limit in Railbelt (MW)	See Table 19.1
Typical Operation	Fuel Saver
Forced Outage (%)	1[b]
Scheduled Outage (%)	1[b]
Equivalent Availability	98
Average Annual Energy	A function of wind resource availability. Plant capacity factor and corresponding average annual energy is estimated to be as follows for the various wind resource classes of Wise et al. (1980):

(a) All data in this data sheet are taken from Volume IV unless indicated otherwise.
(b) Bonneville Power Administration (BPA). 1981 (draft). Technical Assessment of the Potential for Conservation and End Use Renewable Resources in the West Group Area. Bonneville Power Administration, Division of Power Requirements/Division of Conservation, Portland, Oregon.

TABLE 19.1. Estimated Economic Limits to Small Wind Energy Conversion System(a) Development in the Railbelt

	Anchorage Load Center		Fairbanks Load Center		Glennallen Load Center		Total	
($/kWh)	Installed Capacity (MW)	Energy (GWh)	Installed Capacity (MW)	Energy (GWh)	Installed Capacity (MW)	Energy (GWh)	Installed Capacity (MW)	Energy (GWh)
0.05	--	--	--	--	--	--	--	--
0.06	5	16	<1	<1	<1	<1	5	16
0.07	10	31	3	7	<1	1	13	39
0.08	14	41	5	13	<1	2	19	56
0.09	14	41	5	13	<1	2	19	56
0.10	28	71	9	22	<1	3	37	96
0.15	34	81	16	34	4	9	54	124

(a) Assumes full penetration of SWECS whenever economically feasible for cost of power shown. In practice, penetration will likely be substantially less due to constraints such as limitation on installation of SWECS in urban areas and reluctance of many homeowners to deal with a SWECS.

Wind Resource Class	Capacity Factor (%)	Average Energy GWh/yr[a]
1	10	0.009
2	15	0.013
3	20	0.018
4	25	0.022
5	30	0.026
6	35	0.031
7	40	0.035

SCHEDULE

Earliest Commercial Service[b]	1983
Preconstruction Studies and Licensing (years)	1[c]
Construction (years)	<1
Startup (years)	<1
Plant Life (years)	20

COST DATA

Estimated Costs (January 1982)[d]

	2 kW	10 kW
Overnight Capital ($/kW)[e]	2960	2378
Working Capital ($/kW)	--	--
Fixed O&M ($/kW/yr)	30	24
Variable O&M (mills/kWh)	--	--

(a) 10 kW (0.01 MW) machine.
(b) Machines could be production limited if demand were to increase substantially.
(c) Minimum recommended time for wind resource survey.
(d) Base costs from Volume IV, escalated from July 1980 to January 1981, using Handy Whitman distribution plant escalation indices; and escalated from January 1981 to January 1982 using a 9.0% annual rate of inflation plus the 1981 weighted (60% material, 40% labor) capital cost escalator (0.8%) of Table 25.1 and the 0% O&M cost escalator of Table 25.2.
(e) Does not include land or land rights.

Payout Schedule	One shot
Escalation Factors (%/yr 1981 to 2010)	
Capital	See Table 25.1
O&M	See Table 25.2
Economics of Scale	As provided in estimates for 2-kW and 10-kW machines.

TECHNICAL DATA SHEET 20.0

REFUSE-DERIVED FUEL STEAM-ELECTRIC POWER PLANTS

Two steam-electric generating facilities using municipal refuse may be feasible for the Railbelt region. One plant, constructed near Anchorage, would be fired with municipal refuse from the Anchorage area, supplemented with wood waste as available and coal transported by rail from the Nenana field. A plant of 50-MW rated capacity probably could be supported; the proportion of refuse-derived fuel would increase over time with greater Anchorage population growth. A 50-MW plant coming on-line in 1990 could accommodate the average municipal waste production of the Anchorage area until approximately year 2010.

A second plant of smaller size could be constructed near Fairbanks to use refuse from the Fairbanks area and possibly wood waste from sawmills near Fairbanks and Nenana. Supplemental firing by coal from the Nenana field would be required during the early years of plant operation. A plant of 20-MW rated capacity coming on-line 1990 could accommodate municipal waste production from the Fairbanks area until approximately 2010. Either mass-burning or refuse-derived fuel plant designs could be used.

TECHNICAL PERFORMANCE DATA

	Anchorage	Fairbanks
Nominal Plant Size (MW)	50	20
Size Range for Which Data Are Generally Valid (MW)	As Given	As Given
Capacity Credit	Full[a]	Full[a]
Capacity Limit in Railbelt (MW)	50	50
Typical Operation	Baseload	Baseload
Heat Rate (Btu/kWh)	14,000	14,800[b]
Forced Outage Rate (%)	Not Applicable	Not Applicable
Scheduled Outage Rate (%)	Not Applicable	Not Applicable
Equivalent Availability (%)	85[c]	85[c]

(a) With supplemental firing of coal or wood residue.
(b) Obtained by fitting a curve of the form $y = ax^b$ to data of Volume IV.
(c) Average of values in Volume IV.

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	3[(a)]
Construction (years)	1-1/2 - 3
Startup (years)	<1
Earliest Commercial Service	1987
Plant Life (years)	30

FUEL

Composition	Municipal refuse supplemented by coal delivered from Nenana as required.
RDF Availability	See Table 20.1
Heat Value	Nenana Coal: 8,000 Btu/lb RDF: 6,700 Btu/lb[(b)]

COST DATA

Estimated Costs (January 1982)

	Anchorage	Fairbanks
Overnight Capital ($/kW)[(c)]	2890	3230
Working Capital ($/kW)[(d)]	93	94

(a) Estimate.
(b) As received, municipal solid waste would have a heat value of approximately 4500 Btu/lb if direct-fired to a mass burner.
(c) Costs of Volume IV escalated to January 1981 using Handy Whitman steam production plant index; escalated to January 1982 using 9% annual inflation rate plus real capital cost escalation rate of Table 25.1.
(d) 90-day coal pile plus 30-day O&M.

	Anchorage	Fairbanks
Fixed O&M ($/kW/yr)	136[a]	136[a]
Variable O&M (mills/kWh)	14.8[a]	14.8[a]
Fuel ($/MMBtu): RDF[b]	See Table 26.1	
Coal[c]	1.28	1.21

Payout Schedule [d]

	Anchorage		Fairbanks	
Year	$10^{(6)}$$	%	$10^{(6)}$$	%
1	37.3	25	16.6	25
2	74.6	50	33.2	50
3	37.3	25	16.6	25

Escalation Factors (%/year, 1981-2010)

	Anchorage	Fairbanks
Capital	See Table 25.1	
O&M	See Table 25.2	
Fuel (%): RDF	See Table 26.1	
Coal	See Table 26.1	

Economies of Scale

Capital	20-50 MW: as estimated above 50-150 MW: linear
Fixed O&M	None identified
Variable O&M	None identified
Fuel	None identified

(a) Estimates based on fixed and variable fractions of SRI (1979), escalated in accordance with Table 20.1.
(b) Unprocessed municipal solid waste could have a negative cost (tipping fee).
(c) Nenana coal, delivered.
(d) Based on Phung (1978) weak sinusoidal payout schedule.

TABLE 20.1. Estimated RDF Availability (average tons/day)

Year	Anchorage	Fairbanks
1985	396	150
1990	502	190
1995	640	240
2000	777	290
2005	890	330
2010	1010	380

TECHNICAL DATA SHEET 21.0

RESIDENTIAL BUILDING CONSERVATION

Building energy conservation projects encompass a variety of techniques for reducing the electrical load of residential structures heated with electricity. Electricity heated structures currently comprise about 21% of Anchorage households, 9% of Fairbanks households, and 1% of Glennallen-Valdez households.[a] Energy savings and choice of these techniques depend on the size and age of structure and on the climate at the location of the structure. The cost-effective techniques on new structures include extra insulation in the ceiling (R-60), insulated doors, triple pane windows, and extensive care in sealing and caulking to reduce air changes from 1.0 down to 0.25 (Barkshire 1981a). 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. Other assumed improvements include a third pane of glass on all windows, R-8 insulated doors, and sufficient caulking and sealing to bring air infiltration down to 0.5 air changes per hour (Barkshire 1981b). Insulation is assumed to be applied by contractors, whereas glazing, caulking, and weatherstripping are applied by the owner. For new construction, energy "savings" of new construction improvements over standard practices are 289.1 Btu/hr-^{o}F.

TECHNICAL PERFORMANCE

Nominal Plant Size	1500 square foot house
Size Range for Which Data Are Generally Valid (MW)	1000 to 2500 square feet

(a) Obtained from a Battelle-Northwest Railbelt energy end-use survey conducted in April 1981.

Capacity Credit	See Table 21.1[a]
Capacity Limit in Railbelt (MW)	Not estimated
Typical Operation	Conservation with capacity credit. (seasonal peaking offset)
Forced Outage	0
Scheduled Outage (%)	0
Typical Capacity Factor (%)	100
Annual Firm Energy (kWh)	Same as annual energy[a]
Average Annual Energy (kWh)	See Table 21.1[a]

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	<1
Construction (years)	<1
Startup (years)	<1
Earliest Commercial Service	1982
Plant Life (years)	30[b]

COST DATA

Estimated Costs (January 1982)

	New Construction	Retrofits
Overnight Capital ($/kW)		
Anchorage	652	501
Fairanks	566	435
Glennallen-Valdez	605	464
Working Capital ($/kW)	0	0
Fixed O&M ($/kW/yr)	0	0

(a) Equals difference in load between superinsulated house and current best standard practice. See Barkshire 1981a; Barkshire 1981b.
(b) New construction. For retrofit applications, the caulking required to seal the structure may have to be replaced at 20 years.

TABLE 21.1. Performance and Capital Cost of Residential Building Conservation Improvements[a]

New Building	Anchorage	Fairbanks	Glennallen-Valdez
Heat Loss Improvement per Installation (kWh/yr)	21,974	29,300	25,637
Installed Cost of Improvements	$4,885	$5,180	$6,158
Conserved Energy at Peak (kW)	7.49 (-20 F)	9.15 (-40 F)	8.32 (-30 F)
Installed Cost per kW	$652.20	$566.12	$740.14
Retrofit Standard Practice Building			
Heat Loss Improvement per Installation (kWh/yr)	14,503	19,103	16,803
Installed Cost of Improvements	$2,500	$2,651	$3,152
Conserved Energy at Peak (kW)	4.99 (-20 F)	6.10 (-40 F)	5.55 (-30 F)
Installed Cost per kW	$501.00	$434.59	$567.93

(a) 1500 square feet of living space. Improvements are improvements over late 1970's standard building practice as follows:
Walls: R-19 (6" fiberglass batt, 2 x 6 wall)
Floors: R-19 (6" fiberglass batt)
Doors: R-8 (metal insulated)
Roof: R-30 (9" fiberglass batt)
Air changes per hour: 1.0
Base Heat Loss: 503 Btu/hr-^{o}F. In Anchorage, 131 MMBtu per year; in Fairbanks, 173 MMBtu per year. Glennallen-Valdez savings are assumed to be the average of Anchorage and Fairbanks values.

(b) Costs multipliers were estimated as follows by an Anchorage cost-estimating firm for Alaska Renewable Energy Associates:
- Anchorage (base) = 100.0
- Anchorage zone (up to 50 miles) = 110.03
- Anchorage zone (beyond 50 miles) = 122.43
- Fairbanks = 106.04
- Fairbanks zone (up to 50 miles) = 117.71
- Fairbanks zone (beyond 50 miles) = 129.69.

Glennallen-Valdez cost is an average of Anchorage and Fairbanks zones, beyond 50 miles.

TECHNICAL DATA SHEET 22.0

RESIDENTIAL PASSIVE SOLAR SPACE HEAT

The proper placement and use of windows in housing in the Railbelt region have considerable potential for reducing the space heat demand of these structures on an annual basis. However, the ability of the homeowner 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 because of the difficulty of retrofitting an existing structure. The most popular form of retrofit applications of passive solar is to add a greenhouse to the south wall of an existing structure, although this is a relatively inefficient way to reduce heating bills (Barkshire 1981a and 1981b).[a] 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. 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. Sunlight is <u>not</u> generally available during the peak heating periods of December and January to make a net contribution. Consequently, this technology is given no credit for peak demand.

The assumptions made in the Railbelt Electric Power Alternatives Study for passive solar are as follows. A basic 1500 square foot house is assumed to be oriented so that it has 200 square feet of south-facing glass. No thermal storage is assumed. About 19.3 MMBtu of net solar gain is assumed, (about

(a) Retrofits are generally difficult because existing structures have not generally been oriented with solar in mind. Costs of solar greenhouses approach those of regular construction, whereas direct gain (windows) or conservation alone is more cost effective in most cases. The upper assumed limit of market penetration for solar retrofits is 5 to 10% of the building stock.

13.8 MMBtu more than a standard house). The assumed solar retrofit is an 8-foot by 20-foot solar greenhouse, which supplied 10 to 15% of the heat required by the basic 1500 foot house.[(a)]

Technical considerations (site characteristics) limit penetration of passive solar space heat applications to about 35 to 50% of the new building stock, whereas solar greenhouses designed for heat supplement are expected to be limited to 10 to 15% of the existing housing stock.

TECHNICAL PERFORMANCE

Nominal Plant Size	200 square feet of south glazing
Size Range for Which Data Are Generally Valid	60-200 square feet
Capacity Credit	0
Capacity Limit in Railbelt (MW)	Not assessed
Typical Operation	Conservation without capacity credit (fuel saver).
Forced Outage (%)	0
Scheduled Outage (%)	0
Typical Capacity Factor	Not applicable
Annual Firm Energy (kWh)	Unknown
Average Annual Energy (kWh)	4,043[(b)]

(a) The solar greenhouse performace is estimated by Barkshire (1981b) at 10 to 15% of the base house's heat loss of 131 MMBtu per year in Anchorage. The greenhouse costs are estimated in the same sources at $30 to $40 per square foot. Because the estimates are for a relatively elaborate greenhouse, the top end of the cost range is used.

(b) Equals difference from standard practice home, assumed to have 32.5 square feet of south glazing, about 13.8 MMBtu/yr.

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	<1
Construction (years)	<1
Startup (years)	<1
Earliest Commercial Service	1982
Plant Life (years)	30+[a]

COST DATA

Estimated Costs (January 1982)

Overnight Capital	See Table 22.1
Working Capital	0
Fixed O&M ($/kW/yr)	0

(a) Life of the dwelling for new construction. About 10 years for solar greenhouse retrofit.

TABLE 22.1. Performance and Capital Cost of Residential Passive Solar Improvements[a]

New Building	Anchorage	Fairbanks	Glennallen-Valdez
Heat Equivalent Improvement Over Standard House (kWh/yr)	4,043	4,043	4,043
Installed Cost of Improvement	$1,330	$1,410	$1,677
Energy Available at Peak (kW)	0	0	0
Installed Cost per kW	NA	NA	NA
Retrofit			
Heat Equivalent Improvement Over Standard House (kWh/yr)[b]	4,600	4,600	4,600
Installed Cost of Improvement[c]	$6,400	$6,787	$8,067
Energy Available at Peak (kW)	0	0	0
Installed Cost per kW	NA	NA	NA

(a) New construction based on 200 square feet of south-facing glass, no thermal storage. Retrofits based on solar greenhouse.

(b) Assumes for Anchorage 34.4 MMBtu solar radiation, and a heat load (shuttered R-30 greenhouse) of 18.7 MMBtu. Net gain to structure equals 15.7 MMBtu or 4600 kWh/yr in Anchorage. Heat loss in Fairbanks assumed 32% higher for any given R-values, but greenhouse is R-50 rather than R-30. Sunlight is also 15 to 20% greater. Net gain is still 18.7 MMBtu. Glennallen-Valdez is assumed to be the average of Anchorage and Fairbanks. Greenhouse is 8 feet by 20 feet with 130 square feet of south-facing glass. See Volume IV.

(c) Assumes solar greenhouse 8 ft wide x 20 ft long = 160 square feet at $40 per square foot. R-30 insulation, shuttered 130 square feet of south-facing glass. For multipliers, see Technical Data Sheet 21.0.

TECHNICAL DATA SHEET 23.0

RESIDENTIAL ACTIVE SOLAR HOT WATER

Active solar technology has some potential in the Railbelt to reduce the load on the conventional hot water systems. The effectiveness of the system 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).[a] New and retrofit units selected for the study assume 80 square feet of collector using Sola Roll -type technology because this appears to be the most cost effective.[b] About 50% of the annual water-heating load of a family of four can be met with such an installation, at about 80 gallons per day use. The proportion of such use, which can be met by solar during the year, varies by month, from about zero in November through February, to about 85% in April through June.[c]

Limitations on market penetration are expected because of very long payback caused by high installation costs, holding the total market to 5 to 10% of hot water users (Barkshire 1981a).

TECHNICAL PERFORMANCE

Nominal Plant Size	80 square feet of flat collector
Size Range for Which Data Are Generally Valid	80 to 120 square feet

(a) For a more complete description of systems, see Volume IV, Chapter 8.
(b) A trademark from Bio-Energy Systems, Inc., Ellenville, New York.
(c) Although Railbelt households tend to be smaller, more water-using appliances are available than in typical U.S. homes. This was a finding in Battelle-Northwest's residential end-use survey. The 50% figure is from Barkshire (1981b).

Capacity Credit	0
Capacity Limit in Railbelt (MW)	Not assessed
Typical Operation	Conservation without capacity credit (fuel saver)
Forced Outage Rate (%)	Low
Scheduled Outage Rate (%)	Low
Typical Capacity Factor	Not applicable
Annual Firm Energy (kWh)	Unknown
Average Annual Energy (kWh)	3,390[a]

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	<1
Construction (years)	<1
Startup (years)	<1
Earliest Commercial Service	1982
Plant Life	20 years

COST DATA

Estimated Costs (January 1982)

	New Construction	Retrofits
Overnight Capital ($/kW)		
Anchorage	Not comparable with generation systems	
Fairbanks		
Glennallen-Valdez		
Working Capital	NA	NA
Fixed O&M ($/kW/yr)	Not comparable with generation systems	

(a) Equals energy savings for the collector on an annual basis for a system that uses the heated medium (water) directly. This estimate is based on matching loads of a family of 4 persons by month, for 11.57 MMBtu/year. Load is assumed to be 80 gallons/day of hot water.

TABLE 23.1. Performance and Costs of Residential Active Solar Improvements[a]

	Anchorage	Fairbanks	Glennallen-Valdez
Heat Equivalent Improvement Over Standard House (kWh/yr)	3,390	3,390	3,390
Installed Cost of Improvement[b]	$3,000	$3,000	$3,000
Energy Available at Peak (kW)	0	0	0
Installed Cost per kW	NA	NA	NA
Operations and Maintenance Costs	$25/yr	$25/yr	$25/yr

(a) Based on 80 square feet of Sola Roll-type collector, tanks and piping.
(b) Based on $25 per square foot average for Railbelt, plus $1000 other system costs.

TECHNICAL DATA SHEET 24.0

RESIDENTIAL WOOD SPACE HEAT

Wood is already a supplementary fuel of choice in many Railbelt communities. Unlike other dispersed technologies, it is not resource or weather limited at this time. The analysis of wood stoves in the Railbelt Electric Power Alternative Study was done on the presumption that at maximum penetration, one fifth of space heat required by homes heated with passive solar of the supplemental 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--or 20% of the total market (Barkshire 1981b). Inconvenience, fuel cost, and difficulty in using wood in multifamily units should limit maximum market penetration, even at low capital cost.

Many types of wood stoves and fireplace inserts are on the market. The cost and performance assumed in the study are for a high-quality airtight stove of heavy-gauge steel and soapstone. Stoves are available in sizes with heating capabilities ranging from 15,000 to over 100,000 Btu per hour with conversion efficiencies of 20 to 65%. The top end of the conversion efficiency range is chosen, a down-draft stove of about 50,000 Btu/hr capacity, 65% efficiency, lasting 20 years, and costing $2700 completely installed. Installation takes about two days (Barkshire 1981a).

TECHNICAL PERFORMANCE

Nominal Plant Size	50,000 Btu/hr
Size Range for Which Data Are Generally Valid	40-50,000 Btu/hr
Capacity Credit	14.65 kW
Capacity Limit in Railbelt (MW)	Not assessed
Typical Operation	Conservation with capacity credit (seasonal peak offset)
Forced Outage Rate (%)	0

Scheduled Outage Rate (%)	0
Typical Capacity Factor	Not applicable
Annual Firm Energy (kWh)	Unknown
Average Annual Energy (kWh)	See Table 24.1

SCHEDULE

Availability for Order	Available
Preconstruction Studies and Licensing (years)	<1
Construction (years)	<1
Startup (years)	<1
Earliest Commercial Service	1982
Plant Life	20 years

COST DATA

Estimated Costs (January 1982)

Overnight Capital ($/kW)	$177
Working Capital	0
Fixed O&M ($/kW)	$6.82

TABLE 24.1. Performance and Costs of Residential Wood Space Heat

	Anchorage	Fairbanks	Glennallen-Valdez
Heat Equivalent Improvement (kWh/yr)			
New (50%)			
With Solar (25%)	12,365	17,346	14,855
Without Solar (25%)	16,408	21,389	18,898
Retrofit (50%)			
With Solar (15%)	11,808	16,789	14,298
Without Solar (35%)	16,408	21,389	18,898
Average[a]	14,707	19,688	17,197
Installed Cost of Improvement ($)	2,700	2,700	2,700
Capacity Offset at Peak (kW)	14.65	14.65	14.65
Installed Cost per kW ($)	177	177	177
Operation and Maintenance Costs ($/yr)[b]	431	540	486

(a) Assumes new homes comprise about 50% of the stock in each area. Penetration is assumed to be 20% of all types at maximum and proceeds proportionately for all types.
(b) Assumes 65% conversion efficiency. Wood at $80/cord, 12.5 MMBtu/cord effective heat (about 19,300 Btu/cord for birch heat content). Annual maintenance at $100/yr.

TECHNICAL DATA SHEET 25.0

ESCALATION SERIES

The escalation series used for this study are given in Table 25.1 (capital cash) and Table 25.2. All projects used the "standard" series except as indicated. All escalation factors are "real", and do not include general inflation.

TABLE 25.1 Capital Cost Real Escalation Series

	Escalation Factors			
Year	"Standard" %/year[a]	Chakachamna %/year[b]	Browne %/year[c]	Wind Energy %/year[d]
1981	0.8	0.9	0.9	0.9
82	1.4	1.4	1.3	1.2
83	1.4	1.4	1.3	1.2
84	1.0	0.9	0.9	0.7
1985	0.0	0.0	0.0	0.0
86	-0.1	-0.1	-0.1	-0.1
87	0.3	0.3	0.3	0.3
88	0.8	0.8	0.8	0.8
89	1.0	1.0	1.0	1.0
1990	1.1	1.1	1.1	1.1
91	1.6	1.6	1.6	1.6
92	2.0	2.0	2.0	2.0
93	2.0	2.0	2.0	2.0
94	2.0	2.0	2.0	2.0
1995-on	2.0	2.0	2.0	2.0

(a) From Volume XII; 40% labor, 60% material.
(b) From Volume XIV; 30% labor, 70% material.
(c) From Volume XV; 25% labor, 75% material.
(d) From Volume XVI; 7% labor, 93% material.

TABLE 25.2. Operation and Maintenance Cost Real Escalation Series

Year	Standard[a] %/yr	Wind Energy %/yr
1981	1.5	0.0
1982	1.5	0.0
1983	1.6	0.0
1984	1.6	0.0
1985	1.7	0.0
1986	1.8	0.0
1987	1.8	0.0
1988	2.0	0.0
1989	2.0	0.0
1990	2.0	0.0
1991	2.0	0.0
1992	2.0	0.0
1993	2.0	0.0
1994	2.0	0.0
1995-on	2.0	0.0

(a) Includes Chakachamna and Browne hydro.

TECHNICAL DATA SHEET 26.0

FUEL PRICE SERIES

Fuel prices used for the Railbelt Electric Power Alternatives Study are given in Table 26.1. Background information is provided in Volume VII. Note that Table 26.1 is given in 1982 dollars. Fuel prices used for the cost estimates of Volumes II and IV were in 1980 dollars.

TABLE 26.1. Fuel Prices Used for the Railbelt Electric Power Alternatives Study ($/MMBtu)(a)

Year	Beluga Coal(b)	Nenana Coal(c)	Cook Inlet Natural Gas(d) AG&S	Cook Inlet Natural Gas(e) CEA	North Slope Natural Gas(f)	Distillate(g) Fuel Oil	Peat	Refuse-Derived Fuel(h)
1982	1.67	1.75	1.12	0.46	--	6.90	1.75-5.25	0
83	1.73	1.79	1.10	0.46	--	7.04	1.77-5.30	0
84	1.76	1.82	1.11	0.46	--	7.19	1.79-5.36	0
1985	1.80	1.86	1.12	0.51	--	7.34	1.80-5.41	0
86	1.84	1.90	1.41	0.54	--	7.50	1.82-5.46	0
87	1.88	1.94	1.63	0.66	--	7.66	1.84-5.52	0
88	1.91	1.98	1.73	0.70	5.92	7.82	1.86-5.57	0
89	1.95	2.02	1.95	0.78	5.41	7.98	1.88-5.63	0
1990	2.00	2.07	2.20	0.90	4.97	8.15	1.89-5.68	0
91	2.04	2.11	3.80	1.53	4.58	8.32	1.91-5.74	0
92	2.08	2.15	3.89	1.66	4.25	8.49	1.93-5.80	0
93	2.12	2.20	3.97	1.87	3.97	8.67	1.95-5.86	0
94	2.17	2.25	4.06	2.00	3.72	8.85	1.97-5.92	0
1995	2.21	2.29	4.16	2.17	3.50	9.04	1.99-5.97	0
96	2.26	2.34	4.25	4.46	3.32	9.23	2.01-6.03	0
97	2.31	2.39	4.35	4.56	3.16	9.42	2.03-6.10	0
98	2.36	2.44	4.47	4.68	3.02	9.62	2.05-6.16	0
99	2.41	2.49	4.57	4.78	2.90	9.82	2.07-6.22	0
2000	2.46	2.54	4.70	4.91	2.80	10.03	2.09-6.28	0
2000+ escalation	2.1%/yr	2.0%/yr	(i)	(i)	(j)	2.0%/yr	1%/yr	-

(a) January 1982 dollars, 0% inflation.
(b) Minemouth.
(c) FOB rail, Nenana.
(d) Weighted average price to Alaska Gas and Service Co. (without Pacific Alaska LNG project).
(e) Weighted average price to Chugach Electrical Association.
(f) Fairbanks city gate.
(g) Delivered.
(h) Cost of RDF processing offset by tipping fees.
(i) Availabiity of Cook Inlet gas is uncertain following year 2000.
(j) Price is expected to stabilize at about $2.70/MMBtu.

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