Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska

Volume IV

October 1982

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

Battelle
Pacific Northwest Laboratories

LEGAL NOTICE

CANDIDATE ELECTRIC ENERGY TECHNOLOGIES FOR FUTURE APPLICATION IN THE RAILBELT REGION OF ALASKA

Volume IV

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1.0 INTRODUCTION

The Railbelt region of Alaska, as defined for this study, includes Anchorage, Fairbanks, the Kenai Peninsula and the Valdez-Glennallen area. Together, these areas account for about two thirds of Alaska's population. This region is presently served by nine major utility systems. Three are municipally owned and operated, one is a federal wholesaler, and five are rural electric cooperatives. Another entity, the Alaska Power Authority, is empowered to own and operate power generating facilities and to sell power in the region but does not presently do so.

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, all have engaged in various aspects of electric power planning. However, none to date has prepared a comprehensive electric power plan that considers the overall electric energy needs for the Railbelt region and the full set of supply and conservation alternatives available for meeting future needs.

The State of Alaska, Office of the Governor, has contracted with Battelle, Pacific Northwest Laboratories (Battelle-Northwest) to perform a Railbelt Electric Power Alternatives Study. The primary objective of this study is to develop and analyze long-range plans for electrical energy development for the Railbelt region. These plans will contribute to recommendations being prepared for the Governor and the legislature regarding future Railbelt electric power development. These recommendations include whether the State should concentrate its efforts on developing the hydroelectric potential of the Susitna River or if it should pursue other electric power alternatives.

A major task of the Railbelt Electric Power Alternatives Study is to examine available electric energy supply and conservation technologies for their potential viability in the Railbelt region. Technologies found to be technically and economically viable and environmentally acceptable will be considered in the development of electric energy plans for the Railbelt Region.

The purpose of this report is to provide an overview of several candidate electric energy supply and conservation alternatives for Railbelt electric power planning. This information will be used to help select technologies for subsequent in-depth consideration. In general, the following information is presented on each candidate:

- technical characteristics
- siting and fuel requirements
- costs
- environmental considerations
- socioeconomic considerations
- potential Railbelt applications.

This report, Volume IV in a series of seventeen reports, contains 10 chapters and 13 appendices. The following breakdown summarizes the contents of each section. A list of the seventeen reports comprising the study follows the content breakdown.

Section	Contents
Chapter 2.0	- overview of the socioeconomic and geographic characteristics of the Railbelt - descriptions of the existing Railbelt electric energy systems
Chapter 3.0	- the selection of electric power generation and conservation alternatives for consideration in this report - general supporting information relative to the technology profiles
Chapter 4.0	- profiles of technologies typically used to supply baseload power
Chapter 5.0	- profiles of technologies that may be used in either baseload or load-following applications
Chapter 6.0	- profiles of technologies typically operated in a fuel-saver mode
Chapter 7.0	- profiles of energy storage technologies used for supply management

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Chapter 8.0	- profiles of load-shaping technologies used for load management
Chapter 9.0	- profiles of electric energy substitutes
Chapter 10.0	- profiles of building energy conservation techniques
Appendix A	- discussion of electric energy technologies not likely to achieve commercial availability and technical feasibility
Appendix B	- discussion of the availability and price of fossil fuels over the forecast period 1980-2010 for the Railbelt region
Appendix C	- description of the common assumptions and procedures used to estimate capital and O&M costs, fuel costs, and energy costs cited in this report
Appendix D	- description of the water resource impacts associated with each type of steam-cycle facility and their mitigating alternatives
Appendix E	- discussion of the general nature of air pollution that arises from fuel combustion, the broad regulatory framework that has been implemented to control air pollution, and the regulatory considerations that apply to the Railbelt region - comparison of the different fuel combustion technologies used in electric power generation - discussion of the general nature of siting requirements affecting the construction of combustion-fired generating facilities in the Railbelt
Appendix F	- discussion of the aquatic ecology impacts associated with steam-cycle power plants
Appendix G	- discussion of the terrestrial ecology impacts associated with steam-cycle power plants
Appendix H	- discussion of the socioeconomic impacts associated with energy development in the Railbelt
Appendix I	- discussion of the estimates of the cooling water requirements required by each of the technologies discussed in this report

Section	Contents
Appendix J	- discussion of the methodologies for assessing aesthetic considerations, specifically visual, noise and odor impacts
Appendix K	- discussion of the processes that synthesize liquid or gaseous hydrocarbons from fuel
Appendix L	- discussion of the performance of several passive solar options using a representative house
Appendix M	- discussion of the performance of active solar water heating systems in Fairbanks
Appendix N	- discussion of the Fuel Use Act's provisions and conditions under which exemptions can be obtained

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 Manual

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

2.0 BACKGROUND

This chapter provides an overview of the geography of the Railbelt region, a discussion of current electric generating capacity in the Railbelt, and a discussion of the electric load characteristics of the region.

2.1 OVERVIEW OF RAILBELT GEOGRAPHIC AND SOCIOECONOMIC CHARACTERISTICS

The Railbelt region, as shown in Figure 2.1, includes Anchorage, Fairbanks, the Kenai Peninsula, and the Valdez-Glennallen area. Approximately 260,000 people reside in this geographic region, which extends approximately 450 miles from the southern end of the Kenai Peninsula north to Fairbanks.

Geographically, the area is characterized by three major lowland areas separated by three mountain ranges. The lowland areas include the Tanana - Kuskokwim lowland, the Susitna lowland, and the Copper River lowland. The Alaska Range, Chugach and the Talkeetna Mountains form boundaries to the three major lowland areas. As shown on Figure 2.2, much of this land has recently been designated national interest land by the Alaska National Interest Lands Conservation Act of 1980.

Major industries in the Railbelt include fisheries, petroleum, timber, agriculture, construction, tourism, government, transportation, and financial services. The federal government provides employment in both the military and civilian sectors, although these sectors are declining. Current and potential economic activity is generally directly related to development of Alaska's natural resources (Alaska Department of Commerce and Economic Development 1978).

Current estimates indicate that over 20% of U.S. energy resources are located in Alaska. Coal deposits represent from 39 to 63% of the United States' totals; oil, natural gas, and hydroelectric potentials are greater in Alaska than in any other single state (Alaska Department of Commerce and Economic Development 1978). Proper development of these resources is important to Alaska's future economic condition. Energy resource consumption within the State of Alaska is currently as follows: petroleum liquids, 69%;

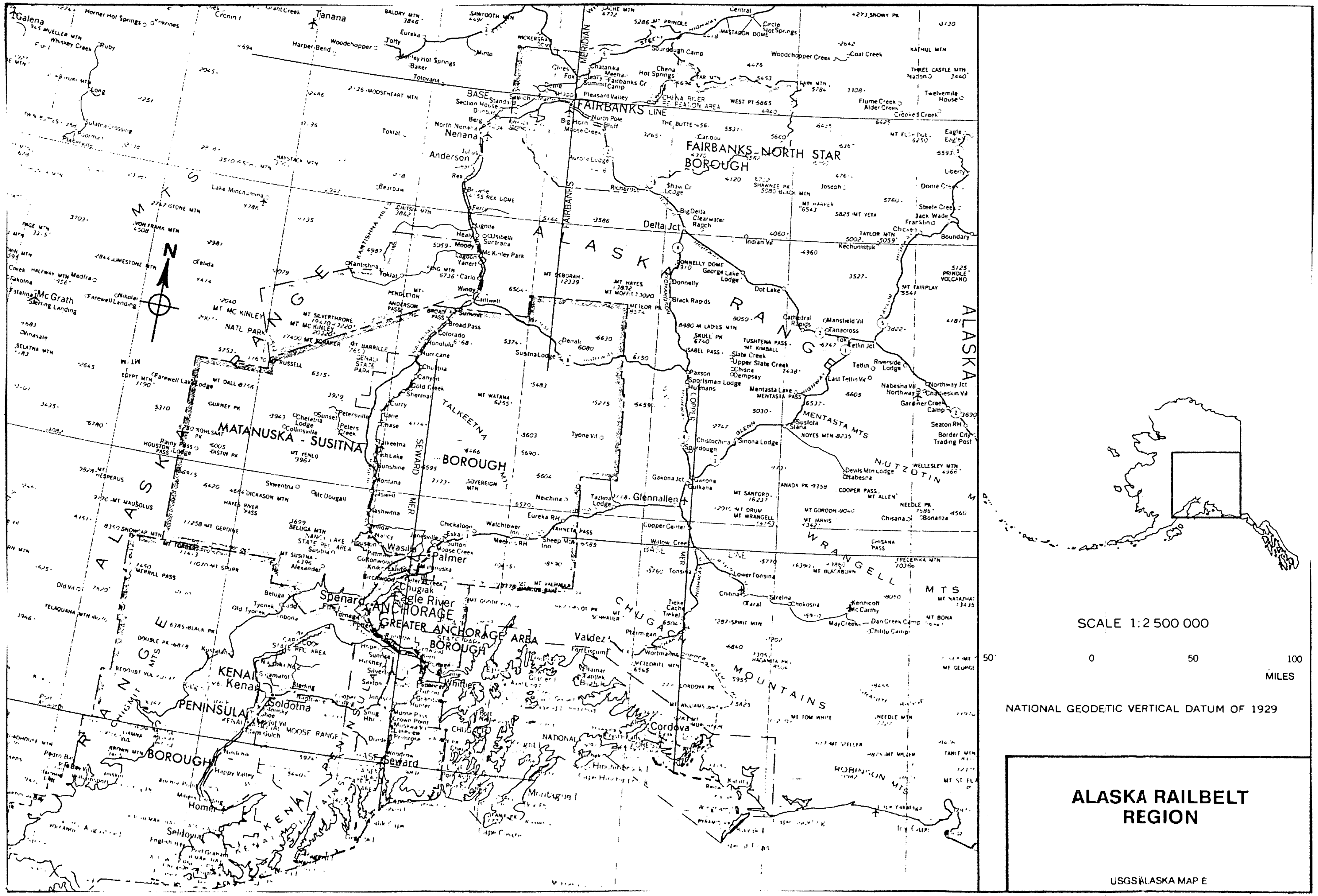


FIGURE 2.1. Alaska Railbelt Region

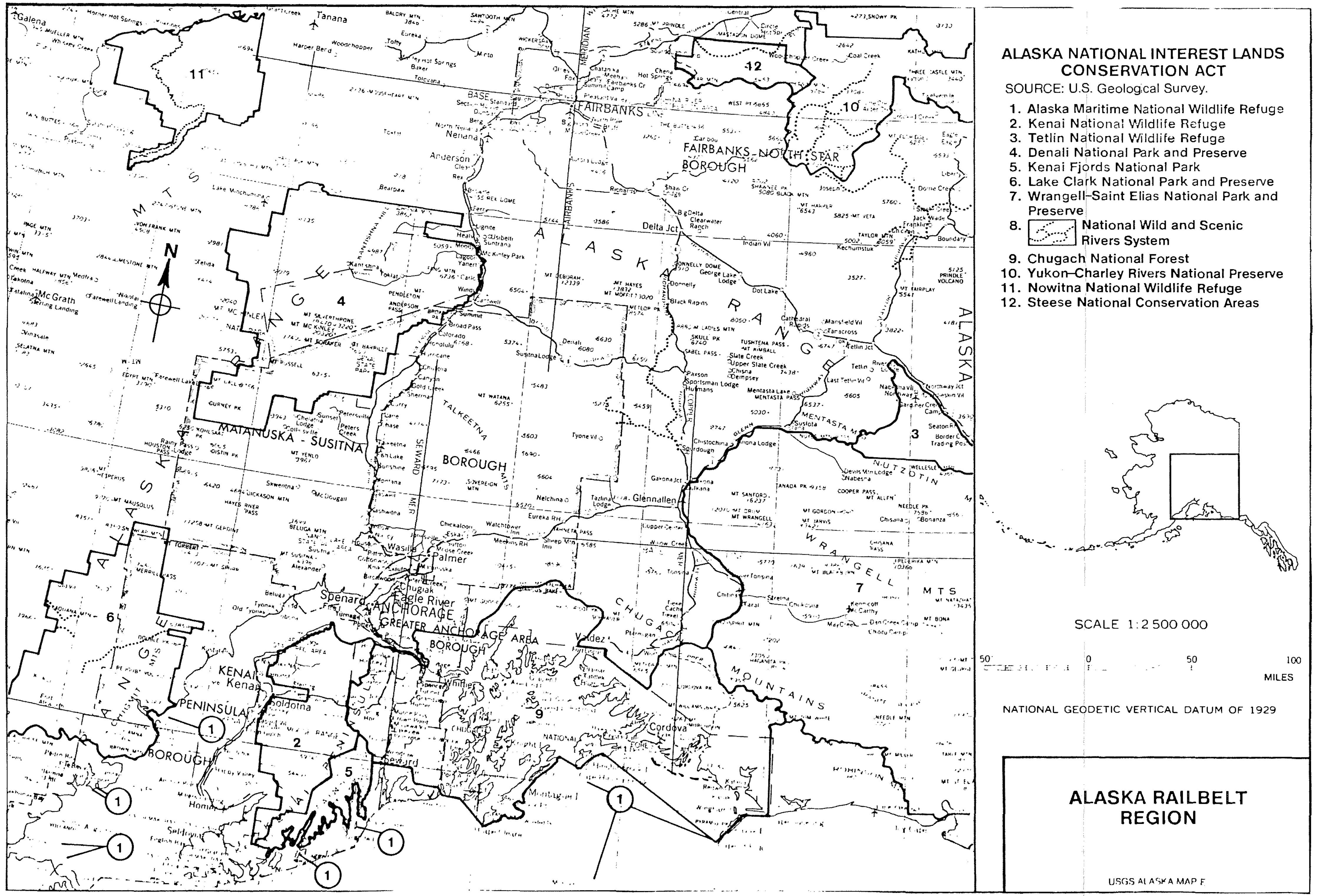


FIGURE 2.2. Alaska National Interest Lands

natural gas, 23%; coal, 6%; and hydropower, 2%. Note that most of the energy consumed in the State of Alaska is petroleum based. Only 2% of the energy currently consumed comes from renewable resources.

2.2 ELECTRIC GENERATING CAPACITY

Eight utilities presently serve the region, as shown in Figure 2.3. The City of Anchorage is served by Chugach Electric Association and Anchorage Municipal Light and Power (AML&P). Most of the Kenai Peninsula is served by the Homer Electric Association, whereas the area near Palmer and Talkeetna is served by Matanuska Electric Association. Each of these systems is interconnected. Seward Electric System serves Seward. Fairbanks is served by Golden Valley and Fairbanks Municipal, which are interconnected. Copper Valley serves Glennallen and Valdez through a transmission line connecting the two towns. Power is also generated by the Alaska Power Administration, military installations, the University of Alaska, and self-supplied industries. The existing transmission system and the proposed route of the Anchorage-Fairbanks intertie are shown on Figure 2.3.

Existing electric generating capacity by major utility and type is shown in Table 2.1. Nonutility generating capacity is summarized in Table 2.2. In addition to the central generating systems, several smaller installations operated by individuals or small communities are found in the region.

Planned expansions of utility system generating capacity are limited. The only system currently considering expansion is AML&P, which plans to add a 74-MW combustion turbine in 1982.

2.3 LOAD CHARACTERISTICS OF THE RAILBELT REGION

The demand for electrical energy in the Railbelt, as well as for most regions in the United States, varies over time. Thus, loads or instantaneous demands on an electric utility's system will change each hour of the day and from season to season during the year. Because electric utilities are required to satisfy the electrical demands imposed by its customers at all times, utilities have to provide sufficient generation, transmission, and distribution

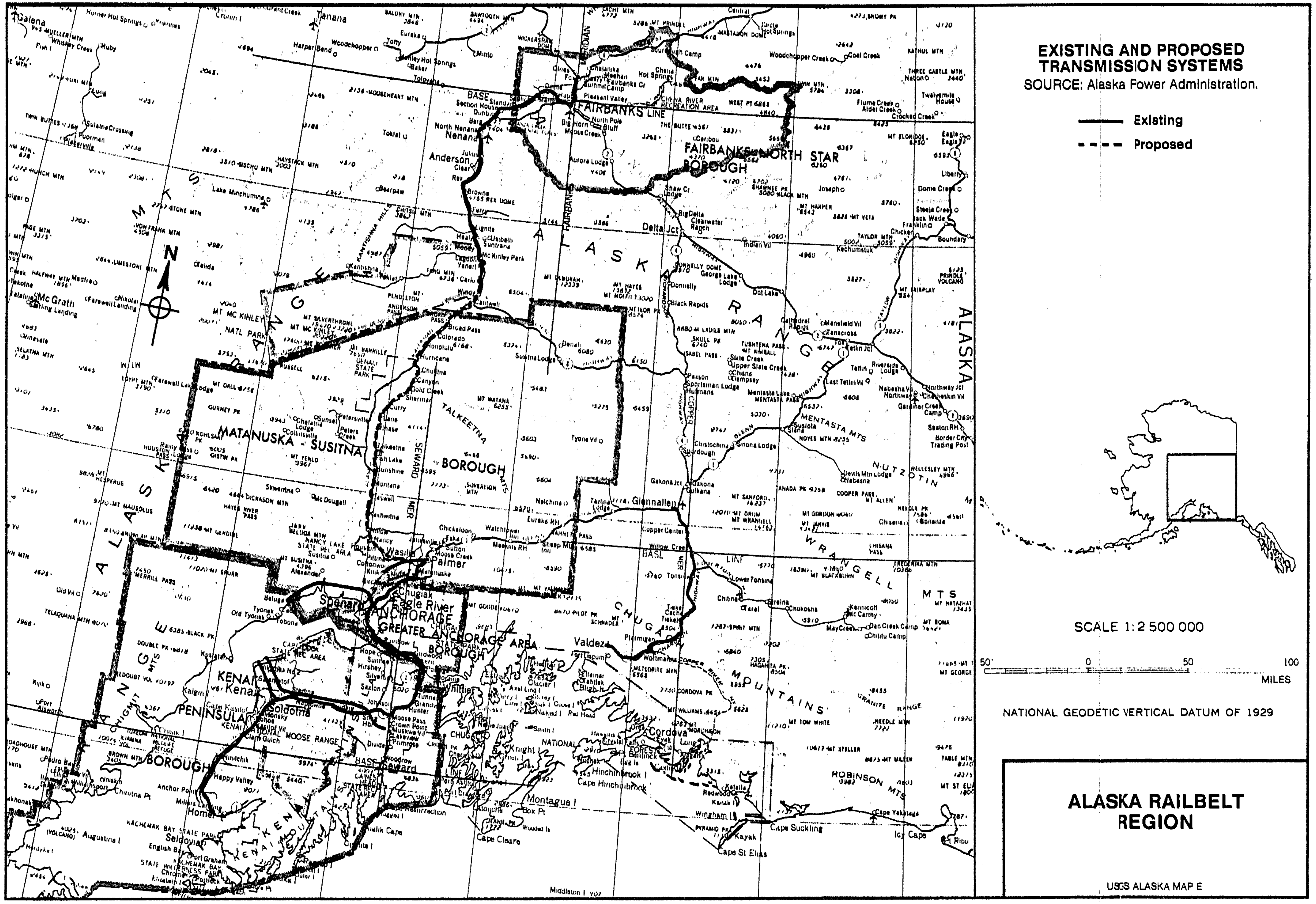


FIGURE 2.3. Existing and Proposed Transmission Systems

TABLE 2.1. Total Generating Capacity (MW)[(a)]: Railbelt Utilities (1980)

	Combined Cycle	Diesel Electric	Hydro-electric	Regenerative Combustion Turbine	Simple-Cycle Combustion Turbine	Steam Electric	Total
Anchorage-Cook Inlet Area							
Alaska Power Administration	0	0	30	0	0	0	30
Anchorage Municipal Light and Power	139	0	0	0	75	0	214
Chugach Electric Association	0	0	16	111	244	0	371
Homer Electric Association	0	2	0	0	0	0	2
Matanuska Electric Association	0	0	0	0	0	0	0
Seward Electric System	0	6	0	0	0	0	6
Subtotal	139	8	46	111	319	0	622
Fairbanks-Tenana Valley Area							
Fairbanks Municipal Utility System	0	8	0	0	28	29	66
Golden Valley Electric Association	0	24	0	0	171	25	220
University of Alaska - Fairbanks	0	6	0	0	0	13	19
Subtotal	0	38	0	0	119	67	304
Glennallen-Valdez Area							
Copper Valley Electric Association	0	16	0	0	3	0	19
TOTAL, ALL AREAS	139	62	46	111	520	67	944

(a) Entries rounded to the nearest MW; therefore, rounding errors may be present.

TABLE 2.2. Generating Capacity (MW)(a): Nonutility Railbelt Installations (1980)

Anchorage-Cook Inlet Area			
Elmendorf AFB (Anchorage)	2	32	34
Fort Richardson (Anchorage)	7	18	25
Subtotal	9	50	59
Fairbanks-Tenana Valley Area			
Eielson AFB (Fairbanks)	4	15	19
Fort Greeley (Big Delta)	6	0	6
Fort Wainwright (Fairbanks)	0	22	22
Subtotal	10	37	47
Total, All Areas	19	87	105

(a) Entries rounded to the nearest MW; therefore, rounding errors may be present.

facilities to meet the largest (peak) hourly load. Therefore, the time-of-use characteristics of system loads have important implications for an electric utility system.

2.3.1 Seasonal Peak Load

In the Railbelt region the consumption of electricity is much greater during the winter season than during other seasons. The major reason for the higher consumption is the need for energy for space heating. Monthly (1979) residential electricity consumption is shown, by utility, in Table 2.3. The table shows that the 1979 winter-summer ratio varied from 1.48 to 2.30 for the various utilities. The seasonal electricity consumption fluctuations are determined mainly by the change in heating degree days.

TABLE 2.3. Monthly Residential Electricity Consumption For 1979[a] (kWh/customer)

	CVEA[b]	CEA	AML&P	HEA	MEA	GVEA
January	620	1,179	1,131	1,418	2,017	1,308
February	646	1,324	762	1,501	1,936	1,495
March	562	1,127	1,062	1,407	1,691	969
April	525	856	783	1,183	1,396	803
May	466	779	678	1,004	1,079	637
June	432	741	568	909	903	613
July	371	726	563	740	850	562
August	426	583	482	737	771	592
September	432	779	611	720	834	671
October	434	783	410	849	962	743
November	571	953	666	1,002	1,245	887
December	549	1,279	917	1,216	1,590	1,258
Monthly Average	491	871	716	1,054	1,270	877
Winter-Summer Ratio[c]	1.48	1.84	1.74	1.73	2.20	2.30
TOTAL kWh/customer	5,892	10,452	8,592	12,648	15,240	10,524
Nonspace Heating Load[d]	5,892	9,828	7,726	11,429	12,090	8,464
Total Minus Nonspace Heat	0	624	866	1,219	3,150	2,060
Estimated Electric Space Heating Customers (%)	0	14	15	30	33	6
Space Heating Average Consumption, kWh/customer	--	4,457	5,907	4,063	9,545	34,333

(a) Fairbanks Municipal Utility System data were not available.
(b) Utilities: CVEA - Copper Valley Electric Association; CEA - Chugach Electric Association; AML&P - Anchorage Municipal Light and Power; HEA - Homer Electric Association; MEA - Matanuska Electric Association; GVEA - Golden Valley Electric Association.
(c) (December + January + February)/(June + July + August).
(d) Based upon the CVEA ratio of total annual sales to sales in the summer months of June, July, and August (4.79).

Source: Institute of Social and Economic Research (ISER) (1980).

2.3.2 Load Duration Curve

Figure 2.4 illustrates the load duration curve for AML&P for 1975.[a] The curve portrays the number of hours of annual generation that were a given percentage of peak load. The curve indicates that for almost all hours, actual loads were at least 30% of the peak. About 250 hours of the year had loads exceeding 80% of the peak.

The "load factor" of a utility system is the ratio of actual energy supplied during a period to the energy that would be supplied if peak load occurred throughout the period. Low load factors indicate a "peaky" load, whereas high load factors are characteristic of a flatter load profile. The 1975 load factor of AML&P was about 0.55. Nationwide, load factors range from about 0.55 to 0.70, indicating that the AML&P load is rather peaky.

2.3.3 Projected Load Growth

Table 2.4 contains the yearly estimated peak loads for the total Railbelt region as well as the total annual electric generation and associated load factor. The 30-year forecast indicates increases in peak demand of approximately 3.5% annually with the load factor remaining essentially constant at about 62%. Overall peak load is forecasted to grow from approximately 690 MW in 1980 to 1800 MW by 2010. This computation, based on the ISER forecast (1980), assumed that the Railbelt utilities were interconnected.

(a) Because 1975 was the most recent normal year in terms of AML&P weather, AML&P developed the load duration curve for that year. Load duration curves were not available for the other utilities in the Railbelt region.

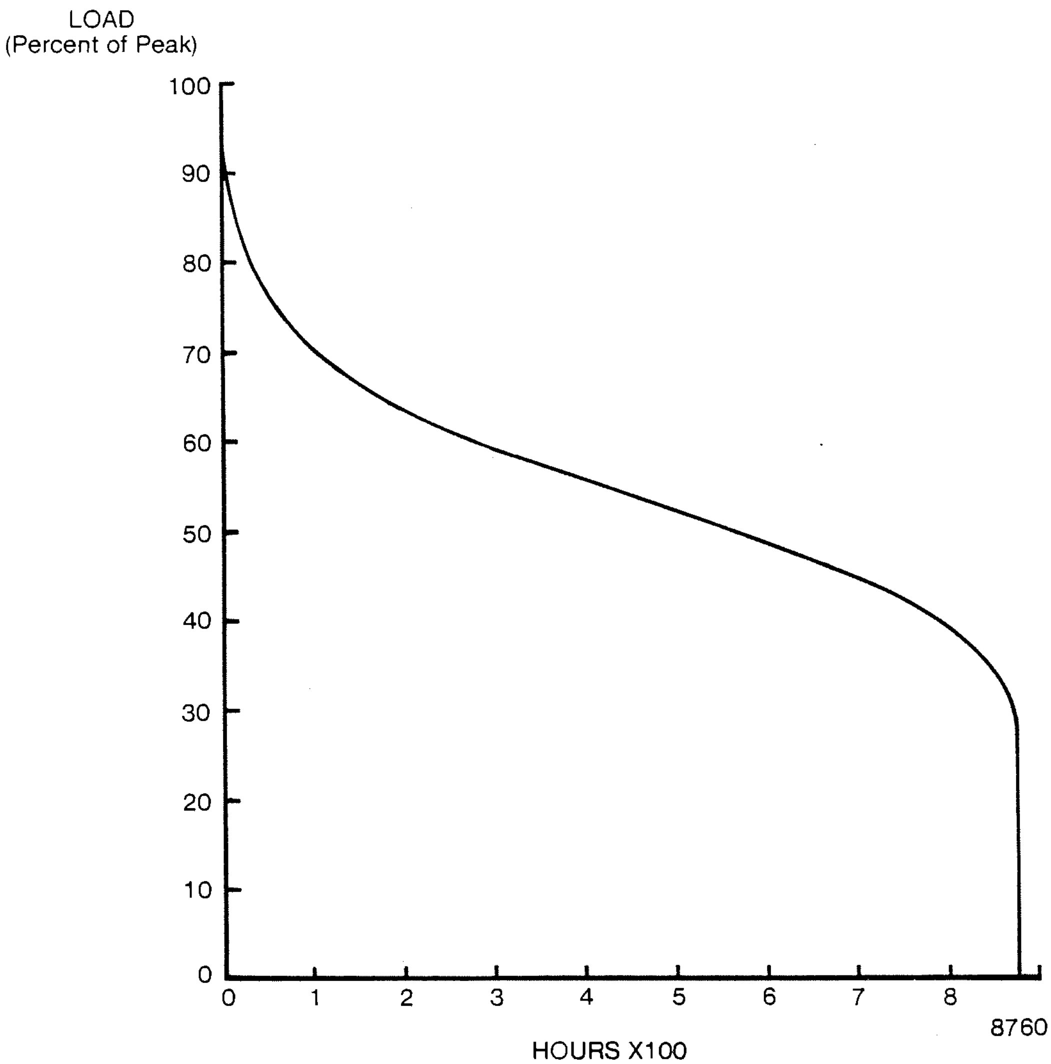


FIGURE 2.4. AML&P Load Duration Curve - 1975

TABLE 2.4. Yearly Estimated Load Growth for the Railbelt Region (ISER Medium Load Growth Scenario)

Year	Total Generation (MWh x 1,000)	Peak Load (MW)	Load Factor (Percent)
1978[a]	3,323	606	62.6
1980[a]	3,522	643	62.5
1981	3,703	676	62.5
1982	3,885	709	62.5
1983	4,066	742	62.6
1984	4,248	775	62.6
1985[a]	4,429	808	62.6
1986	4,528	826	62.6
1987	4,626	844	62.6
1988	4,725	862	62.6
1989	4,823	880	62.6
1990[a]	4,922	898	62.6
1991	5,148	939	62.6
1992	5,373	981	62.6
1993	5,599	1,022	62.5
1994	5,824	1,064	62.5
1995[a]	6,050	1,105	62.5
1996	6,305	1,152	62.5
1997	6,561	1,199	62.5
1998	6,816	1,247	62.4
1999	7,072	1,294	62.4
2000[a]	7,327	1,341	62.4
2001	7,556	1,383	62.4
2002	7,785	1,425	62.4
2003	8,013	1,467	62.3
2004	8,242	1,509	62.3
2005[a]	8,471	1,551	62.3
2006	8,744	1,601	62.3
2007	9,018	1,651	62.3
2008	9,291	1,700	62.4
2009	9,565	1,750	62.4
2010[a]	9,838	1,800	62.4

(a) Computed value. All others interpolated.
Source: Woodward-Clyde Consultants (1980).

3.0 SELECTION OF CANDIDATE ELECTRIC ENERGY TECHNOLOGIES

Potential candidate electric energy technologies for developing Railbelt electric energy plans were identified by first considering the classes of technologies that would either help offset future electric demand or that would help meet future electric demand in the region. Seven classes were identified:

- baseload generating technologies
- baseload/cycling load-following generating technologies
- energy-storage technologies
- fuel-saver (intermittent) generation technologies
- load-shaping technologies
- electric energy conservation technologies
- electric energy substitutes.

Baseloaded power plants operate 65 to 85% of the time and are designed to supply the continuous (base) portion of electric load at low cost. Baseload/load-following plants have more flexible operational characteristics and may be used to meet intermediate and peak loads operating approximately 10 to 50% of the time. Energy-storage alternatives convert the electric energy production of baseload power plants to a storable form of energy. The stored energy is reconverted to electricity during periods of peak demand. Fuel-saver alternatives include those generating devices that are available only on an intermittent basis. Fuel-saver alternatives displace baseload generation by contributing energy to the electric power system, thus reducing overall fuel requirements. Unless provided with storage devices, these technologies normally are not credited as generating capacity since their availability is not assured on a continuous basis. Load-shaping alternatives reduce the need for peaking capacity by shifting the use of electrical energy not dependent on a specific time of day to off-peak times. Electric energy conservation alternatives reduce the demand for electric energy by reducing the consumption of electric power at the end-use stage. Electric energy substitutes substitute an alternative energy resource (solar, wood, etc.) for end uses that often use electric power.

In conformance with the scope of the study, only technologies directly related to electric energy production and conservation were considered. Transmission technologies were not considered because transmission intertie alternatives will be explicitly considered in the development of alternative electric energy plans. Technologies related to the production of fuel for electric energy generating devices were not directly considered because fuel availability and price are considered in a parallel task of this study. Technologies that were considered were limited to those normally operated in conjunction with an electric utility grid; off-grid applications are outside the scope of the study.

To meet the study's objectives, a broad spectrum of currently commercial, emerging, and advanced technologies meeting the criteria established above was identified as potential candidate technologies. These are listed in the left-hand column of Table 3.1. Only the technologies having a reasonable probability of significantly contributing to the generation or conservation of electric energy in the Railbelt region during the study's planning period (1980-2010) were selected for study. Selection of these "candidate" electric energy technologies was based on two screening criteria: commercial availability and technical feasibility.

To meet the criterion of commercial availability, a candidate technology should be currently commercial or should be projected to be commercially available by the year 2000. Such technology would have the potential to significantly contribute to the electric energy needs of the Railbelt before the end of the planning period of this study (2010). Projections of future commercial availability of emerging and advanced technologies are based on current developmental progress (i.e., they do not assume unanticipated acceleration in the rate of development).

Several of the technologies that initially were considered do not appear likely to achieve commercial maturity by the year 2000. These technologies are indicated in Table 3.1 and include magnetohydrodynamic generation, fast breeder reactors, fusion reactors, ocean current energy systems, salinity gradient energy systems, ocean thermal energy conversion systems, and space power satellites.

TABLE 3.1. Candidate Electric Energy Alternatives

Baseload Generating Alternatives	Candidate Electric Energy Alternative	Selection Criteria: Commercial Availability	Selection Criteria: Technical Feasibility
Coal-Fired Steam-Electric	Yes	Available	Yes
Natural-Gas/Distillate-Fired Steam-Electric	Yes	Available	Yes
Biomass-Fired Steam-Electric	Yes	Available	Yes
Peat-Fired Steam-Electric	Yes	Available	Yes
Combined-Cycle Plants	Yes	Available	Yes
Magnetohydrodynamic Generators	No	2000-2005	Yes
Fission Reactors	Yes	Available	Yes
Fast Breeder Fission Reactors	No	2005-2025	Yes
Geothermal Electric	Yes	Available	Yes
Fusion Reactors	No	2025	Yes
Ocean Current Energy Systems	No	Beyond 2000	No (Resource Limited)
Salinity Gradient Energy Systems	No	Beyond 2000	No (Resource Limited)
Ocean Thermal Energy Conversion Systems	No	2000	No (Resource Limited)
Space Power Satellites	No	Beyond 2000	No (Resource Limited)
Baseload/Load-Following Generating Alternatives			
Combustion Turbines	Yes	Available	Yes
Diesel Generation	Yes	Available	Yes
Conventional Hydroelectric	Yes	Available	Yes
Small-Scale Hydroelectric	Yes	Available	Yes
Fuel Cells	Yes	Available	Yes
Fuel-Saver (Intermittent) Generating Alternatives			
Ocean Wave Energy Systems	No	1990s	No (Resource Limited)
Tidal Electric	Yes	Available	Yes
Large Wind Energy Conversion Systems	Yes	Available	Yes
Small Wind Energy Conversion Systems	Yes	Available	Yes
Solar Photovoltaic Systems	Yes	Available	Yes
Solar Central Receiver Systems	Yes	Available	Yes
Cogeneration	Yes	Available	Yes
Energy Storage Alternatives			
Pumped Hydroelectric	Yes	Available	Yes
Storage Batteries	Yes	Available	Yes
Compressed Air Energy Storage	Yes	Available	Yes
Load-Shaping Alternatives			
Direct Load Control	Yes	Available	Yes
Passive Load Control	Yes	Available	Yes
Incentive Pricing	Yes	Available	Yes
Education and Public Involvement	Yes	Available	Yes
Dispersed Thermal Energy Storage	Yes	Available	Yes
Electric Energy Conservation			
Building Conservation	Yes	Available	Yes
Electric Energy Substitutes			
Passive Solar Space Heating	No	Available	Yes
Active Solar Space and Hot Water Heating	No	Available	Yes
Wood-Fired Space Heating	No	Available	Yes

To meet the second criterion, technical feasibility, candidate technologies should demonstrate reasonable potential to operate successfully in the Railbelt environment. As noted in Table 3.1, five technologies do not at this time appear to have this potential. Four are resource limited in the sense that the energy source required for their operation is not available in adequate concentrations in or near the Railbelt region. These technologies include ocean current energy systems, ocean thermal energy systems, salinity gradient energy systems and wave energy conversion systems. One technology, space power satellites, does not appear to be technically feasible at the latitude of the Railbelt because of the large antenna area required to receive microwave power transmitted from space power satellites in geosynchronous equatorial orbit.

The remaining technologies qualified as candidate electric energy technologies are indicated in the second column of Table 3.1. A profile has been prepared for each of these technologies and is included in the following chapters. Brief overviews of the rejected technologies are provided in Appendix A.

4.0 BASELOAD TECHNOLOGIES

Three fundamental baseload generating technologies are considered in this analysis: combustion-fired steam-electric generation; nuclear steam-electric generation; and generation based on geothermal energy. Except for geothermal, all of these alternatives depend on the burning (fission in nuclear plants) of a fuel to vaporize a working fluid, usually water, which is expanded through a turbine to produce electrical power in a generator. A schematic representation of the steam cycle of combustion-fired baseload technologies is presented in Figure 4.1. Because the fuel characteristics differ significantly among combustion-fired steam-electric generating technologies, that discussion is presented in three sections: coal-fired steam-electric; distillate and natural-gas-fired steam-electric; and biomass-fired steam-electric.

All of the baseload technologies require the following: a fuel or energy source; site transportation access facilities; electrical transmission line access; physical site characteristics to support plant operation (e.g., cooling water and stable foundation); environmental capacity to absorb plant effluents; institutional and social infrastructure to support construction and operation of the facility; and a source of capital and operating funds to construct and maintain the facility. Each of these requirements is considered in the discussion of each baseload generating technology.

In the lower 48 states, baseload installations have typically been large, (200 MW or more) oil-, gas-, coal-, or nuclear-fueled steam-electric plants. Because of the Railbelt region's unique development and environmental characteristics, it has not followed the traditional power-producing patterns. In the Railbelt, large base-loaded units have generally not been economically feasible because of sparse population and lack of transmission interconnections. The relative ease of construction, greater operating flexibility, short construction lead times, and lower capital costs of diesel and gas turbine facilities have led to their use in the Railbelt region for baseload capacity. Capacity has been added in small increments, with the largest operating unit being approximately 68 MW. Of the approximately 1000 MW of

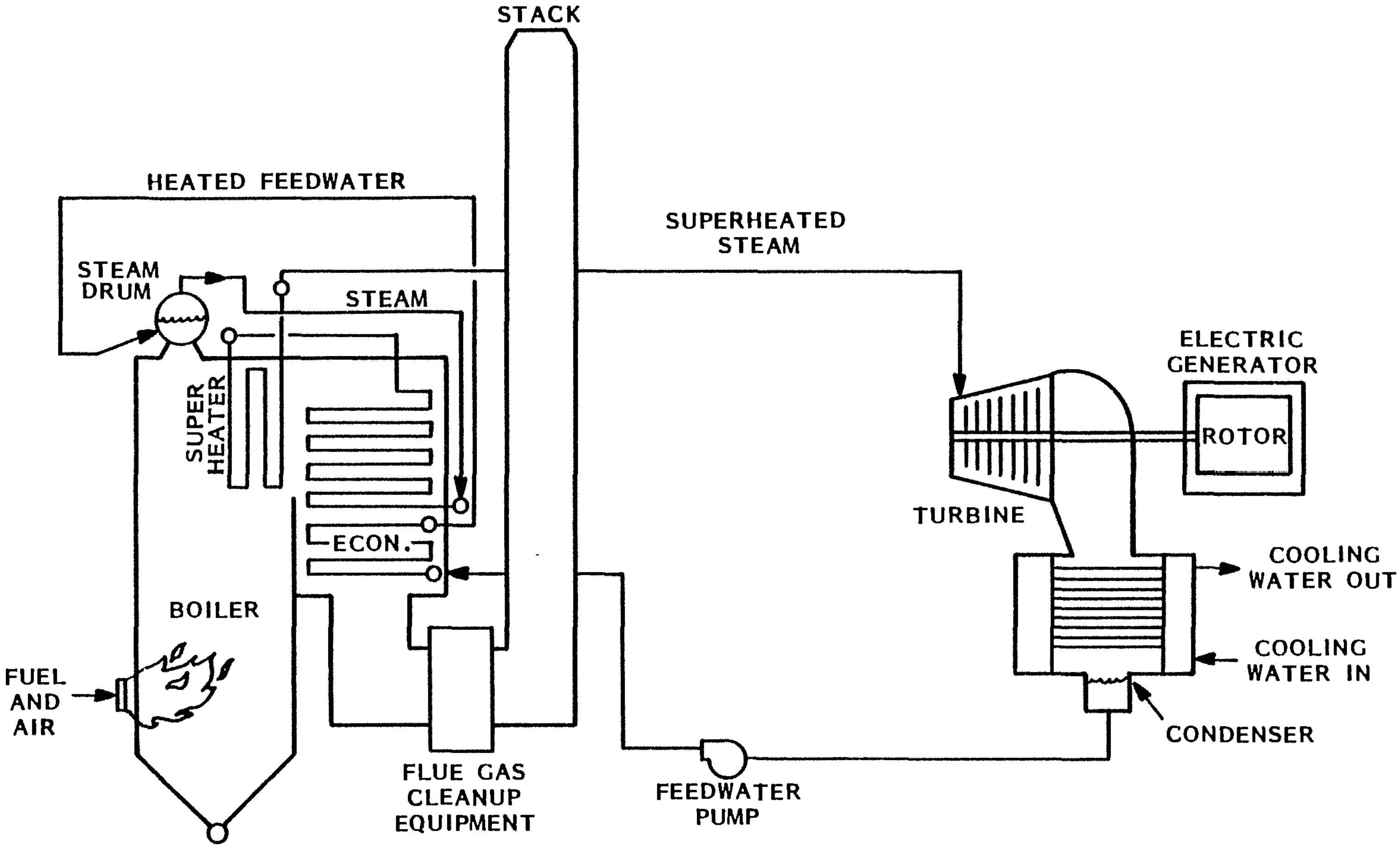


FIGURE 4.1. Typical, Combustion-Fired, Steam-Electric System (without reheat)

nonmilitary capacity installed, only 86 MW is steam electric; 20 MW of this capacity is used as peaking capacity. The largest steam-electric unit currently found in the region is the 25-MW, coal-fired Healy plant (Figure 4.2).

The Railbelt region's projected load growth of approximately 3.5% per year indicates that individual generating units of approximately 10 to 25 MW may continue to be used for the next decade or more if the Railbelt system is not interconnected (Woodward-Clyde 1980). Plant retirements and the advent of the Anchorage-Fairbanks intertie could make the use of generating plants with unit sizes of 100 to 200 MW attractive in the mid-1990s.

Selected characteristics of the baseload technologies considered in this chapter are compared in Table 4.1.

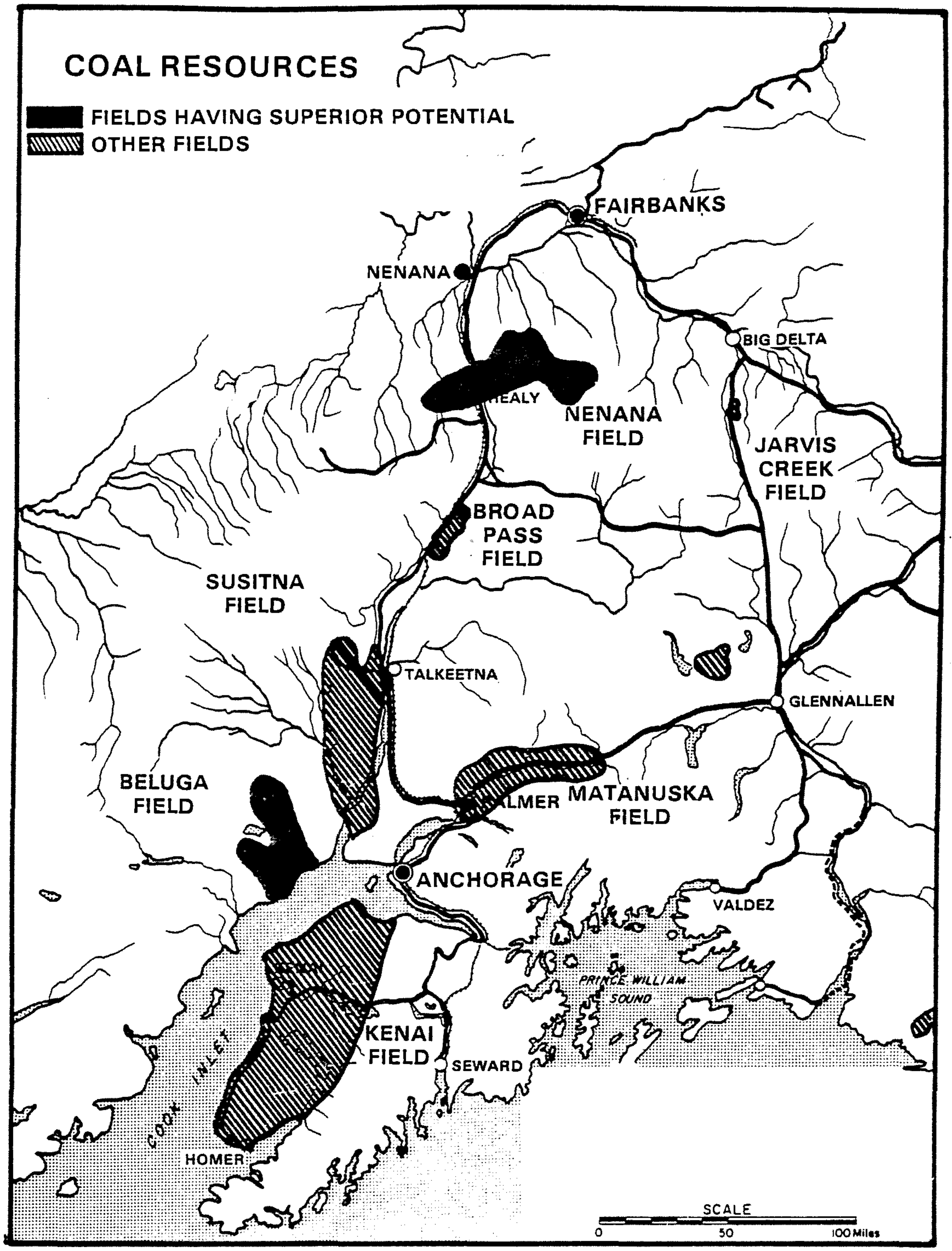


FIGURE 4.2. Coal Resources, Alaska Railbelt Region (USGS 1961 and Joint Federal-State Land Use Planning Commission 1975)

TABLE 4.1. Comparison of Baseload Technologies on Selected Characteristics

	Coal (200-MW Steam Electric)	Oil & Natural Gas (200-MW Steam Electric)	Refuse-Derived Fuel (25-MW Steam Electric)	Nuclear (1000-MW LWR)	Geothermal (50-MW Hot Dry Rock)	Peat[a] (30-MW Steam-Electric)
Aesthetic Intrusiveness						
Visual Impacts	Significant	Significant	Moderate	Significant	Significant	Moderate
Noise	Moderate	Moderate	Minor	Minor	Moderate to Significant	Minor
Odor	Minor	Minor	Significant	Minor	Significant	Minor
Ecological Impacts						
Gross Water Use (gpm)[b]	1800	1800	325	11,000	750	362
Land Use (acres)[c]	225	13-20	25	125	5 (Excluding Wellfield)	~50
Costs						
Capital Cost ($/kW/yr)	2100	900-1330	2160	1850	2550	1166
O&M Cost	30	20-22	60	13	175	204
Cost of Energy (mills/kWh)	Beluga - 57 Nenana - 60	Oil - 120 Natural gas: Cook - 60 North Slope - 143	67	31	57	80-96
Public Health and Safety	No direct safety problems. Possible air-quality degradation.	No direct safety problems. Possible air-quality degradation with high sulfur distillate.	No direct safety problems. Possible air-quality degradation.	No direct safety problems. Possible accidental radionuclide discharge.	No direct safety problems. Possible air-quality and water-quality degradation in vicinity of plant.	No direct safety problems. Possible air-quality degradation.
Consumer Effort	Utility operated.	Utility operated.	Utility or municipally operated.	Utility operated.	Utility operated.	Utility operated.
Adaptability to Growth						
Unit Sizes Available	10-1300 MW	10-800 MW	5-60 MW	800-1200 MW	<1 MW - 50 MW	20-300
Construction Lead Time	3-5 years	3.5-5 years	1.5-3 years	7-10 years	7 years[d]	1.5-3
Availability of Sites	Limited to coal regions and sites near railroad or water transport.	Limited to sites with pipeline access, or (for distillate) barge or rail access.	Limited to ~50 mi of fuel source.	Limited to sites adjacent to port facilities or rail corridor; seismic influenced.		50-100 miles from fuel source

TABLE 4.1. (Contd)

	Coal (200-MW Steam Electric)	Oil & Natural Gas (200-MW Steam Electric)	Refuse-Derived Fuel (25-MW Steam Electric)	Nuclear (1000-MW LWR)	Geothermal (50-MW Hot Dry Rock)	Peat (30-MW Steam-Electric)
Reliability						
Availability	85%	85-90%	85%	68%	65%	80%
Expenditures Within Alaska						
Capital	40%	25%	40%	40%	45%	40%
O&M	90%	91%	90%	89%	88%	90%
Fuel	100%	100%	100%	0%	N/A	100%
Boom/Bust Effects						
Construction Personnel	600	580	65	1300	90	65
Operating Personnel	85	70	25	180	30	25
Ratio	7:1	8:1	3:1	7:1	3:1	3:1
Magnitude of Impacts	Severe	Significant in very small communities. Minor to moderate in all other locations.	Significant in very small communities. Minor to moderate in all other locations.	Severe with the exceptions of Fairbanks and Anchorage.	Severe	Significant in very small communities. Minor to moderate in all other locations.
Consumer Control	Control through regulatory agencies.	Control through regulatory agencies.	Control through regulatory agencies.	Control through regulatory agencies.	Control through regulatory agencies.	Control through regulatory agencies.
Technical Development						
Commercial Availability	Currently available.	Currently available.	Currently available.	Currently available.	Experimental. AFO unknown. Limited to resource areas.	Currently available in Europe. No U.S. experience.
Railbelt Experience	Small scale (<25 MW) plants.	Small scale (<25 MW) plants.	None	None	None	None

(a) Characteristics cited are for power plant only. Peat harvest characteristics are not included.
(b) Recirculating cooling water systems.
(c) All facilities.
(d) 4-7 years for wellfield proving. Three years for plant construction.

4.1 COAL-FIRED STEAM-ELECTRIC GENERATION

Coal-fired steam-electric generation is a mature, reliable technology that supplies more electric power in the United States than any other single generating technology. Uncertainties in petroleum supply and rising petroleum prices are leading the electric utility industry to return to coal-based plants from oil and natural gas use, which became popular in the 1945-1975 period. Small users converted much of their steam-generating capacity to oil or natural gas during this period because of two factors: 1) costs of storing and handling coal, and 2) social pressures for cleaner air, as reflected in the Clean Air Act, which required installation of flue gas cleanup equipment for new coal units. Renewed interest in coal for new installations is due to the large quantities of coal available in the United States, including significant deposits located in the western states and Alaska. Coal deposits in the Railbelt region of Alaska are shown in Figure 4.2.

Recent coal-fired power generation installations in the United States have been large units (greater than 200 MW). However, smaller users and producers of steam are expected to look to coal as a fuel in the forseeable future because of its relatively abundant supply and lower cost when compared to competing fuels. In addition to economic factors promoting coal use, the Powerplant and Industrial Fuel Use Act of 1978 essentially prohibits the use of natural gas and oil for units firing over 100 million Btu/hr (approximately 10 MW or 100,000 lb/hr of steam), unless exemptions can be obtained.

Contemporary coal-fired installations differ from older units in the important area of flue gas cleanup. The Clean Air Act and subsequent amendments require control of particulates, oxides of sulfur (SO_x) and oxides of nitrogen (NO_x). Equipment is installed in the flue gas discharge path to remove SO_x and particulates before the gaseous emissions enter the atmosphere. NO_x emissions are controlled by using modified combustion technologies.

4.1.1 Technical Characteristics

Coal-fired, steam-electric plants have been installed in unit sizes up to 1300 MW, although most utility plants are between 200 and 800 MW. The lower end is limited only by costs; 10 MW appears to be a practical low-end limit based upon conditions existing in the lower 48 states. The projected load growth and characteristics of the Railbelt electrical system appear to favor units from 10 to 25 MW if the Anchorage and Fairbanks systems are not interconnected. Units of 100 to 200 MW may be practical in an interconnected Railbelt system.

Design Features

The principal components of a coal-fired, steam-electric generating facility include the boiler plant, the turbine system, the electric plant, the air pollution control system, and the condenser cooling system (Figure 4.3). The turbine system, electric plant, and condenser cooling system of coal-fired installations are similar to those of steam-electric plants fired by other fuels. The boiler plant and air pollution control system of coal-fired plants differ substantially from those of noncoal-fired, steam-electric facilities. The unique components of a coal-fired plant in comparison with gas- or oil-fired units include th coal handling system, the air pollution control system, and ash handling facilities. These facilities will be described in additional detail. Coal handling and preparation facilities include facilities for receiving, handling and storing raw coal and equipment for preparing the coal for firing.

The design of the unloading station depends on the mode of coal transportation. For transportation by rail, which is the most common mode, the unloading station includes a rail spur (often a loop to facilitate continuous unloading of unit trains), a thaw shed to thaw coal frozen in the railcar, and car unloading equipment. Car unloading equipment is of two general types, trestles or dumping pits for bottom dump hopper cars, and rotary dumping machines for gondola (fixed bottom) cars.

Long-term and live coal storage areas are generally provided. The long-term storage area is usually sized for 60 to 90 days' supply; it may even be sized to hold up to 6 months' supply if the normal source of coal delivery is not reliable because of labor availability or weather conditions. The live storage area, from which the coal is fed to the plant, is usually designed for

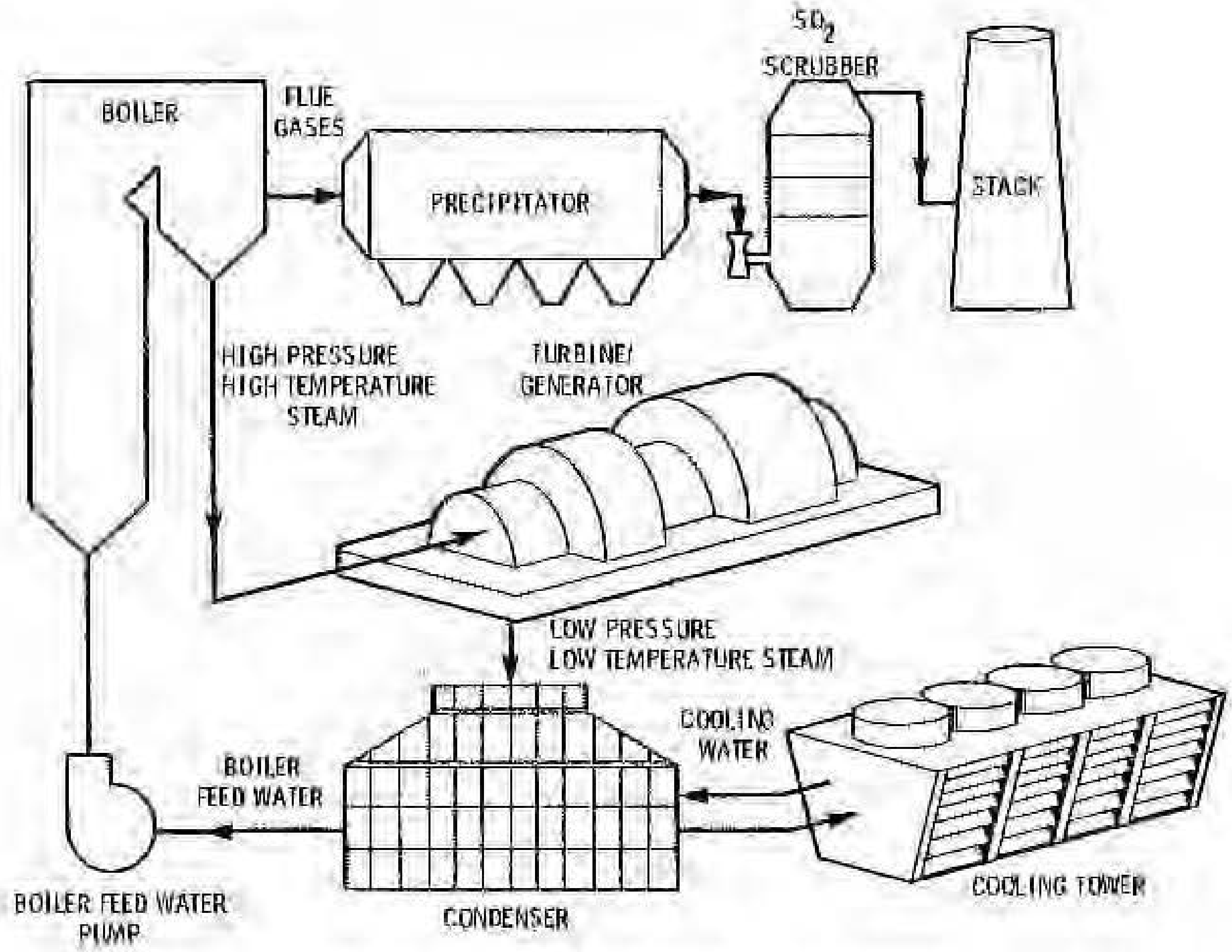


FIGURE 4.3. Coal-Fired Power Plant Components

a 7-day supply. Depending on the plant size, large crane-like stacker-reclaimers or dozers are required for placing the unloaded coal into the appropriate storage area and for retrieving it for use in the plant. In cold climates, frozen coal crushers may be required at the reclaim area.

Most coal-fired plants use a conveyor system to move the coal from the reclaiming area to the plant bunkers. Cold weather regions will require climate protection equipment in addition to dust suppression systems.

Inplant storage bunkers are usually sized for 8 hours of capacity. The bunkers are situated above the mills for gravity feed and require some form of a fire protection system.

The mills are generally located below the bunkers and serve to pulverize and to dry the coal for burning. The mills are extremely large, heavy-duty, slow-speed, high energy-consuming pieces of equipment. The air pollution control system is used to remove environmentally harmful pollutants from the flue gas stream. These pollutants include particulate matter, oxides of sulfur (SO_x) and oxides of nitrogen (NO_x). Each of these pollutants requires control under the provision of the Clean Air Act of 1971 and subsequent amendments.

Particles are removed from the flue gas by electrostatic precipitation or fabric filters (baghouses). The most widely used system has been precipitators, which are capable of 99.9% removal efficiencies. The performance of precipitators is affected by the sulfur content of the fly ash; higher levels of sulfur in fly ash result in enhanced removal efficiencies. This has led to increased use of baghouses for plants burning low sulfur coal.

The most common method of removing sulfur from the flue gas is by lime or limestone slurry scrubbing. In these processes a slurry containing calcium carbonate, prepared from lime or limestone, is used to scrub the flue gas. Sulfur reacts with the slurry to form insoluble calcium sulfites and sulfates that are disposed of as solid waste. Removal efficiencies are about 90% for single units. Either wet or dry systems are available. The wet system results in a sludge requiring dewatering; dry systems are designed such that drying of the sludge occurs in the flue-gas stream, resulting in a product requiring no additional dewatering. The dry system reduces the freezing problems in a cold climate. Several other SO_x removal processes are currently under development, many of which are regenerative processes, producing marketable sulfur byproducts and reducing the need for scrubber feedstock.

NO_x are formed during the combustion process by the combination of atmospheric oxygen with atmospheric nitrogen at elevated firing temperatures. Currently, NO_x are controlled by special firing techniques.

Since coal combustion creates large quantities of ash from both the furnace and the particulate removal equipment, a location for final disposal of the ash must be provided. If a dry ash removal system is used, then only a small, onsite storage area is required because dewatering is not necessary. Wet ash removal systems require impoundments for dewatering. Ash may be marketed as a by-product; otherwise, a permanent disposal site is required. Permanent disposal may be in landfills, although occasionally ash is returned to the mine for disposal.

Performance Characteristics

Plant heat rates are a function of unit size, design, auxiliary equipment, heat sink temperatures, operating mode and operator attention. Typical heat rates for various sizes of coal-fired steam-electric plants are as follows:

Rated Capacity (MW)	Heat Rate (Btu/kWh)
20	10,600-13,000
200	10,200-13,000
400	9,800-12,200
600	9,500-10,600

The most recent data available from the National Electrical Reliability Council (NERC) indicate that coal-fired unit availability varies with unit size as indicated below:

Unit Size	Availability (10-Year Average)
100-199 MW	86.1%
200-299 MW	84.8%
300-399 MW	77.6%
400-599 MW	74.1%

Additional information from the NERC survey indicates that in recent years the units' availability has decreased in every size range. The added complexity of flue-gas cleanup equipment being installed or retrofitted in those years is undoubtedly a major contributor to those decreases. The higher availability of smaller units may be somewhat misleading considering that these units are usually less efficient than the larger units and are therefore held on standby more often than the larger plants. (Being on standby enhances the availability figure by reducing the frequency of equipment failure.)

Coal-fired steam-electric plants have lengthy startup times and low ramp rates and are generally not suitable for load following. Thus, they are typically operated as baseload or intermediate load units. Capacity factors for units in the above sizes range from 45 to 86%; however, for any particular unit the capacity factor will depend on its heat rate, system size and mix, availability, system demand, and the utility's operating procedures. A new base-loaded unit with a good heat rate will have a higher load factor than an older, less efficient plant used for peaking purposes.

Economic lifetimes of coal-fired steam-electric power plants are typically 30 to 35 years. Actual physical lifetimes may be much longer, although the older units generally serve as intermediate or peaking duty units.

New Developments

Fluidized bed combustion (FBC) is under development as an alternative to pulverized coal combustion methods. A fluidized bed consists of a mass of noncombustible particles lying on a perforated plate. As air is forced up through the plate, the bed material starts to exhibit the motion and some of the characteristics of a fluid. If fuel (coal particles about 1" x 1/4") is added and the temperature is raised to about 1100°F by external means, the coal ignites. The bed temperature then increases to about 1500°F and combustion is self-sustaining. If limestone is added to the bed (such that a mole ratio of 3 or 4 parts of calcium to 1 part of sulfur (in coal) is maintained), then sulfur dioxide (SO_2) formation is minimized.

With the exception of the bed and the heat exchange tubes in the bed, the basic boiler components are similar to a conventional unit. The heat transfer coefficient of an in-bed heat exchanger is approximately five times as great as the convection tubes in a conventional boiler. Although corrosion may be a problem with the in-bed tubes, erosion has proven to be minimal (actually less than that of tubes in the gas path of a conventional coal-fired unit). Minimal erosion has been explained by the fact that the fluid motion causes the bed particles to become "rounded" and the bed velocity is low, about 8 ft/sec as compared to 50 ft/sec for the gas path of a pulverized or stoker-fired boiler at the superheater tubes.

Because each bed is limited in physical size (100 ft^2) for practical purposes, large boilers will consist of multiple beds. Each bed produces approximately 50,000 lb/hr of steam. Dead cold beds can be started in about 6 to 8 hours; however, because they retain heat well they can be restarted in about one hour after a two-day shutdown. Bed turndown is limited; however, in a multiple bed design, overall unit turndown is improved by taking individual beds out of service.

Utility application of FBC is currently limited. Although commercial operations (Monongahela Power Co.) exist, the majority of the installations are demonstration plants. The utility industry's interest in FBC has significantly increased in recent years for several reasons:

- Coal can be used as the fuel; therefore, dependence on expensive and sometimes unreliable oil supplies is reduced.
- Coal is burned in intimate contact with limestone; thereby, SO_2 emissions are reduced greatly. Under some circumstances New Source Performance Standards could be achieved without using flue-gas desulfurization systems.

- Combustion occurs between 1500 and 1750°F, which is well below the temperature at which NO_x formation is a problem. The relatively low combustion temperature also limits slag formation and therefore eliminates or at worst greatly reduces the need for a soot blowing system.
- Particulate carryover in the flue gas can be reduced below that of conventional coal-fired boilers. Dust collection equipment (usually baghouses), however, is still needed to meet New Source Performance Standard requirements.
- Carbon loss can be held to less than 0.01%, primarily by reinjection of fly ash into the bed.
- A wide variety of coals (and other solid combustibles) can be burned by FBC with the proper adjustments to fuel size, air velocity and feed rate.
- The bottom ash is powdery rather than hard slag or clinkers, which are characteristic of conventionally fired coal units, therefore, removal and disposal is made easier.
- Coal is not pulverized, thereby eliminating a significant portion of the fuel preparation capital cost and maintenance expense.

FBC does not appear to show any advantage over conventional firing in the areas of thermal efficiency, operating manpower or chemical cost for SO_2 removal. Some advantage is expected in capital cost due to the elimination or downsizing of such equipment as pulverizers, scrubbers, dust collectors and ash handling equipment.

Presently, FBC exhibits the following disadvantages:

- Operating and design experience in utility sizes and applications is lacking, although some industries, such as wood processors, have had many years of actual operating experience.
- Possible corrosion problems may develop in the bed region over a period of time.

- More square footage of boiler plant area is required for equal power output than for conventional firing; however, air-quality control equipment will be smaller or eliminated.

4.1.2 Siting and Fuel Requirements

A complex decision process that considers environmental aspects, economics of transportation, construction and transmission, natural resources, aesthetics, public opinion, and growth patterns is used to site coal plants in the United States. As the siting process has grown more complex, new plant sites tend to be more distant from load centers. The location of the fuel source, the available transportation facilities, and the size of the plant weigh more heavily in the siting of a coal-fired unit than with oilor gas-fired units because coal characteristics vary so widely compared to oil or gas.

Coal-fired steam-electric plants require water for condenser cooling, emission control, ash handling, boiler makeup, general cleaning, and domestic purposes. Typically, water requirements for boiler makeup, emission control, domestic and other noncooling uses amount to approximately 5% of the boiler throughput. Cooling water requirements vary according to the ultimate heat sink employed. Once-through cooling requires water resources approximately 50 times the boiler flow. With the use of evaporative cooling (cooling towers) the makeup required to the cooling system is approximately 65 to 75% of the boiler throughput. Use of dry cooling (air condensers) reduces makeup to a negligible amount. Dry cooling also prevents the formation of water vapor plumes and resulting ice fogging. Dry systems have been used primarily at sites with scarce water; however, the low, ambient air temperatures in the Railbelt region make this a technology worthy of evaluation (see Appendix I).

The acreage of sites required for coal-fired power plants of varying capacities is given in Table 4.2. These estimates account for the siting of plant facilities (including coal storage and handling facilities, power plant systems, cooling systems and solid waste disposal areas) and also onsite housing facilities that would be necessitated by remote siting.

TABLE 4.2. Typical Land Requirements for Coal-Fired Steam-Electric Power Plants

Rated Capacity (MW)	Plant Island (Acres)	Ash and Scrubber Sludge Disposal (Acres)	Total Land Area Required (Acres)
20	5	3	8
200	25	200	225
400	75	400	475
600	120	500	670

Fuel consumption (quantity) for coal-fired steam-electric plants varies with heat rate and with fuel quality. The hourly consumption of coal and limestone for potential power installations requires, in all but the smallest installations, a railroad or waterborne transportation system to deliver coal and limestone for flue-gas desulfurization. Siting coal-fired steam-electric plants at mine mouth eliminates the need for fuel delivery systems. Coal and limestone consumption is shown in Table 4.3 for four plant sizes.

4.1.3 Costs

Capital costs for coal-fired steam-electric generation vary from project to project and depend on the construction schedule, unit size, scope of work, and degree of standardization. O&M costs are difficult to estimate because of the wide variations in utility practice. The cost per kilowatt decreases substantially as unit size increases because larger units require relatively

TABLE 4.3. Fuel Consumption for Coal-Fired Steam-Electric Plants

Rated Capacity (MW)	Coal Consumption (tons/hr)	Limestone (lb/hr)
20	16	150
200	145	1,400
400	275	2,750
600	400	4,000

fewer personnel than smaller units. Estimated capital and O&M costs vary with plant size, as shown in Table 4.4. The basis for these cost estimates are further discussed in Appendix C.

TABLE 4.4. Estimated Costs of Coal-Fired Steam-Electric Plants (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M Costs ($/kW/yr)	Cost of Energy[a] Beluga Coal (mills/kWh)	Nenana Coal (mills/kWh)
20	2560	68	68	71
200	2100	38	57	60
400	1730	27	49	52
600	1500	19	43	46

(a) Levelized lifetime costs assuming a 1990 first year of commercial operation. Fuel costs are provided in Appendix B.

4.1.4 Environmental Considerations

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

The combustion of large amounts of coal leads to a potentially significant deterioration of the surrounding air quality. The atmospheric emissions from a coal facility would require an in-depth review by Alaska and Environmental Protection Agency (EPA) authorities. The expected emissions from a coal-fired power plant and the regulatory framework are presented in detail in Appendix E, where emissions are compared to those of alternative technologies. Note that although impacts from coal combustion are generally greater than those of other fuels, a judicious siting analysis and strict environmental controls will generally allow the operation of a coal-fired power plant near the major Alaskan coal fields. The use of coal is also facilitated by the use of low-sulfur coals common to most of Alaska's reserves. Plants located in the resource areas would have to be designed to mitigate effects on these resources.

Other significant effects from coal-fired steam plants are associated with water supply and wastewater discharge requirements. Many potentially suitable development areas for coal-fired plants border important aquatic resource areas (salmon in streams like the Copper and Susitna Rivers and other marine fish and shellfish in Cook Inlet). Water withdrawal may result in impingement and entrainment of aquatic organisms. Chemical and thermal discharges may produce acute or chronic effects to organisms living in the discharge plume area. Thermal discharges can also cause lethal thermal shock in the Railbelt region. These effects are discussed in greater detail in Appendix F. Plants located in the resource areas would have to be designed to mitigate effects on these resources.

Coal-fired plants will use the same or less water per megawatt than other steam-cycle plants, except a combined-cycle facility. A suitable plant size for the Railbelt region (200 MW) however, would be second only to nuclear plants in total water use and would require approximately 90,000 gpm and 1,800 gpm for a once-through and a recirculating cooling water system, respectively. In addition, water from coal-fired steam plants, particularly from ash or flue-gas desulfurization wastes, generally requires more sophisticated treatment than most other steam plants to reduce its toxic loading.

The greatest impact on the terrestrial biota is the loss or alteration of habitat due to the large amounts of land required for both construction and operation. These land requirements (Table 4.2) are generally greater than those for other types of fossil-fueled power plants. Other impacts could result from gaseous and particulate air emissions, fuel or waste storage discharges, human disturbance, and the power plant facilities themselves; e.g. bird collisions with cooling towers. These effects are discussed in Appendix G. Biological impacts are best mitigated by siting plants away from important wildlife areas and by implementing appropriate pollution control procedures. Although certain impacts can be controlled, land losses are irreplaceable.

4.1.5 Socioeconomic Considerations

The construction and operation of a coal-fired plant has the potential to seriously affect smaller communities and to cause a boom/bust cycle. These effects are due to the remoteness of prospective sites. The magnitude of these impacts is a function of the construction period, the size of the construction work force and the ratio of construction to operating personnel. Construction times, exclusive of licensing and permitting, will vary according to the size, type of equipment, and external factors such as weather and labor force. Construction schedules for coal-fired plants in the Railbelt will vary depending upon whether the boiler is field-erected. A small 20-MW unit could be constructed in approximately 20 months if the boiler is a package design and if the auxiliary equipment is skid mounted. Larger units (above 60 MW) that are field constructed will take from 3 to 5 years. The construction force for a 200-MW plant is estimated to be 600 personnel. An operating work force of 85 would be required.

Impacts would be most severe at the Beluga coal fields since the surrounding communities are small and transportation facilities are poorly developed. Power plant components would most likely be shipped by barge and then transported overland to the site. Secondary impacts would be caused by the construction of haul roads. The largest community in the area is Tyonek, an Alaskan native village with a population of 239. The influx of a construction work force, regardless of plant size, would disrupt the social structure of a community of this size.

Impacts from plant development along the railroad corridor would depend on the plant scale. Existing communities may be able to accommodate construction of a 10- to 30-MW plant but would be severely affected by a large-scale plant. Additional discussion of potential impacts is provided in Appendix H.

The flow of capital expenditures both outside and within the Railbelt are expected to balance for a 200-MW field-erected project and to be proportionately higher outside the region for a 20-MW packaged unit. For a large unit, 50% of the expenditures would flow outside the Railbelt and for a smaller unit, approximately 60% of the project investment would be made outside the Railbelt. The percentage of capital investment for a field-erected plant is larger compared to other baseload technologies because of the large construction work force and extensive field preparation requirements. The flow of O&M expenditures is expected to be 10% spent outside the region and the balance spent in the region.

4.1.6 Potential Application in the Railbelt Region

Some development of coal-fired steam-electric generation has occurred in the Railbelt with coal from the Nenana coal field. A 25-MW, coal-fired plant located at Healy is operated by the Golden Valley Electric Association. In addition, the Fairbanks Municipal Utilities system operates four units at Chena, and the University of Alaska has three small units. The Beluga fields have not been developed, although studies are underway to define the coal resource characteristics and markets (Battelle 1980a).

Coal-fired steam-electric generation shows promise as a potentially major source of baseload power in the Railbelt region. The technology is mature and cold-climate applications have been well-demonstrated elsewhere. Coal costs are forecasted to be relatively low and the resulting cost of power most likely will be competitive with other generating alternatives. Emission of atmospheric pollutants is probably the principal environmental impact to be considered; however, control technology is well established for particulate and sulfur emissions. Moreover, the extremely low sulfur content of Alaskan coal eases sulfur control requirements. Ice fog formation is a potential problem, but most likely can be controlled with wet/dry mechanical draft, heat rejection equipment. NO_x emissions can be controlled within current standards by proper furnace design and firing procedures. The long-term effect of CO_2 emissions on global temperatures is of increasing concern. Control, if required, could be accomplished by regulating global rates of coal combustion, an issue that must be addressed at the international level.

Both the Beluga coal field and the Nenana coal field would be potential sources of coal for coal-fired steam-electric plants. Plants using Beluga coal would likely be located at or near the mine mouth to minimize coal transportation requirements. Electrical transmission would be to the Anchorage load center or to a future Anchorage-Fairbanks intertie.

Future plants using Nenana coal could be located at mine mouth but more likely would be located along the Alaska Railroad some distance to the north or south to avoid impacting the Denali National Park Class 1 Prevention of Significant Deterioration Area. Prospective locations would include near Nenana to the north and in the lower Susitna or lower Matanuska Valleys to the south.

4.2 NATURAL GAS AND DISTILLATE-FIRED STEAM-ELECTRIC GENERATION

The natural gas and distillate (oil)-fired steam-electric generating technologies are well known and widely used in the utility industry. However, future application of these technologies is in question because of the world-wide oil supply and pricing disruptions caused by the OPEC nations, and the resultant passage of the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA). The PIFUA essentially prohibits the use of oil or natural gas for power generation in unit sizes exceeding approximately 10 MW. While exemptions are available to utilities that can prove that no reasonable alternative exists, these exemptions are difficult to obtain. Development of a synthetic fuels industry based on coal or other primary resources may, in the future, provide fuel for larger plants. However, the superior efficiency of combined-cycle plants compared to steam-electric plants would likely result in use of the former alternative in conjunction with synthetic fuel production.

4.2.1 Technical Characteristics

Principal components of a distillate- or natural-gas-fired power plant include the boiler plant, the turbine system, the electric plant and the condenser cooling system. Depending upon environmental regulations and the sulfur content of the fuel, flue-gas desulfurization equipment may be required.

Units have been constructed in sizes ranging from less than 10 MW to 800 MW. Units of 10-MW and 200-MW rated capacity are evaluated in this profile. Units in the 10-MW range are used primarily in heavy industrial applications; however, the purpose, operating procedures, and operating conditions of such applications are usually different from those of a utility and therefore only can give an indication of what can be expected for electrical generation.

Design Features

Distillate-fired boilers require no special or unusual equipment. The plant will require a large, fuel storage facility unless a reliable pipeline is available. The size, type, and number of tanks will depend on fuel reserve requirements. A one-week supply is a common criterion for plants with a reliable source; additional storage for Railbelt sites may be required if the plant is supplied by tank truck or rail. A way to heat the oil may be required, depending on oil type and ambient temperatures.

No special fuel storage or handling provisions are required for gas firing because the fuel is delivered by pipeline at pressure. During periods of extreme cold, when transmission line pressure drops, natural-gas-fired units may have to be shut down or switched to oil, thus decreasing system reliability.

Performance Characteristics

Typical heat rates for various sizes of natural gas and distillate-fired steam-electric plants are shown below:

Fuel	Rated Capacity (MW)	Heat Rate (Btu/kWh)
Natural Gas	10	12,000
	200	11,400
Distillate	10	11,000
	200	10,600

Industrial users frequently obtain plant availabilities of approximately 90%. This high percentage is possible because industrial boilers can be operated at a continuous load, and very often the end product is steam, thereby eliminating downtime due to electrical generating equipment failures. For utility purposes, a well-maintained base-loaded plant is estimated to be available approximately 85 to 90% of the time for 10-MW units. These figures are based on industrial data and data from NERC on the smallest reported units (100 MW). Similar availability is expected with 200-MW units.

Natural gas and oil-fired steam-electric plants, like most steam-electric plants, typically require lengthy startup periods and are characterized by relatively slow response time. Thus, they are commonly operated as baseload units. Older units may see intermediate duty. The typical economic life of a plant is 30 to 35 years, although the physical life of a plant may be much longer. Older plants are often used as intermediate or seasonal peaking units.

4.2.2 Siting and Fuel Requirements

The water resources and air-quality limitations in the siting decision process for small gas- or distillate-fired steam-electric plants are similar to those for coal units. (Flue gas constituents will differ but the regulations, studies, and permits are similar.) Natural gas and usually distillate fuels are environmentally preferable to coal, and thus environmental constraints on siting these facilities should be less rigid than those expected for a comparably sized coal unit. The major siting parameters are related to fuel source and fuel handling considerations and the land area requirements for the power plant site.

A 10-MW distillate plant will require approximately 4 acres of land, whereas a gas-fired plant of comparable capacity would require about 3 acres. The difference is accounted for by tank storage facilities required by the distillate-fired units. Land area allowances are made for boiler, turbine, auxiliaries, oil storage, and electrical switchyard and waste disposal facilities. For a 200-MW plant, land requirements are approximately 13 acres for gas firing and 20 acres for oil firing. These estimates do not include an allowance for employee housing, if such is required. Estimated full-load fuel consumption for various sizes of natural-gas and distillate-fired plants are shown in Table 4.5.

TABLE 4.5. Typical Full-Load Fuel Consumption for Natural Gas and Distillate Steam-Electric Plants

Fuel	Rated Capacity (MW)	Fuel Consumption
Natural Gas	10	2.9×10^6 SCF/day
	200	55×10^6 SCF/day
Distillate	10	480 bbl/day
	200	9170 bbl/day

4.2.3 Costs

The estimated costs to construct, operate, and maintain a facility in the Railbelt region, with construction starting in 1982, are shown in Table 4.6.

TABLE 4.6. Estimated Cost for Gas- and Distillate-Fired Steam-Electric Plants (1980 dollars)

Fuel Type and Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy[a] Distillate (mills/kWh)	Cook Inlet Gas (mills/kWh)	North Slope Gas (mills/kWh)
Distillate - 10	1,920	60	136	-	-
200	1,330	22	120	-	-
Natural Gas - 10	1,360	56	-	73	161
200	900	20	-	60	143

(a) Levelized lifetime costs, assuming a 1990 first year of commercial operation. Fuel costs are provided in Appendix B.

4.2.4 Environmental Considerations

Water resource impacts of constructing and operating a natural-gas-fired or oil-fired power plant are generally mitigated through appropriate plant siting and a water, wastewater, and solid waste management program (refer to Appendix D). These steam-cycle facilities present the least adverse impacts of the combustion technologies. Significant or difficult to mitigate water resource impacts are not anticipated.

The burning of oil or natural gas in steam-electric generators generally presents the least adverse atmospheric impacts of the combustion technologies. The expected emissions from a natural gas or oil-fired power plant and the associated regulatory framework are presented in detail in Appendix E. SO_2 emissions from the burning of residual fuels will be significant and will require conventional scrubbers for large systems. In addition, NO_x emissions resulting from high-temperature combustion may be significant enough to require the application of control techniques such as two-stage combustion.

The most significant and difficult to mitigate impacts from oil or natural gas steam-cycle plants are associated with intake and discharge of water (refer to Appendix D). These plants could be located near many major aquatic resources on Cook Inlet and Prince William Sound or along major salmon rivers in the Railbelt such as the Susitna or Copper Rivers. These plants use the same amount or less water per megawatt than any other steam-cycle design except the combined cycle. A 10-MW plant would use approximately 4,500 gpm for once-through cooling systems and 80 gpm for recirculating cooling systems (see Appendix I). Therefore, if the plants are properly sited and constructed, resulting impacts should be less than other steam-cycle plants (except for combined-cycle units).

The greatest impact on the terrestrial biota resulting from natural gas or distillate-fired steam-electric plants would be loss or alteration of habitat. Land requirements for plant development should be approximately 6 acres for a 10-MW facility and 20 acres for a 200-MW facility. Thus, these plants require considerably less land area than other steam-cycle plants and impacts are not expected to be significant. Also, natural gas and, in general, distillate-fired power plants would probably be placed near existing developed areas, thus avoiding environmental problems of plants sited in remote areas.

4.2.5 Socioeconomic Considerations

Socioeconomic impacts of siting a gas- or oil-fired steam-electric plant will vary with both location and plant scale. The most likely sites for oil-fired plants are near existing refineries or along distribution pipelines. Other possible sites are along the railroad and major highway corridors. Possible sites for gas-fired plants would be adjacent to the Cook Inlet gas fields or near the gas transmission line that links Soldotna to Anchorage. Completion of the North Slope natural gas pipeline would permit siting near Fairbanks and along the Tanana Valley.

The flexibility of siting oil or gas-fired power plants, particularly an oil-fired plant, results in numerous potential sites. If the access were good, a 10-MW unit could be constructed in 20 working months. This estimate is based on a packaged boiler and skid-mounted auxiliary equipment. A 200-MW unit is field constructed, which will require approximately 3.5 to 5 years, depending on such variables as site accessibility, availability of work force, site conditions, and weather. Tank construction for oil firing may add to the construction work force, but the overall construction period should be the same as for a gas-fired plant because tank work can proceed simultaneously with boiler and turbine installation. The construction work forces are estimated to peak at 60 persons for an oil-fired unit and 50 for a packaged gas unit. The difference is due to the tank and unloading facilities needed for oil-fired units. The 200-MW units are estimated to require a peak work force of 580. Operational manpower is estimated at 20 workers for the 10-MW plant and 70 for the 200-MW unit.

Whereas "very small" communities would be significantly affected by the influx of construction workers, "small" communities should not be affected if temporary housing is provided for the workers (see Appendix H). Locations that meet this "small" criterion and that are near a distribution pipeline include Anchorage, Soldotna, and Fairbanks. Secondary locations include Kenai, Seward, Wasilla, and Palmer. The impact of siting a 200-MW plant would be minor in Anchorage and moderate in Fairbanks. For all other locations, including Kenai, Seward, Wasilla and Palmer, impacts would range from significant to severe, primarily due to the inability of those communities to absorb demands on infrastructure and public services that accompany the large construction work force.

Capital and O&M expenditures that would flow out of the region due to the development of these types of facilities would include investment in equipment and employment of specialized supervisory personnel. Due to the moderate-sized construction work force and relatively short installation period, 25% of the project's capital expenditures can be expected to be made within the region and 75% would be spent outside Alaska. Nine percent of the O&M expenditures would most likely be spent outside Alaska.

4.2.6 Potential Application in the Railbelt Region

The sources of distillate fuel in the Railbelt are presently confined to the refineries at Kenai and at North Pole (Figure 4.4). Petroleum pipelines carry refined products from the port of Whittier to Anchorage. These areas are prime sites since fuel refining or pipeline transmission systems are already in place.

Areas served by good transportation facilities connecting to the refineries can also be considered for distillate-fired generation. These areas would include the Kenai Peninsula, locations adjacent to the Alaska Railroad, and major highway corridors. Highway transport would likely be feasible only for smaller plant sizes. For example, a 10-MW distillate-fired plant would require two to three tank truck deliveries per day.

The only practical method for transporting natural gas in quantity is by pipeline. Potential sites are limited to locations where existing service is available or where it can be easily provided. The Anchorage, Cook Inlet, and Kenai regions are well suited because of their proximity to refinery capacity, wells, and gas transmission systems. The proposed North Slope gas pipeline would provide natural gas to the Fairbanks area.

Natural-gas- or distillate-fired steam-electric plant could potentially be used to provide baseload power to the Railbelt region. Of the two fuels, distillate most likely would not be used in the Anchorage area because natural gas is available at a substntially lower cost. Although natural gas is not presently available in the Fairbanks area, the present excess of installed capacity would make constructing a distillate-fired steam-electric units in the near term impractical. In the longer term, the construction of the Anchorage-Fairbanks intertie may obviate the need for new baseload capacity in the Fairbanks area. If new capacity were required in Fairbanks, future availability of North Slope natural gas via the proposed North Slope natural gas pipeline would probably make natural gas the fuel choice between oil and natural gas.

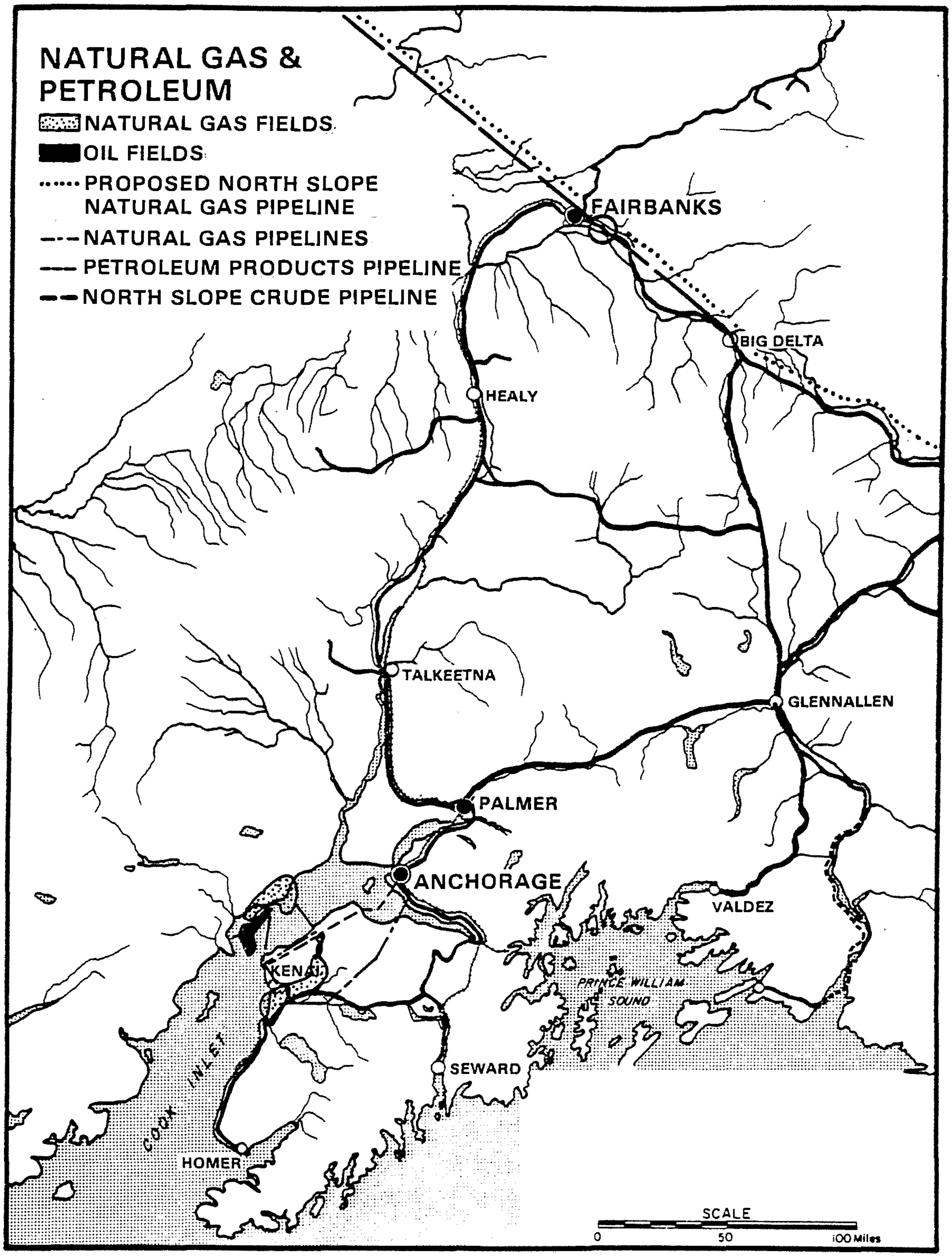


FIGURE 4.4. Natural Gas and Petroleum Supplies in the Railbelt Region

Currently, the Fuels Use Act effectively constrains development of natural gas or distillate-fired steam-electric plants from all but minor applications. The Fuels Use Act prohibits use of natural gas or distillate for baseload electric generating facilities exceeding 10 MW in capacity. Because natural-gas- or distillate-fired steam-electric plants are primarily baseload units, this technology is effectively excluded from future development except under limited situations in which exemptions to the Fuels Use Act may be obtained. Provisions of the Fuels Use Act, including conditions under which exemptions may be obtained, are discussed in Appendix N.

4.3 BIOMASS-FIRED STEAM-ELECTRIC GENERATION

Biomass fuels available in the Railbelt region for power generation include sawmill residue (wood waste) and fuel derived from municipal waste (refuse-derived fuels). Limited quantities of waste oil are also available. Wood waste has been used for industrial power and process steam generation for many years, especially in the timber industry. Use of refuse-derived fuel is a more recent concept and is less well developed in the United States.

4.3.1 Technical Characteristics

Conversion technologies suitable for using biomass fuels include direct-fired steam-electric plants and several thermochemical conversion and/or chemical-based processes for synthetic gas and liquid fuels production. Various gasifiers presently are being developed that could be used for process heat and retrofits of oil- and natural-gas-fired boilers. Suitable gasifiers may be commercially available in less than 5 years if adequate development support occurs (Office of Technology Assessment (OTA) 1980). Methanol synthesis is the near-term option for liquid fuels production. Whereas wood-to-methanol plants are commercially available, herbage-to-methanol processes remain to be demonstrated. Various other thermochemical conversion processes also are being developed with considerable promise for future new and improved fuels and chemicals syntheses.

Another biomass conversion operation that may prove suitable for producing gas for the retrofit of natural-gas-fixed systems is anaerobic digestion. This biological process produces a gas containing methane and carbon dioxide. Appropriate feedstocks include many wet forms of biomass, such as animal manure and some aquatic plants. Digesters for onfarm production of gas from animal manure appear to be the most likely near-to-midterm applications. Various digesters using different feedstocks need to be demonstrated before they can be considered commercially available.

Biomass-fired power plants are distinct from fossil-fired units in that maximum plant capacities are relatively small and specialized fuel handling equipment is required. The generally accepted capacity range for biomass-fired power plants is approximately 5 to 60 MW (Bethel et al. 1979; Jamison 1979). Smaller plant sizes are generally used because of the expense of transporting low-energy-density biomass fuels appreciable distances.

Design Features

The core of a biomass-fired steam-electric power plant is the boiler and the turbine generator. Auxiliary systems are provided for fuel receiving, storage and processing, stack gas cleanup, bottom and fly-ash handling, and condenser cooling.

Because biomass fuels have relatively low heat values and bulk densities in the 10 to 20 lb/ft^3 range, and because they are variable in particle size, moisture content, and contamination, fuel handling systems are of critical importance. Particle sizes are reduced by "hogging" or grinding rather than by pulverizing. Materials handling equipment also must be larger than that used for a coal plant of equivalent capacity to handle the increased volumes of material. Finally, systems for fuel classification, contaminant removal, and possibly drying must be provided.

Preferably, municipal waste will be shredded and classified, and sorted to minimize contamination by metals and glass objects. Metallic and other noncombustible objects must be removed, usually magnetically. Mass burning (firing of unsorted refuse), while practical in some cases, results in less efficient operation of equipment.

Fuel handling systems in the Railbelt region will have to be designed to accommodate cold conditions and frozen fuel. Such systems are routinely installed in northern climates. Since the supply of any one biomass fuel may be insufficient to support a power plant, provisions may have to be made for dual-fuel firing. For example, plants constructed to burn refuse-derived fuel may be supplemented by coal. Research in fuel preparation and fuel gasification is under way to improve upon and to overcome limitations in the efficiency of biomass power plant systems caused by moisture content, low bulk densities, and modest heating values.

Performance Characteristics

The typically high moisture content of biomass fuels, as well as small scales of operation, introduces thermal inefficiencies into the power plant system. However, biomass plant efficiencies improve rapidly as plant scale increases. Heat rates as a function of plant size are shown below (Tillman 1981).

Rated Capacity (megawatts)	Heat Rate (Btu/kWh)
5	20,000
15	15,100
25	14,200
35	14,100
50	14,000

Biomass facilities, which would be operated as base-loaded units, have demonstrated high reliability. Industrial experience shows that load factors of 80 to 90% can be achieved. High load factors are attained by constant attention to maintenance and by proper design. Unit life is forecasted to be 20 years.[a]

4.3.2 Siting and Fuel Requirements

Biomass fuels are generally inexpensive but are characterized by modest heating values. Typical net heating values of biomass fuels are compared to coal below (Metcalf and Eddy Engineers 1979):

Fuel	Heat Value Btu/lb
Refuse-derived fuel	6,700
Waste Oil	19,250
Wood	4,500
Coal	9,000

(a) Electric Power Research Institute. 1982 (Draft). 1981 Technical Assessment Guide. Electric Power Research Institute, Palo Alto, California.

The rate of fuel consumption is a function of plant efficiency and capacity. Fuel consumption as a function of plant capacity is presented in Table 4.7 for a wood waste-fired plant (Tillman 1981).

TABLE 4.7. Wood Waste Requirements by Plant Size

Rated Capacity (MW)	Daily Requirements (tons)	Truck Loads Per Day (Approximate)	Rail Cars Per Day (Approximate)
5	260	10	7
15	600	25	15
25	960	40	25
35	1300	50	35
50	1900	75	50

Siting requirements for biomass-fired power plants are dictated by the fuel quality, fuel source location, and cooling water requirements. Because biomass fuels are high in moisture content and low in bulk density, economical transport distances are unlikely to exceed 50 miles (Tillman 1978). Biomass power plants are thus typically sited close to the fuel source. Sites must be accessible to all-weather highways or rail lines since biomass fuels are usually transported by truck or rail car.

Proximity to the fuel source may be the most limiting factor, although sites also must be accessible to water for process and cooling. Land area requirements are a function of scale, extent of fuel storage, and other design parameters. Typically, a 5-MW, stand-alone power plant will require 10 acres; a 50-MW, stand-alone plant will require 50 acres. These areas are quite large relative to plant capacity because they must accommodate fuel receiving facilities, fuel storage piles, materials handling and preparation systems, boilers, feedwater treatment systems, turbine generators, stack gas cleaning and ash disposal facilities. Substantial buffer zones may be required for a plant using refuse-derived fuel for odor and vermin control requirements. A one- to three-month fuel supply should be provided to ensure fuel availability during prolonged periods of inclement weather. For plants cofired with coal, coal preferably might be used for long-term storage because of its greater energy and the difficulties of storing refuse-derived fuel for long periods of time.

4.3.3 Costs

Biomass-fired power plants, particularly small-scale plants, are expensive to construct. Capital and O&M costs for relevant-scale biomass facilities in Alaska are presented in Table 4.8. Capital and O&M costs were derived from SRI (1980) and are based on a direct-fired, electric generating plant using wood waste as fuel. The cost of power estimates in the table are based on use of dual fuel firing of coal and refuse-derived fuel with the proportion of refuse increasing over the life of the facility. Estimated coal and refuse-derived fuel prices are provided in Appendix B.

TABLE 4.8. Estimated Costs for Biomass-Fired Steam-Electric Plants (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy[a] (mills/kWh)
25 (Anchorage)	2590	200	67
20 (Fairbanks)	2900	200	78
50 (Anchorage)	2450	200	74

(a) Levelized lifetime costs, assuming a 1990 first year of commercial operation. Fuel costs are provided in Appendix B.

4.3.4 Environmental Considerations

Water resource impacts associated with the construction and operation of a biomass-fired power plant are not expected to be significant or difficult to mitigate because of the small plant capacities that are considered likely.

The burning of biomass could lead to significant impacts on ambient air quality. The expected emissions from a biomass facility and the regulatory framework are presented in detail in Appendix E. Impacts arise largely from emissions of particulate matter and NO_x. Particulate emissions can be controlled with electrostatic precipitators or baghouses. The tradeoff between emission controls and additional project costs must be assessed at each facility, but wood- or coal-burning facilities larger than about 5 MW will require air pollution control systems to meet federal New Source Performance Standards.

Potentially significant impacts to aquatic systems from biomass plants are similar to other steam-cycle plants and result from water withdrawal and effluent discharge (refer to Appendix F). Although these plants are second only to geothermal facilities in rate of water use per unit of capacity (730 gpm/MW), the total use for a typical plant would only exceed that of small (10-MW) oil and natural-gas-fired plants because of the small size of prospective plants. Approximately 18,250 gpm and 362 gpm of cooling water would be required for once-through and recirculating cooling water systems, respectively. Proper siting and design of intake and discharge structures could reduce potential impacts.

The major impact on the terrestrial biota is the loss or modification of habitat. Land requirements for biomass-fired plants, approximately 50 acres for a 50-MW plant, are similar to those of coal-fired plants of equivalent capacity and are generally greater than those of nuclear and the other steam cycle power plants on an acres-per-MW basis (see Appendix G).

Potential locations of biomass-fired power plants in the Railbelt region include Fairbanks, Soldotna, Anchorage, and Nenana. All four areas contain seasonal ranges of moose. Waterfowl also inhabit these areas with high use occurring along the Matanuska and Susitna River deltas near Anchorage, and the areas around Nenana. The Soldotna region also contains populations of black bear, and caribou calving areas, migration corridors, and seasonal ranges. Populations of mountain goats, caribou, and Dall sheep occupy habitats in the Susitna and Matanuska River drainages near Anchorage. Impacts on these animal populations will depend on the characteristics of the specific site and the densities of the wildlife populations in the site area. Due to the relatively small plant capacities involved, however, impacts should be minimized through the plant siting process.

4.3.5 Socioeconomic Considerations

To construct and operate biomass-fired facilities, relatively small labor forces are required. For 15- to 30-MW plants, a construction work force of 65 would be required, whereas operating and maintenance would require approximately 25 people. Construction periods would range from 18 months to 3 years (excluding the licensing process). Possible locations for biomass-fired plants include Anchorage, Fairbanks, Soldotna and Nenana. Impacts of biomass-fired plants, as well as plant size, will vary among these locations. Anchorage, Fairbanks, and Soldotna should be able to accommodate the construction of a 5- to 50-MW plant with minimal impacts to the social and economic structure of these communities.

Nenana, an Alaskan native village, has a population of 471, and the surrounding area has an aggregate population of approximately 1,000. Because of Nenana's small population size and undeveloped infrastructure, the impacts of plant construction on Nenana may be significant and will increase with plant size. The transfer of workers and their families for a period of 1 to 3 years may cause a strain on the social fabric of Nenana and may create demands for infrastructure in the nearby community of Anderson (pop. 390). These impacts can be mitigated by limiting the scale of the plant.

The breakdown of capital expenditures is expected to be 60% outside the Railbelt and 40% within the region. Expenditures due to a large capital investment will be offset by employment of an Alaskan labor force. Approximately 10% of the O&M expenditures would be spent outside the region.

4.3.6 Potential Applications in the Railbelt Region

Potential sources of biomass fuels in the Railbelt region include mill residue from small sawmills at Soldotna, Anchorage, Nenana, and Fairbanks (Figure 4.5), and municipal waste from the cities of Fairbanks and Anchorage. Fuel availability for wood residue in the Railbelt region is shown in Table 4.9 (U.S. Department of Agriculture 1978).

Only broad ranges of wood residue availability have been developed because little information is available on lumber production as a function of markets, lumber recovery, and internal fuel markets. The residues considered

TABLE 4.9. Fuel Availability for Wood

Area	Wood Fuel (tons/day)
Greater Anchorage	200-600
Kenai Peninsula	60-180
Fairbanks	10-30
Nenana	40-140

here include bark from debarkers, chips, slabs, sawdust, and planer shavings. Some of these residues could be used as fuel since by-product markets (e.g., pulp mills, particle board plants) for such materials appear to be absent. Harvesting of trees solely to fire electric power plants does not appear to be desirable due to the slow regeneration of forests and the availability of coal at competitive prices.

Estimated future availabilities of refuse-derived fuel for the Anchorage and Fairbanks areas are shown in Table 4.10. Forecasts for Anchorage through 2000 are taken from Metcalf and Eddy Engineers (1979); years 2005 and 2010 are extrapolated using linear regression. Fairbank's estimates are based on ratios between Anchorage and Fairbanks municipal waste production taken from Nebesky (1980). Quantities given are average daily tons of refuse-derived fuel product, processed using ferrous metal magnetic separation followed by air classification. Estimated heat value of the product is 6714 Btu/lb.

In the Railbelt region biomass power plants using municipal refuse supplemented with wood residue and coal may potentially contribute up to 5% of future power needs. With that potential, the biomass-fired units would be central station installations capable of serving individual community load centers or interconnection to a Railbelt power grid.

Since the biomass-fired systems are relatively small, they are particularly adaptable to the modest incremental capacity needs that are forecast for the Railbelt region. The most probable application of the technology appears to be a small plant at Anchorage, which is fired by refuse-derived fuel, waste oil, and such wood residue as may be available and is supplemented by coal

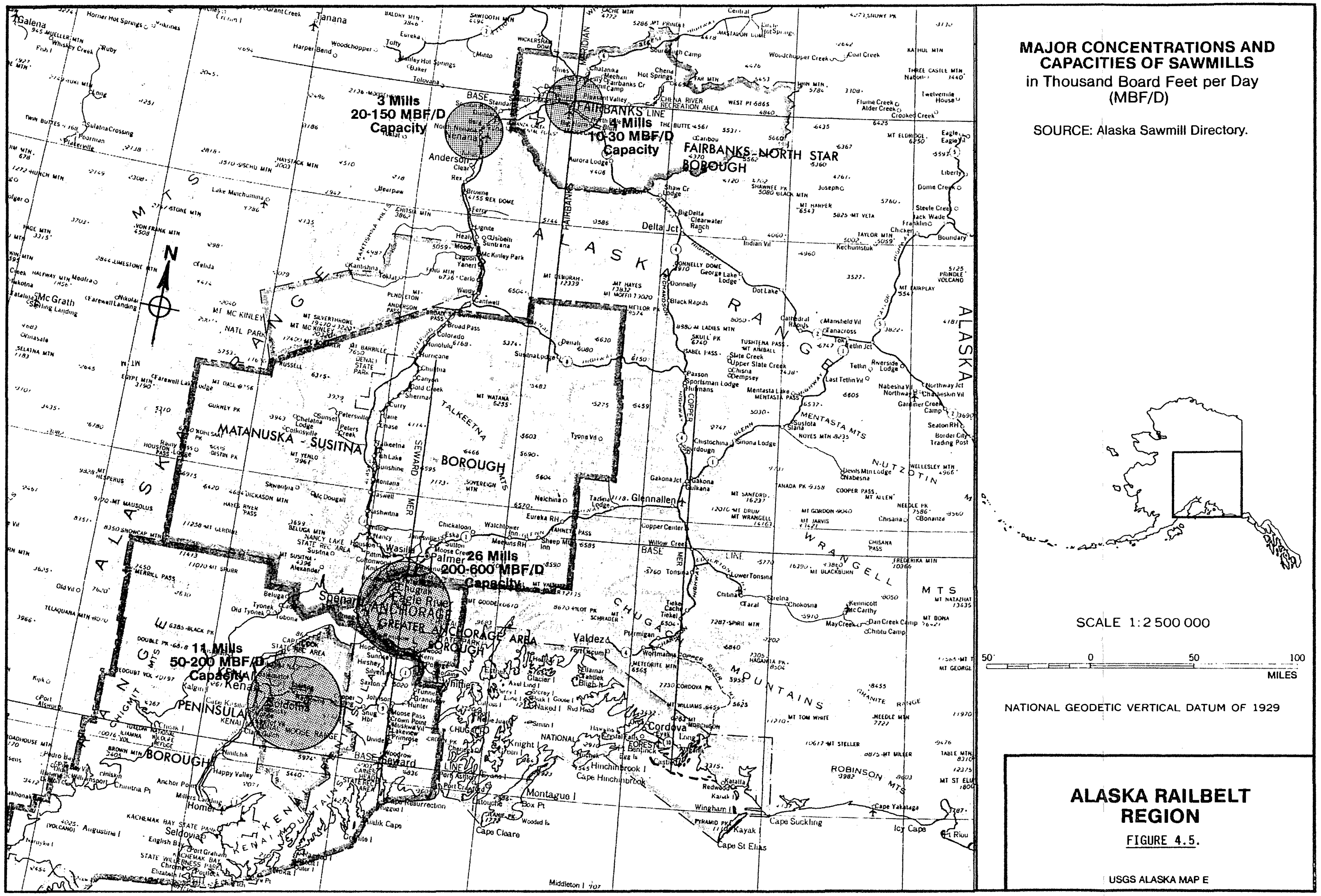


FIGURE 4.5. Major Concentrations and Capacities of Sawmills in the Railbelt Region

TABLE 4.10. Estimated Refuse-Derived Fuel Production (average tons/day)

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

firing as necessary. A smaller plant at Fairbanks may also be feasible, fired by refuse-derived fuel, waste oil and wood residue from Nenana and Fairbanks and supplemented by coal.

4.4 NUCLEAR LIGHT WATER REACTORS

Nuclear steam-electric generation is a mature, commercially available technology. At present, some 73 units with a total installed capacity of 54,000 MW are operable in the United States. An additional 104 units representing approximately 116,000 MW of capacity have either been ordered or are in some phase of the licensing or construction process. Canada, France, Germany, Japan, Sweden, and the United Kingdom also have a large nuclear steam-electric capacity based either on U.S. developed technology or on technologies developed within those respective countries. In spite of this experience, nuclear power is experiencing social and political problems that might seriously affect its viability. These problems manifest themselves in licensing and permit delays and therefore are important to the Alaskan electrical supply situation, given their cost and schedule impacts.

Diminished load-growth rates, concerns over nuclear weapons proliferation, adverse public opinion fueled by the Three-Mile Island (TMI) accident, expanding regulatory activity (also fueled by TMI), and lack of overt political support have resulted in no new domestic orders for nuclear units since 1977. The industry currently is maintaining its viability by completing backlog work on domestic units and by pursuing new foreign orders. Although the current administration has indicated support for nuclear power, not enough time has passed to observe tangible results.

4.4.1 Technical Characteristics

The principal commercial power reactor designs used in the United States are based on the use of natural water ("light water") as the reactor coolant. Light water reactors (LWRs) produce electricity using a steam cycle similar to that of fossil-fuel-fired power plants. However, in a nuclear power plant the heat used to raise steam is obtained by fissioning uranium fuel in a nuclear reactor.

The economics and design trends since the introduction of commercial nuclear power have evolved to the point that almost all plants being constructed are in the 800- to 1,200-MW range. Because of these plant sizes and the resulting costs, nuclear power is a viable option only for utilities having a large electrical baseload. (Nuclear units with generating capacities ranging from 50 to 700 MW are operating in the lower 48 states. However, these are demonstration and first and second generation nuclear facilities and represent unit designs not currently available from domestic vendors.) Smaller plant designs could be obtained from various vendors but are not currently commercially available. Smaller designs could incur licensing difficulties and increased costs because of the lack of standardization. Smaller plants (about 500 MW) are available from foreign suppliers but, again, could incur licensing difficulties.

Two LWR designs, boiling water reactors (BWR) and pressurized water reactors (PWR), are in common use. In BWR designs, coolant water circulates through the core and is heated to form steam at about 1,100 psi for direct use in the turbine. PWR designs include primary and secondary coolant loops (Figure 4.6). The primary loop is operated at high pressure (about 1700 psi) to maintain the primary cooling water in liquid form at all times. The hot primary water is circulated from the reactor to a heat exchanger (steam generator) where steam is formed in the secondary loop for use in the turbine. Reactor designs using other heat exchange systems exist but are not common in the United States.

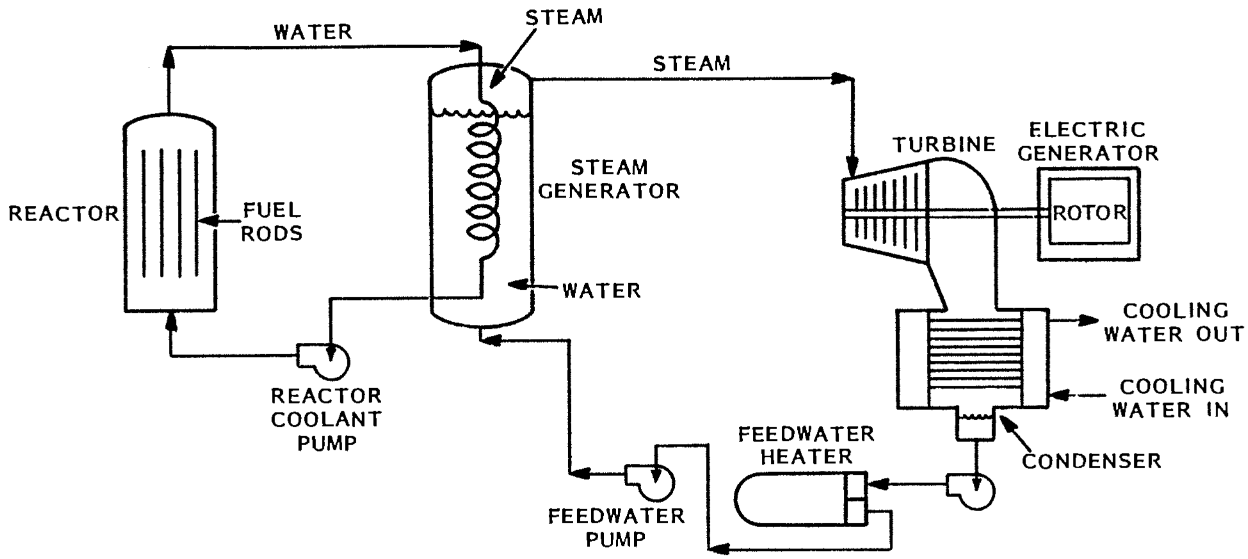


FIGURE 4.6. PWR Steam-Electric Plant

Performance Characteristics

Nuclear power generating plants are typically designed for operation as baseload units because of their characteristically high capital costs and low fuel and operating costs. The more power produced from the plant, the lower cost per unit of electricity delivered. Therefore, nuclear power plant capacity functions are typically close to plant availability factors.

Plant availability is determined by scheduled and unscheduled outages. Scheduled outages for nuclear facilities are based on periodic maintenance requiring plant shutdown and refueling requirements. Typically, refuelings are scheduled annually, and approximately one third of the fuel assemblies are replaced. Because the plants must be shut down for refueling, refueling is normally done during periods of low electrical demand. Typical planned (scheduled) outage rates for LWR plants are about 13%.[a]

Unscheduled outages are due to equipment malfunction. Much of the electrical, heat rejection, and in the case of PWRs, steam system equipment of a nuclear reactor is not fundamentally different than similar components of a conventional steam-electric plant, and similar reliability is experienced. However, the equipment and controls of the primary (reactor) systems are far more complex and sophisticated than in a conventional steam-electric plant. Unscheduled outages due to malfunction of these systems have generally been higher than anticipated, leading to higher unscheduled outage rates overall for nuclear plants than for fossil-fired steam-electric plants. A particularly significant problem in PWR plants has been corrosion and leakage of steam generator heat exchange tubing. Typical, equivalent unplanned outage rates for LWRs are currently estimated to be approximately 22%.[a]

The typical equivalent availability including both planned and equivalent unscheduled outages of LWR plants is estimated to be approximately 68%.[a] The design life of LWRs is generally 40 years; an economic life of 30 years is typically used.

(a) Electric Power Research Institute. 1982 (Draft). 1981 Technical Assessment Guide. Electric Power Research Institute, Palo Alto, California.

4.4.2 Siting and Fuel Requirements

Nuclear plant siting has more constraints than other technologies because of stringent regulatory requirements. These requirements result from the potential consequences of accidents involving the release of radioactive materials. These requirements, however, would not be expected to bar nuclear power development in Alaska.

Under the siting criteria of the U.S. Nuclear Regulatory Commission (NRC) (10 CFR 100), nuclear facilities must be isolated to the degree that proper exclusion areas and low population zones may be maintained around the facility. Nominal distances ranging from 2,000 to 5,000 ft to the nearest site boundary (encompassing areas of 250 to 2,000 acres) usually are sufficient to meet the first criterion for almost any size nuclear facility. Additionally, a physical separation of 3 to 5 miles from areas of moderate population density allows compliance with the second criterion. Because of the Railbelt's generally low population densities, these requirements are of little consequence in the region. Land required for the construction force campsite could serve as the plant exclusion area when the plant is completed.

Seismic characteristics of a potential site are a major factor in plant siting because the nuclear plant must be designed to accommodate forces that result from earthquake activity. Seismic zones and major faults of the Railbelt region are shown on Figure 4.7. Constructing a nuclear plant in Zone 3 would very likely require expensive plant designs and a lengthy licensing process. Siting a plant in Zone 2 would be less difficult. In either case, extensive preapproval geotechnical investigations would be required. Nuclear plants most likely would not be excluded from the Railbelt on a seismic basis since nuclear plants have been designed and constructed on a worldwide basis in each of the types of seismic zones found in the Railbelt region.

In addition to meeting the specific nuclear safety requirements of the NRC, a nuclear plant site must meet the more typical criteria required of any large, steam-electric generation technology. A 1,000-MW nuclear project represents a major, long-term construction effort, involving the transportation of bulky and heavy equipment and large quantities of construction materials. Transportation capable of handling these items limits the potential Railbelt sites to the corridor along the Alaska Railroad and port areas of Cook Inlet and Prince William Sound. The requirement for remote siting must be balanced against the cost of transmission facilities required to deliver power to load centers.

Substantial heat is rejected by a 1,000-MW plant. Therefore, a potential site must have enough cooling water to remove the heat according to environmental criteria for thermal discharges. Once-through cooling of a 1000-MW facility requires a water flow of approximately 3,000 cfs and would almost certainly require coastal siting. Because closed-cycle systems require less water than once-through systems (probably less than 100 cfs), siting options can include some of the rivers of the region (Appendix I).

Reactor fuel, a highly refined form of enriched uranium fabricated into complex fuel elements, is not produced in Alaska and would have to be obtained from fuel fabrication facilities located in the western portion of the lower 48 states. The proximity of the nuclear plant to the fuel source is relatively unimportant because uranium is a high-energy density fuel, and refueling is accomplished on a batch rather than a continual basis. Refueling is required about once a year and is usually scheduled during summer months in cold climates to prevent weather-induced delays and to coincide with periods of low electrical demand.

Recent estimates of U.S. uranium supply show that ample low-cost uranium resources exist to support about ten times the number of reactors now in service or under construction (Piepel et al. 1981). When all low-cost uranium is committed, the fast breeder reactor (FBR), which produces a surplus of fuel-grade plutonium, will become commercially feasible. Because fuel-grade plutonium can be used to fuel LWRs, long-term fuel supply should not be a limiting factor. Although Alaska has identified uranium deposits, the economic forces for developing the resource are tied to the world market conditions rather than to the use of uranium as fuel for nuclear plants located in Alaska.

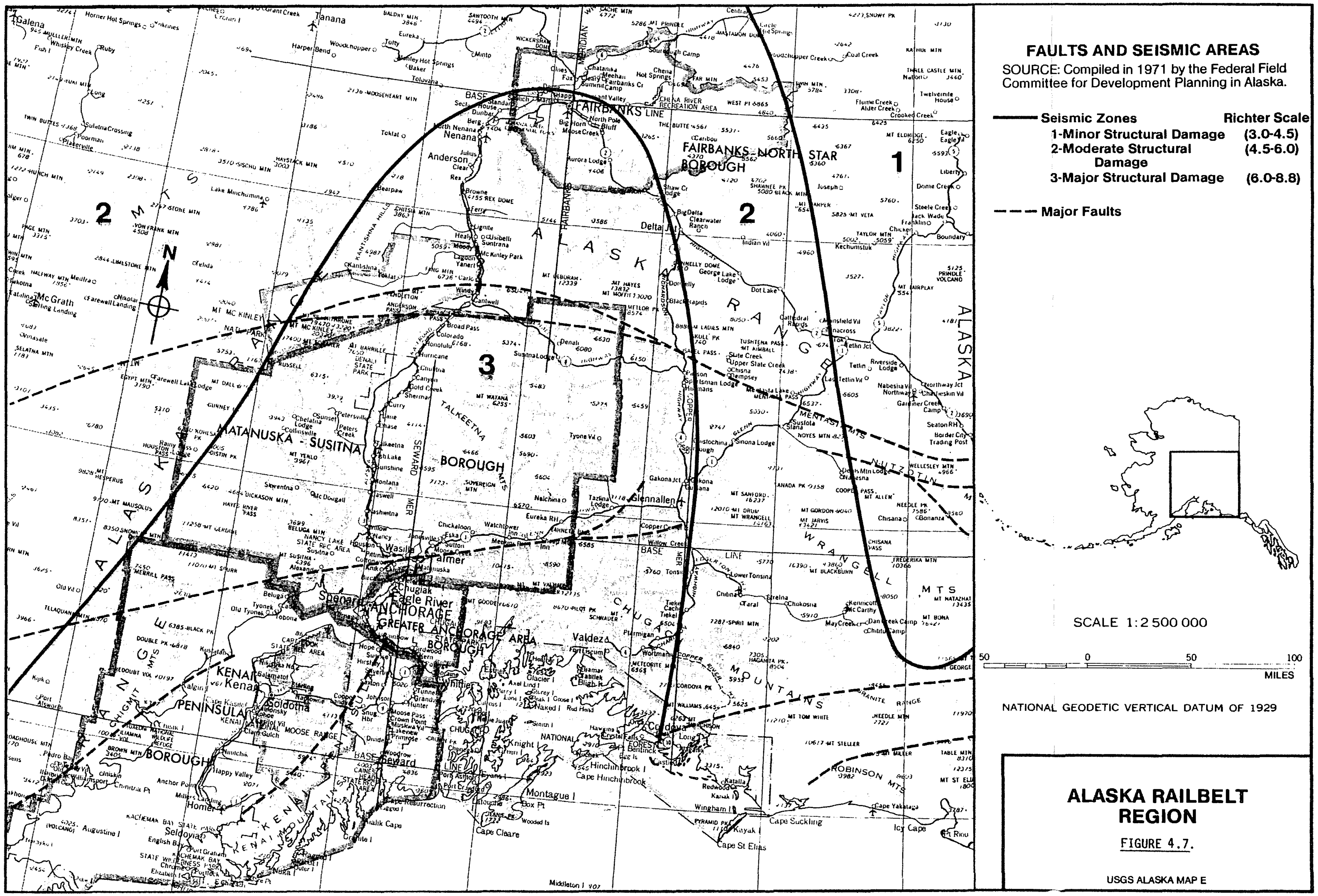


FIGURE 4.7. Faults and Seismic Areas in the Railbelt Region

4.4.3 Costs

The capital cost of a nuclear plant is high relative to other baseload technologies. No overall major cost distinction can be made between the two types (BWR and PWR) of reactors. Each project must be evaluated to determine the most economical type for installation. The cost of the nuclear steam supply system (reactor steam generators and auxiliaries) is higher for a PWR because of the added complexity of the secondary fluid loop; however, this cost is offset by the higher costs of the BWR's containment building and shielding. Conceptual level estimated costs for construction and operation of nuclear power plants in the Railbelt are shown in Table 4.11.

TABLE 4.11. Estimated Costs for Nuclear Power Plants (1980 dollars)

Plant Type and Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/Yr)	Fuel (mills/kWh)	Cost of Energy[a] (mills/kWh)
PWR - 1000	1850	24	7	31
BWR - 1000	1850	24	7	31

(a) Levelized lifetime costs, assuming a 1990 first year of commercial operation.

The capital costs of Table 4.11 are overnight construction costs and do not include escalation or interest during construction. The capital cost estimate is based on observed capital costs of $975 per installed kilowatt for the lower 48, adjusted to Alaska conditions using an adjustment factor of 1.9.

O&M costs are based on estimated Lower 48 O&M costs of 16 $/kWh/yr, adjusted to Alaskan conditions using a factor of 1.5. Fuel costs are discussed in Appendix B.

4.4.4 Environmental Considerations

Water resource impacts associated with constructing and operating a nuclear power plant are generally mitigated through appropriate plant siting and a water and wastewater management program (Appendix D). Note, however, that due to the generally large sizes of nuclear power stations, the magnitude of water withdrawal impacts for a given site may be greater than those for other baseload technologies. Magnitude, however, does not necessarily imply significance. A favorable attribute of nuclear power is the lack of wastewater and solid waste associated with fuel handling, combustion, and flue-gas treatment and experienced with combustion-based technologies.

The generally large unit size for a nuclear facility indicates that these plants would be the largest water users of any steam-cycle plants; approximately 310,000 gpm would be used for a once-through cooling system and 6,200 gpm would be used for a recirculating cooling water system. Their rate of use (gpm/MW) is also higher than many other technologies (Appendix D) because of somewhat lower plant efficiencies. Potential impingement and entrainment impacts would therefore be somewhat higher than for other baseload technologies of comparable size. Detrimental effects of discharge may also be high because of the large quantity of water used.

In addition to the effects on aquatic and marine ecosystems resulting from cooling water withdrawal and thermal discharges, common to other steam-cycle plants, nuclear facilities have the potential for routine low level, and possibly accidental higher level discharge of radionuclides into the aquatic environment. However, under normal operation the discharge water contains fewer hazardous compounds than may be found in other steam-cycle wastewaters.

Nuclear power plants cause no deterioration in air quality other than the routine or accidental releases of radionuclides. A complex meteorological monitoring program is required to assess the potential dosages of these radioactive materials. The wind speeds and dispersive power of the atmosphere play a crucial role in diluting the effluent. Generally, sites in sheltered valleys and near population or agricultural centers are not meteorologically optimal. Large amounts of heat are also emitted by nuclear power plants. Some modification of microclimatic conditions onsite will be noted, but offsite these modifications will be imperceptible. The NRC will ensure that the ambient meteorological conditions are properly measured and considered in the siting of a nuclear power plant. These constraints will not preclude the construction of such a facility in the Railbelt region.

The predominant impact on terrestrial biota is habitat loss. Nuclear power plants require land areas (100 to 150 acres for a 1000-MW plant) second in size to those of coal- and biomass-fired plants (on a per-MW basis). Furthermore, lands surrounding the plant island are at least temporarily modified by auxiliary construction activities (i.e., laydown areas, roads, etc.). These lands possibly could be partially recovered through revegetation. Most of the exclusion area would remain undisturbed.

Other impacts difficult to mitigate could be accidental releases of radionuclides. The effects of such accidents on soils, vegetation, and animals could be substantial. However, releases resulting in substantial impacts are regarded as highly unlikely. The TMI incident, for example, caused no contamination of the surrounding area. Proper plant design and construction should prevent these releases under normal operating conditions.

4.4.5 Socioeconomic Considerations

A construction work force with a peak of 1,300 workers is typically required for a 1,000-MW nuclear plant. In comparison to other baseload technologies, a nuclear power plant has the greatest potential to adversely affect communities. The construction of a nuclear facility could severely strain nearby communities' abilities to provide housing, public services and facilities, and commercial goods and services. Highly skilled workers would be required during both the construction and operation phases, resulting in the migration of much of the work force. The in-migration of construction workers would be augmented by spouses and dependents. The long duration of the construction period (7 to 10 years) would cause a permanent expansion of the existing infrastructure.

Only within the vicinity of Anchorage, where the infrastructure could support a large population influx, could a nuclear facility be constructed without major socioeconomic impact. The siting of a nuclear plant 25 to 50 miles from Anchorage could induce further urban sprawl. Communities with populations of 5,000 or less would experience severe impacts.

Depending on location of the site, a new town could be built to accommodate workers and their families. When construction was finished, most of the construction work force and their families would leave the area, leaving an operating and maintenance crew of approximately 180. The large out-migration would leave the community with abandoned housing and facilities and would drastically alter the social fabric and local economy.

Approximately 60% of the project capital expenditures would be spent outside the Railbelt since all equipment and most of the labor would be imported from the lower 48 states. Approximately 11% of O&M expenditures would be spent outside the region.

4.4.6 Potential Application in the Railbelt Region

As discussed in Section 4.4.2, fuel availability and siting constraints would probably not significantly impair construction of commercial nuclear power plants in Alaska. Potential sites, however, would have to be near existing or potential port facilities or along the Alaska Railroad because large amounts of construction material and very large and heavy components would have to be delivered to the site. Interior sites would present more favorable seismic conditions.

More constraining than site availability is the rated capacity of available nuclear units in comparison with forecasted electrical demand in the region. The forecasted interconnected load of 1,800 MW in 2010 (see Chapter 2.0), will probably be too small to accommodate even the smaller nuclear power plants, primarily from the point of view of system reliability effects and surplus capacity likely to result from introducing such a large facility. Incorporating a nuclear power plant into the Railbelt system would require significant reserve capacity to provide generating capacity during scheduled and unscheduled outages.

In addition to the technical/economic considerations impacting the use of nuclear power in Alaska, current State statutes specifically exclude nuclear energy production from the definition of power projects that can be funded through the Power Development Fund [see Power Authority Act as amended 4483.230(4)].

4.5 GEOTHERMAL GENERATION

Potential high-temperature geothermal resources have been identified in the Wrangell Mountains, east of Glennallen, and in the Chigmit Mountains, west of Cook Inlet. Several low-temperature geothermal sites are found in the Railbelt (Figure 4.8). Geothermal energy may be used for electricity generation, which usually requires temperatures of at least 280°F, or for direct applications, which require temperatures less than 280°F. Direct heating applications include space heating for homes and businesses, applications in agriculture and aquaculture, industrial process heating, and recreational or therapeutic use in pools.

Three types of geothermal resources hold potential for development: hydrothermal, geopressured brine, and hot dry rock. Although hot dry rock resources represent over half the U.S. geothermal potential, satisfactory technologies have not yet been developed for extracting heat from this resource. Hydrothermal systems are in commercial operation today. Hydrothermal geothermal resources are classified as vapor-dominated or liquid-dominated systems. A typical vapor-dominated system produces saturated to slightly superheated steam at pressures of 435 to 500 psi and temperatures of approximately 450°F. Liquid-dominated systems may be subdivided into two types, those producing high enthalpy fluids greater than 200 calories/gram (360 Btu/lb), and those producing low enthalpy fluids less than 200 calories/gram. Wells drilled into high enthalpy, liquid-dominated systems produce a mixture of steam and water. The steam may be separated for turbine operation to produce electricity. Lower enthalpy fluids may be useful for direct heating applications (Considine 1976).

4.5.1 Technical Characteristics

Fundamentally, a geothermal-electric plant uses geothermal heat to form a vapor (either steam or a low boiling point organic material), which is used to drive a turbine generator. Several different geothermal plant designs are available, or have been proposed, as discussed below.

The two basic components of a geothermal electric plant are the well field and the power plant. The well field includes production wells, piping

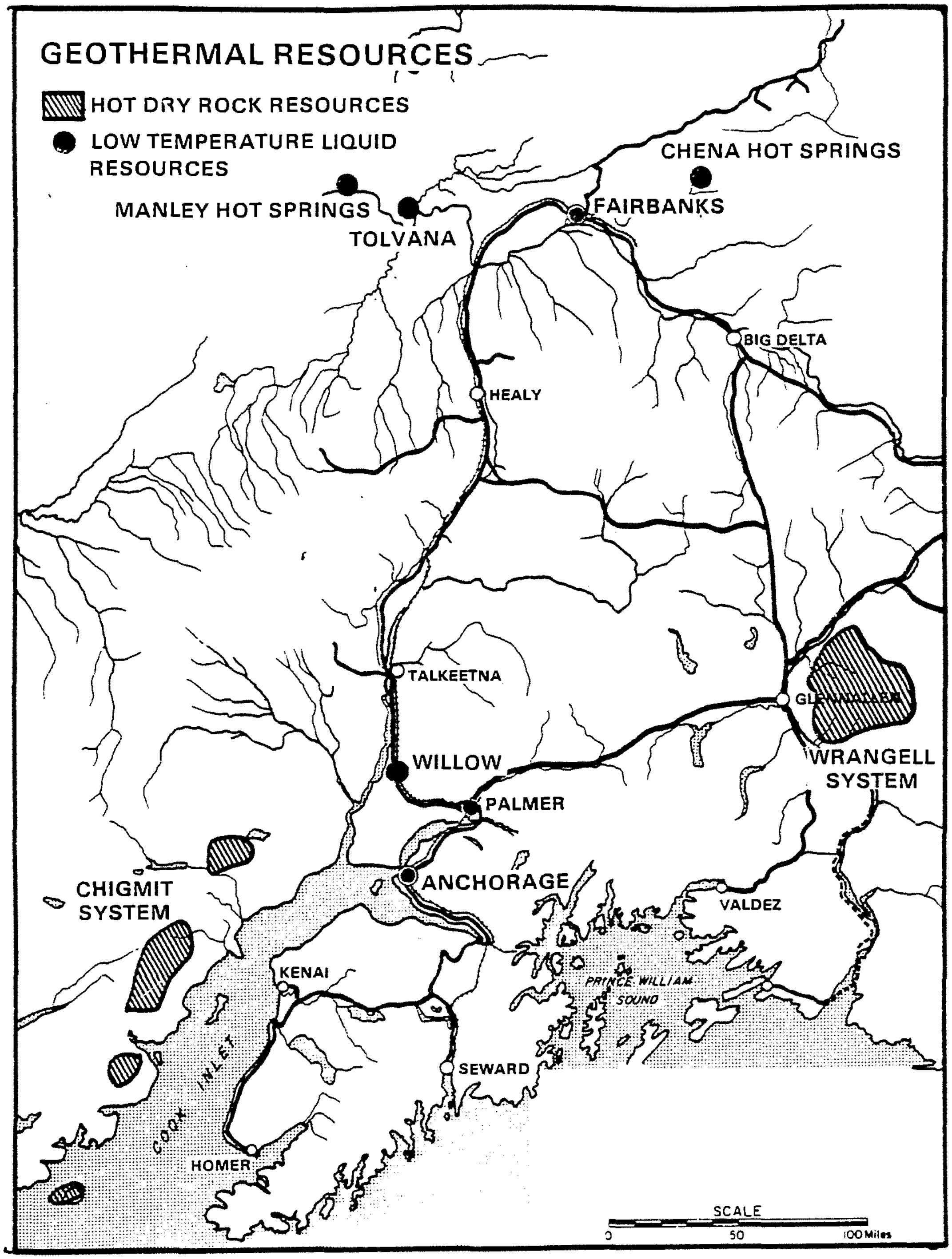


FIGURE 4.8. Geothermal Resources in the Railbelt Region

for conveying fluid to the power plant, piping for returning fluid to the well field for reinjection and the reinjection wells. The power plant includes the turbine, switchyard, and heat rejection equipment. Other equipment, including pumps, steam-flashing drums, and heat exchangers may be located either in the well field or at the power plant, depending upon the type of system used.

Based on the economic tradeoff between the economics of scale inherent in larger power plant sizes and the costs associated with collecting and returning fluid to larger well fields, the optimal geothermal-electric plant size has been determined to be approximately 50 MW. Geothermal resources having greater potential would likely be developed using multiple plants of 50-MW capacity. Wellhead units of less than 1 MW capacity are also available.

Design Features

The specific type of plant that could be selected to develop Alaskan geothermal resources will depend on the temperature, pressure, and quality of the geothermal fluid. Five principal geothermal plant designs have or are being developed: 1) dry steam, 2) flashed steam, 3) binary plants, 4) a combination of flashed steam and binary fluids, and 5) hybrid plants. Dry steam and flashed steam plants are currently commercially available. Binary plants are in the early stages of commercial demonstration with availability for commercial orders anticipated about 1986.[a] The hybrid plant type is not yet commercially available.

In a dry steam plant, steam is brought to the surface via extraction wells and piped directly through manifolds into turbines, which in turn drive the generators. On exiting from the turbine, the steam is condensed in a cooling tower or by direct contact with cooling water and is injected back into the reservoir.

Flashed steam plants operate on steam flashed from depressurized hot water brought to the surface. Utilization efficiency can often be increased by flashing at decreasingly lower pressures (multiple flashing) to obtain as

(a) Electric Power Research Institute. 1982 (Draft). 1981 Technical Assessment Guide. Electric Power Research Institute, Palo Alto, California.

much steam as possible from a given volume of water. Once the steam is separated from the water, it is supplied to turbines as in a dry steam plant. The remaining water fraction and turbine condensate are both reinjected.

The development of flashed steam power plants is more technically demanding for sites having liquid-dominated systems than for vapor-dominated systems. Development of liquid-dominated systems would require larger masses of fluids to be produced to generate a given amount of electrical energy. In addition, corrosion of well casing and piping may be severe, precipitation of minerals from the brines may be considerable, and large pore pressure drops in the reservoir rock may result in subsidence of ground surface.

Binary plants, as depicted in Figure 4.9, use secondary working fluids such as freon, isobutane, or isopentane to drive turbines. Using a binary cycle plant allows electricity to be generated with geothermal fluids that are below the flashing temperature of water. Binary plants may also use geothermal fluids whose direct use would be undesirable because of corrosion or scaling problems. In binary cycle plants, such as that at Raft River, Idaho, the geothermal fluid is pumped from the production well through a heat exchanger, where the secondary fluid is vaporized. The cooled, geothermal fluids are reinjected into the reservoir. The vaporized, secondary working fluid is used to drive turbogenerators and is condensed for reuse. Because the geothermal fluid is reinjected, the reservoir pressure of the geothermal fluid is maintained and gas release is eliminated, thus reducing some scaling or corrosion problems as well as eliminating the potential for major air pollution from gases often encountered in geothermal reservoirs. In addition, scaling and corrosion can be limited to the primary side of the heat exchanger, minimizing replacement and repair requirements.

Binary cycle plants can also be used in conjunction with flashed steam plants. In this arrangement, the water that remains after flashing is passed through a binary cycle unit. Additional energy thus is extracted and the resource is used more efficiently.

The hybrid plant type uses geothermal resources in conjunction with fossil fuels, solar energy, or biomass for power generation. Hybrid plants would supplement geothermal resources with auxiliary energy sources such as coal,

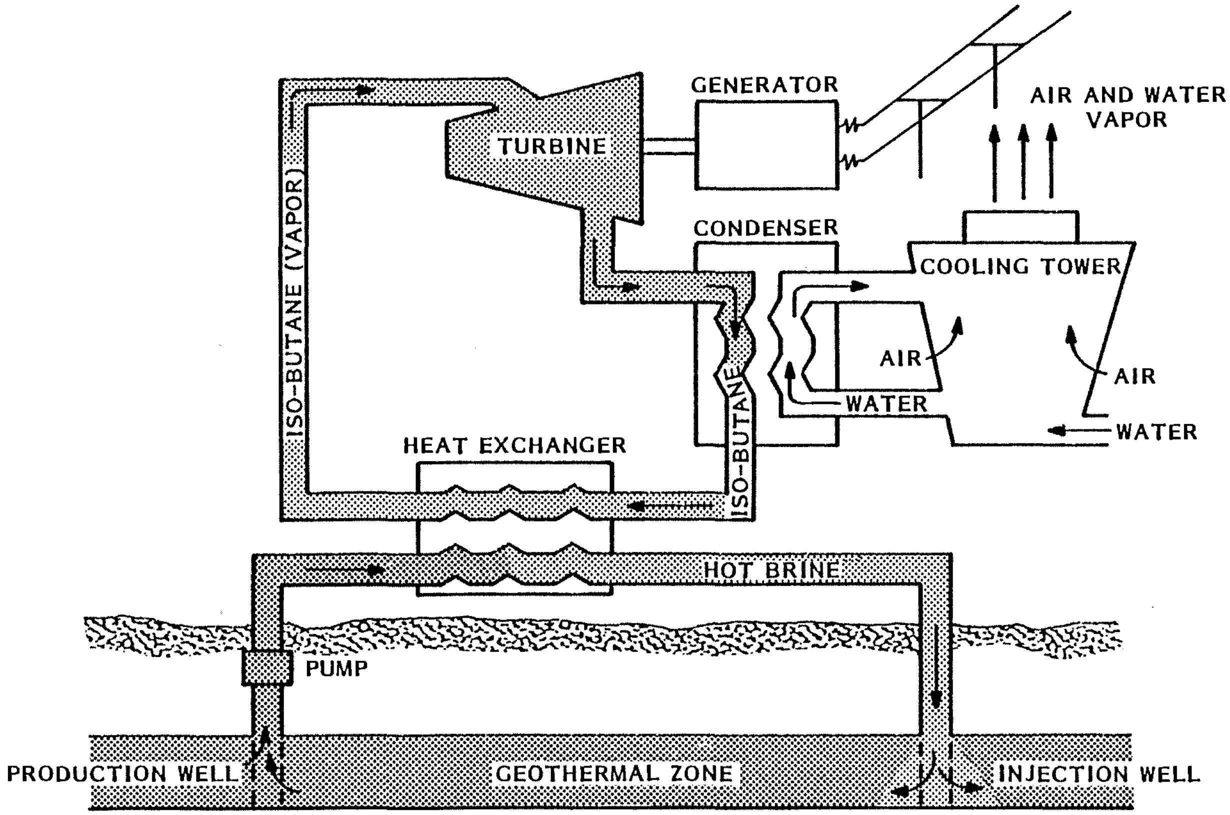


FIGURE 4.9. Binary Cycle Geothermal Power Plant

biomass, or solar energy. One approach is to use geothermal energy to preheat feed water for a boiler fired by the auxiliary fuel. In some cases, such as with the use of biomass, the geothermal resource can also be used to dry the organic fuel, which increases its burning efficiency. The hybrid plant can use geothermal resources that are below the temperature required to produce usable amounts of steam.

Present evidence indicates that the Alaskan geothermal resources are of the hot dry rock type. Hot dry rock resources would be used by injecting a working fluid, probably water, into the hot rock through injection wells. The heated water would then be brought to the surface through production wells, where it would be flashed to steam and used to drive turbogenerators. Hot dry rock technology, however, is not yet demonstrated.

The low thermal conductivity of rock controls the rate of heat transfer to the circulating fluid. Large surface areas are thus required for hot dry rock geothermal development. Los Alamos Scientific Laboratory (LASL) is field testing a rock-fracturing method based on conventional hydraulic fracturing. When high-pressure water is pumped into a well drilled to a predetermined depth, existing fractures are widened and new fractures are created through rock displacement. The working fluid, generally water, is pumped into wells that penetrate to the bottom of a hydraulically fractured zone. The fluid passes through the fractures and into an extraction well, where the heated working fluid is drawn.

Performance Characteristics

The appropriate measure of a geothermal plant's thermodynamic performance is the "geothermal resource utilization efficiency." Well-designed, dry steam geothermal power plants with condensing turbines operate with utilization efficiencies between 50 and 60%. Plants receiving lower quality geothermal fluid, i.e., lower temperature, will exhibit lower efficiencies because a portion of the geofluid has to be sacrificed to raise the energy of the remaining portion to a usable level.

Steam in a geothermal electric generating plant is of moderate pressure at only a few degrees of superheat. Due to the high specific volume of the steam, the heat rate of the turbine is about 22,000 Btu/kWh. This rate is equivalent to a thermodynamic efficiency of 16%, requiring approximately twice the heat rejection as a conventional fossil-fired unit of comparable rated capacity.

The availability of a geothermal plant will vary widely, depending on such factors as technology type, corrosive matter in the fluid, and maintenance and source reliability. A geothermal plant in the Railbelt region is estimated to be available approximately 65% of the time.

The lifetime of a geothermal power plant is forecast to be 30 years. Well life varies widely but averages 15 years. Additional wells are developed during the life of the plant to support continued plant operation.

4.5.2 Siting Requirements

Geothermal plants are always located at the site of the geothermal resource. The four most important siting criteria used to evaluate geothermal resources for application to electric power production are as follows:

1. fluid temperatures in excess of approximately 140°C (280°F)
2. heat sources at depths less than 10,000 ft, with a temperature gradient at 25°F per 1,000 ft
3. good rock permeability to allow heat exchange fluid to flow readily
4. water recharge capability to maintain production.

Individual geothermal wells should have a capacity to supply 2 MW of electricity.

The site must have access available for construction, operation, and maintenance personnel, and a source of water available for condenser cooling (and injection in the hot rock technology). The land area required for the geothermal power plant will be similar to that required for an oil-fired unit; however, the total land area will be vastly larger because of the diffuse location of the wells. A 10-MW plant, excluding wells, can be situated on approximately 5 acres of land. After exploratory wells are sunk to determine the most productive locations (both for production and injection wells), the plant would be located based on minimum cost of pipelines and other siting factors. A network of piping would then be established to complete the installation.

4.5.3 Costs

Identified Railbelt geothermal resources that are potentially suitable for electricity production are limited to the hot dry igneous type. Hot dry rock technology would be required to exploit this resource. Estimated capital and O&M costs of hot dry rock geothermal development, including well field development, are shown in Table 4.12 (DOE 1978 and DiPippo 1980). These costs are highly speculative because of the current early stage of technical development of hot dry rock technology.

TABLE 4.12. Estimated Costs for Hot Dry Rock Geothermal Developments[a] (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy[b] (mills/kWh)
50	2550	175	57

(a) DOE 1978; DiPippo 1980.
(b) Levelized lifetime costs, assuming a 1990 first year of commercial operation.

4.5.4 Environmental Considerations

A problem unique to geothermal steam cycles involves disposing of the geothermal fluid. This fluid is generally saline, and therefore most geothermal plants in the United States practice reinjection into the geothermal zone. If the geothermal zone is highly pressurized, however, not all of the brine may be reinjected, and alternative treatment and disposal methods must be considered. For geothermal fields located in the Chigmit Mountains, brine disposal in Cook Inlet should not be too difficult. The interior fields, however, could require extensive wastewater treatment facilities to properly mitigate water-quality impacts to freshwater resources and to comply with relevant water-quality regulations. Depending upon a specific field's water characteristics, the costs associated with these treatment facilities could preclude development.

Geothermal water is often high in salts and trace metal concentrations and is often caustic. The caustic nature of the solution often corrodes pipes, which can add to the brine's toxicity. Current regulations require reinjection of spent geothermal fluid; however, entry of these brine solutions into the aquatic environment by discharge, accidental spills, or groundwater seepage could cause acute and chronic water-quality degradation.

Geothermal plants have the highest water-per-megawatt use of any steam-cycle plant (845 gpm/MW). A 50-MW plant would use 42,200 gpm for once-through and 750 gpm for recirculating cooling water systems, respectively.

Atmospheric emissions from the development of geothermal resources will consist primarily of CO_2 and hydrogen sulfide (H_2S). Other emissions may consist of ammonia, methane, boron, mercury, arsenic compounds, fine rock particles, and radioactive elements. The nature and amount of these emissions can vary considerably. This uncertainty can be removed only by test wells in the proposed project area. Emissions are also a function of operational techniques. If reinjection of geothermal fluids is used, emissions into the atmosphere may be reduced to nearly zero. Alternatively, H_2S emissions can be controlled by oxidizing this compound to SO_2 and using conventional scrubber technology on the product gases. Emissions may also be controlled in the water stream by an "iron catalyst" system or a Stretford, sulfur recovery unit. Efficiencies of these systems have ranged as high as 90% H_2S removal. At the Geysers generating area in California, H_2S concentrations average 220 ppm by weight. The power plants emit about 3 lb/hr of H_2S per megawatt of generating capacity. Regulation of emissions of other toxic compounds can be controlled by various techniques, as stipulated by the regulations governing the specific hazardous air pollutants. Control of hazardous pollutants will probably not preclude the development of geothermal resources in the Railbelt region.

One of the major geothermal potential areas in the Railbelt is located in the Wrangell Mountains near Glennallen. This area drains into the Copper River, which is a major salmonid stream. The result of accidental discharge of untreated geothermal fluids into this system may have significant impacts on these fish and other aquatic organisms, depending on the size and location of the release.

Other large geothermal areas are in the Chigmit Mountains on the west side of Cook Inlet. Much of this area is close to the marine environment. In general, geothermal waters would have less detrimental effects on marine organisms (because of their natural tolerance to high salt concentrations) than on fresh water organisms.

Land requirements for the geothermal power plant, on a per-kW basis, are low relative to biomass, coal, and nuclear plants and are comparable to those for oil and natural gas plants. The well field, however, would require a much larger area. The primary impact resulting from geothermal plants on the terrestrial biota is habitat loss. The Chigmit Mountain area is remote and is inhabited by populations of moose and black bear. The Wrangell Mountain area is generally more accessible and includes populations of moose, Dall sheep, caribou, and possibly mountain goats. However, geothermal lands are more likely to be located in remote areas than other steam-cycle power plants. Impacts will be greatest in remote areas since an extensive road network would have to be built to service the well field. Roads would cause the direct destruction of habitat and also would impose additional disturbances to wildlife and vegetation because of increased human intrusion. Disturbances to these areas could be extensive, depending on the land requirements of the geothermal well field.

The major geothermal pollutants acting on the terrestrial environment are H_2S, toxic trace elements, and particulates. The impacts of these pollutants can generally be minimized through installation of pollution control devices.

4.5.5 Socioeconomic Considerations

The construction of a 50-MW, geothermal plant would require approximately 90 workers over a 7-year period. Although the construction work force would be moderate in size, the remoteness of the geothermal resources would affect the magnitude of the impacts. To develop the geothermal resources in the Chigmit Mountains, the power plant components would be shipped by barge and then hauled overland. Semipermanent construction camps would be required to house the workers. Impacts to the coastal communities may therefore be confined to the disturbance caused from transporting equipment. An operational work force of 30 will be required because of the technology's relatively high maintenance requirements.

Impacts to communities from development of the Wrangell Mountain resource could be expected to be more severe since Glennallen (pop. 360) is a large enough community to attract workers and their families. The in-migration of the work force to Glennallen would place a strain on community's infrastructure. Haul roads would have to be built from the Glennallen-Gakona-Gulkana area. Secondary impacts to the communities would result from the transportation of equipment to the site.

Project capital expenditures are estimated to be 55% outside the region and 45% within the Railbelt. The large investment in production and reinjection wells and equipment would be offset partially by the moderate-sized construction work force and long construction period. Approximately 12% of O&M expenditures would be spent outside the region because of the high percentage of expenditures on supplies.

4.5.6 Potential Application in the Railbelt Region

Only hot dry rock (hot igneous) and low-temperature, liquid-dominated hydrothermal convection systems have been identified in or near the Railbelt region (Figure 4.8). Hot dry rock geothermal resources with temperatures that may be high enough to generate electricity have been discovered in the Wrangell and Chigmit Mountains. The Wrangell system (Mt. Sanford, Mt. Drum, and Mt. Wrangell), located approximately 200 miles from Anchorage, has subsurface temperatures exceeding 1200°F. The Chigmit system (Mt. Spar, Black Peak, Double Peak, Redoubt Volcano and Iliamna Volcano), to the west of Cook Inlet, is isolated from the load centers by 200 miles of rugged terrain. Little is known about the geothermal properties of either system.

The geothermal areas (with the exception of Mt. Spurr) of both the Wrangell and Chigmit Mountains are located in lands designated as National Parks (Figure 4.2). The federal Geothermal Steam Act prohibits leasing and developing National Park lands. Development could be possible, however, if townships within these areas are selected by a Native corporation under the Alaskan Native Claims Settlement Act, and if the surface and subsurface estates are conveyed to private ownership. The Alaska National Interest Lands Conservation Act of 1980 allows the granting of right-of-ways for pipelines, transmission lines and other facilities across National Interest Lands for access to resources surrounded by National Interest Lands.

Some low-temperature geothermal resources in the Fairbanks area are used for heating swimming pools and for space heating. In southwest Alaska some use is made of geothermal resources for heating greenhouses as well as for space heating. A low-temperature hydrothermal resource in granite rock has been identified in the Willow area. A deep exploration well was discovered to have a bottom hole temperature of 170°F. Exploration data to date indicate that while this resource may prove useful for low-temperature applications, its relatively low temperature makes it an unlikely source for electric generation.

Based on current knowledge of Railbelt geothermal resources, little near or mid-term potential for geothermal-electric development is foreseen for the Railbelt. Presently identified resources of sufficient temperature to support electrical generation are of the hot dry rock type for which the technology for development is yet in the experimental stage. Because of the widespread presence of active igneous systems in the Railbelt region, further exploration for geothermal resources suitable for electrical development appears to be warranted. Some potential appears to be available for development of low-temperature hydrothermal resources for direct applications. For example, for the proposed state capital at Willow might be explored.

4.6 PEAT-BASED STEAM-ELECTRIC GENERATION

Peat consists of partially decomposed plant matter and inorganic minerals that, over time, have accumulated in a water-saturated environment. In Northern Europe and the Soviet Union, peat has been extensively used as a fuel resource. The Soviet Union has more than 6500 MW of peat-fired, electric generation capacity in operation or under construction. The largest unit now under construction is rated at 1000 MW (Tibbetts and Ismail 1980). In Ireland, 440 MW is produced from several peat-fired units ranging from 25 to 40 MW (O'Donnel 1974). Peat provides some 399 MW of electric power and 600 MW equivalent of district heating in Finland. Other countries, including Canada, the United States, Sweden, and West Germany, have active peat-fuel research programs.

Significant peat reserves are found in Europe and North America and account for over 95% of the estimated worldwide resources. In the United States peat lands are estimated to cover 52.6 million acres, making the United States second only to the Soviet Union (200 million acres) in total peat-land area (Punwani 1980). Almost 51% of the domestic peat resources are located in Alaska. An estimated 27 million acres is outside the permafrost zones. Peat within the permafrost zones is not included since overwhelming problems are associated with its extraction.

Primarily because of the availability of other lower cost fuels, little peat has been used in the United States as a fuel resource. Studies are currently assessing the resource potential and fuel applicability of peat in several areas of the country, including Maine, Michigan, Minnesota, North and South Carolina, and Alaska. The potential Alaskan peat resource areas are shown in Figure 4.10.

4.6.1 Technical Performance

Peat can be used to generate electricity either by burning it directly to fire a steam-electric plant or by converting it to a gas and using the gas to fire a combustion turbine unit. Boilers ranging from 20 to 300 MW of thermal output and designed to handle peat are commercially available from European manufacturers. Peat has traditionally been burned directly in steam-electric

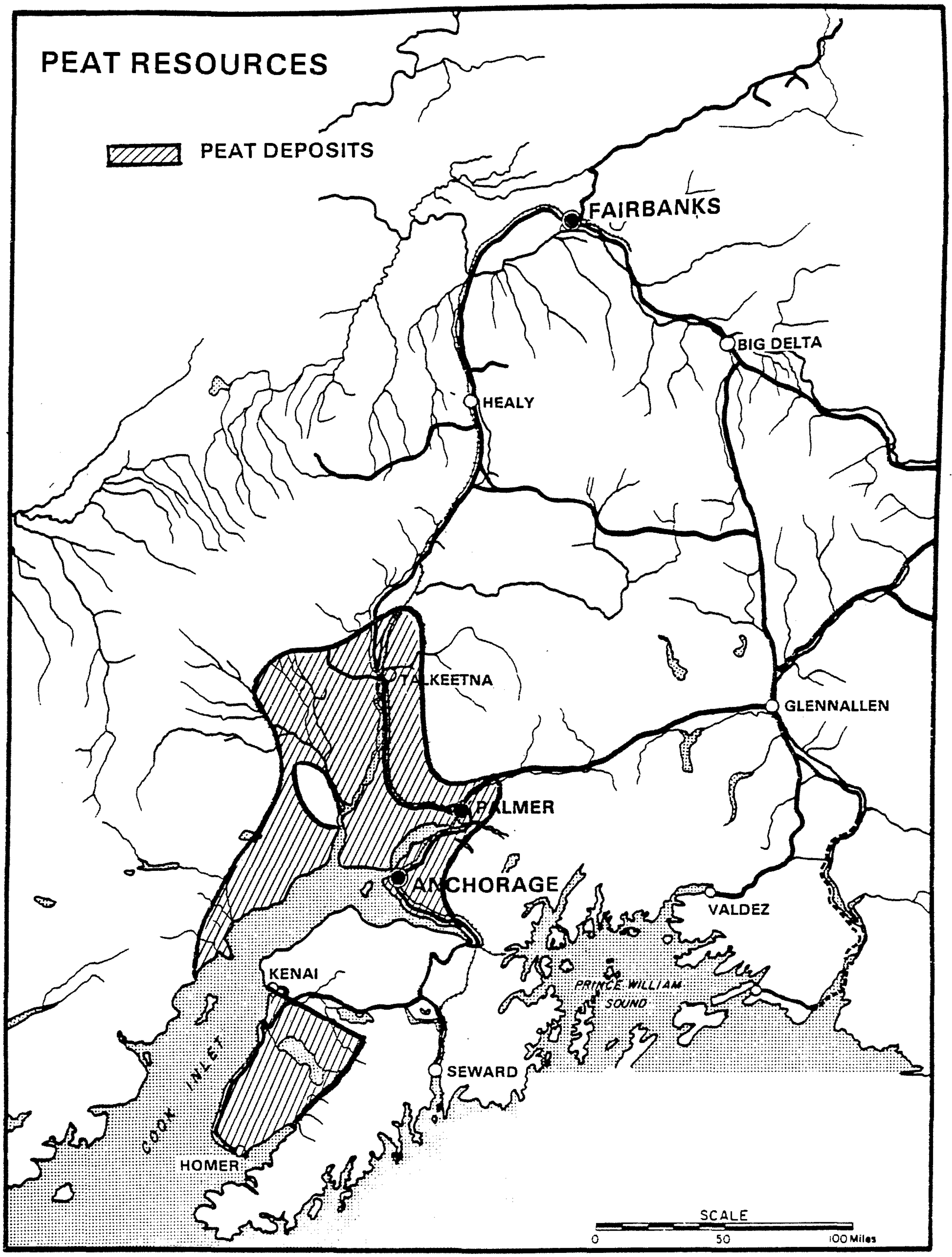


FIGURE 4.10. Peat Resources of the Railbelt Area

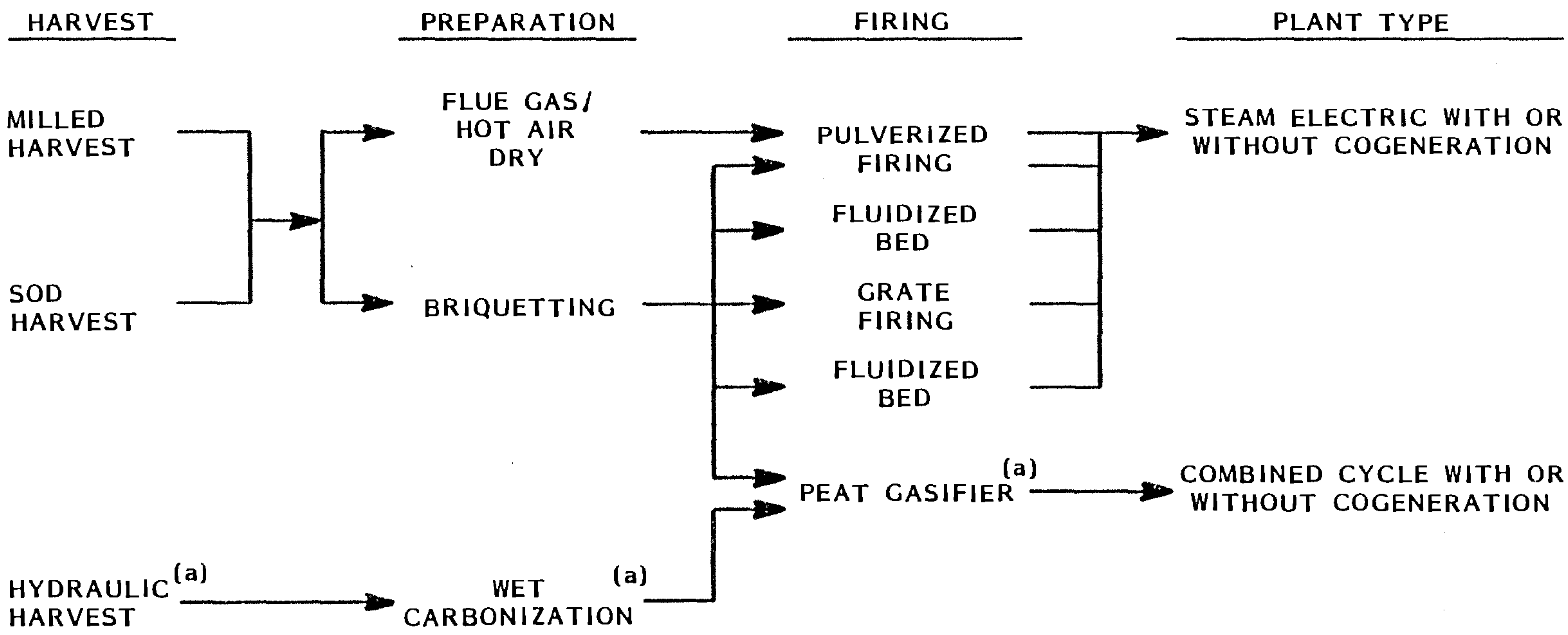
plants to generate electricity. Peat gasifiers, however, are currently in the advanced research and development stage. Laboratory and process development unit-scale gasifiers have been produced in the United States, Sweden, and Finland. In the United States, Rockwell International and the Institute of Gas Technology have been involved in gasifier and gasification system configuration design and development (Punwani 1980).

Design Features

A diagram of various peat fuel utilization systems is presented in Figure 4.11. The two principal methods for extracting peat in quantity are sod-peat harvesting and milled-peat harvesting. Both are dry harvesting methods and require drainage of the bog prior to peat extraction. The steps of bog preparation for such harvesting include clearing surface vegetation, dredging, rerouting surface streams, and developing a network of ditches and waterways to collect and to route the bog waters away from the harvest area. As the bog dries, it can be leveled and cleared of debris. This preparation typically takes several years.

Sod harvesting of peat, the oldest mechanical method of peat harvesting, is used extensively in Ireland, Finland, and Germany. The peat is dredged or excavated from the bog and compressed and cut into bricks or cylinders about 14 inches long. The bricks (sods) are left on the bog surface to dry. This drying can limit the harvests to only two per season, as occurs in Ireland (DOE 1979c). Sod harvesting is very labor intensive.

Milled harvesting is much more mechanized than sod harvesting. Once the bog is dried, the surface is scraped to a depth of half an inch or less and the scrapings are milled over a spiked drum. The shreds are then left on the field to dry, possibly in ridges, if the weather and drainage warrant. After about 2 to 3 days of drying, the peat is harvested either by vacuum harvesters or by mechanical picking equipment. A problem with this method, however, is the potential environmental pollution of suspended particle matter. This material is defined as "criterion pollutant" by the Clean Air Act and could limit the viability of this harvesting method in the United States. Also, milled harvesting creates a significant potential for bog fires, which can burn out of control for several months.



[a] UNDER DEVELOPMENT

FIGURE 4.11. Power Production Alternatives Using Peat

A harvesting procedure currently in the developmental stage is slurry peat harvesting (a hydraulic or wet harvesting technique). Once the bog is cleared, but not drained, a dredge or backhoe can be used to extract the peat onto a moving screen. It is then washed by water jets to form a slurry of water and peat. The slurry is pumped by pipes to a dewatering operation. The success of this type of harvesting will depend on the development of the dewatering operation and the environmental impacts. Further development of hydraulic peat harvesting techniques is considered necessary before it is commercially successful (DOE 1979c).

Peat-fired steam-electric power plants are physically similar to coal-fired units. The primary components of a peat-fired plant are the fuel receiving, storage and processing systems, the boiler, the turbine generator, the stack gas cleanup equipment, and the condenser cooling system.

Although most components are similar to those used in coal facilities, the unique properties of peat require certain modifications to several plant systems. The high moisture content, low energy density, the content of volatile matter, and general bulkiness of peat require larger fuel storage areas and fuel handling systems and a furnace volume greater than that required for a coal-fired plant producing the equivalent amount of electric power.

The peat received at power plants has a moisture content of no greater than 60 to 65%. Natural peat is approximately 90% water. The currently used harvesting methods, both milled and sod, rely on solar and convective drying to produce a fuel at a moisture content of 30 to 55%. At 50% moisture content, Alaskan Railbelt peat samples have an average heating value of about 6500 Btu/pound (EKONO 1980). The actual combustion process requires a further reduction, depending on the combustion process used, to 10 to 25% moisture content.

Direct combustion of peat can be accomplished using pulverized firing, grate firing, or fluidized combustion. Most pulverized-fired facilities today use recirculated flue gases or hot air to dry the milled or sod peat prior to feeding it into the boilers.

To use peat in grate-fired boilers, however, the peat must be pressed into suitable pellets or briquettes. Fluidized-bed combustion systems and peat gasification units also generally require that peat be prepared to a specific size and shape. Sod-harvested peat generally does not require compaction. Milled peat (the primary method of peat harvesting today), however, is regularly compacted for grate-fired operations in Northern Europe and the Soviet Union. To be pressed into suitable briquettes the peat's moisture content, density, and fiber content must be homogeneous. Preparation involves blending, crushing, and screening prior to drying to about 10% moisture content and final compaction. The dryer heat may be generated from combustion of rejected fibers. Such prepared peat is estimated to have a heating value of 10,000 Btu/pound (Rohrer 1979). A diagram of a peat-fired boiler system is presented in Figure 4.12.

Another process, wet carbonization, has the advantage of overcoming the time-consuming and uncertain air drying of peat on the bog. Wet carbonization, currently in the pilot plant stage, uses hydraulically harvested peat fed into the plant as a peat slurry (Rohrer and Bertel 1980). The slurry passes through pulping, screening, and preheater stages to a steam-heated reactor. In the reactor, the peat is heated under pressure to produce some carbon loss (carbonization) and dewatering of the peat. It is then filtered, flash dried, and pelletized. For gasifier feed and other onsite applications, the final thermal drying and/or pelletizing are often not necessary.

Peat gasification plants are currently being developed that would take advantage of peat's inherent high chemical reactivity to produce a clean burning substitute gas to fire combustion-turbine power plants. Hydraulically harvested peat would be sent in a peat slurry to the facility, where it would pass through the wet carbonization dewatering process. The resulting peat material would be fed into a gasifier. Different basic types of gasifiers could be used, including entrained flow and fluidized bed gasifiers. By controlling the gasification temperatures and pressures, the gaseous and liquid product mix can be significantly varied. Peat gasification could yield lowor medium-Btu fuel gas, substitute natural gas, fuel liquids, and ammonia

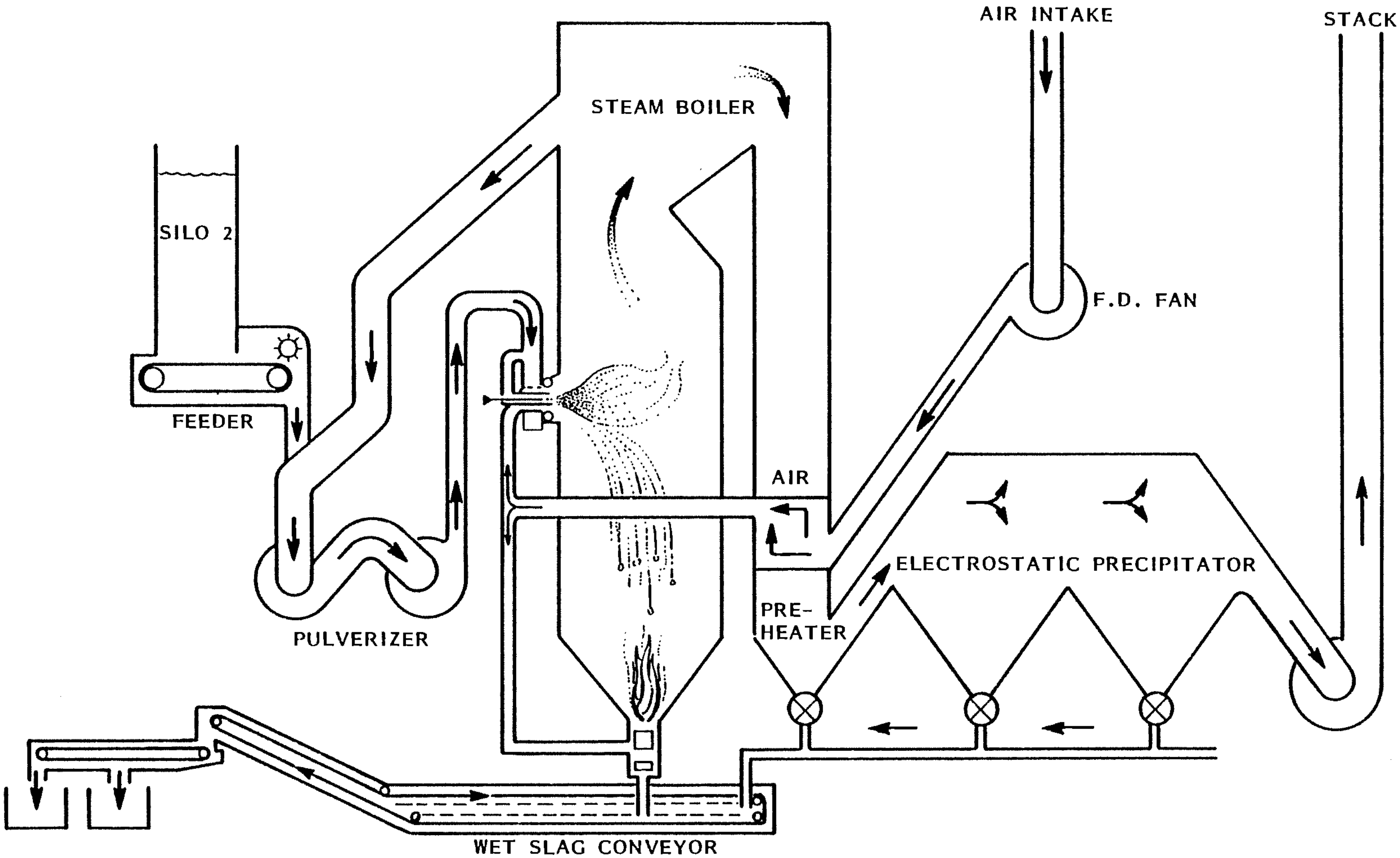


FIGURE 4.12. Fuel System of a Peat-Fired Boiler

and sulfur by-products. Peat, typically higher in nitrogen and lower in sulfur than coal, will yield relatively more ammonia and less sulfur by-products than coal gasification under less severe operating conditions. Available data on peat gasification currently are limited to laboratory-scale operations (DOE 1979c).

Downstream units, in addition to the combustion turbine or combined cycle unit and gas fuel storage facility, would include equipment for heat recovery, gas quench, acid gas removal, water gas shift, and methanation, depending on the desired gasification products. A conceptual flow diagram of the peat gasification system is shown in Figure 4.13.

Performance Characteristics

Peat, because of its inherent high moisture content, introduces thermal inefficiencies into the combustion process. Efficiencies increase with the size of the plant, as shown below (Tillman 1980):

Rated Capacity (megawatts)	Heat Rate (Btu/kWh)
5	20,000
15	15,100
25	14,200
35	14,100
50	14,000

Condensing cycle plants of 100 MW or larger can achieve a 35% overall efficiency rating (EKONO 1980). If the steam from the turbine exhaust can be used for industrial processes or for district heating, the overall thermal efficiency of the plant can be increased significantly.

Because peat-fired power plants are capital-intensive units, they generally are operated as baseload units. The achievable load factor of such direct-fired peat units is similar to that of other biomass-fired plants (about 80%). These high load factors are attained by proper design and maintenance. The reliability of a power plant is a function of the individual reliability of numerous system components, including the fuel receiving,

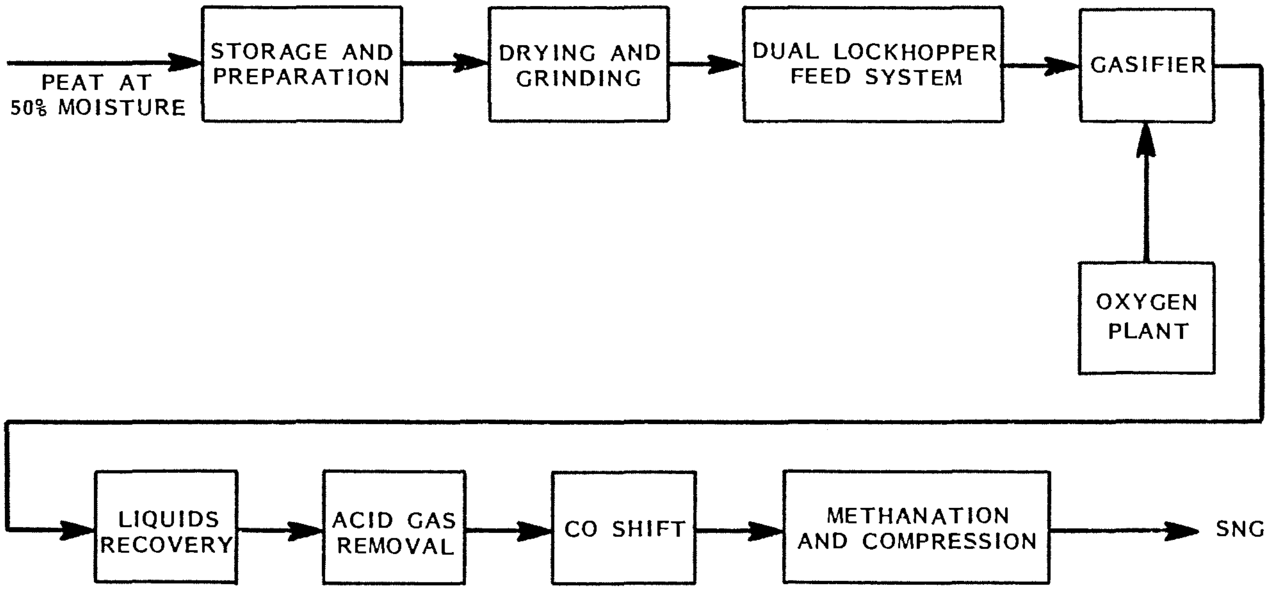


FIGURE 4.13. Peat Gasification Flow Sheet

preparation and handling systems, the boiler, the steam turbine generator and the associated steam equipment, and the pollution control equipment. Increasing the complexity of any system tends to diminish the reliability. The lifetime of peat-fired steam-electric generating plants is estimated to be 30 years.

4.6.2 Siting and Fuel Requirements

The siting of a peat-fired power plant depends on several factors, many of which are location specific. General siting factors, however, include the location of the fuel source, the condition of the fuel, transportation and transmission line access, and cooling water availability (for steam-electric generation facilities). Another siting consideration may be the location of potential cogeneration steam users.

Peat is a transportation-intensive material. Because of its high moisture content and low energy density, the practical transportation of milled- or sod-harvested peat is limited to about 50 miles by truck and 100 miles by rail (EKONO 1980). Although similar limitations have been established for peat slurry lines, rough indications of the cost can be seen in coal-slurry, pipeline cost estimates. To avoid excessive transportation costs, peat-fired units are generally being proposed for bog-side operation.

Peat-fired power plants' fuel requirements are a function of the plants' thermal conversion efficiency and plant scale. Representative fuel requirements for various sizes of peat-fired plants are presented below:

Rated Capacity (MW)	Daily Requirements @ 50% Moisture Content (tons)
5	260
15	600
25	960
35	1300
50	1900

Land requirements for peat-fired plants are similar to those of coal-fired plants and are generally greater than those of other steam-cycle power plants on an acres-per-MW basis. A 5-MW stand-alone plant could require about 10 acres, whereas a 40-MW plant is estimated to require 60 acres, largely due to the ash disposal and the fuel storage areas (Tibbetts and Ismail 1980). The 40-MW, peat-fired, steam-electric generation plant being examined for New Brunswick, Canada, is anticipated to require 1400 tons of peat each day (Ismail 1980).

4.6.3 Costs

The economies of scale for peat-fired electric power generation are rather steep, as shown in Table 4.13. The information in this table was produced in a recent study of Alaskan peat utilization potential (EKONO 1980).

TABLE 4.13. Estimated Costs for Peat-Fired Steam-Electric Power Plants (1980 dollars) (EKONO 1980)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy[a] (mills/kWh)
1	2600	1000	246-269
30	1166	204	80-96

(a) Levelized lifetime costs, assuming a 1990 first year of commercial operation. The ranges reflect potential fuel costs (Appendix B).

These cost estimates compare favorably with those made for the 40-MW, peat-fired power plant scheduled to be built in New Brunswick (Ismail 1980). Over its 30-year lifetime, the cost of power was estimated to be $0.05/kWh (54.8 mills/kWh). This estimate, in constant 1979 dollars, was based on $1.90 levelized delivered cost of peat.

4.6.4 Environmental Considerations

The use of peat as an energy resource will have an impact on the quality of the region's air, water, and land resources. The nature and degree of these impacts will depend on the particular harvesting, fuel preparation and energy conversion technologies selected.

The peat harvesting operation is one of the major potential sources of airborne pollutants. The amount of fugitive dust produced during harvesting, handling, and storage depends on the harvesting techniques used. The milled-peat method, in which the bog is drained and the peat is milled and ploughed into ridges for air drying, generates the greatest amount of dust. This dust also creates a serious explosion problem during storage and handling activities. Another difficulty is the prevention and control of bog fires. These problems of dust, explosion potential, and bog fires are essentially eliminated if the peat is harvested in its wet state by hydraulic means.

If the peat is used to fire a direct combustion boiler of greater than about 5 MW, the required air-pollution control equipment will minimize the emissions to their legal limits. The expected emissions from a peat facility and the regulatory framework are presented in Appendix E. The impacts of air pollutants on the terrestrial environment are presented in Appendix G.

The air emissions from peat gasification operations will be controlled by air pollution equipment developed for coal gasification and oil refining facilities to levels below those required by New Source Performance Standards. Combustion-turbine operation using peat-based synthetic gas would produce minimal air emissions.

Potentially significant impacts to the aquatic systems could result from harvesting, processing, and/or the conversion process. Conventional harvesting operations producing milled peat or sod peat remove only a small portion of the total peat deposit in one year and cut to a depth of about 5 to 8 inches each year (DOE 1979c). Therefore, a large area must be cleared and drained to provide an adequate volume of peat and a sufficient drying area. (Assuming a heat rate of about 6700 Btu per pound, 7500 cubic feet of peat harvested per acre per year and 22 pounds per cubic foot, a 30-MW plant would require, using a mill harvesting operation, some 2300 acres of peat to be harvested annually.) The draining of the bog can have significant impacts on the aquatic system. The pH of the drainage water differs from normal surface water and the ditching of the bog could possibly have an impact on surrounding lakes, rivers, and streams. Bog waters may also contain such chemicals as phosphorous and nitrogen compounds, which may contribute to the eutrophication of the receiving waters. Heavy metals in the bog water may be introduced into the local watershed along with possible detrimental organic waste products such as polyphenolic humic acids. These impacts are currently under investigation. Possible mitigation requirements being considered include the separation of drained bog waters from the local natural surface waters.

Hydraulic harvesting does not require bog drainage and as a result avoids many of the problems associated with sodor milled-peat operations. After the bog area to be harvested is cleared, all the peat is removed by backhoe or by other mechanical systems. The methods for control of hydrology and water quality in and around hydraulic, peat-harvesting operation will depend on the specific harvesting plan that is used and the land reclamation option that is selected. Potential water-quality control methods include buffer zones, pH control operations and permeability control systems. The selection of one or more methods strongly depends on the interactions among peat harvesting techniques, local hydrology and water quality, and land reclamation options. Proposed land reclamation of harvested bog areas has included agricultural developments, forest plantations, and recreational water areas.

Condenser cooling water requirements for peat-fired power plants would be similar to other steam-cycle plants (see Appendix I). The rate of water required would be about 750 gallons per minute per megawatt (gpm/MW) passing through the condensor. For a once-through cooling system, this translates to 18,250 gpm for a 25-MW facility. If a recirculating cooling system is employed, the makeup water requirements would be reduced to about 362 gpm. Onsite water treatment facilities and the proper siting and design of intake and discharge structures will contribute to reducing the aquatic impacts from the power plants. Similar equipment, procedures, and proper siting will be necessary to minimize the aquatic impacts of peat gasification units. Proposed activities include onsite biochemical treatment of contaminated water, and the concentration of inorganic salts into salt form for disposal.

4.6.5 Socioeconomic Considerations

To construct and to operate peat-fired power plants, relatively small labor forces are required. For 15- to 30-MW plants, a construction force of 65 would be required. An operating staff of up to about 25 could be necessary for such size plants, depending on the specific peat processing and combustion processes employed. A peat-gasification - combustion-turbine facility of similar power output would require a slightly larger operating force. Construction periods for the power plants would range between 18 months to 3 years (excluding the licensing process) (EKONO 1980). If the plants are developed and operated in association with the peat harvesting operations ("at bog-side"), the personnel requirements and construction period would be increased. Therefore, for conventional harvesting, the operations staff could double and between 3 to 6 years could be needed to prepare the bog. If hydraulic harvesting is employed, the preparation time could be as little as 6 months.

A preliminary assessment of peat resources in the Railbelt identified bogs in the Matanuska-Susitna Valley as potential sources of fuel peat (EKONO 1980). Prime locations for bog-side plants include the Willow, Houston, and Knik areas. The socioeconomic impacts of harvesting and plant operations may be significant on Houston and Knik and to a lesser degree on Willow. These impacts will increase as the size of the facility increases. Houston has a population of 69, Knik has about 40 residents, and Willow has 38 people. The influx of some 65 construction workers and their families for up to 3 years and the permanent residence of between 15 and 50 operations staff families (depending on plant size and harvesting operations) could put a severe strain on the social and economic structure of these communities. These impacts may be mitigated by limiting the scale of the plants.

The breakdown of capital expenditures is expected to be 60% outside the Railbelt and 40% within the region. Expenditures due to a large capital investment will be offset by employment of an Alaskan labor force. Approximately 10% of O&M expenditures would be spent outside the region.

4.6.6 Potential Applications in the Railbelt Region

The Matanuska-Susitna Valley and Kenai Peninsula appear to have peat bogs that could possibly be suitable for energy production (EKONO 1980). Six sites, all located in the Susitna Valley, were selected for detailed consideration. The selection was based on a consideration of a variety of factors, including organic soils information, population centers and transportation systems locations, vegetation and ecosystem distribution, surficial geology data and ownership plats. These six bogs also met other criteria including transportation distance to major users, bog area limits (greater than 80 acres), and continuity of the bog. The six areas examined were Mile 55 Kettles, 12 miles west of Wasilla and 2 miles south of the Parks Highway; Nancy Lake West, bordering the west edge of the Parks Highway northwest of Houston; Stephen Lake, 5 miles northwest of Knik; Nancy Lake East, same vicinity as its western namesake; Miles 196 West, alongside the Parks Highway north of Kashwitna; and Rogers Creek, located off the Parks highway, about 3 miles north of Willow. Of these sites, Nancy Lake East appears to be one of the more suitable, based on the preliminary resource study. If the entire bog, with an estimated average depth of 7 feet, contained fuel-quality peat, it would provide fuel for a 30-MW cogeneration plant for about 15 years (EKONO 1980).

The quality of the Alaskan peat resources is its limiting factor as an energy resource. Using existing data, the EKONO study (1980) found that the ash content seems to be the prevailing problem. Only 36% of the peat samples analyzed for ash had less than a 25% ash content, the limit for peat fuel as specified by the U.S. Department of Energy. Another problem is the lack of continuous, high-quality peat resources.

Although the quantity of peat resources is not yet well defined, present data are sufficient to indicate that Alaska has significant fuel peat resources. Current resource information is not sufficient to allow a firm estimate of potential power production from peat to be made. Further site-specific investigations are necessary to identify suitable peat resources and potential power plant sites. In addition, developmental work needs to be done on several advanced technologies proposed for use in Alaska (including the hydraulic-harvesting, wet carbonization system and the peat gasification units). The time necessary to complete these resource assessment and technology development activities will preclude this resource as a power generation alternative for the Railbelt at this time. Depending on the results of these activities, and the economic, environmental and socioeconomic factors associated with its use, peat could be a possible power generation resource in the Railbelt in the next decade.

5.0 CYCLING TECHNOLOGIES

The primary characteristic of cycling technologies is the capability to adjust the output of generating units on an hourly or even more frequent basis according to system demand. The cycling technologies would satisfy intermediate load and peaking service electrical requirements in the Railbelt region.

The lack of a regional grid system and the unique pattern of growth of the Alaska Railbelt have resulted in technologies traditionally considered cycling (certain combustion turbine and combined-cycle units) being used for baseload service. This practice can be expected to change as the area grows, as natural gas and oil prices increase, and as an interconnected transmission system is developed.

Four currently available technologies and one emerging technology have been identified as candidate cycling technologies for the Railbelt:

- combustion turbines
- combined cycle
- diesel electric
- conventional hydroelectric (intermediate and large scale)
- fuel cells.

The first four technologies are already in use in the Railbelt region. Fuel cells represent an emerging technology and are undergoing a demonstration in New York City. A comparison of selected characteristics of the cycling technologies considered in this study is provided in Table 5.1.

TABLE 5.1. Comparison of Cycling Technologies on Selected Characteristics

	Combustion Turbines (70 MW, Gas-Fired)	Combined Cycle (200 MW Gas-Fired	Diesel (12 MW)	Hydroelectric (4-366 MW)
Aesthetic Intrusiveness				
Visual	Minor	Moderate	Minor	Moderate to Significant
Noise	Moderate	Moderate	Moderate	Minor
Odor	Minor	Minor	Locally moderate	None
Ecological Impacts				
Gross Water Use (gpm)	0	600	0	Bulk of streamflow passed through turbines
Land Use (acres)	6	6	4	Site-Specific, 100s to 1000s
Costs				
Capital ($/kW)	560	960	700	1890-11,275
O&M ($/kW/yr	40	35	35	38-225
Cost of Energy ($/kW)	58 (136)(a)(b)	49(a)	100 (173)(b)	23-738
Public Health & Safety	No direct safety problems. Possible long-term air quality degradation.	No direct safety problems. Possible long-term air-quality degradation.	No direct safety problems. Possible local air-quality degradation	Safe
Consumer Effort	Utility operated.	Utility operated.	Utility, community or consumer operated.	Larger facilities utility operated. Intermediate facilities could be community operated.
Adaptability to Growth				
Unit Sizes Available	05-80 MW	90-250 MW	.03-15 MW	15-400 MW
Construction Lead Time	1 yr	2-4 yr	1 yr	5-10 yr
Availability of Sites	Limited by access to fuel supply and air-quality control areas	Limited by access to fuel supply, availability of cooling water and air-quality control areas.	Limited by CO non-attainment areas	Sites limited to streams having favorable discharge, topography and geology.
Reliability				
Availability	88%	85%	90%	90%
Expenditures Within Alaska				
Capital	20%	30%	20%	45%
O&M	81%	84%	92%	89%
Fuel	100%	100%	100%	--
Boom/Bust Effects				
Construction Personnel	30	45	25	300
Operating Personnel	12	15	2	5
Ratio	2.5:1	3:1	12:1	60:1
Magnitude of Impacts	Minor to moderate in all locations.	Minor to moderate in all locations.	Minor in all locations.	Severe in small communities. Moderate to significant in Fairbanks & intermediate-sized communities. Minor in vicinity of Anchorage.
Consumer Control	Control through regulatory agencies	Control through regulatory agencies	Potential for consumer control	Control through regulatory agencies for utility-operated facilities. Community control for municipal projects.
Technology Development				
Commercial Availability	Currently Available	Currently Available	Currently Available	Currently Available
Railbelt Experience	Extensive	Limited (2 plants)	Extensive	Limited (3 projects)

TABLE 5.1. (Contd)

	Fuel Cell Station (10 MW, Phosphoric Acid)	Fuel Cell Station[c] (10 MW, Molten Carbonate)	Coal Gasifier[d] - Fuel Cell - Combined Cycle (1000 MW)	Natural Gas[e] - Fuel Cell - Combined Cycle (250 MW)
Aesthetics Intrusiveness				
Visual	Minor	Minor	Significant	Moderate
Noise	Negligible	Negligible	Moderate	Moderate
Odor	Minor	Minor	Moderate	Minor
Ecological Impacts				
Gross Wtr	20	Not Available	Not available	Not Available
Land	2	<10	~100	~10
Costs				
Capital	750	810	2230	1500
O&M	43	43	39	20
Cost of Energy ($/kW)	49 (143)(a)(b)	43 (142)(a)(b)	43(f)	(g)
Public Health & Safety	No direct safety problems	No direct safety problems	No direct safety problems. Possible minor air-quality degradation in vicinity of plant.	No direct safety problems
Consumer Effort	Utility or municipally operated. Very small-scale cogeneration plants could be operated by building owners.	Utility or municipally operated. Very small-scale cogeneration plants could be operated by building owners.	Utility operated.	Utility operated.
Adaptability to Growth				
Unit Sizes Available	<1-25 MW	<1-25 MW	100-1000 MW	~25-1000 MW
Construction Lead Time	1 yr	1 yr	3 yr	3 yr
Availability of Sites	All areas with potential access to natural gas or fuel oil.	All areas with potential access to natural gas or fuel oil.	Beluga area, ARR line	All areas with natural gas supply.
Reliability	91%	91%	83%	80-90%
Expenditures Within Alaska				
Capital	20%	20%	Unknown	Unknown
O&M	90%	90%	Unknown	Unknown
Fuel	100%	100%	100%	100%
Boom/Bust Effects				
Construction	90	90	Several hundred	Several hundred
Operating	5	5	~50-100	~50-100
Ratio	18:1	18:1	Unknown	Unknown
Magnitude of Impacts	Significant in very small communities. Minor to moderate in all other locations.	Significant in very small communities. Minor to moderate in all other locations.	Severe in all locations except Anchorage or Fairbanks.	Severe in all locations except Anchorage or Fairbanks.
Consumer Control	Control of utility-operated units through regulatory agencies. Consumer control of small (building-scale) units.	Control of utility-operated units through regulatory agencies. Consumer control of small (building-scale) units.	Control through regulatory agencies.	Control through regulatory agencies.
Technology Development				
Commercial Availability	Commercial Demonstration Stage, AFO 1984(c)	Developmental Stage AFO 1990	Developmental Stage AFO 1990	Developmental Stage AFO 1990
Railbelt Experience	None	None	None	None

(a) Using Cook Inlet gas as fuel.
(b) Costs external to parentheses are for baseload operation (65% capacity factor). Costs in parentheses are for peaking service (10% capacity factor).
(c) Present evidence indicates that molten carbonate fuel cells may be unsuited for load-following service. Due to low plant capital costs, however, fuel cell stations using molten carbonate fuel cells may be suitable for non-load-following peaking duty.
(d) Present evidence indicates that molten carbonate fuel cells may be unsuited for load-following service. Load following capability could be achieved using supplementary (duct-burner) steam plant firing.
(e) Available for order.
(f) Based on Beluga coal.
(g) No economic evaluations of this technology were located; thus, no reliable cost data are available.

5.1 COMBUSTION TURBINES

Combustion turbines have been used for nearly two decades in the utility industry, primarily to provide peaking and emergency power generation. Combustion turbines are readily suited to cyclic duty operation, and they can be brought on-line quickly from a cold start. Their simplicity makes them ideally suited for operation in remote locations, and they can be operated unattended if necessary.

The main disadvantages of combustion turbines are two-fold. They are relatively inefficient compared to large, conventional, fossil fuel plants. Secondly, the petroleum-based fuels, which they most readily use, are in short supply. The relative inefficiency of these units can be overcome by incorporation of gas turbines into more efficient cycles (such as combined cycle, cogeneration, or regenerative cycle) in which increased thermodynamic efficiencies stem from the use of rejected heat. The fuel availability problem may be overcome by development of synthetic fuel production (Appendix K).

5.1.1 Technical Characteristics

A combustion turbine power plant essentially consists of a gas turbine that drives a generator. Plant designs are highly standardized and available in unit sizes ranging from 0.5 to 80 MW.

Design Features

The combustion turbine power plant uses a gas turbine engine as the prime mover. This engine, which is similar to an aircraft jet engine, can burn either liquid or gaseous fuel. The fuel is burned continuously in the presence of compressed air, and the hot exhaust is allowed to expand through a gas power turbine. The power turbine drives the inlet air compressor and the electric power generator, as shown in Figure 5.1.

Most of the energy entering a combustion turbine as fuel is lost in the form of exhaust gas heat. Only minor mechanical losses are encountered in the turbine/generator machinery itself. Alternative cycles, including the regenerative cycles, the combined cycle and cogeneration cycles, have been developed, which use part of this exhaust gas heat to improve efficiency. The combined cycle and cogeneration cycles are discussed in separate technology

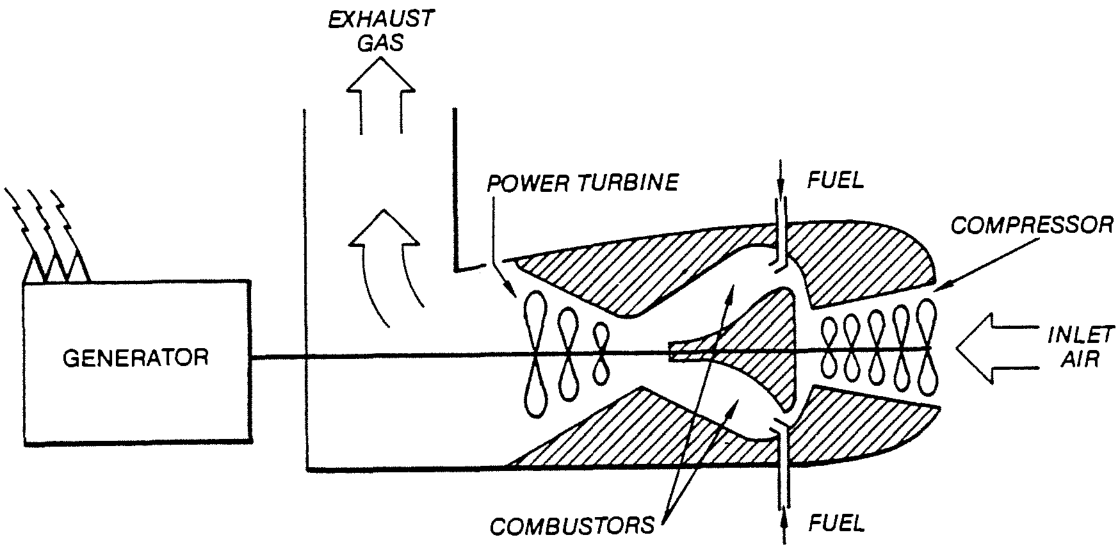


FIGURE 5.1. Simple-Cycle Combustion Turbine

profiles. In the regenerative cycle, combustion air leaving the compressor section is channeled through an air-to-air heat exchanger located in the turbine exhaust. The energy thus absorbed by the combustion air decreases the requirement for fuel and thus increases the combustion turbine efficiency. This cycle is used in several installations in the Railbelt. Other complex cycles using interstage cooling and gas reheat have been proposed but are not currently used in commercial power plants.

Combustion turbine power plants are not complex to build since most of the equipment arrives at the site assembled, and installation requirements are minimal.

Performance Characteristics

Combustion turbine power plants typically have been less efficient than fossil-fired, steam-electric generating stations. However, recent advances in combustion turbine technology, particularly improvements in blade metallurgy and cooling and in combustor efficiency, have significantly increased combustion turbine output and efficiency. Heat rates and conversion efficiencies of combustion turbines are presented in Table 5.2 for different plant sizes.

TABLE 5.2. Heat Rates of Combustion Turbines

Rated Capacity (MW)	Heat Rate (Btu/kWh)
20 - 100	10,000 - 11,000 (LHV)[a]
0.5 - 20	12,000 - 14,000 (LHV)[a]

(a) Lower heating value. For natural gas the LHV is 910 Btu/ft^3 and the higher heating value is 1024 Btu/ft^3.

Combustion turbines are reliable and are available to meet demand approximately 88% of the time. Typical plant life is 20 years.

5.1.2 Siting and Fuel Requirements

The simple-cycle, combustion turbine power plant has fewer siting constraints than conventional fossil fuel or nuclear plants. Only limited space is required, no cooling water is required, and no operating personnel are necessary. The primary siting constraints relate to atmospheric emissions and fuel supply.

The exhaust from combustion turbines typically contains SO_x when residual fuels are used, as well as NO_x. These constituents comprise the pollutants of greatest regulatory concern. Carbon monoxide (CO), unburned hydrocarbons, and particulate matter can also be present. The quantity of each particular contaminant emitted is a function of the size of the machine, the manufacturer, the type of fuel burned, and the extent to which emission control techniques are used. The suitability of a particular site will depend upon the degree to which these contaminants can be controlled.

The technology also requires a location to which fuel can be easily delivered. Combustion turbines need to be located adjacent to a distribution pipeline or railroad to permit transportation of large volumes of fuel. A plant with fuel storage would require a 6-acre site; without fuel storage, it would require 3 acres.

Future power plants using synthetic fuels derived from coal will have to be located adjacent or close to the coal gasification plant if medium or low Btu gas is used, since these fuels cannot economically be moved by pipeline over long distances. If synthetic liquid fuels are used, the same fuel transportation constraints that exist for liquid petroleum fuels would apply.

Combustion turbines can use a wide variety of natural and synthetic liquid and gaseous fuels, ranging from heavy residual oils to medium Btu synthesis gases. Combustion turbines operating in the Railbelt use natural gas or distillate oil. The performance of the turbine varies slightly with each fuel, and whereas the basic design of the combustion turbine is the same regardless of the fuel type, some modifications in design are required.

Natural gas is perhaps the best combustion turbine fuel for performance and operating simplicity. Heat rates are generally better and exhaust emissions, especially for sulfurous oxides and particulates, are almost nonexistent. Less maintenance is required, since the combustion products of natural gas are not nearly as corrosive as other liquid fuels. One drawback to using natural gas is that it must be supplied at a moderate pressure, usually around 300 psig. If the supply pressure is not adequate, a gas compressor must be used, which can offset the heat rate advantage of natural gas.

Distillate oil used in combined-cycle power plants is normally a light distillate, Grade DF-2 or equal. Heavier grade distillates can be used if appropriately treated. Distillate oil can contain sulfur, fuel ash, and trace metals not generally present in natural gas. Sulfur and fuel ash contribute to exhaust emissions, and trace metals can cause corrosion, which will reduce the life of the combustion turbine. However, the amount of contaminants in distillate oil is generally much lower than in heavier liquid fuels. A minimal amount of treatment equipment, if any, is required to make distillate oil an acceptable fuel. Because Alaska crude oils are in the medium to heavy category, a greater proportion of locally produced distillates would be in the heavier range.

Combustion turbines can burn a variety of synthetic fuels, although little operating experience with synthetics has been gained to date. Experience is lacking mainly because of the high cost and limited availability of synthetic fuels. However, certain synthetic fuels, notably gas synthesized from coal, are approaching economic viability. Potential application of synthetic fuels to Railbelt power facilities is described in Appendix K.

Methanol is a liquid synthetic fuel that may be derived not only from coal but also from tar sands, oil shale, and biomass. It is suitable as a combustion turbine fuel and requires only a minimum of modifications to existing hardware. Methanol produces fewer emissions than petroleum-based fuels. It contains virtually no nitrogen and no sulfur. Further, since methanol has a theoretical flame temperature approximately 300°F below that of distillate oil, thermally produced NO_x emissions are substantially reduced. CO emissions are increased slightly, but are still comparable to distillate CO emissions, especially when water injection is required to reduce NO_x emissions in distillate oil.

To use any of these fuels, a fuel transportation system must be provided. Natural gas will not require storage as long as an adequate gas supply is readily available through local distribution. Distillate oil is normally stored on site, and the amount of storage is generally a function of the reliability of the source of supply. Both storage and transportation of low Btu synthesis gas are impractical, and thus the combustion turbine power plant must be located adjacent to the gasification plant. Medium Btu synthesis gas can be transported economically via pipeline to distances up to approximately 100 miles. This capacity removes the limitation of locating the combustion turbines at the gasification plant, and several power plants may be served by a single gasification plant. Like other liquid fuels, methanol may be stored on site. However, it is somewhat more volatile than distillate oil and requires special handling.

5.1.3 Costs

Combustion turbine power plants are generally regarded as having the lowest capital cost per kilowatt of any current technology. The brief construction times, often 1 year or less, contribute to low construction costs.

As with any other facility, some economy of scale is associated with a combustion turbine power plant. Virtually all of the capital expenditures are for package equipment. Unlike steam systems, field erection costs are minimal. Estimated costs are presented in Table 5.3. O&M costs vary significantly and published costs can be misleading. Even with identical combustion turbines, many operators report significantly different O&M costs. One reason for this difference is that maintenance costs are more directly associated with operating practices than with equipment. For example, cyclic duty is much more demanding than continuous operation. Extended operation at peak load rating and premature loading without a proper warm-up period can drastically reduce machine life, as can improper fuel selection and inlet air contamination. Also, maintenance practices differ significantly among utilities. Some utilities rely heavily on preventative maintenance, whereas others only perform necessary maintenance. In addition, the methods of recording O&M costs are not uniform, and differences in reported costs may result purely from accounting practices.

TABLE 5.3. Estimated Costs for Combustion Turbine Power Plants (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy (mills/kW)[a] Cook Inlet Natural Gas	North Slope Natural Gas	Distillate @ Fairbanks
50	720	40	60 (149)	146 (236)	127 (217)
70	560	40	58 (136)	144 (223)	125 (204)

(a) Levelized lifetime production costs, based on 1990 first year of commercial operation. Costs shown external to parenthesis are based on baseload operation (65% capacity factor). Costs enclosed in parenthesis are based on peaking service (10% capacity factor)

5.1.4 Environmental Considerations

Combustion turbines do not require cooling or other process feedwater for their efficient operation. Small quantities of water will be required for domestic use, equipment cleaning, and other miscellaneous uses. If standard engineering practice is followed, water resource effects should be insignificant.

Combustion turbine generators are comparatively inoffensive sources of air pollution when compared to alternative combustion technologies. This comparison is provided in Appendix E along with a discussion of the regulatory framework and various siting considerations. Sulfur emissons can be controlled by using low-sulfur oils or natural gas. Emissions of NO_x can be controlled by using water or steam injection. These emissions will not preclude the siting of combustion turbines anywhere in the Railbelt region, except that their operation within the Fairbanks or Anchorage nonattainment areas may be difficult to justify. Optimum siting would have to consider nonattainment areas and Class 1 PSD proximity to natural gas pipelines, barge terminals, railroads, or other sources of fuel and load centers.

Because cooling water is not required for combustion turbines, aquatic biota would not be impacted. The only potential impacts would be from construction runoff (refer to Appendix F). Proper construction techniques would eliminate the potential for impacts on the aquatic environment.

Land losses and human disturbance resulting from combustion turbine power plants represent the most significant impacts on the terrestrial biota. Land losses, however, will generally be small (6 acres for 140-MW plant including fuel storage). These losses will be increased if fuels requiring storage and waste disposal facilities are used. The overall land requirements for combustion turbine plants are usually much smaller than those for combined-cycle, steam-electric, or other conventional power plants.

In addition to land losses, combustion turbine power plants fueled by fossil or synfuels release gaseous and particulate matter that could affect the terrestrial biota. SO_2 and certain trace elements from distillate fuel use could be the most ecologically offensive pollutants. The impact of toxic air emissions as well as habitat loss and human disturbance on soils, vegetation, and wildlife is described in Appendix G. These impacts could be minimized by siting plants away from sensitive ecological communities and by installing effective pollutant control devices.

5.1.5 Socioeconomic Considerations

Due to the relatively small work force and acreage requirements for combustion turbine development, socioeconomic impacts can be expected to vary more with location than with plant scale. The absence of major siting constraints allows flexibility in locating a combustion turbine facility. Thirty construction workers will be required for a 70-MW plant for a period of 9 months, and 12 workers will be needed to operate the plants. To minimize impacts, combustion turbines should not be sited in very small towns, although installing a construction workcamp would lessen the demand for housing and public services.

A combustion turbine is a capital-intensive facility. Approximately 20% of the project capital expenditures would be invested within the Railbelt, whereas 80% would likely be spent outside the region. Approximately 19% of operating expenditures would be spent outside Alaska because of the large allocation of costs for outside maintenance.

5.1.6 Potential Application in Railbelt Region

Combustion turbine power plants currently operating in the Railbelt vary from 3 to 80 MW, with the newer being the large-frame industrial machines in the 60 to 80 MW range. They have been used in the Alaskan Railbelt since the early 1960s and currently furnish approximately 64% of the total capacity in the region. The main reasons for their wide use in the Railbelt have been their low capital costs, short construction lead time, relatively small unit size (suitable for small utility systems), and the availability of inexpensive gas and distillate fuels.

A significant amount of additional combustion turbine capacity is not expected to be installed in the Railbelt in the future. The prospect of future cost increases in natural gas in the Cook Inlet area will require more efficient units of natural gas to be used as an electrical generation fuel. The need for more efficient units is likely to be met by natural gas combined-cycle plants, described in the following section. Combined-cycle plants have much greater efficiency than combustion turbine units and provide similar operating flexibility.

In the Fairbanks area, substantial surplus combustion turbine capacity is in place, making any need for additional units unlikely. When the Anchorage-Fairbanks intertie is complete, low-cost energy most likely will be imported from base-loaded Cook Inlet natural gas combined-cycle plants. Operation of the existing Fairbanks combustion turbines then would be limited to reserve and peaking purposes. New combustion turbine units most likely would not be needed. If inexpensive North Slope natural gas were delivered to Fairbanks, new gas-fired plants probably would be combined cycle or possibly fuel cells, if the latter technology becomes commercial.

Possible future applications of combustion turbines in the Railbelt could include 1) installations to meet unexpected load growth, 2) installations to serve isolated loads and 3) black start reserve units. The short lead time required for combustion turbine installation and their low capital cost makes these units ideal for meeting unexpected demand for new capacity. Several qualities of combustion turbines make them attractive for serving small isolated loads. These qualities include the availability of units of modest rated capacity and low capital cost, the capability of burning readily transportable liquid fuels, simplicity of operation, and load-following capacity. Combustion turbines can be started and brought on-line quickly. This capability together with low capital cost makes these units valuable for reserve service.

Future application of this technology is presently restricted by the Fuel Use Act, which restricts petroleum fuel and natural gas use. The Fuels Use Act generally limits use of petroleum or natural gas for electricity generation to peaking units operating 1500 hours per year or less. After 1990 the use of natural gas is prohibited. However, combustion turbine power plants that are integrated with a coal conversion plant or fueled by a product such as low or medium Btu gas, methanol or distillate oil from such a plant could be used. Some exemptions from the provisions of the Fuel Use Act are available, including units used for cogeneration. Further discussion of the provision of the Act is provided in Appendix N.

5.2 COMBINED-CYCLE POWER PLANTS

The combined-cycle power plant relies on two proven technologies, the combustion turbine and conventional, steam-cycle power generation. Combined-cycle plants are efficient and reliable generating resources that have been in commercial operation over a decade. These plants are capable of closely following growth in demand since generating capacity can be added in relatively small increments.

5.2.1 Technical Characteristics

The combined-cycle power plant is so named because two different thermodynamic cycles are used simultaneously to produce electricity. (This differs from cogeneration, which produces two forms of energy, electricity and process heat.) A combustion turbine combined-cycle plant consists of a conventional, combustion turbogenerator, as described in the combustion turbine profile (Section 5.1) with an exhaust heat recovery boiler supplying a steam turbogenerator.

The minimum economical size of a large-frame, combustion turbine, combined-cycle plant is 90 MW. This is slightly larger than a large combustion turbine plant (60 to 80 MW). Plant sizes up to about 250 MW are available.

Design Features

The heat recovery boiler of a combined-cycle plant uses the thermal energy in the combustion turbine exhaust to produce superheated steam, which is then used in the steam turbine to generate additional electricity. By recovering energy that would otherwise be wasted, the combined cycle substantially improves the efficiency of a simple-cycle, combustion turbine plant. The process of generating electricity in a combined-cycle plant is depicted in Figure 5.2.

The early combined-cycle plants resulted from "repowering" existing steam-electric generating facilities. Combustion turbines with heat recovery boilers were retrofitted to provide steam for existing steam turbine generators. When fuel prices increased drastically during the mid 1970s, several utilities

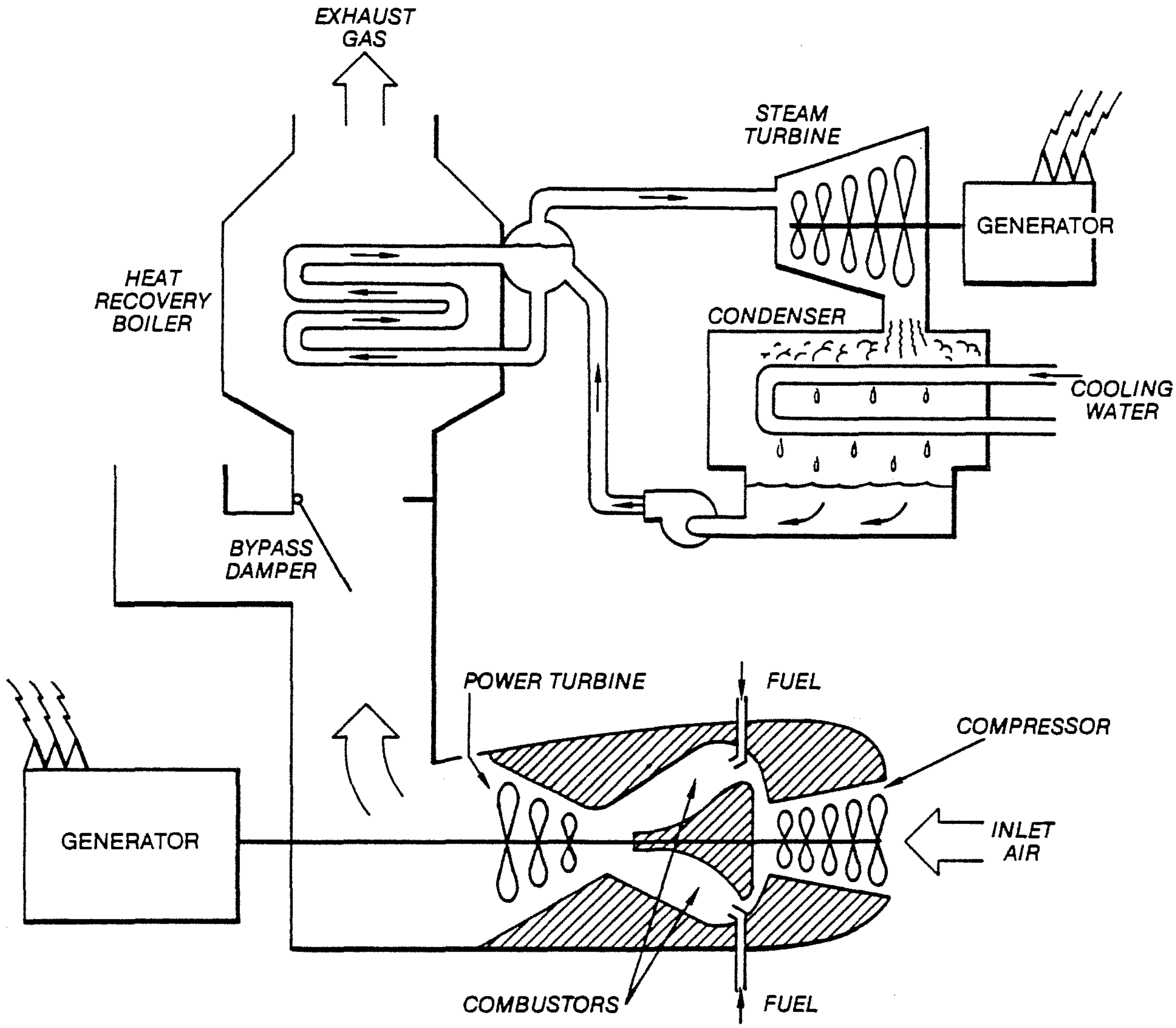


FIGURE 5.2. Combined-Cycle Power Plant

retrofitted simple-cycle, combustion turbine plants to combined-cycle operation, thus increasing generating capacity and markedly improving efficiency.

Converting a simple-cycle, combustion turbine plant to combined cycle normally does not restrict the use of the facility as a simple-cycle plant. Combustion turbine exhaust dampers allow the heat recovery boiler to be bypassed entirely (Figure 5.2). The steam cycle can be started up when necessary after the combustion turbines are on-line. Further, only one steam turbine is normally furnished for several combustion turbine, heat-recovery boilers. This steam turbine can operate at partial load if any of the combustion turbines are out of service. This capability allows a combined-cycle plant considerable flexibility in electrical output. Additional operating flexibility can be provided by exhaust duct firing whereby the waste heat boiler can be separately fired without operation of the combustion turbines.

Combined-cycle power plants can be erected more rapidly than conventional, large power plants of equivalent capacity. Two to 4 years is a typical construction time for a new plant. They are usually constructed in phases, with the combustion turbine portion erected first. This process allows the combustion turbines to generate power while the balance of the plant is still under construction. Combined-cycle plants therefore traditionally have been used where generation is needed to fill critical shortages.

Performance Characteristics

Combined-cycle plants are considerably more efficient than simple-cycle, combustion turbine plants, since turbine exhaust heat is converted into useful electrical energy. Average annual heat rates are provided in Table 5.4. Compared to other conventional fossil generation technologies of comparable capacity, a combined-cycle plant would use less fuel and would reject less heat to the environment.

TABLE 5.4. Heat Rates of Combined-Cycle Plants (EPRI 1979a)

Fuel	Rated Capacity (MW)	Heat Rate (Btu/kWh)
Distillate	250	8600
Residual	250	8685

Combined-cycle plants are generally used for intermediate duty applications (2,000 to 4,000 hr/yr), but they are efficient enough for baseload operation. For example, the AML&P Anchorage 2 Plant is operated as a baseload plant. Since the combustion turbines can be operated independently of the steam cycle, combined-cycle plants can also meet peaking duty requirements.

The reliability of combined cycle compares favorably with other combustion technologies. On the average, combined-cycle power plants are available 85% of the time, compared to 78% for nuclear steam electric and 92% for natural-gas-fired steam electric. The response time to changes in load is very good, making a combined cycle useful for load-following applications. Typical plant life is 30 years (EPRI 1979a).

5.2.2 Siting and Fuel Requirements

Like the simple-cycle, combustion turbine plant, a combined-cycle plant has siting constraints related to air emissions (see Section 5.1). In addition, the combined-cycle plant has further constraints imposed by the steam cycle, which requires water for condenser cooling and boiler makeup. However, because the combustion turbine portion of the total combined-cycle plant (approximately two thirds) requires essentially no cooling water, water requirements are much less than a similar sized, conventional steam-electric plant.

Fuel storage and handling requirements for combined-cycle plants are the same as those described in Section 5.1 for combustion turbines. A pipeline source of gas is required for natural gas units. Distillate-fired units require a pipeline or rail supply of fuel. Natural gas, distillates, and synthetic fuels may be used. A typical 200-MW, combined-cycle plant composed of two combustion turbines and one steam turbine would require 12 acres with fuel storage and 6 acres without fuel storage. These estimates do not include buffer areas, which may be required for noise suppression.

5.2.3 Costs

Capital costs in 1980 dollars for combined-cycle plants are obviously higher than those for simple-cycle plants, but are still substantially less than other fossil fuel or nuclear facilities. Typical costs for a combined-cycle plant are presented in Table 5.5. Estimated capital costs of retrofitting a steam turbine/generator and heat recovery boilers to convert a simple-cycle combustion turbine into a combined cycle are also shown in the table.

TABLE 5.5. Estimated Costs for Combined-Cycle Facility (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy (mills/kW) Cook Inlet Natural Gas	North Slope Natural Gas	Distillate @ Fairbanks
90 (New Plant)	1000	35	50	111	96
200 (New Plant)	920	35	49	110	96
90 (Retrofit)	240	35	39	99	85
200 (Retrofit)	320	35	40	100	86

(a) Levelized lifetime production costs, based on 1990 first year of commercial operation. 65% capacity factor is assumed.

Capital expenditures for combined-cycle plants are largely for equipment, although some field erection is required, particularly for larger waste heat boilers and associated steam-cycle equipment. Combined-cycle plants require less labor for construction than do steam-electric plants.

O&M costs for combined-cycle plants are fairly constant over a large range of plant sizes. O&M costs for combined-cycle plants seem to suffer the same recording and reporting disparities as simple-cycle combustion turbines. Reported O&M costs vary considerably as a result of different operating and maintenance practices as well as accounting practices. Reported O&M costs for combined-cycle plants are generally about 1 mill/kWh less than those for simple-cycle, combustion turbine plants. This difference may result because the baseload operation typical of combined-cycle plants is less demanding of machine life than is the cyclic duty typical of combustion turbines.

5.2.4 Environmental Considerations

Water resource impacts associated with the construction and operation of combined-cycle power plants are generally mitigated through appropriate plant siting criteria and a water and wastewater management program (refer to Appendix D). A favorable attribute of combined-cycle power plants is that, on a per-megawatt basis, these facilities require much less water for cooling than any other conventional steam-cycle systems. They also produce little solid waste and therefore minimize disposal and wastewater treatment requirements. Significant, or difficult to mitigate, water resource impacts should not pose restrictive constraints on the development of combined-cycle plants.

Air-quality impacts of combined-cycle plants are similar to those of combustion turbines (see Appendix E). No_x emissions can be controlled through water or steam injection techniques. SO_2 emissions are negligible with natural gas fuel, but for distillate fuels SO_2 emissions can be reduced by using low sulfur oils. Water vapor is discharged from the waste heat rejection system of the boiler unit. The formation of plumes can be eliminated by using a wet or wet/dry cooling tower system (Appendix I). No offsite meteorological effects of system operation will be detectable.

Potentially significant water withdrawal and effluent discharge impacts that are common to all steam-cycle plants would be the lowest on a per-megawatt basis for combined-cycle plants. A typical water-use rate of these facilities is 150 gpm/MW or 3 gpm/MW for once-through or recirculating cooling water systems, respectively.

The greatest impact resulting from combined-cycle power plants on the terrestrial biota is the loss of habitat. The amount of land required is generally small (6 acres for a 200-MW plant) but can be larger (12 acres) if plants are fueled by distillate oil or certain types of synfuels that require onsite fuel storage. Distillate-fired plants may also require land for ash and scrubber sludge disposal. Combined-cycle plants generally have greater land demands than simple-cycle plants because of the need for condenser waste heat rejection systems.

In addition to direct habitat loss, combined-cycle plants can affect terrestrial biota through gaseous and particulate emissions. SO_2 and emissions from certain trace elements probably have the highest potential for terrestrial impacts. This potential, however, highly depends on the fuel type. Distillate oil-fired plants produce the highest levels of SO_2 emissions, whereas natural gas-fired plants produce almost none. The specific impacts of these emissions and those of land loss and human disturbance on the terrestrial biota are described in Appendix G. The impacts on soils, vegetation, and wildlife can be minimized by siting plants away from sensitive ecological areas and by installing adequate pollution control devices.

5.2.5 Socioeconomic Considerations

Construction of a 200-MW combined-cycle plant will require approximately 45 persons for a period of 2 to 4 years. The operating and maintenance force would consist of approximately 15 persons. Since the construction work force is relatively small, impacts should vary more with site location than with plant capacity. Severe construction-related impacts would likely only occur in very small communities where the infrastructure is insufficient to meet new demands. These impacts can be lessened by siting a combined-cycle plant in a community with a population greater than 500.

Since combined cycle is a capital-intensive technology, the largest portion of expenditures outside the region would be attributed to equipment. Approximately 70% of the project's capital expenditures would be spent outside Alaska, whereas 30% would be spent within the Railbelt. Approximately 16% of O&M expenditures would be spent outside the region. Fuel (natural gas or distillate) would likely be purchased in state.

5.2.6 Potential Application in the Railbelt Region

Widespread use of combined-cycle technology is relatively recent, dating from the mid 60s. One plant, the 139-MW AML&P Anchorage 2 unit, is currently operating in the Railbelt, and conversion of Chugach Electric Beluga Units 6 and 7 to combined-cycle operation is underway.

Further application of natural gas combined-cycle units in the Railbelt appear to be promising if Cook Inlet natural gas prices continue to remain at their relatively low levels and if exemption to Fuel Use Act prohibition could be obtained. The high efficiency and relatively low capital cost of combustion turbine combined-cycle units would result in continued supply of low-cost electricity. These units' operational flexibility, which allows them to be operated in either baseload or load-following capacity, also adds to their desirability in a relatively small utility system. The high efficiency of these plants would also extend natural gas supplies as far as is possible with currently available fossil-fuel technology. Questions remain, however, as to the long-term availability of natural gas in the Cook Inlet region.

Construction of new, natural-gas-fired, combined-cycle plants may be severely curtailed because of the provisions of the Powerplant and Industrial Fuel Use Act (PIFUA) of 1978 (10 CFR 500). The PIFUA prohibits petroleum or natural gas use as a primary energy source in new base-loaded electric power plants. Exemptions are available, for example, for plants incorporating provisions for cogeneration. Additional discussion of the provisions of the Fuels Use Act is provided in Appendix N.

An alternative application of combined-cycle technology in the Railbelt is conversion of existing combustion turbine units to combined-cycle configuration. The conversion, which would likely be feasible for newer and larger combustion turbine units only, would extend fuel supplies and allow economic operation of the retrofitted plans as baseload units. Conversion candidates are found in both the Fairbanks and Anchorage areas.

In the longer term, a promising application of combined-cycle technology may be in integrated, coal gasifier combined-cycle plants. Coal gasification technology, currently in the the developmental stage (Appendix I) may be used to supply a low or medium Btu synthetic fuel gas that can be used to fire combined-cycle plants. Physical integration of the gasifier and combined-cycle plant reduces waste heat loss and increases overall plant efficiency. If coal costs were low, such a plant appears capable of economically competing with conventional, pulverized, coal-fired powerplants. Recent research (Fluor Engineers and Constructors, Inc. 1980) indicates that gasifier-combined-cycle units might be operated in load-following duty, an advantageous feature not possessed by conventional coal-fired powerplants. Coal-gasifier, combined-cycle plants would not be subject to provision of the PIFUA.

5.3 DIESEL GENERATION

Diesel generation accounts for approximately 5% of the Railbelt's electric generating capacity. Approximately 36 MW of utility capacity exists, whereas institutional (e.g., military) power generators operate approximately 17 MW. These units are used as "black start" units (units that can be started with batteries, compressed air or gasoline engines when a power outage occurs), peaking units, and standby units. Diesel generators also are used as load-following (cycling) units in remote locations and in small communities in the Railbelt.

5.3.1 Technical Characteristics

A diesel generating plant consists of a diesel cycle, internal combustion engine driving a standard electricity generator. Diesel installations in the Railbelt region range in size from 1.5 to 7.2 MW, although a much larger range of unit sizes is available. Stationary diesel generator sets have been built in capacities ranging from 30 kW to 15 MW. Units ranging in size up to 20 MW, using slow-speed, two-stroke diesels, are under construction.

Design Features

The diesel engine was invented to simulate the idealized Carnot thermodynamic cycle. In the diesel cycle, air is admitted and compressed with fuel until ignition occurs. During combustion additional fuel is added to the cylinder to maintain constant pressure. Expansion of the combustion products performs the work (i.e., drives the generator).

The diesel cycle varies from the Otto (spark ignition) cycle in that the compression of air provides sufficient heat for fuel ignition. Compression ratios typically range from 12:1 to 15:1 and can reach 20:1, contrasted with spark ignition ratios ranging from 6:1 to 10:1. These higher compression ratios contribute to the relatively high thermal efficiencies of diesel units.

Performance Characteristics

The fuel consumption of diesels is largely a function of thermal efficiency. Typical heat rates of relatively modern diesels in the Railbelt region are about 10,500 Btu/kWh (a thermal efficiency of 33%). Very large, slow-speed units have achieved heat rates of 8,500 to 9,700 Btu/kWh, with efficiencies ranging from 35 to 40%. Very small units may have heat rates that approach 11,400 Btu/kWh.

In contrast to combustion turbines, diesel power has the advantage of being able to efficiently operate at less than full load. Fuel consumption rates for a Caterpillar 900-kW generator demonstrate this characteristic (Table 5.6).

TABLE 5.6. Fuel Consumption Rates and Equivalent Heat Rates for a Diesel Generator Operating at Various Loads

Kilowatts	Fuel Consumption (gallons/hr)	Heat Rate (Btu/kWh)[(a)]
900	70	11,100
800	60	10,700
700	52	10,600
600	45	10,700
500	39	11,200
400	32	11,400

(a) Assuming a heating value of 19,000 Btu/lb; specific gravity of 0.9.

Diesel units are reliable. Experience in the Railbelt area indicates a forced outage rate of only 10%. Life spans of 20 years are common, with life spans reaching 30 years for well-maintained units. Units in remote locations may have a much shorter life because of poor maintenance.

Diesel units are able to quickly respond to startup and shut down. These units are used in the Railbelt and elsewhere as black start emergency units. Diesels can also be used to augment fuel-saver technologies, such as wind or tidal power when natural conditions preclude power generation from the fuel-saver technologies.

5.3.2 Siting and Fuel Requirements

Diesels are well suited for generation throughout the Railbelt region. The small, high-speed units are compact, usually are prefabricated, and require little site preparation. An 850-kW machine, for example, is approximately 15 x 5 x 7 ft high and weighs 12 tons. Mediumand low-speed units are larger, usually are site erected, and require more foundation work. Diesel units require a noise-suppressing, weatherproof structure plus fuel storage facilities. Sites for even the largest units seldom exceed 2 to 5 acres, and many sites in remote Alaska villages are 1 acre or less.

Siting requirements are few. Closed cooling systems are generally employed; thus, a constant supply of cooling water is not required. Units may be remote controlled, allowing unattended operation. The principal site constraints for diesel units include access to fuel supply and site accessibility via barge, rail, or truck for delivery of the unit. Air shipment of units has been used in remote locations such as communities in the Alaska's interior.

Auxiliary systems associated with diesel units are minimal. Fuel storage is required, particularly in remote locations where fuel deliveries may be yearly. Waste heat boilers may be attached for cogeneration (see Section 7.1). The small size of diesel units and the relatively clean fuels consumed generally eliminate the need for extensive pollution control systems, although sound suppression systems are required.

Diesel units can be fueled by a variety of liquid and gaseous hydrocarbons. Available data show that Alaska diesel units are fueled by distillate oils, although other fuels such as natural gas have been used. Synthetic fuels, such as low and medium Btu gas from coal and biomass conversion and methanol, also have been proposed for diesel units.

5.3.3 Costs

Diesel power is typically expensive. Most of the capital cost expenditure is for the equipment, which is purchased outside Alaska, and the transportation of that equipment to Alaska. Only small erection expenditures are necessary. For smaller, high-speed units traditionally used in Alaska, operating costs are largely incurred for purchase of fuels and lubricants. Remote control of several systems by a single operator is possible in multiple unit systems. Replacement of parts in remote villages is costly because of transportation expenses for parts and possibly labor derived from Anchorage or outside Alaska. In remote areas, consumers may play a role in diesel maintenance and have a direct role in the decision to supply electricity.

Estimated capital, O&M, and levelized costs of power for diesel plants of various capacities are provided in Table 5.7.

TABLE 5.7. Estimated Costs for Diesel Electric Generation (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Levelized Cost of Energy (mills/kWh)[a]
3	850	55	105 (205)
6-9	800	45	103 (191)
12	700	35	100 (173)

(a) Levelized lifetime production costs based on 1990 first year of commercial operation. Costs external to parentheses are for baseload operation (65% capacity factor). Costs in parentheses are for peaking service (10% capacity factor). Fuel is distillate at Fairbanks.

5.3.4 Environmental Considerations

Diesel electric generating systems do not require cooling water or continuous process feedwater for operation. Also, they require extremely small tracts of land for all plant facilities. Impacts to the water resources and to aquatic and marine ecosystems from both construction and operation of these plants will be insignificant.

Air-quality emissions from diesel engines will be confined mainly to CO and particulates. High sulfur residual fuels are generally not used in these engines. CO emissions can be controlled by using catalytic converters, and particulate emissions can be controlled by optimizing engine operation. In the Railbelt, these facilities may be sited almost anywhere, with the possible exception of CO nonattainment areas (Anchorage and Fairbanks).

Impacts on the terrestrial biota from diesel systems should be minimal. Land requirements are small (less than 5 acres) and air pollution potential is low. Access road requirements would also be minimal since plants would be sited in or adjacent to developed areas. Possible impacts due to noise and fuel storage can generally be resolved through noise-suppression devices and the avoidance of important wildlife habitat.

5.3.5 Socioeconomic Considerations

The impacts of siting diesel generators in the Railbelt are expected to be minimal due to the inherent limitation of plant scale (0.05 to 20 MW) and the absence of major siting constraints. A large diesel generator would require a small construction crew of 5 to 25 workers for 1 month to 1 year, depending upon unit size. One or two people on a part-time basis could fulfill the O&M requirements. The work force could be composed primarily of residents, making diesel power compatible with very small, small, and intermediate-sized communities.

Since diesel electric generation is capital intensive, a large portion of the capital funds would be sent outside Alaska. Approximately 80% of the capital investment of the project would be made outside of the Railbelt, whereas 20% would be spent inside the region. Because of the small outside maintenance requirements, 92% of O&M expenditures are expected to remain within the region. Fuel most likely would be purchased from within the region.

5.3.6 Potential Application in the Railbelt Region

Because small increments of capacity are available and because diesel generators can be installed quickly, they can be used to provide baseload capacity or reserve capacity for small communities in the Railbelt region. Their efficiency, particularly at partial loads, plus their reliability, make them particularly suited to the remote villages. Cost of operation is the limiting factor because of their dependence on high-priced, refined petroleum products.

The most likely future use of diesel electric units within the Railbelt area that is served by the larger interconnected utilities would be for black start reserve units.

5.4 INTERMEDIATE- AND LARGE-SCALE HYDROELECTRIC PLANTS

Hydroelectric plants convert the energy of flowing water to electric power. Generation of electricity from falling water is a mature technology and the economics are well established. The viability of hydroelectric developments depends on streamflow and site characteristics, project design, proximity to load center, ability to meet estimated electrical demand, and environmental and socioeconomic impacts.

The first hydroelectric plant in the United States was put into operation at Appleton, Wisconsin, in 1882, a few days after the first thermal electric plant began operation. Prior to 1919, development of hydroelectric plants was slow because transmission of electricity over great distances was inefficient. As transmission efficiencies were improved, hydroelectric developments progressed rapidly. For decades in many regions of the United States, thermal plants served primarily as standby units in case of equipment failure or as supplements to hydroelectric units during peak demand hours. Because the growth in electric power demand has outstripped the supply of suitable hydroelectric sites in the Lower 48, the more recent trend has been toward the use of thermal power to carry baseload, with hydropower supplementing thermal generation for peak loads.

Of the 610 GW of installed capacity for the United States (DOE 1979a), about 11.5% (70.4 GW) is hydroelectric capacity. About 80% of the peak load demand for the Pacific Northwest is provided by hydropower (Pacific Northwest River Basins Commission 1980). In comparison, only 13% of all electric energy consumed in the Railbelt is from hydroelectric resources.

5.4.1 Technical Characteristics

Two basic types of hydroelectric plants exist: conventional and low head. By definition, conventional plants have heads greater than 20 meters (66 ft), and low-head plants have heads less than or equal to 20 meters. Low-head plants are usually small and have become more economically feasible as energy prices have risen. Very few economical low-head sites have been identified in Alaska. However, many conventional and small, high-head sites exist.

Intermediate and large-scale hydroelectric projects are defined as sites having an installed capacity greater than 15 MW. Significant differences in operational capability are also inherent in this distinction, as small-scale hydro projects are more likely to be "run-of-river" and not capable of producing scheduled peak power generation. Thus, small-scale projects often operate in a fuel-saver mode in contrast to intermediate and large-scale projects, which generally have storage and are thus capable of operating as load-following units. Small-scale and microhydro units are discussed in Section 7.6.

An inventory of technically feasible hydroelectric sites in the Railbelt region has identified sites having potential installed capacities ranging from the 2 to 3600 MW (Table 5.8).

Design Features

The major components of a conventional hydroelectric development include a dam or diversion structure, a spillway for excess flows, hydraulic turbines, a conduit (penstock) to convey water from the reservoir to the turbines, generators, control and switching apparatus, a powerhouse for housing equipment, transformers, and transmission lines (see Figure 5.3). Additional requirements may include fish passage equipment, trash racks at the entrance to the penstock, gates for penstock and spillway flow control, a forebay (small reservoir that regulates flow into the penstock from the canal, if present), a surge tank (to prevent pipe damage from forces created when flow in the penstock is changed rapidly), and a tailrace (a channel into which water is discharged after passing through the turbines). No two hydropower projects are exactly alike. The type and arrangement of the plant best suited to a given site depends on many factors, including head, available flow, and general topography of the area.

Four types of dams exist, classified on the basis of configuration and construction materials: gravity, arch, buttress, and earthfill. The first three are usually constructed of concrete. More than one type of dam may be included in a single development. For example, a concrete gravity dam that contains spillway and low level outlets may be constructed across the main river section with earth or rock-fill wing dams extending to either abutment.

TABLE 5.8. Technically Feasible Hydroelectric Sites in the Railbelt Region

Site	Stream	Firm Energy (GWh)(a)	Average Annual Energy (GWh)(b)	Installed Capacity (MW)(c)
* Allison Creek(d)	Allison Creek	18	33	4 (8)
Big Delta	Tanana River	987		226
Bradley Lake	Bradley Creek	410 (315)(e)	347(e)	94 (90)(e)
* Browne	Nenana River	385	410	80 (100)
* Bruskasna	Nenana River	(f)	140	40 (30)
* Cache	Talkeetna River	220	220	50 (50)
Canyon Creek	Canyon Creek	131		27
Caribou Creek	Caribou Creek	90		19
Carlo	Nenana River	840(f)		30
Cathedral Bluffs	Tanana River	693		158
* Chakachamna	Chakachatna River	1600	1925	366 (480)
Chulitna (East Fork)	East Fork Chulitna River	59		12
Chulitna (West Fork)	Chulitna River	68		14
Coal Creek	Matanuska River	307		64
Coffee	Beluga River	160		37
Crescent Lake I	Crescent River	79		41
Crescent Lake II	Crescent River	29		6
Deadman Creek	Deadman Creek	165		34
Devil Canyon	Susitna River	(g)		738 (400)
Eagle River	Eagle River	45		9
Fox	Unknown	Unknown		Unknown
Gakona	Copper River	727		150
Gerstle	Tanana River	438		100
Granite Gorge	Talkeetna River	345		72
Grant Lake	Grant Creek	19(h)	27(h)	7(h)
Greenestone	Talkeetna River	246		51
Gulkana River	Gulkana River	164		34
Hanagita Lake	Hanagita River	160		33
Healy	Nenana River	(f)		130
* Hicks	Matanuska River	286	245	59 (60)
Hurricane	Chulitna River	166		34
Jack River	Jack River	Unknown		Unknown
* Johnson	Tanana River	920		210
Junction Island	Tanana River	2330		532
Kantishna River	Kantishna River	394		82
Kasilof River	Kasilof River	193		40
* Keetna	Talkeetna River	324	395	74 (100)
Kenai Lake	Kenai River	552		115
Killey River	Killey River	100		21
King Mountain	Matanuska River	210		44
Klutina	Klutina River	263		54
Kotsina	Kotsina River	133		28
Lower Beluga	Beluga River	72		15
* Lower Chulitna	Chulitna River	394		90
Lower Lake Creek	Lake Creek	105		22
Lower Kenai	Kenai River	263		55
* Lane	Susitna River	1052		240
Lowe	Lowe River	254		55
Lucy	Chulitna River	71		15

TABLE 5.8. (Contd)

Site	Stream	Firm Energy (GWh)(a)	Average Annual Energy (GWh)(b)	Installed Capacity (MW)(c)
McClaren River	McClaren River	263		55
McClure Bay	Unknown	Unknown		Unknown
McKinley River	McKinley River	201		42
Million Dollar	Copper River	1927		440
Moose Horn	Kenai River	290		60
Nellie Juan	Nellie Juan River	47		10
Ohio	Chulitna River	144		30
Power Creek -I	Power Creek	66		14
Power Creek -II	Power Creek	Unknown		Unknown
Unknown	Unknown			
Rampart	Yukon	34,200		5040
Salmon	Bremmer River	86		18
Sanford	Copper River	385		80
Sheep	Talkeetna River	149		31
Sheep Creek I	Sheep Creek	94		20
Sheep Creek II	Sheep Creek	Unknown		Unknown
Unknown	Unknown			
* Silver Lake	Duck River	48		10
Skwentna	Skwentna River	(i)		98
* Snow	Snow River	278	220	63 (50)
Solomon Gulch	Unnamed	11		2
South Fork	South Fork Bremmer River	156		32
Stelters Ranch	Kenai River	403		84
* Strandline Lake	Beluga River	81	85	17 (20)
Summit Lake	Gulkana River	164		34
Talachulitna	Skwetna River	1390(i)		75
Talachulitna River	Talachulitna River	137		28
* Talkeetna -II	Talkeetna River	215	215	50 (50)
Tanana River	Tanana River	315		65
Tazlina	Tazline River	503		104
Tebay Lakes	Tebary River	193		40
Teklanika River	Teklanika River	272		57
Tiekel River	Tiekel River	105		22
* Tokachitna	Chulitna River	806		184
Totatlanika	Totatlanika River	114		24
* Tustumena	Tustumena Glacier	102		21
Upper Beluga	Beluga River	210		48
Upper Lake Creek	Lake Creek	74		15
Upper Nellie Juan	Nellie Juan River	57		12
Vachon Island	Tanana River	2050		426
Van Cleave	Unnamed	10		2
Watana	Susitna River	5520(g)	6070	478 (800)
Whiskers	Susitna River	368		84
Wood Canyon	Copper River	21,900		3600
Yanert -II(j)	Nenana River	298		62
Yentna	Yentna River	(i)		145

(a) Alaska Power Administration (1980) estimates shown.
(b) Acres American (1981b) estimates, unless noted.
(c) Alaska Power Administration, installed capacity proposed by Acres American (1981b) shown in parentheses.
(d) Asterisks indicate the 17 sites that are potential alternatives to the Upper Susitna Project.
(e) Obtained from telephone conversation with John Denniger from the Alaska Power Administration, Juneau, Alaska.
(f) Healy, Bruskasna and Carlo operated as a system.
(g) Devil Canyon and Watana operated as a system. Firm energy estimate based on preferred plan (Watana/Devil Canyon) of Acres American (1981b).
(h) CH_2M-Hill (1981).
(i) Skwentna, Talachulitna and Yentna operated as a system.
(j) Would inundate Carlo and Bruskasna sites.

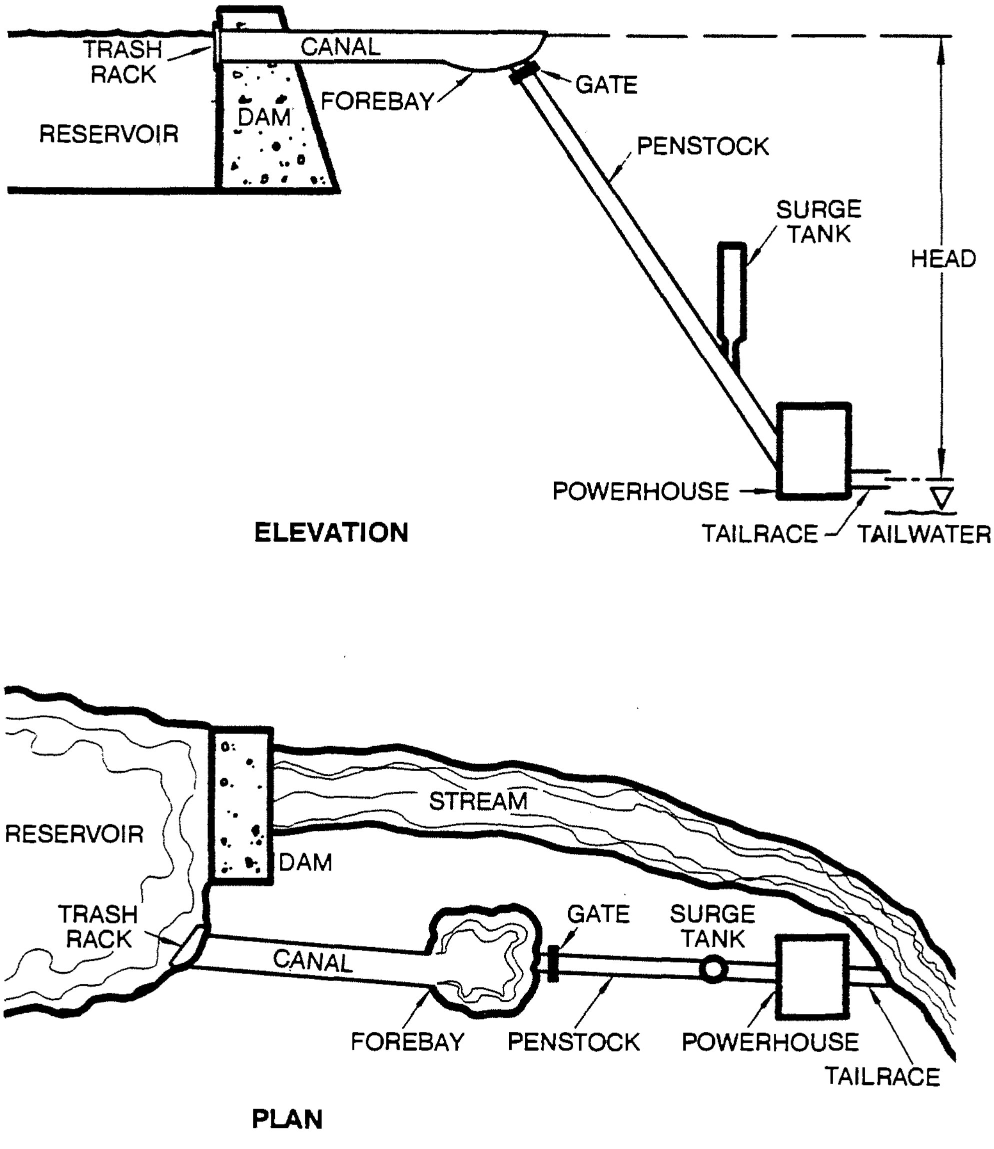


FIGURE 5.3. A Typical Hydropower Installation

The type of dam chosen for a particular site is a function of engineering feasibility and cost. Feasibility is governed by topography (e.g., if the dam site is located in a narrow canyon or in a flatter area), geology (foundation characteristics, rock permeability), and climate. Cost depends on the design, availability of construction materials near the site, and the accessibility to transportation facilities.

A spillway is provided to discharge major floods without damaging the dam and other project components. The spillway may be uncontrolled, or it may be controlled with crest gates so that outflow rates can be adjusted. The required discharge capacity depends on the design flood (the largest flood that statistically might be expected), normal discharge capacity of outlet works, and the available reservoir flood storage.

The powerhouse does not have to be located at the dam. Various combinations of open canals and pressure conduits (pipes flowing full with water under pressure) can be used to convey waters from the reservoir and intake structure to the turbines in the powerhouse. Open canals can be used to convey water over a relatively flat terrain. Penstocks are used for the elevation drop between the reservoir and the powerhouse.

A hydraulic turbine transforms the kinetic energy of flowing water into mechanical energy that performs useful work when harnessed to a generator. Three basic types of hydraulic turbines exist: impulse (e.g., Pelton wheel), which derives mechanical output from one or more jets that impinge on the periphery of a wheel (the runner), and two reaction types (Francis and propeller), which harness the combined actions of pressure and velocity of water passing through the turbine runner and water passages. Impulse turbines are inefficient at heads other than the design head, and they are usually used in high head (650 to greater than 3,300 ft) installations. This type of unit is suitable for small, high-head application in Alaska. The Francis-type reaction turbine is widely used for high-unit capacity installations and with hydraulic heads in the range of 100 to 2,400 ft (medium range). Propeller-type reaction turbines are used for hydraulic heads less than 100 ft.

The powerhouse that houses and protects hydraulic and electrical equipment may be either a surface or an underground structure. The surface powerhouse consists of a substructure to support the hydraulic and electrical equipment and a superstructure to house and protect this equipment. An alternative arrangement, which reduces the superstructure cost, provides only individual housing for each generator. The disadvantage of this "outdoor powerhouse" arrangement is that units cannot be disassembled during inclement weather. This design most likely would not be used in Alaska. The second type of powerhouse, the underground powerhouse, is constructed in a natural or manmade cavern. This arrangement is used in certain topographic conditions, particularly narrow canyons, which preclude the convenient siting of a surface powerhouse.

Performance Characteristics

In its present state of technological development, the hydraulic turbine is simple, efficient, easily controlled, and long lived. It has the ability to serve as a baseload, a cycling, or a standby unit. Also, it is capable of assuming full load in a matter of minutes, and of following load variations with minimal attention. The turbine can drop load instantly without damage. Because of its simplicity and flexibility, the hydraulic turbine can be operated automatically with little attention.

Overall energy conversion efficiencies of a hydroelectric development are about 80 to 85%. This estimate includes generator, turbine, and transformer efficiencies and hydraulic friction losses, but not transmission losses. The response time for hydroelectric generators is very good. When startup time is not critical, a few minutes are adequate to provide full power. If response time is critical, turbines can be kept on spinning reserve at full rotational speed using reduced flow volumes. Full power is then available in a matter of seconds.

Plant availability is typically about 90%. Full outages are rare for plants having multiple generating units. Hydroelectric plant lives are often forecasted to be 50 years for economic purposes, although 100-year plant lives are frequently assumed for large federal projects.

5.4.2 Siting Requirements

The power potential of a hydroelectric development is a function of the head and streamflow available at a given site. Higher head and greater streamflows increase the power generation potential of a site. If the head differential is available over a short horizontal distance, the length of water conductors is reduced, resulting in lower total project costs. Dam, spillway, water conductor, powerhouse, and switchyard structures must be located and designed for specific topographical and geotechnical site conditions.

Dam height (a major contribution to cost) must be optimized to provide storage and seasonal regulation without loss of water over the spillway. Smaller or low-head hydroelectric projects generally have little reservoir storage capacity and must be operated as run-of-river. Therefore, these projects depend upon seasonal fluctuations of water supplies, which lead to spilling of excess flows during the wet season and reduced generation during the dry season. For conventional or low-head projects, basic information is needed about the drainage area, runoff characteristics, and any major water usage upstream and downstream of the project. If adequate records are not available, the necessary data must be synthesized using correlations of nearby streamflow data. Streamflow duration data (and head) are used to calculate average annual energy and dependable (firm) capacity for the site.

Site geophysical conditions determine the availability and cost of construction materials, type and height of dam, and required seepage treatment. These conditions also strongly influence the general location of major civil works (dam, penstock, canals) for the project. Fault lines, sedimentary deposits, potential seismic activity, and great depth to hard rock can result in excessive construction costs, thus eliminating otherwise suitable sites.

Rail or road access is required for transportation of material and equipment.

The land area required for a hydro facility is largely a function of reservoir size and may be significant. Because of variation in topography, are requirements must be determined on an individual project basis.

5.4.3 Costs

Capital costs for hydroelectric developments are site specific and vary according to type, size, head, and location of the project, the amount and cost of required land, and required relocations. The costs of reservoirs and waterways (penstocks and canals) vary considerably and may have little relationship to the installed generating capacity. The costs of powerhouses vary less, although two plants of the same capacity sometimes have a cost differential of 50%. Civil components (dams, spillways and other nonmechanical or nonelectrical features) of low head and small hydro developments usually carry a smaller percentage of the total development costs than features for conventional hydro developments.

O&M costs are determined primarily by plant size. Other factors include the type of operation (baseload or peaking), annual generation, number and size of units, operating head, and other conditions peculiar to individual plants.

5.4.4 Environmental Considerations

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

Important hydrologic impacts are also associated with the operation of a hydroelectric plant. Large diurnal fluctuations in river flow can result when hydropower is used for peaking power or load following. Large and rapid fluctuations can adversely affect aquatic biota and could be hazardous to downstream recreationists. On a seasonal time scale, the reservoir level can vary greatly, again potentially affecting aquatic biota and making the reservoir unattractive for recreation (especially when the reservoir is low). If designed with adequate storage capacity, reservoirs can attenuate flood flows, thereby helping prevent flood damage to property downstream. Conversely, low river flows can be augmented to improve water quality and aquatic habitat. Because many rivers in the Railbelt region exhibit wide natural flow variations, flow regulation can be a significant positive impact.

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

Water, as it falls over a spillway, is turbulent, and atmospheric gases (nitrogen and oxygen) are entrained and readily dissolved, often to the point of supersaturation. This condition can result in fish mortality. The effects are most pronounced in organisms that inhabit shallow areas or surface levels. Supersaturation can be minimized by spillway design and operating measures.

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

The dam construction and reservoir development of at least several square kilometers in size will cause some variation in meteorological conditions. Conditions will generally be less extreme near an unfrozen reservoir, resulting in warmer nights and cooler days. No perceptible change in precipitation patterns will occur. When reservoirs are frozen and snow covered, nighttime temperatures will be less than those observed before the reservoir was constructed. These modifications will be small and generally will not be perceptible beyond a mile from the reservoir.

Hydroelectric projects alter the streamflow characteristics and water quality of streams, which results in corresponding changes in the aquatic biota. Although impacts occur on all levels of the food chain, the impacts on fish (particularly anadromous salmonids) are usually of most concern. In the Railbelt potential effects that will be most difficult to mitigate include the following: 1) loss of spawning areas above and below the dam; 2) loss of rearing habitat; 3) reduced or limited upstream access to migrating fish; and 4) increased mortalities and altered timing of downstream migrating fish. An initial assessment of the potential hydropower sites in Alaska indicates that these impacts could occur at many locations, especially for anadromous fish DOE 1980b). Many of these potential sites are located on major anadromous salmon streams such as the Tanana, Beluga, Skwentna, Susitna, and Copper Rivers.

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

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

With the exception of run-of-the-river projects, hydroelectric energy projects require large amounts of land for water impoundment. Although the amount of land required varies with the energy-producing capacity of a plant and the characteristics of a river basin, they generally exceed those of other energy technologies. Therefore, the greatest impact on the terrestrial biota is the inundation of large areas of wildlife habitat. Inundation of flood plains, marshes, and other important wildlife habitat can adversely affect big game animals, aquatic furbearers, waterfowl, shorebirds, and raptors. Big game animals could be affected by loss of seasonal ranges and interruption of migratory routes. Winter ranges particularly are critical habitats for migratory big game animals. Large reservoirs could also cause genetic isolation of migratory big game animals and other wildlife. The flood control provided by dams may significantly reduce the extent of wetland habitats because of the elimination of seasonal inundation of large areas downstream of dam sites. This feature may affect moose and other wetland species. Aquatic furbearers could be adversely affected by the loss of riparian habitats. Correspondingly, waterfowl and shorebird nesting, loafing, and feeding areas could be eliminated by the flooding of these habitats. The re-establishment of riparian and riverine habitats is generally prevented by the constantly fluctuating reservoir levels of plant operation. Fluctuating water levels could also destroy trees and other natural structures used by raptors for perching, nesting, and roosting sites. Fish-eating raptors and bears could be further affected by the loss of anadromous fish if anadromous fish populations are reduced by the project.

In addition to the losses of wildlife habitats resulting from inundation, access roads to remote locations will cause extensive disturbance to wildlife. Not only will habitat be replaced by roads, but isolated wildlife populations, such as grizzly bears, will be adversely affected by increased human activity and numbers. Also, other wildlife could be affected from increased hunting pressure, poaching, and road kills. The magnitude of these and other potential impacts will depend on the wildlife population densities at each specific site.

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

5.4.5 Socioeconomic Considerations

The construction and operation of a large hydroelectric plant has a high probability of causing a boom/bust cycle. A conventional hydroelectric project of 100 MW installed capacity would likely require a construction work force of 200 to 400 personnel for 5 to 10 years. The resident operating work force could range from zero for unmanned facilities to 10 to 12 persons. The primary reason large projects create adverse effects is the remoteness of the larger sites. All sites identified in this study are located at or near communities with a population of less than 500. An in-migration of the 250 to 1,000 workers required for a plant in the range of 100 to 1000 MW could more than quadruple the population. Installing a construction camp would not mitigate the impacts on the social and economic structure of a community.

The expenditures that flow out of the region account for investment in equipment and supervisory personnel. For a large-scale project, a larger proportion of the expenditures is attributed to civil costs. Approximately 35% of an investment in a large project would be made outside the region, whereas 65% would be made within the Railbelt. Approximately 11% of O&M expenditures would be spent outside the Railbelt and 89% would stay within the region.

5.4.6 Potential Application in the Railbelt Region

Alaska's history of hydropower development dates back to the 1840s when water was used to power a sawmill at Sitka. In the period following World

War II, development of resources, and thus demand for electrical energy, increased significantly. In 1956, the total electric generating capacity was approximately 100 MW. Hydroelectric power comprised 52% of that capacity. By 1976, the State's electricity generating capacity had increased to 940 MW, but hydro represented only 13% of that capacity. One intermediate-scale hydro project is operational in the Railbelt, the Eklutna project (30 MW) near Anchorage. The Solomon Gulch (19 MW) project near Valdez is under construction and will serve Valdez and Glennallen when finished.

Several studies of Alaskan hydropower potential have been undertaken including those by the Federal Power Commission, the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, the U.S. Geological Survey, and the State of Alaska. Over 700 potential sites throughout the state have been identified in these surveys (Federal Power Commission 1976).

Following a review of these studies, Acres American (1981b) identified a total of 91 technically feasible undeveloped large-, intermediate- and small-scale sites in the Railbelt region (Acres American 1981b) (Table 5.8). Also shown in Table 5.8 are the Devil Canyon and Watana sites comprising the Upper Susitna Project.

Using a four-step site evaluation process based on economic, environmental, and land use considerations, Acres American (1981b) identified a short list of 17 sites as potential alternatives to the Upper Susitna Project. In Table 5.8 these sites are indicated by asterisks preceding the project name. Each of these sites was judged to be economically feasible and environmentally acceptable, although four (Talkeetna-2, Lower Chulitna, Lane and Tokachitna) ranked "poor" (although not "unacceptable") in the environmental evaluation.

Fourteen of the Upper Susitna alternative sites are intermediate or large scale. These 15 sites, together with the Upper Susitna sites (Devil Canyon and Watana), plus one additional large-scale Railbelt site (Bradley Lake) being seriously considered for development are listed in Table 5.9 and located as shown on Figure 5.4. Also provided in Table 5.9 are summaries of the economic, environmental, and land-use characteristics of these sites.

As is evident from the capacity and firm energy characteristics of the sites listed in Table 5.9, abundant potential for hydroelectric development

TABLE 5.9. Summary of More Favorable Potential Intermediate and Large-Scale Hydroelectric Sites in the Railbelt Region[a]

Site	Big Game Present	Waterfowl, Raptors Endangered Species	Anadromous Fisheries	Agricultural Potential	Wilderness Potential	Cultural, Recreational and Scientific Features	Estimated Capital Cost[b] ($/kW)	Estimated O&M Cost ($/kW/yr)[c]	Estimated Cost of Power (mills/kWh)
Bradley Lake	Black Bear Grizzly Bear	Peregrine Falcon	None	25-30% Marginal Soils High-Quality Forests	Good to High Quality Scenery	Boating	2,900[d]	58	49
Browne	Black Bear Grizzly Bear Moose Caribou (winter)	Low Density of Waterfowl	None	More than 50% Marginal Soils	None	Boating Potential	6,245	125	95
Bruskasna	Black Bear Grizzly Bear Moose Caribou (winter)	Low Density of Waterfowl, Nesting and Molting	None	None Identified	Good to High Quality Scenery	Boating Potential, Proposed Ecological Reserve	7,933	160	126
Cache	Black Bear Grizzly Bear Moose (winter) Caribou (winter)	None Identified	Spawning Area	None Identified	Good to High Quality Scenery Primitive Lands	Boating Potential	11,275	225	179
Chakachamna	Black Bear Moose	Waterfowl Nesting and Molting	Present	Spruce and Hardwood Forest	Good to High Quality Scenery, Primitive and Natural Forest	Boating	2,997	60	48
Devil Canyon[f]	Black Bear Brown Bear Moose Caribou	Low Population of Waterfowl, Cliff Nest- ing Areas for Ravens and Raptors	Spawning Areas Downstream	Unknown	Wilderness Quality Lands	Hunting, Boating	1,890	38	23[g]
Hicks	Black Bear Grizzly Bear Caribou Moose (winter)	Waterfowl Nesting and Molting	Present Downstream	None Identified	Average Quality Scenery	Hunting	8,817	180	141
Johnson	Black Bear Grizzly Bear	Low Density Waterfowl Nesting and Molting Area	Spawning Area	25-50% Suitable Soils Spruce-Hardwood Forest	None Identified	Boating	Not Available	Not Available	120[e]

TABLE 5.9. (contd)

Site	Big Game Present	Waterfowl, Raptors Endangered Species	Anadromous Fisheries	Agricultural Potential	Wilderness Potential	Cultural, Recreational and Scientific Features	Estimated Capital Cost(b) ($/kW)	Estimated O&M Cost ($/kW/yr)(c)	Estimated Cost of Energy (mills/kWh)
Keetna	Black Bear Grizzly Bear Caribou (winter) Moose (Fall & Winter)	None Identified	Spawning Area	None Identified	Good to High Quality Primitive Lands	High Boating Potential	4,767	95	77
Lane	Black Bear Moose Caribou	Low Density Waterfowl Nesting and Molting Area	Spawning Area	More than 50% Suitable Soils Spruce-Poplar Forest	None Identified	Boating Potential	Not Available	Not Available	65(e)
Lower Chulitna	Black Bear Grizzly Bear Caribou	Medium Density Waterfowl Nesting and Molting Area	Spawning in Vicinity	More than 50% Suitable Soils	Selected for Wilderness Consideration	Boating Potential	Not Available	Not Available	59(e)
Snow	Black Bear Dall Sheep Moose (winter)	Nesting and Molting Area	None	None Identified	None Identified	Chugach N.F. Proposed Biological Reserve	5,092	100	738
Strandline Lake	Black Bear Grizzly Bear Moose	Nesting and Molting Area	None	25-50% Marginal Soils	Good to High Quality Scenery, Primitive Lands	None Identified	6,300	130	94
Talkeetna II	Black Bear Grizzly Bear Moose (fall & winter) Caribou (winter)	None Identified	Spawning Area	None Identified	Good to High Quality Scenery, Primitive Lands	Boating Potential	9,993	200	158
Tokachitna	Black Bear Moose Caribou	Medium Density Waterfowl Nesting and Molting Area	Spawning in Vicinity	50% of Upland Soils Suitable	Nearby Primitive Area	Boating Potential	Not Available	Not Available	64(e)
Tustumena	Black Bear Dall Sheep	None Identified	None Identified	None Identified	Selected for Wilderness Consideration Good to High Quality Scenery, Primitive Lands, Natural Features	None Identified	Not Available	Not Available	125(e)
Watana(f)	Black Bear Brown Bear Moose Caribou	Low Population of Waterfowl	Spawning Areas Downstream	Unknown	Wilderness Quality Lands	Hunting Boating	3,890 (I) 4,030 (II)	78 (I) 81 (II)	50 (I)(f) 80 (II)(f)

(a) Environmental and land-use characteristics and capital cost estimates taken from Acres American (1981b) unless otherwise noted.
(b) Costs are overnight construction costs in July 1980 dollars.
(c) 2% of capital costs used for all projects.
(d) Preferred alternative. Provided in a telephone conversation with John Denniger from the Alaska Power Administration, Juneau, Alaska.
(e) Power costs were determined using cost indices provided in APA (1980) with Chakachamna estimate as a base.
(f) Devil Canyon and Watana dams comprise the Upper Susitna project, which is planned to be constructed in three stages, Watana I (680 MW), Watana II (1020 MW), Devil Canyon (600 MW). Average cost of power following construction of all stages is 56 mills/kWh.
(g) Corps of Engineers (1980).

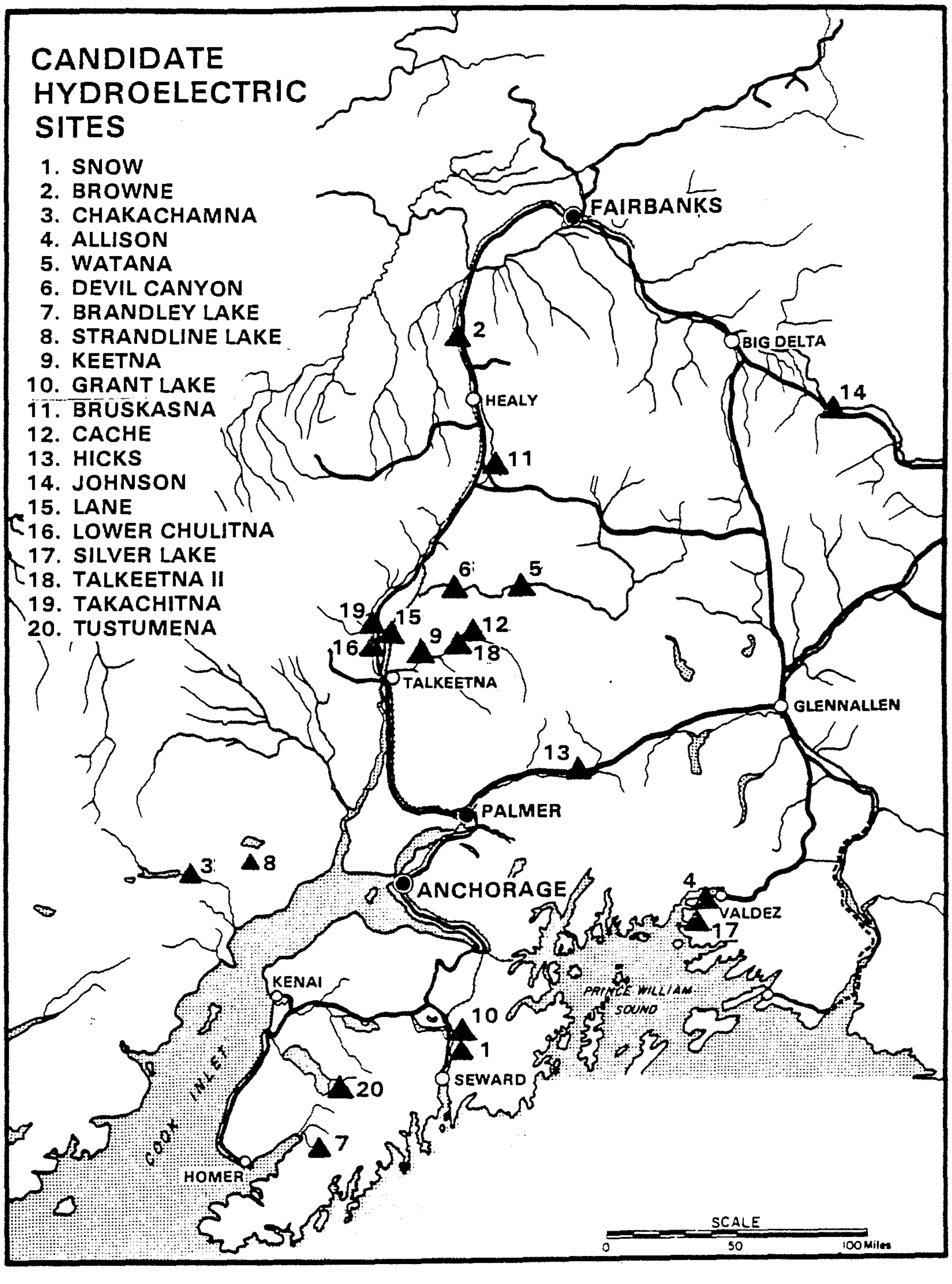


FIGURE 5.4. Potential Hydroelectric Resources

exists in the Railbelt region. Hydroelectric power offers the advantages of flexibility of operation and minimal atmospheric environmental impacts. However, hydrologic, ecological, and socioeconomic impacts can be severe if sites are not carefully selected and proper mitigative techniques are not implemented. Although initial capital costs tend to be high, facility lifetimes are long and variable operating costs are low, resulting in power costs that are relatively secure from inflationary effects.

5.5 FUEL CELLS

The fuel cell is a solid state device for production of electricity by electrochemical combination of hydrogen and oxygen. The hydrogen is supplied by reforming a hydrocarbon fuel, and the oxygen is obtained from the atmosphere. Fuel cell technology is in the demonstration stage and several fuel cell stations have been constructed for commercial testing.

5.5.1 Technical Characteristics

The basic fuel cell plant consists of a fuel processor, the fuel cell section, and a power conditioner (Figure 5.5). The purpose of the fuel processor is to reform the hydrocarbon fuel (usually a gaseous or liquid hydrocarbon) to produce hydrogen feedstock for the fuel cells. The fuel cell section includes the fuel cells, configured in series to achieve the desired voltage and current capacity. The power conditioner includes inverters to change the DC power output of the cells to AC, and transformers to match the output of the fuel cell station with the grid.

Although the "stand-alone" fuel cell station is the only configuration presently in commercial operation, other fuel cell configurations are being studied. Coal gasifier fuel cell plants would use low or medium Btu coal-derived synthetic gas as a source of hydrogen for fuel cell operation. Second generation molten carbonate fuel cells, with much higher operating temperatures than first generation phosphoric acid fuel cells, could be used either in stand-alone fuel cell stations or in a combined-cycle mode of operation. In combined-cycle operation fuel cell reject heat would be used in a waste heat boiler, either to raise steam for a steam-driven turbine generator or for district heating. A fuel cell - combined-cycle plant could be fueled by oil, natural gas or coal-derived synthetic fuels.

Plant sizes will depend upon the plant configuration and operation. Stand-alone fuel cell stations will be highly modular and likely constructed in sizes of tens of megawatts. Larger sizes, although technically feasible, will likely not be common due to the suitability of fuel cell stations for dispersed siting. Coal gasification fuel cell plants and fuel cell - combined-cycle plants will likely be more centralized, in sizes ranging to hundreds of megawatts.

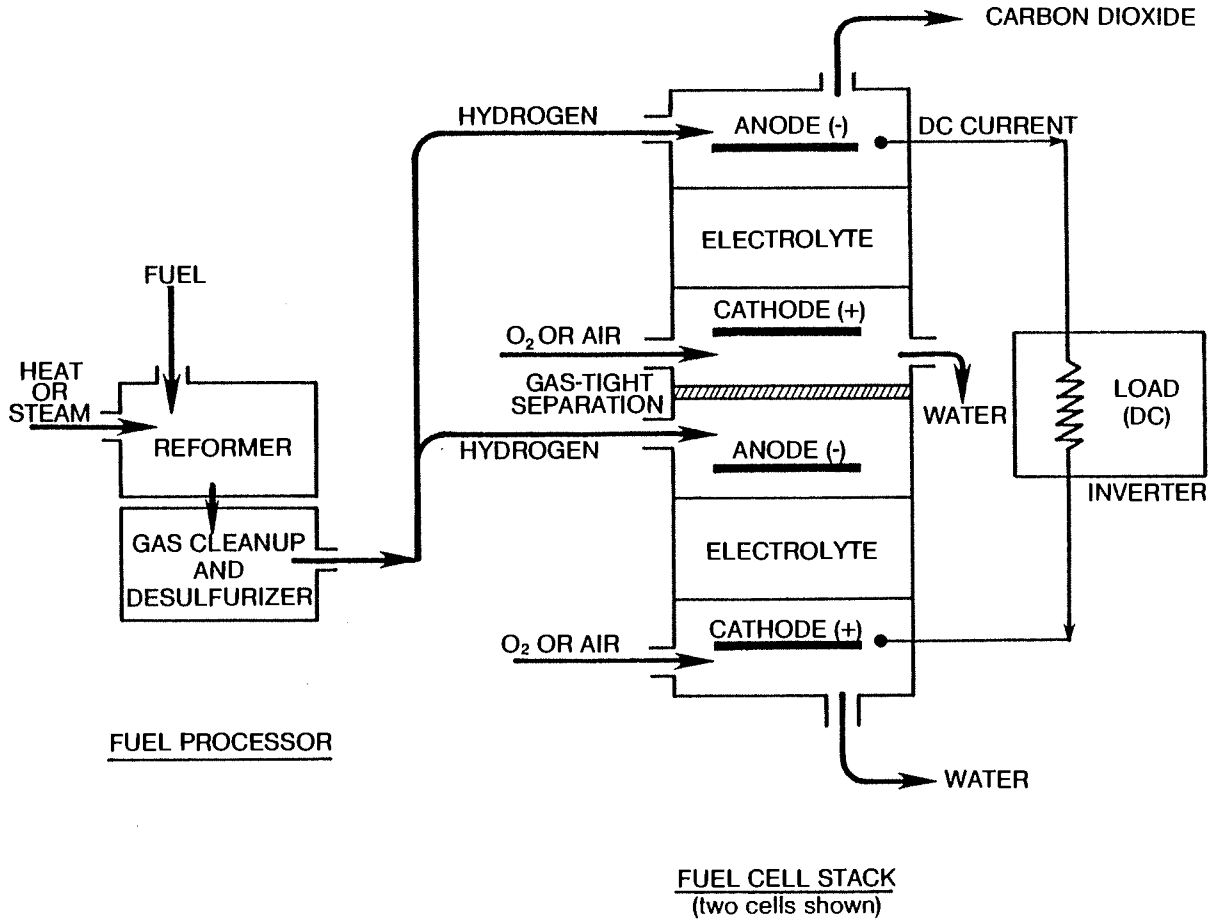


FIGURE 5.5. Typical Fuel Cell Plant

Design Features

A single fuel cell consists of positive and negative electrodes, immersed in an electrolyte. The electrolyte may be an aqueous acid, an aqueous alkaline, a molten salt or even a solid. Catalysts are provided to speed up the reaction.

Cells currently being produced use phosphoric acid as the electrolyte, and hydrogen-rich fuel and oxygen (or air) as the reactant gases (Marianowski and Rosenberg 1972). Hydrogen reacts at the anode to form electrons and positive ions. The electrons pass through an external circuit to the cathode, and the circuit is completed by ions, which pass through the electrolyte. At the cathode, the electrons, ions, and oxygen combine to produce water. Direct current is produced, which must be converted to alternating current for grid-connected applications.

Second-generation fuel cells use molten carbonate electrolyte and operate at higher temperature than the phosphoric acid cell. This design is more efficient because of reduced polarization losses. The molten carbonate fuel cells can tolerate several ppm of H_2S in the fuels, unlike the phosphoric acid fuel cells in which the catalysts are poisoned by sulfur compounds. Therefore, the molten carbonate fuel cell is more suitable for using synthetic fuels derived from coal. A further advantage of the molten carbonate cell is that waste heat is available at temperatures sufficiently high (1200°F) for making high-pressure steam. This steam can then be expanded through a turbine to generate additional electricity. Combined-cycle efficiencies of 60% should be attainable (Bowman et al. 1980). Cogeneration with molten carbonate fuel cells is also a possibility for the utility interested in supplying district heat or industrial process heat.

A third-generation fuel cell using a solid-oxide electrolyte is now in the laboratory research phase, but many development problems are yet to be solved. Optimum materials for electrodes have not yet been defined, but experimental results with lanthanum cobalt oxides indicate that the solid electrolyte fuel cell could be a promising candidate for commercial uses during the 1990s.

An individual fuel cell produces an output of about 0.8 V under load. Individual cells are connected in series to provide greater output voltage and are connected in parallel to provide greater output current. For example, one current design uses 456 cells stacked in a cell stack assembly to produce 300 VDC at a current of 500 amps (United Technologies Corp. 1978). The cell stacks can be connected in series or parallel to produce megawatt quantities of power at 2000 to 3000 VDC.

An entire fuel cell system, including fuel processor, power system, power conditioner, and control system, can be designed in modular form, which can be preassembled at the manufacturing plant to reduce the labor required at the installation site. Using factory mass production, unit costs may be reduced. Using the modular arrangement, modules conceivably could be added or shifted to new locations, depending upon changes in local load conditions.

Performance Characteristics

Because they are not based on a thermodynamic cycle, efficiencies of the fuel cell are typically better than conventional methods of converting thermal energy to mechanical energy for power generation. Estimated heat rates of fuel cell plants are provided in Table 5.10.

Phosphoric acid fuel cells can respond to load changes very quickly and are thus suitable for use in a load-following (cycling) mode. The time constant of the fuel processor is the control factor. For example, a demonstration plant that is designed to follow a load change between 35 and 100% of full power within 2 seconds has been built. Moreover, the efficiency of fuel cell plants is practically constant over wide ranges of loads. This constancy means that they are suitable for partial load operation to meet "spinning reserve" requirements of a utility grid.

Coal gasifier - fuel cell plants using molten carbonate cells may not be as suitable for load-following operation. Although the carbonate cell has a good turndown capability, coal gasifiers do not. Thus, if this type of fuel cell plant is run as a load-following plant, an alternative use for coal-derived gas should be provided when electrical demand decreases. As one solution, this type of plant could shift to methanol production during low load periods. The stored methanol could be converted back to hydrogen during

TABLE 5.10. Estimated Heat Rates of Fuel Cell Plants

Type of Plant	Electrolyte	(MW)	(Btu/kWh)
Fuel Cell Station	Phosphoric Acid	10	9000[a]
Fuel Cell Station	Molten Carbonate	10	7300[b]
Coal Gasifier- - Fuel Cell- - Combined Cycle	Molten Carbonate	1000	7130[b]
Natural Gas- Fuel Cell- Combined Cycle	Molten Carbonate	--	∿5700[b]

(a) EPRI 1979. EPRI 1982 suggests that an annual average heat rate of 8300 Btu/kWh may be obtained if operating under intermediate load conditions.
(b) EPRI 1979; Reconfirmed in EPRI 1982.
(c) Based on estimate of 60% thermodynamic efficiency by Bowman et al. (1980). No specific design studies have been performed on this type of plant.

high electrical load periods, thus reducing the required capacity of the gasification plant. A second problem with using the molten carbonate cell in cycling service is the adverse effects of thermal cycling on this cell design. Because of the high operating temperature, 1200°F, excessive thermal cycling may lead to cracking in the electrolyte tile. For these reasons, the molten carbonate cell is more suitable for baseload operation.

The reliability of a fuel cell plant depends to some extent on the type of fuel that is used; plants are expected to be extremely reliable when a clean fuel is used. An availability of approximately 91% is predicted for dispersed fuel cell stations (EPRI 1979). Because of their greater complexity, the availability of gasifier - fuel cell - combined-cycle plants is anticipated to be somewhat lower than fuel cell stations, approximately 83% (EPRI 1979). The reliability of fuel cell - combined-cycle plants fired by natural gas or distillate could be expected to be intermediate between these two estimates. Scheduled outages for maintenance will therefore be less than for the conventional coal or gas-fired plants.

Presently, fuel cell manufacturers recommend a rework of the cells every 10,000 operating hours. Design goals are for a cell with 40,000-hour operating life (EPRI 1980b).

Plant design lifetimes are anticipated to be 20 years for dispersed fuel cell stations and 20 to 30 years for fuel cell - combined-cycle plants.

5.5.2 Siting and Fuel Requirements

Considerable flexibility in siting is possible because of the modular design, compact size, and modest environmental effects of fuel cell stations. Small fuel cell stations would create very little noise and very little visual intrusion and could be sited in dispersed locations in the Railbelt, such as small communities, electric substations, or even individual neighborhoods, assuming adequate fuel distribution systems.

The principal siting constraint for such plants would be the source of fuel. Plants operating on natural gas would require a gas pipeline. Liquid fuels such as naphtha or distillate oil could be supplied by pipeline, tanker truck, or rail. Fuel storage facilities would be required for plants supplied by truck or rail.

Considerably more stringent siting requirements would apply to a gasifier - fuel cell plant or a large natural gas - fuel cell - combined-cycle plant. Siting requirements for these plants would be similar to those for coal gasification plants and combined-cycle plants, respectively, as discussed elsewhere in this report. A medium Btu gas fuel could economically be transported by pipeline for moderate distances (up to 100 miles), allowing remote or dispersed siting of the fuel cell generation plants.

Current demonstration fuel cell plants are of the dispersed station size, varying in size from 25 kW to 11 MW. Assuming no onsite fuel storage, a complete 40-kW plant would require less than 1 acre, and a 5-MW plant would require 1 to 2 acres. If 30-day fuel storage were required (considering use of a liquid fuel such as naphtha), these area requirements would approximately double. The larger proposed plants, such as a coal gasifier - molten carbonate plant, will likely require less area than a coal plant of comparable capacity because land for flue gas desulfurization waste disposal would not be required of the fuel cell plant.

Little, if any, external water is required for a noncombined-cycle fuel cell plant because water formed by the fuel cell process is usually sufficient for cooling and heat recovery systems. The fuel cell stacks are normally cooled by the process gases passing through the structure, although forced air cooling has also been satisfactorily tested. Cooling water would be required for the steam section of a fuel cell combined-cycle plant.

Fuel cells consume different types of fuel, depending upon the type of electrolyte. Phosphoric acid fuel cells use hydrogen, generally produced by reforming a hydrocarbon fuel in the presence of steam, to produce H_2 and CO. The resulting CO is passed over a catalyst to convert the CO to H_2O and CO_2 and more H_2 by the shift reaction. A fuel processor is typically used to convert propane, methane, naphtha, or No. 2 fuel oil to hydrogen. At present, the most fully developed process is for naphtha and methane as fuel for phosphoric acid fuel cells. A demonstration fuel cell station in New York City will use either naphtha or methane gas as its fuel supply.

In the molten carbonate and solid-oxide fuel cells, CO is the fuel, being catalyzed on the electrode surface to form H_2 and CO_2 in the presence of steam. The molten carbonate cell must have CO_2 available at the cathode, along with the oxidant such as oxygen or air, to provide the CO_3 charge carriers in the molten carbonate electrolyte.

The shortage of natural liquid and gaseous fossil fuels (required to obtain hydrogen) has prompted research in developing fuel cells that would use coal-derived gaseous fuels directly. Coal can supply H_2 and CO as gaseous fuels, but the CO cannot be directly used in H_2-O_2 (phosphoric acid) fuel cells. Both gases may work in a molten carbonate fuel cell, but reliable operation of this design has not been demonstrated. Coal gas, synthetic gas, and methyl-base fuels are also suitable for generating hydrogen, although use of these fuels will require minor modifications to the fuel processor.

5.5.3 Costs

Capital costs for phosphoric acid fuel cell plants are not yet competitive with comparable conventional power plants (combustion turbine or combined-cycle plants) now being installed in the United States. In addition, the typically high cost of suitable fuel contributes to costs of power currently exceeding that of conventional coal plants. However, in the Railbelt, natural gas is currently available at prices very competitive with coal. Furthermore, mass production of phosphoric acid cells should result in a decrease in "real" (i.e., adjusted for inflation) capital cost. Estimated costs derived from EPRI (1980b) for phosphoric acid fuel cell stations using naphtha as fuel are given in Table 5.11 in 1980 dollars and adjusted for Alaska. Note that this technology is not commercially available and therefore the costs represent a de-escalation of values expected in the late 1980s.

Because of the early stage of technical development of molten carbonate fuel cells, only preliminary estimates can be made of the costs of coal gasifier - fuel cell - combined-cycle plants. EPRI has prepared an estimate of the cost of constructing and operating a coal gasifier - fuel cell - combined-cycle power plant using Texaco gasifier technology and molten carbonate fuel cells (EPRI 1980). The EPRI estimate was used as the basis for the cost estimate for this type of plant in Table 5.11, which is assumed to be constructed at a rural Alaskan site.

No engineering-economic assessment of a natural gas - molten carbonate fuel cell power plant was located for this study. Thus, reliable cost data for this technology are not available. Most likely the capital costs of this technology would be somewhat less than the capital costs of a coal gasifier - fuel cell - combined-cycle plant.

5.5.4 Environmental Considerations

Fuel cells produce water at elevated temperatures during normal operation. Characteristic cell operating temperatures for phosphoric acid cells are 20 to 90°C. Molten carbonate cells operate at temperatures to 1200°C. A typical value given for waste heat disposal, to avoid electrolyte decomposition, is about 30% of the heat of reaction. This will correspond to about 260 Kcal/kW (66 Btu/kW) (Davis and Rozeau 1977; Adlhart 1976).

For a cell operating at the theoretical maximum efficiency of 100%, the product water formed is approximately 421 grams/kWh. For a 10-MW plant, this corresponds to a water production rate of approximately 27,000 gal/day (Davis and Rozeau 1977). For phosphoric acid plants, operating at 20 to 90°C, this

TABLE 5.11. Estimated Costs for Fuel Cell Plants (1980 dollars)

Type of Plant	Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy[a] Beluga Coal (mills/kWh)	Cook Inlet Natural Gas (mills/kWh)	North Slope Natural Gas (mills/kWh)	Distillate @ Fairbanks (mills/kWh)
Fuel Cell Station (Phosphoric Acid)	10	750	43	--	49 (143)	111 (206)	97 (192)
Fuel Cell Station (Molten Carbonate)	10	810	43	--	43 (142)	94 (193)	83 (182)
Coal Gasifier-Fuel Cell-Combined Cycle (Texaco/Molten Carbonate)	1000	2230	39	43	--	--	--
Fuel Cell - Combined Cycle (Molten Carbonate)	(No economic evaluations of this technology were located; thus no reliable cost data are available)						

(a) Levelized lifetime production costs, based on a 1990 first year of commercial operation. Costs shown external to parentheses are based on baseload operation (65% capacity factor). Costs enclosed in parentheses are based on peaking service (10% capacity factor).

product water would likely be discharged from the plant or used for local space heating. Waste water from a molten carbonate plant could be flashed to steam and used to drive a conventional steam turbine in a bottoming cycle, or used in the fuel processor to reform the hydrocarbon fuel. Additional cooling water also may be used to maximize the usage of the reject heat in producing steam. The quantity, however, would be very design specific. Regardless of the specific facility application, an appropriate water and wastewater management plan incorporating suitable waste heat rejection technologies would be required to ensure that thermal discharges comply with pertinent receiving stream standards.

Gaseous emissions from the operation of fuel cells are very low compared to combustion-based power generation technologies. Sulfur, from fuels containing sulfur, will not be oxidized and can easily be recovered from process streams. Fuels that are essentially free of sulfur and nitrogen, including hydrogen or natural gas, will not produce oxides of nitrogen. Carbon dioxide and water vapor will be formed in large quantities, similar to that associated with combustion, but will cause no detectable environmental impacts. Because of the high efficiencies of fuel cells and the ease of controlling potential pollutants, fuel cells represent a dramatic improvement in air-quality effects compared to combustion technologies.

The quantity of makeup water for cooling, if any is needed, will depend on the operating characteristics of each plant. If cooling water is required, its potential impacts on aquatic ecosystems will be similar to those of other steam-cycle plants. Because water-use requirements vary with fuel cell plant design, no direct per-megawatt comparison can be made with another plant. For small dispersed plants, adverse effects on the aquatic environment can be avoided by proper construction and siting.

The impacts of fuel cell energy systems on terrestrial biota are relatively slight since the air pollution potential is very low and relatively small land areas are required. Dispersed fuel cell stations would be sited within or adjacent to developed areas where access road and transmission corridor requirements would be minimal.

5.5.5 Socioeconomic Considerations

Sites for fuel cell power plants would be determined by the type of plant and availability of fuel. Small-scale fuel cell stations using natural gas or distillate as fuel would likely be located in or near load centers to minimize transmission losses. Close in-siting of these plants will be feasible because of the ready availability of suitable fuels in populated areas and the absence of environmental effects. Because of their modularity and potentially small size, such plants could service small communities and thus be located near them. An estimated 90 persons would be required over a period of a year to construct a 10-MW fuel cell station. An operating staff of approximately 5 would be required. Construction of this type of facility could cause a significant socioeconomic impact in a small community but relatively little impact in a larger community. A one- to two-year construction period should be typical.

Natural gas - fuel cell - combined-cycle plants and coal gasifier - fuel cell - combined-cycle plants would likely be developed as central stations in locations proximate to a suitable fuel supply. A suitable location for natural gas fired - fuel cell - combined-cycle plant would be the western Cook Inlet area. However, because this type of plant will have relatively benign environmental effects, siting closer to urban areas will be feasible. Thus, the best location would be established by a trade-off analysis of natural gas transport versus electricity transmission.

Coal gasifier - fuel cell - combined-cycle plants could be located either in the Beluga area, supplied by Beluga coal, or along the Alaskan Railroad supplied by Nanana coal. A 3-year construction period would be typical with a construction work force numbering in the hundreds. The operating staff would be on the order of 75 to 100 people for a plant of this type.

Capital expenditures that would flow out of the region due to development of a fuel cell facility would include investment in high-technology equipment. An expected 80% of the project expenditures would be made outside the region, with 20% spent within the Railbelt. Approximately 90% of operating and maintenance expenditures would be spent outside the Railbelt.

5.5.6 Potential Application to the Railbelt Region

Fuel cells represent an emerging technology. It is not yet commercially available and has thus not been applied in Alaska. Present-day demonstration fuel cells, which generally use phosphoric acid as the electrolyte, are expected to be commercially available within the next few years. Satisfactory operation of phosphoric acid fuel cells has been demonstrated in several small plants (1 MW or less), which have operated for periods in excess of 100 hours. Single cells have been operated for periods approaching 100,000 hours. A plant with 4.8-MW output is under construction in New York City and one with an output of 10 MW is under construction in Tokyo, Japan (Glasser 1980). Commercial production facilities are being built by a major electrical equipment manufacturer, with 11-MW fuel cell modules to be commercially available around 1985. Given a 2-year preconstruction lead time and a 1-year construction period, phosphoric acid fuel cell stations could be available for operation in the Railbelt as early as 1988.

The molten carbonate cell has been under development at a modest level for about 25 years and is currently about 5 years behind the phosphoric acid cell technology. Good progress and accelerated effort have characterized this concept in past few years of its development; thus this second-generation fuel cell could be generating multi-megawatt power on a demonstration basis within 3 to 4 years. DOE is funding a significant effort to achieve a molten carbonate system demonstration in 1986 or 1987. Fabrication processes are being developed with current funding from DOE and EPRI. However, commercial availability is not anticipated until after 1990 (Mansour 1980).

Coal gasifier - fuel cell - combined-cycle power plants based on molten carbonate cell technology are forecast to be available for commercial order by 1990 (EPRI 1982). Given a 4-year preconstruction lead time and a 3-year construction period (EPRI 1982), these plants could see commercial service in the Railbelt as early as 1996. However, because of foreshortened construction seasons in the Railbelt, a 4-year construction period might be more realistic, leading to a 1997 earliest commercial service date.

The commercial availability of natural gas-fired - fuel cell - combined-cycle plants will likely parallel that of coal gasifier - fuel cell - combined-cycle plants based on molten carbonate cell technology. Assuming 1990 commercial availability (EPRI 1982), a 2-year preconstruction lead time and a 1-year construction period, fuel cell stations based on molten carbonate cell technology could be available for commercial operation in the Railbelt by 1993.

Potential obstacles to commercialization of fuel cells for electric power generation are threefold: technical development, insufficient orders, and national fuel policy. The first factor, status and prospects of technical development, has been discussed previously. Relative to the second factor, enough orders must be generated to take advantage of the economies of scale that are needed to produce fuel cells at competitive prices. No one utility is currently in a financial position to sponsor the potentially high cost of developing production facilities for fuel cells, so the development time table is assumed to depend upon federal funding. The Tennessee Valley Authority (TVA) is planning a pilot plant in Muscle Shoals, Alabama, to develop the use of coal-derived gas as a fuel for phosphoric acid cells. The TVA will use a portion of the flow of hydrogen, carbon monoxide, and carbon dioxide gases from an ammonia-from-coal plant. Within 3 years, TVA also plans to construct a 10-MW fuel cell plant that will use the full output of the coal gasifier at this site. The Energy Research Corporation is currently experimenting with the conversion of methanol to hydrogen for use in the phosphoric acid fuel cell. Conversion of biomass is also a possible method to obtain hydrogen for the fuel cell.

A third factor potentially impacting use of fuel cell plants is the Fuels Use Act. Essentially the Fuels Use Act prohibits use of petroleum or natural gas fuels for electric power generation, with several exceptions. The exceptions are more fully discussed in Appendix N; however, the general impacts of the FUA on the four types of fuel cell plants discussed in this section are summarized below:

- Phosphoric acid fuel cell stations, using distillate or natural gas for fuel could be constructed and operated for peaking or intermediate load duty, although generally they could not be used for baseload duty under current FUA provisions unless mandated by environmental considerations or state law.

- Molten carbonate fuel cell stations, using distillate or natural gas for fuel, could be constructed and operated for peaking or intermediate load duty. These stations could be used for baseload applications if at least 10% of waste heat were used in cogeneration applications, or if mandated by environmental considerations or state law.

- Coal gasifier - fuel cell - combined-cycle plants would be exempt from FUA provisions.

- Fuel cell - combined-cycle plants operating on natural gas could be operated as intermediate or peaking plants, but could be operated in a baseload application only if more than 10% of waste heat were used for cogeneration, or if mandated by environmental considerations or state law.

When commercially available, fuel cell based power plants could serve useful roles in the Railbelt electric power system. Several applications appear to be potentially feasible:

<u>Peaking or Intermediate Load Duty in the Anchorage Area</u>

- Given continued availability of reasonably low-cost natural gas in the Anchorage area, fuel cell stations in the 10 to 25-MW size range would serve well as peaking and intermediate load-following units. Given some decrease in capital cost, the greatly superior heat rate of fuel cell stations would make them preferable to simple-cycle combustion turbines for this application. Earliest availability would be 1988.

Base, Intermediate or Peaking Load Duty in the Fairbanks Area

- If the Fairbanks area continued to be electrically isolated from the remainder of the Railbelt region, fuel cell stations in the 10 to 25-MW size range would be appealing successors to the combustion turbine power plants currently in use in the Fairbanks area. The superior heat rate and flexible scale of fuel cell stations contribute to the feasibility of this application. Earliest availability would be 1988.

Coal-Based Baseload Power

- Coal gasifier - fuel cell - combined-cycle plants in the 200 to 300 MW size range could eventually serve as the baseload component of the Railbelt electric power system. The excellent heat rate and potentially modest environmental effects of these plants would suit them well for such applications in lieu of coal steam electric or coal gasifier - combustion turbine - combined-cycle plants. Earliest availability would be 1997.

Natural Gas-Based Baseload Power

- If natural gas continues to be the fuel of choice in the Anchorage area, natural gas fired - fuel cell - combined-cycle plants could eventually serve as the baseload component of the electric power system. The excellent heat rates of these plants would maximize the electric power generating potential of the natural gas supply and would provide protection against rising natural gas prices. Such plants may be able to be retrofitted to synthetic gas firing as natural gas prices continue to rise. Earliest availability would be 1997.

Natural Gas-Based Baseload Power and District Heating

- Because of the likely modest environmental impacts of a natural gas fired - fuel cell - combined-cycle plant, such a plant could likely be sited in sufficient proximity to urban areas to allow the development of a district space heating system based on fuel cell waste heat. Earliest availability would be 1997.

6.0 STORAGE TECHNOLOGIES

Energy-storage technologies provide a way to use baseload electrical generating capacity to meet peak demands. Energy from baseload plants is stored during offpeak hours and is subsequently released during peak periods. The net effect is to substitute relatively inexpensive baseload generating capacity for peaking capacity. A second application of energy storage technologies is for storage of energy from intermittent operating generating facilities (e.g. wind, solar and tidal plants), increasing the availability of energy from these types of generating facilities. A third application is to provide an emergency standby power supply in case of power station or transmission system failure.

Three types of energy-storage systems are described in this chapter: hydroelectric pumped storage, battery-storage systems and compressed-air energy storage (CAES) systems. Of these systems, the only one in widespread commercial use is hydroelectric pumped storage. Battery-storage systems may become commercially available in the next ten years. One commercial compressed-air storage plant is in operation in West Germany. However, the technology is in the preliminary design stage in the United States. No technological breakthroughs are required to establish CAES commercially, and its commercial development will likely depend substantially upon the comparative economics of CAES and competing storage systems.

Selected characteristics of hydroelectric pumped storage, battery-storage systems, and compressed-air energy storage systems are compared in Table 6.1.

TABLE 6.1. Comparison of Storage Technologies on Selected Characteristics

	Pumped Storage (25 MW, Above Ground)	Battery Storage (10 MW/5 hr (50 MWh)	Compressed Air Energy Storage (1000 MW, Hard Rock)
Aesthetic Intrusiveness			
Visual Impacts	Significant	Minor	Significant
Noise	Minor	Minor	Moderate
Odor	None	Minor	Minor
Ecological Impacts			
Gross Water Use (gpm)	Site Specific	None	Moderate
Land Use (acres)	Site Specific	0.5	~100
Costs			
Capital Cost ($/kW)	950	110 - 240	690
O&M Cost ($/kW/yr)	10.0	6.5	10.7
Cost of Energy (mills/kWh)			
w/ 20 mill electricity	42	38 - 44	54
40 mill electricity	63	65 - 72	67
80 mill electricity	110	110 - 130	94
Public Health & Safety	Safe	Potential local chemical hazard.	Potential aquifer pollution. Potential air pollution.
Consumer Effort	Utility operated.	Utility operated.	Utility operated.
Adaptability to Growth			
Unit Sizes Available	1.5 - 400 MW	4 - 40 MW (for 5 hr)	200 - 1000 MW
Construction Lead Time	5 - 7 yr	1 yr	5 - 6 yr
Availability of Sites	Limited to suitable topography.	Widely available.	Limited to suitable geology.
Reliability			
Availability	85%	>90%	>90%
Expenditures Within Alaska			
Capital	45%	15%	55%
O&M	88%	88%	45%
Fuel	100%	100%	100%
Boom/Bust Effects			
Construction Personnel	350	20-40	150-300
Operating Personnel	10	Not known	(<100)
Ratio	35	Not known	1.5-3:1
Magnitude of Impacts	Minor in vicinity of Anchorage. Moderate to severe in all other locations.	Minor	Major in all locations except Anchorage & Fairbanks.
Consumer Control	Control through regulatory agencies.	Control through regulatory agencies.	Control through regulatory agencies.
Technology Development			
Commercial Availability	Currently available.	1988-1992	Currently available.
Railbelt Experience	None	None	None

(a) Costs are based on 100-MW installed capacity and may be higher for a 25-MW plant.

6.1 HYDROELECTRIC PUMPED STORAGE

A hydroelectric pumped-storage plant consists of an upper and a lower reservoir, a reversing turbogenerator, and interconnecting piping. Water is pumped from a lower reservoir to the upper reservoir during off-peak hours. During peak demand periods, the water is allowed to flow from the upper reservoir through turbines to the lower reservoir; power is generated in the process. A net energy loss occurs with pumped-storage facilities because of system pumping losses and generator inefficiencies. However, these losses are more than compensated for by the difference in power production costs between the baseload plants used to fill the pumped-storage reservoir and the peaking plants that are displaced by operation of the pumped-storage plant.

Pumped-storage plants had their commercial origin in the United States in 1929. The first domestic installation was the 7-MW Rocky River Plant near New Milford, Connecticut. This facility was followed by the 8.5-MW Flat Iron Plant built by the Bureau of Reclamation in Colorado in 1954.

Pumped-storage generation has undergone several important changes as a result of advancing technology and changing system needs. The most significant, single technological advancement was the development of the single runner, reversible pump/turbine with high-head pumping capacity. These units currently have pumping capabilities as high as 600 meters (1800 ft).

6.1.1 Technical Characteristics

The major components of a pumped-storage project include upper and lower reservoirs, water conductors, and the powerhouse, which contains pumping and generating equipment. A typical pumped-storage arrangement is shown in Figure 6.1.

Commercially operating pump/turbines have been built with capacities ranging from 1.5 MW up to 400 MW (TVA's Raccoon Mountain project) with larger units anticipated for the future.

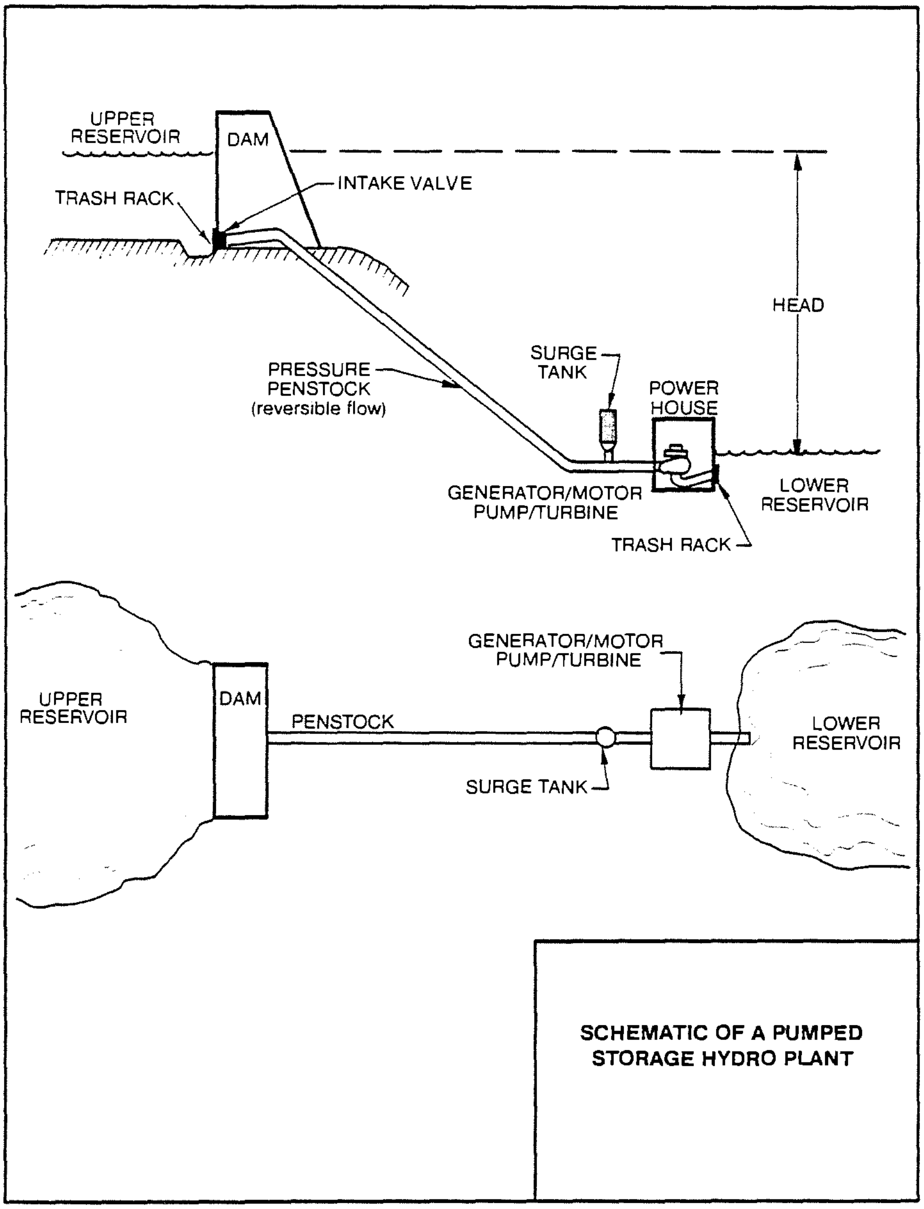


FIGURE 6.1. Schematic of a Pumped Storage Hydro Plant

Design Features

Several hydroelectric pumped-storage arrangements are possible:

Natural Upper and/or Lower Reservoir. The natural reservoir may consist of any large body of water of adequate volume, such as rivers or lakes. A natural reservoir may also consist of a basin, surrounded by higher topography or mountainous terrain, with dams constructed across the basin valleys or low points.

Manmade Upper and/or Lower Reservoir. The manmade reservoir consists of constructing the complete reservoir using perimeter dikes. This approach is generally used on flat or nearly flat terrain where an upper reservoir is to be built on a plateau or high, level bluff.

Underground Lower Reservoir. The underground reservoir would use underground, natural rock caverns or an underground rock excavation and would have an underground powerhouse. The upper reservoir may be either natural or manmade, as described above, or it may use the storage reservoir of an existing, conventional hydro plant.

Conversion of Existing Hydro Plant. In this approach an existing conventional hydro plant would be converted entirely to pumped storage. The existing reservoir would be used as the upper reservoir, and the lower reservoir would be formed by constructing a lower dam downstream of the existing dam.

Conventional Hydro with Pumped Storage. In this approach, a seasonal pumped-storage facility would be built in conjunction with a conventional hydro project. During periods of high river flow and during off-peak hours, the excess water normally discharged over the spillway of the existing structure could be used to run pump/turbines to pump water to an offsite, upper reservoir. During the peak demand hours, this stored water would be discharged back though the pump/turbines, operating in a generating mode, to the river.

To form the reservoir, several dam types are used, generally depending on the valley conditions, local geology, availability of construction materials, and cost. Typical dams may include concrete gravity, concrete arch, or earth or rockfill dams with an impervious central core. Perimeter dikes are typically constructed of earth and rockfill with an impervious central core or an impervious liner.

Upper reservoirs are provided with an emergency spillway. The spillway conveys excess water caused by accidental overpumping away from the reservoir in a controlled manner. When formed by a dam structure, lower reservoirs also include a spillway. The function of this spillway is similar to that for a conventional hydro dam. Since a lower reservoir dam would normally be located along an existing stream or river, the spillway would discharge flood flows from the existing waterway. Water conductors between the reservoirs may be rock tunnels or aboveground penstocks, depending on the project configuration, site geology, topography, and cost.

The major powerhouse equipment consists of one or more reversible pump/turbines coupled to motor/generators. During periods of low electrical demand the pump/turbines, driven by the motor/generators, pump water from the lower to the upper reservoir. During peak demand hours, the pump/turbine unit transforms the kinetic energy of flowing water into mechanical energy to drive the motor/generator as a generator.

The powerhouse may be either a surface or an underground structure. The surface powerhouse consists of a substructure to support the hydraulic and electrical equipment and a superstructure to house and to protect this equipment. Underground powerhouses are constructed in natural or manmade caverns. This scheme is used in certain topographic conditions, particularly narrow canyons, for which no convenient site exists for a conventional powerhouse, and for underground pumped-storage plants. Its feasibility depends on site geology and cost.

Performance Characteristics

Overall conversion efficiency (kWh in/kWh out) of hydroelectric pumped storage plants are about 72% (EPRI 1979b). Equivalent annual availability is estimated to be 95.5% for an underground pumped-storage plant (EPRI 1979b), availabilities for surface facilities should be similar.

Unit lifetime is estimated to be 45 years for underground pumped-storage plants (EPRI 1979b). Lifetimes for surface facilities should be similar to the 50-year economic lifetime community accepted for conventional hydroelectric facilities.

6.1.2 Siting and Fuel Requirements

The size and feasilibity of a pumped-storage project are strongly influenced by site characteristics. Availability of water, land, transmission lines, and access roads are important considerations in the site selection process. In addition, potential sites are evaluated for topography, geology, seismology, and availability of construction materials.

Site topography, specifically the effective head and reservoir storage capacity, determines the power generating duration and rated capacity. Topography also determines the extent of dam construction required to contain the reservoir; maximum use of natural embankments is desirable. The length of the water conductors largely depends on topography. Longer conductors will add to construction costs and will result in larger generating losses and pumping costs. The shortest possible horizontal distance between the upper and lower reservoirs is desirable.

Geologic conditions can affect all plant structures. The presence of unfavorable geologic conditions can result in seepage and stability problems that can be costly to rectify. The competency of the rock will also determine the type of water conductors used (tunnels versus aboveground penstocks) and whether an underground powerhouse can be considered.

Sites characterized by high seismic activity should be avoided, although, if necessary, a project could be designed to resist seismic loads at an overall cost increase. Embankment slopes would have to be flatter; additional restrictions would have to be placed on fill materials; and structures would have to be more massive.

Availability of construction materials also is an important consideration in the site selection process. All concrete structures will require quantities of fine and coarse aggregate. Depending on the configuration of potential dam structures, a considerable amount of fill material also could be required. This material could range from a large, rockfill-sized material down to impervious soil fill. Potential borrow pits should be located as close to the construction site as possible to minimize construction costs. No single site is likely to ideally satisfy all requirements, and therefore the relative technical and economic merits of several candidate sites will have to be evaluated before selecting a single site.

The fuel requirements for a pumped-storage project consist of the electricity required to compensate for electrical and mechanical losses during plant operation. This electricity is normally supplied from base-loaded oil, gas, coal or nuclear plants. Water is, of course, required for system operation.

6.1.3 Costs

Capital investment costs for pumped-storage development are site specific and vary according to type, size, head, location of the project, amount and cost of required land, and required relocations. The costs of reservoirs, power tunnels and penstocks vary considerably with site characteristics and may have little relationship to the installed generating capacity. However, an installed capacity cost of $950/kW (1981 dollars) is generally accepted for low-capacity, pumped-storage projects (less than 100 MW). Unit investment costs are a function of capacity and generally decrease as plant capacity increases; however, for very large pumped-storage plants (greater than 100 MW), investment costs begin to rise.

Plant size, number of pump/turbine units, annual generation, operating head, and site-specific conditions for individual plants are maor factors in maintenance costs. Fuel costs include the cost of pumping water from the lower to upper reservoir and transmission losses. The cost of pumping water depends on the source of off-peak electric power used for pumping.

Table 6.2 shows the estimated costs of hydroelectric pumped-storage plants. The costs were developed based on data from Ebasco, U.S. DOE (1979a) U.S. Army Corps of Engineers (1979) and Electric Power Research Institute (EPRI)(1979b). Note, however, that hydroelectric pumped-storage costs are highly site specific and can vary significantly from the costs of Table 6.2.

6.1.4 Environmental Considerations

The impacts of a hydroelectric pumped-storage facility on the water resources of both the upper and lower reservoirs can be similar to those discussed in Section 5.4.4 for a conventional hydroelectric facility. The major impacts occur from basin flooding and the alteration of the hydrologic regime of the water body. In addition, a natural upper reservoir may experience adverse impacts due to possible modifications in the water-quality regime if differences exist in the water-quality characteristics of the upper and lower reservoirs (i.e., from introduction of lower quality water from the

TABLE 6.2. Estimated Costs of Hydroelectric Pumped-Storage Plants (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)	Electric Energy Cost (mills/kWh @ baseload energy costs shown)[a]		
			20	40	80
100	950	10	56	77	120
400	600	7	46	67	110
500	500	6	43	64	110
>1000	500	4	47	63	110

(a) Assumes 1990 as first year of commercial operation and 50-year economic life; incremental costs with 20, 40 and 80-mill baseload power are shown.

lower reservoir). These impacts are site and facility specific, being a function of reservoir volumes, mixing rates, reservoir water-quality, and many other variables. These water-quality impacts also will affect the lower reservoir, again depending upon site-specific characteristics and whether the lower reservoir is a natural of manmade water body.

Both reservoirs could experience increased scouring and elevated trubidity levels associated with the pumping process and hydroelectric facility discharge design. Proper engineering and plant operation can minimize these impacts.

Creation of a manmade reservoir, either upper or lower, may affect the local hydrologic regime because of increased groundwater seepage and evaporation. Also, underground caverns used for water storage, whether natural or manmade, may impact groundwater quality due to the potential solvation or reaction with the local rock media. Proper site selection criteria and design should minimize these impacts.

No impacts on air quality would result from the use of pumped-storage techniques. Development of an artificial reservior may produce some changes in the microclimate. However, these changes will pertain mainly to temperature and humidity values near the reservoir and will not be perceptible offsite.

Biological impacts of pumped storage are similar to those of conventional hydroelectric plants. Depending on the size, pumped-storage projects typically alter the stream flow characteristics and water quality of streams, which results in corresponding changes in the aquatic biota. Although impacts occur on all levels of the food chain, the impacts on fish (particularly salmonids) are usually of most concern. The following are the potential effects most difficult to mitigate: 1) loss of shoreline spawning areas in lower and upper reservoirs; 2) loss of rearing habitat; 3) increased mortalities of fish passing through turbines; and 4) entrainment of fish due to pumping and discharge from one reservoir to the other. Construction may result in elevated turbidity, gravel removal from the stream, and expanded public fishing in the area because of improved access. Plant operation may result in altered nutrient movement, affecting primary production; water-flow pattern changes, modifying species composition; and altered temperature regimes, affecting migration timing. Also, depending upon spillway design and location, a pumped-storage project may result in gas supersaturation in either the lower reservoir or at downstream locations. This gas supersaturation possibly may result in fish mortalities. Competition and predation among and within species also may be changed.

Mitigative procedures are possible for many impacts and are frequently incorporated into the facility design. Fish hatcheries are commonly used to replace losses in spawning habitat. Screening or diversion structures are used to direct fish away from critical areas. Controlled pumping and release of water (including both flow and temperature regulation) can be used to improve environmental conditions during spawning, rearing, and migration.

Potential pump-storage sites in the Railbelt region have not been identified. However, potential terrestrial impacts of pumped-storage facilities are similar to those of conventional hydroelectric developments (see Section 5.4.4) and include wildlife habitat loss from land inundation and wildlife disturbance from increased human intrusion. Unlike conventional hydroelectric plants, impacts may not be limited to riverine ecosystems. Lowland wildlife populations, particularly moose and caribou, would be impacted by inundation of habitat. Pumped-storage reservoirs can be developed in basins lacking major surface water systems, such as forested areas, using containment dikes. To reduce terrestrial impacts, pumped-storage facilities should be sited in areas of low wildlife value. Other mitigative actions could include enhancing the value of a reservoir to certain wildlife (i.e., waterfowl).

6.1.5 Socioeconomic Considerations

Since pumped storage is a labor-intensive technology, impacts would vary with both plant scale and location. The construction work force requirements would range from 350 for a 100-MW plant to 1200 for a 1000-MW plant, for a period of 4 to 5 years. Plant operation and maintenance requirements would range from a staff of approximately 10 for a 100-MW plant to 30 for a 1000-MW plant. The large differential in construction and operating personnel could cause a boom/bust cycle in remote areas.

A 100-MW plant would have minor socioeconomic impacts if located near Anchorage. The magnitude of the impacts on Fairbanks and intermediate-sized communities would depend on the extent to which the local labor pool could reduce the number of migrants. Small and very small communities would be severely affected by a 100-MW plant because of the substantial population increase.

A 1000-MW plant would affect all locations of the Railbelt, with the exception of Anchorage and possibly Fairbanks. Construction camps would not relieve the impacts to remote areas since the construction period is sufficiently long (5 to 7 years) to result in semipermanent settlement by the work force dependents and secondary inmigrants.

An estimated 55% of the project's capital expenditures would flow out of the region, and 45% would remain within the Railbelt. Approximately 12% of O&M expenditures would be spent outside the region.

6.1.6 Potential Application to the Railbelt Region

No hydroelectric pumped-storage projects have been developed in the Railbelt region. However, under certain future conditions, the development of energy-storage systems may become desirable in the Railbelt.

Electric energy storage systems may become desirable in systems having one of two conditions:

1. A low diurnal load factor, high-cost peaking capacity and low-cost baseload capacity.
2. A low-cost source of intermittent power, large in capacity compared with system loads.

The Railbelt system is currently characterized by a fairly low load factor (Chapter 2) and surplus capacity. In the Anchorage area, the variable operating costs of baseload plants (primarily gas-fired combined-cycle plants) are low; variable costs of peaking units (primarily gas-fired combustion turbines) are slightly higher, but still reasonably inexpensive. In the Fairbanks area, variable costs of baseload capacity (coal steam-electric and oil-fired combustion turbines) range from moderate to high; variable costs of peaking capacity (oil-fired combustion turbines) are high.

Given these conditions, energy-storage systems could find application in the Railbelt under several circumstances.

1. <u>Natural gas continues to be used as the primary electric-energy resource in the Anchorage area, and natural gas prices rise over time</u>. <u>Energy storage in used to provide peak power from high efficiency combined-cycle plants</u>. Currently, simple-cycle combustion turbines (or the combustion turbine sections of combined-cycle plants) are used for peaking purposes in the Anchorage area. Although the heat rate of combustion turbines is substantially higher than that of combined-cycle plants, the combustion turbines continue to be used for peaking duty because of the sunk costs of the existing combustion turbines and the low cost of gas. Use of energy storage plants, operating with electricity generated by combined-cycle plants, might be desirable if gas costs increase substantially. Use of energy-storage systems might be even more attractive if increasing baseload demand resulted in conversion of existing combustion turbines to combined-cycle plants, thereby forcing a choice between new combustion turbine plants or energy-storage plants for capability.

2. Coal is developed as a major regional electric energy resource. Energy storage is used to provide peaking capability using coal-fired baseload plants as sources of energy. Contemporary coal-fired power plants are highly efficient generating devices but are not readily suited to load-following application. Energy storage facilities could provide a way to obtain load-following capability in a coal-based system. Alternatives to use of energy storage facilities for this application in the Railbelt would include construction of hydro capacity for peaking application or continued use of gas-fired combustion turbines for peaking.

3. Cook Inlet tidal power is developed for electric energy production. Energy storage is used for leveling plant output. The proposed Cook Inlet tidal power project would produce a large quantity of energy, cycling with the tides. The potential output of the proposed project would be so large that only a portion of the tidal plant output, if untimed, could be absorbed by the Railbelt electric power system. An energy storage facility could provide a way to use a larger fraction of tidal plant output.

4. A large block of intermittent dispersed wind or solar capacity is developed. Energy storage is used in conjunction with these units to provide firm capacity. This application is not unlike the previously described (Cook Inlet tidal) application, except the energy storage capacity required would likely be greater relative to the installed solar or wind capacity because of the intermittent nature of the wind or solar resource (as compared with the cyclic nature of the tidal resource). Storage capacities equivalent to several days output most likely would be required to firm up the capacity of solar or wind generation.

5. Lengthy transmission interties and large central generating plants are constructed. Dispersed energy storage plants are used to enhance system reliability.

Hydroelectric pumped-storage plants represent only one of several possible ways to store electric energy for the applications described above.

However, it is the one technology that is fully proven in commercial service and would likely receive most serious consideration for near-term application. Of the potential applications described above, hydroelectric pumped storage would be suitable for all except number 5. Dispersed, smaller scale energy storage facilities (such as battery storage plants) would be more suitable for enhancing the reliabiity of a highly centralized system. The principal disadvantages of a hydroelectric-pumped storage facility include the need to locate a suitable site and the potentially significant environmental impacts.

6.2 STORAGE BATTERIES

Utility-scale use of storage batteries is an emerging technology that may find applications for load leveling and for energy storage with intermittent (fuel-saver) generating alternatives. In a load-leveling capacity, electricity would be converted from high-voltage AC into lower voltage DC and would be stored in the batteries in hours of low demand. During peak hours the process would be reversed to carry part of the utility's load. The economic use of storage batteries for load-leveling applications thus requires the availability of low-cost baseload power to offset high-cost peaking sources.

Storage batteries also may be potentially useful with "fuel-saver" generating options; e.g., wind turbines, solar devices and tidal hydroelectric devices. Coupled with storage batteries, the fuel-saver options could be granted capacity credit.

EPRI and DOE have funded the development of batteries for utility load leveling. Battery prototypes are to be tested in the Battery Energy Storage Test Facility (BEST), sponsored jointly by DOE and EPRI. To provide actual operating experience with battery storage coupled to a power grid, the DOE is initiating a Storage Battery for Electric Energy Demonstration project (SBEED). Plans call for completion, in 1984, of a facility consisting of a 30 MWh, lead-acid battery coupled to a 10 MWh, AC-DC converter (Kalhammer 1979).

6.2.1 Technical Characteristics

A 100-MWh (20-MW capacity for 5 hours) zinc-chloride, load-leveling battery plant is shown in Figure 6.2. Storage-battery systems include batteries, equipment for power conditioning and for utility interface. Power conditioning equipment consists of an inverter/converter module, which converts DC to AC or AC to DC. The utility interface includes a transformer filter, controls, and associated switch gear. Other items included in the plant are the cell handling equipment, cooling system, and instrumentation. Commercial battery-storage systems are expected to be sized in the 20 to 200 MWh capacity range.

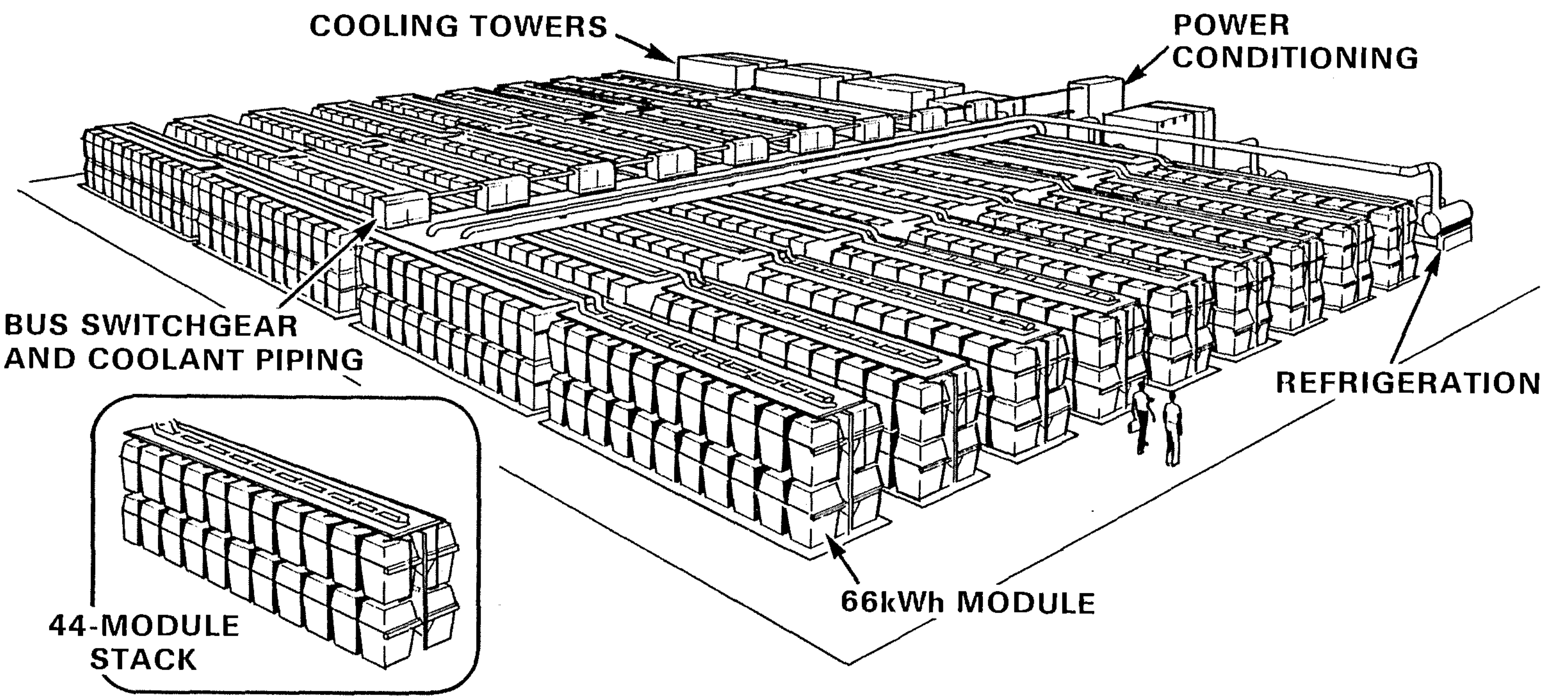


FIGURE 6.2. 100-MWh, Zinc-Chloride, Load-Leveling Battery Plant[a]

(a) The battery subsystem consists of 1584 modules on 36 44-module racks, one of which is shown inset (Energy Development Associates (EDA) 1979).

Design Features

Several new types of storage batteries are under development for utility application. Among these are the advanced lead-acid battery, the sodium-sulfur battery, the iron-chromium Redox fluid battery, the zinc-chloride battery, the lithium metal-iron sulfide battery, the zinc-bromine battery, and the hydrogen-chlorine battery. The most promising battery types for utility applications include Redox (Lewis Research Center), zinc-bromine (Exxon), sodium-sulfur (Ford and Dow) and zinc chlorine (Energy Development Associates) (Krauthamer and Frank 1980).

The Redox flow cell uses chromium-chloride and iron-chloride solutions, which are pumped through a "stack" of flow cells. In each flow cell, the fluids are separated by an ionic-permeable membrane. The fluids transfer electrical charge through the membrane as each fluid reacts at a separate inert-electrode surface, but chromium and iron remain in solution, barred from passing through the membrane. One concern is that the maximum stack voltage is limited to 100 volts. Another concern is the ultimate life of the membrane. A 1-MW unit is planned for installation in the BEST facility in FY96.

Zinc-bromine batteries have been developed by Exxon, Gould, and General Elecric. The Exxon design, which apparently has the economic advantage, employs a cation exchange membrane and inexpensive, conductive plastic composite electrodes. The Gould design uses titanium electrodes. Areas of concern in the Exxon design are limited stack voltage and life of the cation selective membrane.

Sodium-sulfur batteries have been developed by Ford, Dow, and General Electric. The batteries operate at 300 to 350°C, with molten sodium and sulfur as reactants. The Ford and General Electric designs are similar. Areas of concern with the cells include cracking of seals, corrosion by polysulfides, and long-term stability of the beta alumina separator, which separates the molten sodium from the molten sulfur.

The major difference in the Dow sodium-sulfur battery is that the ion-conducting glass fibers are used as a separator instead of beta alumina. Major areas of concern are breakage of the tiny, hollow glass fibers, and complex manufacturing. Also, the ability of the cell to withstand the thermal cycling of startup and shutdown is unknown. These problems are reflected in the low probability of availability (20%) cited in Table 6.3.

The zinc-chlorine battery is being developed by EDA. The cell consists of a zinc electrode, a chlorine electrode, and an aqueous, zinc-chloride electrolyte. Important safety and environmental impact considerations revolve around accidental release and dispersion of toxic amounts of chlorine (EDA 1979). Other areas of concern include hydrogen evolution from the anode, removal of zinc from the anode, requirement of special charging equipment, and maximum stack voltage of 21 volts. A 5-MWh, zinc-chloride system was to be installed in the BEST Facility in 1981.

Performance Characteristics

Table 6.3 presents a summary of performance parameters of eleven advanced battery systems. Station equivalent annual availability is estimated to exceed 90% (EPRI 1979b). A 30-year economic lifetime with several interim replacements of batteries is estimated.

6.2.2 Siting and Fuel Requirements

One of the EPRI criteria established for utility battery plants is minimum siting restrictions. Designs should allow unlimited siting in urban, suburban, and rural areas (EDA 1979).

Battery plants in the 20 to 200 MWh range could be located at substations in the utility subtransmission or distribution network (EDA 1979). Covering an area of 8 kWh/ft^2, a 100-MWh plant can be located on a half-acre site at a utility substation (EDA 1979). "Fuel" requirements for a battery-storage plant could be either electricity from baseload plants or electricity from intermittent generating plants.

6.2.3 Costs

A summary of cost estimates for advanced battery-storage systems is given in Table 6.4. Results are based on a facility with a 10-MW power rating with 5 hours of storage capacity (50 MWh) and a 30-year life. Costs for a facility

TABLE 6.3. Performance of Advanced Electrochemical Storage Batteries (Krauthamer and Frank 1980)

Battery Type	Cycles at 80% DOD[a]	Battery Efficiency at 80% DOD	Throughput Efficiency (Battery + Power Conditioner)	Projected Availability for Order[b]	Probability of Availability
Advanced Lead-Acid	4000	80-85%	70-78%	1985	0.95
Sodium Sulfur (General Electric)	2500	76%	70%	1985	0.95
Sodium Sulfur (Ford)	2500-5000	75%	69%	1985	0.80
Sodium Sulfur (DOW)	3000	90%	83%	1990	0.20
Iron-Chromium Redox (NASA Lewis Research Center)	10000	75%	69%	1990	0.80
Zinc Chloride (Energy Development Associates)	2500-3500	71-74%	65-68%	1985	0.95
Lithium Metal-Iron Sulfide (Argonne)	3000	85%	78%	1990	0.70
Zinc-Bromine (Gould)	2500	70%	65%	1990	0.70
Zinc-Bromine (Exxon)	2500-5000	80%	74%	1990	0.70
Zinc-Bromine (General Electric)	2000	75%	69%	Unknown	Unknown
Hydrogen-Chlorine (Brookhaven National Laboratory)	Unknown	65%	60%	Unknown	Unknown

(a) Depth of discharge.
(b) Quantities of 1000 MWh/yr.

rated at 100 MWh would likely be similar due to the modularity of a battery storage facility. Levelized costs are greatly influenced by initial investment and battery replacement costs.

Estimated capital costs for advanced battery-storage systems that appear most promising for utility application are given in Table 6.4. These costs were computed on the same basis, but they are only tentative estimates. The batteries' actual manufacturing costs, O&M costs, and lifetimes are not well known. In addition, balance-of-plant costs shown are only rough estimates. For example, updated costs for a zinc-chlorine battery system show balance-of-system costs of $175/kWh (EDA 1979) as compared with $30.7/kWh estimated in Table 6.4.

O&M costs were estimated at 19 mills/kWh (EDA 1979), compared with 0.6 mills (1981 dollars) in the source from which the estimates of Table 6.4 are taken (Krauthamer and Frank 1980). EPRI estimates that advanced storage-battery's fixed O&M costs to be 0.3 $/kW/yr and variable O&M costs to be 2.0 mills per kWh (EPRI 1979b). The EPRI estimates, escalated to 1980 and regionally adjusted, are shown in Table 6.4.

Estimated incremental power costs for a variety of advanced storage battery systems for 20, 40, and 80 mill baseload power costs are shown in Table 6.4. Costs will be kept to a minimum by component modularization and by reduction in building requirements, although Alaskan installations most likely will require weather protection. Modules will be factory assembled, which reduces site construction labor and construction time.

6.2.4 Environmental Considerations

Advanced battery facilities are to be designed to have minimum impact on their surroundings. The land area required for a 100-MWh station would be about one-half acre; this could be at an existing substation. Airborne emissions are expected to be minimal and heat releases to the surroundings should be low. An unavoidable short-term impact on air quality, including dust and equipment emissions, plus noise and some solid waste would occur during construction. As discussed previously, the materials used in certain battery designs may present a potential chemical hazard.

TABLE 6.4. Estimated Costs of Advanced Battery Storage Systems, 10-MWe Storage with 5 Hours of Capacity[a]

Battery Type	Battery Efficiency (%)	Number of Replacements Over 30-Year Life	Battery Initial Cost ($/kWh)	Balance of System Cost ($/kWh)	Present Value of Battery Replacement Cost ($/kWh)[c]	Total System Initial Cost ($/kWh)[d]	Battery Replacement Cost ($/kWh)	O&M Cost[e] ($/kW/yr)	Electric Energy Cost[f] (mills/kWh) @ Baseload Energy Costs Shown: 20	40	80
Iron-Chromium Redox (Lewis Research Center)	69	0	74	37	0 (110)	111	(g)	6.0	40	69	130
Zinc-Bromine (Exxon)	74	1	49	37	21 (110)	107	32	6.0	38	65	120
Sodium-Sulfur (Ford)	69	1	66	42	28 (140)	136	43	6.0	43	72	130
Sodium Sulfur (Dow)	90	3	50	39	155 (240)	244	79	6.0	43	65	110
Zinc Chloride (EDA)	74	2	59	40	75 (190)	194	73	6.0	44	71	130

(a) Capital costs, battery efficiency and number of replacements based on Krauthamer and Frank (1980); capital costs are adjusted to Alaska using 1.3 adjustment factor.
(b) 10-MW Storage with 5 hours of capacity (1980 dollars).
(c) Present value at time of commercial operation, discounted at 3%.
(d) Battery initial cost plus balance of system cost plus present value of battery replacement cost.
(e) O&M costs are from EPRI (1979b), escalated to 1980, adjusted to Alaska using a 1.3 adjustment factor and assuming full cycling on a daily basis (equivalent of 21% capacity factor). Plant rating taken at 10 MW for purpose of O&M costing.
(f) Assumes 1990 startup date; 30-year economic life.
(g) A small salvage value was allowed in Krauthamer and Frank (1980); no salvage was assumed for this analysis.

6.2.5 Socioeconomic Effects

The maximum construction work force for a battery-storage facility would be 20 to 40 persons. Factory assembled modules will reduce the work force required for onsite construction. Battery stations will be unattended. Construction of a battery-storage facility of 100 MWh capacity is estimated to require one year (EPRI 1979b). The Alaskan construction season is typically shorter than that estimated by EPRI for lower 48 conditions. However, battery-storage systems would likely be enclosed, allowing construction to be completed during cold seasons. The logical location of a battery plant would be near a load center where peaking power is required. Because a load center would be near an existing population center, the impact of construction would be small.

Most of the money spent on such a project would be for purchase of equipment manufactured outside Alaska. Out-of-state capital spending is estimated to be 85%.

6.2.6 Potential Application to the Railbelt Region

Considerations that govern the application of battery energy-storage systems to the Railbelt include 1) commercial availability of the technology, 2) potential need for energy storage facilities, and 3) the technical characteristics of battery-storage systems.

Utility-scale battery-storage systems are expected to become available for commercial order in the 1988-1992 time period. Given the anticipated one-year construction period, these systems could be available for commercial operation in the period 1989-1993. Thus, any Railbelt application will be in the mid- to long-term.

Circumstances under which development of energy-storage projects might be attractive in the Railbelt region are discussed in Section 6.1.6 of this chapter. These include 1) use of energy storage projects in conjunction with natural-gas-fired combined-cycle baseload plants to meet peak loads, 2) use of energy storage projects in conjunction with coal-fired baseload plants to meet peaks loads, 3) use of energy storage projects to retime output of the proposed Cook Inlet tidal power project, 4) use of energy storage projects in conjunction with dispersed smaller scale intermittent power projects (solar or wind) to provide firm power, and 5) use of energy storage projects to enhance system reliability.

Battery-storage units, when commercially available, will have the advantages of 1) few siting restrictions, 2) modest environmental impacts, 3) modularity in size, and 4) short lead times. The principal disadvantages will likely be few economics of scale with larger plants sizes and high interim capital replacement costs. In view of these characteristics, the most promising future applications of battery-storage systems appear to be in conjunction with dispersed wind or solar generating units to provide firm capacity, and in conjunction with a highly centralized system to enhance system reliability. Technically, storage batteries could provide energy storage for the other potential applications discussed above. However, the plant size required would be substantial, and hydroelectric pumped storage or CAES facilities with their potential for economics of scale with larger plant sizes would be preferred for such applications.

6.3 COMPRESSED AIR ENERGY STORAGE (CAES)

CAES is a relatively new technology for large-scale, centralized storage of electricity. During off-peak hours surplus energy from the utility grid is used to compress air that is cooled and stored underground in an excavated hardrock cavern, a solution-mined salt cavern, or an aquifer. Then, during peak-demand hours, the air is released from the cavern and is expanded in turbines to generate electricity. The primary objective of CAES is to use relatively inexpensive baseload power more effectively and thereby reduce the need for peaking devices fired by expensive oil and natural gas.

After the air is compressed in a CAES plant, it is cooled before it is stored underground. Then, when the air is recovered for power generation it must be reheated to permit efficient expansion in the turbine. Reheating is accomplished by burning fuel oil, as in a conventional gas turbine. The energy contributed by the fuel is significant, and therefore a CAES plant is a net generator of electrical energy as well as a storage device. The ratio of input electrical energy to output electrical energy for an oil-fired CAES plant is about .75.

The first (and only) CAES plant started operation in Huntorf, West Germany in 1978 and has proved to be highly successful, surpassing predictions for reliability and operational flexibility. It is a 290-MW unit that employs two solution-mined salt caverns for air storage.

In the United States, CAES is being investigated by EPRI, DOE, and individual electric utilities. EPRI and DOE have sponsored three preliminary CAES engineering design studies, led by three electric utilities: Middle South Services, Inc. (MSS); Potomac Electric Power Co. (PEPCO); and Public Service Indiana (PSI). These studies addressed design, economic, environmental, safety, and siting considerations. Each focused on one storage medium: MSS on salt, PEPCO on hardrock, and PSI on aquifers. In general, the results of these studies indicate that CAES would be cost effective and would reduce system consumption of petroleum fuels. The decision to build a CAES plant is still pending for these utilities.

6.3.1 Technical Characteristics

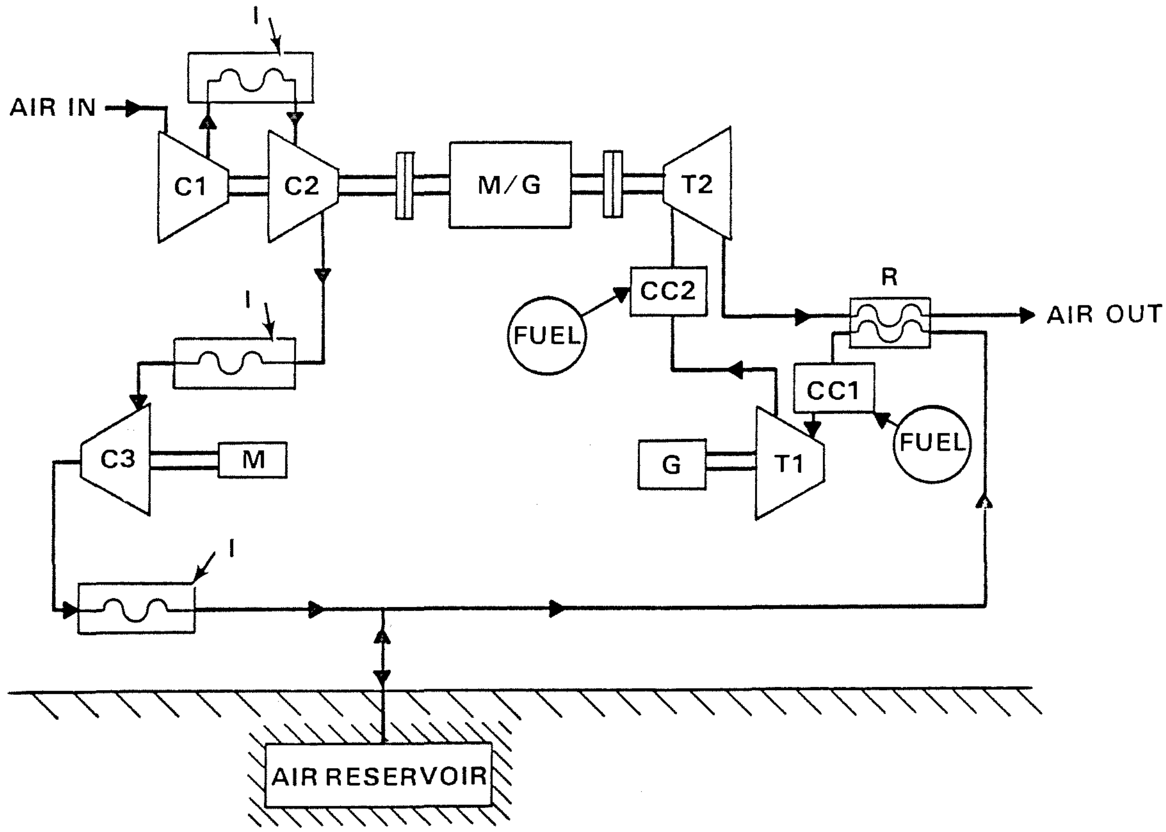
The major components of a CAES plant are the turbomachinery and the air storage reservoir. The turbomachinery consists of a large-volume, high-temperature compressor train coupled to a reversible motor/generator through a clutch assembly. The motor/generator in turn, is coupled to a high-volume turbine train through another clutch assembly. The motor/generator powers the compressor during the charging cycle and generates electricity during the recovery cycle. A CAES turbomachinery schematic that is standard for most CAES designs is depicted in Figure 6.3. However, for the air storage reservoir and for the air reheat equipment several options exist that radically affect the construction and operation of the CAES plant. Plant sizes are expected to range from 200 to 1000 MW.

Design Features

Three major storage options exist: hard-rock-mined caverns, solution-mined salt domes, and aquifers. Each has advantages and disadvantages.

Salt domes are the least expensive to develop. The solution-mining technique entails drilling a well into a salt dome and continuously pumping in fresh water. Over a period of time the salt dissolves. (The two Huntorf caverns took 12 and 16 months to mine.) While water is being pumped in, the resultant brine is pumped to the surface for disposal. An advantage of salt is that contact with the water during the solution-mining process heals small fissures and helps to prevent air leakage.

Salt also has disadvantages. One is the tendency to flow, or creep, when exposed to high pressures over a period of time. The tendency is accelerated by elevated temperatures and could cause a gradual reduction in cavern volume. Salt creep is not entirely destructive, however, because it tends to heal cavern fissures. Another potential drawback of these reservoirs is salt carryover to the plant's turbines, where it could result in system corrosion. The Huntorf system is designed so that air velocities near cavern walls are never high enough to carry brine droplets up into the turbines.



Key:	C - Compressor	R - Regenerative Heat Exchanger
	I - Intercoder	CC - Combustor
	T - Turbine	T - Gas Turbine
	M - Motor	M/G - Motor/Generator

FIGURE 6.3. Schematic for the Turbomachinery in a Conventional CAES Plant

The advantages of hard rock as a compressed-air storage medium include the widespread availability of potential sites and a well-established excavation technology. The major problem is the difficulty of knowing before excavation whether the deep rock is suitable for caverns. Rock may be highly fractured, requiring expensive shoring or site abandonment. Fissures in the rock could also permit air to escape, and grouting the entire cavern may be required. (Natural caverns are generally not considered for compressed-air storage because of the difficulty of exploring, reinforcing, and sealing them properly.) A hard-rock reservoir is more expensive to develop than a salt cavern; mining is labor and equipment intensive, and large, expensive shafts are required for excavation.

Sand, gravel, or sandstone aquifers, as with rock beds, are widely available in the United States and can be developed into compressed air reservoirs without excavation. A series of wells is drilled into the aquifer, and air is slowly injected, forcing the groundwater away from the well casing. During air discharge, water pressure drives the air out of the well. High porosity and permeability are necessary for rapid charging and discharging of the CAES system through a reasonable number of wells. The aquifer must also have an impermeable, dome-shaped caprock to prevent air from migrating upward and escaping laterally.

The aquifer storage medium is not yet proven. Natural gas is commonly stored in aquifers, but these aquifers are not subject to the daily cycling that would be experienced with a CAES plant. Weakening of the aquifer matrix may be a problem with CAES cycling and elevated temperatures. Aquifer plugging may also prove to be a difficult problem with extended use.

The turbines generate electricity most efficiently when the incoming air is maintained within a small range of pressures. Therefore, the air in the cavern should be maintained at a constant pressure rather than at a constant volume. In a hard-rock system, constant pressure is achieved by use of a surface water reservoir connected to the bottom of the air storage cavern through a J-tube (see Figure 6.4). The water column over the compressed air is maintained at a constant height, exerting a constant pressure on the compressed air. The compensating reservoir is unsuited to a salt cavern because of dissolution problems. The reservoir is unnecessary for an aquifer storage system because the displaced groundwater in the aquifer fulfills the same purpose.

A conventional CAES plant reheats the air in an oil combustion unit before it is expanded in the turbine. Advanced CAES configurations that would eliminate this dependence upon petroleum fuels have been investigated. One particularly promising technology is thermal energy storage. The heat of compression is stored (rather than discarded in cooling towers) and recaptured by the compressed air before expansion in the turbine. The heat recaptured then reduces or entirely eliminates dependence upon fuels. The CAES plant is no longer a net generator in this latter case, with an electrical input-to-output ratio of about 1.5:1.0.

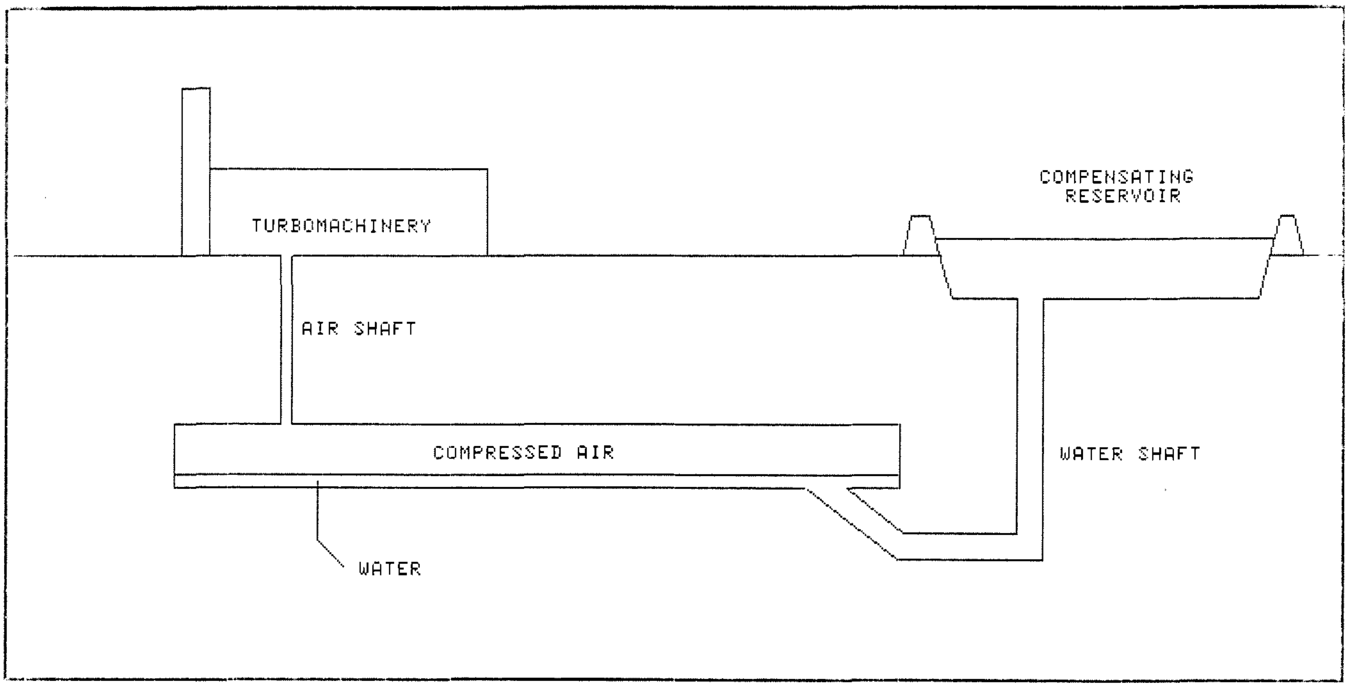


FIGURE 6.4. Component Plan for a Hard-Rock CAES Plant

Coal combustion technologies are also under investigation as an alternative to oil firing. However, coal gasification or pressurized fluidized bed combustors would be required, and these technologies are not yet ready for commercialization.

Performance Characteristics

The electrical input/output ratio of a conventional (reheat) CAES plant is about .75:1.0. The reheat heat rate is generally about 4000 Btu (of reheat fuel) per kWh out. CAES plants using regenerative heating arrangements are expected to have an electrical input/output ratio of about 1.5:1.0. The equivalent annual availability of CAES plants is estimated to be approximatly 90% (EPRI 1979b). A 30-year plant life is anticipated.

6.3.2 Siting and Fuel Requirements

Siting a CAES plant is a major task, with most of the effort expended in the search for a suitable geologic structure. Hard-rock masses, salt domes, and aquifers are abundant, but many geologic structures may be unsuited to compressed air storage. Extensive literature searches and field investigations are necessary to identify and confirm prime sites. Construction of a CAES plant in an unfavorable geologic setting can result in stability or leakage problems, which are costly to correct. Availability of water, land, transmission lines and transportation access are also important factors in the site selection process. The CAES plant can be located anywhere on a transmission line and need not be close to the generation source nor the load centers.

The surface portion of a CAES plant is similar to that of more conventional power plants, and the same topographic requirements exist. In addition, a hard-rock CAES plant will require about 30 acres for a pressure-compensating reservoir. An aquifer CAES plant will require many interconnected wells, and the topography must be suited to the economic construction of a complex piping system. A salt cavern CAES has no specialized surface requirements.

Water will be required for several purposes, including construction, sanitary needs, cooling, and pressure compensation (hard-rock plant only). Where feasible, a CAES plant will generally employ wet cooling for cooling the compressed air (before storage) and the turbomachinery. Water will also be required for solution mining of the cavity in a salt cavern CAES plant.

Transportation access (road, rail, or water) will be required during construction, and during operation for fuel delivery.

6.3.3 Costs

Capital investment costs for CAES plants are site specific and depend upon plant size, reheat technology, and the type of storage medium employed. Significant economies of scale can be realized by increasing plant size from 200 MW (generally the smallest plant considered) to 1000 MW. Only minimal scale advantages are foreseen for larger plants.

The cost of the aboveground equipment is highly dependent upon the technology selected for reheating the air. Oil- or gas-fired units are the least expensive. Other technologies, such as thermal energy storage and coal combustion, will have considerably higher construction cost, but may result in a lower busbar cost of power.

The cost of the air storage facility will depend upon the type of storage facility developed and the storage duration required. In general, a hard-rock cavern is more expensive than a salt cavern, and aquifer storage lies somewhere in between. Designs typically call for 8 to 11 hours of storage at full plant output. However, weekly storage cycle may be selected, which would require 20 to 30 hours of storage, and correspondingly higher capital cost.

No CAES plants have been constructed in the United States, so actual U.S. construction costs are not available. The PEPCO plant (924 MW, hard-rock cavern) has been estimated to cost about $550/kW in 1981 dollars. O&M costs are expected to be about $8.50/kW/year (at a 20% capacity factor).

Adjusting these estimates to 1980 dollars and Alaskan conditions gives the cost provided in Table 6.5.

TABLE 6.5. Estimated Costs of a Hard Rock CAES Plant (1980 dollars)

Rated Capacity (MW)	Capital ($/kW)	O&M ($/kW/yr)[a]	Electric Energy Cost (mills/kWh @ baseload energy costs shown)[b,c]		
			20	40	80
924	690	10.70	54	67	94

(a) At 21% capacity factor.
(b) Assuming 1990 startup date; 30-year economic life; Cook Inlet Natural Gas; incremental costs with 20 mill, 40 mill and 80 mill baseload power are shown.
(c) Based on the use of Cook Inlet natural gas for reheat (Appendix B).

6.3.4 Environmental Considerations

The environmental impacts of a CAES plant depend upon the type of storage medium employed. The most serious impacts may result from the construction activities.

For a salt plant, the principal environmental impact and also the most likely area of regulatory concern is with the disposal of the brine resulting from the solution-mining operation. Each cubic meter of cavern will result in 7 to 10 cubic meters of brine. Brine disposal options include underground injection, ocean disposal, and ponding/evaporation. Underground injection generally is the most environmentally benign and the least expensive option.

Construction of a mined, hard-rock cavern poses the problem of disposal and long-term care of the rubble excavated from the cavern. The amount of material is significant; a 1000-MW plant would produce waste rock covering 40 acres to a depth of 17 feet. A continuing environmental problem of the surface wastes most likely will be control of sediment in runoff. A sedimentation pond may be required.

During operation, the major environmental impact would be air pollution from the combustion of natural gas or oil for reheating the compressed air before power generation. The impact should be similar to a gas turbine, but on a lesser scale, since fuel consumption per unit of power output is about one third that for a peaking oil-fired combustion turbine. Oil handling and storage, although commonplace activities, also pose some threat to the environment.

Alteration of groundwater quality is a potential environmental problem. Aquifer CAES systems pose the greatest danger, but air escaping from hard-rock or salt CAES storage caverns can potentially affect groundwater quality. Contaminants can be released from the rock matrix through the introduction of oxygen and carbon dioxide or heat of compression. In aquifer systems, improper casing or inadequate chlorination can pollute groundwater through the introduction of micro-organisms. These potential effects are site specific and can be minimized by proper site selection and design.

Impacts on wildlife habitat would be limited to the actual plant area, and the vicinity. The turbomachinery is noisy, but any adverse impact can be minimized by site selection and enclosure design. If the plant is located in a remote area, increased traffic and dwellings could have a significant impact on the terrestrial environment.

6.3.5 Socioeconomic Considerations

Construction of a large CAES plant is labor intensive, entailing from 150 to 300 men over a five-year period (depending upon the air-storage medium and stage of construction). Subsequent operation of the plant is not labor intensive and would involve only a few men. (The Huntorf plant is operated on an unmanned basis.) The large differential in size of construction and operating crews may cause a boom/bust cycle in remote areas. A small plant would have only minor socioeconomic impact near Anchorage, but decidedly greater impact on intermediate and smaller sized communities.

A 1000-MW plant would affect all locations of the Railbelt with the exception of Anchorage, and possibly Fairbanks. Construction camps would not relieve the impacts to remote areas since the construction period (5 to 6 years) is long enough to create semipermanent settlement by the work force dependents and secondary inmigrants.

An estimated 55% of the project expenditures would flow out of the region and 45% would remain within the Railbelt.

6.3.6 Potential Application to the Railbelt Region

The key requirement for CAES is an adequate supply of low-cost, excess baseload capacity that can be stored for peaking and intermediate load generation. The outlook for CAES is good for many parts of the United States with excess baseload capacity in a well-integrated system, and distinct peaking power requirements. Presently, the Railbelt region does not have a suitable baseload generating capacity to warrant consideration of CAES.

Several circumstances under which use of energy storage systems may become feasible in the Railbelt region have been described in Section 6.1.6. CAES could potentially provide energy storage capability for the first four circumstances discussed (although storage would be central, not dispersed for application in conjunction with dispersed wind, or solar units and therefore would require a well-integrated transmission network). CAES would be less suitable for providing dispensed system backup capacity. Key considerations influencing the selection of CAES over competing energy-storage options include 1) economics, 2) lack of suitable sites for pumped hydroelectric storage and 3) availability of liquid or gas fuels for supplemental firing of CAES combustion turbines. Development of a CAES facility depends upon the availability of suitable geology.

6.4 <u>OTHER ENERGY STORAGE TECHNOLOGIES</u>

Several energy storage technologies have been conceptualized, and recently, many of these have been the object of significant research and development efforts. Those energy storage technologies that are currently commercially available or show promise of near-term commercial application have been discussed in the preceding section. Other, less developed storage technologies include the following:

<u>Hydrogen</u> - Hydrogen can be produced by using off-peak electricity from base-load plants to electrolyze or to decompose water. This hydrogen would be stored and subsequently reconverted to electricity in a fuel cell or burned in a gas turbine. Significant development is still required to improve the cost and efficiency of hydrogen storage.

<u>Flywheels</u> - Electric energy can be converted into rotational energy stored by a flywheel. This stored energy would then be used to generate electricity during the peak demand hours. This method presently has limitations in its energy storage capacity and efficiency, which preclude it from being economically competitive.

<u>Magnetic Energy Storage</u> - Some conceptual designs have been developed for magnetic storage units capable of storing the entire 10 hour output of a 1000-MW thermal plant. However, most of the work done in this area is exploratory and conceptual. The main engineering problem foreseen in this area is the design of superstructures capable of containing the mechanical forces generated by the large magnetic fields. Also, this type of system is expected to be economical only in large sizes.

7.0 FUEL-SAVER TECHNOLOGIES

"Fuel-Saver" technologies supply energy to the power grid but typically cannot be assigned capacity credit because of the intermittent or cyclic availability of the energy source. Candidate fuel-saver technologies for potential Railbelt application include the following:

- cogeneration[a]
- tidal power projects
- large wind energy conversion systems
- small wind energy conversion systems
- solar photovoltaic systems
- solar thermal-electric plants
- small-scale hydroelectric and microhydroelectric plants.

Capacity credit can be assigned to these technologies if energy storage devices are provided, or, in some instances, if the level of penetration permits assignment of capacity credit on the basis of statistical analysis of energy availability.

A comparison of selected characteristics of the fuel-saver technologies discussed in this chapter is provided in Table 7.1.

TABLE 7.1. Comparison of Fuel-Saver Technologies on Selected Characteristics

	Cogeneration (20-MW, Natural Gas Steam Cycle)[a]	Tidal[b]	Large Wind Energy Conversion Systems (10-2.5 MW Machines)	Small Wind Energy Conversion Systems (0.01-MW Stand-Alone Unit)	Solar Photovoltaic (10-MW Station)	Solar Thermal (10 MW)	Small-Scale Hydroelectric Project (15 MW)
Aesthetic Intrusiveness							
Visual	Minor to Moderate	Moderate to Significant	Significant	Moderate	Significant	Significant	Moderate
Noise	Minor	Minor	Minor to Moderate	Minor	Minor	Minor	Minor
Odor	Minor to Significant[c]	Minor	None	None	Minor	Minor	None
Impacts on Biota							
Gross Water Use (gpm)	180	Site-Specific	0	0	0	150	Bulk of streamflow passed through turbine.
Land Use[d] (acres)	8	Site-Specific	1225	1/4	50	200	
Cost of Energy							
Capital ($/kW)	850	2800-3600	1500	2000	11,000[d]	1500	Site specific, 10's to 100's.
O&M ($/kW/yr)	25	50-70	13-22	20	30-40[d]	40	800-20,000
Cost of Energy (mills/kWh)	34 (typical)	50-80	54-72	46-91	620[d]	91	16-400 10-260
Public Health & Safety	Safe. Possible long-term air quality degradation.	Safe	Safe	Safe	Safe	Safe	Safe
Consumer Effort	Typically consumer operated maybe by a	Utility operated.	Utility or community operated.	Community or consumer operated.	Various size installations could range from consumer-operated rooftop arrays to utility-operated control systems.	Utility operated.	Utility, community or consumer operated.
Adaptability to Growth							
Unit Sizes Available (MW)	25-100	46-25,100	0.1-2.5	0.0001-0.037	<0.001-10	10-100	<0.1-15
Construction Lead Time (years)	1-3	7	3	1-2	1-2	5	2-4
Availability of Sites	Oil Refineries Military Bases Institutions Large Buildings	16 potential, 3 preferred sites in Cook Inlet.	Limited to few mountain and coastal sites having favorable wind reso··	Sites limited to acres of favorable wind resources.	Wide availability of potential sites. No specific sites identified.	No specific sites identified.	Sites limited to streams having favorable discharge, topography and geology.
Reliability							
Availability	85%	40%	87%	Not available.	40%	40%	Not available.

TABLE 7.1. (Contd)

	Cogeneration (20-MW, Natural Gas Steam Cycle)[a]	Tidal[b]	Large Wind Energy Conversion Systems (10-2.5 MW Machines)	Small Wind Energy Conversion Systems (0.01-MW Stand-Alone Unit)	Solar Photovoltaic (10-MW Station)	Solar Thermal (10 MW)	Small-Scale Hydroelectric Project (15 MW)
Expenditures Within Alaska							
Capital	33%	67%	20%	Not available.	19%	19%	40%
O&M	83%	89%	85%	Not available.	81%	81%	90%
Fuel	100%	-	-	--	--	--	--
Boom/Bust Effects							
Construction Personnel	30	300	12	4	100	60	20
Operating Personnel	15	30	0	0	10	25	4
Ratio	2:1	10:1	-	--	10:1	2.5:1	5:1
Magnitude of Impacts	Minor to moderate in all locations.	Minor in vicinity of Anchorage. Significant to severe in all other locations.	Minor to moderate in all locations.	Minor in all locations.	Utility-scale installations: Minor in vicinity of Anchorage & Fairbanks; moderate to severe in all other locations. Dispersed installations: minor.	Utility-scale installations: minor in vicinity of Anchorage & Fairbanks; moderate to severe in all other locations.	Minor in all locations except smallest communities.
Consumer Control	Consumer Controlled.	Control through regulatory agencies.	Control through regulatory agencies.	Customer controlled.	Range of possible ownership-utility to individual.	Regulatory agencies.	Control through regulatory agencies for utility-operated facilities. Community or customer control for municipal or individually owned plants.
Technology Development	Commercially available.	Commercially available but not mature.	Commerical demonstration stage.	Commercially available.	Commercially available but not fully mature.	Research and developmental stage.	Commercially available.
Railbelt Experience	Widespread district heating applications.	None	Limited (two small wind farms).	Limited (two small wind farms plus scattered individual installations).	No utility-scale installations.	None.	Limited (one small-scale hydro facility).

(a) Cogeneration is treated as a fuel saver because operation of a cogeneration facility depends upon the operation of the associated industrial plant or district heating facility.
(b) Attributes generally do not depend on size.
(c) If municipal waste is used as fuel.
(d) 1980 technology.

7.1 COGENERATION

Cogeneration is the simultaneous production of electricity and useful heat. The heat can be distributed as steam or hot water to commercial and residential users in district heating systems or can be used for industrial process heating applications. Opportunities for cogeneration occur when large, stable demands for heat and electricity occur simultaneously. Typically, the demand for heat becomes the driving variable. Cogeneration opportunities exist only with industrial or commercial development. Cogeneration capacity can be expanded simultaneously with increases in industrial capacity. A major barrier to the development of cogeneration was removed with the passage of the Public Utility Regulatory Policies Act of 1978. The Act essentially allows industries and other nonutility generators to sell power to a utility at a fair market value.

Cogeneration systems generally range from 25 to 100 MW, although high electricity costs prevail in locations where the 5 to 25 MW range is becoming economical. Cogeneration systems are generally smaller than condensing steam-electric power plants because of their tie to manufacturing facilities, although systems in the 100 to 400 MW range have been designed and built for large manufacturing complexes.

7.1.1 Technical Characteristics

Cogeneration facilities are classified as those using "topping" cycles and those using "bottoming" cogeneration cycles. Both exist commercially, although the topping cycles predominate. Topping cycles capture available energy at temperatures above those required for process or space heat applications and are used at installations whose primary purpose is to produce low-quality heat for process or space heating applications. Three topping cycles are available: 1) steam turbine topping, 2) combustion turbine topping, and 3) diesel generator topping. Cycle selection is usually determined by relative power and steam demand, fuel availability and cost, and process heat system design. Bottoming cycles are used to capture otherwise rejected low-level heat and to convert this heat into electric power. Bottoming cycles can use waste heat from high-temperature process heating systems or waste heat rejected from thermal generating plants. Bottoming cycles generally use large, low-pressure condensing turbines.

Cogeneration systems exhibit high thermodynamic efficiencies in comparison to condensing power cycles. Heat rates in cogeneration typically range from 4,200 to 6,500 Btu/kWh. Comparable heat rates for condensing power plants are typically 9,000 to 11,000 Btu/kWh. The higher efficiencies result from the ability to capture heat otherwise rejected. The high efficiencies of cogeneration systems, other than diesel, depend upon operating at full loads. Turbines are quite inefficient when operated at less than 70 to 80% of capacity.

Steam Turbine Topping Cycle

In the steam turbine topping cycle, as depicted in Figure 7.1, high-pressure/high-temperature steam is raised in the boiler, is passed through a noncondensing turbine, and is exhausted at or near process conditions to the process steam header. The exhaust steam is then used for process purposes. Power production comes from the differences in energy content of the steam between turbine inlet (throttle) and exhaust. As throttle pressure is increased and exhaust pressure is decreased, the power generation/steam production ratio is increased.

System capacity is generally determined by manufacturing or space heating steam needs. Manufacturers with requirements for only one steam quality[a] use simple, back-pressure turbines. Where more than one type of steam is needed, multiple-point, automatic extraction turbines are used.

The overall efficiency of electrical cogeneration is determined by boiler efficiency plus turbine-generator heat rates. For example, a typical small-scale, wood-fired cogeneration system as used in a sawmill has a heat rate of 6000 Btu/kWh and an overall efficiency of 65%. A comparable coal-fired unit would have a heat rate of 4200 to 4500 Btu/kWh, and an overall efficiency of about 85%.

(a) Steam quality refers to the pressure and temperature characteristics of a given steam supply.

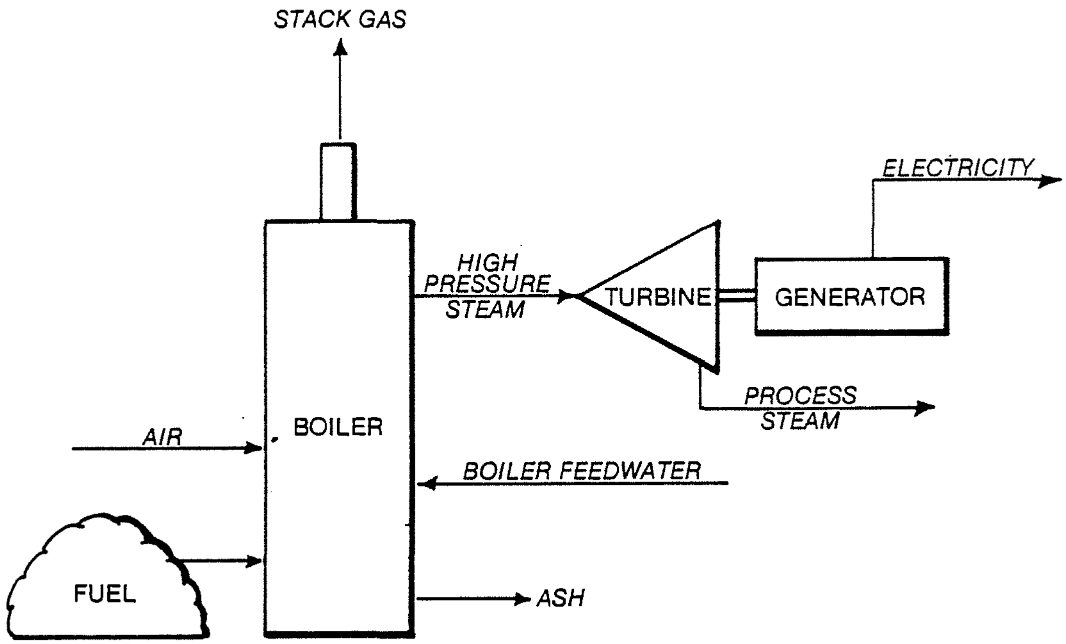


FIGURE 7.1. Simplified Schematic of Steam Turbine Topping Cycle

The primary advantage of the steam cycle is its ability to use virtually any fuel directly. Solid fuels such as coal, peat, biomass, and organics can be employed as well as liquid and gaseous hydrocarbons. A second advantage is the manufacturing community's familiarity with boilers and their operation. This cycle is employed at the University of Alaska.

Combustion Turbine Topping Cycle

Combustion turbine topping cycles, as shown in Figure 7.2, integrate a combustion turbine and a heat recovery boiler to simultaneously produce electricity and steam. Combustion turbine topping cycles may also be used to produce warm process air, such as for drying operations, by passing the turbine exhaust through an air/air heat exchanger.

Combustion turbine technology is described in Section 5.1. The second major component of the system is the heat recovery boiler. These components are typically finned watertube boilers accepting turbine exhaust gases at about 900°F and exhausting them at 350-450°F, depending on the quantity of SO_2 in the exhaust stream. An economizer for feedwater heating is typically added to remove additional heat from the stack gas (Figure 7.2).

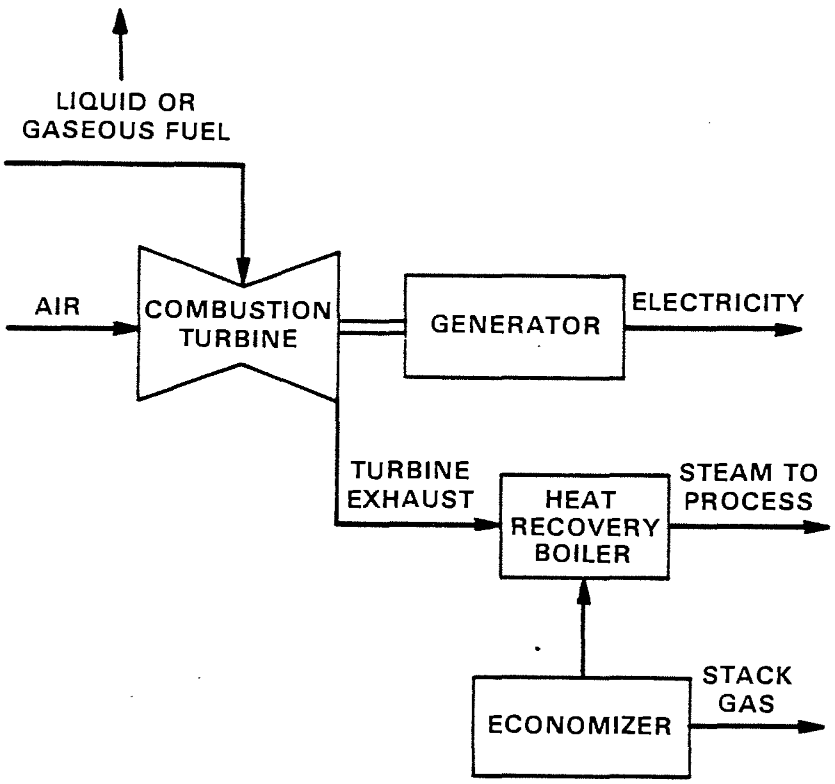


FIGURE 7.2. Simplified Schematic of Combustion Turbine Topping Cycle Producing Process Steam

The primary advantage of a combustion turbine cycle is the high electrical power/steam ratio. The power/steam ratio for combustion turbines may be up to four times that of steam topping cycle turbines. It is also less costly because of the possibility for constructing boilers without expensive feedwater treatment systems, pressure parts, and extensive superheaters. The overall efficiency of combustion turbine topping cycles also is about the same as that of steam turbine topping cycles. Typical heat rates (i.e., that portion of the heat rate used to produce electric power) range from 5000 to 6000 Btu/kWh.

A potential drawback of combustion turbine topping cycles is the petroleum-based or natural gas fuel requirements of combustion turbines. Natural gas and distillate oil are the preferred fuels, although heavier oils have been used, and such synthetic fuels as medium Btu gas (e.g., 350 Btu/ft^3) and methanol have been proposed. However, solid fuels such as coal, peat, biomass, and municipal waste cannot be used unless gasified. The gas produced from solid fuels must be upgraded to optimize the power cycle. Development of low Btu gas turbines is proceeding, however, to take advantage of low Btu synthesis gas.

Diesel Generator Topping Cycle

Diesel topping cycles are similar to combustion turbine topping cycles. Diesel generator sets are used to generate electricity with exhaust gases being used to raise steam or to produce hot water in waste heat boilers. Diesel generator topping cycles may be used in institutional and high-density residential installations ("total energy systems") where the electricity is used for the house load with surplus sold to the utility and the stream or hot water is used for space heating. These cycles also may be appropriate for smaller manufacturing establishments such as seafood processing plants.

Diesel generation, which has been described in Section 5.3, has three potential advantages over combustion turbine-based systems: 1) the higher power/steam ratios, typically twice those of combustion turbines; 2) the ability to be used at small (e.g., <1 MW) scale; and 3) the ability to operate efficiently on partial loads. These advantages may be particularly significant in smaller communities within the Railbelt particularly those communities amenable to a hot water district heating system.

Diesel generation requires the premium gaseous fuels or oil required by combustion turbine systems. Low Btu synthesis gas from coal and biomass has been used successfully in diesel equipment; however, this use results in substantial derating of the equipment.

Bottoming Cycles

Currently available bottoming cycle technology converts reject steam into electricity by using large, specially designed condensing turbines that can handle saturated steam. The cogeneration concept is illustrated in Figure 7.3. Water rates[a] for these turbines are high. For example, a

(a) Water rate refers to the amount of water required to be circulated through the turbine (as steam) to produce a given amount of electrical energy.

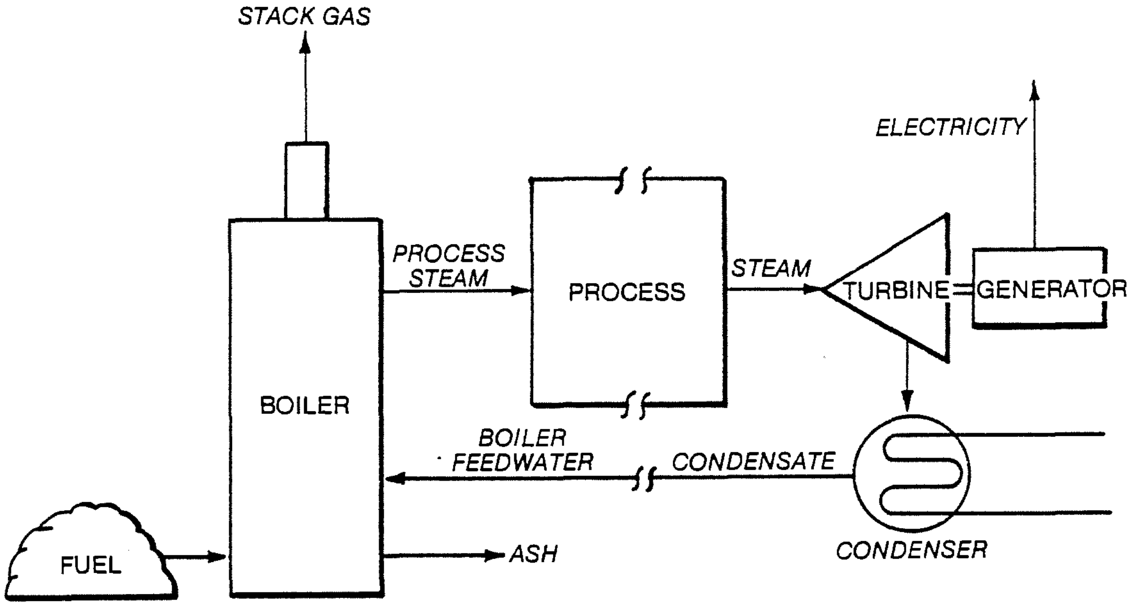


FIGURE 7.3. Simplified Schematic of a Bottoming Cycle

turbine accepting 65 psig steam and condensing at 3 inches of mercury has a water rate of approximately 25 pounds of steam per kWh. With a lower vacuum, water rates increase.

Performance Characteristics

The electrical heat rates of cogeneration installation depends upon the basic combustion technology used and the quality of steam or hot water drawn off for process or district heating use. Typical heat rates are discussed under the specific cogeneration technology headings above.

Cogeneration plant availability is similar to the availability of the combustion technology upon which it is based. Actual capacity factors, however, are frequently dependent upon the demand for process or district heating energy.

Plant lifetimes are similar to those of the basic combustion technology; however, shorter lifetimes could be anticipated for retrofit of an existing, older manufacturing facility.

7.1.2 Siting and Fuel Requirements

All cogeneration systems must be located at or near steam or process heat users. Typically, the cogeneration system will be located on the manufacturer's premises, although some have been located up to 1 mile away. Systems producing heat for district heating must be located close to heating loads, although hot water generally can be transported over longer distances than steam. Since cogeneration systems are usually located at or near manufacturing or high-density, commercial-residential heat loads, they are also located near electrical load centers. Proximity to fuel sources is not required unless the fuel can not readily transported over long distances, which would apply more to biomass fuels than to fossil fuels.

Fuel requirements for cogeneration systems are determined largely by cycle type, as discussed in Section 7.1.1. Steam turbine topping and bottoming cycles can be fueled by virtually any combustible energy source. Combustion turbine and diesel topping cycles, however, require premium liquid or gaseous fuels (e.g., distillate oil, methanol, natural gas).

Quantities of fuel required for electricity generation are determined by the heat rate (Btu/kWh) for given plants. Heat rates are determined by several site-specific variables. Typical values for cogeneration facilities are normally in the 4500 to 6500 Btu/kWh range depending on cycle, power/steam ratio, process steam conditions, and other parameters.

7.1.3 Costs

Cogeneration project costs are site specific. Costs vary substantially as a function of manufacturing requirement, the cycle employed, and conditions at the site. Representative capital costs for a range of sizes are shown in Table 7.2.

O&M costs depend on cycle, capacity, and degree of system complexity. An additional variable is the availability, at the site, of operators having the necessary operation and maintenance skills. For example, at refineries maintenance can be accomplished by existing plant crews. For many applications, however, a special maintenance crew must be hired. Labor and maintenance costs are somewhat higher for steam turbine systems than for combustion

TABLE 7.2. Representative Capital Costs for Selected Cogeneration Cycles (1980 dollars)

Rated Capacity (MW)	Steam Turbine Topping Cycle[(a)] ($/kW)	Combustion Turbine Topping Cycle ($/kW)	Diesel Generator Topping Cycle ($/kW)
3	1,470	760	800
5	1,180	-	-
10	850	-	-
20	850	550	-
75	-	400	-

(a) Assumes natural gas-fired boiler.

turbine systems, primarily because of the complex water circuit. However, if synthetic fuel systems (e.g., low Btu gasifiers) are tied to combustion turbines, this differential may disappear. Representative values for O&M costs would be about $25.00/kW/yr. Estimated costs for a typical, natural-gas-fired, steam turbine topping cycle are provided in Table 7.3.

Despite the complexities and costs of cogeneration, the price of power from such systems is generally lower than that of condensing power stations. The power price is lower mainly because cogeneration is more efficient in the generation of electricity, and thus the quantity of fuel consumed/kWh is less. Much of the capital investment can be charged against the process steam production, and the power generation cycle can be treated as an incremental investment; therefore, many of the operating costs can be treated in incremental fashion. Cogenerated power costs are generally less sensitive to rising fuel prices than condensing power cycles because of the highly favorable heat rates associated with cogeneration systems.

7.1.4 Environmental Considerations

Conversion of an existing industrial facility to cogeneration would generally produce minimal incremental impacts on an area's water resources because most makeup water requirements, effluent discharges, and appropriate treatment facilities would be accounted for in the existing facility.

TABLE 7.3. Estimated Costs of a Representative, Natural Gas-Fired Steam Turbine Topping Cogeneration Cycle

Rated Capacity (MW)	Capital[a] ($/kW)	O&M[a] ($/kW)	Cost of Electric Energy[b] (mills/kWh)
20	850	25	34

(a) Incremental costs for electric plant equipment.
(b) Levelized lifetime cost, assuming 1990 first year of commercial operation. 65% capacity factor, Cook Inlet natural gas (prices given in Appendix B).

With a steam topping cycle, a small increase in boiler feedwater and boiler blowdown requirements could be expected. In addition, a slight increase in ash handling requirements could possibly add to water requirements, depending upon the ash handling system design. However, a slight decrease in overall plant-makeup water requirements could result because of increased condensate recovery.

A bottoming cycle will increase the steam requirement as much as three to four times per kWh compared to a conventional condensing plant. Cooling water requirements would increase correspondingly. Boiler feedwater and blowdown would remain essentially unchanged from the original facility.

Potentially adverse water resource impacts of constructing and operating a cogeneration facility are generally minimized through appropriate plant siting and water, wastewater, and solid waste management programs (refer to Appendix D). Water resource impacts that are difficult to mitigate are not anticipated with the development of cogeneration facilities, especially in light of small power plant capacities that are considered.

Any of several possible atmospheric impacts may be associated with the development of cogeneration facilites. These impacts occur because many different fuels, processing systems, facility sizes, and combustion techniques may be used. For existing facilities, the incremental air-quality impacts resulting from cogeneration systems are probably negligible unless a great deal of additional fuel is consumed. These systems use heat or power that has already been generated for other purposes, and they extract a portion of the available energy for electric power generation. Cogeneration typically may be characterized as having a very low atmospheric impact when compared to other combustion systems.

New cogeneration facilities will require an extensive review of air-quality impacts, especially for the larger (>25 MW), more economically viable systems. Emissions from coal and biomass combustion facilities will be greater than those of oil and gas combustion facilities. Incremental impacts attributable to electricity production may be considered minimal because the emissions basically are associated with the industrial process or system to which the cogeneration facility is attached.

Converting an existing steam production facility to a cogeneration system is not expected to result in significant incremental impacts on aquatic or marine ecosystems. Additional water requirements are minimal. Moreover, steam bottoming cycles reduce waste heat rejection to the aquatic environment compared with noncogeneration facilities. The aquatic ecosystem impacts of constructing and operating a complete cogeneration facility would depend upon fuel and process type and would be similar to those experienced with comparable, steam-cycle facilities (refer to Appendix F).

Incremental terrestrial ecosystem impacts associated with adding electrical generating facilities to an existing steam plant will be minimal. Generally, few additional acres are required. Although slightly greater amounts of air pollutants may be produced when compared with the processing plant alone, impacts on the terrestrial biota should generally be negligible. Impacts of constructing and operating a complete cogeneration facility would depend upon fuel and process type, but would be similar to those experienced with comparable, steam-cycle facilties (refer to Appendix G).

7.1.5 Socioeconomic Considerations

Several potential sites for cogeneration have been identified in the Railbelt. The refineries located in Kenai and Fairbanks are prime potential sites for cogeneration as well as the proposed refinery at Valdez. Other potential sites are located primarily in Anchorage and Fairbanks and includes industries, military installations, universities, hospitals, and large apartment complexes.

The size of the construction work force will vary from 25 to 250, depending on plant scale. Assuming that a maximum plant size of 100 MW requires a labor force of 250, the impacts of construction should be minor in the Anchorage area and moderate in the Fairbanks area. Although both Valdez and Kenai have experienced the influx of large work forces from the construction of a pipeline terminus and oil refineries, both communities have relatively small populations (3173 and 4326, respectively). A boom/bust cycle can be avoided in these communities by installing construction camps.

Capital expenditures of a cogeneration facility would flow primarily out of Alaska because of the amount of equipment compared to the moderate-sized work force and relatively short construction time. The estimated percentage breakdown of project investment is approximately 67% outside of Alaska and 33% within the state. Due to the relatively large outside maintenance requirements, 17% of the O&M expenditures would be spent outside the Railbelt.

7.1.6 Potential Application in the Railbelt Region

Significant potential exists in the Railbelt for cogeneration. The two oil refineries on the Kenai Peninsula, the refinery outside Fairbanks and the proposed Alpetco refinery at Valdez (Figure 7.4), have the most potential for cogeneration in the Railbelt region. Generally, oil refineries have a potential for producing 11-12 kWh/bbl; of that, 50 to 67% would be in excess of the producing facilities' needs and available for transfer to the utility grid (Gyftopoulos, Lazaridis, and Widner 1974). Current production capacity has a potential for developing approximately 50 MW at existing refineries. About 210 million kWh/yr of saleable energy could be produced assuming that adequate demand for power exists and the refineries operate at an annual load factor of 80%. The proposed Alpetco refinery had the potential to generate approximately 300 million kWh/yr. In the Railbelt region other petroleum- related activities with cogeneration potential include oil pipeline pumping stations, natural gas pipeline pumping stations, and natural gas liquefaction (LNG) facilities, if such plants are developed.

Outside the petroleum industry, manufacturing focuses on lumber and fish processing. The 51 lumber mills in the region are small (e.g., 1000 board ft/day) and are well below the scale required for cogeneration. The fish processing industry has little potential for cogeneration (Resource Planning Associates 1977), although some cogeneration may be occurring in these industries (U.S. Bureau of Census 1978).

Industry in the Railbelt currently generates 414 million kWh/yr and military installations generate 334 million kWh/yr. This generation represents a combination of self-generated power and cogeneration. The University of Alaska, for example, generates 22 million kWh/yr using a steam topping cycle system. The combined 748 million kWh of self-generation represents 24% of the total 3,140 million kWh generated in the Railbelt region in 1980. Hospitals, large apartment complexes, and other institutions in Anchorage, Fairbanks, and Valdez provide potential for central space heating systems fired by cogeneration (total energy systems).

7.2 TIDAL POWER

Tides are caused by gravitational attraction of the moon and sun. Both the daily and annual positioning of the earth, moon, and sun affect the tides. The full tidal cycle (peak-to-peak) is about 12.9 hours.

The variation of open sea tides is only about 2 ft, but as tidal flows travel across the shallower water of a continental shelf, the open ocean fluctuation is amplified by shoaling effects. By the time the tidal flow reaches the coast, the surface level variation is amplified three or four times. Further amplifications occur in certain estuaries where level variations increase by another factor of two to four. Tidal fluctuations may be used to provide energy for direct use or for electric generation.

Tidal mills were used as early as medieval times in the estuaries of Britain and France. Dutch colonists built a tidal power grinding mill in Brooklyn, New York in 1617. Early versions of tidal mills worked as simple, undershot water wheels. Sea water was contained at high tide by wooden flaps and released to drive the water wheels when the tide fell. These plants were cumbersome and inefficient, but they could be relied upon when river mills had ceased to function in periods of drought.

Tidal-electric power has thus far been developed at only two sites: the Rance Project (240 MW) on the northwest coast of France, and the Kislogubsk tidal power station (0.4 MW) on Kislaya Bay, USSR (Cotillan 1974). Development of tidal power plants has been slow because the technology for low-head, high-discharge turbomachinery is still being developed. In its present state of development, the low-head reversible hydraulic turbine is easily controlled and long lived, but is neither compact nor highly efficient.

Cook Inlet is one of the few sites in the world with significant tidal power potential. A reconnaissance study sponsored by the State of Alaska identified sixteen potential tidal power sites in Cook Inlet ranging in size from 46 to 25,100 MW installed capacity (Acres American Inc. 1981a).

The underlying principles of tidal power plants are similar to those of hydropower. The electrical energy that can be developed at any tidal site depends on several interrelated factors, including usable head (which varies continuously with tidal fluctuations), area of the tidal basin, capacity of sluiceways to fill the basin, capacity of turbine and generating units, and mode of operation.

Tidal power's major benefit is that, like hydropower, the plant operation uses a renewable energy resource. The primary disadvantage is that electricity generation depends on the cyclical pattern of tides. Since tidal power plants can provide only intermittent energy, either backup generating capacity or a complementary storage technology such as hydro pumped storage must be available to meet load.

7.2.1 Technical Characteristics

Tidal power projects consist of one or more reservoirs (or basins), a barrage, a switchyard and transmission lines. A typical tidal power project is depicted in Figure 7.5. The barrage usually consists of a powerhouse, a sluiceway section, and dike or dam connections to shore, thus forming a controlled tidal basin. The powerhouse contains turbines, generators, control

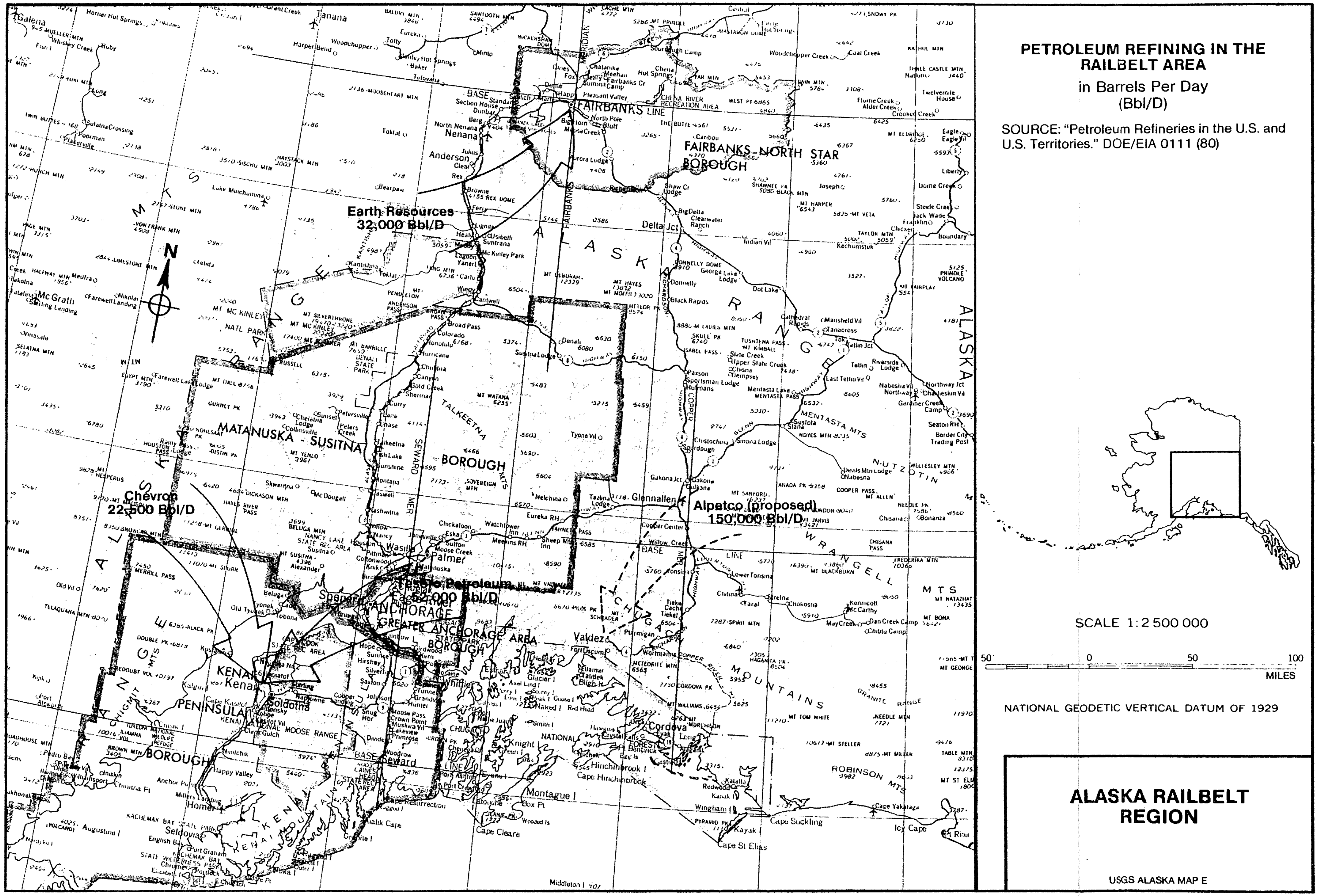


FIGURE 7.4. Petroleum Refining in the Railbelt Region

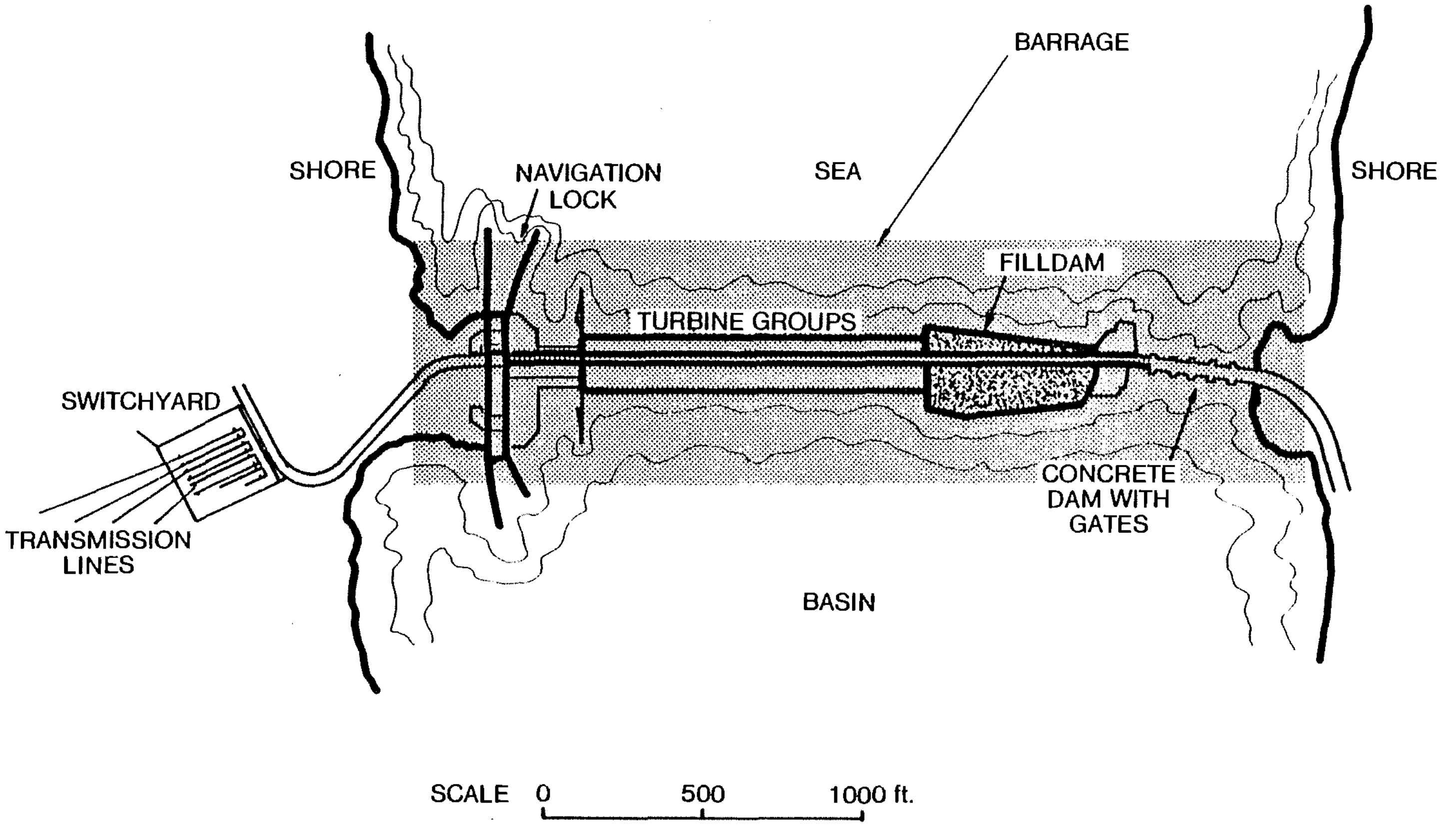


FIGURE 7.5. A Typical Tidal Power Plant

and switching apparatus, and transformers. Additional components may include trash racks on both sides of turbine water passages, concrete forebays, and tailrace approaches. Existing tidal generating plants range in size from less than 1 MW to 240 MW. Generating efficiencies are about 60%. Outage rates would likely be similar to conventional hydroelectric plants. Typically, conventional hydro plants would experience a 5% forced outage rate, 1 1/2% scheduled outage rate and 94% equivalent annual availability. Because of the modular design of a tidal power plant, full outages would be unlikely. Plant life would be 50 to 100 years.

Tidal power is a relatively inflexible technology for the following reasons:

- Because power generation is a function of cyclical tidal characteristics, demand occurring out of phase with the tides cannot be accommodated without retiming facilities such as pumped storage plants.
- Full power is only available at maximum tide levels.
- Without retiming, tidal power plants have no dependable capacity; i.e., the plant cannot serve a continuous load over extended intervals of time.

Because of these characteristics, tidal power developments must be used in conjunction with complementary cycling generating capacity or energy storage systems. An alternative approach to compensate for the intermittent nature of tidal power generation would be to incorporate pumped storage in the project to artificially prolong the natural tidal cycle. A tidal pumped storage facility still must be complemented by flexible load plants, such as pumped-storage, hydroelectric, or cycling thermal plants. Certain industries capable of using the intermittent power of a tidal plant have been proposed for development in conjunction with tidal facilities to better use the intermittent energy production of tidal plants.

Refinements in equipment technology and construction procedures are necessary to accelerate commercialization of this technology. Specific obstacles to the development of tidal power technology have included limited availability of low-head turbogenerator units and the difficulties and expense of barrage construction. Recent renewed interest in low-head hydropower development is helping to spur the manufacture of low-head turbogenerator units. In addition, the cost of construction can be reduced through the development of prefabricated barrage sections. For example, power house and sluiceway modules may be prefabricated in drydocks, or on slipways. Each module includes a horizontal water duct incorporating an intake, space for a turbogenerator set, and a draft tube (Figure 7.6). Provision for two or more turbogenerater sets might be incorporated in a single module. Modules are then floated to the barrage site and sunk at slack water level onto dredged, level, rock-rubble foundations. Similarly, sluice gate sections could be prefabricated, floated to the site, and installed. This prefabrication method was used to build the tidal-power station at Kislaya Bay, USSR (Bernstein 1974). Design and construction periods for a tidal electric plant would be lengthy. A seven-year preconstruction period and an eleven-year construction period were estimated for the Eagle Bay site studied in Acres American (1981a).

7.2.2 Siting Requirements

Three site conditions are necessary for an economically viable tidal power development: 1) a mean tidal range of about 20 ft or more, 2) an estuary or coastal indentation that, when dammed, will not substantially reduce the tidal range, 3) shoreline configuration permitting use of a reasonably short barrage, and 4) an interconnected electrical generating system capable of supplying capacity during slack tide periods. Without any one of these three prerequisites, a tidal energy development will probably be precluded, although the latter constraint can be overcome by constructing a complementary energy-storage system.

Foundation conditions should be level hard rock, although shallow sedimentary deposits overlying level hard rock can be accommodated. Sharply irregular or deep, porous sedimentary foundations should be avoided. Ideal sea depths are about 60 to 100 ft.

7.2.3 Costs

Reconnaissance-level cost estimates have been prepared for the three Cook Inlet sites selected in the Acres American reconnaissance study (1981a) as

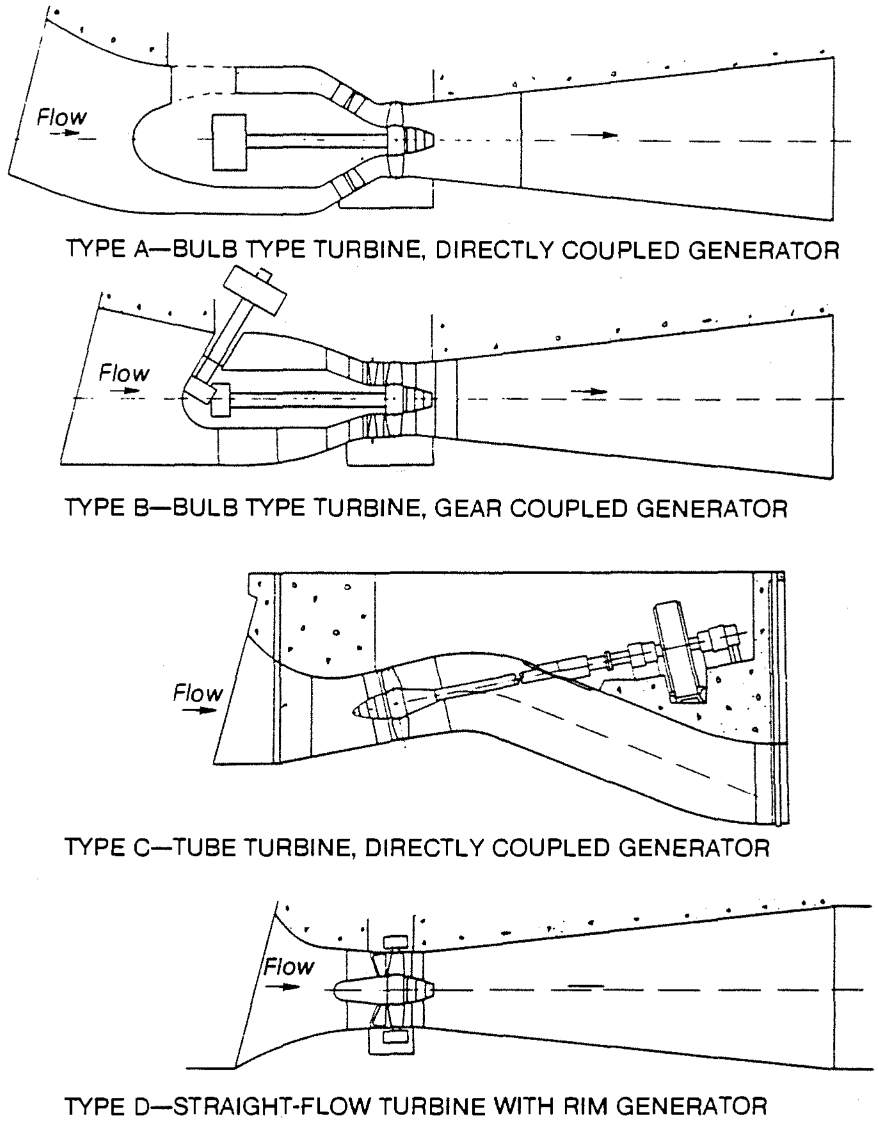


FIGURE 7.6. Types of Turbine/Generator Sets for a Tidal Power Plant

having the best prospects for development. A summary of estimated costs for these three sites is provided in Table 7.4.

7.2.4 Environmental Considerations

The placement of a barrage to harness tidal power separates a natural embayment into two artificial basins. This separation can cause major changes in the water circulation patterns of the unrestricted outer basin. The present hydrologic regime of the Knik Arm of Cook Inlet, the prime tidal power candidate site, is governed by large tidal fluctuations in this shallow, narrow

TABLE 7.4. Representative Cost Estimates for Tidal Power Plants[a] (1980 dollars)

Site	Rated Capacity (MW)	Capital ($/kW)	O&M[b] ($/kW/yr)	Cost of Energy[c] Raw (mills/kWh)	Currently Useable[d] (mills/kWh)	Retimed[e] (mills/kWh)
Eagle Bay	720	3587	72	53	80	70
Eagle Bay	1440	2466	49	44	111	73
Point McKenzie	1260	3051	61	50	123	76
Rainbow	928	2820	56	49	97	71

(a) All costs except those indicated from Acres American (1981a) were discounted to July 1980 using total Hydro Production Plant, Pacific Region, Handy Whitman, 1982.
(b) Not provided in Acres American (1981a), estimated at 2% of total investment cost.
(c) As calculated in Acres American (1981a), discounted as described in (a) to July 1980. Financial assumptions used are similar to those used elsewhere in this report.
(d) Based on energy that could be absorbed by current Railbelt electric energy system without retiming.
(e) Assumes retiming using pumped-storage hydro.

basin. Because of this characteristic, waters are well mixed laterally, longitudinally, and vertically with each tidal cycle. In summer, a net outward movement of inlet waters occurs, caused by large inflow of glacial meltwater from tributary streams, whereas in winter with reduced runoff, practically no net outflow occurs (U.S. Army Corps of Engineers 1972).

With development of a tidal power project, tidal flow would no longer move uniformly up the Knik Arm but rather through sluice gates and reversible turbine locations. The circulation and mixing patterns of this basin would be greatly affected. Waters would probably not be as well mixed and lateral separation could be expected. Also, the amount of water exchanged between the Knik Arm and the Upper Inlet would be reduced. This aspect would decrease Knik Arm's flushing rate. The net movement of water out of the Upper Inlet would also be affected by the reduction in water exchange, although the magnitude of this impact would depend upon the plant's specific design characteristics.

Circulation and flow patterns in the mid-Inlet and "outer" upper Inlet could also be affected. At present, this area is characterized by a net inward movement of saline oceanic water up the eastern shore and a net outward movement of fresh water runoff from the Knik Arm and the Susitna River along the western shore. These water masses are well-mixed vertically, but lateral separation is maintained throughout the mid-Inlet (U.S. Army Corps of Engineers 1972; Science Applications Inc. 1979). The phase shift of outflow from the Knik Arm would affect this pattern, but the magnitude of the change would probably not be significant because of the relatively small freshwater contribution of Knik Inlet tributaries. If, however, the tidal power project encompasses both the Knik Arm and the Turnagain Arm or if the project is coupled with a Susitna River energy development project in the future, significant changes in Cook Inlet circulation patterns would be likely.

These alterations in flow patterns would probably lead to water-quality changes. Pollutants, such as treated sanitary waste from facilities in Anchorage, Eagle River, and Palmer, are discharged into the inner bay. The decrease in flushing and subsequent increase in residence time would increase pollutant concentrations. Constricting the water flow to a few intake and outlet conduits also would alter the spatial distribution of these pollutants and other biologically important substances such as nutrients. While the water quality of the area is generally considered acceptable, high concentrations of nutrients, organic material, and iron can be experienced, especially during spring and summer runoff (Selkregg 1974; U.S. Army Corps of Engineers 1972). Depending upon the specific reduction in flushing rate and mixing, localized water-quality conditions could become problematic.

The modification of a natural embayment to a controlled basin also changes the marine environment from a high energy area to a low energy area. This change would especially affect sediment distribution and movement. The dam would act as a sediment trap so that the large sediment load derived from the Knik and Matanuska Rivers would no longer easily move seaward with the tides but would accumulate at a faster rate in the inner bay. This could change sediment transport and shoaling patterns in the entire Inlet, and possibly in the area of the Palmer Bay Flats and Eagle River Flats.

Water transportation may also be affected by tidal power projects that obstruct navigable waters. This problem can be overcome with locks, which then places constraints on the number of boats traveling to and from an estuary. This could be significant to the traffic entering the Port of Anchorage, but depends upon the specific location of the barrage.

No impacts on air quality or meteorological resources will result from the development of tidal-electric power generation facilities.

The major potential impact on aquatic ecosystems for a tidal power plant located on the Knik Arm of Cook Inlet would be restricted movement of aquatic organisms, such as salmonoids, larval shellfish, and plankton, and the increased mortality of these organisms when they pass through the turbines. Of particular concern are the major salmon runs that pass through Knik Arm into several major streams, including Fish Creek, Eagle River, Ship Creek, Knik River, and the Matanuska River tributaries (Alaska Department of Fish and Game 1978). In addition to salmon, smelt pass through this area to the Knik River to spawn. These fish are not only important commercially but also supply sport fishing in many of these streams (U.S. Army Corps of Engineers 1972).

Restricted flow inside the bay could result in increased siltation from the large quantities of sediment discharged by the Matanuska River and other Knik Arm tributaries. This sediment discharge, in turn, could result in habitat destruction and increased benthic organism mortality. Flow patterns may be altered outside the tidal barrier, changing movement of plankton and other marine organisms. One advantage of such a structure may be to reduce turbidity in the outer portions of Cook Inlet, possibly resulting in higher primary production from increased light penetration. Also, the structure itself may provide a substrate for attachment of sessile marine organisms.

Similar problems to the Knik Arm may occur if a tidal power facility were constructed on Turnagain Arm because of the many similarities between the two areas. Salmon, although not as abundant, are also present in some of the small streams that enter this area (Alaska Department of Fish and Game 1978). Siltation may not be as significant in these regions due to the lack of major stream inflow.

Marine mammal habitats will be reduced as a result of the barrier presented by the tidal power barrage and by the modification of shoreline vegetation by changes in the tidal cycles. In general, seal and sea-lion haul-out areas could be eliminated. Intertidal vegetation and organisms fed upon by aquatic furbearers and waterfowl would be modified, and bald eagles and other fish-eating raptors could also be negatively affected if anadromous fish passages through the barrage were reduced.

The Knik and Turnagain tributaries of Cook Inlet are environmentally sensitive areas. Both tributaries are used by seals, sea-lions, and water fowl. The Turnagain tributary contains three key waterfowl areas: Chickaloon Flats, Potter Marsh, and Portage Marsh. Various puddle ducks, geese, and sand hill cranes feed and rest in these areas during seasonal migration periods. These groups of birds also use Palmer Flats and Eagle River Flats of the Knik tributary. Irregular tidal cycles could alter the intertidal biotic communities of these areas and could reduce their value to waterfowl and various shorebirds.

Both tributaries are also used by harbor seals. Establishing a barrage would effectively end their use of these areas. Lastly, only the Knik tributary appears to contain major salmon runs, which if blocked or substantially reduced, could negatively affect bald eagles and ospreys that feed upon salmon.

Terrestrial impacts resulting from tidal energy development of the Knik and Turnagain tributaries could be partly mitigated. However, losses to marine mammals could not be relieved. Waterfowl and various shorebird habitats could be kept relatively unchanged by maintaining tidal cycles similar to normal ones. Tidal cycles could not be maintained if tidal energy production were supplemented by a combination pumped-storage system. The loss of salmon as a food source to fish-eating raptors could also be relieved by increasing salmon production on nearby tributaries, if densities of fish-eating raptors on these streams are not at saturation levels for reasons other than food availability. If these streams were saturated for other reasons, then losses could not be mitigated.

7.2.5 Socioeconomic Considerations

A tidal power plant requires a large construction work force and a small operating work force, creating the potential for a boom/bust cycle. A work force of 200 to 500 would be required for a Rance-scale (240-MW) plant for 7 years. The size of the construction work force would not vary greatly with plant scale since excavation and barrage construction are general requirements independent of generating capacity. The larger plants proposed for Cook Inlet, however, would require approximately eleven years for construction. A staff of 20 to 50 would be required during the operating phase. Compared to other fuel-saver technologies, tidal power has the greatest potential to impact smaller communities.

Since the two tidal sites (Knik Arm and Turnagain Arm) identified in the Railbelt are located close to Anchorage, impacts on the surrounding area due to construction should be minimal. The project offers potential employment to unemployed persons residing in the greater Anchorage region. Therefore, a work force would not have to be brought in from other areas of Alaska, which would alleviate the demand for housing or services.

Since tidal power is a labor-intensive technology and participation by the Anchorage area labor force is expected, the expenditures for labor should be kept primarily within the region. Some of the material expenditures, particularly those for embankment materials, would also remain within the region. Therefore, approximately 67% of the total capital expenditures would be spent within the Railbelt. Approximately 33% of the total capital cost would be for equipment imported from the lower 48 states or foreign suppliers. Approximately 11% of O&M expenditures would be spent outside Alaska and 89% spent within Alaska.

7.2.6 Potential Application in the Railbelt Region

A tidal power reconnaissance study of Cook Inlet was recently completed for the Alaska Power Authority. This study identified sixteen potential sites in Cook Inlet (Acres American, Inc. 1981a). The sites ranged in size from a site at Port Graham with the potential for an installed capacity of 46 MW and net annual energy production of 584 GWh to a site at Anchor Point across the inlet with a potential installed capacity of 25,100 MW and net annual energy production of 318,000 GWh.

Based on the scale, likely development costs, location, and potential environmental effects, a subset of three more favorable sites were selected for further study (Figure 7.7). These three sites were Rainbow on Turnagain Arm, Point McKenzie/Point Worongof on Knik Arm, and Eagle Bay/Goose Bay on Knik Arm.

Further study of these three sites resulted in recommendation of the Eagle Bay/Goose Bay site for further study. The proposed plant 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 first powerhouse unit; 60 powerhouse modules, each containing a bulb turbine-generator of 24-MW 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. Total installed capacity would be 1440 MW. An estimated 1600 GWh of energy of a total potential of 4000 GWh could be used by the Railbelt electric energy system without retiming (energy storage). Provision of a 1200-MW pumped hydroelectric storage retiming facility would increase the useable energy to 3200 GWh annually.

An alternative using thirty 24-MW turbine-generators was also proposed. This alternative would produce 2300 GWh of raw energy, 1530 GWh of useable energy without storage and 2050 GWh of useable energy with an accompanying 450-MW pumped hydroelectric storage project. Estimated capital and O&M costs and costs of energy for the proposed Eagle Bay/Goose Bay project are summarized in Table 7.4.

Advantages of Cook Inlet tidal power development include provision of an electric energy supply based on a renewable energy source, relatively free from the effects of inflation. An additional potential advantage is the possibility of a shorter highway access to lands borderig Knik Arm across from Anchorage. Disadvantages include potentially severe environmental effects, high capital cost and the need to either effectively absorb intermittently generated power or to provide an ancillary energy storage facility.

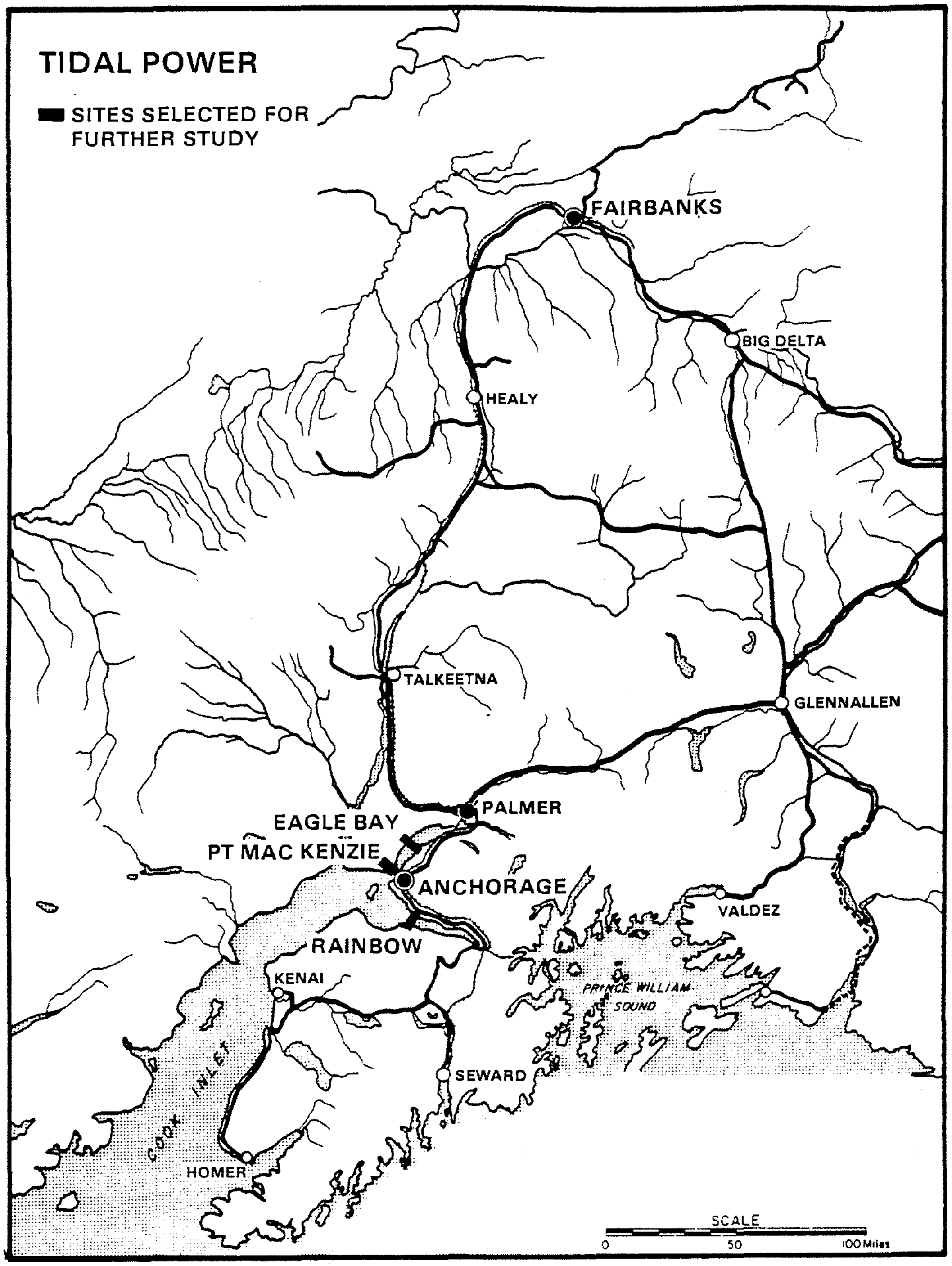


FIGURE 7.7. Tidal Sites Selected for Further Study

7.3 LARGE WIND ENERGY CONVERSION SYSTEMS

Until the mid 1930s wind energy supplied a significant amount of energy to rural areas of the United States. With the advent of rural electrification wind energy ceased to be competitive with other power alternatives. However, rising fuel costs and the increased cost of power from competing technologies has renewed interest in the development of wind resources. This energy source may be significant in electric power generation in rural areas, small communities, and possibly for large, interconnected energy systems.

This section will focus on large wind turbines of 0.1-MW or more rated capacity that might be employed as centralized power-generating facilities by a utility. Currently, several machines are in the demonstration phase. In 1979 the MOD-1.2-MW, 200-ft diameter turbine was completed at Boone, North Carolina. Three MOD-2 wind turbines, each rated at 2.5-MW capacity, have been recently completed near Goldendale, Washington by the Bonneville Power Administration (BPA), U.S. DOE, and NASA. These and other wind turbines in the 1-MW range of rated output are available for production, but the economics of assembly line production have not yet been realized.

7.3.1 Technical Characteristics

A typical wind machine consists of a rotating blade assembly, a transmission to convert the relatively slow blade rotation to appropriate generator speed, an electrical generator, a supporting structure, and electrical transformation, switching and control equipment. Horizontal machines also require equipment to control the position of the machine relative to the wind. Large wind energy conversion systems range in size from 100 MW to 2.5 kW each. Machines of larger capacity are in the design stage.

Design Features

The wind machines used to convert the energy in the wind to rotational energy are classified according to the axis of rotation relative to wind direction as: 1) horizontal axis, 2) vertical axis, and 3) cross-wind horizontal axis.

Horizontal axis rotor systems represent the conventional, windmill-type machine whose axis of blade rotation is horizontal and parallel to the wind direction. This design is illustrated in Figure 7.8. Vertical axis rotor systems have a vertical axis of blade rotation. The most common representatives of this system are the Savonius and Darrieus machines (Figure 7.9). Vertical axis systems are generally less efficient than the horizontal rotor systems. However, since they do not need a tower, their construction costs are less and they have the added advantage of being insensitive to wind direction. Cross-wind, horizontal axis systems are of a paddle-wheel design and do not represent an improvement over either of the other two designs (Inglis 1978). At the current stage of development, horizontal axis designs appear to be preferred for megawatt-scale machines.

Wind energy is characteristically a diffuse source of energy in which the theoretical output of an individual wind machine is a function of the cube of the wind speed, the wind machine efficiency, and the area intercepted by the turbine blades. Therefore, the factor of primary importance in establishing wind power potential is the wind speed characteristic of a site.

Wind generators operate within well-defined wind speed ranges. The "power profile" depicts the power output of the turbine as a function of the wind speed. The power profile for the MOD-2 (Figure 7.10) indicates the cut-in speed (14 mph), rated speed (28 mph), and cut-out speed (47 mph). Because wind turbines must be designed to fit load system and wind conditions, a smaller wind turbine with a lower cut-in speed, a lower rated speed, and a lower power rating may be preferred in some cases to a larger machine with higher cut-in wind speeds.

The production of wind power electricity is an intermittent process because of the nature of wind itself. The physical or structural reliability of the wind turbines is generally well established for the small units but is uncertain for the newer, large units. The availability of large wind machines, when fully developed, is expected to be approximately 87%.[a] The capacity

(a) Electric Power Research Institute. 1982. 1981 Technical Assessment Guide (Draft). Electric Power Research Institute, Palo Alto, California.

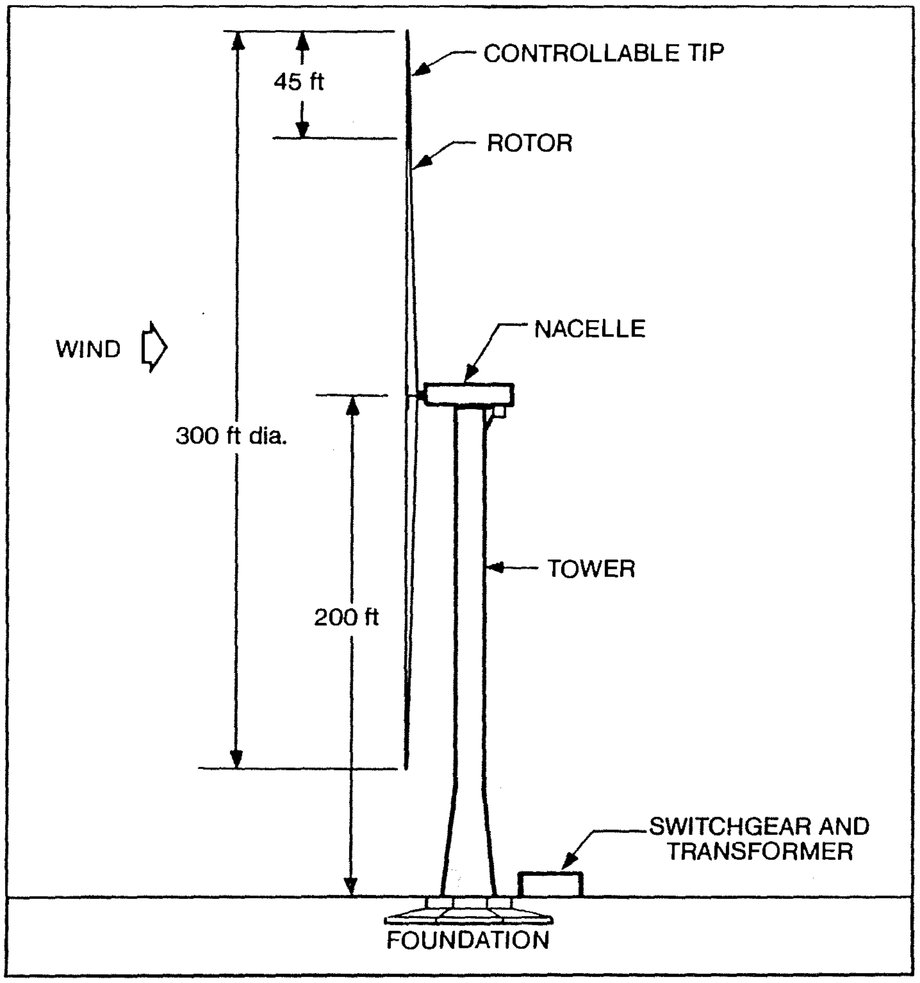


FIGURE 7.8. MOD-2 Wind Turbine Generator

factor for wind turbines will probably range between 30 and 50%, but this factor is a function of the wind resource at the site.

Weather factors such as icing or high winds reduce the machine's reliability. Equipment life in the Railbelt's harsh climate may pose a problem. Towers and blades must be able to withstand storms, winds, icing, or snow loading. Tower foundations need to withstand repeated freezing and thawing. High mechanical loads are experienced during tower and blade icing conditions. Equipment exposed to the elements may experience lubrication problems in subzero temperatures.

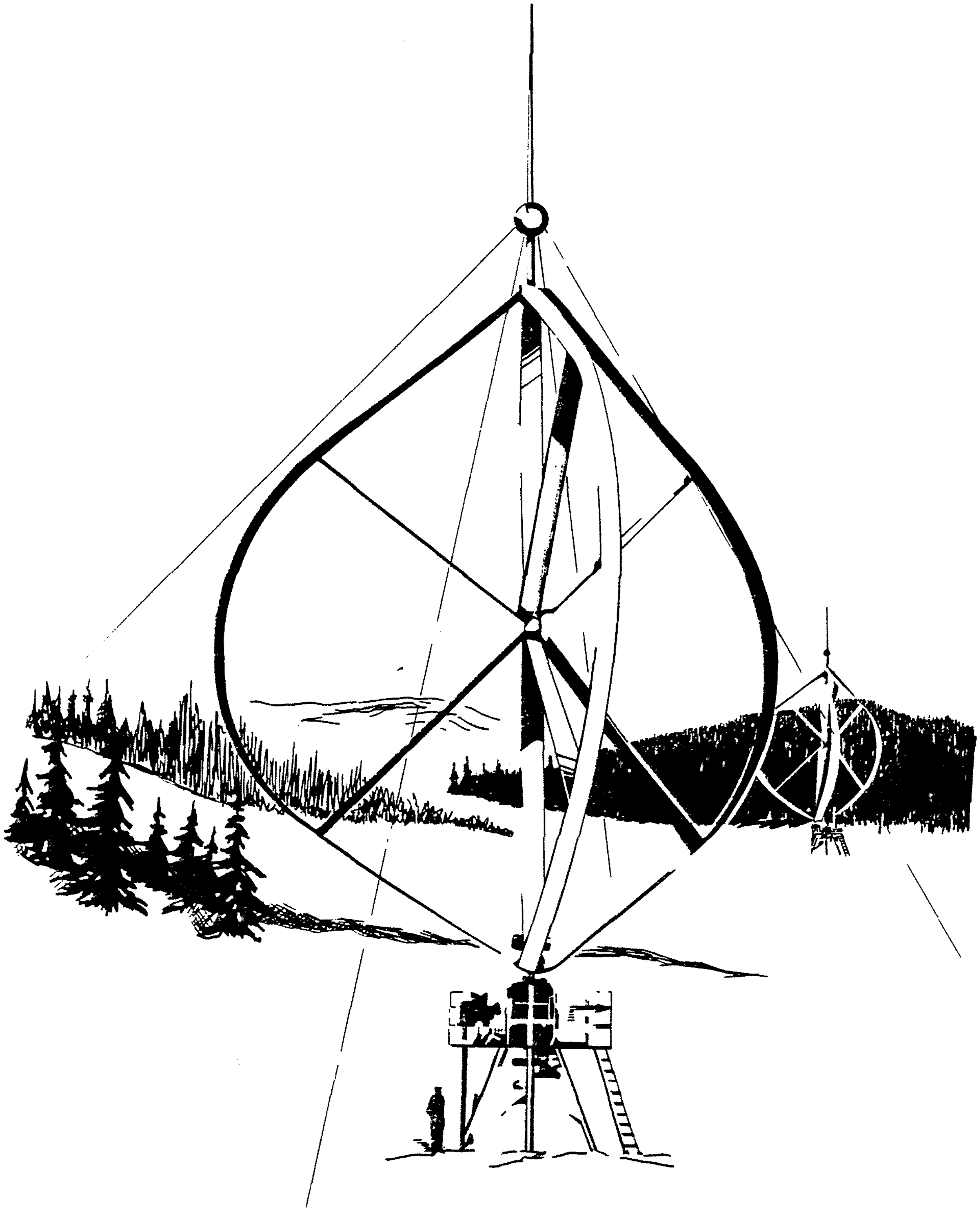


FIGURE 7.9. Vertical Axis Wind Turbine (Darrieus Type)

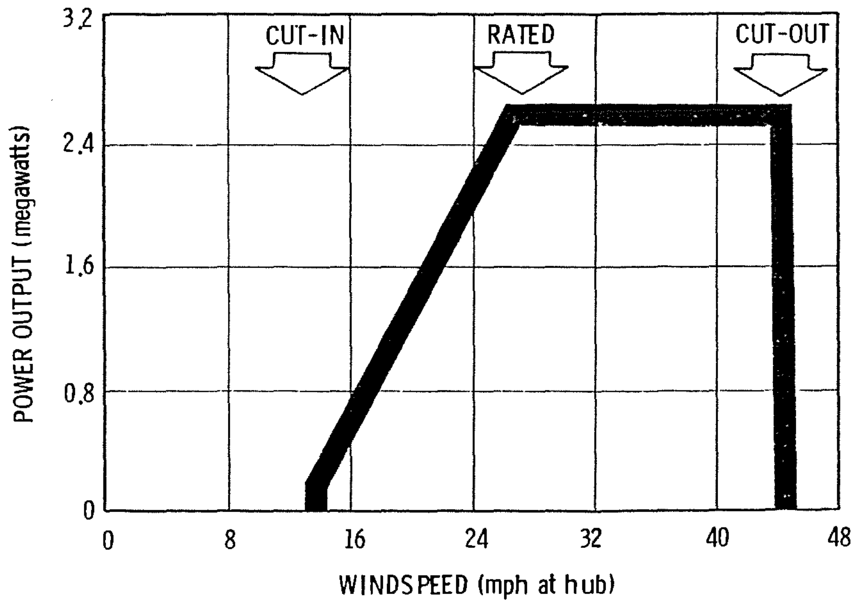


FIGURE 7.10. Power Profile of the MOD-2 Wind Machine

Grouping wind turbines into "wind farms," as at Gambell, Alaska, can reduce problems with equipment failures. Any one turbine could be shut down for repair or maintenance without greatly affecting the farm's output. The farm's overall reliability is much greater than the reliability of single-unit generation systems.

Optimum use of wind turbines may require backup power generation and storage requirements because of the variability of wind speeds. Wind turbines or a wind farm may be developed at sites where the wind pattern closely approximates the load pattern. Such development helps alleviate storage requirements and load management difficulties.

In a grid with existing hydro capacity, storage can be accomplished by displacing hydro production; that is, not as much water is used to generate electricity when the wind generators deliver power. The water not used is held behind the dam for future use. The rapid response time of hydropower installations effectively complements the intermittent production of wind energy conversion systems. However, the displacement storage cannot be used unless hydro provides a large portion of capacity; otherwise, the hydro facility will already be scheduled to provide peaking power. Simple-cycle combustion turbines may also be used in conjunction with wind systems to provide power when the wind machines are not operating.

Because generating capacity can be added in relatively small increments, wind turbine construction can easily follow load growth. Wind power capacity additions, however, must be coordinated with provision of complementary power generation and storage capacity. Machine lifetime is anticipated to be 30 years.

7.3.2 Siting Requirements

The siting of the wind turbines is crucial to satisfactory performance of wind energy conversion systems. The most significant siting consideration is average wind speed and variability. These considerations depend on large-scale weather patterns but are also affected by local topography, which can enhance or reduce the average wind speeds. Since wind energy potential is directly proportional to the cube of the wind speed, siting wind machines to take advantage of even small increases in average wind speed is important (Hill 1977). Extremely high winds and turbulence may damage the wind turbines, and sites exhibiting these characteristics must be avoided.

Other important siting considerations include the proximity of the site to load centers, site access, founding conditions, and meteorological conditions. Undesirable meteorlogical conditions, in addition to turbulance, include glazing conditions, blowing sand or dust, heavy accumulations of snow, and extreme cold.

Wind-powered energy requires varying amounts of land area for development. The amounts of area required depend on number, spacing, and types of wind-powered units used. The area can range from approximately 2 acres for one 2.5-MW generating unit to over 100 square miles for a 1000-MW wind farm. Developments of the 1000-MW size, because of their requirements for persistent high-velocity winds, would probably be established in remote areas.

7.3.3 Costs

The major costs of developing wind power are the equipment and erection costs. The O&M costs are difficult to project because of a lack of standardization and little operating experience. Estimated O&M costs are, however, projected to be small compared to initial installation costs.

Costs for large turbines adjusted to 1980 dollars range from $740 to $850 per installed kilowatt (Inglis 1978). These costs assume production runs of 100 or more machines. Estimates provided by the Boeing Company for this level of production for the MOD-2 turbines being installed near Goldendale, Washington indicate a cost of about $800 per installed kilowatt capacity. Currently, the 2.5-MW MOD-2 machine sells for $6.5 million each (2600 $/kW). Costs of installation at remote locations are uncertain, particularly if shipping the units or installing them onsite is very difficult. Estimated costs for large wind energy conversion systems located in the Railbelt are shown in Table 7.5.

TABLE 7.5. Estimated Costs for Large Wind Energy Conversion Systems (1980 dollars)

Rated Capacity	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy ($/kW)[a]
2.5 MW	1500	13-22	72-54

(a) Levelized lifetime costs assuming a 1990 first year of commercial operation. Range represents capacity factors of 30% and 40%, respectively.

7.3.4 Environmental Considerations

Wind turbines extract energy from the atmosphere and therefore can cause slight modifications to the surrounding climate. Wind speeds will be slightly reduced at surface levels and to a distance equivalent to 5 rotor diameters, which would be approximately 1500 ft for a single, 2.5-MW facility. Small modifications in precipitation patterns may be expected, but total rainfall over a wide area will not be affected. Nearby temperatures, evaporation, snowfall, and snow drift patterns will be affected only slightly. The microclimatic impacts will be qualitatively similar to those noted around large, isolated trees or tall structures.

The rotation of the turbine blades may interfere with television, radio, and microwave transmission. Interference has been noted within 0.6 miles (1 km) of relatively small wind turbines. The nature of the interference depends on signal frequencies, blade rotation rate, number of blades, and wind turbine design. A judicious siting strategy could help to avoid these impacts.

Stream siltation effects from site and road construction are the only potential aquatic and marine impacts of this technology. Silt in streams may adversely affect feeding and spawning of fish, particularly salmonids, which are common in the Railbelt region. These potential problems can be avoided by proper construction techniques and should not be significant unless extremely large wind farms are developed.

Because of the relatively large land requirements, the potentially remote siting locations, and the possible need for clearing of vegetation, wind energy projects could significantly affect terrestrial biota through loss or disturbance of habitat. Also, wind generating structures could cause collisions with migratory birds. Other potential impacts include low frequency noise emanating from the generators and modification of local atmospheric conditions from air turbulence created by the rotating blades. The impacts of these latter disturbances on wildlife are unclear at present.

In the Railbelt region environmentally sensitive areas having favorable wind resources include exposed coastal areas along the Gulf of Alaska, mountain passes, and possibly hilltops and ridgelines in the Interior. Alteration of coastal bluffs could affect seasonal ranges of mountain goats in the Kenai Mountain Range, and nesting colonies of sea birds in the Chugach Islands, Resurrection Bay, Harris Bay, Nuka Pass, and other areas along the Gulf Coast. Shoreline development could affect harbor seals and migratory birds. Harbor seals use much of the coastline for hauling-out. The Copper River Delta is a key waterfowl area. Scattered use of shoreline habitat by black bear, brown bear, and Sitka blacktailed deer occurs in Prince William Sound. The presence of wind energy structures in any of these areas could potentially cause collisions with migrating waterfowl, bald eagles, peregrine falcons (an endangered species), and other birds, if situated in migratory corridors. If situated on critical range lands, inland development of wind energy could negatively affect Dall sheep, mountain goat, moose, and caribou.

These terrestrial impacts can generally be mitigated, although habitat lost through development is irreplaceable. However, these losses can be minimized by siting plants in areas of low wildlife use. Critical ranges of big game, traditional haul-out areas of seals and nesting colonies of birds, and known migratory bird corridors or key feeding areas could be avoided. The feasibility of mitigation will, of course, depend on the size of the wind energy development.

7.3.5 Socioeconomic Considerations

Construction of a 1 to 2.5-MW wind turbine would require approximately 2 years for site selection and monitoring and 6 months for field erection. During the monitoring period, a survey party would periodically visit the site to collect data. A wind turbine requires a small construction work force of 10 to 15 persons, no permanent onsite operating work force, and minimal maintenance requirements. In comparison to the other fuel-saver technologies, wind power would create very few demands on community infrastructure.

Since the construction and operating and maintenance requirements are minimal, a community's population size is not a siting constraint. Individual wind turbines should therefore be compatible with communities of all sizes.

Installation of a 100-MW wind farm would require a construction work force of approximately 60 over a period of a few years. The impacts of constructing a wind farm on small communities may be significant because of the work force size and length of construction period.

The cost breakdown for a wind turbine investment is based on the assumption that the monitoring field work, site preparation, and installation would be performed by Alaskan labor and that all components would be imported from outside manufacturers. Under these assumptions approximately 80% of the expenditures would be sent outside the region, while 20% would remain within Alaska.

A wind turbine system consisting of five machines has been installed at Gambell on St. Lawrence Island in Alaska to provide wind electric power for community facilities. Another wind turbine has been installed at Nelson Lagoon on the Alaskan Peninsula.

7.3.6 Potential Application in the Railbelt Region

A comprehensive wind energy resource atlas of Alaska has been recently completed for the U.S. Department of Energy's Wind Energy Program (Wise 1980). This atlas was compiled by the Arctic Environmental Information and Data Center of the University of Alaska. The principal information contained in this atlas are maps of wind power density and corresponding certainty ratings for the state as a whole and in greater detail for four major sub-regions (northern Alaska, south central Alaska, southeastern Alaska, and southwestern Alaska). Other information that is provided includes estimates of the percentage of land area subject to various levels of wind power density, seasonal average wind power and wind characteristics of selected stations. The information is presented at a macroscale level based on data cells of 1° longitude by 1/2° latitude in size (717 cells for the state). The resulting wind resource maps are at a far greater level of detail than any previously compiled for the state, and while not of sufficient detail to support specific siting decisions, are of suitable detail to suggest specific subregional areas having promising wind resource potential. A map of wind power density in the Railbelt region, based on the Alaska Wind Energy Resource Atlas, is provided in Figure 7.11.

Seven classes of annual average wind power density are shown in Figure 7.11 and the characteristics of these classes are shown in Table 7.6. To provide some perspective on the relative significance of these wind power classes, a minimum annual average wind speed of 6.5 m/sec at 10 m height has been estimated to be required for a wind resource to be considered as a viable energy option (Hiester 1980). This estimate roughly corresponds with wind resource Class 5. This criterion is based on estimated mass production costs of the current generation of large-scale wind machines as represented by the MOD-2 design. The Goodnoe Hills site in Washington State, where three MOD-2 machines are currently being tested and considered to be a prime wind resource site, is in wind power density Class 6. The cut in speed of a MOD-2 machine is approximately 14 mph (Figure 7.10), equivalent to the mean wind speed (at approximate hub height) of wind power Class 2. Full power output of a MOD-2

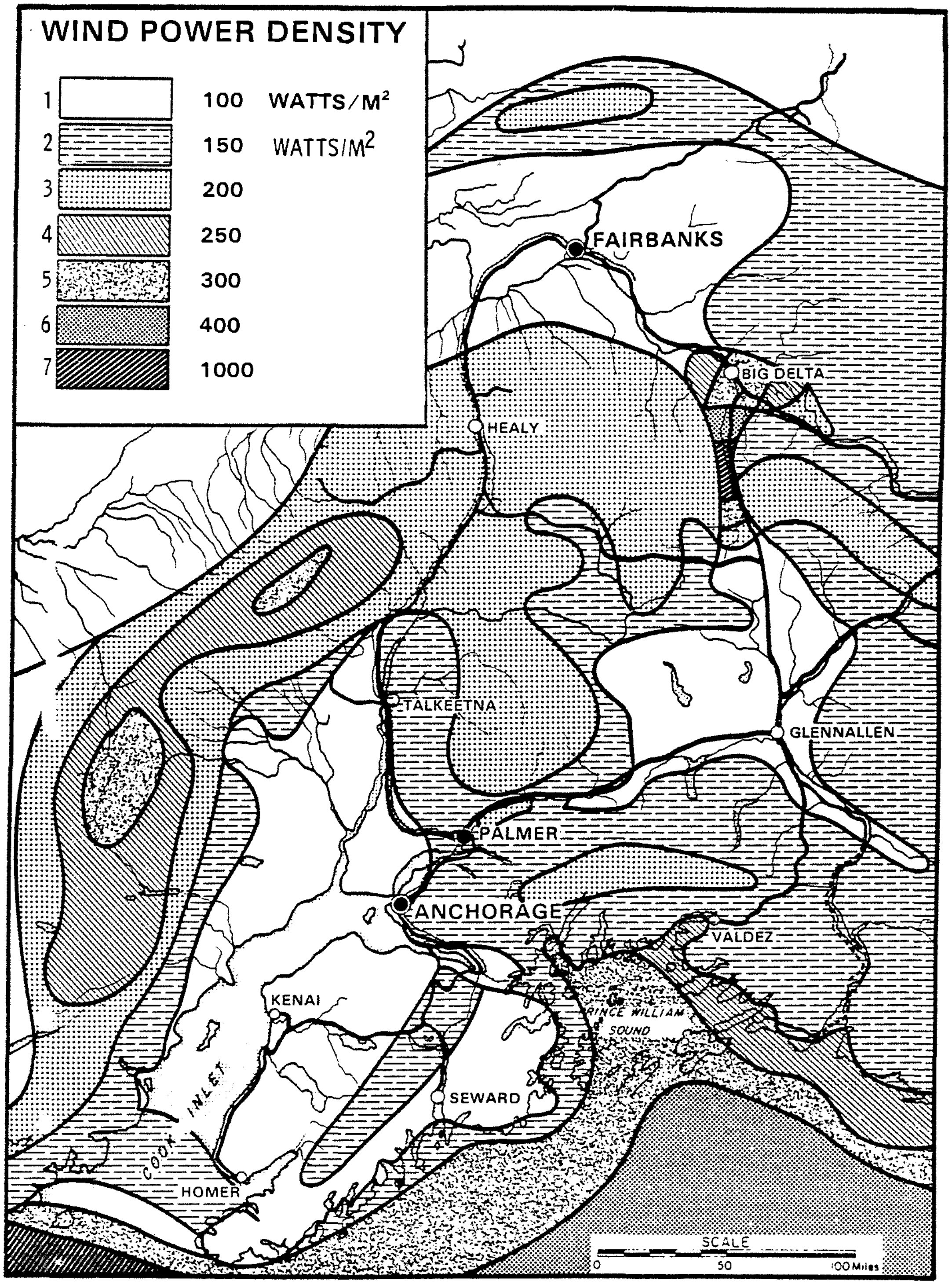


FIGURE 7.11. Wind Power Density of the Railbelt Region (Wise 1980)

TABLE 7.6. Wind Power Density Classes

Wind Power Class	10 m (33 ft) Wind Power Density (watts/m^2)	10 m (33 ft) Mean Wind Speed (mph)	50 m (164 ft) Wind Power Density (watts/m^2)	50 m (164 ft) Mean Wind Speed (mph)
1	100	9.8	200	12.5
2	150	11.5	300	14.3
3	200	12.5	400	15.7
4	250	13.4	500	16.8
5	300	14.3	600	17.9
6	400	15.7	800	19.7
7	1000	21.1	2000	26.6

machine is achieved at 25 mph, greater than the mean wind speed of a Class 7 site. In general, Class 4 areas and above are considered to have "high" annual average wind power.

Three areas within the Railbelt are considered major wind resource areas from a statewide perspective (Wise 1980). These areas include the Lower Cook Inlet, the Gulf of Alaska coast and exposed ridges and summits of the Alaska Range.

The lower Cook Inlet area from Iliamna Lake to the Barron Islands (off the tip of the Kenai Peninsula) is a corrider for strong winds. Whereas large-scale, offshore wind power development is probably not feasible in the near term, onshore locations at the tip of the Kenai Peninsula are at the edge of this resource area and may possess promising sites. Some thought has been given to construction of offshore wind machines. Power could be transferred to shore using submerged cables, or hydrogen produced by electrolysis of water. However, such designs are presently speculative (Considine 1976) and most likely would not be developed until terrestrial machines have been more fully developed.

Exposed area along the Gulf of Alaska coast should experience mean annual wind power of Class 4 or higher. Offshore data indicate wind power of Class 7 or higher. Existing settlements tend to be at sheltered sites and do not exhibit strong wind characteristics; however, more exposed coastal sites may prove to be more favorable.

Class 4 and higher sites are thought to be located along ridge crests in the Alaskan Range to the west of the Susitna River and at Isabell Pass north of Paxson. The wind power potential of ridge top sites tend to be highly site specific and wind speeds can vary significantly from one ridge crest to another as a result of orientation and proximity to other ridge lines. The mapped data of Figure 7.11 represent the lower limits of wind power for exposed areas.

Finally, a Battelle-Northwest study that addressed the wind resource potential of the Cook Inlet area (Hiester 1980) concluded that no conclusive evidence indicates that large-scale generation of electric energy by megawatt-scale wind turbines is a significant energy option in the Cook Inlet area. However, six sites were judged to have sufficient wind energy potential to warrant site-specific wind measurements. These sites include the following (Figure 7.11):

- the hills north of Homer
- Portage Creed Valley
- Bird Point (Turnagin Arm)
- Cantwell-Summit-Broad Pass area
- Anchor Point (Cook Inlet)
- Tahneta Pass (Glennallen Highway).

Wind resources showing considerable promise for large-scale wind energy development appear to be present in the Railbelt Region. The most promising area appears to be Isabell Pass because of its very high wind power density, winter peaking characteristics and relative accessibility. The primary drawback of this area is its remoteness from major load centers. Other areas showing promise include ridge tops in the Alaska range west of the Susitna River, exposed locations along the Gulf of Alaska and at the tip of the Kenai Peninsula, and selected sites in the Cook Inlet area.

Further studies are necessary to assess wind energy potential of the areas identified above. These studies include the following: preparing and examining detailed contour patterns of the terrain, modeling selected sites, monitoring meteorological conditions at prime sites for at least 1 year (preferably 3 years), analyzing site meteorlogical characteristics using modeled and measured data, developing site-specific wind duration curves, and selecting final sites.

7.4 SMALL WIND ENERGY CONVERSION SYSTEMS

Small wind energy conversion systems (SWECS) are wind machines with rated output of 100 kW or less. Typically, the siting of these machines would be dispersed at individual residences or in small communities, as compared to the large wind energy conversion systems (Section 7.3), which would be sited generally in clusters, as centralized power production facilities.

7.4.1 Technical Characteristics

Historically, battery-charging systems have been the primary application for small wind energy conversion systems in Alaska; however, this situation is beginning to change. Several small wind machines are now in commercial production in sizes ranging from 0.1 to 37 kW. Figure 7.12 shows some of SWECS's many possible uses, both currently existing and under development. The profile in this section focuses on SWECS that interface directly with the utility grid. Off-grid installations are not considered.

Design Features

SWECS are available in horizontal and in vertical axis configuration. Horizontal axis machines (Figure 7.13) exhibit superior efficiency but require a substantial tower to support the generating equipment as well as the blades. In addition, the blade/generator assembly must yaw in response to changing wind direction, requiring provision of head bearings, slip rings and machine orientation devices.

Although of lower efficiency than horizontal axis machines, the vertical axis designs (Figure 7.9) minimize tower structure and eliminate the need for head bearings or slip rings. Because of these advantages, vertical axis machines may exhibit superior cost characteristics in the small wind machine sizes.

The three most common types of generator systems used in SWECS are induction AC generators, synchronous AC generators, and DC generators. Synchronous generators must be driven at a constant speed, corresponding to the desired frequency of the power produced. Synchronizing microprocessor controls are

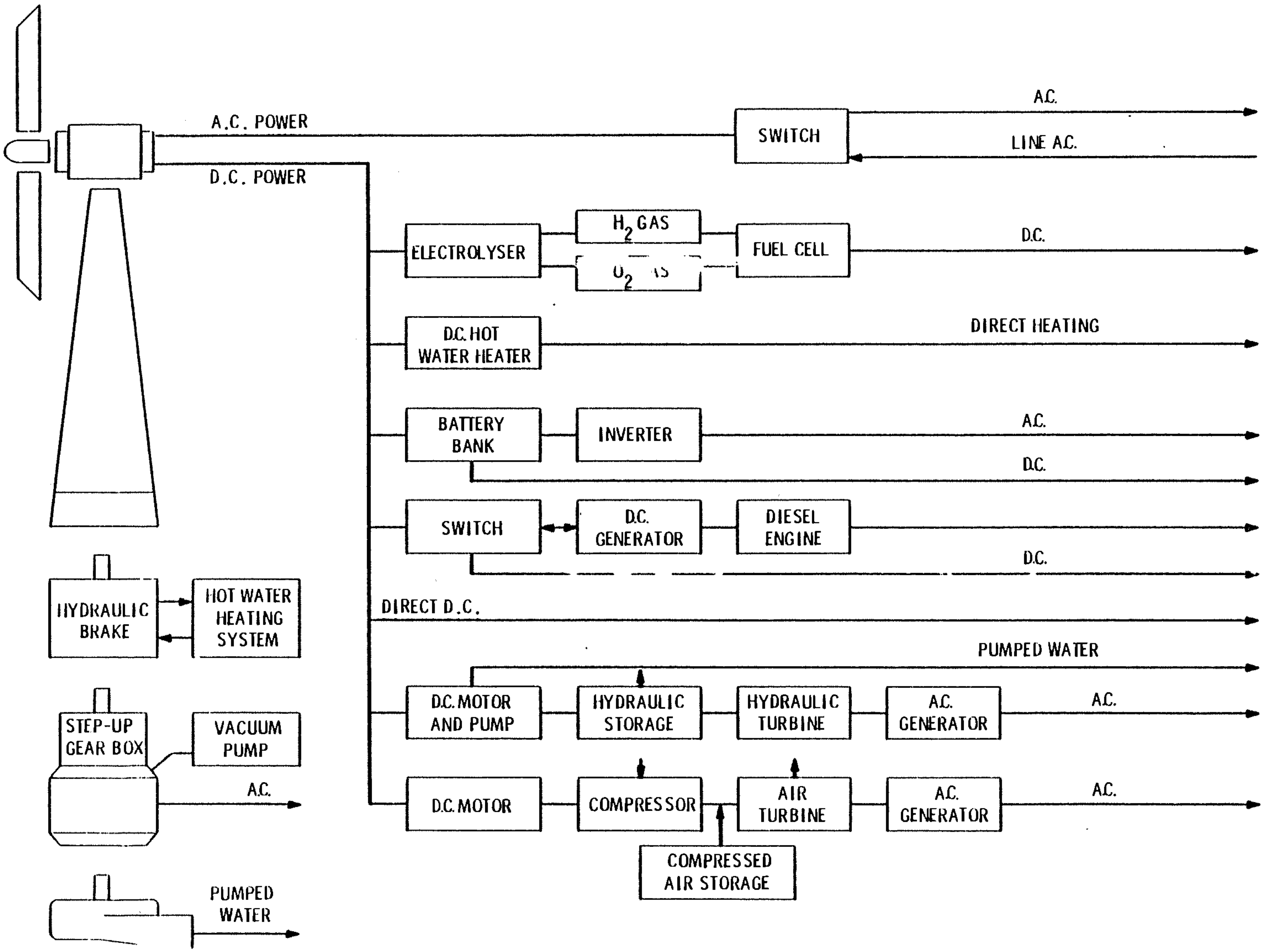


FIGURE 7.12. Alternative SWECS Configurations

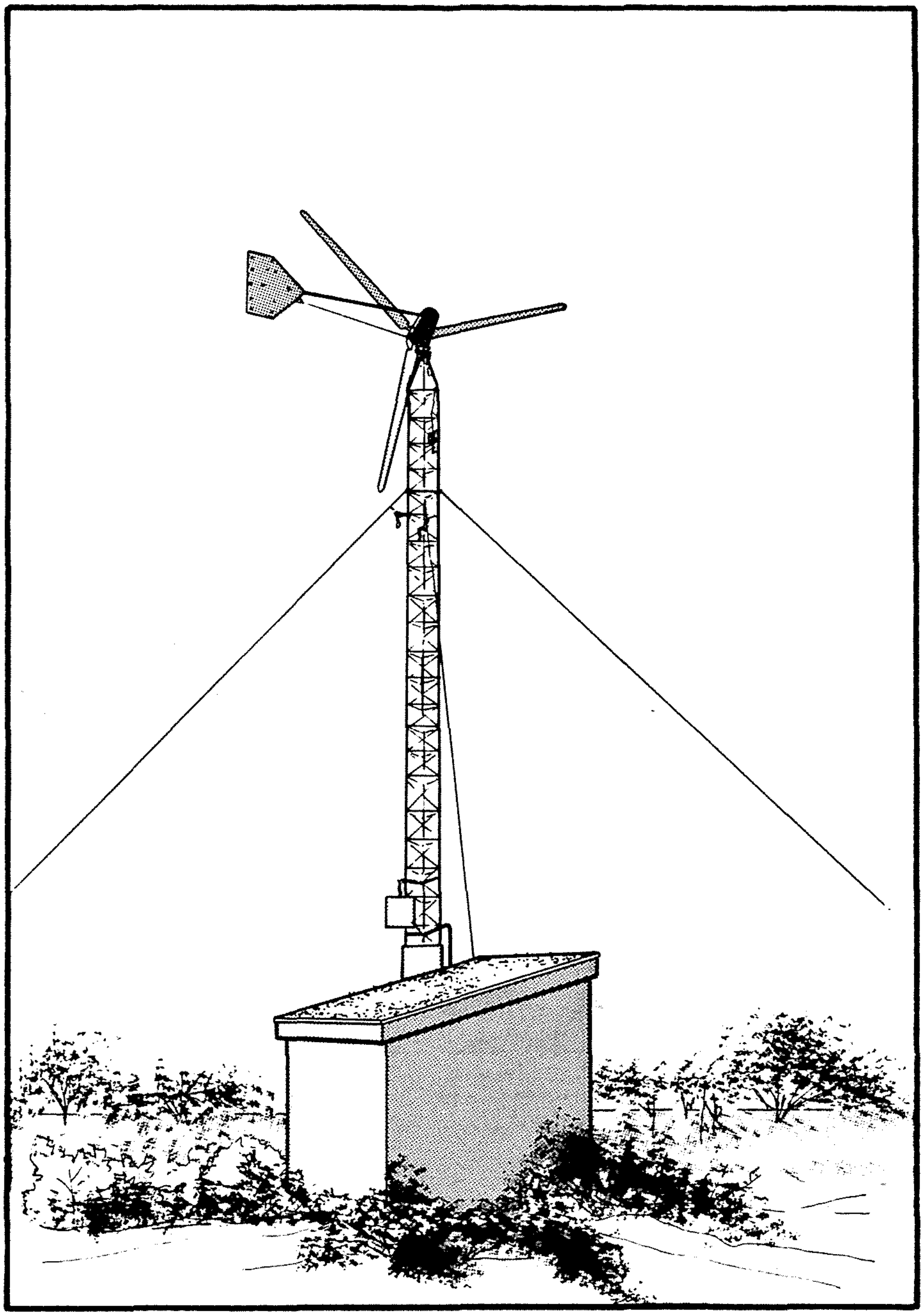


FIGURE 7.13. A Typical Horizontal Axis Small Wind Machine

built into the machine to control frequency. This type of machine may be used to generate 60 Hz alternating current either in conjunction with or independent of a utility grid. The rotor must turn at constant RPM, somewhat sacrificing machine efficiency at extreme wind velocities. Future SWECS using synchronous generators may incorporate variable speed transmissions, allowing rotor speed to vary with wind velocity.

Induction generators will provide synchronized alternating current at any speed above a given minimum speed. Rotor RPM can thus vary with wind velocity, enhancing machine efficiency. Because it requires external synchronization, machines using induction generators normally must be connected to a utility grid.

SWECS that generate DC power are typically used for charging batteries in remote sites. Either a brush-type DC motor or an alternator and DC rectifier are generally used. The DC power can be used directly, can charge batteries, or can be inverted to AC power. A synchronous inverter may be used with a DC generator to convert the DC power to AC synchronized with the utility.

Performance Characteristics

Horizontal axis machines have somewhat greater conversion efficiencies than vertical axis machines; however, the capital cost advantage of higher conversion efficiencies may be offset by the structural advantage of the vertical axis machine. The theoretical maximum conversion efficiency of a SWECS is 60%. Most wind generators currently manufactured in the U.S. have conversion efficiencies of 15% to 30% (electricity at the base of the tower).

On-grid SWECS are usually not considered to be firm capacity and operating as fuel-saver devices. However, in regions as climatically diverse as the Railbelt, studies have shown that with simple load management techniques, wind machines can be given significant capacity credit in grids without storage (Timm 1980).

Energy storage is "built into" grids having hydroelectric facilities with reservoir storage capacity. Energy produced by wind machines offsets hydro production requirements. During periods of calm, stored water is used to follow load. Hydroelectric pumped storage, or other energy storage facilities, could be used to augment grid storage capacity.

Because of the short lead time required to install a SWECS (less than 1 year if wind data are available, 2 years if not) and because of their small size allowing for incremental additions, SWECS are extremely adaptable to any load growth pattern. Potential machine lifetime is not presently well understood but most likely would be about 20 years.

7.4.2 Siting Requirements

A minimum wind speed of 7 to 10 mph is typically required for operation of a SWECS. An annual average of 10 mph is usually considered a lower economic cut-off for most applications; however, this figure depends on the site, costs of energy from alternative sources, and particular wind generator design.

Each site must be evaluated for terrain (Figure 7.14) and what affect that may have on wind speeds at different heights (Figure 7.15). Sites having favorable exposure to the wind typically include ridge crests, hilltops, mountain summits and large clearings. Local topography, such as valleys oriented to the prevailing wind, may enhance general regional wind characteristics. Locations such as valleys oriented perpendicular to the prevailing wind, canyons, sites in the lee of hills, and forested and urban sites tend to have less favorable wind characteristics.

A small wind machine that is to be intertied to the utility grid must be reasonably close to existing or planned power lines. This requirement may eliminate many ridge tops because of the transmission line costs. Small wind

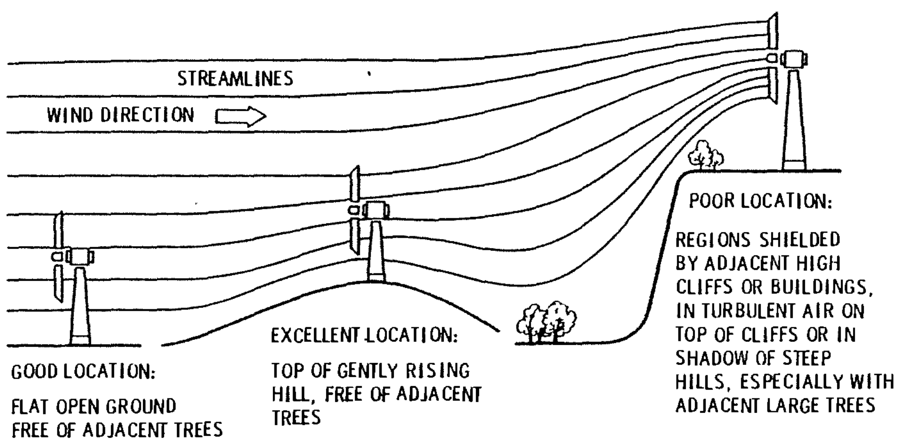


FIGURE 7.14. The Effect of Local Terrain on Wind Machine Performance

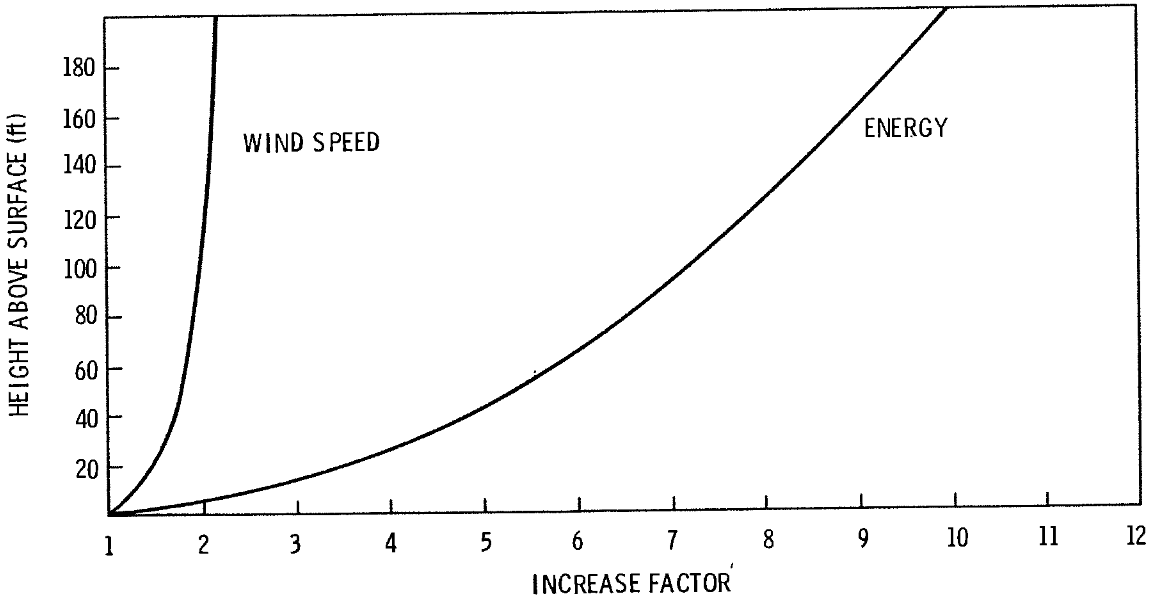


FIGURE 7.15. Example of Increase in Energy Available with Increased Tower Height

machines mounted on towers require no more than 100 ft[2] at the base plus any exclusion area that the owner wishes to fence off for safety reasons (usually no more than about 5 blade diameters).

7.4.3 Costs

Depending on the application, tax credits, and the type of system, installing a residential-sized unit with an installed capacity of 2 to 10 kW would require an initial investment of $5,000 to $20,000 (Table 7.7). O&M costs of 1% of installed costs ($50-$200/year) would be representative, but depends on the system.

TABLE 7.7. Estimated Costs of SWECS (1980 dollars)

Rated Capacity (kW)	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy (mills/kWh)[a]
2	2500	25	113-56
10	2000	20	91-46

(a) Levelized lifetime costs assuming a 1990 first year of commercial operation. Range represents capacity factors of 20% and 40%, respectively.

7.4.4 Environmental Considerations

Studies have shown that SWECS have somewhat enhanced local wildlife due to downwind shelters. A possible adverse impact on low flying night migratory birds in bad weather also has been indicated, although the kill rate is not significant. Aesthetic impacts are difficult to assess and highly subjective. Many people surveyed have found small wind machines to be visually pleasing. Noise from small generators is not significant with proper blade design. Radio frequency interference can be mitigated with proper blade design (nonmetallic) and siting. Potential safety risks involve the possibility of tower or blade failure and aircraft collision. Actions taken to decrease those risks include: a) maintenance of an exclusion area around the turbine; b) automatic monitoring of turbine operation; c) regular preventative maintenance; d) visitor control measures; and e) adherence to FAA requirements for tall structures. No injuries or deaths are anticipated over the life of the plant.

7.4.5 Socioeconomic Considerations

By siting SWECS in "wind farms," rows of generators can be lined up as a wind break for combined use in an agricultural project. Land use in cities would pose a significant problem with safety considerations and building codes, but rural land, which constitutes most of the Railbelt, presents no such difficulties.

Typically, SWECS require a small, two- to four-man crew for installation, and maintenance can generally be performed by two people. No major influx of temporary or permanent labor forces should result from construction or operation of a facility. The necessary manpower, talent, and expertise are currently available within the Railbelt.

The chief advantage of SWECS is that once they are installed, no capital is required for fuel expenditures and very little is needed for operation and maintenance (all of which would stay in the region). If SWECS were manufactured in the Railbelt region, a significant portion of the capital cost could also stay in the region.

The convenience of this technology to the consumer depends on the system. Induction generator systems require only an annual inspection and lubrication of the wind generator. Synchronous generator systems being installed today are totally microprocessor controlled and need no maintenance other than periodic generator inspection and lubrication. Maintenance contracts, which would free the consumer from any maintenance responsibilities, are presently available.

7.4.6 Potential Application in the Railbelt Region

Until recently only a few SWECS manufacturers existed. Today over 50 exist, with a half dozen mass-producing generators at a rate of 20 to 200 per month. The demand, however, is currently outpacing the supply, and several manufacturers report back-orders of 120 days, or more. However, 60 to 90 days is generally quoted as delivery time.

A dealership and repair network already exists in the Railbelt region and would grow as the number of installed SWECS increases. Engineering and design expertise is also present in the region. A survey conducted in 1981 indicated that five system design organizations, four suppliers and one installer were operating in the Railbelt.

The major obstacle to the availability of wind generators seems to be the lack of venture capital in an unstable economic climate, which makes needed plant expansion difficult for manufacturers. Once market penetration and mass production have brought the unit cost down and manufacturers have internalized major R&D efforts, then widespread use of SWECS is possible.

A wind energy resource atlas has recently been compiled for Alaska (Battelle, Pacific Northwest Laboratories 1980b). Figure 7.16 shows Railbelt areas that are estimated to have average annual wind speeds of 11.5 mph or more at elevations typical of SWECS (10m, 33ft). Wind resource data of Figure 7.16 are based on conditions expected in locations of favorable exposure.

As Figure 7.16 shows, the major population centers of the Railbelt are not located in areas promising adequate wind resources for SWECS applications. However, localized topographic and meteorological effects may provide local

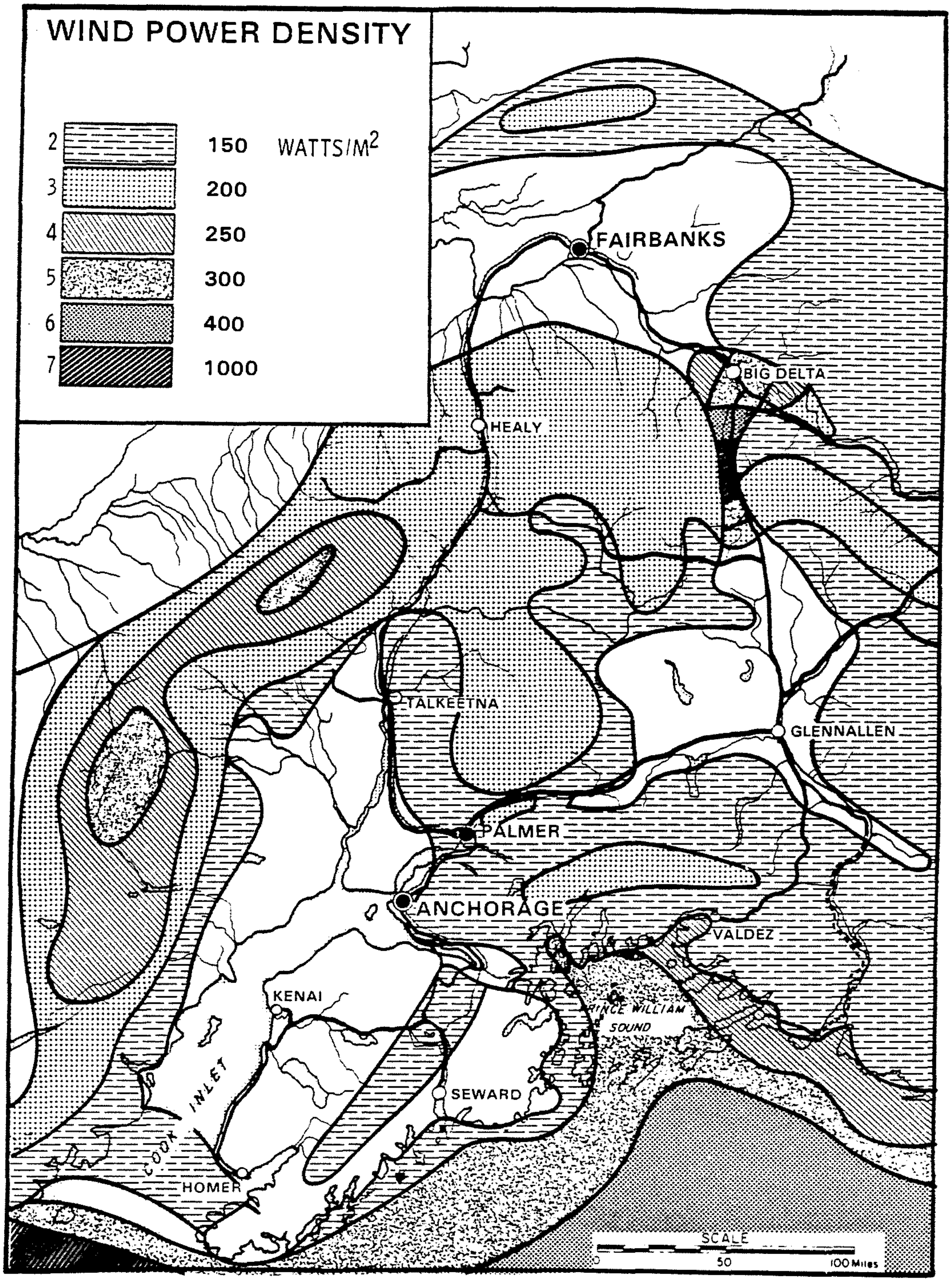


FIGURE 7.16. Potential Wind Resources for SWECS Development in the Railbelt Area

occurrences of wind conditions favorable to the operation of SWECS in areas not appearing favorable at the macro scale of the existing Alaska wind resource assessment. A few examples are as follows:

- The annual average recorded for Anchorage is 5 mph taken at the international airport. Closer to the mountains at the site of an installed wind generator the average is 6 mph. At Flat Top Mountain, a homeowner who plans to install a SWECS has recorded months of 15 mph averages.
- In Homer the recorded annual average is 9 mph at the airport, while on the "spit" the average is reported to be closer to 13 mph. Further up the hill at the site for an 18-kW SWECS, the winds have not been measured but are expected to be better than at the airport.
- In Fairbanks the average windspeed is recorded as 4 mph, yet the speed increases going out of the valley. The average wind speed almost triples near Murphy Dome.
- A recent study done by Battelle-Northwest (1980b) of the Cook Inlet area identified six regions with potentially sufficient winds for megawatt-scale turbines, but lack of useful wind data did not allow candidate sites to be selected or site-specific costs to be identified for large wind systems.

Because of the lack of local wind resource data, little basis exists for a quantitative assessment of SWECS's possible contribution to the Railbelt region. The bulk of future SWECS development, however, appears to be scattered in localized "wind spots" that are not presently inventoried and in the few communities located in areas of more favorable general wind characteristics.

An order of magnitude estimate of the potential contribution of small wind energy conversion systems to the Railbelt electric power system was prepared for this report. Estimates were based upon full penetration of SWECS (i.e., one for every residence) in all areas having wind resources of 150 watts/m^2 or greater (Figure 7.16). Within wind resource areas characteristic of the populated areas of the Railbelt, SWECS begin to be cost effective at marginal power costs of 60 mills per kilowatt hour. Assuming full penetration, it appears that approximately 5 MW of SWECS capacity, generating 15 GWh annual average energy, would be cost effective at marginal energy costs of 60 mills per kilowatt hour.[a] At marginal costs of 100 mills per kilowatt-hour it is estimated (Table 7.8) that approximately 37 MW of SWECS capacity, producing approximately 96 GWh annual average energy would be cost-effective.

The estimates of Table 7.8, as noted above, are based on full penetration of SWECS. In practice, penetration would be substantially less due to such constraints as spatial limitations on SWECS installation in urban areas and homeowner reluctance to install and maintain SWECS.

(a) Note, however, that customers see average, not marginal energy costs and thus would not invest in SWECS based on pure cost effectiveness.

TABLE 7.8. Estimated Small Wind Energy Conversion Systems Development Potential, by Load Center

Cost of Energy (mills/kWh)	Anchorage L.C. Installed Capacity (MW)	Anchorage L.C. Energy (GWh)	Fairbanks L.C. Installed Capacity (MW)	Fairbanks L.C. Energy (GWh)	Glennallen L.C. Installed Capacity (MW)	Glennallen L.C. Energy (GWh)	Total Installed Capacity (MW)	Total Energy (GWh)
50	--	--	--	--	--	--	--	--
60	5	16	<1	<1	<1	<1	5	16
70	10	31	3	7	<1	1	13	39
80	14	41	5	13	<1	2	19	56
90	14	41	5	13	<1	2	19	56
100	28	71	9	22	<1	3	37	96
150	34	81	16	34	4	9	54	124

(a) Order-of-magnitude estimates of development potential, assuming full penetration of SWECS whenever cost effective for cost of power shown. In practice, penetration will be substantially less due to constraints to development.

7.5 SOLAR PHOTOVOLTAIC SYSTEMS

Two basic methods for generating electric power from solar radiation are under development: solar thermal conversion and photovoltaic systems. Solar thermal systems involve the conversion of solar energy to heat via a transfer medium. This medium (working fluid) can be water, steam, air, various solutions, or molten metal. Energy is realized as work when the fluid is used to drive a turbine. In photovoltaic systems solar energy is converted to electric energy by activating electrons in photosensitive substances. The subject of this section is solar photovoltaic systems.

Available solar energy is diurnally and seasonally variable and is subject to uncertainties of cloud cover and precipitation. Solar energy facilities must either be employed as a "fuel-saving" option to displace conventional generation, or they must be installed with storage capacity. In addition, if the diurnal and annual load profiles are out of phase with available solar energy resources, the inducements for developing this resource are further reduced. Load profiles and solar resource availability generally do not correspond in the Railbelt region, where demand generally peaks in winter and at night.

7.5.1 Technical Characteristics

Photovoltaic cells operate by using a semiconductor material to capture the energy in light. Energy is captured when a light photon collides with an atom in the semiconductor material with enough energy to dislodge an electron and to permit it to move freely in the material. A vacant electron position is left behind at the site of this collision, causing a migration of electrons within the collector material. An electrical current is created, which induces a voltage specific to the cell material.

At present, commercially available photovoltaic cells are made of silicon wafers and are assembled largely by hand. Nearly two dozen technologies and automatic assembly techniques are under development. Photovoltaic technology is undergoing a burst of innovation comparable to the integrated, circuit-semiconductor technology. New and more efficient cell designs capable of converting 30 to 40% of the sunlight falling on them to electricity have been proposed.

Design Features

Photovoltaic cells are manufactured in modular units (panels) with voltages of 3 to 24 volts and current outputs from the milliamp range to about 3 amps. The cells are load sensitive; as the load is increased, the voltage decreases. Because the panels are modular, they can be easily added together, to form units of various sizes. Possible applications range from dispersed rooftop mounted arrays to central station applications.

A photovoltaic power station consists of arrays of photovoltaic panels mounted on tracking or nontracking support structure, inverters to convert the dc output of the photovoltaic cells to ac current, and grid interconnection equipment up to the limits of various auxiliary systems (Hill 1977). Photovoltaic system conversion efficiencies currently range from approximately 2 to 13%.

Specific types of photovoltaic systems that are undergoing research and development include concentrated sunlight photovoltaics and cogeneration photovoltaic systems.

Concentrated Sunlight Photovoltaics. Parabolic reflectors are used for concentrating sunlight onto an array of solar cells to reduce the number of cells required for a given power output. Conversion efficiencies as high as 18% have been reported for cells operating in sunlight concentrated 300 times (Metz and Hammond 1978). Research at Bell Labs has produced a concentrated sunlight photovoltaics system with an efficiency of 15% (Rawls 1981). Design improvements are expected to result in cells that have an efficiency of at least 20%, with slight increases in costs. Parabolic reflectors have one specific disadvantage - to work well, automatic tracking mechanisms must be provided to keep the reflectors focused at the sun. With the sun low in the sky during the winter months in Alaska or in early and late afternoon, these systems would be inefficient.

Cogeneration Photovoltaic Systems. The attractiveness of photovoltaic devices can be increased significantly if the energy not converted to electricity can be used. Energy not converted to electricity appears as thermal energy, warming the photovoltaic cells. This energy can be captured by water pumped over the back surfaces of collecting cells. The resulting warm water, between 60°F and 170°F, can be used for space heating and for domestic hot water heating.

Using photovoltaics in a cogeneration mode reduces the electrical efficiency of the cells. However, high-efficiency cells are less affected by high-temperature operation than are silicon devices. In most cases, if a use for low-temperature thermal energy exists, accepting the losses of electrical conversion efficiency and using the thermal output from the cells directly is preferable. Using these systems could be more efficient than using straight photovoltaic systems for certain applications. However, even in regions having favorable solar resources, these options are expensive.

Performance Characteristics

As stated earlier, conversion efficiencies for photovoltaic systems range from 2 to 13%. Including resistance losses of interconnection and power conditioning equipment results in typical control station conversion efficiencies of 8%.

Experience with photovoltaic systems to date have shown the systems to be extremely reliable. Maintenance can be scheduled during periods of no sunlight, essentially eliminating scheduled plant outages during hours of sunlight availability. Likewise, due to plant modularity and generally high reliability of plant components, it appears that unscheduled outage rates would be low. The resulting plant availability is high, estimated to exceed 90%.

Because of the high plant availability, the capacity factor of photovoltaic plants will be largely controlled by the availability of solar radiation. Available solar insolation data for the Railbelt are extremely limited; however, it is unlikely that an average annual capacity factor exceeding 20% could be achieved in the best sites. As discussed in Section 7.5.6, available solar radiation in the Railbelt region would be greatly skewed to the summer months, with relatively little available to meet peak winter loads. Estimated economic life for a central station photovoltaic system is 20 years.

7.5.2 Siting Requirements

Solar electric generating systems are optimally located in areas with characteristically clear skies. The geographic latitude of the proposed site also plays an important role in determining the intensity of solar insolation. Low sun angles, characteristic of Alaskan latitudes, provide less solar radiation per unit area of the earth's surface, requiring a greater collector area to achieve a given rated capacity. Increasing the "tilt" of collectors relative to the surface of the earth increases the solar power density per unit area of collector but results in shading of adjacent collection devices at low sun angles. These factors, plus low solar radiation availability during the months of greatest demand, place severe constraints on the development of solar energy in the Railbelt region.

In addition to the latitudinal and cloudiness constraints, potential sites must not be shaded by topographic or vegetative features. This type of shading does not present a severe restriction for development in the Railbelt region. The potential for snow and ice accumulation also inhibits development of solar energy resources but should not be a severe constraint at most locations.

Because of their relatively low conversion efficiencies and the diffuse power of incident solar radiation, photovoltaic systems would be fairly land intensive if used for centralized power production. A 10-MW photovoltaic plant would require approximately 20 to 50 acres, depending upon cell spacing and other variables.

7.5.3 Costs

Table 7.9 gives the estimated costs for solar photovoltaic systems. Costs of photovoltaic systems are extremely high compared to other technologies, mainly because of cell manufacturing costs. The costs of photovoltaic cells are currently much higher than projected to be by previous research and development progress.

Capital cost for a 4-ft^2 photovoltaic array (18 volts, 2.5 amps) with a rated capacity of 30 watts is $500 or about $17,000/kW of capacity. Costs as low as $11,000 kW of capacity have been reported by the federal government

TABLE 7.9. Estimated Costs for Solar Photovoltaic Systems

Rated Capacity	Capital Costs ($/kW)	O&M Costs ($/kW/yr)	Cost of[a] Energy ($/kW)
10 MW	11,000[b]	30-40	620
10 MW	500[c]	30-40	54

(a) Levelized lifetime cost assuming 1990 first year of commercial operation. 15% annual average capacity factor.
(b) Current (1980) costs.
(c) Department of Energy estimate, 1986.

when buying in large quantities. DOE had forecasted these costs to be $2000/kW in 1982 and $500/kW in 1986, and as low as $100 to $200/kW in the mid 1990s (EPRI 1980b). However, these projections are largely based on efficiency improvement and production cost reduction goals, and as mentioned earlier, projections of cost reduction have failed to fully materialize.

The average life of a typical photovolatic cell is about 20 years, so provisions for replacement will have to be included in the maintenance costs. Other costs include maintenance of battery storage systems, voltage conversion systems, and the auxiliary backup system. Operating labor costs include cleaning the photovoltaic array (removing ice, snow and dirt), checking batteries and conversion systems, and maintaining a backup system, if one is used. O&M costs are estimated to be 30 to 40 $/kW/yr.

7.5.4 Environmental Considerations

Photovoltaic systems do not require cooling water or other continuous process feedwater for operation. Small quantities of water are required for domestic uses, equipment cleaning, and other miscellaneous uses, but if standard engineering practice is followed, water resource effects should be insignificant. If hot water cogeneration systems are employed in conjunction with photovoltaic systems, continuous feedwater will be required to offset system losses. Because cooling water is not required, water resource effects should be minimal.

Photovoltaic electric power conversion systems have no impact on ambient air quality because they do not emit gaseous pollutants. Only minor modifications of the microclimate will occur near a solar energy facility. No net discharge of heat occurs as with fossil, biomass and nuclear facilities, and the net effect is a slight reduction in the heat available from solar radiation, corresponding to the plant efficiency.

Due to minimal water requirements, the operation of photovoltaic systems will have insignificant impacts on fresh water or marine biota. The major terrestrial impact of photovoltaic systems is habitat loss. This loss could be severe for utility-scale systems because of the land-intensive characteristic of these technologies. If these systems are located in remote areas, the potential for wildlife disturbance through increased human access may also be significant.

7.5.5 Socioeconomic Considerations

Solar photovoltaic systems require a large construction work force and a small operating and maintenance staff. A 10-MW, photovoltaic plant would require a construction work force of 100 and an operating and maintenance work force of 10. The impacts would range from moderate to severe on communities with populations of less than 5,000. Construction lead time would range from 1 to 2 years.

Although a relatively large construction work force is used, solar electric generating options require large investments in high-technology equipment. Of the project investment, 80% would be spent outside Alaska and 20% would remain in Alaska.

7.5.6 Potential Application in the Railbelt Region

Solar insolation data collected at Fairbanks and at Matanuska, near Anchorage, were examined. The data reflect the influence of both cloudiness and the annual cycle in sun angle at these locations. At Fairbanks the total daily solar radiation on a horizontal surface is 13 Btu/ft^2 in December and 1,869 Btu/ft^2 in June. At Matanuska these values range from 48 Btu/ft^2 in December to 1,730 Btu/ft^2 in June (Figure 7.17). In comparsion, in the arid

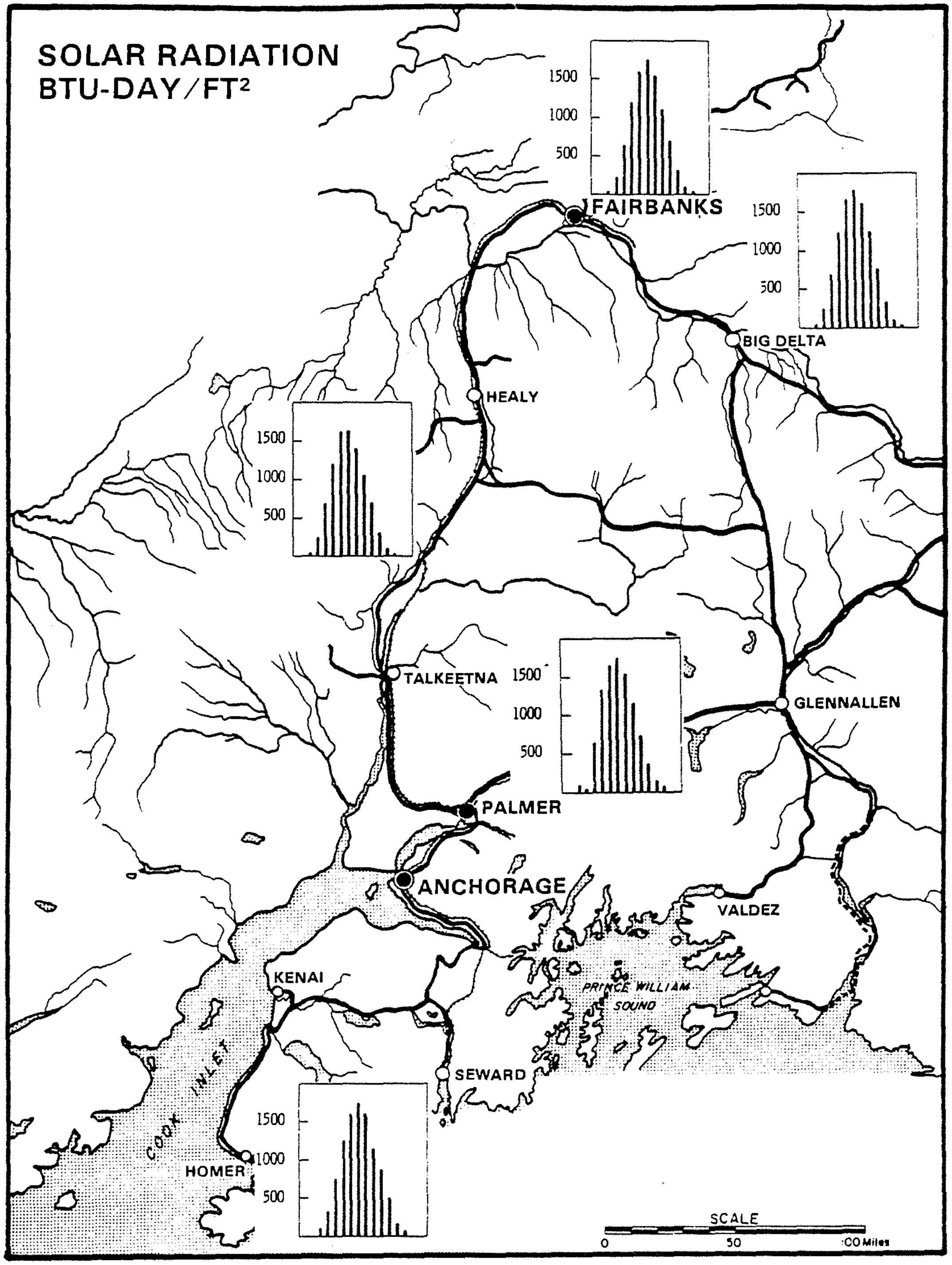


FIGURE 7.17. Solar Insolation for Selected Railbelt Locations

southwestern United States, January values of 1,200 Btu/ft^2 are common with many areas having July values over 2,500 Btu/ft^2. Even in less favored areas, such as Minnesota, these same values vary from 550 Btu/ft^2 to 2,000 Btu/ft^2 during the year. These data indicate that while an abundant supply of solar energy exists on a horizontal surface in midsummer in Alaska, the midwinter values are an order of magnitude less than those of even poor sites in the remainder of the country. Even on south-facing vertical walls, the daily total solar radiation in Matanuska is only 300 Btu/ft^2 in December, which indicates that the mere reorientation of collecting surfaces will not alleviate the lack of wintertime solar insolation.

The lack of winter sunshine in the Railbelt clearly limits the development of solar energy as a resource for electric power generation for two reasons. First, plant utilization in the winter would be extremely low, leading to low annual capacity factors, resulting in high production costs. Second, the Railbelt is characterized by a winter peaking electrical load because of increased demands for space heating and electric lighting in the winter months. Solar-based electrical production would not coincide with the period of maximum annual load, requiring nonsolar generating facilities to be used during the winter months. Alternatively, an extremely large amount of solar capacity could be installed to meet wintertime loads; however, this capacity would be idle during summer months, again leading to high production costs.

7.6 SOLAR THERMAL ELECTRIC SYSTEMS

As discussed in the preceding section two basic methods for generating electric power from solar radiation are under development: solar thermal conversion and photovoltaic systems. Solar thermal systems involve the conversion of solar energy to heat via a transfer medium. This medium (working fluid) can be water, steam, air, various solutions, or molten metal. Energy is realized as work when the fluid is used to drive a turbine.

Available solar energy is diurnally and seasonally variable and is subject to uncertainties of cloud cover and precipitation. Thus solar thermal systems, like solar photovoltaic systems, must either be employed as a "fuel-saving" option or they must be installed with adequate storage capacity. In addition, if the diurnal and annual load profiles are out of phase with available solar energy resources, the inducements for developing this resource are further reduced. Load profiles and solar resource availability generally do not correspond in the Railbelt region, where demand generally peaks in winter and at night.

7.6.1 Technical Characteristics

Solar thermal systems use focused sunlight to provide concentrated thermal energy. This energy is then used to impart heat to working fluid, which is then used to drive turbogenerators to produce electricity.

Design Features

The two most advanced solar thermal systems are power towers and parabolic dish collectors.

Power Towers. A power tower uses solar energy to raise a working fluid to high temperatures for the generation of electricity or process heat. Optical studies show that the best way to generate high temperatures using solar energy is with a point-focusing array of mirrors that track the sun (heliostats). The solar radiation is focused on a boiler set atop a large tower. Heliostats that concentrate sunlight several hundred times are used to raise the temperature in the boiler to 500°C, and the resulting steam can be used to produce electricity using a steam turbine. Back pressure or extraction turbines can be used to obtain process heat for cogeneration applications.

The first solar thermal test facility (5 MW) has been completed at Sandia Laboratories near Albuquerque, New Mexico, for $21 million. The second is a 10-MW electric plant built near Barstow, California, developed at a cost of $130 million. These two projects, largely funded by the government, are due to be followed by a 100-MW demonstration plant in the late 1980s, and finally a 100-MW prototype commercial plant in the mid 1990s.

Parabolic Dish Collectors. A regime of intermediate operating temperatures (300 to 600°C) can be provided by solar systems in which the optical standards are not as critical as those required for high-temperature systems. The efficiencies, however, are markedly superior to those of the low-temperature collectors used for space and water heating. Intermediate temperature collectors could be used for process heat, crop irrigation, and decentralized generation of electricity.

One such system is the parabolic tracking dish. The system operates by directing the sun's radiation to the focus of a large dish where the energy is absorbed by the working fluid. To produce electricity, the fluid is circulated through a small heat engine (Hill 1977). Higher temperature systems are being studied. The Solchan concept uses solar energy to drive an endothermic reaction of gaseous compounds to achieve an operating temperature of 750°C (Krieger 1981).

Performance Characteristics

Conversion efficiencies for solar-thermal systems are climate sensitive and range from 10 to 70%. Because of the lack of operating experience with solar thermal systems, no reliability data are currently available.

Assuming that unscheduled outage rates will approach those characteristic of other generating facilities and that scheduled outages can be performed during hours which the sun is not shining, capacity factor will be controlled primarily by the availability of solar radiation. As discussed in Section 7.5, information on solar insolation in the Railbelt is extremely limited. It is unlikely that an average annual capacity factor in excess of 20% could be achieved even in the best sites. In addition, available solar radiation in the Railbelt region would be greatly skewed to the low-load summer months.

Estimated plant life for solar thermal power plants is 30 years.

7.6.2 Siting Requirements

Solar thermal systems, like photovoltaic systems, are optimally located in areas with characteristically clear skies. The geographic latitude of the proposed site also plays an important role in determining the intensity of solar insolation. Low sun angles, characteristic of Alaskan latitudes, provide less solar radiation per unit area of the earth's surface, requiring greater collector area to achieve a given rated capacity. Increasing the "tilt" of collectors to the surface of the earth increases the solar power density per unit area of collector but results in shading of adjacent collection devices at low sun angles. These factors, plus low solar radiation availability during the months of greatest demand place, severe constraints on the development of solar energy in the Railbelt region.

In addition to the latitudinal and cloudiness constraints, potential sites must not be shaded by topographic or vegetative features. This type of shading does not present a severe restriction for development in the Railbelt region. The potential for snow and ice accumulation also inhibits development of solar energy resources but should not be a severe constraint at most locations.

Solar thermal plant efficiencies are higher than for photovoltaic systems, resulting in somewhat less land requirements. A typical, density-packed 60-MW tower would require approximately 160 acres (Metz and Hammond 1978).

7.6.3 Costs

Cost estimates for solar thermal systems in the 10- to 100-MW capacity range are expected to be 1500 $/kW (1980 dollars) when commercially available (1997) (Table 7.10). Construction time is estimated at 5 years. Annual O&M costs are expected to be 30 to 40 $/kW/yr (EPRI 1980b).

TABLE 7.10. Estimated Costs for Solar Thermal Systems

Rated Capacity	Capital Costs ($/kW)	O&M Costs ($/kW/yr)	Cost of[(a)] Energy ($/kW)
10 MW	1500	30-40	91
100 MW	1200	27-36	75

(a) Levelized lifetime cost assuming 1997 first year of commercial operation and 15% capacity factor (comparable to 1990 first year of operation costs given elsewhere in this report due to lack of fuel escalation).

7.6.4 Environmental Considerations

Solar thermal conversion systems would produce water resource effects similar to those of other steam-cycle facilities. Boiler feedwater and condenser cooling water will be required and will necessitate proper management techniques (refer to Appendix D). Cooling water requirements are extremely site specific, as efficiencies ranging from 10 to 70% are possible depending upon climatic factors.

Solar thermal conversion systems may also be operated using a working fluid other than water. Proposed working fluids include liquid sodium, sodium hydroxide, hydrocarbon oils, and sodium and potassium nitrates and nitrites. These substances have the potential to adversely affect water quality through accidental spills and normal system flushing. Specialized transportation and handling techniques will be required to minimize the risk of spills and to mitigate potential impacts.

Solar thermal systems have no impact on ambient air quality because they do not emit gaseous pollutants. However, water vapor plumes may emanate from cooling systems. These plumes would likely be of less consequence than for nuclear or combustion-fired steam-electric plants because solar-thermal systems operate best in full sunlight when the humidity tends to be well below saturation. Under these conditions, the water droplets are quickly evaporated into the dry atmosphere. The plumes can also be mitigated by using dry or wet/dry cooling tower systems.

Only minor modifications of the microclimate will occur near a solar energy facility. The heat is merely redistributed within the facility and will not affect climatic conditions offsite.

The major terrestrial impact of solar thermal conversion systems is habitat loss. This loss could be severe for utility-scale systems because of the land-intensive characteristic of this technology. If these systems are located in remote areas, the potential for wildlife disturbance through increased human access may also be significant. Spills of nonwater working fluids, if used, could adversely affect local ecosystems.

7.6.5 Socioeconomic Considerations

Solar thermal conversion systems require a large construction work force and a small operating and maintenance staff. A 10-MW central receiver would require a construction work force of 60 and an operating and maintenance staff of 25. The impacts of the system would range from moderate to severe on communities with populations of less than 5,000.

Although a relatively large construction work force is used, solar electric generating options require large investments in high technology equipment. Of the project's investment, 80% would be spent outside Alaska and 20% would remain in Alaska.

7.6.6 Potential Application in the Railbelt Region

As discussed in Section 7.5, data indicate that while an abundant supply of solar energy falls on a horizontal surface in midsummer in Alaska, the midwinter values are an order of magnitude less than those of even poor sites in the remainder of the country.

The lack of winter sunshine in the Railbelt clearly limits the development of solar energy as a resource for electric power generation for two reasons. First, plant utilization in the winter would be extremely low, leading to low annual capacity factors, resulting in high production costs. Second, the Railbelt is characterized by a winter peaking electrical load because of increased demands for space heating and electric lighting in the winter months. Solar-based electrical production would not coincide with the period of maximum annual load, requiring nonsolar generating facilities to be used during the winter months. Alternatively, an extremely large amount of solar capacity could be installed to meet wintertime loads; however, this capacity would be idle during summer months, again leading to high production costs.

7.7 SMALL-SCALE HYDROELECTRIC AND MICROHYDROELECTRIC POWER PLANTS

Small-scale hydroelectric plants are those having installed capacities of 15 MW or less. Microhydroelectric facilities are defined for this profile as facilities having installed capacities of 100 MW or less. There is, however, no consistent cutoff between microhydro and small-scale hydro facilities, and the interface between the two classes of facilities may be as great as 1 MW.

7.7.1 Technical Characteristics

Small hydroelectric and microhydroelectric facilities differ from larger conventional hydro facilities in several ways. First, most small hydro and microhydro projects have heads of 100 feet or less. The turbine and other powerhouse costs are more closely correlated to river flow rather than head, and therefore the per-kilowatt costs of this equipment can be relatively high. Second, such facilities are generally constructed based soley on the benefits of power production. This is in contrast to many larger projects that may be justified on flood control, recreation, or other benefits in addition to the power generated. Finally, many small-scale hydro and microhydro projects have little or no working storage and they operate as run-of-the-river units. Capital costs are therefore reduced, but scheduled peak power generation is not available.

At minimum, a typical microhydro or small hydro electric generation facility consists of a hydraulic turbine, an electric generator, a powerhouse, a water intake structure and a penstock. Grid-integrated units also require a power transmission system. Also, depending on the specific site situation and facility configuration, additional equipment and structures may be necessary, including dams/impoundments, pressure tunnels or conduits, and other civil features.

Design Features

Principal turbine components consist of the runner, a supply case to convey the water to the runner, wicket gates to control the quantity of water and to distribute it to the runner, and a draft tube to convey the water away from the turbine. Hydraulic turbines are generally classified as either impulse or reaction turbines. The impulse type turbine derives its mechanical output from the pressure of one or more high-velocity jets of water hitting the periphery of the runner. Reaction turbines use the combined action of pressure and velocity of the water that completely fills the runner and water flow passages.

The net head of water available dictates the type of turbine suitable for a particular site (Figure 7.18). Reaction turbines are classified as either Francis (mixed flow) or Propeller (axial flow). Either type of turbine may be mounted vertically or horizontally. Propeller turbines include such trade named units as Tube, Bulb, and Straflo. Impulse turbine designs are classified as Pelton and Turgo. Cross sections of the various commercially available turbine types are shown in Figure 7.19.

Water wheels can also be used to generate electricity, although at a significantly lower efficiency than higher speed turbines. The undershot, breast, poncelet and overshot wheels are usually large diameter, slow turning wheels best suited to generating mechanical power for such equipment as pumps and lathes. In many areas they must be housed in large structures or provided with some form of protection to avoid freeze-up during cold weather operation.

The generators, either synchronous or induction, are selected to match the turbine type, turbine orientation, and the nature of the grid interconnection. A generator for a bulb turbine is located in the bulb, whereas a horizontal generator is generally required for tube turbine. A vertical shaft generator is appropriate for most Francis turbine installations.

Off-grid installations use synchronous ac or dc generators. Synchronous ac generators require a turbine governor to maintain the required constant operating speed, but have the advantage of providing alternating current. Direct current generators allow direct connection of battery storage facilities, but require inverters if ac power is desired.

On-grid installations typically use induction ac generators, with frequency controlled by the utility grid. Single-phase utility interconnection may be made with a dc generator with a solid state static inverter (Federal Energy Regulatory Commission (FERC) 1979).

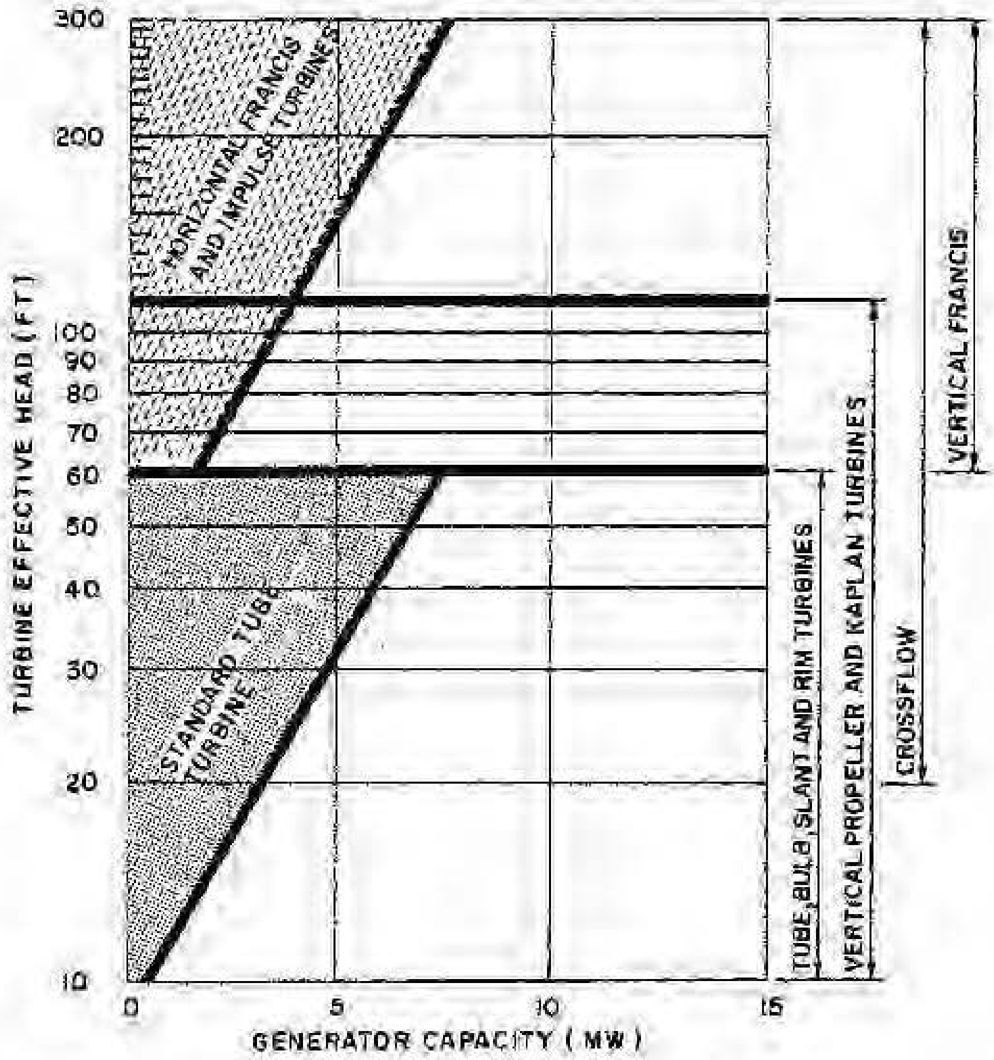


FIGURE 7.18. Turbine Operating Range

Many manufacturers of turbine-generator units for microhydroelectric power plants are currently marketing small packaged units and standard designs, particularly reaction turbine systems. These manufacturers are located both in Europe and North America.

As described in Section 5.4.1, four basic categories of dams exist. Reservoirs may be one of two primary types. One is a run-of-the-river impoundment where the head is low and the reservoir capacity is small. In this type

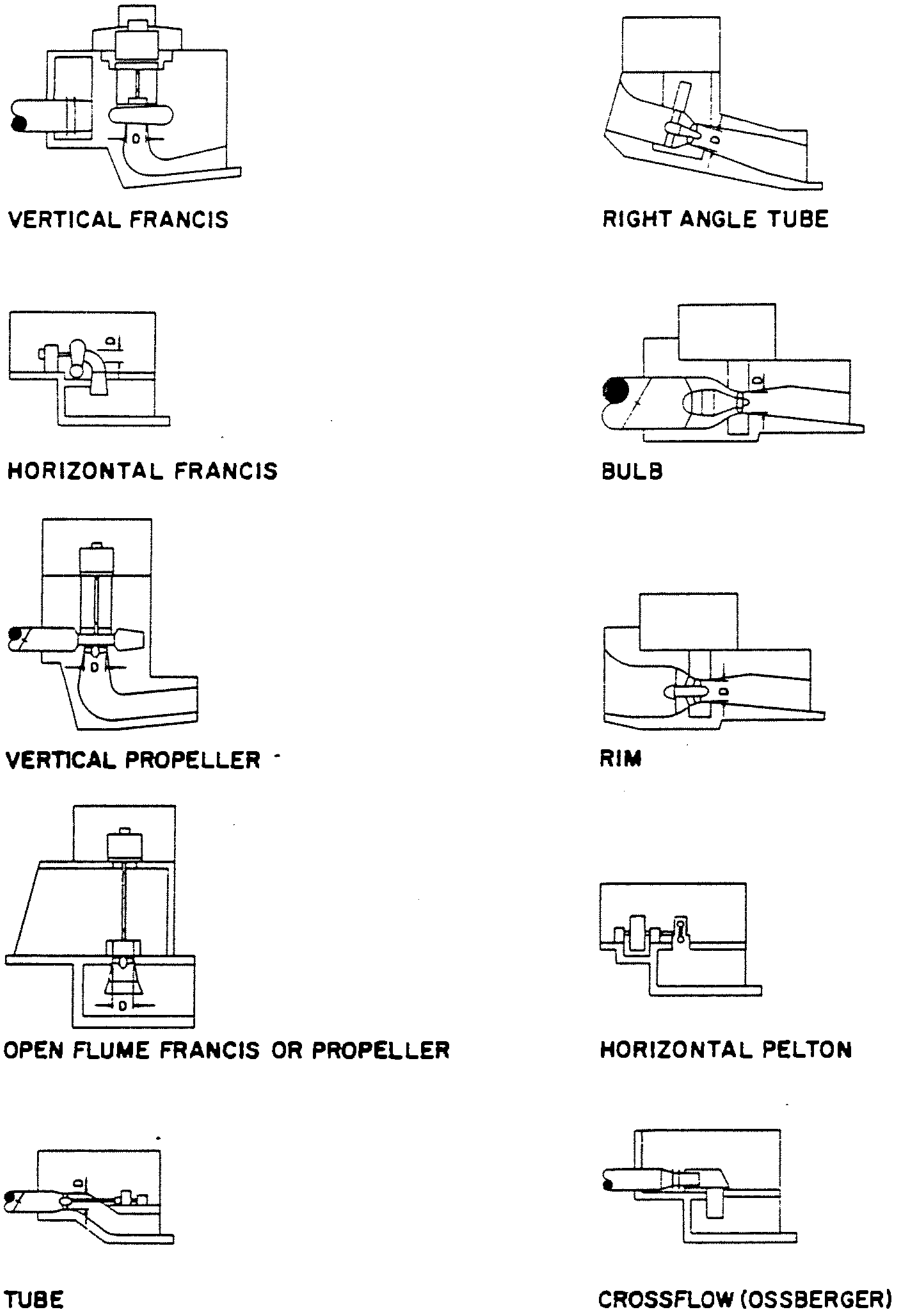


FIGURE 7.19. Turbine Cross Sections

of reservoir, the water level fluctuates little. Storage reservoirs have a greater capacity and are designed to accommodate significant fluctuations in level, depending on power demand requirements.

Associated with these dam-reservoir installations are various appurtenant works to control the flow, including spillways and outlet structures. Fish ladders, navigation locks, and log sluices may also be required for certain sites.

Performance Characteristics

The typical efficiencies for various hydroelectric facilities range from 50 to 85%, depending on the components and scale of the installation. If the head and discharge rate are relatively constant, an overall efficiency rating of 85% can be achieved. When the head and/or flow rate varies, a more precise analysis of the efficiency is obtained by taking the product of the turbine efficiency and all other losses (generally assumed to be 0.95). As the head and/or flow rate vary, the expected efficiency of the turbine drops off from a maximum of 90% at 100% rated capacity to about 75% at 20% capacity.

For microhydro installations, the average overall efficiencies of reaction and impulse turbines are about 80 to 85%. Water wheel efficiencies range from a low of 25% for undershot units to 60 to 70% for overshot wheels. On the average, microhydro plants are 50 to 70% efficient, with the higher efficiencies occurring in high-head, high-speed turbine units.

Specific information on plant availability is not available but is likely to be high. Grid-connected microhydro units are generally operated as fuel savers. The typical plant capacity factor for these units ranges from 60 to 100% (Alward, Eisenbart and Volkman 1979) with an assumed plant life of about 13 years.

7.7.2 Siting Requirements

The primary siting requirement is the need to ensure that a sufficient, minimum continuous flow of water exists. Both the minimum flow rate and the portion of this flow that is available for power generation must be known. The percentage of the minimum flow that can be diverted to power generation is influenced by factors such as fish requirements, agricultural needs, and recreational/aesthetic restrictions. One manufacturer of microhydro components suggest that no more than 25% of the stream flow be used for power generation. This is only a rough figure and each site must be evaluated individually.

In siting a small-scale hydroelectric or microhydroelectric facility, considerations must be made for the distance to existing transmission grids and roads. Overall capital costs for smaller installations are very sensitive to the cost of access and transmission facilities. Land requirements for nonreservoir civil features should be relatively small because typically such installations are unattended and remotely operated. This reduces the requirements for working space, storage area, maintenance facilities, and operations facilities. If a dam is necessary, the siting of a hydroelectric plant must also be based on a full understanding of the physical characteristics of the land.

7.7.3 Costs

Cost estimates for microhydroelectric facilities cover a wide range. This range results from the numerous design variables inherently involved in such units. Some of the major cost features include the hydraulic turbine, the generator, the turbine generator accessory equipment, the civil works, the transmission system, and the access roads. The size and resulting costs of these and other design features are site dependent - the available operating head and the general remoteness of the site have a signficant effect on the facilities' total cost. In Table 7.11 the estimated capital, O&M, and power costs for small hydro and microhydro plants in Alaska are presented for both remote and local facilities. The distinction is made due to the major costs associated with access road and transmission systems needed to develop a

TABLE 7.11. Cost Summary for Grid-Connected Small Hydro and Microhydro Plants (1980 dollars)

Type of Facility	Capital ($/kW)	O&M ($/kW/yr)	Cost of Energy (mills/kWh)[a]
Local Facilities 0.1-15.0 MW	800-15,000	16-290	10-190
Remote Facilities[b] 0.1-15.0 MW	6,500-20,000	130-410	83-260

(a) Levelized lifetime cost assuming 1990 first year of commercial operation; 80% capacity factor.
(b) Five miles from existing roads or transmission lines.

remote hydroelectric site. The cost data presented in Table 7.11 were based on information from the Corps of Engineers (1979), FERC (1979), and Alward, Eisenbart and Volkman (1979).

These cost estimates compare favorably with estimates made by the Corps of Engineers and others in assessments of the capital costs for various, small hydroelectric projects currently undergoing feasibility studies in Alaska. These projects, located in the Chignik, Perryville, and Nikolski areas, were estimated to generally cost between $2000 and $18,000/kW.

7.7.4 Environmental Considerations

Because of the small size of microhydro and small hydro facilities, their environmental impacts generally should not be significant. The facilities are not anticipated to pose significant threat to plants and mammals in the area or to create any major problems with the surrounding ecological communities - particularly where no reservoir is required. However, one area of concern is the impact on the passage of the anadromous fish, if present. Fish passage facilities would be required to mitigate this problem. Such passage facilities should be operated only at times of resident fish migration to prevent the passage of undesirable fish, which may have been previously blocked from entering the upstream areas by small waterfalls in the stream system.

Another item of concern is the environmental effects of the transmission access and facilities needed to tie the hydro facility to the utility grid. The new cuts through the forest for the power corridors and access roads could disrupt wildlife habitats and migration patterns. The more remote the sites are from existing power transmission corridors and access roads, the greater the likelihood of such detrimental impacts.

Other environmental considerations of potential importance include the aesthetic impacts of the access roads, transmission lines, and civil works if numerous small hydropower plants were developed, and the human intrusion into previously undisturbed wildlife habitat to develop and operate these facilities. The potentially large number of microhydro sites required to produce significant amounts of energy would aggravate these problems.

A preliminary assessment of the terrain, precipitation, transmission systems, and access roads (Mark Fyer and Associates 1980) identified the Fairbanks, Seward-Portage and Anchorage-Palmer areas as possibly having suitable microhydro and small hydro sites. The Glennallen-Valdez area may also have similar potential for microhydro and small hydro development. Lands surrounding these potential sites contain waterfowl and seasonal ranges of moose. The Seward region contains populations of black bear, migration corridors, and seasonal ranges of caribou. Impacts on these animal populations will depend on the characteristics of the specific site and the densities of the wildlife populations in the site area. Due to the relatively small plant capacities involved, however, impacts should be minimized through the plant siting process.

7.7.5 Socioeconomic Considerations

Microhydro and small hydro facilities will require a relatively small labor force for construction and a minimal number of people for operation. Because such hydro facilities are site specific, specifying the size of these construction and operations forces is difficult. Depending on the size of the facility, the distance to existing services, and the required civil features, the construction force can range up to about 20 individuals. Operation and maintenance can require anywhere from one part-time individual to about 3 to 5.

Construction periods for 100 kW to 15 kW facilities can also span a wide range. A preliminary estimate for construction and startup is 12 to 24 months (excluding the licensing process). Preconstruction studies and licensing may require an additional 12 to 24 months.

Possible locations of small hydro and microhydro facilities would include sites near the communities of Seward, Moose Pass, Whittier, Anchorage, Palmer, Glennallen, Valdez, and Fairbanks. Fairbanks, the Anchorage-Palmer area, Valdez, Glennallen and Seward should be able to accommodate the construction and operations forces required for small-scale hydro facilities with minimal social and economic impact. Because of the small populations and undeveloped infrastructure of Whittier and Moose Pass, these communities could possibly experience a minor to moderate impact, depending on the type and size of hydro development. The transfer of up to 20 or more workers and their families for a period of 1 to 2 years may cause a strain on the social and economic structure of the towns. These impacts would be significantly reduced for small hydro or microhydro facilities that require only minimum civil works.

The breakdown of capital expenditures is expected to be 60% outside the Railbelt and 40% within the region. Approximately 10% of the O&M expenditures would be spent ouside the region.

7.7.6 Potential Applications for the Railbelt Region

One small-scale hydroelectric project, the 15-MW Cooper Lake project on the Kenai Peninsula, currently exists in the Railbelt region. One additional small-scale project, the 7-MW Grant Lake project near Seward is currently in the planning stage. An interim feasibility study (U.S. Army Corps of Engineers 1981) has been completed on a third site, Allison Creek, as discussed below. A review by Acres American (1981b) identified technically feasible hydroelectric sites in the Railbelt region (Table 5.8). Of these sites, 15 (including Grant Lake) are small-scale projects (Table 7.12).

Further assessment by Acres American (1981b) of these sites on the basis of economic, environmental and land use considerations resulted in the identification of two sites, Allison Creek and Silver Lake, as having promising potential.

Three potential small-scale hydroelectric projects, Grant Lake, Allison Creek and Silver Lake, totalling 25 MW installed capacity and producing an estimated 99 GWh annual firm energy, thus show promise for development in the Railbelt. Environmental and cost characteristics of these projects are summarized in Table 7.13.

A preliminary assessment of potential microhydro capacity in the Railbelt as a function of cost was prepared for this report, based upon an earlier assessment of the Seward to Fairbanks "core" area of the Railbelt (Mark Fryer and Associates 1980). Within this area, Fryer and Associates identified the Seward to Portage and the Anchorage to Palmer areas as being potential areas for microhydro and small hydro development.

TABLE 7.12. Technically Feasible Small-Scale Hydroelectric Sites in the Railbelt Region

Site	Stream	Firm Energy[a] (GWh)	Average Annual Energy (GWh)	Installed Capacity[a] (MW)
Allison Creek	Allison Creek	32[b]	37[b]	8[b]
Chulitna (East Fork)	East Fork Chulitna River	59	NA	12
Chulitan (West Fork)	West Fork Chulitna River	68	NA	14
Crescent Lake II	Crescent River	29	NA	6
Eagle River	Eagle River	45	NA	9
Grant Lake	Grant Creek	19[b]	27[b]	7[b]
Lower Beluga	Beluga River	72	NA	15
Lucy	Chulitna River	71	NA	15
Nellie Juan	Nellie Juan River	47	NA	10
Power Creek I	Power Creek	66	NA	14
Silver Lake	Duck River	48	NA	10
Soloman Gulch	Unnamed	11	NA	2
Upper Lake Creek	Lake Creek	74	NA	15
Upper Nellie Juan	Nellie Juan River	57	NA	12
Van Cleave	Unnamed	10	NA	2

(a) Data from Acres American (1981b), except as indicated.
(b) U.S. Army Corps of Engineers (1981).
(c) CH2M-Hill (1981).

The Fryer assessment took into account the terrain features, the annual average precipitation, access roads and the transmission systems. Several critical factors that were not examined because they were site specific included the seasonal flow variations and the annual freezing index, a parameter used to estimate the depth of frost penetration and the thickness of lake and stream ice.

Fryer and Associates estimated that development of 50 microhydro projects averaging 50 kW of continuous power each was possibly the upper limit for these areas, although the specific cost of the energy generated by these facilities was not given.

TABLE 7.13. Summary of More Favorable Small-Scale Hydroelectric Sites in the Railbelt Region

Site	Big Game Present	Waterfowl, Raptors Endangered Species	Anadromous Fisheries	Agricultural Potential	Wilderness Potential	Cultural, Recreational and Scientific Features	Estimated Capital Cost[b] ($/kW)	Estimated O&M Cost ($/kW/yr)[c]	Estimated Cost of Power (mills/kWh)
Allison Creek	Black Bear Grizzly Bear	Resident Seabirds and Raptors Peregrine Falcon	Spawning Area	None Identified	Good to High Quality Scenic Area	None Identified	4,288[b]	86[c]	58[d]
Grant Lake	Moose (fall & winter) Mountain Goat (winter) Sheep (winter)	None Identified	Migration Pathway	None Identified	Average Quality Scenery	Hunting	2,220[e]	38[e]	35[d]
Silver Lake	Black Bear Grizzly Bear Seals	Resident Seabirds and Raptors	Present	Western Hemlock Sitka Spruce Forest	Good to High Quality Scenery, Primitive Lands	Chugach N.F. Boating Potential	NA	NA	46[e]

(a) Data from Acres-American (1981b) unless otherwise indicated.
(b) U.S. Army Corps of Engineers (1981).
(c) 2% of capital cost.
(d) Levelized lifetime cost of energy, assuming a 1990 first year of commercial operation.
(e) Cost of energy estimated using cost indices of APA (1980) with Allison Creek as a base cost.

Because of the significant percentage of capital costs associated with the construction of access roads and utility grid intertie transmission lines, Battelle's preliminary resource assessment considered only areas within 5 miles of an existing highway or road. Based on this assessment (Table 7.14) it was concluded that very little grid-connected microhydro development would be cost effective at marginal energy costs of less than 100 mills per kilowatt hour. At marginal energy costs of 100 mills per kilowatt hour, less than 1 MW of microhydro capacity producing approximately 2 GWh annual average energy would be cost effective.

Further study of potential microhydro sites would be required to more firmly establish the potential of this resource in the Railbelt.

TABLE 7.14. Estimated Microhydroelectric Development Potential, by Load Center

Cost of Energy (mills/kWh)	Anchorage L.C. Installed Capacity (MW)	Anchorage L.C. Energy (GWh)	Fairbanks L.C. Installed Capacity (MW)	Fairbanks L.C. Energy (GWh)	Glennallen L.C. Installed Capacity (MW)	Glennallen L.C. Energy (GWh)	Total Installed Capacity (MW)	Total Energy (GWh)
90	--	--	--	--	--	--	--	--
100	<1	1	<1	<1	<1	1	<1	2
150	1	8	<1	<1	1	6	2	14

8.0 LOAD MANAGEMENT

Because electric utilities are required to satisfy the electrical demands imposed by its customers at all times, they have to provide sufficient generation, transmission, and distribution facilities to meet the annual peak load. Activities that reduce the magnitude of load peaks will thus reduce the investment in generating capacity required to meet peak load. Load management is any action taken by a utility to directly affect customer loads or to influence customers to alter their electrical use characteristics. The objective of load management is to shift or shed peak loads to derive a more economical load profile.

8.1 LOAD MANAGEMENT TECHNIQUES

Load management techniques consist of changes in consumption patterns on the customer side of the meter. The customer may be either an end user of electric power (e.g., residential, commercial or industrial) or a utility distributing power from a wholesaler to end-use consumers.

This section summarizes five general load management methods that may be applied to the Railbelt region:

1. direct control of customer loads by the utility
2. passive control of customer loads
3. incentive pricing of electricity
4. education and public involvement programs
5. thermal energy storage.

8.1.1 Direct Load Control

Direct load control is the control of specific customer loads by the electric utility. These loads are cycled or deferred during periods of peak loads or emergencies. Residential loads for space and water heater use can be controlled directly, but interruptions in this type of service can cause customer inconvenience or discomfort. Economic incentive (i.e., lower rates) may be provided to compensate for customer inconvenience. The effectiveness of these incentives depends on their operating parameters and importance to customers.

Studies evaluating loads subject to direct-load control have been conducted primarily in urban areas having load characteristics different from those found in the Railbelt. These studies constitute the most complete set of data on load shaping. If these data are to be presented in their complete context, a variety of load shaping experiences must be shown, including some not applicable (e.g., air conditioning) to the Railbelt. Such general data are presented in this section, whereas a more specific discussion of applications to the Railbelt region can be found in Section 8.4. The types of electrical loads that have been selected most frequently for direct load control are shown in Table 8.1.

TABLE 8.1. Electrical Loads Most Frequently Selected for Direct Load Control (Economic Regulatory Administration 1980)

	Class of Service		
Loads	Residential	Commercial	Industrial
Water Heaters	X	X	
Central Air Conditioners	X	X	
Central Space Heaters	X	X	
Swimming Pool Pumps	X		
Nonessential Loads		X	X

A recent Electric Power Research Institute (EPRI) study (1979a) summarized another study that surveyed 2,000 United States households and obtained data on electric consumption by major appliance from August 1976 to July 1977. Tables 8.2 and 8.3 contain information cited in this study. Table 8.2 shows market penetration for major electric appliances. Table 8.3 presents daily electric consumption by appliance per month. Unfortunately, the study did not include data on time-of-day characteristics. Nevertheless, the information in the tables indicates the potential importance of these residential loads for direct control applications.

Unfortunately, appliances currently used for residential lighting, cooling, and refrigeration are not designed to permit load management. Refrigeration may have potential for load management if thermal storage can be economically incorporated into the design. Electric clothes drying is a substantial

TABLE 8.2. Regional Market Penetration for Major Electric Appliances (Western U.S.) (EPRI 1979a)

Appliances	Penetration (Percent)
Freezer	37.89
Range	37.89
Cooktop and Oven	29.21
Dishwasher	42.37
Clothes Washer	84.21
Clothes Dryer	45.00
Water Heater	11.84
Central Air Conditioning	6.58
Room Air Conditioning	18.16
Swimming Pool Pump	3.68
Electric Heater	3.16

load that usually can be shifted to off-peak hours. In the commercial sector, water heating and space heating offer the most potential, whereas other potentially controllable loads include lighting, air circulating fans, and perhaps elevators. The potential for using off-peak energy in the industrial sector is limited because most loads cannot be deferred or avoided without adverse economic consequences. In the agricultural sector, irrigation pump motors, space heating of animal dwellings, grain drying, feed grinding, and specific dairy cooling operations offer potential for load management (Arthur D. Little 1979).

Direct load control may be implemented by either local or remote control. Local systems depend on the use of a timing or physical sensing device to determine when end-use devices should be employed. Local control devices include the following:

- clock timer switches
- temperature sensing controllers
- photocontrollers
- load levelers.

TABLE 8.3. Average Daily Electric Consumption by Appliance Per Month (kWh/day) (EPRI 1979a)

Appliance	1976 August	1976 Sept.	1976 Oct.	1977 May	1977 June	1977 July
Refrigerator	4.80	4.81	4.57	4.73	4.87	4.97
Freezer	4.13	4.10	3.88	3.78	3.84	3.81
Range	1.84	1.95	2.20	1.87	1.74	1.76
Clothes Washer	0.24	0.25	0.26	0.25	0.23	0.21
Clothes Dryer	2.70	2.72	2.83	2.74	2.68	2.40
Dishwasher	0.36	0.37	0.39	0.42	0.39	0.36
Water Heater	11.66	10.42	10.50	10.49	9.42	9.45
Central Air Conditioner	21.96	14.53	4.41	11.22	25.23	31.25
Room Air Conditioner	6.54	4.63	1.42	2.23	5.96	8.98
Swimming Pool Pump	3.03	2.72	3.20	4.83	4.53	2.20
Electric Heat	1.57	1.30	1.77	1.97	1.60	1.80
Cooktop	1.45	1.52	1.70	1.16	1.12	1.10
Separate Oven	1.00	1.21	1.55	1.16	1.11	0.97

Clock-timer switches are electrically driven controls that automatically turn external circuits on or off at a preset time. These switches have been used for several years, particularly for off-peak electric water heater control. Temperature sensing controllers are outdoor thermostat-cycle timers that can control heating or air-conditioning loads. In a test case run by Georgia Power Co. on central air conditioners, the diversified peak demand was reduced 1.4 kW per central air-conditioner unit controlled by the thermostat. Photocontrollers are light-sensitive controllers that have been used to control outdoor lighting, but could also be used to control appliances where use did not depend upon specific time-of-day operation. Load levelers establish a priority of operation among circuits. A single-circuit, load leveler removes one circuit from service when a predetermined current load in a priority circuit has been attained. In residential use, first priority loads might include electric range or dryer. The circuit being controlled would be a water heater, electric heater, or air conditioner. Multicircuit load levelers can control up to five loads in sequence. The multicircuit controller can be used on residential homes with zoned heating and has resulted in a 32% average reduction of kW demand (Economic Regulatory Administration (ERA) 1980).

Remote systems permit a utility to control loads through direct communication. Special or separate meters are not necessary. Remote control techniques include the following systems:

- ripple-control
- power-line carrier control
- sine-wave alternation
- radio-control
- telephone-control.

Ripple control systems use the utility's existing transmission and distribution network to transmit control signals. Ripple control signals are transmitted at frequencies of 200 to 1500 Hz, superimposed on the underlying 60Hz frequency. Although bidirectional ripple systems have been recently developed, most systems employed over the years are unidirectional from the utility to a customer control point. Power line carrier (PLC) systems are similar to ripple control systems in principle except that PLCs operate at higher frequencies (5-300 kHz) than ripple systems. The sine-wave alternation system is under development. With this system, signals are sent by brief fluctuation of the electrical frequency. Prototype units of an experimental, two-way, automatic sine-wave alteration communication systems (TWACS) designed for New England Power Service Co. by A. D. Little, Inc. have been built by Emerson Electric Company. Radio-control systems use FM radio transmitters to transmit encoded commands from the utility to radio-controlled switches on the customer's appliance circuits. Telephone control systems link the utility with its customer through the telephone system. At present, the most likely application for telephone control systems would be for meter reading.

8.1.2 Passive Controls

Passive controls are load-control devices that are owned and controlled by the customers themselves. For the utility, these types of control systems are less reliable than the more active forms of demand control because they are controlled by the consumer, not the utility. This method has a major advantage, however, because the utility makes no direct investment in the control equipment. These controls are similar to direct controls except that the customer, not the utility, retains the ultimate control over their operation.

Passive controls are typically implemented through economic incentives and disincentives to encourage change in consumption patterns. However, unlike active controls, power is always available to loads controlled by passive controls if the customer desires. Thus, the load management benefits to the utility with passive controls are not as dependable as under direct controls.

8.1.3 Incentive Pricing of Electricity

Under the pricing technique, rate structures are established so that load management objectives are achieved through the market mechanism. Rates are designed so that a premium price is paid for electricity during the periods of highest demand, thereby encouraging customers to delay consumption to periods when demands are not as great. Incentive pricing schemes include time differentiated rates, interruptible rates and inverted rates.

Time Differentiated Rates

Two fundamental types of time-differentiated rates exist: 1) rates based on time-differentiated accounting costs (TDAC); and 2) rates based on time-differentiated marginal costs (TDMC). Accounting costs, as used in TDAC rates, are average costs of producing power. Marginal costs, as used in TDMC rates, are costs incurred to supply additional increments of electrical power.

Allocating costs to specific time (rating) periods enables rate designs that give explicit information to customers about the costs of power for use at various times. The use of TDMC (marginal) costs results in higher incremental costs for the use of electricity during peak periods than TDAC rates and therefore provides greater disincentive for curbing peak period consumption. Both TDAC and TDMC rates, however, can reduce peak loads, but the actual level of reduction or shift depends upon customer responsiveness to time-differentiated prices (EPRI 1977).

If demand is very price sensitive, time-differentiated pricing can cause changes in load shapes. Moreover, time-differentiated pricing should promote efficiency in the allocation of generating resources to the extent that consumers are willing to pay prices that reflect marginal costs. In a nationwide survey conducted for the Electric Utility Rate Design Study to measure residential response to time-differentiated rates, the following conclusions were reached (Elrick and Lavidge, Inc. 1977).

1. Most residential customers who had not experienced time-differentiated pricing or load controls preferred voluntary reductions or more power as ways to handle growth in peak load.
2. Residential customers, when faced with limited power availability, preferred voluntary reductions to time-differentiated pricing or controls.
3. Almost 80% of the residential users and more than 50% of the commercial and industrial customers stated that they would reduce energy consumption to save money or to avoid higher charges when faced with time-differentiated peak use charges four times as great as charges for off-peak use.

Interruptible Rates

Interruptible rates have been set up for customers who have usually agreed to have their electrical use controlled or modified during peak periods or system emergencies. The most straightforward rate of this type is exemplified by a discount or credit to customers who agree to have some portion of their loads interrupted under specified peak or emergency conditions. Interruptible rates might also be available to customers whose loads are regulated by active load-control devices.

Interruptible rates may or may not cause a change in the existing rate structure. These rates should reflect the savings that accrue to the utility as a result of users foregoing some electrical power during peak periods. Curtailment or interruption of service usually entails an agreement or special contract that modifies another standard rate.

Inverted Rates

As opposed to the usual declining block structure, inverted rates establish unit price increases as consumption of electrical energy rises. The rationale behind this approach is that new capacity tends to be more costly than existing capacity. Therefore, the growth in electricity consumption that tends to increase costs over time should be dampened by the price mechanism.

One advantage of incentive pricing is that requirements for capital equipment are relatively low. Time-differentiated rates require special metering equipment; interruptible rates and inverted rates require no special metering devices. However, for larger customers, the costs of metering represent a relatively small percentage of their total electric bill. Time-differentiated meters would permit customers who monitor their energy consumption to determine cost savings realized by altering energy consumption patterns.

8.1.4 Education and Public Participation

All load management options require the consumer to alter electricity consumption patterns. Effective communication with customers is thus a prerequisite to successfully implementing any load management technique. Education and public involvement programs are needed for each of the options described above and are potentially an effective load management tool in themselves. The effectiveness of such programs depends on the relationship between the utility and its customers and public attitude and awareness. In areas where people pride themselves on their individualistic styles of life, appeals to the general need to modify consumption patterns may not be effective. This method of load management also not is as reliable as others in that the utility has virtually no control over the exact amount of load that will be shifted.

Under current economic, energy, and regulatory conditions, the role of marketing and public relations activities has changed in direction and scope. Instead of promoting the use of electricity, utilities now often strive, through the promulgation of information and incentive programs, to retard the increased use of electrical energy. Today, utilities foster conservation and load management in their advertising in public newspapers or in informative materials included with the electrical bill. Examples of such techniques include energy tax tips about eligibility for federal tax credits for energy conservation, and brochures describing energy-saving devices in the home such as special shower heads, clotheslines, solar water heating, insulation, etc. These and other public participation techniques merit consideration in pursuing load-management objectives.

Although some state regulatory commissions may prohibit utilities from promoting electrical consumption and now require utilities to promote load reduction, the Alaska Public Utility Commission (APUC) has no orders to this effect. The APUC, of course, encourages energy conservation and load reduction activities by utilities and their customers. However, APUC does not monitor the loads of various utilities in Alaska.

8.1.5 Thermal Storage

The basic objective of thermal energy storage is to store heat produced during off-peak periods for use in space or water heating during peak periods. Energy produced by solar collectors, industrial waste, or base-loaded generators during off peak periods is used to heat a fluid that is stored for later use. In most applications, customers purchase storage equipment to obtain operating cost reductions through low off-peak rates. If the storage devices are appropriately sized, the customer should not experience inconvenience or discomfort even if the storage unit is controlled by the utility. On-off switching of the storage devices may employ the same communication and control technologies as direct and passive load control. A separate meter is usually used to distinguish the power requirement of the storage system from the balance of customer load.

Currently, water is the most commonly used fluid for storage because of its abundance, low cost, nontoxic nature and relative ease of handling. Thermal storage systems may range in size from large, central storage units to residential scale devices. Proposed large-scale central storage systems include deep sea insulated bags with steel reinforcing nets, flexible bags under noncohesive overburden, fixed volume tanks with separating disks, or underground porous rock formations (aquifers). The Alaska coastline in the

Railbelt area has been identified as suitable for undersea storage. The criterion is suitable depth a short distance from shore (Powell and Powell 1980). A recent study has concluded that a large bag system (4.5 x 10^6 ft^3) storing 450°F water at a pressure of 420 psi at 900 ft will cost about $1/$ft^3$ for storage only. The stored hot water can be used for feedwater heating in a central station, space heating in densely populated areas, or for a flashed-steam peaking turbine for electrical production during peak-demand cycles.

Energy storage equipment available for space heating and cooling and water heating in the residential and commercial sectors are listed below (ERA 1980).

<u>storage space heaters</u>

- static room storage heaters
- dynamic room storage heaters
- central ceramic storage heaters
- hydronic central storage heaters
- in-ground heat storage

<u>storage domestic hot water heaters</u>

<u>bulk storage devices</u>

- multiple reservoir storage
- Annual Cycle Energy System (ACES)
- Supplemental Electric Storage System (SESS)
- Constant Energy Input System (CEIS).

Static room storage heaters consist of a ceramic brick storage core heated by electric resistance heating elements during the off-peak power period. Although not widely used in the U.S., static room storage heaters are used in Europe to heat hallways, foyers and small rooms such as bathrooms. Dynamic storage heaters are similar in construction to static room storage heaters, but the dynamic heaters use fan-forced convection to achieve better control of room temperature. Dynamic room storage heaters can be used for heating single family or multifamily dwellings and office buildings (ERA 1980).

Central ceramic storage heating units use off-peak power to charge a ceramic brick core and have thermostatically controlled fan-forced convective discharge. An average size heater, for example 20 kW, weighs over 3000 pounds. Central storage heating systems of the ceramic brick type have potential in the residential housing sector.

Hydronic central storage heaters consist of insulated tank(s) in which water is heated by electric immersion heaters, an electric boiler, or a heat pump during off-peak periods. The heated water is then circulated during peak periods to hydronic heating units in the spaces to be heated. Alternatively, the water is used to heat air, which is circulated through the spaces to be heated. Residential-scale hydronic storage units are available. A typical unit consists of a sealed and insulated water tank of 212 gallons heated to 265 - 280°F and 50 psig. Hydronic storage can be used for commercial heating (and cooling) as well. An in-ground, heat-storage reservoir beneath a building can also be used for space heating. The thermal reservoir can be charged using resistance heat or heat pumps operated during off-peak periods radiated to the building at different times, depending upon building temperature (ERA 1980).

Storage domestic hot water heaters store water heated during off-peak periods for use during peak periods. The control of water heating is the simplest and most often used approach of residential load shifting (ERA 1980).

Bulk storage devices include multiple reservoir storage, annual cycle energy systems (ACES), supplemental electric storage systems (SESS), and constant energy input systems (CEIS). The multiple reservoir consists of several storage media that can work in parallel. In the ACES system a heat pump draws heat from a large tank of water in the winter; in summer, melting of the ice provides air conditioning. SESS is essentially a water heat-storage system being tested for residential and commercial use. Stored water is heated off-peak and circulated through a water coil to supplement a heat pump. CEIS is a water heat storage system with electric resistance immersion heaters sized for 24-hour level operation to satisfy design heating requirements (ERA 1980).

8.2 LOAD MANAGEMENT APPLICATIONS

Load management techniques are used in many industrialized countries. The earliest use of load management was found in Europe. Recently, in the United States, many load management programs have been implemented or are in various stages of development. These projects are too numerous to summarize here and the reader is referred to recent summaries published by Energy Utilization System (EUS), Inc. (1979) and Electric Power Research Institute (1980a). Many of these programs have proved to be cost effective, although generally, they are in experimental or demonstration phases and findings are not conclusive.

The feasibility of load management techniques depends on a specific electric utility's operating system, load profile, type of loads, as well as socioeconomic factors. Therefore, although favorable results have been obtained by some winter-peaking utilities outside Alaska, implementation of similar programs in the Railbelt should be attempted only after detailed, utility-specific studies.

8.3 COST EFFECTIVENESS OF LOAD MANAGEMENT ALTERNATIVES

Load management programs are considered to be cost effective if the capacity and energy cost savings (benefits) exceed the incremental cost of alternative generation and transmission sources plus the costs of implementing the load management and technologies. In addition, customer acceptance and technical feasibility need to be considered in making an assessment of a load management technique (Barron 1979).

8.3.1 Costs

Three types of costs need to be considered when evaluating a load management option: 1) the direct costs of installing and operating the load management options; 2) foregone revenue; and 3) production costs incurred to meet demand shifts to nonpeak periods.

The direct costs of installing and operating load management options include the capital and operating and maintenance costs of control hardware, meters and storage devices; and general administrative and promotional costs.

Capital cost information on load management control systems is presented in Table 8.4. Capital cost information on thermal storage systems is presented in Table 8.5.

Revenue is foregone as a result of implementing load management schemes if incentive rates are used, either directly as a load management option, or as a promotion to adopt load management hardware. Incentive rates for the latter purpose are necessary to compensate for customer costs and inconvenience of using load management devices.

The third cost that must be considered is the incremental cost of meeting demand shifted to periods of low demand. This cost will generally be the variable cost of baseload equipment operation, although new, baseload capacity may be required. If new, baseload capacity is required, then the capacity costs must be considered.

8.3.2 Benefits

Benefits to be considered when assessing the economics of load management include reduced operation of intermediate and peak load generating facilities and possible deferrals of capacity additions. If effective, a load management option will result in reduced operating requirements for peak and possibly intermediate load capacity. The cost savings will be the variable cost of operation (energy cost). Fixed costs of existing idle capacity will still be incurred. A load management program may also defer need for new peaking capacity. If so, the benefits will include avoided fixed (capacity) costs.

8.3.3 Timing

An advantage of load management programs is that they can be implemented rather quickly (e.g., 2 to 3 years to conduct a small load management test) (EPRI 1980a). Therefore, many years of the costs do not have to be incurred, as they do when constructing a major power plant).

8.4 INSTITUTIONAL, REGULATORY, AND ENVIRONMENTAL CONSIDERATIONS

A load management program controls an individual's use of energy through direct or indirect methods. Such control methods do not rely on the supply and demand mechanism of an uncontrolled situation, but rather on the belief

TABLE 8.4. Load Control Cost Summary (EPRI 1980a)

System	Average Installed Hardware Cost ($ Per Point)	Central Control and Transmission Cost ($ 1,000's)	Total Installed Cost as a Function of Total Customers ($ 1000's)						
			1,000	5,000	10,000	20,000	40,000	80,000	100,000
Radio	85	500	585	185	135	110	97	91	90
Ripple	110	850	960	280	195	152	131	120	118
Unidirectional PLC	95	950	1,045	285	190	142	118	107	104
50% Bidirectional PLC	140	950	1,090	330	235	187	163	152	149
Hybrid	90	515	605	193	141	115	103	96	95
Priority Relay	55	--	55	55	55	55	55	55	55
Load Management Thermostat	95	--	95	95	95	95	95	95	95

TABLE 8.5. Thermal Energy Storage Systems Summary of Payback Period Calculations (EPRI 1980a)

Thermal Storage System	Base System	Potential kW Savings Winter	Summer	Percent IC ($)[a]	Payback Period Con Ed Rates[b] (Years)	Payback Period, Jersey Central Rates (Years)	Percent IC ($)[a]	Payback Period Con Ed Rates[b] (Years)	Payback Period Jersey Central Rates (Years)
Room Ceramic	Electric Baseboard	8	--	2,210	3.1	8.0	3,664	5.2	14.6
Central Ceramic	Electric Furnace	12	--	1,285	1.8	4.9	2,520	3.4	9.7
Pressurized Water	Electric Furnace	12	--	2,593	3.5	10.0	3,020	5.4	15.1
In-Ground	Electric Baseboard	8	--	--	--	--	131	0.2	0.5
Annual Cycle Energy System	Heat Pump with Electric Water Heater	8	3	8,292	11.97	33.64	12,600	10.13	50.95
Daily Cycle Energy System	Heat Pump	12	3	5,130	8.8	24.8	7,690	13.2	37.2
Dual Heating System	Electric Furnace	10	--	675	0.95	2.2	1,000	1.4	4.0

(a) Includes maintenance.
(b) Based on presently offered time-of-day rate.

that a fair program will be developed for all customers. If a control program is instituted, certain individual choices can be opted in favor of the "fair" plan.

With direct control load management techniques, the individual homeowner or commercial customer relinquishes considerable control of personal energy use as the utilities cycle or defer loads during local or system peak loads. Indirect methods, such as pricing mechanisms, cause the customer to alter individual consumption patterns, which does not give the utility as much control over the load as do the direct measures.

In most areas where load management has been tried, programs have been well accepted. With an effective public communications program by the local utilities, similar results are expected in the Railbelt region. If such a program is successfully implemented, it can produce certain institutional and environmental benefits. These benefits should be evaluated in assessing the merit of a load management option. For example, a successful program will defer and possibly will eliminate the need for certain energy facilities. Any delay or elimination of these facilities will suspend associated environmental problems. The extent of benefits to the environment are assessed by comparing the electricity savings from the load management plan to the specific generation option that is foregone. In general, air and water emissions and other impacts of resource extraction will be avoided.

Recent activities of regulatory bodies have led to several attempts at curbing load peaks. Because of the multiplicity of rate designs and objectives, a review of the actions of individual states is not included in this profile. However, some states have made major advances in this area. Of particular importance to the electric utility industry is the Public Utility Regulatory Policies Act (PURPA) of 1978.

PURPA, part of the National Energy Act, set standards for electric utilities in the followiung areas: 1) cost of service; 2) declining block rates; 3) time-of-day rates; 4) seasonal rates; 5) interruptible rates; and 6) load management techniques (PURPA 1978). Rates charged by the utility for providing electric service to each class of consumers are to reflect the cost of providing such service. In general, the energy component of a rate may not decrease as kilowatt-hour consumption increases, except when the costs of providing electric service are demonstrated to also decrease as consumption increases. The rates charged for providing electric service to any class of electric consumers are to be on a time-of-day basis, reflecting the costs of providing electric service to that class of consumers at different times of the day unless such rates are not cost effective. The rate charged by an electric utility for providing service to each class of consumers is to be on a seasonal basis, to the extent that costs vary seasonally. Electric utilities are to offer industrial and commercial consumers an interruptible rate reflecting the cost of providing interruptible service. Each electric utility is to offer to its electric consumers such load management techniques as the state regulatory authority (or the nonregulated electric utility) has determined are practicable, cost effective, and reliable and can provide useful energy or capacity management advantages to the electric utility.

8.5 POTENTIAL APPLICATION IN THE RAILBELT REGION

The opportunity for load management in the Railbelt region appears to be limited mainly because few loads are controllable. For example, in the AMP&L residential class, less than 10% of the customers have all-electric homes and fewer than 10% have electric water heaters. The availability of inexpensive gas in the Anchorage area has induced many residential customers to convert from electric to gas water heating. Additional opportunities for load management in the commercial sector appear to be limited because energy-saving devices are used in most of the office buildings. The municipal dock area and local military bases seem to be the only potential areas for load management in Anchorage.[a]

The AMP&L rate structure reflects energy conservation and load management objectives. The "all-electric" rate schedule has been eliminated, a 12-month ratchet[b] clause has been adopted, and an electric time-differentiated rate is available to residential customers.

Although a few obvious opportunities for applying load management techniques in the Anchorage area exist, further shaving of winter daily peaks appears to be possible and might be preferred to new generation capacity. The daytime winter peaks are about twice as large as the night loads. With a peak load of about 120 MW, a 10% reduction in load would represent 12 MW. Control of water heaters might be economical, although AML&P considered water heaters with thermal storage but determined, based on preliminary economic analysis, that they were not cost effective. The winter space heating load is uniform all day and therefore provides no opportunity for shifting space heating loads to other hours. An additional constraint that must be considered is the need for scheduled maintenance of generating units. Scheduled maintenance is generally accomplished in the summer during periods of low load.

Fairbanks Municipal has built load and energy-conserving features into their rate structure. However, in the Fairbanks area, load management possibilities also appear to be limited. Like Anchorage, little or no industrial load exists and the commercial load is relatively flat from 8:00 a.m. to 5:00 p.m.[a] Oil is used for heating, and it is expensive; however, electricity is even more expensive on a comparable basis. One area where load reduction might be possible would be controlling electric auto engine heaters. Initial analysis suggests, however, that this load may be difficult to control even though it contributes significantly to load peaks.

In summary, the Railbelt utilities are currently employing load management alternatives. They will continue to be useful for shaping loads in a manner compatible with future resource development and electrical consumption patterns. These techniques, however, can only be employed within the context of the utilities' planning and operating systems and connected load. At present, the nature of connected load somewhat limits opportunities for substantial load management. If low-cost power were to become widely available in the future, resulting in expansion of space and water heating electrical loads, aggressive load management programs may become desirable. However, the

(a) Obtained from personal communication with Mr. Myles Yerkes, Chief Engineer, Municipal Light and Power, Anchorage, February 6, 1981.
(b) A demand ratchet clause causes maximum past or present demands to be taken into account in establishing billings for present and subsequent periods. This type of clause has the effect of increasing a customer's billing rate for the entire year if demands during peak periods exceed certain levels.

need for such programs would depend upon the type of generation and storage capacity available in the future. Use of hydroelectric generation, for example, or construction of energy storage systems, would reduce the need for load management techniques.

9.0 ELECTRIC ENERGY CONSERVATION IN BUILDINGS

Conservation technologies, as defined in this study focus on the benefits of significantly reducing a structure's overall heating load. A few individuals in the Railbelt have reduced their fuel bills by as much as 70% by adding extra insulation and reducing air infiltration when building. Others are realizing less but still significant savings by upgrading their existing homes and structures.

Most buildings constructed in the Railbelt use materials and techniques better suited to more temperate climates. Only in very recent years have designers and builders begun to recognize the need for an "Alaska-specific" approach for designing a building's thermal envelope.

The measures addressed in this report, if implemented on a large scale, would contribute to reducing fuel demands in the Railbelt region. Whereas relatively little electric space heating currently is found in the Railblelt, building conservation could significantly reduce electricity demand if low-cost electricity became widely available and electrical space heating became common.

9.1 CONSERVATION MEASURES

Conservation, or thermal efficiency, is not difficult to achieve in most buildings. Conservation is the end product of applied current knowledge and of techniques already commonly used. The following four factors determine the energy efficiency of any building, and if properly implemented, they offer the greatest potential for energy savings in both new construction and retrofit of existing structures:

1. an insulation envelope to reduce conduction
2. sealing to minimize infiltration of air
3. vapor barrier to retard moisture transfer
4. efficient space heating and hot water systems.

These factors are discussed for new construction and the concept of an "Alaska-specific" design. The "Alaska-specific" design is a house that has been developed with particular consideration to the severity of the regional climate. It incorporates building techniques that allow for additional insulation to resist heat transfer and to enhance thermal efficiency. The design could and should become even more specific to location. For instance, a structure in Fairbanks would be more heavily insulated than one in Anchorage to accommodate the more severe Interior climate.

9.1.1 Insulation

Conduction is the transfer of heat through a solid material. In buildings conduction occurs through the "envelope," which consists of the walls, windows, floors and ceiling separating the interior conditioned space from the elements. The resistance of heat transfer through these components is measured in "R values," which is used to rate insulation materials comparatively. The higher the "R" value, the greater the insulating ability of the material. The two major ways of reducing conductive heat losses are to reduce the total area of the envelope exposed to the exterior and to provide thermal resistance in the materials comprising the envelope.

Two fundamental parameters apply to minimizing surface area. First, structures should be multi-story rather than spread out with a large roof area (California "ranch" style). Secondly, the simpler the shape, the more energy-efficient it is. For example, a round or square building has the least area exposed to the elements. On the other hand, the increased exterior surface of a building elongated along the east/west axis may be offset by the solar gain available because of its orientation, if it is designed to take advantage of solar gain.

Window area is critical to thermal efficiency because this component of the envelope loses more heat than other areas. Windows can lose up to ten times the amount of heat of the adjacent walls. An energy-efficient design incorporates the least amount of window area consistent with aesthetics or livability of the interior space. Window orientation is also important. Southerly or easterly orientation can gain heat during most of the year and thus contribute to the heating of the interior space. Conversely, northerly or westerly windows lose a larger amount of heat and should be kept to a minimum. Additionally, window heat loss can be reduced by using hermetically sealed thermal units in wooden frames or aluminum frames with a thermal break, and by incorporating multiple glazing. Conductive losses through multiple glazing will remain high, but can be reduced further by using thermal shutters or movable insulation, which are placed over the windows at night or during cloudy periods.

Considerable disagreement exists but, not much practical information, on the best window insulation system for Alaska. Several manufacturers are making thermal shutters, most at a fairly high cost. None have yet been proven effective in Alaska, although significant product testing is occurring. Some quantified answers should be available in the next year.

Walls, floors, and ceilings can be made more resistant to heat loss by adding more insulation than has been recommended in the past. However, the structural design must provide a sufficiently thick shell to accommodate additional insulating material. Walls, in particular, pose a problem for the designer of Alaska-specific housing because of traditional framing systems. In these systems, the framing members of the wall are made up of wooden studs and plates (Figure 9.1, no. 1), which contribute significantly to conductive heat loss. Wood is only a fair insulator, and plates and studs allow greater heat transfer between the interior and exterior than intervening insulated spaces.

Several methods of improving the thermal resistance of conventional construction have been used in Alaska. The most common approach is to use a rigid foam board insulation, either on the exterior or interior, under the finish skin (Figure 9.1, no. 2). This board increases the insulating value of the stud wall, reducing the conduction loss through framing members. Because conventional frame construction depends upon the diaphragm action of the exterior and interior sheathing to provide shear strength, the structural integrity of the wall must be taken into account when placing foam board insulation beneath the sheathing.

In a second approach, known as the "cross-hatch" method (Figure 9.1, no. 3), 2 x 2 or 2 x 4 furring strips are nailed perpendicular to the wall studs, usually on the inside of the wall. The horizontal members are placed

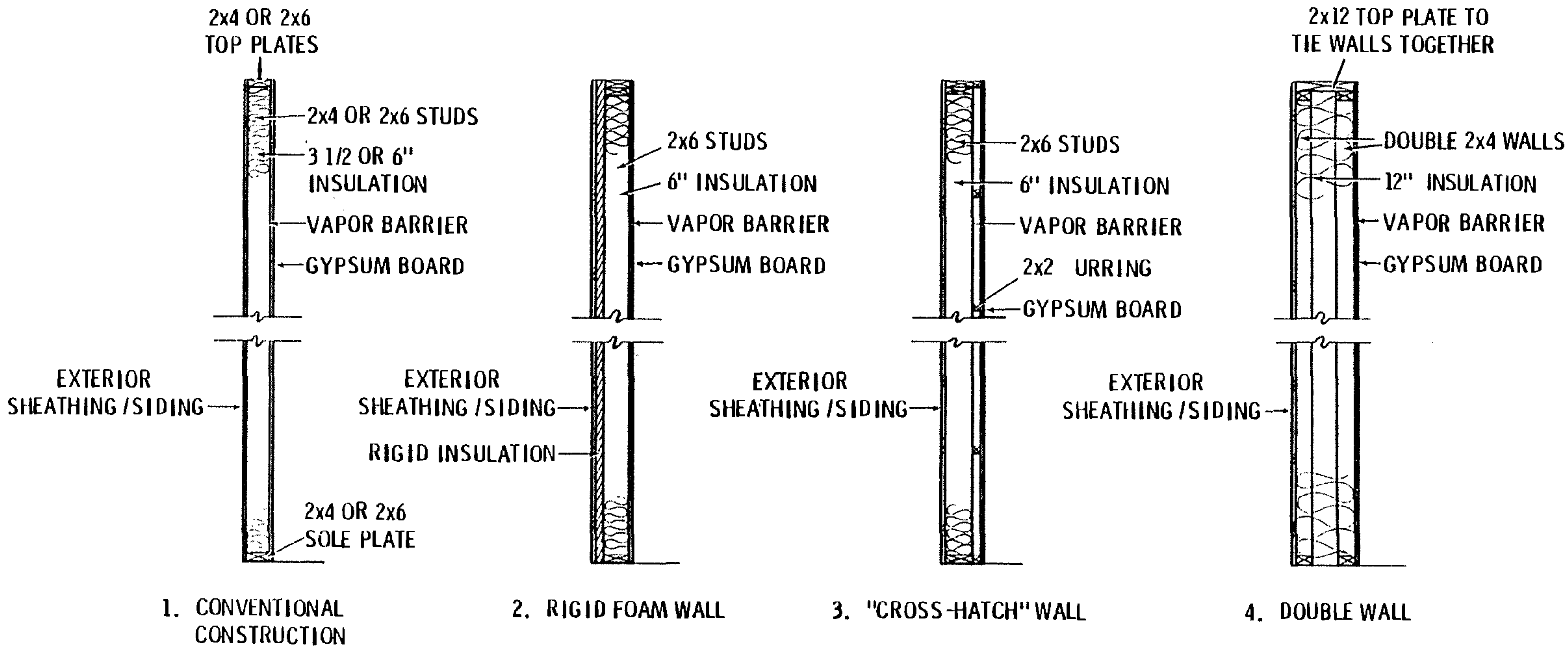


FIGURE 9.1. Energy-Conserving Wall Systems

usually at 2 ft on center, and the interior finish nailed to them. This approach reduces the area of transfer by conduction to a 1 1/2-in. square at each junction of the framing members.

Two "cross-hatch" designs are in use. In one design the exterior wall is insulated and a vapor barrier is applied. The "cross-hatch" is then added. Electrical cables and "thin-line" electrical outlet boxes are put in the space created by the furring, thus better ensuring an unbroken vapor barrier. In the second design, rigid insulation is applied in the 1 1/2-in. space created by the furring, giving a greater insulating value and avoiding structural problems resulting from applying rigid insulation to the exterior of the wall framing.

The third wall system employed is the double wall, in which two 2 x 4 walls are set a specified distance apart and are joined only at the top plate (Figure 9.1, no. 4). The space between is filled with insulation. The main advantage of this approach is that the walls may be set any distance apart and filled with relatively inexpensive fiberglass or cellulose insulation. If this method is used, conduction losses may be reduced to a minimum.

The cost effectiveness of these wall systems varies throughout the region. However, the increased thermal resistance offered by these wall systems in comparison to conventional 4-in. and 6-in. frame walls, developed for use in more temperate climates, is important to note. While urethane insulation can be used to give high insulating values in conventional walls, it does nothing to eliminate conduction loss through the framing members.

Ceilings are relatively easy to insulate heavily since most designs provide for an attic that is spacious enough to accommodate insulation values in excess of R-60, which is adequate in most of the Railbelt. The problem lies at the point where the roof meets the wall. Here, the available space for insulation is insufficent to accommodate adequate insulation and to still provide air circulation above the insulation layer.[a] The solution lies in

(a) Ample air circulation must be provided to prevent "sweating" or condensation and subsequent deterioration of the insulation and surrounding wood.

using an "arctic" or "Arkansas" truss (Figure 9.2). The arctic truss is constructed with raised ends so that a constant thickness of insulation can extend to the roof edge, while still allowing room for ventilation. Even if extra insulation is not applied during construction, the entire roof area could be upgraded later with this method.

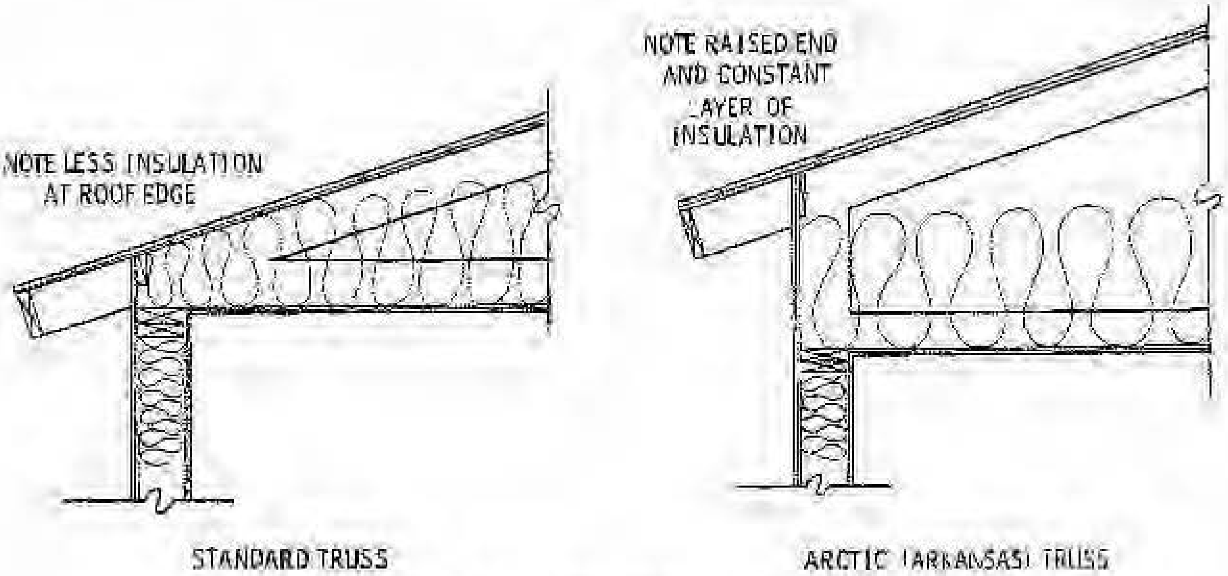


FIGURE 9.2. Energy-Conserving Roof

In the past, designers and builders mistakenly believed that floor insulation could be minimized, and any extra expenditures for insulation could be applied to the ceiling. Recent studies are showing that adequate floor insulation minimizes stratification of air temperatures between floor and ceiling. The colder floor in standard construction drives warmer air to the ceilng, adding to heat loss.

Conductive heat loss can also be reduced by using insulated headers over wall openings rather than solid wood, wood I-beams in the floor, and closed roof systems. These methods present a much smaller area to the exterior than their counterparts constructed of solid timber.

9.1.2 Sealing

Infiltration is air leakage into a building through cracks and crevices, around windows and doors, and through floors and walls. Its magnitude depends on type of construction, workmanship, and condition of the building and cannot be effectively controlled by the occupants (American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) 1977). Current research indicates that infiltration accounts for up to 50% of the heating load of a typical building. Principal sources of infiltration include sole plates, window and door frames, door operation, furnace combustion air and ventilation devices.

The primary measure to reduce this heat loss is to freely caulk critical areas such as the sole plate and around window and door casings to close all holes in the envelope. Texas Power and Light Co. has found that the sole plate of the walls, which is seldom caulked in conventional construction, accounts up to 25% of the infiltration load on typical buildings. Other areas of heat loss due to infiltration include electric outlets, vents, and ducts. These areas should be sealed as tightly as possible. The larger joints can be sealed with a foam urethane.

A large volume of warm air is spilled out each time the outer door of a house is opened. This infiltration loss can be reduced by adding an arctic entry, which is basically an enclosed porch or vestibule. The outer door provides a trapped air space on the porch, and assuming only one door is opened at a time, warm air exchange will be reduced.

The source of furnace combustion air can contribute heavily to infiltration. If air is drawn from within the house, it creates a draft, drawing warm air out of the house. As the warm air is expelled, it is naturally replaced with colder air entering through cracks in the envelope. A simple remedy is to draw combustion air from the exterior, taking precautions to thoroughly seal around the penetration in the envelope. A damper that prevents infiltration when the furnace is not operating also should be installed.

A good vapor barrier (discussed below) also retards infiltration - if moisture cannot escape, air cannot enter or escape. If the vapor barrier is properly installed and measures are taken to reduce infiltration, the number of air changes per hour (ACH) can be reduced from a typical 1 1/2 to 3 to less than one. However, reduction in air changes can lead to a deterioration of the indoor air quality. An air change of less than 0.5 per hour is considered detrimental to an occupant's health. If cigarette smoke or other interior pollutants exist, minimum air exchange should be as high as one ACH.

Insufficient air change can be remedied with a heat exchanger. The trapped moisture and stale air can be expelled by an air-to-air heat exchanger that draws out stale moist air and replaces it with fresh outside air. At the same time it uses the expelled warm air to preheat the incoming fresh air. Manufacturers of air exchange units claim a heat transfer efficiency rate of 65 to 70%. However, these units have some operating problems in colder climates. Condensation tends to form on the coils, resulting in ice formation and subsequent unit failure. This problem is not insurmountable, however, and more testing is being done to further develop these units. They most likely will become an integral part of the Alaska-specific house.

All of these measures to reduce air infiltration are fairly inexpensive when compared to the resulting reduction in infiltration and the subsequent fuel savings.

9.1.3 Vapor Barriers

The primary objective of a vapor barrier is to prevent the transfer of moisture from the conditioned interior space into the insulation itself. Tests show that a 3% moisture content can reduce insulation effectiveness by almost 25%. The vapor barrier is particularly important in the Alaskan climate where the extreme temperature difference between the interior conditioned space and the atmospheric temperature accelerates moisture transfer. Not only does moisture drastically reduce insulation effectiveness, it also leads to permanent deterioration of the insulating material and structural members.

A vapor barrier must be continuous and sealed on all seams and around penetrations in the envelope, such as plumbing and electrical outlets. This important element should be installed on the warm side of the insulation.

Whereas a vapor barrier is installed in most new Alaskan buildings, they are often poorly installed, resulting in leaks and penetrations that allow moisture transfer.

9.1.4 Space Heating and Hot Water System Efficiency

Hot water heaters account for about 15% of the fuel consumption in many homes. Establishing the exact load represented by hot water systems is difficult because of the many variables, such as lifestyle, preferred water temperatures, etc.

One major weak spot in the domestic hot water system is with the storage tank itself; most have only 1 to 2 inches of glass fiber insulation, resulting in an insulation factor of approximately R-6. By covering the unit with an insulation jacket, the R-value can be raised to R-20 or 25. If the tank is located in an unheated space, such an improvement can provide savings of approximately 1.2 MMBtu/yr on a 52-gallon tank maintained at 120°F (Carter and Flower 1980). With these savings the insulation jacket will pay for itself in a matter of months. If applied on a regional level, these savings could add up to a significant amount of energy saved.

Other hot water energy savers, such as flow reducers, thermostat setbacks, stack robbers and water preheaters are all worth implementing. Collectively, they may result in considerable savings.

Space heating units can consume excessive amounts of energy due to improperly maintained burners, dirty stacks, and dirty intake filters. All of these are easily repaired.

A more difficult problem might arise if a furnace is larger than necessary. Excessive size can result from an improper judgment in initial design or from a reduction in the heat load following an extensive retrofit of a building. This furnace will be operating at less than design efficiency and consequently will be using more fuel than necessary. At current fuel prices, replacing expensive furnace equipment is difficult to justify. However, homeowners need to be aware of inefficiencies in their heating systems. In some cases they might choose to replace a furnace if remodeling or other extensive home improvement is planned.

9.1.5 Retrofitting

The objective of retrofitting is the same as that of an Alaska-specific design - to achieve maximum thermal efficiency in a building. The methods used are basically the same. The limitations are obvious; rebuilding, particularly when adding additional insulation to existing walls, is more difficult and often more costly.

The design and condition of the existing structure are important factors in retrofitting. A total upgrade on a fairly new building may not be cost effective; caulking and other simple measures may be best in that case. On the other hand, an older structure with little or no insulation could easily pay back the investment on a total upgrade in a few years.

If the structure has an attic space, additional insulation can be added. Rigid insulation at the junction of the roof and wall may be a good approach to providing more insulation in this confined space because rigid insulation gives a higher R-value per inch than blanket insulation. Floors built over a crawl space can have insulation added either between the floor joists or along the perimeter wall. Masonry basement walls can be insulated either inside or out.

The walls of a house are a prime example of a "closed" system with finished surfaces on both sides. If additional insulation is desired, a second wall usually must be added either outside or on the interior. This addition is often done using rigid insulation and applying a new skin. This approach is labor intensive and thus costly, so usually is considered only after other retrofit measures, if at all. However, in an older building with high fuel bills, it may well prove cost effective.

Upgrading windows in older buildings is easily done by adding thermal glazing. Thermal shutters will further retard heat loss; however, shutters that are functionally reliable and that will appeal to the mass market demands have yet to be developed.

Adding a proper vapor barrier when retrofitting is difficult unless all interior finish surfaces are removed. Barring this, several paints are available that will act as a vapor barrier. While not as effective as a continuous polyethylene vapor barrier, the paints will nonetheless help keep the insulation dry, an important consideration in a thermally efficient house.

Infiltration can be reduced in the retrofit by caulking the entire perimeter of the sole plate and around penetrations in the envelope. Residents can usually perform this task in a single day at a nominal cost. Caulking to reduce infiltration is the least expensive retrofit measure and yet returns large savings to the consumer. Simple caulking can reduce infiltration losses by as much as 50%. Another effective measure that reduces infiltration is the addition of an "arctic entry" to frequently used exterior doorways. Such an addition greatly reduces the volume of cold air entering the house when doors are opened.

9.2 PERFORMANCE CHARACTERISTICS

Performance characteristics of interest include efficiency, coincidence to load, adaptability to growth, and type of load service.

9.2.1 Efficiency

The energy efficiency of a structure depends on the extent of conservation methods employed. The amount of energy saved by building conservation measures depends upon the lifestyle of the occupants and upon weather conditions. A hypothetical but representative Alaskan house was used to provide a comparative demonstration model of the heat loss and resulting annual heating load in each of three cases: before retrofit, after retrofit, and the Alaska-specific design. These comparative results are detailed in Table 9.1. Each of the three cases was then considered for three population centers of the Railbelt - Homer, Anchorage, and Fairbanks - and summarized in Table 9.2.

Conservation technologies as defined in this study can be said to be 100% efficient in that once installed, they are working to their full potential. Insulation vapor barriers and sealing that is protected from the weather will generally last as long as the structure with little or no maintenance. Weatherstripping and exterior sealing subject to physical wear and weathering will need to be periodically repaired or replaced. Conservation will continue

TABLE 9.1. Comparison of Heat Losses for Three Design Variations on a Representative House

Building Element	Area (sq ft)	Case 1 Before Retrofit		Case 2 After Retrofit		Case 3 (Alaska-Specific Design)	
		Design Criteria	Heat Loss (Btu/hr/°F)	Design Criteria	Heat Loss (Btu/hr/°F)	Design Criteria	Heat Loss (Btu/hr/°F)
Floor	1,500	R-10	150	R-19	78.9	R-22	67.5
Walls	1,280	R-10	67.4	R-19	67.4	R-40	31.8
Windows	130	R-1.84	70.6	R-2.79	46.6	R-10[a]	13
Doors	36	R-2.5	14.4	R-8	4.5	R-19	1.9
Ceiling	1,800	R-19	94.7	R-30	60	R-57	31.6
Infiltration		1.5 ac/h[b]	324	.75 ac/h	162	.25 ac/h	54

(a) Shuttered at night.
(b) Air changes per hour.

TABLE 9.2. Comparative Annual Heating Loads and Costs: Retrofit of Representative House and Alaska-Specific Design

Location/Case	Annual Heating Load (MMBtu)	Annual Savings (MMBtu)	Baseload (%)	Annual Savings Oil[a] ($)	Annual Savings Electricity[b] ($)	Annual Costs Oil[a] ($)	Annual Costs Electricity[b] ($)
Homer: 10,364 degree days							
Case 1 - Before retrofit	179.4	Base	Base	Base	Base	2081	2002
Case 2 - After retrofit	104.3	75	41.8	870	839	1211	1163
Case 3 - Alaska-Specific design	54.1	125.3	69.8	1453	1375	628	627
Anchorage: 10,911 degree days							
Case 1 - Before retrofit	189	Base	Base	Base[c]	Base	646[c]	1852
Case 2 - After retrofit	110	79	41.8	270[c]	774	376[c]	1078
Case 3 - Alaska-Specific design	57	132	69.8	451[c]	1294	195[c]	558
Fairbanks: 14,345 degree days							
Case 1 - Before retrofit	248.1	Base	Base	Base	Base	2879	5398
Case 2 - After retrofit	144.4	103.8	41.8	1204	2258	1675	3140
Case 3 - Alaska-Specific design	74.9	173.3	69.8	2010	3769	869	1629

(a) 138,000 Btu/gal, 70% furnace efficiency with the following January 1981 oil prices: Homer - $11.60 MMBtu; Fairbanks - $11.60/MMBtu.
(b) Electricity at the following prices: Anchorage - $0.035/kWh; Fairbanks - $0.075/kWh; Homer - $0.04/kWh.
(c) Anchorage case is for gas @ $3.42/MMBtu.

to reduce the heating load of a structure to a constant level, relative to the differential between indoor and outdoor temperature, throughout the useful life of the insulation and sealing techniques employed.

9.2.2 Coincidence to Load

The relationship of conservation to load is different from those of technologies that generate power. The ability to adapt to loading demands is not possible since conservation is static. However, widespread adoption of building conservation may result in a flattening of the annual load profile for two reasons. First, the Railbelt load is winter peaking and secondly, space heating energy savings attributable to conservation increase in proportion to the temperature differential between interior and exterior temperatures.

9.2.3 Adaptability to Growth

Conservation technologies are easily adapted to growth patterns because of their simplicity and dispersed nature. However, an inherent danger is that under sudden "boom" growth situations conservation measures can be slighted to hasten construction projects or to lower front-end construction costs. The resulting inefficient structures will increase the burden on other energy sources. A concerted effort and understanding of conservation efforts by designers, builders, consumers and financial institutions will help to prevent such a scenario.

9.2.4 Type of Load Serviced

Electricity for space heating does not currently comprise a large percentage of the Railbelt's heating demand. Electric heat from portable radiation heaters generally tends to serve as a supplemental heat source during extremely cold periods (contributing to the winter peak load of the Railbelt). Thus, conservation measures as defined herein will have little overall effect on the immediate electrical demand. However, if changing relative fuel prices result in a future shift to electricity for space heating, building conservation may have a significant impact on future electrical demand.

9.3 COSTS

The cost of conservation is difficult to measure on a large scale at this point, due to its dispersed nature. Retrofit costs for existing structures will vary substantially depending on original construction and the condition at the time of retrofit.

Virtually no cost studies on conservation have been performed in the Railbelt area. Preliminary cost estimates recently performed in northwest Alaska showed unit costs ranging between $1.30/MMBtu for simple caulking and weatherstripping to $16.50/MMBtu for a full wall/roof insulation upgrade on an existing building. For the representative house discussed in Section 9.2, the retrofit measures returned savings of 41.8% of the annual heating load in comparison to the base case and the Alaska-specific design returned savings of 72.3%.

For a conventional house costing $100,000, "superinsulation" can cost an additional $7,000 to cover heavier insulation, extra structural members, additional labor for "detailing" the house to plug air leaks, shutters over the windows, and an air-to-air heat exchanger. Very preliminary studies done by Alaska Renewable Energy Associates have shown that the conservation investment equalled 5 to 7% of the total investment for this conventional house. These figures are very rough and may be high. Assuming that the investment is financed for 30 years at 15% interest, cost per million Btu would be $7.80. State of Alaska home load programs at 10% would bring this figure down, as would the conservation load program at 5% interest. As a comparison, recent home heating oil costs were approximately $8.40/MMBtu in Anchorage and $8.20/MMBtu in Fairbanks (Appendix B). Furnace inefficiencies would result in somewhat higher comparative costs.

As stated earlier, conservation measures that are protected from weather and physical wear (e.g., insulation and vapor barriers) will generally require no maintenance. Weatherstripping and sealing exposed to the elements will require periodic replacement.

9.4 ENVIRONMENTAL IMPACTS

Building conservation technologies have few detrimental environmental impacts. The materials employed are usually nontoxic. Air, water and land are unaffected by conservation. The technology need not have any impact on community aesthetics; the "styles" of buildings do not have to change at all. The building envelope is affected, but not necessarily the exterior of the structure. A positive environmental impact from building conservation technologies is that population growth need not lead to increased air pollution and other effects of increased fuel combustion. The possibility of injury or death to either the consumer or installer is negligible and most likely would not result in any increase beyond what is now experienced in the light construction industry.

9.5 SOCIOECONOMIC IMPACTS

Since conservation technologies require little or no operational maintenance other than that already necessary in the home, the individual experiences little inconvenience after the initial installation, with the exception of movable insulation/shutters. However, this inconvenience would seem to be a relatively minor inconvenience when compared with the control an individual gains over heat loss. An energy-conserving building is comfortable and relatively draft-free. The reduced cost of heating allows occupants to keep the building warmer for less money.

As conservation measures become more widely implemented, new business opportunities will result and existing business may be revitalized. Consulting and technical support groups, installation contractors, and suppliers will be needed to accommodate regional retrofits and new construction demands. An attractive aspect is that these support businesses can be at a community level and thus may create local jobs and enhance local economies.

Determining the impact of conservation on employment is difficult because many homeowners will probably do their own work, but retrofitting jobs could help to balance the loss of jobs in new construction due to high interest rates. The duration of these jobs and businesses is, again, difficult to determine without more research.

Certain skills and businesses can be adapted to accommodate the variety of services and materials related to conservation. For example, materials used in conservation can complement the inventories of local hardware and general mercantile stores. New "conservation specialty" stores may develop in larger communities. Also, existing home repair contractors and handymen can easily include conservation technologies as a part of their services.

On a regional level, conservation measures will result in a reduction of fossil fuel expenditures and an increase in mortgage and short-term home loan expenditures. Assuming cost-effective conservation measures are undertaken, surplus money will remain in the consumers' hands.

Community and regional governments could also have smaller expenditures for fuel. Operation costs and taxes to the community then would be reduced. The reduction in energy demand will reduce the need for investments in additional power plants. Because most conservation measures tend to be lower in cost over the long term than are investments in generating facilities, proper long-range planning could result in significant economic benefits throughout the region.

9.6 POTENTIAL APPLICATION IN THE RAILBELT REGION

Addressing and quantifying the effectiveness of conservation technologies in the Railbelt is difficult because it is influenced by the quality of the existing structure, its use, and its occupants. Lack of a regional data base on the condition of the building stock, type of heating systems, and the resulting energy consumption is the most severe impediment to quantifying the potential impact of conservation within the Railbelt.

Building conservation technologies are immediately available as mature, well-developed technologies. Building conservation can be easily implemented into existing and new construction at a regional scale without complex manufacturing or distribution systems. The materials and techniques are available throughout the Railbelt. Nothing more exotic than standard insulations and caulking compounds are needed for most applications. Those items not readily available soon will be, as interest and understanding grows.

The principal impediments to widespread implementation of energy conservation measures include poor understanding of the cost effectiveness of conservation measures, the tendency among builders to reduce front-end costs to improve the marketability of their products, and constraints established by obsolete building codes. Poor understanding of the cost effectiveness of conservation, rather than the availability and level of the technology, has led to the relative slow growth of conservation technologies.

Given that the "state-of-the-art" is here, the designers, builders and consumers must understand the benefits of conservation from an economic standpoint. Education of consumers is needed to end the idea that conservation means a return to pre-industrial revolution lifestyles. Education is equally important for designers, planners and installers, who must understand how different conservation measures must be employed to achieve maximum effectiveness. Further analysis of the cost and performance of specific new construction and retrofit conservation measures is required to determine the appropriate order and extent of implementing conservation measures.

Developers and financial institutions have historically attempted to reduce the front-end costs of construction to increase marketability. The concept of life-cycle costing needs to be promoted to consider the technologies that increase heating efficiency and thus reduce operating and maintenance costs over the life of the building. While practiced to some extent in commercial building, this concept needs to be expanded and applied to residential dwellings. Real estate sales in the United States have had an impact on financial policy, particularly in the Northeast, where an energy-efficient home commands as much as 9% more in value than its inefficient neighbor. Although this phenomenon has not yet become the standard in Alaska, such factors cannot be ignored in the future, considering escalating fuel prices. The problem of outdated and conflicting building codes has never been addressed in Alaska. More research is required to determine whether these pose a problem.

10.0 ELECTRIC ENERGY SUBSTITUTES

Electric energy substitutes include passive solar space heating, active solar hot water and space heating, and wood space heating. A comparison of selected characteristics of the electric energy substitutes is provided in Table 10.1.

10.1 PASSIVE SOLAR SPACE HEATING

Passive solar relies on a combination of a thermally efficient building envelope to contain heat, south glazing to capture solar energy, some form of thermal mass to store this energy for release at night or during cloudy periods, and design techniques to distribute heat by convection. Passive solar uses no mechanical means such as pumps or fans to distribute heat from the sun into the living space. Essentially, the building is the system.

Passive solar space heating technologies have been available since very early times. The sun's benefits historically have been considered when siting, designing, and constructing cities and homes. With recent dramatic increases in fuel prices, individuals are once again realizing that solar energy can provide significant benefits. Hundreds of passive solar structures are now working successfully in the Lower 48. Although the phenomenon is fairly new in the Railbelt, several buildings that rely on the sun for a large portion of their heating needs have been constructed in the last few years.

Passive solar techniques can be implemented on various levels. Simply orienting the house to the south will provide some solar gain. Enlarging the amount of south-facing glass will further add to the effectiveness. In both cases, however, solar heat is available only when the sun is shining. To be most effective, the passive solar house must have some form of storage mass to retain heat for release at night or during cloudy periods. The optimum solar building will rely on a combination of the following features:

TABLE 10.1. Comparison of Electric Energy Substitutes on Selected Characteristics

	Superinsulation with Passive Solar Space Heating (One Household)	Superinsulation Active Solar Hot Water and Space Heating (One Household)	Wood Space Heating Wood, Furnace (One Household)[a]
Aesthetic Intrusiveness			
Visual Impacts	Minor	Minor	Minor - Moderate[b]
Noise	None	None	None
Odor	None	None	Minor
Ecological Impacts			
Gross Water Use (gpm)	None	None	None
Land Use (acres)	Nil[c]	Nil[c]	None
Costs			
Capital Cost ($/kW)	610 - 1015[d]	Insufficient information to estimate costs.	154
O&M Cost ($/kW/yr)	25[d]		3
Cost of Energy Saved (mills/kWh)	8 - 12[e]		69 - 78[f]
Public Health and Safety	Potential effects from interior air-quality degradation unless adequate air exchange is provided.	Potential effects from interior air-quality degradation unless adequate air exchange is provided.	Potential increase in fire hazard. Potential air quality degradation.
Consumer Effort	Consumer-operated; minor effort (less than hour/week).	Consumer-operated; minor effort (less than hour/week).	Consumer-operated; moderate to major effort (several hours/week).
Adaptability to Growth			
Unit Sizes Available	Household scale.	Household scale.	Household scale.
Construction Lead Time	Less than one year.	Less than one year.	Less than one year.
Availability of Sites	Most new housing; physical and solar access constraints on some existing stock.	Most new housing; physical and solar access constraints on some existing stock.	Most new housing; physical constraints on some existing stock.
Reliability			
Availability	Insulation - 100% Solar ~40% annually, less during space heating season.	Insulation - 100% Solar ~40% annually, less during space heating season.	Close to 100%.
Expenditures Within Alaska			
Capital	Not known	Not known	Not known
O&M	100%	100%	100%
Fuel	100%	100%	100%
Boom/Bust Effects	Minor	Minor	Minor
Consumer Control	Direct	Direct	Direct
Technical Development			
Commercial Availability	Currently available.	Currently available.	Currently available.
Railbelt Experience	Little	Little	Widespread

(a) Effects cited are for household only; external effects due to wood harvesting will be experienced.
(b) Atmospheric haze could result from extensive use of wood heating in populated areas.
(c) Additional site coverage may be required to accommodate sunspaces - no additional developed area should be required unless lower density development is required to preserve solar access.
(d) Based on average kW savings during six-month heating season of 10 kW. Includes both superinsulation and passive solar features.
(e) Based on 30-year bond life at 3% interest (comparable with financial parameters used for other alternatives in this study). Note that cost of savings would be greater to homeowner if nominal conventional mortgage rates were used.
(f) 69 mills/kWh for Fairbanks; 78 mills/kWh for Anchorage.

1) a thermally efficient building envelope to contain heat
2) south glazing to capture solar energy
3) thermal mass to store the energy for later release
4) proper design techniques to distribute heat by the natural properties of air convection.

Passive solar may appear to be an inappropriate technology for the Railbelt because the solar resource provides the minimum amount of energy when the need is greatest. In December and January in all areas of the region, south glass will actually lose more heat per square foot than it will gain. However, the high heating loads and length of the heating season make solar attractive. During late winter and early fall, the properly designed, passive solar structure can obtain nearly all of its heating needs from the sun in Alaska's Railbelt.

10.1.1 Passive Types of Solar Systems

Three distinct types of passive solar systems have been studied and installed in the Railbelt. While other options are available, none have been seriously considered to date in Alaska. A brief description of the three (see Figure 10.1) follows:

1. Direct Gain - Direct gain, the simplest of solar strategies, uses south-facing windows to bring sun directly into the living space. It therefore provides the greatest amount of solar heat for immediate use. Some form of storage mass, usually stone or tile flooring, water containers, or phase change materials, is used to store excess gain. The major drawback to direct gain is that the heat captured can escape back out the windows at nighttime or during cloudy periods, unless some form of insulation is placed over the glass.

2. Indirect Gain (greenhouse/sunspace) - An attached solar greenhouse works on the same principal as direct gain. The difference is that the sunspace acts as a buffer between the elements and the main living space. Solar radiation enters the greenhouse through south glazing; heat not needed in the sunspace is directly vented into the main living area with heat that is conducted through the common wall. Windows, doors, and vents in the wall

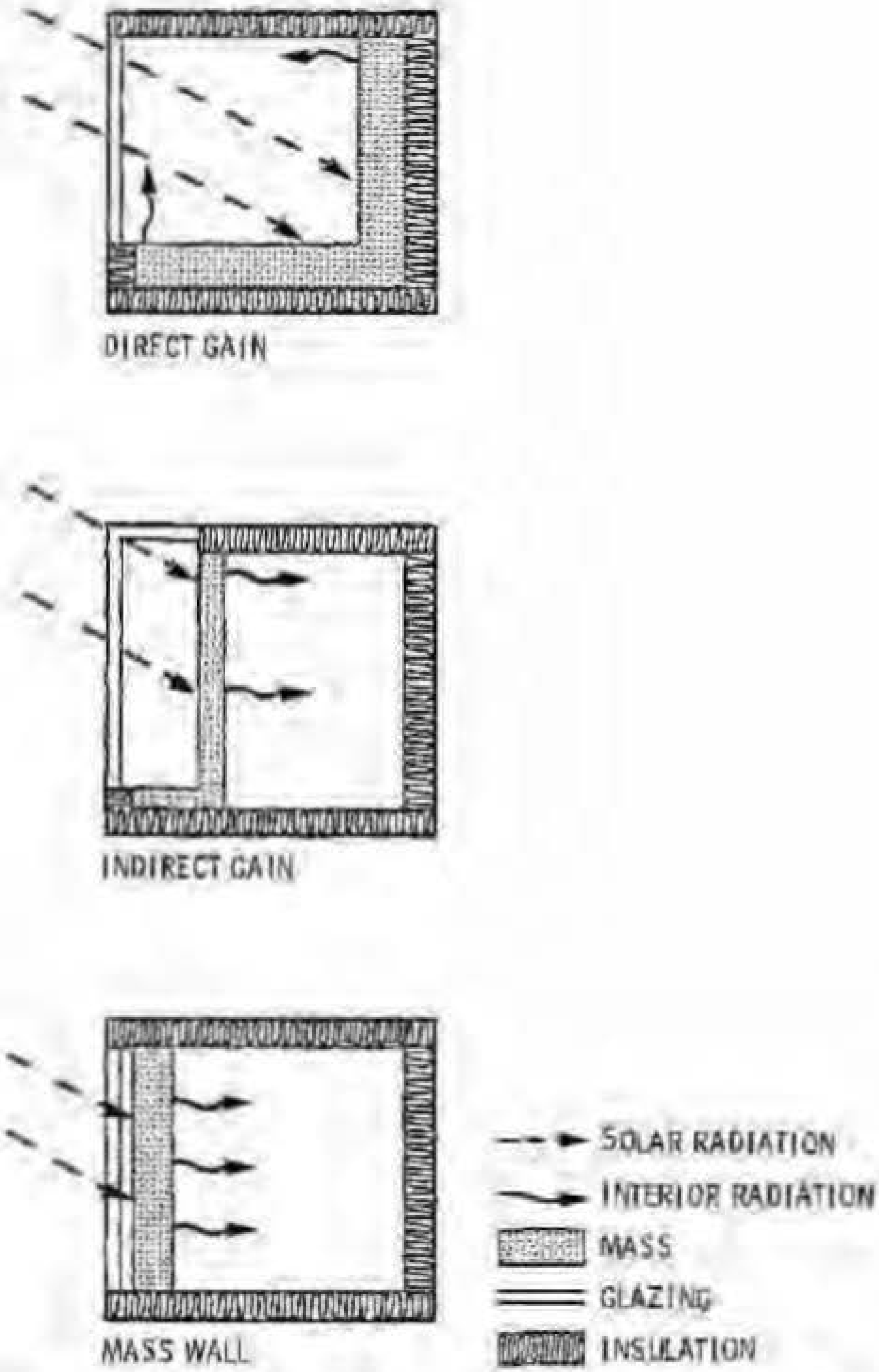


FIGURE 10.1. Passive Solar Systems Appropriate for Alaska

are commonly used. At night, heat lost from the house must first pass through the sunspace before being lost outside.

Several factors will affect the system's performance. A poorly insulated or inefficient greenhouse will not allow much heat transfer into the house because the bulk of the sun's energy will be used up in heating the sunspace. Venting into the main structure must be designed correctly to efficiently move the heat. Finally, the effect of a large expanse of glass is much the same in this strategy as in direct gain; a significant amount of heat is lost back out the glass without night insulation.

Some form of heat storage is usually applied in this strategy also. The back wall of the sunspace is sometimes constructed of stone or concrete, as is the floor. Containers of water placed along the rear wall also are used.

The attached greenhouse has other benefits, such as plant and food production, added living space, and psychological benefits.

3. Mass Wall (water/masonry) - The mass wall employs quite a different concept than the first two approches. In this strategy, sunlight passes through the glazing and strikes a water or concrete mass located directly behind the glass. Heat is absorbed by the exterior surface of the storage mass and slowly works its way to the interior for subsequent release to the living space. As with the other systems, night insulation is important in this system. Without it, stored heat will be lost back outside. Insulation is usually placed on the exterior of the glazing or between the windows and the storage mass on the interior side. Venting the space between the wall and the glazing to the living space will facilitate, by convection (either natural or fan assisted), rapid morning warm-up when the sun is shining. Such a strategy is called a Trombe wall.

Several important considerations must be taken into account when considering a passive solar home or structure in the Railbelt. The amount of south facing glass is a variable in direct relation to the square footage of the building and the thermal efficiency of the structure's envelope. Indiscriminately placing glazing to the south will not necessarily ensure an effective solar design. Overglazing can result in a total heating load higher than the "standard" home constructed today, as well as overheating problems in the summer.

As mentioned, movable insulation is an important factor to improve performance of passive solar in the region. Whereas benefits can be derived from south glass without shutters, the most effective system will employ insulation to retard heat loss during nonsunlit periods through glass, often the weakest point in the building's envelope.

Some form of storage mass should be provided in all systems to soak up excess solar gain and to dampen the wide swings in the interior temperatures, which can result from variation in available solar radiation. In direct gain and sunspace applications, concrete floors and walls, water drums and containers are all used to provide mass. Builders have found that even an additional layer of gypsum board will help regulate temperatures.

Water will transfer heat faster and hold potentially 50% more heat per unit volume than concrete. The features make it an attractive storage medium, but little work has been done with it in Alaska because designers fear that the water close to the glass may freeze, bursting its containment. If these design problems can be solved, water walls may be a feasible solution, since they tend to be less costly than concrete.

Other storage media can be used in conjunction with the various system types. The two most common are rock bed storage and phase change materials. Very little is known about the effectiveness of either in the Railbelt because installations are few and recent. Rock beds in particular have been avoided by designers because they require a large volume to provide adequate solar storage in the region. The volume required may limit the practicality of retrofitting to existing structures, due to the cost of incorporating the rockbed into the existing structural systems and living spaces. Rock beds may be more effective in new construction; however, no study has been done.

Phase change materials have the advantage of being fairly light; they may be incorporated into existing structural systems where concrete or water may be too heavy. Phase change materials consist of a low melting point chemical encapsulated in a container. The chemicals will change from a solid to a liquid at a certain temperature (81°F in several models), storing the heat of fusion. Once fully charged, they will release this heat back to the space, slowly changing from liquid to solid as they give up energy. Phase change materials offer the second advantage of requiring much less volume than other storage mediums for the same amount of energy stored. However, they are fairly costly at present and have no long-term record of success. In addition, the temperatures needed to achieve phase change may not be constantly met in all passive solar applications. Nonetheless, phase change materials may be a viable solution to the problem of providing heat storage in existing buildings. Much study needs to be done with these new products to determine their effectiveness in the Railbelt.

Finally, the thermal efficiency of the structure will have an overwhelming impact on the usefulness of solar heating systems. Given that solar access is more limited in Alaska than in the southern United States, a structure built to the same specifications as those in more temperate climates will not realize a significant benefit from the sun's heat. A building that is heavily insulated in recognition of the severe climate in Alaska will reduce its heating load accordingly. Once this load is reduced, passive solar becomes much more attractive as a heating source.

10.1.2 Technical Characteristics

Technical characteristics important to evaluation of passive solar applications include system efficiencies, coincidence to load, adaptability to load growth, convenience and control, electrical load offset and complementary technologies.

Passive Solar Efficiencies

The efficiencies of passive solar technologies can vary widely with the type of strategy employed. A multitude of other factors in addition to the system type (direct gain, greenhouse, etc.) will also affect efficiency. These factors include, but are not limited to the following: orientation, obstructions and shading, exterior temperatures, building heat loss, and the absorption and heat capacity of thermal storage. Because solar energy relies on the sun, it does not produce a constant amount of energy as might a central fuel-fired plant.

Because the amount of energy produced will vary with each particular installation, the actual efficiencies cannot be quantified on a widespread scale at this point. This situation will continue until existing systems in the Railbelt region are monitored. The examples below help illustrate the broad range of possibilities.

A direct gain system using double-pane vertical glass, oriented due south with no obstructions or shading, will transmit approximately 75% of the available solar insolation when the sun is striking the glazing at a perpendicular angle. Direct gain offers the highest efficiency of any passive solar approach because the only variable affecting the solar gain is the irregularities in the glazing itself. Several disadvantages exist, however. Glare and overheating of the living space may result unless accounted for by proper design. Furniture and rugs may fade over a period of time from exposure to direct sunlight. Finally, heat gain will be quickly lost at night without some form of movable insulation over the windows. Although figures will vary throughout the region depending on location, studies have shown that without shutters a net loss occurs through solar glazing during much of the heating season. Shutters are essential for optimum performance. The thermal performances of windows with various levels of glazing are compared in Figure 10.2. For each case the performance is compared with and without an R-9 shutter in place during the nighttime. South-facing windows with shutters clearly are the best performers.

The efficiencies of the greenhouse/sunspace are much the same as those of direct gain, with one major difference. Since solar heat must be transferred from the sunspace to the house, the thermal efficiency of the greenhouse itself will have an overwhelming impact on the amount of usable heat for the main structure. As mentioned earlier, a minimally insulated greenhouse will use most or all of the solar gain to maintain ambient temperature within itself. On the other hand, a thermally efficient sunspace using night

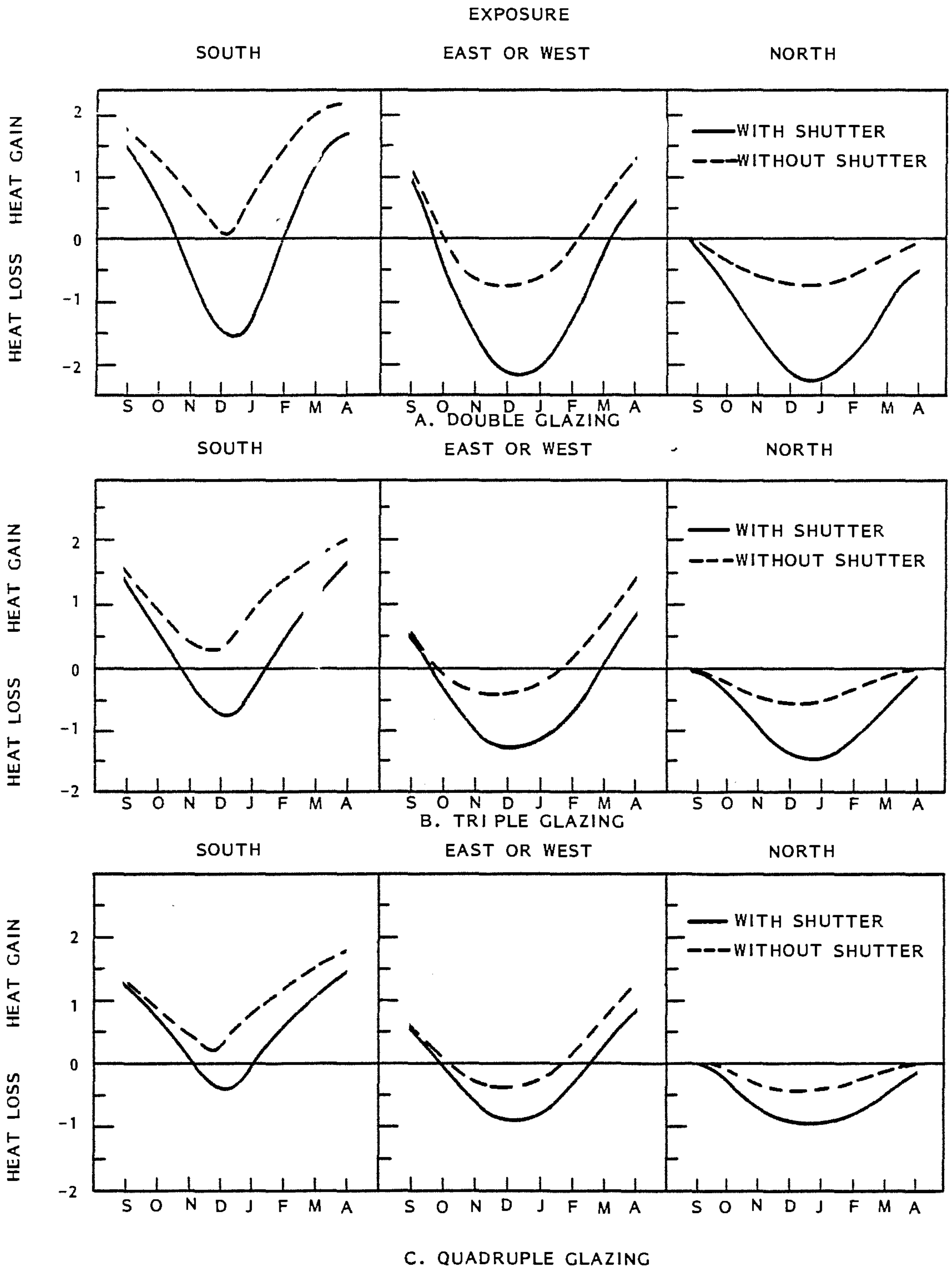


FIGURE 10.2. Solar Gain Versus Heat Loss with Various Levels of Window Glazing and Directional Orientation in Anchorage, Alaska (thermal energy transfer = 10^4 Btu/ft^2)

insulation over the windows will provide a significant amount of heat to the living area. Studies done for Anchorage[a] show that the amount of heat that is collected in a fairly small, attached greenhouse and that is available for use in the main structure will range from 0% in an all-glass, commercially manufactured greenhouse to 53% for a custom-designed unit insulated to R-50, with south glazing only (see Table 10.2).

The efficiencies of the mass wall (concrete/water) concept is the most difficult to quantify. No actual applications appear to exist in the Railbelt. J. A. Barkshire from Alaska Renewable Energy Associates has designed what is believed to be the first Trombe wall to be built in Alaska. No data on its performance are, however, available.

The only existing study of Trombe walls in the Railbelt was generated by Alaska Renewable Energy Associates (Seifert 1980), using computer simulation to model performance using 150 ft^3 wall sizes in 1500 ft^2 heavily insulated houses. Percentages of the yearly heating load displaced by solar gain vary from 36% in Fairbanks to 53% in Homer. While the results (listed in Table 10.3) indicate that storage walls can be effective, actual installations must be monitored to validate the findings.

The space between the glazing and the mass wall can reach temperatures as high as 130 to 200°F. Because heat transfers from warm to cold, exterior temperatures will have an impact on the system's efficiency. The colder the outside air is, the more heat will be lost back out the glazing because of the high temperatures encountered in the space between the wall and the glazing. This loss can be reduced, however, by installing additional glazing or movable insulation.

Solar efficiencies vary widely depending on many factors. Not enough work has been done to make accurate projections. Actual installations and studies done show that passive solar can provide a significant amount of the heating needs; actual monitoring of systems will be necessary to quantify this work further.

(a) Alaska Renewable Energy Associates (AKREA). 1980 (Draft). Passive Solar Greenhouses for Alaska. Alaska Renewable Energy Associates, Anchorage, Alaska.

TABLE 10.2. Usable Solar Heat for the Main Structure from an Attached Greenhouse At Anchorage, Alaska[a]

Greenhouse Type	Yearly Heat Load (MMBtu)	Yearly Solar Radiation (MMBtu)	Heat to House (MMBtu)	% of Heat to House
R-2 (All glass manufactured greenhouse-2 panes)	61	42.4	-18.6	-30
R-19 Insulation (130 ft^2 glazing-unshuttered)	31.7	34.4	2.7	9
w/shutters (R-10)[b]	22.1		12.3	36
R-30 Insulation (130 ft^2 glazing-unshuttered)	28.3	34.4	6.1	18
w/shutters (R-10)	18.7		15.7	46
R-50 Insulation (130 ft^2 glazing-unshuttered)	25.9	34.4	8.5	25
w/shutters (R10)	16.3		18.1	53

(a) Assumes an 8' x 20' greenhouse with 130 ft^2 south glazing, opaque end walls and roof, one insulated door in end, and full solar access with due south orientation.
(b) Assumes shutters closed 12 hours per day during the heating season (September-May).

Coincidence to Load

The ability of a passive solar installation to offset a structure's heating demand will depend on several factors: the type of system, proper design, and coincidence of insolation with demand (both diurnal and seasonal). Because of these factors, each case is very likely to be different. The few existing Railbelt systems are showing that during the mid-winter months (December and January), some type of backup heat is required. As outdoor temperatures warm and the amount of sunlight becomes greater, the systems appear to be meeting most of the heating needs. However, these homes are very heavily insulated and therefore have a reduced heating demand compared to the typical structure. These are very preliminary findings and should not be considered conclusive. Without some form of storage mass to carry solar gain over into the nighttime or cloudy periods, passive solar systems are reliable only when the sun is shining.

TABLE 10.3. Simulated Comparative Heating Needs of Home Built to ASHRAE 90-75 Versus Passive Solar Design[a]

Heating Needs	Location Homer	Matanuska Valley	Fairbanks
ASHRAE 90-75 Annual Heating Load[b] (MMBtu)	155	162	218
Passive Design Annual Heating Load (MMBtu)	89	89	111
Percent Decrease in Heating Load	43	45	49
Heat Provided by Sunlight (MMBtu)[c]	47	42	40
Sunlight as a Percent of Passive Heating Load	53	47	36
Heat Provided by Backup Fuel (MMBtu)	42	47	71
Passive Design Heating Savings (MMBtu)	113	115	147
Percent Reduction in Fuel Consumption	73	71	67

(a) AKREA, computer simulations.
(b) Based on 1,500 square-foot home.
(c) Assumes 150-cu-ft Trombe wall.

Adaptability to Alternative Future Growth Patterns

Passive solar technologies may be added quickly on an incremental basis. The length of time between construction startup and operation is extremely short. A simple retrofit may require only a week and a new structure may require only up to 3 to 4 months. Consumer acceptance, site solar access and the economic feasibility of applications will be the major factors determining future adoption of passive solar technology.

Consumer Convenience and Control

Passive solar offers both advantages and disadvantages to the consumer in terms of convenience and control. Its effectiveness depends on the willingness of the individual to understand and to make maximum use of the sun's ability to heat space.

For the passive system to achieve optimum performance, movable insulation must be placed over the glazing when the sun isn't shining. Although the amount of time required for operation will differ depending on the amount of glass and type of shutters used, a broad average would be 10 to 15 minutes per day, or 5 to 7.5 hours per month.

Type of Electrical Load Offset

The majority of structures in the Railbelt region are heated by natural gas, oil, and to a much lesser extent by wood. Electricity for space heating comprises such a small percentage of the electrical load that passive solar space heating would have little immediate effect on the demand for electricity.

The ability of passive solar to affect the daily load curve will depend on the storage capacity of systems installed. A simple direct gain system with no storage will require full backup heating at night and during periods of no sun to alleviate wide swings in temperature inside the dwelling. The addition of storage mass will help dampen these swings and will reduce dependence on traditional modes of heating during times when the sun is not shining.

If all installations were of the direct gain type, with no heat storage, the effect on demand would be to reduce the baseload. The peak load would remain the same since full backup systems would be needed when the sun was not shining. If all systems were to incorporate some form of storage mass, the peak load would be reduced because the carryover of heat in the storage system would offset load during the peak loading hours. In all cases annual peak loads would be unaffected.

Complementary Technologies

A thermally efficient building is a prerequisite for optimum solar performance. The amount of heat available from the sun does not equal heat loads in "typical" Alaskan buildings during much of the winter months, but by reducing the heating load through conservation, solar energy systems can provide a large percentage of the remaining loads.

Passive and active solar used together constitute a hybrid system. In the Railbelt, such systems can work well together, particularly when passive is used for space heating and active is used for domestic hot water heating (DHW). The DHW load will be fairly constant throughout the year, including summer months. Computer simulation has shown that the sun can provide virtually all of the DHW needs in the summer and can act as a preheater for the main system during much of the spring and fall months.

Even with a combination of solar and conservation, a backup space heating system is required in the Railbelt. A typical large home in Anchorage might use between 100 and 150 thousand Btu/hr during the colder winter months to maintain comfortable temperatures. A super-insulated passive solar home of the same size will use only 35 to 45 thousand Btu/hr, a reduction of 65 to 70%. The remaining energy requirement can be met by a typical wood stove.

Burning with wood is not for everyone. Other alternatives include conventional central heating systems (downsized to compensate for reduced energy demands of a well-insulated, passive solar structure) or "spot" heaters in critical areas of the house. Spot heaters may make economic sense; they are less capital intensive to install and potentially less costly to operate over the life of the structure.

10.1.3 Siting Considerations

Siting considerations for passive solar installations include insolation, orientation, and solar obstruction.

Insolation

Insolation is defined as the total amount of solar radiation, including direct, diffuse and reflected, which strikes a surface exposed to the sky.

Incident solar radiation is measured in langleys per minute, or Btus per square foot per hour or per day.

Insolation varies throughout the Railbelt region, depending on several factors, including latitude and percentage of cloud cover throughout the year. A very broad average figure would be 300,000 Btu/ft^2/yr on a horizontal surface. In comparison, Albuquerque, New Mexico, has approximately 700,000 Btu/ft^2/yr of insolation. Obviously, solar radiation in the Railbelt falls far below those figures of geographical areas nearer the equator. However, the long heating seasons and high heating loads in the Railbelt can justify use of available radiation.

Because the zenith angle of the sun is so low in the region, obstructions in the sun's path can be a problem. However, that postion is an advantage in maximizing usable solar radiation. The greatest amount of available energy is intercepted when the sun's rays strike the collector surface at a perpendicular angle. The greater the variance from perpendicular, the more radiation is reflected away from the glazing surface. Because of the low sun angles prevalent during the heating season in the Railbelt, vertical glass is an excellent collector.

Research done in the region shows that the difference in percentages of solar gain between vertical glass and tilted glass is minimal within a $\pm 20\%$ range.[a] Vertical glass, particularly stock manufactured window units, is cheaper to install than custom designed tilted glazing, particularly when retrofitting existing buildings for passive solar.

Only Anchorage and Fairbanks are currently measuring insolation on vertical surfaces. Longer term data gathering of insolation on vertical surfaces at many sites is necessary to form a scientific base of available solar radiation in the Railbelt region.

(a) A general rule of thumb for optimum tilt of glass is latitude plus 15°. Thus, in Anchorage: 61° latitude plus 15° = 76°, which is very close to vertical.

Orientation

The bulk of solar radiation usable for space heating is found in the southern sky. Therefore, the collection area should be oriented close to due south. However, a variance of 20° or so from due south will not have a significant impact on performance (see Table 10.4).

Developers often have failed to take into account the impact of the sun when designing subdivisions and building sites. As a result, some existing structures would have difficulty capturing solar radiation. On the other hand, many existing buildings can be retrofitted to use solar gain. Some assessment of current building stock must be made before a knowlegeable forecast can be given. New construction usually can be oriented correctly, if the topography of the building lot will allow siting to the south.

TABLE 10.4. Percentage of Radiation Striking a Surface at Given Incident Angles[a]

Incident Angle (degrees)	Solar Intercepted (percent)
0	100.0
5	99.6
10	98.5
15	96.5
20	94.0
25	90.6
30	86.6
35	81.9
40	76.6
45	70.7
50	64.3
55	57.4
60	50.0
65	42.3
70	34.2
75	25.8
80	17.4
85	8.7
90	0.0

(a) The incident angle is the angle in degrees at which the sun is striking a surface.

Solar Obstruction

The single largest problem facing solar technology in Alaska centers around the possibility of obstructions in the path between the sun and the collector surface. The sun is low on the horizon during much of the winter in the Railbelt. It rises to a zenith angle of only 6° in Anchorage and 4° in Fairbanks on December 21st. Because of these angles, short objects can block useful solar radiation (see Figure 10.3).

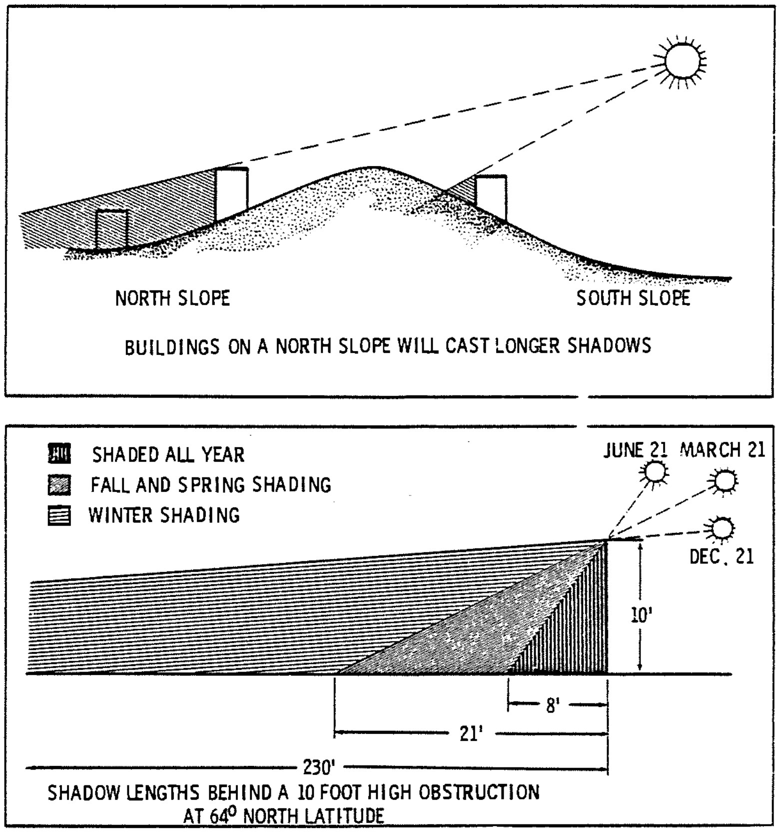


FIGURE 10.3. Solar Shading Effects in the Railbelt

Because of insufficient information, the severity of solar shading in the Railbelt cannot be currently assessed. The problem is less significant in areas where housing density is lower, particularly in the more rural areas. The lack of large trees and tall buildings in the region further reduces shading and obstruction problems. However, the mountainous terrain causes some solar obstruction. In urban areas where the density of housing is high, the possibility of shading problems increases.

Resolution of the siting problems will require studies to develop optimum siting patterns for higher density development to use in planning and review. In addition, design professionals, developers, builders, and the general public must be made aware of the benefits of orienting structures to take advantage of solar insolation.

10.1.4 Costs

Virtually no estimates of the capital costs for passive solar systems are available for the Railbelt. This stems from several factors: the relatively small number of existing applications, the wide range of types and degrees of passive solar installations, the reliance of most solar buildings in the region on heavy insulation and efficient thermal envelopes to reduce heat load, and the difficulty in differentiating between passive solar systems costs and general building costs. In addition to these factors, differences between new structures and retrofits usually exist because retrofits often involve some expense in tearing out and revamping to accomodate passive solar components.

Preliminary studies show an increase of between 6 to 10% above normal construction costs for a new passive solar, superinsulated home. Thus, in a $100,000 "typical" home, an added expenditure of $6000 to $10,000 could be expected. Total heating load would be reduced by 65 to 75% through conservation and solar measures. However, some passive solar or conservation strategies have little or no incremental costs. For example, in new construction the movement of window glazing from a north to south wall carries no incremental costs, but significantly reduces heating loads. Similarly, a well caulked and well sealed home is only slightly more expensive to build but much less expensive to heat.

Early figures show an increase in installed cost of 4 to 12% over base costs if solar is added to the home. The low-end figure reflects the addition of simple glazing, and the high end reflects a heavily insulated structure with some form of storage mass built in. These translate into unit costs ranging from $3.50 to $15/MMBtu. The least expensive installation is not necessarily the most cost effective because it may not displace enough of the heating load with solar to pay for itself within a reasonable amount of time. The following example will help to illustrate the possibilities:

Base Case: A 1500-ft^2 home in Fairbanks is built to ASHRAE 90-75 standards with a 218 MMBtu/yr heating load.

Passive Solar/Superinsulation Case: Conservation (superinsulation) and passive solar design with concrete storage mass (150 ft^3) will cut the heat load of the above house to 71 MMBtu/yr, a savings of 147 MMBtu/yr. O&M costs are $25.00/yr.

Costs per incremental MMBtu saved were then estimated for the passive solar/superinsulated case, assuming $6,000 and $10,000 incremental capital costs of the passive solar/superinsulated design.

	Cost of Savings	
	$/MMBtu	mills/kWh[a]
A. $6,000 incremental capital cost--		
1. 15% interest, 30-yr term, conventional loan	6.38	22
2. 10% interest, 30-yr term, State loan	4.49	15
3. 5% interest, 20-yr term, alternate energy loan	3.58	12
4. 3% (real) interest, 30-yr term[b]	2.34	8
B. 10,000 incremental capital cost--		
1. 15% interest, 30-yr term, conventional loan	10.53	36
2. 10% interest, 30-yr term, State loan	7.38	25
3. 5% interest, 20-yr term, alternate energy loan	5.86	20
4. 3% (real) interest, 30-yr term[b]	3.52	12

(a) For electric resistance space heating.
(b) Real interest rates, as used for comparison elsewhere in this report (no tax credits).

By comparison, the cost of fuel oil in the region as of January 1981 was as follows:

Anchorage $8.40/MMBtu

Homer $8.69/MMBtu

Fairbanks $8.20/MMBtu

These examples constitute broad averages only and represent only one particular case, a superinsulated new house with maximum solar considerations. This particular example is an "extreme" case. Capital costs will be less with structures employing lesser degrees of insulation, sealing and passive solar design. The varying range of fuel costs in the region makes it difficult to determine how much of a front-end cost is economically feasible. The cost effectiveness of the passive solar/superinsulated case would be improved if tax credits were considered. Also, note that conservation and solar technologies are virtually inflation proof once installed, whereas fuel oil is not.

Until further study is done, particularly with solar retrofits, these figures should be viewed as estimates. However, the retrofits show economic potential in many parts of the region, particularly since the examples neither reflect added tax incentives nor address future fuel inflation costs.

In the examples a figure of $25 dollars per year was set aside for O&M costs. This figure reflects a "worst case;" in reality these costs may approach zero because passive systems are extremely simple, with few or no moving parts. The costs depend on the particular system, but generally, passive systems will last the life of the building with little maintenance costs.

Various financing scenarios further complicate cost estimates. The State of Alaska presently has a program to install alternative energy systems at 5% interest on a 20-year term, up to a maximum of $10,000. This sum is sufficient to incorporate most passive solar installations on a small scale. Obviously, unit costs would be much lower over the life of the structure under this rate than with conventional financing.

Costs can generally be viewed on an incremental basis. A new structure that is oriented south with the majority of its windows placed there will cost little, if any, more than a standard structure. Adding a larger expanse of glazing will increase the cost. Finally, adding storage mass in conjunction with glazing will mean higher initial investment. Several options for a 1500-square-foot structure are analyzed in Appendix L.

The useful life of a passive system will generally be as long as that of the structure. Virtually no replacement of parts or maintenance are needed because the components are part of the structure. Because the system is "built in," system operation time and cost are minimized.

10.1.5 Environmental Impacts

Environmental impacts from passive solar technologies are minimal, almost nonexistent. No traceable air or water pollution has been recorded in dispersed application. Solar is an ideally benign fuel source for the environment.

The potential detriments to the environment center on two factors: aesthetics and reflected glare. Aesthetic appeal is, of course, subjective and not quantifiable here. It is however, an important factor. Since the concept of passive solar centers on the building and its components, the designers must ensure an aesthetically pleasing structure. Numerous examples of passive solar buildings throughout the United States are considered "ugly" by their critics. On the other hand, just as many or more examples of successful installations can be found. Entire solar subdivisions, such as those in the city of Davis, California, are both pleasing to look at and pleasant to live in. Perhaps the strongest point to make is that passive solar housing does not have to look different from the more "traditional" buildings, except for the expanse of south facing glass. Figure 10.4 shows an example of a building incorporating passive solar design.

Reflected glare off south glazing is a potential problem in solar application. The extent of the problem in the Railbelt is not known at this point. Glare is more prevalent when the sun strikes the glazing at an acute angle; i.e., the less perpendicular the sun's rays to the collector surface, the

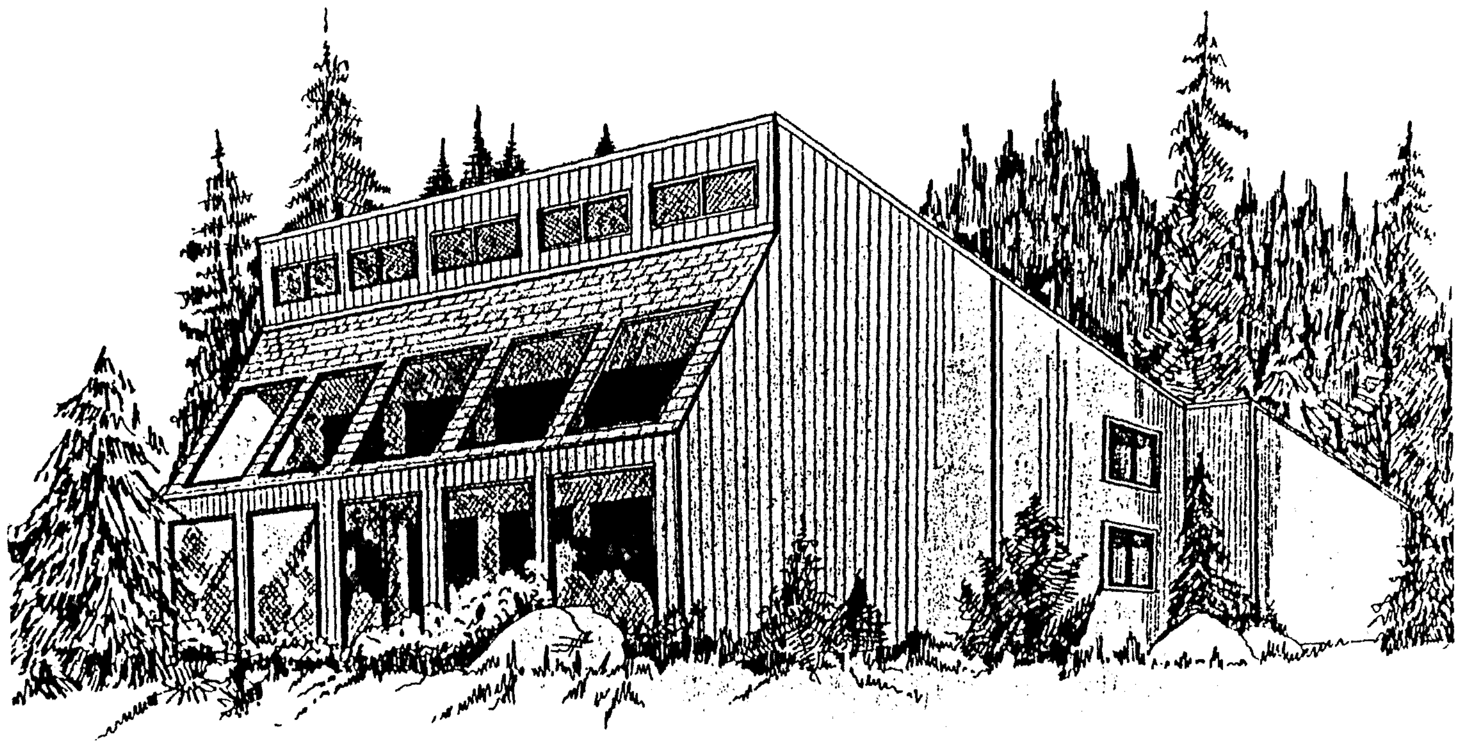


FIGURE 10.4. An Example Building Incorporating Passive Solar Design

more glare encountered. During the winter, vertical glass will not cause excessive glare problems. In summer, proper design of the roof overhangs will ensure that enough of the glass is shaded to alleviate most glare. During the spring and fall the phenomenon could cause problems to passing motorists and pedestrians. The few solar system installations in the Railbelt region precludes answers at this time. However, newly introduced "etched" glazing or various glare control films can mitigate glare problems.

Consumer safety poses no real problem with passive solar if precautions are taken to avoid impacting and breaking the glazings. Glazing in locations susceptible to impact should be of tempered glass. Because most systems are simple and benign, danger to the consumer is far less than, for example, a central fuel-fired furnace system. Workers certainly face a higher percentage of danger when installing systems, but potential injury and death is limited to those instances the worker might encounter during standard construction.

10.1.6 Socioeconomic Impacts

The socioeconomic impacts of passive solar technologies for space heating center on three areas: 1) land use, 2) consumer convenience and control, and 3) regional economics.

Land Use

The patterns of land use would be affected if passive solar technologies were considered on a widespread scale. Solar obstruction and shading would need to be addressed in site planning to prevent the degradation in efficiency of an individual solar application by a building placed in the sun's path at a later date. Such a measure can be implemented through zoning, subdivision and site planning procedures. This type of legislation has been adopted in a few states. The 1979-80 session of the Alaska legislature passed SB 438, a bill relating to energy. One section of the bill states:

> "An easement obtained for the purpose of protecting the exposure of property to the direct rays of the sun must be created in writing and is subject to the recording requirements for other conveyances of real property."

However, the wording implies a policy statement and not a regulation. As such, no administrative network of funding was provided to institute such action. Without further development of land-use management procedures that include consideration of solar access, an individual risks losing the benefits of his expenditure for solar energy by unregulated obstructions to the south.

Land-use planning for solar access is a fairly new science. Although studies have been done in the Lower 48, no such work has been done in the Railbelt. Existing studies show that such access does not necessarily require lower density of housing.

The low sun angles prevalent in the Railbelt during the middle of winter would probably be a limiting factor on solar gain in "typical" subdivision design. Two options are available. The first involves limiting density of units so that solar gain is available during the entire year. The second approach leaves the density of units per acre as exists today, with the planning process including proper orientation and placement of structures. From a purely economic standpoint, the second option would be chosen unanimously. However, shadows would probably negate solar gain during December and early January in such cases. Because of the long heating season, solar would still be beneficial during a large part of the winter. For development plots with greater than a 5% south sloping grade, no reduction in housing density is required to assure solar access.

<u>Consumer Convenience and Control</u>

Passive solar offers the following advantages:

- virtually no maintenance or replacement of parts during the building's lifetime because the components are a part of the structure
- little or no operator attention with the exception of optimal thermal shutters
- a significant portion of heating needs provided in case of power failure or fuel shortages
- reduction of dependence on uncontrollable factors affecting fossil fuel pricing and availability

- reduction of fuel expenditures and thus more disposable income available to the individual
- safety.

Potential disadvantages include the following:

- necessity of operating shutters
- wide temperature swings within a heated space if no storage mass is present to regulate the variance in available solar radiation.

Regional Economics

Because passive solar is a decentralized technology, it will create jobs and new capital ventures at a local level as well as at a regional level. Since the skills required to design and to install systems are relatively straightforward, using standard materials and techniques, most of the human resource needed most likely exists in the region. If pursued on a fairly widespread scale, the potential for long-lasting jobs in new and existing businesses is promising. Although numbers are not quantifiable within the limits of this profile, early studies in the United States have shown that decentralized options provide more benefits in terms of local employment than larger, centralized projects (Buchsbaum and Benson 1980).

An increase in employment and business at the regional level would most likely result in an increase in the amount of capital staying in the region, further providing economic benefits outside the construction sector. The extra income available to the consumer by reduced fuel expenditures would become part of the region's economy. While an in-depth economic analysis cannot be done until the degree of penetration of the solar technologies in the market place can be better assessed, preliminary study and common sense indicate that passive solar would have a positive impact on the economy.

10.1.7 Potential Application to the Railbelt Region

Passive solar is an emerging technology in the Railbelt. Currently, only a few structures have been designed specifically to take advantage of the maximum amount of available solar radiation. Until very recently, cheap fuels have provided little incentive to explore alternative forms of heating.

During times of major building activity so prevalent in the boom and bust economy of the region, the trend has been towards minimizing front-end cost, with little or no regard to future operating costs.

A combination of energy conservation and passive solar in new construction can cut energy demands by 60 to 70% in an individual dwelling. The potential of passive solar and conservation in existing buildings is difficult to quantify without knowing the structure's existing condition and solar access. A 30 to 50% reduction in the heating load is possible if these two technologies were combined. Without an assessment of existing building stock, an aggregate projection is difficult (Seifert and Zarling 1978).

The potential contribution of passive solar is difficult to assess on a region-wide scale. Little data exist on the performance of the few installed systems, and the number of buildings having good solar access in the Railbelt is not known. Therefore, two examples of typical structures are presented here to illustrate the impact passive solar can have on an individual unit. The first model is a house insulated to the standard level now prevalent in the Railbelt; the second is a superinsulated home using heavy insulation and other techniques to radically decrease its energy consumption. Both structures have floor areas of 1500 square feet. Glass area is varied to show the impacts of different glass sizes on passive solar heating (see Table 10.5).

TABLE 10.5. Solar Heating Fractions for Various Railbelt Applications

House	Solar Heating Fraction (%)[(a)]	
	w/150 ft^2 glazing	w/ 200 ft^2 glazing
Anchorage		
1. Typical House	23	30
2. "Superinsulated" House	45	57
Fairbanks		
1. Typical House	17	22
2. "Superinsulated" House	33	41

(a) Amount of annual heating load supplied by passive solar heat.

Obviously, the less heat that has to be supplied to a structure, the more attractive solar heat becomes. Note that in the superinsulated structures the heating load has already been reduced radically, and although passive solar is supplying 40 to 50% of the heat, the combination of conservation and solar reduces the load up to 70%. Several of these structures in the Railbelt are using 25 to 30% as much energy as their neighbors by combining an efficient thermal envelope with solar heat.

Passive solar technologies use materials and building techniques common to the building trades - an important attraction. Because passive solar in the Railbelt is best exemplified by an energy-efficient house coupled with south glazing, it is easily accessible to the designer's and builder's present skills.

Development of a thorough understanding of the cost effectiveness of various levels of passive solar design followed by education of designers, developers, builders, and consumers is the key to successful implementation of solar technologies. The efficient passive solar house in the Railbelt employs a combination of several techniques: a thermally efficient building envelope, south glazing, a continuous vapor barrier, reduced infiltration, and some form of heat storage system. All of these components can be integrated into a house with materials already available in the region. A few components not stocked in the state would help to refine passive systems, and they are available on fairly short notice from suppliers in the Lower 48.

Education of the building trades is essential. The building industry is historically slow to adapt to changes in technology. No matter how well the design and specifications are drawn up, education of builders and craftsmen will be necessary to ensure that passive solar systems work to their designed efficiency. However, interest among builders in the region toward passive solar technology appears to be high.

Existing financial practices present an additional obstacle to developing passive solar technologies in the Railbelt. Commercial lending institutions historically tend to consider the front-end costs of constructing a building only. The concept of life-cycle costing must be taken into consideration if passive solar is to be successful; O&M costs (i.e., fuel) over the life of the building must be integrated into the overall cost. The degree of acceptance of the life-cycle costing concept among lending institutions is not clear. Scattered reports indicate some bankers' resistance to extra costs for solar. On the other hand, several lending institutions in the Anchorage area have extended loans for passive-solar-designed homes, despite higher initial costs.

Real estate appraisers present another possible obstacle. Most do not seem to understand how to include passive solar in their reporting. To quote one appraiser:

> "I suppose what I'm trying to say is that I really don't know (how to appraise the market value of a solar house). An appraiser's job is to estimate value based on fact occurrences and, unfortunately, there haven't been enough fact occurrences to give a true and accurate answer." (Seifert 1980).

Most Alaskan appraisers of solar homes do not understand how to value reduced heating bills. Energy use is simply not a factor in the training and scope of work of the appraiser. Once again, education of these professionals is necessary.

The State of Alaska has an alternative energy revolving loan program available to the consumer at low interest rates to help offset the initial costs of systems. The loan ceiling is $10,000, at 5% interest with a 20-year term. In most cases, this money in itself will cover additional costs for the passive system. While several administrative problems have occurred in the first year of the loan program operation, consumer interest is high, and efforts continue to resolve the flaws. The program is an important step toward solving some of the financial obstacles discussed.

10.2 ACTIVE SOLAR SPACE AND HOT WATER HEATING

"Active" solar systems require auxiliary pumping energy to function properly. These systems differ from passive solar systems, which require very little or no auxiliary energy. Active solar energy use is an accepted technology, with thousands of installed systems throughout the United States.

10.2.1 Types of Active Solar Systems

Three varieties of dispersed active solar systems are currently available in Alaska: liquid-based, flat-plate collector systems for space heating; liquid-based, flat-plate collector systems for hot water heating; and hot air systems for space heating. A large variety of manufactured collectors is available throughout the United States, and several models applicable to the systems mentioned above can be found at wholesalers and retailers in Anchorage and Fairbanks. In addition, site-built and locally manufactured units fabricated by sheet metal and plumbing shops are available, particularly in the Fairbanks area.

Liquid-Based Flat Plate Collectors for Space Heating

The flat-plate solar collector (Figure 10.5) is the most common configuration used today in active solar energy systems. Active solar systems employing flat-plate collectors are the most common type used to retrofit homes and

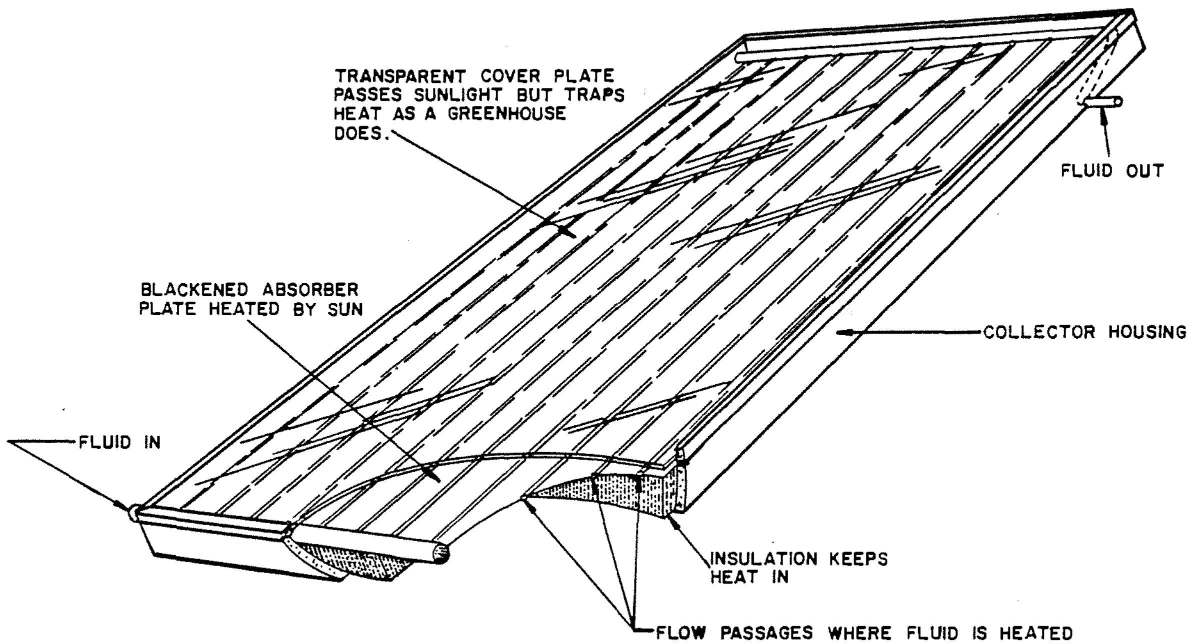


FIGURE 10.5. A Typical, Liquid-Based, Flat-Plate Collector

businesses because they offer greater installation flexibility. In flat-plate, liquid-based collectors, the absorbing surface has several tubes running lengthwise through it. Liquid is pumped through the tubes. Sunlight heats either the tubes directly, or the plate, which then transfers heat to the tubes. The heated liquid can be used for either space or water heating applications (Figure 10.6). For year-round use in the Railbelt, a liquid-type, flat-plate collector must incorporate antifreeze in the heat exchange fluid to prevent freezing.

Flat-plates can accept either direct or indirect sunlight from a wide range of angles. The absorber plate is fabricated from a material that is a good conductor, such as copper or aluminum. It is painted black to absorb as much radiation as possible. As the plate warms up, it transfers heat to the fluid within the collector, but also loses heat to its surroundings. To minimize this heat loss, the bottom and sides of a flat-plate collector are insulated, and a glass or plastic cover is placed above the absorber with an air space between the two. The cover permits sunlight to come through while reducing the amount of heat escaping. If the collector is located in a cold region (such as the Railbelt), two layers of glazing are sometimes used, although the cost effectiveness of double glazing needs further research.

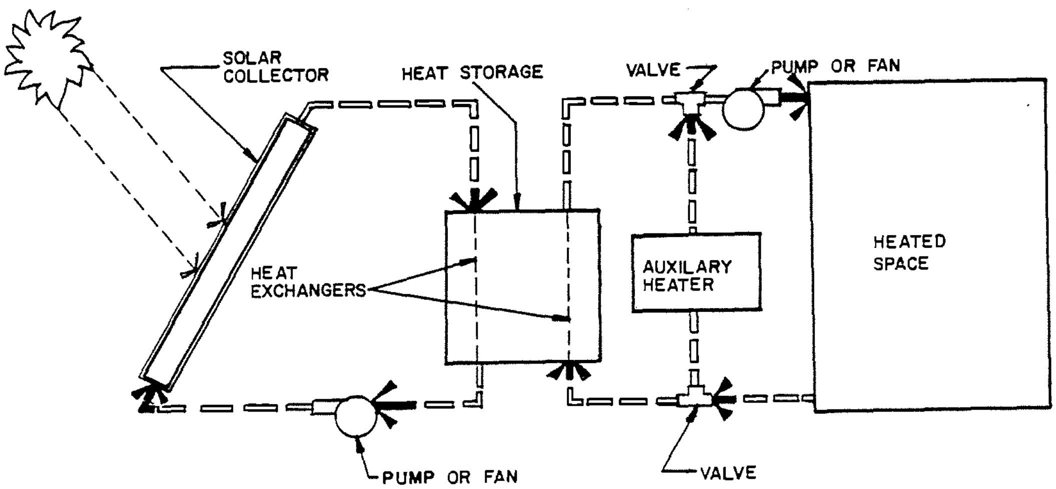


FIGURE 10.6. Typical Active Solar Space Heating System

Currently less than 20 operating double glazed systems exist in the Railbelt area, and none have been monitored to determine the efficiency of double glazing.

A version of the flat-plate collector, which may be applicable for Alaska, is called SolaRoll®.[a] The system consists of a unique exchanger/absorber plate made of a black, flexible elastic monomer that can withstand freezing. The system has an anticipated 30-year lifetime and performance tests indicate that SolaRoll encased in a standard site built or locally manufactured insulated collector frame performs better than average metal solar collectors. The system is tailored for do-it-yourself installation and requires no nails, screws, plumbing elbows or tees, or battens for assembly. Soldering, welding, sealant, or paint also is not needed. SolaRoll is an example of the types of technological advances that continue to make solar collectors cheaper and better (Seifert 1980).

Active systems require an energy storage system for optimal effectiveness. Storage for the liquid types usually consists of a well-insulated water tank, with an exchanger to draw off heat as needed for the main distribution system (see Figure 10.6).

<u>Liquid-Based Flat-Plate Collectors for Hot Water Heating</u>

Active solar systems for domestic hot water systems use the same type of collectors used for space heating systems. Figure 10.7 shows a typical hot water heating installation. A heat exchange loop must be provided in hot water heating systems to prevent the antifreeze from contaminating the potable water supply in the event of a leak.

Active solar for hot water heating offers many attractions in the Railbelt region. Water heating is a year-round activity, so a much closer match exists between resource availability and load than for space heating. The collector can be much smaller than that needed for space heating; thus, installation costs are much lower. Although solar hot water heating will likely not provide a great portion of midwinter needs, during fall and spring months it will supply a large portion of the load. During summer, nearly 100% of hot water

(a) A trademark from the Bio-Energy Systems, Inc., Ellenville, New York.

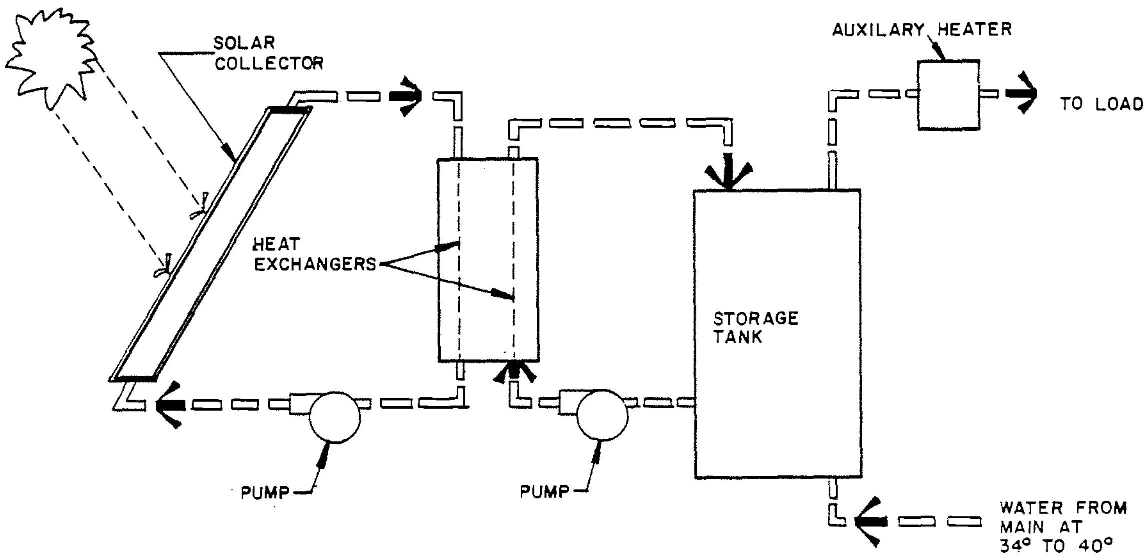


FIGURE 10.7. A Typical Active Solar Domestic Hot Water Heating System[a]

(a) R. Seifert. 1981 (Draft). Alaska Solar Design Manual. Institute of Water Resources, University of Alaska, Fairbanks, Alaska.

can be heated by the sun. Appendix M gives examples of performance characteristics for active solar water heating in two prototypical homes in Fairbanks.

Hot Air Systems for Space Heating

Active air collectors (see Figure 10.8) are usually thicker than liquid-based collectors because they handle higher mass flow rates; because a given volume of air absorbs fewer Btus than a similar volume of liquid. To keep the collector temperature low, thus improving efficiency, more air must pass through the system per unit time. One approach to this technology is to pump the hot air directly into the living space. Preliminary calculations show this to be effective when combined with a thermostatistically controlled fan. A more common approach involves ducting the heated air from the collector into a rock bed to provide storage for later use. A separate ducting system then carries this air into the living space. No data on the performance of these systems in the Railbelt region are available.

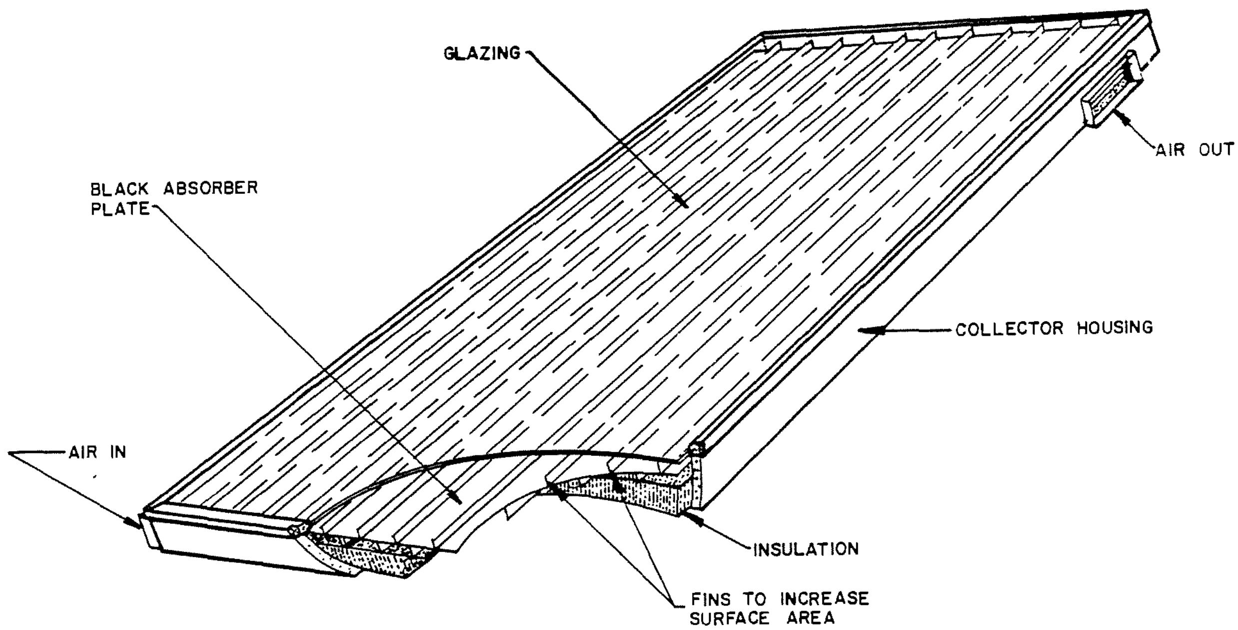


FIGURE 10.8. A Typical Air Solar Collector

On first examination, the use of active solar for space heating in the Railbelt region would seem to be inappropriate because the building heating load is greatest when the resource is at its minimum. However, in many parts of the Railbelt, space heat is needed at least 9 to 10 months of the year. The number of heating degree days in Homer, Alaska in May is greater than that of Davis, California in December. Davis is considered a model solar community, with 500 to 600 solar homes. This comparison would suggest that although active solar will not make a significant contribution to heating during mid-winter months in the Railbelt, it can reduce heating bills on an annual basis.

10.2.2 Technical Characteristics

Important technical characteristics of active solar systems include system efficiency, coincidences to load, adaptability to load growth, convenience and control, electrical load offset and complementary technologies.

Active Solar Efficiencies

In the Railbelt, active solar collectors make effective use of 30 to 40% of the sun's energy that strikes their surface. This is their raw performance under optimal conditions; it assumes no obstructions in the sun's path and the collector tilted perpendicular to the sun on an average annual basis (usually at the latitude angle for domestic hot water, and latitude plus 10 to 15° for space heating). Several other variables can reduce the efficiency of a system. For example, the greater the temperature difference between outside ambient air and the collector surface, the less efficient the system because of excessive heat loss back out the glazing. A differential of 100 to 180°F is generally acceptable. The "optimum" situation described above assumes that the temperature of the collection fluid is about 140°F.

A collector's efficiency can only approach 30 to 40% if the heated medium is used directly, such as water out of the tap or air ducted into the house. Transfer of the heat from the collection fluid via heat exchanger, as in a copper flat-plate domestic hot water system with an ethylene glycol collecting fluid, will reduce efficiency by another 8 to 12%. In space heating installations where heat is transferred from the collection fluid into a storage medium and then again to a distribution fluid, an additional 8 to 12% loss can occur. Until some monitoring of installed systems in the Railbelt is undertaken, actual performance cannot be accurately predicted.

Coincidence to Load

The ability of an active solar installation to meet heating loads (whether for space or hot water) depends largely on the efficiency of the installed system, the collector area, and whether a storage system is used. The degree of solar access is also a factor. While little data exist, active solar is expected to have little impact on loads during the coldest and darkest of the winter months because of the relative lack of insolation and high heating demands. During the rest of the heating season the impact of solar will be greater, although the degree is not yet known. One thing is certain without a storage system to carry over the benefits of solar gain to nighttime and cloudy periods, the load-following capability of an active solar system is limited.

Adaptability to Load Growth

Active solar is just as adaptable to future growth as the other dispersed technologies. Because solar is dispersed, installers with a minimum of training can put solar into place quickly with little lead time.

Consumer Convenience and Control

Active solar space heating and hot water systems are largely automated, not requiring homeowner attention for normal operation. Periodic maintenance requirements are slight, typically consisting of seasonal cleaning of collector glazing and winter draining of heat exchanger fluids to prevent freezing.

Type of Electrical Load Offset

Electricity for space heating comprises such a small percentage of the electrical load that active solar space heating would have little immediate effect on the demand for electricity. Moreover, because of the limited availability of solar insulation in the winter, active solar space heating systems would require a full backup locating system, and, for homes using electrical backup, generating capacity to supply the backup systems.

Active solar hot water heating systems typically have substantial storage in the form of water storage in the heat exchanger unit as well as the backup hot water tank. These systems could thus trim daily peak loads during late spring, summer and early autumn months. The backup hot water heating system and associated generating capacity would be required during winter months.

Complementary Technologies

Active solar for space heating can provide a significant portion of the heating needs to a structure only when the building has been upgraded to consume less energy than a standard building. Building conservation is therefore not only a complementary but also a necessary technology that should accompany an active solar application. A popular and cost-effective approach is the "hybrid" system, where passive solar is used for space heat and active solar for hot water needs.

10.2.3 Siting Considerations

The same meteorological considerations apply to active solar systems as were discussed for passive solar systems (see Section 10.1.4). The sun angles are so low in the region that collectors placed vertical or close to vertical are more effective than horizontal collectors; a collection surface perpendicular to the sun's rays will capture the maximum amount of radiation.

Orientation

As discussed in Section 10.1.4, the collector surfaces should be oriented as due south as possible, although a variance of several degrees will not seriously affect performance. In fact, recent research in the Lower 48 states indicates that active solar hot water systems will still perform very well when oriented as much as 90° off of south (Solar Age Magazine 1980). No testing has yet been done to verify this phenomenon in the Railbelt, but the potential ramifications may be significant for retrofitting active solar systems to existing housing. Most housing in the region has been oriented haphazardly in relation to solar access. Collectors can be mounted in several places and by several means: on a rack on the ground, on a wall of the structure, and on the roof using mounting racks. Such mounting racks are often used to "skew" the collector, so that it faces south on a roof that may be oriented in another direction. However, mounting the collector "in line" with the roof of an existing structure is simpler, less costly, and generally more aesthetically pleasing.

The number of existing structures adaptable to active solar space and/or hot water heating in the Railbelt is not yet known. Field work will be required to determine this.

Solar Obstructions/Shading

The same solar obstructions/shading considerations apply to active solar systems as were discussed for passive solar systems (see Section 10.1.4).

10.2.4 Costs

Unit costs of active solar energy will vary widely, depending on type of system installed, the amount of collector area used, and the efficiency of the end use of the system. Little work has been done in this area. Matt Berman and Eric Myers of the Alaska Public Interest Research Group have compiled one of the most complete cost analysis to date on active solar in Alaska. They used a standard home, a retrofitted structure, and a "superinsulated" house for space heating cost comparisons and they also looked at hot water heating (Table 10.6). They calculated the cost of energy based on several different

TABLE 10.6. Active Solar Cost Analysis for Fairbanks, Alaska[a]

	Load Served (%)	Cost of Energy Saved ($/MMBtu)
Standard Home (Space Heat)	5.2 - 37.3	12.83 - 34.16
Retrofitted Home (Space Heat)	6.3 - 39.1	12.60 - 32.31
Superinsulated Home (Space Heat)	7.5 - 41.9	12.61 - 31.10
Hot Water Heating	15 - 61.6	12.53 - 24.30

(a) Assumes a collector cost of $15/ft^2, including storage, with financing at 9.5% interest over 20 years with no down payment.

collector sizes to define the "optimum" investment. These cost figures are projections only; not enough systems have been installed to know actual initial capital costs.

O&M costs will be a part of every active solar system; the amount depends on the type and size of the installation, as well as the care given to design and construction. A very broad estimate must be made, since little precedent exists in Alaska. An average figure of $25 to $50 per year over the life of the system seems likely for such items as burned out pumps, piping or ducting repairs, and glycol solution replacement once a year if the system is drained down annually.

10.2.5 Environmental Impacts

The environmental effects of active solar energy use are almost entirely positive. Once the system is manufactured and installed, it should supply 10 to 20 years of pollution-free energy at an average rate of 400 Btu/ft^2/day in the Railbelt. Early concern over the aesthetic devaluation of neighborhoods from many roof-mounted solar collectors has been replaced by the increased real estate appraisal values for homes with solar systems.

Injuries and deaths accredited to the solar technologies are rare. Because most installations tend to be small and relatively simple to install, the hazard rate is no higher than that involved in standard, light construction.

10.2.6 Socioeconomic Impacts

If active solar were to be employed on a widespread basis, it would most likely have the same socioeconomic benefits that the other dispersed technologies have. Design and installation would be provided by Alaskan firms, on a widely dispersed basis. As a result, cash flow would also tend to be dispersed, with more of it staying in the region than if a large centralized project were undertaken. However, an outflow would occur because both manufactured collectors and components for job-built collectors largely would be shipped into Alaska.

The reduction in capital expenditure for fuel at the individual level would obviously result in more spending power, and more cash would likely be available for other items. The impacts of the benefits would depend on the amount of market penetration, but generally, the socioeconomic impact of active solar would be beneficial.

Because active solar is an isolated gain system, it does not affect an individual's lifestyle in the same way that a passive solar design does (opening and closing shutters, etc.). Much depends on the particular system; some systems are totally automatic, while others require at least a minimum degree of daily participation. Whether this is a potential burden depends on the user and would be difficult to assess here.

Benefits from reduced fuel usage and subsequent dollar savings are obvious. An ability to maintain comfortable temperatures in the dwelling (or hot water supply) during times of fuel disruption is an additional advantage. Finally, the investment is inflation proof, which is not true for most traditional heat sources.

The amount of maintenance required for an active system depends on how well the initial design and installation incorporated repair and replacement considerations. If copper is used in the collector, the system will have to be drained down during the coldest months of the year to prevent freezing and subsequent bursting of pipes. A plastic absorber can eliminate this requirement. Because so few systems have been installed in the region, estimating the maintenance and operation time required by the consumer is difficult. A figure of 3 to 6 hours per month for a well-designed system is a reasonable estimate.

10.2.7 Application to Railbelt Energy Demand

The high cost of fuel and the extreme heating loads of the Railbelt region combine to make active solar use attractive. However, the use of active solar energy in Alaska has many constraints. The low winter sun angle coupled with extreme, low temperatures makes active solar collection difficult for 1 to 3 months of the year, depending on latitude, cloud cover, and site variables. The effect of the interaction of these variables has never been studied for Alaska, and definitions of solar access angles for the state are not currently available. Until latitude-specific, economic-based definitions of solar access data are gathered, a collector for a site with an unobstructed south view is assumed not to be useful between December 1 and January 15 at the southern extreme of the Railbelt, and between December 15 and February 1 in Fairbanks.

Although no in-depth studies have been done, preliminary work in various Anchorage neighborhoods has shown that as much as 35 to 45% of the existing building stock may be adaptable to retrofits for active and/or passive solar.[a] Determining the overall potential of active solar would be extremely difficult at this point. The number of dwellings with solar access is unknown, the actual performances of active systems are undocumented, and market penetration of active solar technologies is difficult to assess because availability is still fairly low in the region.

In a study performed in 1980 by the Alaska Center for Policy studies, Richard Seifert (1980) of the University of Alaska Institute of Water Resources writes:

> "There is very little basis upon which to predict the impact and market penetration of (active) solar energy systems for Alaska. Presently, there are active technology systems functioning in Alaska, but they are rare and usually not commercial systems, but

(a) Alaska Renewable Energy Associates, in-house study, 1980.

rather owner-built. Without further demonstrations of the technology within Alaska and marketing development, the prospects for active solar applications look grim. The most probable level of use of active solar systems will depend upon the commitment of the state and other government agencies to promote this technology. Being optimistic, but more realistic, the contributions are likely to be from 20 to 25% of the maximum possible."

Even a 20 to 25% level of use seems optimistic, as Seifert points out. The high cost of initial investment in an active space heating system would likely preclude a large market penetration. This situation will remain unless front-end costs decrease significantly.

Active hot water heating, on the other hand, could conceivably provide a significant reduction for electric power demand. Prospects for offsetting load look better. Research by Seifert shows that, on an annual average, 50% of the hot water needs can be met by active solar collectors in a typical Railbelt installation. If 40 to 50% of the building stock had good solar access, 20 to 25% of the energy needed for water heating could be displaced. All of these figures are based on broad assumptions and as such must be considered preliminary. Further work needs to be done to define active solar's impact in the region.

Several dealers sell active collectors. Most of the collectors are for hot water heating and are part of a kit that includes the tank, collector, and other components. Sheet metal shops in the Fairbanks area will custom make collectors on demand. In general, however, the consumer will have little help when looking for an active system. All of the dealers surveyed had no idea of the effectiveness of their particular systems, and they did not know the optimal number of square feet of collector area for a particular installation. This lack of design knowledge appears to be widespread also among architects and engineers. Demand for active solar has not been sufficient for many to have had experience with it in the Railbelt.

Many obstacles to commercialization, such as lack of designers, installers and dealers, have been mentioned. Resistance by financial institutions is likely to be an impediment, as the high initial costs may tend to reduce the willingness of financial institutions to lend money for active solar systems. The largest single obstacle centers around the complete lack of knowledge pertaining to active solar use in Alaska. Until technical and economic feasibility is demonstrated, a large segment of the population will likely remain skeptical.

10.3 WOOD FUEL FOR SPACE HEATING

Several factors point to wood as an alternative to gas, oil and electricity for residential heating in the Railbelt area. Although the future role of wood in meeting space heating needs is difficult to quantify, information indicates recent dramatic increases in wood fuel use. This profile examines the nature and extent of wood usage for home heating in the Railbelt area, including the potential for growth and the adaptability of this alternative to increased demand.

10.3.1 Technical Characteristics

The principal types of wood-fired space heating systems include fireplaces, fireplace inserts, box stoves, airtight box stoves, base-burning airtight stoves, front-burning airtight stoves and wood-fired furnaces. The characteristics of the major types of wood-burning units are reviewed below. Emphasis is placed on measures that enhance the energy efficiency of wood-burning units. These measures include draft control, combustion of volatile gases, use of outside air for combustion and ways to transfer heat to living spaces.

Fireplaces

Fireplaces are still used for some home heating needs, chiefly as a secondary source. Conventional fireplaces do not permit any draft control and generally have little capability to transfer heat of combustion to the living area. The more sophisticated, steel fireplace shells incorporate provisions for outside combustion air, circulation of living space air around the shell and glass doors. The latter provide relatively ineffective draft control but do serve to control warm air loss up the chimney when the fireplace is not in use. Few masonry fireplaces are being incorporated in new residential construction; most new installations have steel fireboxes and chimneys.

Fireplace Inserts

Fireplace inserts provide an opportunity to use an installed fireplace while incorporating some of the advantages of wood stoves, such as draft control, baffling for secondary combustion, and improved heat radiation. Many of these units draw combustion air from the outside, thus cutting the loss of warm air from the structure.

Box Stoves

Box or chunk stoves are the simplest and most common type of wood-burning unit available. They come in many forms, including kitchen, Franklin, potbelly and parlor stoves. These types generally do not have very good draft control and therefore burn excessive amounts of wood. Most introduce air under the fire, which allows large amounts of unburned gas to be carried up the chimney, taking with it a good deal of potential heat. Most use room air for combustion.

Airtight Box Stoves

Airtight box stoves have controlled-draft damper systems, some with automatic thermostats, to give more positive control of both primary and secondary combustion air. Most introduce air below and above the fire to promote combustion of volatile gases. Some designs preheat incoming combustion air. Some incorporate thermostatically controlled stack heat exchangers to recapture heat for space heating.

Base-Burning Airtight Stoves

Base-burning airtight stoves take the principles of the controlled draft (airtight) box stove one step further and add a second chamber for better combustion of gases. These stoves bring secondary air through a preheating channel so it will not significantly cool the volatile gases. In addition, the flue outlet is located at the base of the firebox, forcing all the exhaust products to pass by the hottest part of the fire before leaving the stove. Under proper conditions these stoves can be fairly efficient, but need frequent tending.

Down-Draft Airtight Stoves

Down-draft airtight stoves are relatively simple in design. Air is drawn through air ports in the stove top, producing a blow torch effect. Volatile gases from fresh fuel are driven through the glowing coals promoting combustion of these gases. In some models, primary air enters above the fire but below the main load of wood. This primary draft flows down and outward through the coals, pulling volatile gases with it. Secondary air is introduced under the coals where it can oxidize these superheated gases. Gases continue to burn in the secondary chamber. This draft pattern prevents heat of the fire from rising up through a fresh wood load, isolating it from the fire until the wood has dropped into the combustion zone. Thus, even a fresh load of fuel will not cool to the fire below. Volatile gases from the new fuel wood are released more slowly for more efficient burning.

Front-Burning Airtight Stoves

Front-burning airtight stoves characterize the Scandinavian approach to efficient burning. Primary air is directed into the coals, forcing volatile gases into the burning area. Secondary air is introduced above the fire to burn escaping gases in a baffled secondary chamber.

Wood Furnaces

Wood-fired furnaces are also available. These allow the installation of a central, forced-air heating system fired by wood. Wood furnaces generally have substantial fuel capacity to allow a long burn time between refuelings, thermostatic draft control, and Btu ratings sufficient to heat larger residential dwellings. A typical wood-fired furnace incorporates the combustion features of the better free-standing wood stove designs.

Mixed fuel systems are also available. They incorporate many of the features described above while providing the advantage of flexibility in fuel choice. A typical mixed-fuel unit will burn wood as well as coal.

Estimates of conversion efficiencies for the eight stove types and for standard fireplaces are given in Table 10.7. Other factors, such as the material used in the stove's construction, may significantly alter these figures. Warpage of stove walls or door frames may introduce unwanted air, as well as signal the end of the stove's useful life. The effectiveness of a system is indicated not only by Btu output but also by the ability to put the heat into the structure instead of losing it to the chimney.

The feasibility of converting to wood heating as either backup or a full-time system varies widely with the area to be heated and the structural implications involved in installation. In most cases, special accommodation must be made for pipes or chimneys, requiring careful attention to safety factors. Additionally, it may be desirable to integrate the wood heating system with the central heat distribution system of the building to distribute heat from the wood system throughout the structure.

TABLE 10.7. Conversion Efficiencies for Wood-Fired Units

Wood System Type	Conversion Efficiency (%)	Typical Heat Output (Btu/hr)	Installed Cost ($)
Standard fireplace	up to 10	30 - 50,000	
Fireplace with glass doors & outside combustion air	15 - 25	53,000	1129
Simple box stove	20 - 30	40,000	299
Airtight box stove	40 - 50	20,000	339
Base-burning stove	40 - 60	50,000	
Down-draft stove	50 - 65	40 - 50,000	700
Front-end combustion stove	50 - 60	15 - 40,000	
Mixed-fuel furnace	50 - 60	112,000	6000

Source: Matson/Oregon State University Extension Service.

Design features that contribute to the overall energy efficiency of a structure all work to improve the reliability of wood for heating purposes. These features include siting, window size, placement and building size, as well as standard conservation measures, such as proper insulation and weather-stripping. Proper installation and the operation (fire-tending, drafting) of wood heating systems also contribute to the reliability of wood as a fuel.

10.3.2 Fuel Requirements

Table 10.8 lists mechanical and physical properties of tree species found along the Railbelt (USDA Forest Products Laboratory 1974). For the consumer, the column representing millions of Btu per cord is the important consideration. This column illustrates the relative superiority of birch (prevalent in the Railbelt area) over other species by a significant margin. Inherent moisture values vary according to species. Moisture content (MC) of 20% is considered acceptable by most technical sources and wood stove manufacturers.

TABLE 10.8. Railbelt Wood Characteristics[a,b]

Area	Species	MMBtu/Cord 20% MC[c]
Coast:	Sitka Spruce	15.2
	Hemlock	17.2
Interior:	White Spruce	15.2
	Black Spruce	15.6
	Aspen	14.1
	Birch	19.3
	Cottonwood	12.5

(a) Source: USDA Forest Products Laboratory 1974.
(b) Values are given for a standard 128-cu ft cord, containing 90 cu ft of solid wood and bark.
(c) Derived from Galliet, Marks, and Renshaw (1980).

For wood fuel to reach combustion temperatures, its inherent moisture must be heated and turned to steam. Therefore, the moisture content is directly related to the available heat: at 50% moisture content, 13% of the fuel's heat value is required to vaporize the moisture. At 67% moisture, 26% of the heat value is needed for drying.

Changes in moisture content of fuel complicate control of combustion. If combustion is running smoothly with fuel of 50% moisture content and suddenly much drier fuel is introduced, the combustion rate will increase rapidly. A oxygen deficiency will result, leading to incomplete combustion, which results in a plume of dense black smoke.

Consumers have considerable control over moisture content of wood. The type of wood used and the length of drying time are two factors affecting moisture content. In addition, cutting wood during the dry seasons will usually ensure a lower moisture content.

Wood is generally available year round, although consumers must plan for harvest or purchase of wood supply. Important factors include wood type and quality and storage. Most wood used in the Railbelt (see Table 10.9) for fuel is harvested by small operators or individuals using chainsaws and pickups or snowmachines. Wood appears to be gathered year round and is typically gathered from areas accessible by public roads.

Only one commercial firewood supplier in Anchorage considers his operation to be full-time and relies on it as a sole source of income. He would not disclose any data concerning wood sources or volume because he felt it was confidential information. Of the other suppliers sampled, none had been in business more than 1 year, and only one plans to expand his operation into a full-time business. Distance traveled to cut wood ranged from 2 miles to 90 miles (one-way). The source of wood is state and private lands but the greater amount is taken from private lands being cleared for development. All suppliers stated that their sales were limited only by accessibility to harvest areas, and not by resource shortage.

Birch is the most common wood in the Anchorage area and ranges from $75 to $95 per delivered cord. Spruce is most common wood in Fairbanks and ranges

TABLE 10.9. Survey of Railbelt Wood Suppliers[a,b]

Anchorage:		Distance Traveled (mi)	Public Land	Private Land	Annual Harvest (Cords)	Primary Wood Type	Delivered Price ($/Cord)
Supplier:	1	50 to 90	X	X	6	Birch	85
	2	90	X		NA[b]	Birch	90
	3	80	X		45	Birch	85
	4	35	X		15	Birch	75
	5	5		X	500	Birch	95
	6	2		X	25	Birch	80
Fairbanks:							
Supplier:	1	40	X		400	Spruce	80
	2	25	X		400	Spruce	90
	3	50	X		200	Spruce	85

(a) In-house survey by Alaska Renewable Associates, 1981.
(b) The primary Anchorage commercial supplier will not reveal data.

from $80 to $90 per cord. Distances traveled range from 25 to 50 miles (one-way) and state land is the primary source.

10.3.3 Costs

Space heating costs using wood compare very favorably with other sources, especially when harvested by the dispersed, individual method. This situation will continue, unless transportation fuel costs rise dramatically.

The unit cost for wood heating over the life of the structure is difficult to assess, as several assumptions must be made. These assumptions include future costs of firewood, whether it is gathered commercially or by the individual homeowner, and the installed cost of the woodburning unit.

The installed cost of the woodburning unit will vary, depending on the intended end use and quality of the unit. Simple box stoves can be installed for as little as $350 to $400, although the useful life will almost always be under 10 years. Well-built, airtight stoves will range in cost from $700 to $1600 and will last 20 to 30 years with a significantly higher heat output than the type listed above. The wood furnace units with full ductwork can run $3000 to $6000, particularly if a multipurpose unit is purchased (e.g., oil/wood).

Table 10.10 lists typical fuel wood costs for both the Anchorage and Fairbanks regions. These figures are based on costs quoted by commercial suppliers in each area and do not take into consideration the efficiency of combustion units.

O&M costs are difficult to assess because they will vary on a case-by-case basis. Some of the wood furnace units burn at such high temperatures that they will not require stack cleaning as often as those types of wood stoves that accumulate creosote in the stack with lower burn temperatures. Professional stack cleaning ranges from $60 to $85 in the Railbelt region. Obviously, the homeowner could do this work himself and save considerable expense. Other maintenance items include stove and stack repair, wood pile maintenance, and repair or replacement of chain saw parts (or units) if wood is cut by the individual. A broad O&M cost per year for someone relying largely on wood for heating might be $100, depending on the individual. Estimates of the cost of wood heating are provided in Table 10.11. The costs of energy provided in Table 10.11 are based on 3% financing for comparability with costs provided elsewhere in this report and are not representative of costs experienced by a homeowner under current (nominal) financial conditions.

TABLE 10.10. Fuel Wood Costs for the Railbelt Area

Location	$/Cord[(a)]	$/MMBtu
Fairbanks	$80.00	$5.48
Anchorage	$90.00	$6.30

(a) 90 ft^3 of wood within 128 gross cubic feet (4'x4'x8') used for standard cord.

TABLE 10.11. Representative Wood Space Heating Costs (1980 dollars)

Type of Unit	Capacity (MMBtu/hr)	Capital Cost[a] ($/unit)	O&M Cost ($/unit/yr)	Fuel Costs[b] Anchorage ($/MMBtu)	Fuel Costs[b] Fairbanks ($/MMBtu)	Energy Costs[c] Anchorage ($/MMBtu)	Energy Costs[c] Fairbanks ($/MMBtu)	Equivalent Electric Energy Costs[d] Anchorage (mills/kWh)	Equivalent Electric Energy Costs[d] Fairbanks (mills/kWh)
Box Stove	0.04	654[e]	100	11.54	10.04	41.8	47.7	142	163
Airtight Stove	0.05	1150	100	11.54	10.04	19.2	21.7	65	74
Furnace	0.1	4500	100	11.54	10.04	20.1	22.8	69	78

(a) As installed.
(b) Levelized fuel costs over a 20-year operating life at 1-1/2% real escalation/year. Based on base year (1980) costs as follows: Anchorage - \$6.30/MMBtu; Fairbanks - \$5.48/MMBtu.
(c) Levelized 20-year lifetime costs for energy input to the residence based on the following efficiencies: box stove - 25%; airtight stove - 57.5%; furnace - 55%. Costs are real (3% discount rate).
(d) Levelized 20-year lifetime costs, based on displacement of electric resistance space heat. Costs are real (3% discount rate).
(e) Includes replacement of unit at 10 years, discounted at 3% to first year of installation.

10.3.4 Environmental Considerations

Wood for heating poses three environmental issues: fire hazards, air-quality effects and impacts of wood harvest on forests.

Fire Hazard

House fires resulting from wood stoves can usually be attributed to faulty installations and improper maintenance of the stack. When a stove is heavily dampered, the flue temperature is lowered, which allows creosote from flue gases to condense and build up on the stack. When the fire is later stoked and allowed to burn hot, the creosote can ignite, creating a 'stack fire'.

Burning green wood can increase creosote buildup as well as spark emissions that can ignite a roof or surrounding vegetation. Both of these fire problems are avoided through frequent cleaning of the stack, at least twice each year, by a spark arrestor screen in the flue, by proper use of the stove itself, and by burning a hot fire with well-seasoned wood.

Table 10.12 summarizes data on residential fires attributed to "failures in heating systems." Anchorage data refer to heating systems in general; "wood-specific" data are not separately available. Fairbanks data are available for wood-specific systems. The data for the two municipalities are categorized differently and are thus difficult to compare. The Fairbanks data are the most useful because of the high usage of wood there. The low occurrence of chimney fires suggests that safety is not a problem. Furthermore, chimney fires have decreased, whereas wood consumption has increased.

TABLE 10.12. Wood Heat Fire Hazards

Area	Year	Total Residential Fires	Type of Fire: Heating System Failures No.	%	Chimney Fires No.	%
Municipality[a] of Anchorage	1980	326	23	(7)	1	(0.3)
	1979	777	29	(4)	1	(0.12)
Municipality[b] of Fairbanks	1980	Not Available	Not Available		Not Available	
	1979	166	Not Available		7	(4)
	1978	66	Not Available		4	(6)
	1977	81	Not Available		5	(6)
	1976	107	Not Available		9	(8)
	1975	119	Not Available		4	(3.4)

(a) Figures provided by John Fullenwider, Deputy Fire Marshall, Fire Protection Division, Municipality of Anchorage
(b) Figures provided by Eric Mohromon, Fire Inspector, Municipality of Fairbanks

Fire Department sources from both areas emphatically stated that most fires attributed to wood result from improper installation. The most common fault seems to lie with stoves and stacks being located too close to combustible material.

Air-Quality Effects

Air-quality monitoring in Anchorage in 1980 could not detect suspended particulates attributable to wood combustion. The total suspended particulates did not exceed the state standard of 150 micrograms per cubic meter over a 24-hour period and has actually decreased over the past 3 years. Percentages of decrease on an annual basis are not presently compiled.

Monitoring for suspended particulates has not yet begun in Fairbanks. However, the amount of carbon monoxide produced by the wood combustion has been extrapolated to be 4.25% of the total carbon monoxide in the air. Also, 70% of the carbon monoxide resulting from space heat of all types is attributed to the use of wood. The level of carbon monoxide in Fairbanks also decreased during the past 3 years. Although annual data were not available, the cause is attributed to mild winters and reduced traffic.

No effort has been made to quantify public perception of woodburning aesthetics. Wood smoke creates a visual and odor impact that is not pleasing to all. However, as yet no indication has been given that this is of major concern to many.

Wood Harvest Effects on Forests

The nature and extent of environmental degradation from wood fuel harvesting will depend upon harvest methods and enforcement of land-use regulations. Dispersed, small-scale, wood fuel harvest will tend to follow other developments such as road and residential road building; permanent patterns will emerge more clearly as land status stabilizes. Multiple-use public lands will probably be increasingly important for this type of harvest. Public lands close to urban areas will probably be more actively managed in the future. Although federal and state government and Native corporations own the largest areas of commercially viable timber,[a] future plans for these areas are not presently known.

Coastal forests regenerate quickly and thoroughly in most harvest areas. Site-specific problems may result from high concentrations of slash, insect and animal damage, climatic conditions, or soil deficiencies. Interior forests are less likely to regenerate naturally and may need some form of artificial regeneration such as planting or direct seeding to ensure renewability. Planting costs per acre are high for both types, averaging \$150 to \$400, depending on density, cost of planting stock, labor, transportation and overhead. Direct seeding costs for the Fairbanks area are about \$20 per acre, when equipment and adequate seed supplies are available. Although seeding of spruce requires more effort than hardwoods, more research on all species is required before full-scale planning for "energy plantations" can be developed in the Railbelt area.

10.3.5 Socioeconomic Considerations

Socioeconomic impacts of wood fuel for space heating center on three areas: 1) consumer convenience, 2) adaptability to growth, and 3) regional economics.

(a) Commercial timber stands are those having a potential wood formation rate of 20 ft^3/acre or more.

Consumer Convenience

Wood fuel provides an independent source of heat in case of power failure. In the Railbelt heating systems that accommodate wood as well as other fuels (coal, oil and/or gas) are available and are capable of rapid and easy change-over if necessary. Firewood is also a relatively inexpensive heat source, particularly if the user provides the labor for producing the wood supply. However, the weight and bulk of wood in storage and handling, whether cut or purchased by the user, can create an inconvenience. Unlike other heat sources, wood fires require regular attention in stoking and ash removal. Like other sources, to maintain safety and optimal performance of heating systems, wood burning equipment requires regular maintenance. The amount of maintenance varies somewhat depending on the type of wood-burning system and the type of wood as well as the frequency of use. Generally, manufacturers recommend that stoves be stoked every 2 hours to achieve maximum burn efficiencies. Stoking can typically be accomplished in 5 minutes or less. Using this figure and a 16-hour "stoking period" (assuming that stoking does not occur at night), an individual would spend 40 minutes a day or 20 hours per month tending the stove during the season requiring continual heat. Assuming this "heating season" could last 6 months or longer in parts of the Railbelt, up to 120 hours per year would be required. Approximately 2 hours per month would also be required for cleaning the stove and maintaining the wood pile.

Adaptability to Growth

Suppliers of wood-burning units in the Railbelt area could meet considerably greater demand for both primary and secondary heating systems. Available systems include several models that can accommodate other fuels (coal, oil, gas) and that are adaptable to incremental increases in heating capacity without installation of a new central source in a given structure. Wood resources in the Railbelt area also appear to be capable of sustaining increased demand.

Although the dispersed individualized process of harvesting wood for fuel in the Railbelt area is not highly visible, demand for firewood has increased dramatically in the last several years. Both state and federal land managers have designated areas near Anchorage and Fairbanks under their jurisdiction for wood-cutting or gathering purposes. State-required permits for firewood cutting are issued by the Alaska Department of Natural Resources. The permits are issued by two offices, the South Central District Office for the Anchorage and lower Railbelt areas and the North Central District Office for the Fairbanks and upper Railbelt areas.

Table 10.13 shows the number of personal use permits issued by year, the estimated number of cords taken, and the number of commercial sales to firewood distributors in each area. These figures do not represent the total wood fuel consumption in the area since cutting from private lands is not monitored. In the case of commercial cutters this consideration is significant because a large portion of their annual supply is removed from sites for development such as subdivisions. Additionally, trespassers remove a large amount of wood from state land without permits. The number of "illegal" harvestors was estimated to be 10%[a] in the North Central District, and 45%[b] in the South Central District. Consequently, the table does not reflect the real demand for firewood in the Anchorage area but it does indicate to some degree the increased demand for 1980 - 49% in the South Central District (Anchorage) and 28% for the North Central District (Fairbanks).

Some sources estimate that about 50% of the households in the North Star Borough use wood as primary or secondary heating source, which implies that about 7,000 homes are heated with wood. However, AKREA has not been able to confirm these figures, and the North Star Borough Public Information Office[c] has confirmed that the Borough does not have data on the percentage of homes heated by wood and cannot support the 50% estimate. The only data available show that in 1979, 6.5% or approximately 910 of the homeowners in the municipality possessed permits to cut firewood. It is also known that 36% of the

(a) Based on conversation with Mike Peacock, Timber Management Forester, South Central District Office, February 1981.
(b) Based on conversation with Fred Bethune, Administrator Forest Practice Act, North Central District Office, February, 1981.
(c) Source: Heather Stockard, Environmental Technician, Fairbanks North Star Borough.

TABLE 10.13. Summary of State Firewood Permits

North Central District[a]

Year (Jan.)	Personal Use Permits: No. of Permits	Increase (%)	No. of Cords[b]	Commercial Sales: No. of sales[c]	No. of Cords
1981	400		4,000[d]	7	700
1980	2300	28	21,000	60	6,000
1979	1800	125	18,800	22	2,200
1978	800	110	1,800	0	0
1977	380		3,800	0	0

South Central District[e]

Year (Jan.)	No. of Permits	Increase (%)	No. of Cords	No. of sales	No. of Cords
1981	74		222[d,f]	(unknown at this time)	
1980	960	49	3,000[f]	14	1,175
1979	643		1,829[f]	0	0
1978	Not available				
1977	Not available				

(a) Source: Department of Natural Resource, Division of Forest, Land and Water Management, South Central District Office.
(b) Estimated at 10 per permit.
(c) Issued by bid to commercial suppliers.
(d) To date of writing (January 1981).
(e) Estimated at 3 cords per permit.
(f) Source: Department Natural Resources, Division of Forest, Land & Water Management, South Central District Office.

1800 permits issued in 1979 were issued to people who live within the municipality of Fairbanks. The 6.5% appears to be a low estimate of the total number of homes using wood since wood-cutting permits are not required for cutting on private lands.

To further define the increase in wood heating, AKREA surveyed major wood stove suppliers in the Anchorage area. Based on dealer estimates, average sales increased 300% from 1978 to 1980. The increase seems to be leveling out for 1981, with a 25% increase expected. Clearly this is a very rough indication of the trend, but it appears to be the only available data. The 1981 sales might exceed the expected 25% because of a state loan program that provides for the purchase of wood stoves.

Management officers from both state districts expressed concern over their ability to meet the present demand for firewood. Both officers stated that the resource is sufficient to meet future demands but it must be made accessible by cutting in logging roads for public use. Neither office was able to quantify the present or future demand, but efforts are being made in that direction. A report from the North Central District Office is expected in the near future.

With an array of landowners of divergent interests gaining title to lands in the Railbelt area, a more comprehensive approach to managing lands for firewood procurement may be needed. Permitting may be adopted by federal or municipal agencies, and additional lands will probably be designated for the purpose. Consideration will have to be given to access across private and public lands, and a distinction between wood cutting and deadwood gathering may have to be made. Pressure will probably be applied to permit use of these areas by small commercial operators within certain guidelines if demand continues to grow at present rates.

Two other factors may have a positive impact on fuel wood supply: the availability of slash resulting from predictable increases in large-scale commercial logging operations, and the possible use of other sources of fuel such as driftwood along rivers, streams and coastal areas. Also, wood is now being recovered from the lands being prepared by the state for development of agricultural sites.

Regional Benefits/Employment

Jobs per million board feet of wood harvested are estimated by the U.S. Forest Service at 7.5 for harvest, transportation and manufacturing sectors combined. These figures apply only to Southeast lumber and pulp operations. Just as primary industrial wood harvest and processing tend to generate secondary jobs, including those in direct industry support and community infrastructure and services, a smaller, but similar benefit is realized from dispersed, small-scale wood fuel gathering. Each cord of wood harvested in the Railbelt area displaces about 15.6 million Btu of other energy forms. A significant point related to displacement is the retention and recirculation of dollars saved by individual wood users in the community after more costly forms of energy have been displaced. Impacts of wood-cutting on employment and local economies are unquantifiable but predictably favorable.

10.3.6 Potential Application to the Railbelt Region

The Railbelt region contains large reserves of commercial and noncommercial grade timber. The bulk of the Railbelt forests are of the Interior Forest type with birch, spruce, aspen and cottonwood the dominant species. (The fuelwood characteristics of these species are provided in Table 10.8.) Regeneration of these forests is slow, but could be improved with mechanical seeding techniques.

Many site-specific or small-scale forest studies and inventories have been conducted in the Railbelt area, although the data base remains incomplete on a regional scale. A 1967 U.S. Forest Service study remains the most recent comprehensive attempt to inventory the forest resources of Southcentral, Interior and Western Alaska to date and is the basis for estimates of available Railbelt forest resources used in this report.

Table 10.14 provides a summary of forest resource data, including total wood volume, standing wood energy, and annual potential wood energy figures. In general, an abundant supply of wood of several types is available to meet large increases in demands for many types of uses. However, land ownership status poses an important and unknown factor in attempting to define how much energy the wood resource can satisfy. Land ownership status continues to shift dramatically because of land selection and use by Native corporations, the State of Alaska, municipalities, and management decisions by federal land agencies.

Land title is a social constraint that limits wood energy development. Public and private land ownership within the Railbelt area is changing quickly and will remain unsettled in the near future. Although no clear pattern of development has emerged, pressures are great to put land in private hands and to classify public lands for multiple uses. Wood usage is heavy in the area with most of the wood coming from state and federal lands.

TABLE 10.14. Wood Energy Summary/Railbelt Area

Forest Type and Unit Number[a]	Total Wood Volume (million cu ft)		Standing Wood Energy (10^9 Btu)		Annual Potential Wood Energy (10^9 Btu)	
	Commercial[b]	Noncommercial	Commercial[b]	Noncommercial	Commercial[b]	Noncommercial
Interior						
1.	827.3	1,461.2	140,790	25,538	2,277	1,149
2.	525.7	32.9	91,877	5,742	1,110	259
3.	1,431.0	590.2	250,100	103,147	3,939	4,642
4.	192.2	130.3	35,362	30,648	5,289	1,025
5.	434.8	217.8	75,994	38,058	1,197	1,713
TOTAL	3,411.0	2,432.4	594,123	203,133	13,812	8,788
Coastal						
2.	515.0	100.2	88,963	17,234	1,018	971
3.	859.1	294.7	147,756	52,019.2	1,646	1,468
4.	50.7	34.9	8,705	14,864	97	173
TOTAL	1,424.8	429.8	245,424	84,117	2,761	2,612
RAILBELT TOTAL	4,835.8	2,862.2	839.547	287,250	16,573	11,400

(a) Units correspond to units designated by U.S. Forest Service (1967) that fall within the Railbelt area.
(b) Commercial timber stands defined as those representing 20 cu ft/acre/yr or more of potential growth.

Private ownership is increasing because of programs to transfer state lands to private ownership under the Alaska Native Claims Settlement Act. Preliminary indications are that most Native land with commercial forest potential will be placed under long-term management. Most small-lot private landowners prefer to obtain wood from someone else's land, whether for fuel or construction. They believe, correctly, that trees enhance their property values.

Vandalism of private property and illegal cutting of green wood are only two potentially severe land management problems associated with wood harvesting. Terrain and road systems pose additional constraints on accessibility to wood resources. Future air-quality guidelines may also inhibit development of wood as an alternative fuel. Dramatic increases in particulate levels, either cumulatively in the long term from the increases in wood burning or from periodic short-term situations resulting largely from climatic factors, may provide the incentive for greater controls. Regulations governing wood smoke emissions may also be influenced by concern for increases in pollutants from other sources, such as auto exhaust.

Factors contributing to an increase in wood fuel use include the relative simplicity of wood stove installation and operation, the adaptability of units to a variety of structural heating requirements, and the aesthetic attraction of wood heating. Wood has long had a foothold as a practical heat source in the Railbelt. Recent studies point to a dramatic increase in wood burning in the residential sector. Many people, usually outside the larger urban areas, depend on wood for their sole heating source. In the larger population centers, wood heat tends to be more of a secondary source, although this may be changing to some degree.

The amount of heat that wood can provide in an individual unit will depend on the stove or fireplace used, and the condition of the structure. A small and/or tightly built building can be entirely heated from wood. A larger and older house in Anchorage and Fairbanks will lose too much heat during times of peak loading (colder winter days and nights) for wood to provide all of the heat, unless some conservation techniques are first undertaken. However, wood could supply all needs during less severe months. Whereas determining the amount of space heating energy that wood-fired units would contribute to the region is difficult, a figure of 10 to 15% of total demand is quite realistic eventually.

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APPENDIX A

ELECTRIC ENERGY TECHNOLOGIES NOT SHOWING PROMISE FOR APPLICATION TO THE RAILBELT REGION

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Energy technologies selected for consideration in this study were limited to those technologies having a reasonable probability of significantly contributing to the generation or conservation of electric energy in the Railbelt region during the planning period encompassed by this study (1980-2010). Thus, selection of candidate electric energy technologies for the Railbelt region was based on two screening criteria: commercial availability and technical feasibility.

Commercial Availability. A candidate technology should be currently commercial or be projected to be commercially available by the year 2000. A technology that would be commercially available by year 2000 was believed to have the potential to significantly contribute to the electric energy needs of the Railbelt prior to the end of the planning period of this study. Projections of future commercial availability of emerging and advanced technologies are based on current developmental progress (i.e., they do not assume unanticipated acceleration in the rate of development).

Several potential candidate technologies do not appear likely to achieve commercial maturity by the year 2000. These include magnetohydrodynamic generation, fast breeder reactors, fusion reactors, ocean current energy systems, salinity gradient energy systems, ocean thermal energy conversion systems, and space power satellites.

Technical Feasibility. Candidate technologies should demonstrate reasonable potential to operate successfully in the Railbelt environment. Five technologies do not at this time appear to have this potential. Four are resource limited in the sense that the energy source required for their operation is not available in adequate concentrations in or near the Railbelt region. These technologies include ocean current energy systems, ocean thermal energy systems, salinity gradient energy systems and wave energy conversion systems. A fifth technology, space power satellites, does not appear to be technically feasible at the latitude of the Railbelt because of the large area of antenna required to receive microwave power transmitted from space power satellites in geosynchronous equatorial orbit. Brief overviews of the rejected technologies are provided below.

MAGNETOHYDRODYNAMIC GENERATORS

Magnetohydrodynamics (MHD) is an energy conversion technology that has the potential to increase the efficiency of thermal electrical generation plants from about 34 to 48% (Corman and Fox 1976).

In an open cycle MHD generation system (Figure A.1), fossil fuel is burned at a sufficiently high temperature that the product gases are ionized (4000-5000°F). Electrical conductivity of the hot gases is increased by "seeding" with readily ionized material (salts of cesium or potassium). When the gas is channeled through a magnetic field, an electric current is produced in the gas. The current (DC) can be removed directly with metal electrodes. The DC output of the MHD channel is converted to alternating current using solid state inverters (Corman and Fox 1976). The gases exit through a series of heat exchangers and a heat recovery steam generator, which drives an AC generator.

The seed material, heat recovery potassium carbonate (K_2CO_3), is used to both increase conductivity and capture sulfur as potassium sulfate (K_2SO_4). A regenerative seed recovery system with integral Claus plant converts K_2SO_4 to K_2CO_3 plus elemental sulfur.

Problems that may delay implementation of MHD technology include predicted high forced outage rate, short plant life expectancy, difficult partial load operation, difficult operation and control, corrosion problems and poor potential for retrofit (Corman and Fox 1976).

An open-cycle MHD facility would be a large central fossil-fired power plant. Gaseous emissions of oxides of nitrogen (NO_x) and oxides of sulfur (SO_x) are estimated to be substantially less than those from a conventional coal-fired power plant (Corman and Fox 1976). A MHD facility is estimated to

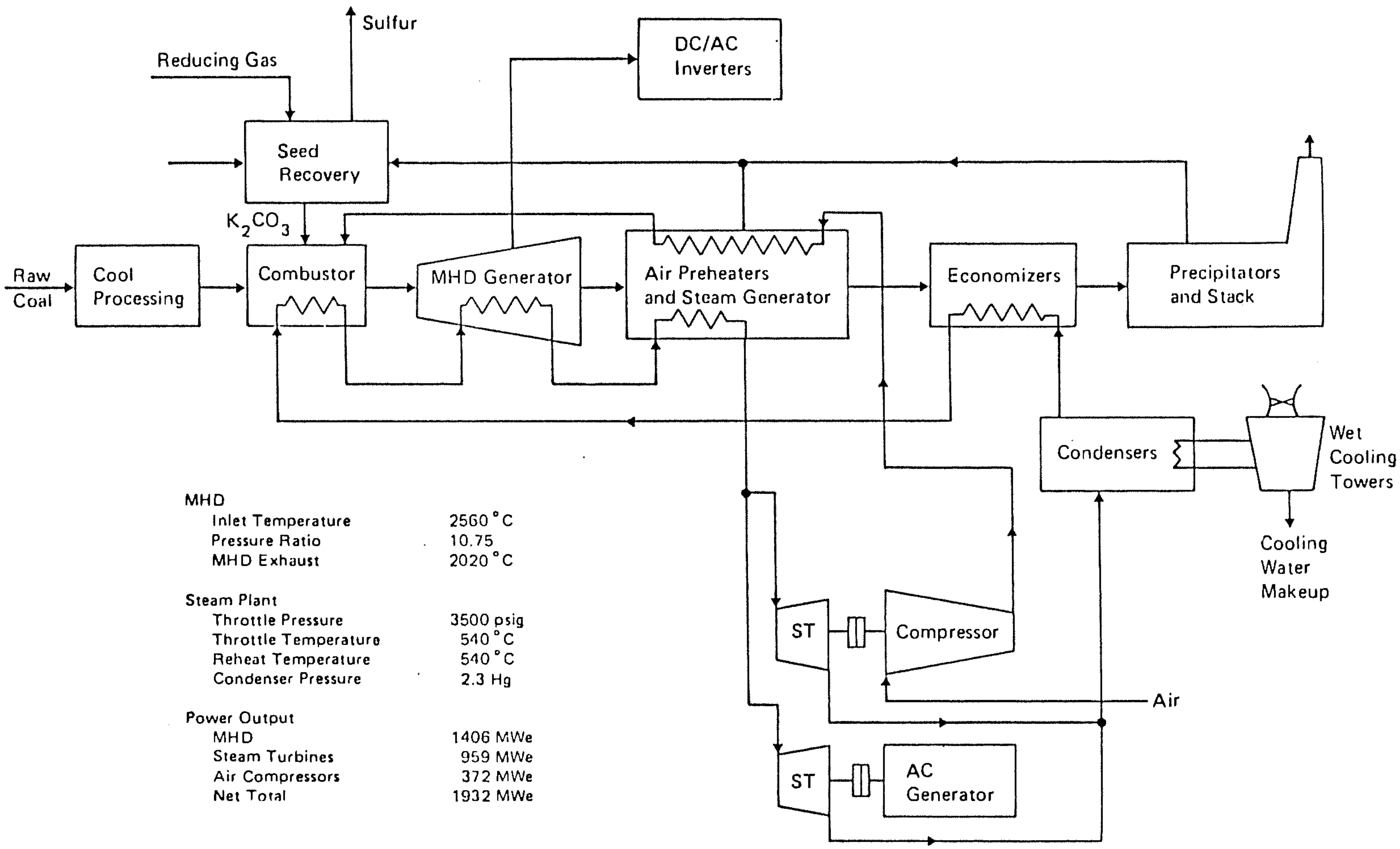

FIGURE A.1. Open-Cycle MHD/Steam Power Plant (National Academy of Sciences 1977) consume only 60% as much make-up water as a conventional steam plant and to use less than 40% of the total water requirement of a conventional plant (Corman and Fox 1976).

A 250-hour test of a 200-kW system was run successfully in 1978 (Energy Daily 1978) at Avco Everett Research Laboratory in Everett, Massachusetts. A coal-fired power plant with a demonstration open-cycle MHD generator is under construction in Butte, Montana.

In 1976 a commercial MHD facility was estimated to be operational by 2003 (Corman and Fox 1976). In an International Energy Agency (IEA) study, the reference start year for a coal-fired MHD electric power plant was 2005 (IEA 1980). Because the Reagan administration believes that confirmation of engineering feasibility and commercial demonstration should be the responsibility of the industry, MHD funding has been cut from $60.5 million in FY 1981 to zero in 1982 (U.S. DOE 1981). Therefore, the time scale for development of commercial MHD conversion systems most likely will not be consistent with the planning period of the Railbelt Electric Power Alternatives study.

FAST BREEDER FISSION REACTORS

A fast breeder reactor (FBR) is a facility designed to generate electricity by using the heat produced by controlled nuclear fission of plutonium. A breeder produces more plutonium from uranium than it consumes by converting ^{238}U to ^{239}Pu at a greater rate than ^{239}Pu is fissioned. When isotope ^{238}U (which constitutes 99.3% of natural uranium) in the fuel absorbs a neutron, it subsequently decays to ^{239}Pu, which is the main energy source for the breeder. The heat generated by fission is removed by liquid sodium coolant in a primary loop. Heat is exchanged to an intermediate sodium loop. From the intermediate coolant loop, heat is exchanged to water coolant using a steam generator. The following steam cycle is similar to that of conventional fossil or nuclear power plants.

The overall thermal efficiency of an FBR is slightly higher than that of a light water reactor (LWR) because it operates at higher temperature. A commercial breeder facility would be about 1000 MWe capacity, operated as a baseload plant.

Siting considerations for an FBR are the same as those for conventional nuclear plants. These include adequate water for cooling, geologic and seismic stability, and 100 to 400 acres of land remote from a large population center. Rail or barge access for spent fuel transport is required. Impacts from a breeder plant include local impacts during construction, heat release to the environment and fog created by cooling towers.

Full commercial development of the breeder reactor requires the construction of reprocessing and fuel fabrication facilities. Fuel reprocessing provides for recovery and purification of plutonium contained in the spent fuel. Fuel fabrication prepares the recovered plutonium for recycle to a power plant.

Current U.S. experience with breeders is being acquired at the Department of Energy Fast Flux Test Facility (FFTF), which achieved full power in December 1980. The capacity of this reactor is 400 MW thermal, approximately equivalent to 133 MWe; it is not, however, used for generation of power. The Clinch River Breeder Reactor, also sponsored by DOE, will generate 350 MWe. The Conceptual Design Study Reactor (CDS) is a 1000-MWe facility. The proposed schedule calls for completion in 10 years. A 1200-MWe commercial prototype reactor is expected to be operational about 2001, with the first commercial plant to be in the 2006-2023 period (DOE 1979). It is therefore highly unlikely that breeder reactors will be established in the commercial market by the year 2000.

FUSION REACTORS

Fusion power results from the conversion of mass into energy when two light nuclei collide and combine (fuse) to become a single, heavier atom. The heavy isotopes of hydrogen, deuterium (D) and tritium (T) are employed in DT fusion, the first likely commercial candidate. The reaction is as follows:

$$ {}^{2}_{1}\mathrm{D} + {}^{3}_{1}\mathrm{T} + \text{plasma energy} \rightarrow {}^{4}_{2}\mathrm{He} + {}^{1}_{0}\mathrm{n} + \text{fusion energy} $$

Deuterium is present in water in sufficient quantities to potentially supply power at present rates of consumption for millions of years. The other fuel component, tritium, is created by neutron capture in a lithium blanket region surrounding the fusion reaction chamber (Dingee 1979).

The heat produced would be used with conventional steam generation via an intermediate heat exchanger or possibly closed-cycle MHD (Dingee 1979). Fusion power plants are projected to be large, 1000 MWe, for example, and would be operated as base-loaded facilities. Siting considerations are similar to those for a conventional LWR. A suitable site should have adequate cooling water, and satisfactory geology and seismic stability, and transportation facilities to a burial site for solid radioactive wastes. In addition, a large exclusion area is likely to be required to preclude effects of strong magnetic fields associated with the plant on electrical and communication systems and on human health.

The inventories of tritium, a radioactive isotope with a 12-year half life, would be greater than for present fission designs (Strand and Thompson 1976). Consequently, some tritium is anticipated to escape the plant in both liquid and gaseous effluents.

Because of the high temperature involved, fusion plants may be more efficient than present LWRs. Nevertheless, cooling water requirements, heat releases and fog created by cooling towers may have significant impacts on plant siting.

Net energy production using a fusion reaction requires the numerical product of confinement time (seconds) and density (ions/cubic centimeter) to be greater than 200 trillion at a temperature over 100 million °F. No fusion device has yet to reach "breakeven" - where fusion energy release is just equal to the energy supplied to run it. Breakeven is expected to first be reached by the Tokamak Fusion Test Reactor sometime in 1983 (Blake 1980); however, commercial availability of fusion reactors is not anticipated until late in the first quarter of the twenty-first century. This time scale is not consistent with the Railbelt Electric Energy Alternative Study.

OCEAN CURRENT ENERGY CONVERSION

Several proposals have been written for extracting power from ocean currents using, in principal, relatively simple installations such as turbines and paddle wheels (Isaacs and Schmitt 1980).

DOE has supported preliminary studies of large submerged ducted turbines for ocean current energy conversion. In this device, turbines, driven by current flow kinetic energy, drive electrical generators. Power is transmitted to shore with a sea-floor cable. The structure envisioned is about 200 to 300 ft in diameter and of hollow aluminum construction and has a rotational speed of 1 RPM. An individual unit would provide 75 MWe (Lissaman et al. 1980). The designers of this device have proposed mooring 132 such turbines in the Florida current to deliver 10,000 MWe to the Florida power grid.

Even a major ocean current has very low energy density, equivalent to about 5 cm of water head, and the Florida current of the Gulf Stream is the only candidate for U.S. production of energy from ocean currents (Booda 1978). The Florida current runs at about 2.5 to 2.9 knots off Miami, whereas the Alaska current runs at 1 knot (U.S. Department of the Interior 1970). Since kinetic energy is proportional to the square of velocity, the Florida current energy density is approximately six to eight times that of the Alaska current.

The preliminary design study of ocean current energy conversion was funded by DOE. The study calculated turbine and power extraction performance, and tested a 1-meter rotor model (Lissaman et al. 1980).

In 1980 ocean turbines were projected to be commercialized by 1999. However, DOE-funded work was assumed to continue, and a full-scale prototype was assumed to be complete in 1985. Since ocean energy systems funding has been terminated (DOE 1981), the continuing U.S. development of ocean current energy conversion is uncertain at this time. Because of funding cutbacks, ocean current energy conversion most likely will not be commercial in the U.S. by the year 2000. Even if ocean current energy conversion were commercial, Alaska would not be a good location for a facility, considering the very low energy density of the Alaska current.

SALINITY GRADIENT ENERGY CONVERSION

Salinity gradient energy conversion, a large potential source of power, involves the recovery of the energy mixing of waters of high and low salinity. The energy density of this process is equivalent to about 240 meters of water head (equivalent to an ocean thermal energy conversion (OTEC) plant with a temperature difference of 23°F) (Isaacs and Schmitt 1980). Theoretical energy available is 2 MW per 1 m^3/sec fresh-water river flow into the sea (Olsson, Wick and Isaacs 1979).

Three approaches have been proposed for extracting power from salinity gradients: 1) osmotic exchange against a hydrostatic pressure (pressure-retarded osmosis); 2) the dialytic battery (inverse electrodialysis) and 3) vapor exchange between two solutions (inverse vapor).

Pressure-retarded osmosis uses the osmotic pressure gradient (about 23 atm) across a semipermeable membrane, which separates seawater (at 35 parts per thousand salinity) and fresh water. To extract power, the pressurized solution is released through a hydroturbine (McCormick 1979). This concept requires large amounts of fresh water, and the facility must be sited at a river.

The dialytic battery consists of anionic-permeable and cationic-permeable membranes in a battery container. Salt water is passed between alternate membrane pairs, while fresh water separates one pair from another. Positive and negative charges are transferred to electrodes at the ends of the membrane stack. A 100-watt model has been studied (McCormick 1979).

Inverse vapor compression involves vapor exchange between two solutions, preferably at elevated temperatures. Due to lower vapor pressure of salt water, water vapor will transfer from fresh water to salt water in an evacuated chamber. Power can be extracted if a turbine is placed in the vapor flow between the two solutions (Olsson, Wick and Isaacs 1979). This scheme uses no membranes, only heat exchangers and turbines. Vapor pressure differences increase dramatically with temperature, so a low-grade source of heat would be advantageous. Power is required to create and maintain a vacuum in the chamber (Olsson, Wick and Isaacs 1979).

The energy density of a salinity gradient is a function of the difference in salinity between the two working fluids. The energy density of a system of saturated brine (260 parts per thousand) and fresh water is about 20 times greater than a system of seawater (35 parts per thousand) and fresh water (Isaacs and Schmitt 1980).

Energy densities for Alaskan salinity gradient resources would be slightly lower than seawater-fresh water system values presented because of the lower salinity of Alaskan coastal waters. The salinity of seawater off Alaska is 31.5 to 32 parts per thousand most of the year (U.S. Department of the Interior 1970), about 10% less than salt water in the referenced experiments.

Salinity gradient energy conversion is in the experimental stage. Salinity gradient research was conducted by DOE under ocean energy systems, which is no longer funded (DOE 1981). Therefore, the commercialization of this technology is uncertain at best. Considering the current low state of development of salinity gradient energy conversion technology and the funding situation, this technology most likely will not be an option in the time frame of this study.

OCEAN THERMAL ENERGY CONVERSION (OTEC)

OTEC uses the temperature difference between surface water and ocean depths to generate electricity. A conventional thermodynamic cycle is used with ammonia or propane as the working fluid (Figure A.2). The working fluid is boiled by the warm seawater; the vapor is run through a turbine where power is extracted; the fluid is cooled by cold deep-ocean water and is pumped back to the warm water heat exchanger.

The efficiency of the system is based on the difference in temperature between shallow and deep water. Surface water in the tropics is heated by the sun to about 79 to 84°F. Cold water from about 3000 to 6000 ft deep originates in the Arctic or Antarctic and has a temperature of 39 to 44°F (Booda 1978).

The efficiency of a closed-cycle OTEC system is limited by the Carnot efficiency of a heat engine. An ideal heat engine working at upper and lower temperatures of 80°F and 40°F (540°R and 500°R, respectively) would have an efficiency of 650-500/540, or 7%. Real equipment with friction and pumping losses would have efficiency of about 3%. A 100-MW plant would have to pump 30,000 ft^3 of seawater per second (Forbes et al. 1979).

Tropical or subtropical seacoasts or offshore regions appear to be best suited for OTEC power plants. A minimum temperature difference of about 30°F and depth of about 2000 ft are required. DC power would be transmitted to the

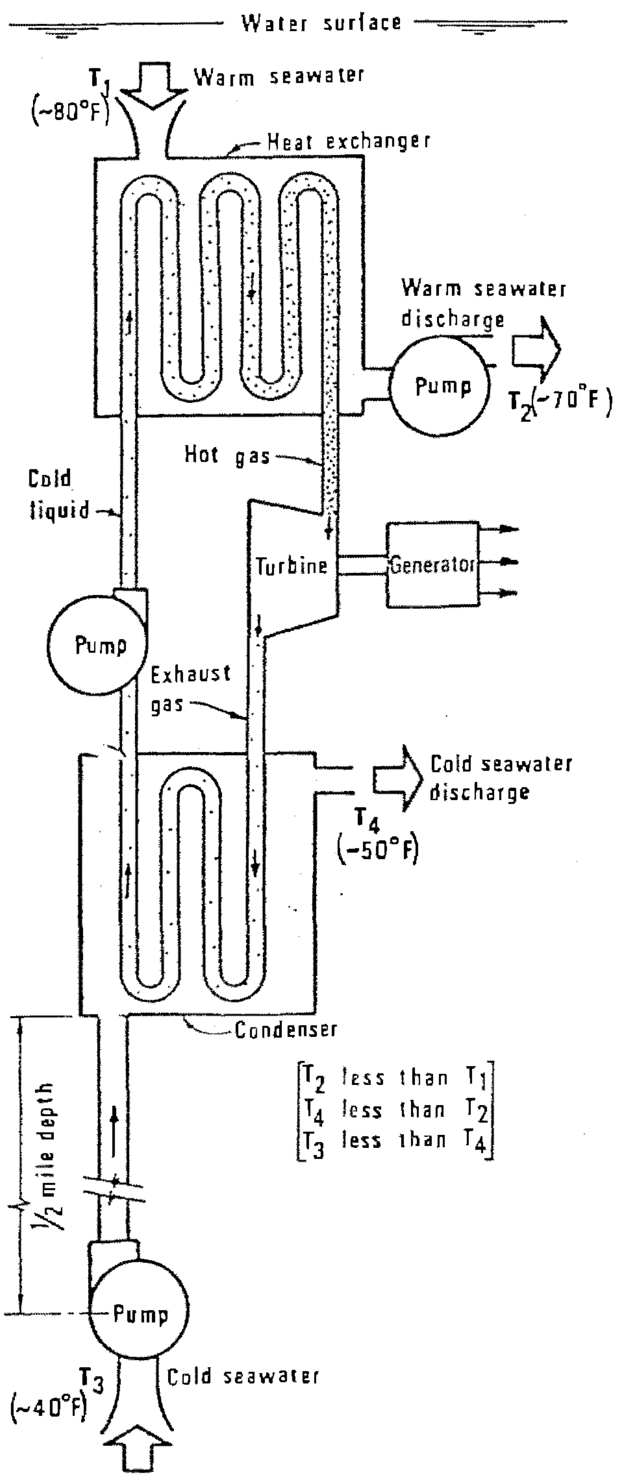

FIGURE A.2. Seawater Power Plant Using Ocean Thermal Difference load center by undersea cables. The proposed size of a commercial OTEC plant is about 200 to 400 MW (Richards 1979). Potential impacts include interference with ocean transportation, fisheries, and sea life, and influence on natural ocean circulation.

A demonstration of the feasibility of OTEC has been performed by DOE. Because the current administration considers the private sector responsible for developing marketable systems once technical feasibility is established, the DOE budget for OTEC has been reduced from $34.6 million in FY-1981 to zero in FY-1982 (DOE 1981).

A commercial prototype OTEC powerplant was envisioned to be completed about 1990 (Richards 1979). The reference start year for commercial operation of a 100-MWe ocean thermal gradient electric power plant was taken to be 2000 in an International Energy Agency study (IEA 1980). Activity of the private sector will evidently determine the actual development schedule for OTEC.

Sites for OTEC plants are generally restricted to 20° north and south of the equator (Booda 1978). OTEC power is not feasible near Alaska because the concept depends on warm (80°F) ocean surface temperatures characteristic of the tropics. The mean surface temperature off the south coast of Alaska varies from 42°F in winter to 54°F in summer (U.S. Department of the Interior 1970).

OCEAN WAVE ENERGY SYSTEMS

Many methods of ocean wave energy conversion have been suggested. Most of these methods fall into the following categories: 1) heaving bodies, 2) pitching or rolling bodies, 3) cavity resonators, 4) wave focusers, 5) pressure converters, 6) surging bodies, 7) flapping bodies, 8) rotating outriggers, and 9) combinations of the above (McCormick 1979). DOE-sponsored efforts include a full-scale wave energy conversion program with the IEA. The apparatus, known as "Kaimei," is a cavity resonator system (Figure A.3). On the deck of Kaimei are three air turbines, which are excited by the air motions above the rising and falling of the surface of the water (Figure A.4). Each turbogenerating system is designed to deliver 125 kW in a 2-meter sea with a wave period of 6 seconds (McCormick 1979).

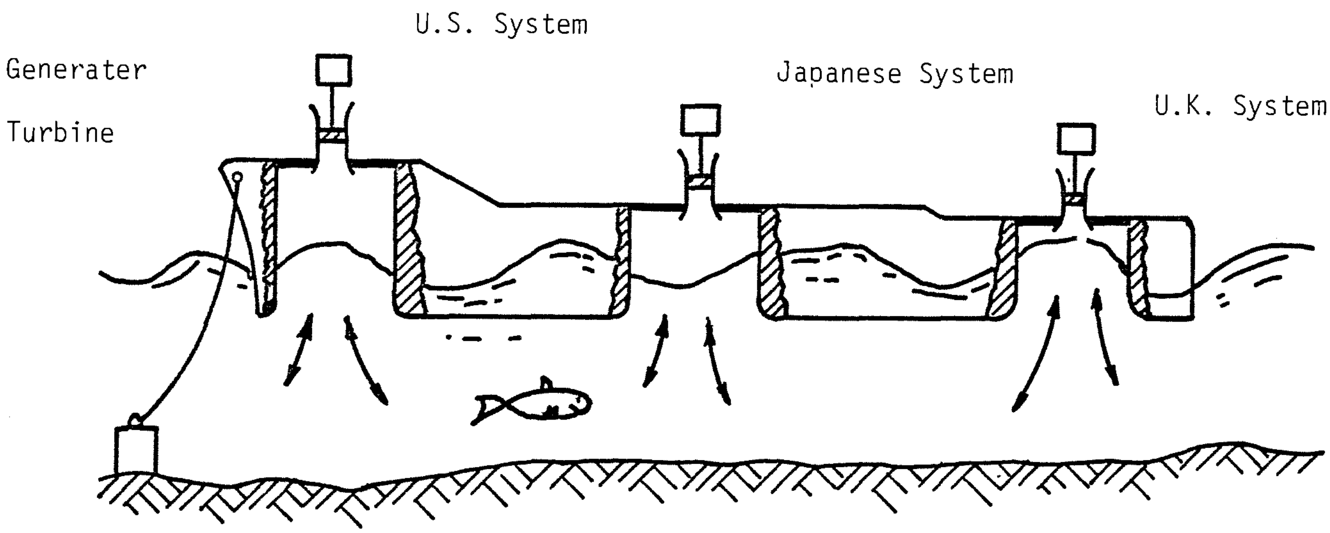

FIGURE A.3. The "Kaimei" Floating Wave Energy Conversion System (McCormick 1979)

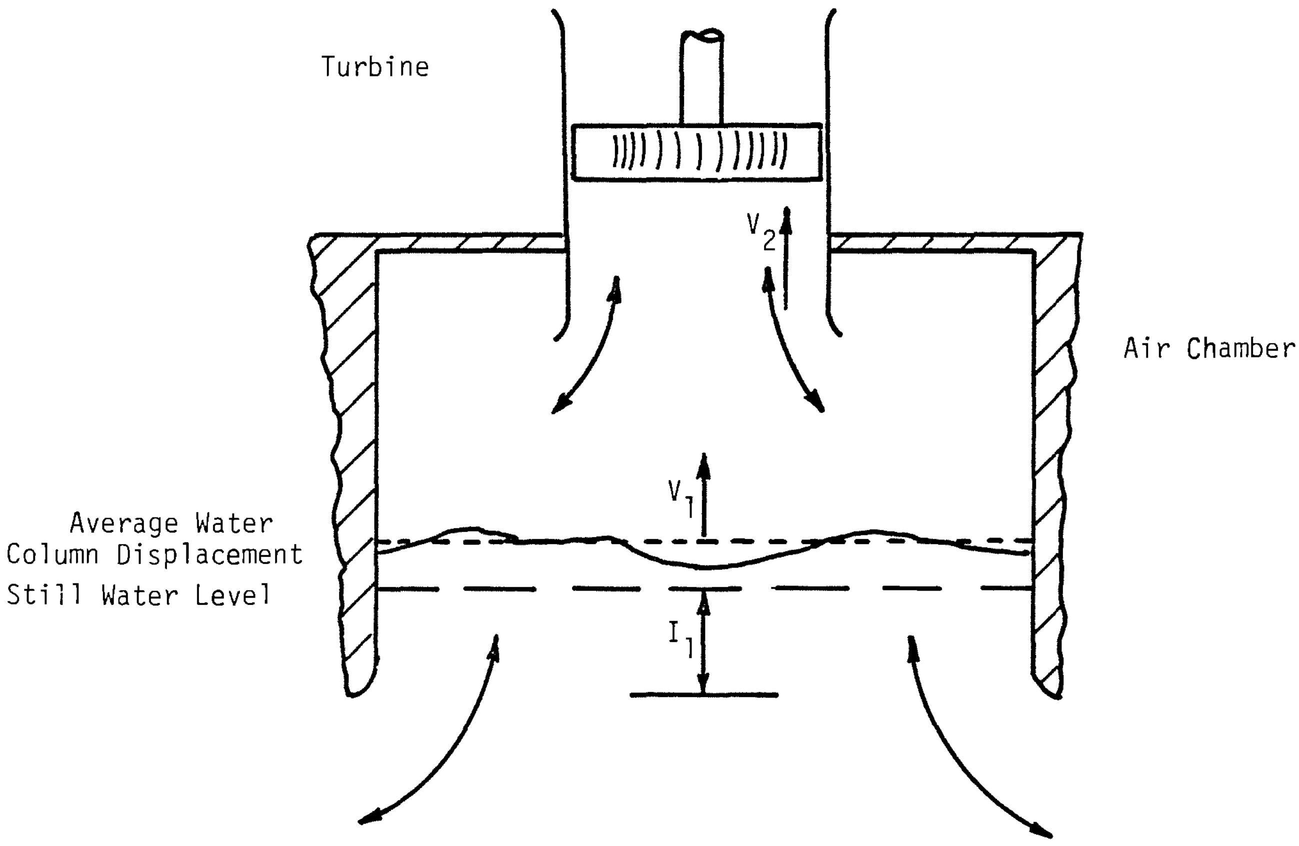

FIGURE A.4. A Water Column/Turbine System (McCormick 1979)

DOE has also sponsored research on wave-focusing systems. Wave focusing is accomplished by four techniques: 1) radiant wave interaction, 2) Fresnel-type focusing, 3) refraction, and 4) channeling.

Radiant wave interaction occurs when a body is in resonance with the incident wave. Fresnel-type focusing is done by a lens-type structure that causes wave diffraction or refraction. A refraction wave energy device, called DAM-ATOLL, was developed at Lockheed. The device, a lenticular hump on the sea floor, causes incident waves to refract and focus on a vertical axis turbine located at the center of the dome. The dome could be constructed by dredging or dumping (Isaacs and Schmitt 1980).

Wave focusing by converging channels appears to be feasible only in or near the surf zone where energy is relatively low. Thus, DOE has not sponsored studies in this area (McCormick 1979).

Wave energy density has been estimated to be equivalent to 1.5 meters of water head. This compares with 570 meters for OTEC, with a 36°F temperature difference (Isaacs and Schmitt 1980). Siting requirements will include an ocean location with relatively consistent waves and near a load center. Such a facility would probably be used as a "fuel saver" because of the variability in wave action.

The DOE considers only the northern half of the Pacific coast a promising area for ocean wave energy conversion. An estimated 5 to 50 MW per kilometer of coastline could be generated (Booda 1978). The northern California and Oregon coasts have 5 ft waves 20 to 30% of the time in spring and winter, and 30 to 40% of the time in summer and autumn. In contrast, off the Alaskan coast, the frequency of waves of 5 ft and over varies from less than 5% in the spring to 10 to 20% in the fall (U.S. Department of the Interior 1970).

Currently, wave energy systems are in the developmental stages. Problems requiring resolution include the need for equipment to withstand large storm waves, corrosion and fouling; energy storage and/or transmission devices for transfer of energy to shoreside load centers; and the capital costs of fabrication and installation (Forbes et al. 1979).

An IEA study assumed 1990 as the reference starting year for commercial operation of a 2 MWe wave power plant (IEA 1980). Wave energy research programs have been supported by DOE and depend on government funding. Wave energy studies have been about 4% of DOE's ocean energy systems budget. Since ocean energy systems will not be funded in FY-1982 (DOE 1981), the fate of wave energy development is uncertain.

The coast of Alaska is not an optimum location for wave energy power plants, as shown by wave height/frequency statistics. In addition, the development of wave energy technology is uncertain and may not be available in the time frame under consideration.

SPACE POWER SATELLITES

The space power satellite (SPS) concept is based on large (5 km x 10 km) solar collectors in geostationary orbit that transmit power to a receiving antenna (rectenna) on the earth. The rectenna would consist of an array of inclined solar panels 3 meters wide in long rows. Power is converted from DC to AC and stepped up to 500 kV for transmission (Brown et al. 1980). The microwave power transmission link cannot be scaled down economically to capacities less than a gigawatt (1000 MW) (Sperber and Drexler 1980). The conceptual design of a satellite power station developed in the DOE/NASA Concept Development and Evaluation Program (1977-1980) calls for a capacity of 5 gigawatts.

The rectenna requires a large area of relatively flat land with an area of low population density. Variables that exclude rectenna siting include water, military reservations, settlement, marshland, or perennially flooded areas, highways and unacceptable topography. Other potential exclusion areas include Indian reservations and national interest lands. Other variables affecting design and cost of the rectenna site include snowfall, freezing rain, sheet rainfall, wind, lightning density, hail, seismic risk, timbered areas, and water availability (Ankerbrandt 1980).

The Ground Receiving Station (GRS) should be near a load center, but located to avoid radio interference. An optimum location would be a desert area. In a prototype assessment of environmental impact of siting and construction of a GRS, the California desert about 250 km north of Los Angeles was used for baseline data (Bachrach 1980).

The land area required for a GRS is about 400 km^2 at 35° latitude. At the latitude of the Railbelt area, about 63°, an area of about 1200 km^2 would be needed (Reinhartz 1980). Construction of a GRS in a desert area at 36° is expected to require 25 months, with an average work force of 2500. Approximately 450 workers would be required for 24-hour, 365-days-per-year operation (Bachrach 1980). A GRS facility in more difficult terrain that covers three times the area may then require a construction work force of 7500 or larger, and an operations crew of 1350.

Construction of a GRS facility would displace existing land uses and would totally disrupt the ecology of the site. It also would have great socioeconomic impact from the immigration of construction workers. Significant issues include health effects of long-term exposure to low-level microwaves and effects on telecommunication, particularly interference with defense requirements (Valentino 1980).

The objective of the DOE-NASA-sponsored SPS program is "to develop by the end of 1980 an initial understanding of the technical feasibility, economical practicality, and the societal and environmental acceptability of the SPS concept" (Glaser 1980). The technology will not be developed for at least 10 years, and commercialized in no less than 20 years (Glaser 1980). The conceptual Development and Evaluation Study guidelines call for initial commercial operation of power satellites in the year 2000 (Schwenk 1980). The SPS assessment program has been completed, and the program is closed. Future SPS funding appears uncertain. Principal problems requiring resolution include solar cell conversion efficiency and cost, microwave power transmission, space transportation, and construction operation, maintenance and active control of the SPS structure (Schwenk 1980).

An SPS system currently does not appear to be a candidate technology for supplying power to Alaska for several reasons:

- The time scale for development is uncertain; funding has been discontinued indefinitely.
- The projected size of a generation system, 5 GWe (5000 MWe), is much larger than demand forecasts for the Railbelt region.
- The northern latitude of the Railbelt region requires a much larger rectenna area and lower power density than a more southerly site, which makes the system even less cost effective.

APPENDIX B

FUEL AVAILABILITY AND PRICES

APPENDIX B

FUEL AVAILABILITY AND PRICES

Many technologies discussed in this report rely on fossil fuels (oil, gas, coal, peat), renewable fuels (municipal waste and biomass) and light water reactor (LWR) fuel. Forecasts of the future availability and prices of these fuels are essential to assessing the technical feasibility and costs of power for each technology. In this appendix, the availability and price of fossil fuels over the forecast period 1980-2010 are addressed for the Railbelt region. These fuels are covered in more detail in Volume VII of the Railbelt Electric Power Alternatives Study.

Each of the various fuels currently has different prices, even if they are reduced to dollars per/million Btu (MMBtu). Price differentials are expected to continue in the future, although the differentials among fuels may change markedly with time. Each fuel is addressed separately, with a consideration of the Railbelt region's geographic differences and the factors that determine prices.

When a current price for a fuel is not available, the concept of opportunity cost is used to develop the back price and forecast. This concept provides that the resource price is equal to the price the resource will command in an alternative market, less the appropriate transportation and handling fees. Alaska is familiar with this net back method of price determination, which is currently used to evaluate their royalty gas and oil resources. Table B.1 and Figure B.1 summarize fuel availability and the price faced by the electric utilities for the forecast period.

NATURAL GAS

Natural gas, from Cook Inlet fields (Figure B.2), is currently the predominant nontransportation fuel for both direct end use and electrical power generation in the Cook Inlet Region. The cost of gas to the electric utilities now ranges from about $0.25 to $2.30/MMBtu for use in combustion turbines and from $1.55 to $2.46 per MMBtu for residential direct end use. These

TABLE B.1. Fossil Fuel Availability and Price

Fuel Type	Estimated Reserves	Availability	Price/10^6 Btu (January 1982 $'s)	Annual Real Escalation Rate
Coal				
Beluga/Cook Inlet	350×10^6 tons	1988	1.69 Mine	2.1%
Nenana/Interior	240×10^6 tons	Present	1.75 FOB Rail	2.0%
Natural Gas				
Cook Inlet[(a)]	3,900 Bcf	Present	0.86 City Gate	6.6% avg.
North Slope/ Interior	21,500 Bcf	1987	5.92 City Gate	-4.3% avg.
Liquids/Methanol	3,800 Bcf	1995		
No. 2 Heating Oil	Adequate	Present	6.90 Delivered	2%
Peat	N/A	1988	(b)	<1%
Refuse/Derived Fuel				
Anchorage	--	1985	--	--
Fairbanks	--	1988	--	--

(a) Volume weighted average price to Alaska Gas and Servie and Chugach Electrical Association.
(b) Estimates range from 1 to 3 times the price of coal.

prices are the lowest in the United States, primarily as a result of long-term contracts signed when an excess of natural gas existed and the producers, lacking a major market outlet, faced a "buyer's market." This price situation is not expected to continue in the future, primarily because of expiration of contracts and natural gas deregulations.

Forecasting the supply and price of Cook Inlet natural gas is quite complex because contracts have established the quantity, current price, and price escalation rate for various portions of the gas, and because the terms of these contracts differ. In addition, new or incremental supplies used to meet demand in excess of the contracted supply are priced by their opportunity

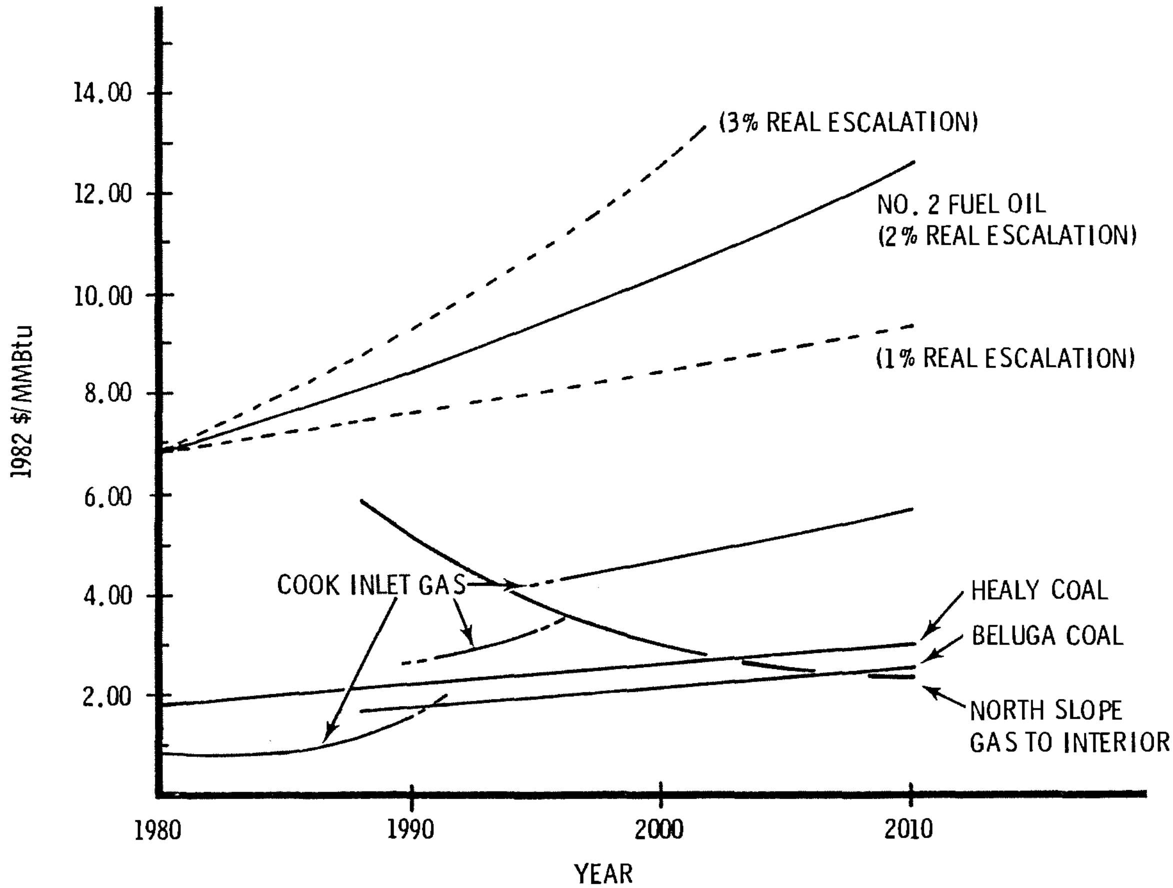

FIGURE B.1. Projected Fuel Prices to Railbelt Utilities, 1982 $/MMBtu, 1980-2010

value, which is the net-back from liquid natural gas (LNG) sales to Japan. Determining price for Cook Inlet gas requires a forecast of both price and quantity from each contractural source to develop the weighted average gas price for the region. The result of this forecasting is a price escalation that is not smoothed over the forecast period. This uneven price escalation is evidenced in Figure B.1 by gas's constant price from 1980 to 1985 and the escalation over the rest of the period, with stepped increases occurring in 1990 and 1995 when major contracts expire. After 1995, gas's price and escalation rate are determined by its opportunity value because current purchase contracts will have expired. The price of natural gas then is assumed to escalate at approximately 2% faster than inflation - the same real annual rate as for oil. Current information about Cook Inlet natural gas reserves and

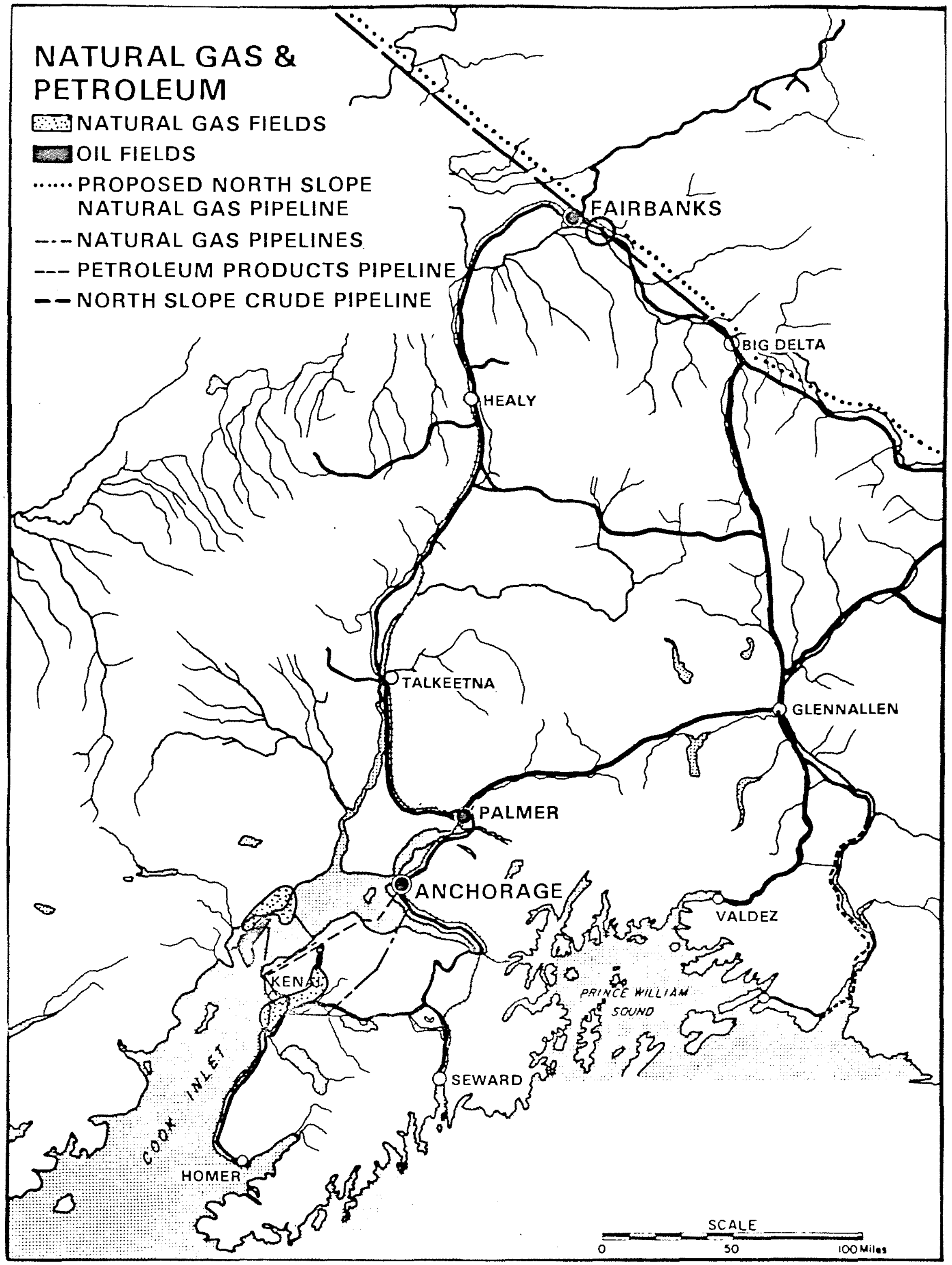

FIGURE B.2. Natural Gas and Petroleum Resources in the Railbelt Region total demand on those reserves indicates that availability to the Alaskan market could become a major problem as early as 1990 and almost certainly by the year 2000.

The North Slope reserves of natural gas are sufficient to supply the Alaska Natural Gas Transportation System (ANGTS) to capacity (2 to 2.4 Bcf/day) for the forecast period. This gas may begin flowing in 1986 or 1987. If only Alaska's royalty share is diverted to serve the Fairbanks area, the supply of gas would be about 100 Bcf per year. A current estimate of the delivered price of gas to the "lower 48" is about $10/MMBtu in 1982 dollars with the January 1982 maximum wellhead price of $2.13/MMBtu. The net-back provides a first year city gate price of about $5.92/MMBtu to Fairbanks then declining due to the pipeline tariff structure. The wellhead value of the gas is not scheduled to decontrol under existing law and escalates only with the rate of inflation.

COAL

Two sources of coal are available to the Railbelt (Figure B.3). The Usibelli mine located at Healy is the only mine currently producing coal. The cost of this coal is assumed to escalate in real terms at the historical rate. A second potential source is the Beluga coal field, which has been targeted as a source of supply for the Anchorage area and as export to markets on the Pacific Rim. As discussed below, this field may enter production about 1988. Beluga coal is expected to escalate at the same rate as other coal supplies serving the Pacific Rim export market at a real rate of about 2.1% annually.

Note that a great deal of uncertainty is involved in developing the Beluga coal fields. These coal fields are now in the exploratory and predevelopment phase. The coal has yet to be produced in any significant quantity and thus, from an availability standpoint, must be considered prospective. Located in an area with very little to no infrastructure development, these fields, while containing very large reserves, are not likely to produce coal unless a firm market of 5 or more million tons per year can be established. On an electric power equivalent basis, this annual tonnage amounts to about 1400 MW of base-load coal-fired power generation capacity.

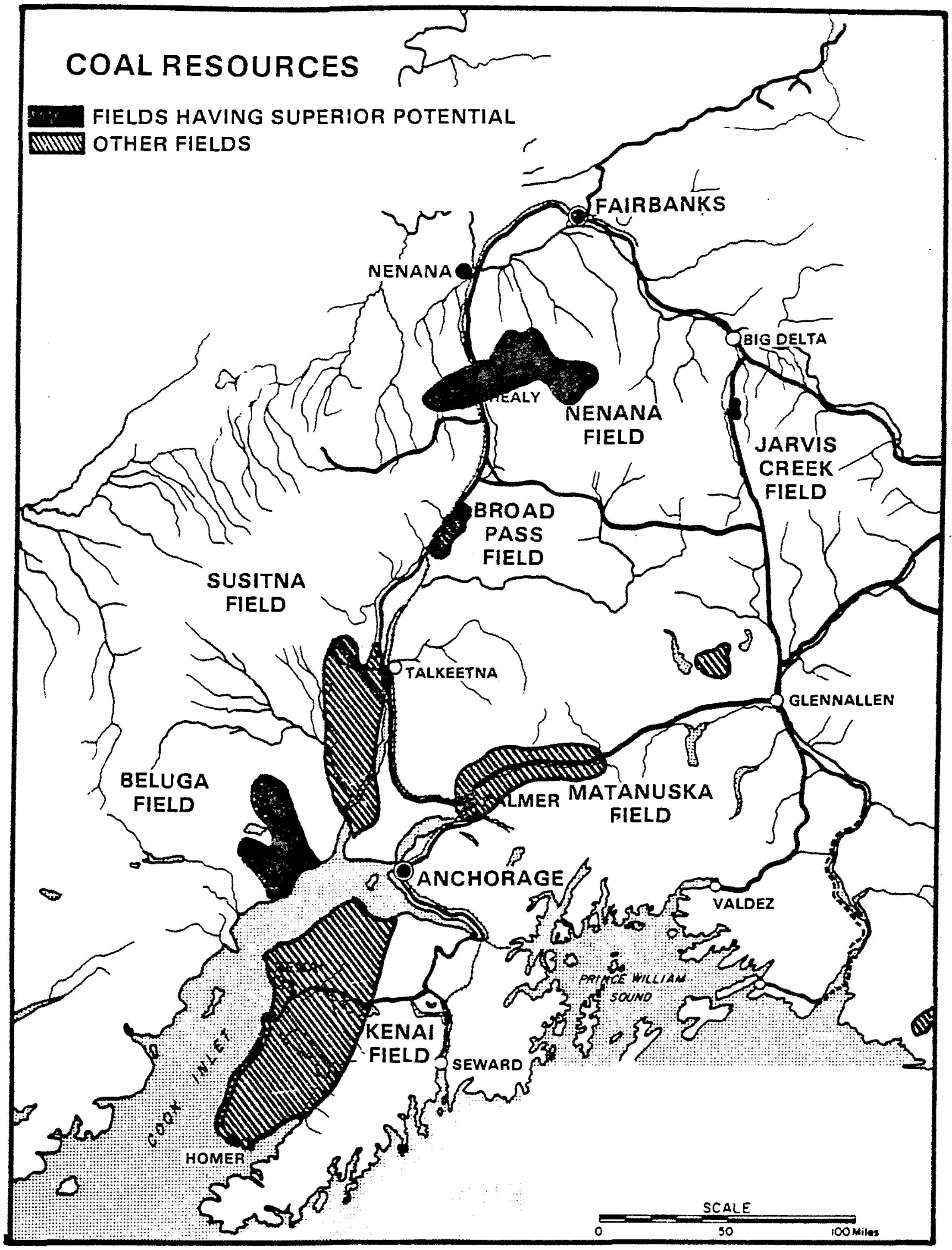

FIGURE B.3. Coal Resources of the Railbelt Region

If coal-fired power generation becomes a significant factor in the Railbelt, generation capacity most likely would be added in increments of 200 or 400 MW. This staging requirement appears not, in itself, to support opening of the Beluga fields. As a result, the establishment of an export market is a prerequisite to the availability of Beluga coal for in-state use. Whereas the Beluga fields could be developed for electrical generation only, the reduced scale of such an operation would increase production costs markedly.

Alternative sources of coal in the Railbelt exist in the Matanuska Valley (Evans Jones Mine, now abandoned) and on the Kenai Peninsula. The Matanuska source would require more costly underground mining, and the reserves on the Kenai are believed to consist of thin isolated beds suitable for low tonnage local supply but not for central station power generation.

PETROLEUM PRODUCTS

Distillate fuel oils (such as home heating oil, diesel fuel, and combustion turbine fuel) now serve substantial markets in the Railbelt (probably second to natural gas in total), particularly in isolated communities and in the greater Fairbanks area. These fuels are used both directly by consumers and also by the electric utilities. In the Cook Inlet region, distillate fuels are currently used as a backup supply by the electric utilities for peak loads that natural gas supplies are not able to meet.

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

PEAT

Peat is an abundant resource in the Matanuska and Susitna Valleys, on the Kenai Peninsula and in the Fairbanks region (Figure B.4). The extent of its use is currently unknown. Raw peat as harvested (essentially surface mined) contains about 90% water and must be dried to less than 50% moisture prior to use as fuel. Currently, no firm estimates of peat costs, including harvesting and preparation, have been developed for Alaska conditions.

Although information for peat development in Alaska is lacking, a preliminary feasibility study (EKONO 1980) estimates a range of likely prices from about 1 to 3 times the price of coal on a Btu basis, depending upon the harvesting and processing method used. The only real escalation likely to occur is that associated with transportation and handling, which is set at less than a 1% real annual rate.

WOOD

Wood is used extensively in the nonmetropolitan areas of the Railbelt for space heating. It is also used as a reliable back-up fuel. Costs of cordwood for space heating purposes are currently about $5.50/MMBtu in the Fairbanks area and $6.30/MMBtu in the Anchorage area.

Sufficient quantities of wood wastes may be available from logging and sawmill operations to support a small-scale biomass-fired generating plant, especially if municipal waste were also used for fuel. Harvesting trees solely for firing electric power plants is generally not considered a viable option in the Railbelt because of the slow rate of timber growth and availability of alternative fuels.

MUNICIPAL WASTE

Municipal waste or refuse-derived fuel (RDF) is a candidate for central station fuel in large urban areas where collection already takes place and disposal occurs at relatively few landfill sites. The solid waste materials currently generated in Greater Anchorage (including sawmill residue) have been estimated to contain sufficient energy to fuel a 20-MW power plant. Municipal wastes are generated in significant quantities only in large urban areas.

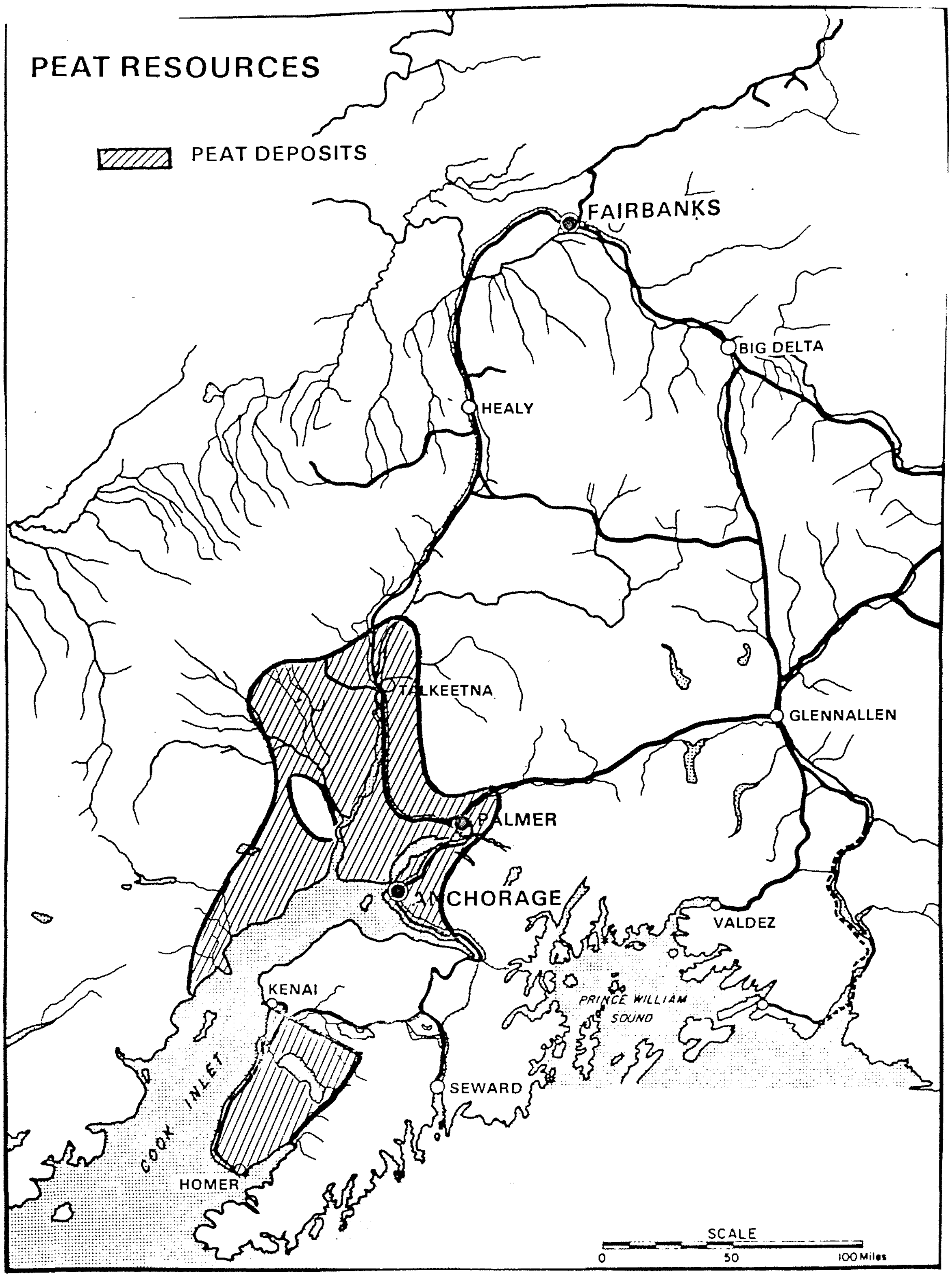

FIGURE B.4. Peat Resources in the Railbelt Region

Because wastes are bulky, transportation costs to potential power plants sites outside of recognized air-quality control problem areas are expected to be excessive relative to coal fuel to similar power plants.

PROPANE AND BUTANE

Propane and butane (low-pressure gas or LPG) are products of petroleum refining operations or are extracted from natural gas prior to its transmission through pipeline systems. Currently, LPG is not a major fuel in the Railbelt region.

With the advent of natural gas production on the North Slope, significant quantities of LPG would be produced and separated from the methane and ethane fractions. As of mid 1981, the LPG is expected to be used locally as fuel to support North slope oil and gas operations. Thus, extensive LPG availability in the Railbelt region is highly speculative.

NATURAL GAS LIQUIDS/METHANOL

The delivery of natural gas liquids (NGL) to the Railbelt depends on the construction schedule of the ANGTS and the real price of crude oil. Current plans call for construction of an NGL pipeline following the ANGTS, with a real crude oil price in the range of $50 to $52/barrel. This schedule provides for delivery of NGL in the mid to late 1990s.

Methanol production is tied closely to the ANGTS because the natural gas from that system would serve as the feedstock, but the timing of methanol production appears to be tied to petrochemical production that may accompany the NGL pipeline. Current methanol prices have been in the range of $.90 to $1.00/gal. The net-back price at Alaska tidewater would range from $0.85 to $0.95/gal or $13.29 to $14.86/MMBtu. This price must incorporate Fairbank's city gate price for the methane feedstock of about $5.92/MMBtu, suggesting that production and transportation costs from Fairbanks to tidewater can be no greater than $7.34 to $8.91/MMBtu. Currently, methanol production is not cost competitive with other fuels in the "lower 48" and is not projected to become cost competitive until after the year 2000.

SYNTHETIC FUELS

Considerable interest exists in the development of synthetic fuels derived from low-cost and abundant reserves of coal and, to a lesser extent, peat. Several processes are in the research and development stage and a few (e.g., gasification of coal) are nearing the commercial demonstration stage. These are capital-intensive projects, and their economic success primarily depends on their ability to displace oil and natural gas at world prices and to achieve economies of scale in large installations. To reduce transportation costs, such plants are expected to be located near the primary resource.

Two firms, Placer Amex Inc. and Cook Inlet Region Inc., are studying the possibility of low Btu gasification of Beluga coal followed by synthesis of methyl alcohol. A fairly large market for the methanol product would be required to achieve economies of scale. Should the methanol project proceed, both low Btu gas and methanol could conceivably become available in the Cook Inlet region. In the case of low Btu gas, power plant operations would have to be closely integrated with the gasification operation. Additional discussion of synthetic fuel production is provided in Appendix K of this report.

HYDROGEN

If surplus electrical generating capacity from hydroelectric or tidal systems is available, hydrogen could be produced by electrolysis using that energy, which might otherwise be lost. The hydrogen could be stored for later use in fuel cells or in combustion turbines to generate electrical energy.

Alternatively, hydrogen could be supplied as a gas similarly to natural gas for direct end use. Because of hydrogen's physical and chemical nature, existing natural gas distribution systems or appliances most likely could not be used.

Finally, hydrogen can be used as an automotive fuel by conversion to a metal hydride for compactness of storage. Hydrogen fuel technologies received some interest in the 1970s, but currently little research and development activity is aimed at commercial applications.

LIGHT WATER REACTOR (LWR) FUEL

LWR fuel costs are a function of uranium costs, waste management costs and transportation costs. The energy density of reactor fuel is very high, and the costs are believed not to be especially sensitive to location in Alaska.

Estimated fuel cycle costs and forecasted uranium prices developed in a recent study (White and Merrill 1981) were used to derive the fuel cycle costs (fresh fuel plus disposal of spent fuel) of 7.8 mills/kWh. This cost is leveled over a 30-year period with a 5% adder for transportation of fresh fuel to a Railbelt location and return of spent fuel to the lower 48. Assuming a 65% capacity factor, the fuel cycle costs would be $44 million ($1980) for a 1000-MW reactor ($44/kW yr).

Long-term fuel supply for LWRs should not be a problem. LWRs currently operate on an enriched uranium fuel derived from naturally occurring low-cost uranium mined and processed in the lower 48 states. Recent estimates of U.S. uranium supply show that ample low-cost uranium resources exist to support about ten times the number of reactors now in service or under construction (Piepel et al. 1981). When all low-cost uranium is committed, the fast breeder reactor, which produces a surplus of fuel-grade plutonium, will become commercially feasible. Because plutonium can be used to fuel LWRs, long-term fuel supply should not be a problem.

APPENDIX C

COST ESTIMATING METHODOLOGY

APPENDIX C

COST ESTIMATING METHODOLOGY

The purpose of this appendix is to describe common assumptions and procedures used to estimate costs cited in this report. Three aspects of cost estimating are described: 1) estimation of capital and O&M costs, 2) estimation of fuel costs and 3) estimation of energy costs.

CAPITAL AND OPERATION AND MAINTENANCE COSTS

The conceptual capital cost estimates and O&M estimates for the various technologies described in each profile were derived by determining average 1980 costs for representative plants of varying capacities in the contiguous United States.[a] Then, a location adjustment factor was applied for the construction and operation of a similar plant in the Alaska Railbelt. Average 1980 costs were developed through a survey of power plant costs for recently completed facilities, and projected cost estimates were derived from technical studies for power plants in various stages of development. For electric generating technologies that have not yet attained commercial development status, such as fuel cells and solar conversion systems, costs were derived from data contained in recent research status reports and various technical studies.

Location adjustment factors were developed based upon an analysis of considerations that contribute to Alaskan construction costs, which are typically higher than costs experienced in the contiguous states. Prime contributing factors to the higher construction costs in Alaska include remoteness, limited accessibility, short construction season, and severe climatic conditions. For

(a) Only a few of the technologies considered in this report are presently represented in the Railbelt region. To take advantage of cost experience gained from installations in the lower 48, cost information from the contiguous states was used to develop the cost estimates appearing in this report.

example, the Railbelt region only has one railroad and a limited number of highway routes. Travel to areas not served by highway or rail is by airplane, water, or track-type vehicles. Typically, construction sites are remote and require room and board construction camps for workers. The general practice of working overtime during the long summer day also adds to the cost of construction. Workers routinely work a a 60-hour week and therefore receive overtime pay for the 20 hours over the standard 40 hours.

Cost adjustment factors developed by the U.S. Department of the Army (1978) were also used. The Department of the Army (1978) has developed cost adjustment factors for numerous locations within the United States and many foreign countries. The data were developed from bid experience and are intended as guidelines in preparing and reviewing conceptual cost estimates for budgets. Adjustment factors identified for specific Railbelt locations are shown in Table C.1.

TABLE C.1. Alaskan Cost Adjustment Factors

Area	Location Adjustment Factor
Alaska (General)	1.32
Anchorage	1.7
Elmendorf AFB	1.90
Fairbanks	1.9
Fort Greeley (Big Delta)	2.2
Kenai Peninsula	2.1

These location adjustment factors reflect the average statistical differences in labor and material costs for the construction of similar facilities. They do not reflect abnormal differences due to unique site considerations. Washington, D.C. is the base with a factor of 1.00.

Based upon these considerations, location adjustment factors of 1.4 to 1.9 were used in this study to develop capital cost estimates, while a factor of 1.5 was used for O&M cost estimates. Values at the upper end of the range were used for labor-intensive technologies requiring extended construction schedules, such as nuclear and large coal-fired facilities. Lower values were used for technologies where expenditures are primarily related to equipment, and where construction requirements are generally not extensive, such as combustion turbines and diesel facilities. The assignment of an adjustment factor also included consideration of the potential sites in the Railbelt.

Whereas the costs generated from these adjustment factors provide order-of-magnitude estimates suitable for a comparative decision-making process, limitations exist when using only a single adjustment factor. For the capital cost estimates of constructing a power plant facility, three cost elements are involved (equipment, material, and labor). A different adjustment factor could apply to each depending on the specific technology considered. Also, a single adjustment factor does not allow for site variations, some unique to the Alaska Railbelt. For example, camp facilities might be required at a remote site but not for a facility constructed near a population center. Similarly, O&M costs are generally divided into fixed (salary related) and variable costs (equipment and supplies). Separate cost adjustment factors might be appropriate for the two cost categories.

The development of adjustment factors associated with each of the above categories requires additional, more detailed study that is beyond the level of these technology profiles. However, the use of a single adjustment factor provides conceptual, order-of-magnitude cost estimates suitable for a comparative decision-making process.

FUEL COSTS

Fuel cost and availability were estimated by a separate task in this project. Summarized time series of the estimated costs of principal fuels are provided in Appendix B of this report.

COST OF ENERGY

The energy costs provided in this report are (except where indicated) levelized lifetime revenue requirements taken at the busbar of the plant (for generating technologies) or at the point of end use (for conservation technologies).

A revenue requirements analysis is a common and accepted method of assessing investment alternatives of regulated utilities (EPRI 1982), differing from discounted cash flow analysis commonly used in corporate investment analysis only in that a rate of return on investment is a given in revenue requirements analysis (and cost of production is the objective), whereas in discounted cash flow analysis, the rate of return is the objective, given a market price. The revenue requirements analysis used in this study was largely based on an approach developed by Phung and Rohm (1977). Costs commonly included in a revenue requirements analysis include the following:

Capital Investment Costs

- Return on debt
- Return on equity
- Income taxes
- Book depreciation
- Property tax
- Insurance

Operating Expenses

- Fuel
- Operation
- Maintenance

Levelizing the lifetime revenue requirements provides a generally accepted means of comparing alternatives, which may be subject to differing cost streams through the life of the alternative. For example, consider the cost comparison of a natural gas and a hydroelectric plant. The natural gas plant may begin life with low energy production costs due to modest capital investment costs and low fuel prices. However, as natural gas prices rise over time, the revenue requirements of the gas-fired plant may increase substantially. The hydro plant, conversely, may begin life with higher production costs due to capital investment costs greatly exceeding those of the natural gas facility. Revenue requirements, however, being largely comprised of fixed capital carrying costs, will remain essentially constant through the life of the facility. "Levelizing" the production costs is a method of comparing the value of these dissimilar revenue requirement streams. In levelizing, the present value of each year's revenue requirements (PWRR) is obtained by discounting annual revenue requirements from the year of occurrence back to a base year (Equation C.1) (taken as first year of commercial operation in the present study). The present values of revenue requirements are summed (Equation C.2) to obtain a total present value of all revenue requirements over the economic (PWRR) life of the plant. An equivalent uniform annual revenue requirement ($\overline{R}$) is then determined (Equation C.3). This is the annual revenue requirement that, if constant throughout the life of the facility, would lead to the same total present value as the actual series of annual revenue requirements. The equivalent uniform annual revenue requirement is divided by levelized annual energy output ($\overline{E}$) to obtain the levelized unit costs ($\overline{C}$) provided in this report (Equation C.4).

$$PWRR_t = \frac{RR_t}{(1+i)^n} \tag{C.1}$$

where

$PWWRR_t$ = the present value of revenue requirements occurring during year t, n years into the plant life.

RR_t = the revenue requirement of year t including capital investment costs (carrying charges) and expenses (fuel, operation, and maintenance cost)

i = the discount rate.

$$PWRR = \sum_{t=1}^{m} PWRR_t \tag{C.2}$$

where

PWRR = the total present value of all annual revenue requirements over the plant life

m = the economic (book) life of the plant.

$$\overline{R} = [CRF(i,m)] \quad [PWRR] \tag{C.3}$$

where

$\overline{R}$ = The uniform annual revenue requirement (levelized revenue requirement). When taken as a series over the life of the plant, it has an aggregate present value equal to the aggregate present value of the actual revenue requirement stream.

$CRF_{(i,m)}$ = the capital recovery factor at discount rate i over service life m, as follows:

$$CRF_{(i,m)} = \frac{i}{1-(1+i)^{-m}}$$

$$\overline{C} = \frac{\overline{R}}{\overline{E}} \tag{C.4}$$

where

$\overline{C}$ = levelized unit cost of production (mills/kWh)

$\overline{R}$ = levelized annual revenue requirements

$\overline{E}$ = levelized annual energy production, obtained as follows:

$$\overline{E} = CRF_{(i,m)} \sum_{t=1}^{m} \frac{E_{(t)}}{(1+i)^{t}}$$

where $E_{(t)}$ = annual energy production, year t.

(a) Although a 1990 first year of commercial operation is adopted to facilitate a uniform cost comparison, all technologies could not be available for commercial operation in 1990 due to maturity of the technology construction schedule or other reasons.

All estimates of energy costs are predicated on a 1990 plant startup date.[a] Use of a uniform 1990 year of commercial operation ensures that all technologies are treated consistently from the standpoint of future escalation in capital, O&M and fuel costs.

Project financing was, in all cases, based on 100% public (state) debt financing. A 3% (real) interest rate on debt was used; other financial parameters used also corresponded to public financing (Table C.1). All cost assessments were done on a "real" basis to purge the results of uncertainties attributable to the effects of general inflation.

Real escalation in capital and O&M costs was taken to be zero during the planning period. Fuel costs were escalated (in real terms) as described in Appendix B. Because general inflation was excluded from the analysis, the levelized revenue requirements at first year of commercial operation (1990) were equivalent to the 1980 price year dollars used for all costs in this assessment. No discounting from 1990 to 1980 was then required to express levelized revenue requirements in 1980 dollars. The financial and technical parameters generally used in the cost calculation discussed above are summarized in Table C.1. These premises generally agreed with financial premises used in the Acres American Upper Susitna Project Development Study (Acres American 1981a), and the Acres American Cook Inlet Tidal Power Assessment (Acres American 1981b).

TABLE C.2. Premises for Cost Assessment

First Year of Commercial Operation	1990
Start of Construction	corresponding to construction period cited in text
Economic (Bond) Life	as cited for technology in text
Capacity Factor	constant over life of facility, as cited in text
Financing	100% debt
Cost of Debt	3% (real)
General Inflation	none
Federal and State Taxes	none
Insurance	0.25% capital value/year
Capital Cost Escalation	none
O&M Cost Escalation	none
Fuel Cost Escalation	As in Appendix B
Discount Rate	3% (real)

Construction Payout Schedule[a]

Construction Period	Payout Schedule
1 year	one shot
2 years	constant
3 + years	weak sigmoid (Phung 1978)

(a) Used to estimate interest during construction.

APPENDIX D

WATER RESOURCE IMPACTS FROM STEAM-CYCLE POWER PLANTS

APPENDIX D

WATER RESOURCE IMPACTS FROM STEAM-CYCLE POWER PLANTS

The construction and operation of any steam-cycle electric generating facility will potentially result in three types of water resource impacts: water consumption impacts, water-quality impacts, and hydrologic impacts. Most of the potential impacts can be satisfactorily mitigated through appropriate power plant site selection, engineering design, and operating procedures. Design criteria, operating procedures and resulting costs associated with proper mitigation will vary considerably depending upon site technology and fuel-specific factors.

Water resource impacts associated with each type of steam-cycle facility and their mitigation alternatives are described below. Unless a specific technology is identified, the discussion generally applies to all steam-cycle facilities.

WATER CONSUMPTION EFFECTS

Consumptive water losses associated with the operation of any steam-cycle power plant requiring a substantial water supply for cooling and other plant uses can reduce the downstream flow of the water resource. The significance of this impact depends on the magnitude of the plant's water requirements relative to the flow of the river or to the hydraulic conductivity of the aquifer serving as the supply. Because the Railbelt region's surface water supplies are plentiful, use of groundwater for power plant operation should be limited. Groundwater use can be envisioned in at least two applications: 1) the use of Ranney well collectors in alluvial aquifers close to a river system for mitigating entrainment and impingement of aquatic organisms; and 2) the possible use of groundwater in coastal areas to supply a plant's fresh water requirements when salt water condenser cooling systems are employed.

The amount of water required by a specific plant depends upon the type of cooling system used (once-through or recirculating), the type of steam cycle, the site, and the specific water management techniques used to maximize water reuse and to minimize power plant makeup requirements. Estimates of water requirements are presented in Table D.1 for various steam cycles and plant capacities.

To comply with existing federal and state regulations, once-through cooling water systems will most likely be limited to coastal areas employing salt water cooling. Interior sites will most likely use some form of recirculating cooling water system (see Appendix I).

Based upon the general siting constraints presented in each technology description, the most probable power plant water supply sources in the Railbelt region are listed in Table D.2. Selected USGS streamflow data for these resources are presented in Table D.3.

Since water withdrawal impacts are relative to the flow of the river, a comparison of the information presented in Tables D.1 and D.3 can provide an overview of potential effects. If all water demand is assumed to represent total consumption (as it would for a zero discharge plant), then the maximum water consumption for any of the plants identified in Table D.1, using a recirculating cooling water system, would be less than 1% of the average flow for rivers identified in Table D.3. Plant water demand should also be a small percentage of each river's minimum recorded flow. For plant sizes likely to be constructed in Alaska, 200 MWe for example, total plant demand (again for a zero discharge plant) represents less than 10% of minimum flow for all but the smallest streams of Table D.3. These conclusions suggest that impacts on water flow should not be significant.

WATER QUALITY EFFECTS

Construction and operation of any steam-cycle facility can potentially significantly affect water quality. For most steam-cycle facilities, construction impacts are primarily associated with runoff and erosion from the site while the soil is exposed. Other common pollutant sources include construction camp and site domestic and sanitary facilities, concrete batch plants, construction dewatering, and dredge spoil. The development of geothermal fields requires large quantities of drilling mud, which requires

TABLE D.1. Estimated Water Requirements Associated with Various Steam-Cycle Facilities

		Plants Utilizing Once Through Cooling Water Systems						Plants Utilizing Recirculation Cooling Water Systems					
	Approximate Thermal Efficiency	Cooling[a] Water	Total Plant Demand (1000 gpm)[b]					Cooling[c] Water	Total Plant Demand (1000 gpm)[d]				
Steam Cycle	(Percent)	(gpm/MW)	20 MW	50 MW	200 MW	400 MW	600 MW	(gpm/MW)	20 MW	50 MW	200 MW	400 MW	600 MW
Biomass	17-24	730	14.6	36.5	-	-	-	13	0.29	0.725	-	-	-
Coal	30-37	450	9.0	22.5	90	180	270	8	0.18	0.45	1.8	1.8	5.4
Oil	29-37	450	9.0	22.5	90	180	270	8	0.18	0.45	1.8	3.6	5.4
Natural Gas	27-34	450	9.0	22.5	90	180	270	8	0.18	0.45	1.8	3.6	5.4
Synfuel	24-30	675	13.5	33.7	135	270	405	12	0.27	0.68	2.7	5.4	8.1
Geothermal	7-16	845	16.9	42.2	169	-	-	15	0.30	0.75	3.3	-	-
Nuclear	30	620	-	-	124	248	372	11	-	-	2.5	5.0	7.5
Combined Cycle	40	150	-	7.5	30	-	-	3	-	0.15	0.6	-	-

(a) Based upon estimates presented in Kim et al. 1975 and adjusted for thermal efficiencies.
(b) Cooling water requirements assumed to represent 100% of total plant demand.
(c) Derived from methodology presented in Nelson 1974.
(d) Cooling water requirements are assumed to represent 90% of total plant demand for all technologies except geothermal. For geothermal, cooling water requirements assumed to represent 100% of total plant demand.

TABLE D.2. Possible Power Plant Water Sources in the Railbelt

Water Resources	Possible Facility Type
Cook Inlet	All
Prince William Sound	All except geothermal
Susitna River	All
Matanuska River	All
Copper River	Coal, synfuel, geothermal
Gulkana River	Coal, synfuel
Tanana River	Nuclear, geothermal
Nenana River	Coal, synfuel, nuclear
Chena River	Geothermal

management and subsequent disposal. Potential impacts from all of these wastewater sources are generally mitigated through appropriate wastewater treatment and recycle facilities. The water-quality parameter of primary concern during a plant's construction phase is suspended sediment (SS). Facilities to manage this wastewater constituent are generally incorporated into a site erosion and sediment control plan.

The type and quantity of potential water pollutants resulting from power plant operation are greatly dependent upon the type of steam cycle used and the size of the plant. Potential sources of water pollution include cooling system blowdown, fuel pile runoff, demineralizer regeneration wastewater, ash handling and flue gas desulfurization waste, geothermal fluid discharges, fuel oil releases, radioactive wastes (nuclear plants only) and miscellaneous cleaning wastes.

Cooling Water Blowdown

In general, all power plants using closed-cycle cooling systems periodically discharge ("blowdown") water from the cooling system to remove accumulations of sediment and other undesirable materials. The quantity and quality of coolant blowdown depend upon the type of cooling system used and the specific characteristics of the source. In general, total dissolved solids (TDS), chlorine, and waste heat are the primary pollutants of concern.

TABLE D.3. Stream Flow Data for Selected Railbelt Locations

Station Name and Location	U.S.G.S. Number	Years of Record	Average Flow cfs	Average Flow 1000 gpm	Maximum Flow cfs	Maximum Flow 1000 gpm	Minimum Flow cfs	Minimum Flow 1000 gpm
Susitna River near Cantwell	15291000	11	6,295	2,825	55,000	24,686	400	180
Susitna River at Gold Creek	15292000	28	9,667	4,338	90,700	40,709	600	269
Tanana River near Tanacross	15476000	24	7,931	3,559	39,100	17,549	1,400	628
Tanana River at Fairbanks	15485500	5	(17,000)[a]	7,630	68,300	30,655	3,100	1,391
Tanana River at Nenana	15515500	17	(22,000)[a]	9,874	186,000	83,483	4,000	1,795
Chena River near Two Rivers	15949300	10	680	305	16,800	7,540	20	9
Chena River near North Pole	15493000	5	756	339	12,300	5,521	50	22
Chena River at Fairbanks	15514000	29	1,450	651	74,400	33,393	(160)[b]	72
Nenana River near Healy	15518000	27	3,527	1,583	46,800	21,000	190	85
Copper River near Chitina	15212000	22	37,100	16,652	265,000	118,940	2,000	989
Matanuska River at Palmer	15284000	24	3,857	1,731	82,100	36,849	234	105
Gulkana River at Sourdough	15200280	5	1,085	487	9,170	4,116	200	90

(a) Estimated, based on 2 years of record.
(b) Minimum not determined, 1978 minimum given.

Fuel Pile Runoff

Steam cycles using solid fuel, i.e., coal, peat and various forms of biomass, require management of fuel pile runoff. For coal, this wastewater is generally of low pH and high in sulfates and iron and has various concentrations of other metals, depending upon the specific coal source. For biomass fuels, the prime parameters of concern are the chemical and biochemical oxygen demand, although other important pollutants may also be present, such as metals in municipal solid waste.

Demineralizer Regeneration Wastewaters

All steam-cycle facilities except geothermal power cycles produce demineralizer regeneration wastewaters that have high TDS levels and generally low pH values.

Ash Handling and Flue Gas Desulfurization Wastes

Fossil fuel and biomass steam cycles produce ash as a by-product of combustion, although the amounts vary greatly with the type of fuel. Wastewater produced during ash handling and ash transport, and leachates from solid waste landfills generally have high TDS levels and elevated concentrations of metals. Coal generates the largest quantities of solid waste, including fly ash, bottom ash, and flue gas desulfurization wastes.

Geothermal Fluid Discharges

At geothermal plants, the geothermal fluid itself can be highly saline (high in TDS), and the dissolved substances in the fluid can be concentrated during the process of electricity generation. The quality of geothermal fluids is highly variable, however, and can exhibit significant differences even between wells in a specific well field. Water-quality data reported in the literature for geothermal plants located throughout the world exhibit variations that range from benign to extremely toxic.

Fuel Oil Releases

Potential oil pollution impacts associated with oil-fired power plants and other facilities that may use oil as an auxiliary fuel include accidental release of oil through spillage or tank rupture. Potentially significant impacts that may result from oil releases are generally mitigated through the federally mandated implementation of a Spill Prevention Control and Countermeasures (SPCC) Plan, as required under 40 CFR 110 and 40 CFR 112. This plan is intended to ensure the containment of all releases and the proper recovery or disposal of any waste oil. The plan must also be formulated in light of the Alaska Oil and Hazardous Substances Pollution Regulations.

Radioactive Wastes

Problems associated with the release of radioactive wastes from nuclear facilities are generally mitigated through compliance with Nuclear Regulatory Commission guidelines. However, accidental releases are possible; therefore, all potential transmission media, including groundwater and surface water resources, are extensively studied during project development to minimize any impacts related to such releases.

Miscellaneous Wastewaters

Steam-cycle plants generally have many other miscellaneous wastewaters derived from floor drainage, system component cleaning, and domestic water use. The quantity and quality of these wastewaters will vary considerably, but oil and grease, suspended solids, and metals are the effluents of most concern.

All of these enumerated wastewaters are strictly managed within a specific power plant. The management vehicle is generally termed a "water and wastewater management plan" and for some plants is developed in conjunction with a "solid waste management plan." The purpose of these plans is to balance environmental, engineering, and cost considerations and to develop a plant design and operational procedure that ensures plant reliability and environmental compatibility and that minimizes costs.

For Railbelt plants, relevant regulations would include the following: Clean Water Act and its associated National Pollutant Discharge Elimination System (NPDES) permit requirements and federal effluent limitation guidelines; Alaska State water-quality standards (which regulate all parameters of concern in all Alaska waters depending upon the specific water resource's designated use); the Federal Resource Conservation and Recovery Act and Alaska solid waste disposal requirements; and the Toxic Substances Control Act.

Compliance with all regulations does not eliminate water resource impacts. Alaska water-quality standards permit a wastewater discharge mixing zone; water-quality concentrations will therefore be altered in this area. Downstream water quality will also be altered because receiving stream standards are rarely as high as the existing water quality of the receiving water body. If secondary impacts associated with wastewater discharges, such as those to aquatic ecosystems, are deemed significant, further waste management and treatment technologies may be employed. Water-quality impacts can only be completely avoided if the plant is designed to operate in a "zero discharge" mode. This is technically possible for all steam-cycle power plants, but can be extremely costly.

Typical water-quality values for selected rivers in the Railbelt region are given in Table D.4. Based on these values, no extraordinary or unusual water-quality characteristics appear to preclude construction or operation of a properly designed steam-cycle power plant. Most of the river systems can be considered moderately mineralized based upon the total dissolved solids values and the concentrations of the major ionic components. Values for calcium, magnesium, and silica are not low and will limit the natural reuse (without treatment) of several wastewater streams, most significantly cooling tower blowdown. "Standard" power plant water management technologies will be required to mitigate any adverse water-quality impacts.

A potential water-quality problem that can arise, not from wastewater discharge, but rather from atmospheric emissions associated with fossil fuel power plants, is acid precipitation (rain). Acid rain occurs when gases such as sulfur dioxide, hydrogen sulfide, and nitrogen oxides are converted in the atmosphere to sulfuric and nitric acids. If these acids are present in significant quantities, they can acidify precipitation to below pH 5.6, the normal pH of rain and snow at equilibrium with carbon dioxide in the atmosphere. The effects of extensive acid precipitation on sensitive ecosystems can include changes in soil and water chemistry with attendant adverse impacts to terrestrial and aquatic biota. Sensitive ecosystems are generally in areas underlaid by highly siliceous types of bedrock such as granite, some gneisses,

TABLE D.4. Water-Quality Data for Selected Alaskan Rivers[a]

River/Location	U.S.G.S. Station No.	Flow cfs	Silica mg/	Iron mg/	Manganese mg/	Calcium mg/	Magnesium mg/	Sodium mg/	Potassium mg/
Copper River near Chitina	15212000	6,100	14	--	--	36	9.3	12	1.6
		159,000	8.5	--	0.02	23	3.5	4.3	2.0
Matanuska River at Palmer	15284000	11,600	4.5	0.02	--	28	1.8	3.8	0.9
		566	6.3	0.07	--	44	4.8	8.9	0.9
Susitna River at Gold Creek	15292000	34,000	5.7	--	--	12	1.4	3.1	1.3
		1,960	11	0.19	--	34	4.5	11	2.4
Susitna River at Susitna Station	15294350	6,790	10	0.09	0.13	26	4.2	7.1	1.5
		148,000	3.6	0.07	0.85	17	2.3	1.8	1.5
Chena River at Fairbanks	15514000	10,200	6.4	2.7	0.75	12	2.3	1.1	2.1
		182	23	3.2	0.82	36	7.6	4.9	2.8
Tanana River at Nenana	15515000	4,740	19	--	--	54	10	4.8	2.9
		34,300	7.4	--	--	24	5.0	2.7	1.9
Nenana River near Healy	15518000	497	8.2	--	--	36	10	5.6	2.6
		8,750	4.0	0.55	--	18	3.6	2.7	1.4
Gulkana River at Sourdough	15200280	286	--	--	--	--	--	--	--
		6,130	--	--	--	--	--	--	--
Talkeetna River near Talkeetna	15292700	1,930	7.3	--	--	19	2.2	8.3	1.0
		19,800	5.1	--	--	8.1	1.0	2.6	0.5
Yukon River at Ruby	15564800	345,000	6.2	0.19	0.02	27	6.1	2.2	1.9
		26,900	12	0.39	0.02	46	10	3.9	2.0
Chakachutna River near Tyonek	15294500	6,640	5.3	0.03	0.01	9.1	2.1	1.4	1.5
		15,100	5.3	0.94	0.05	14	1.8	1.5	1.7
Skwentna River near Skwentna	15294300	6,760	11	--	--	17	5.0	4.4	0.9
		1,330	13	--	--	28	4.3	7.7	1.7
Lowe River near Valdez	15226500	--	5.0	--	--	28	0.8	1.2	2.7
		390	2.0	0.04	0.02	22	1.0	1.4	2.5
Fortymile River near Steel Creek	--	1,100	11	0.08	--	20	7.5	4.6	1.2

(a) Adapted from U.S.G.S. Water Data Report AK-77-1 and U.S.G.S. Open File Report 76-513.

TABLE D.4. (Contd)

River/Location	U.S.G.S. Station No.	Flow cfs	Silica mg/	Iron mg/	Manganese mg/	Calcium mg/	Magnesium mg/	Sodium mg/	Potassium mg/
Copper River near Chitina	15212000	116	26	18	0.09	--	--	174	7.2
		78	15	3.2	0	--	--	98	7.6
Matanuska River at Palmer	15284000	61	29	2.5	0.2	--	--	94	7.0
		100	41	13	0.25	--	--	169	8.1
Susitna River at Gold Creek	15292000	36	6.0	4.0	0.14	--	--	52	6.8
		98	12	29	0.11	--	--	152	8.0
Susitna River at Susitna Station	15294350	82	15	13	0.24	0.0	--	116	6.9
		59	13	2.2	0.05	1.1	11.3	64	8.1
Chena River at Fairbanks	15514000	30	10	0.7	0.27	--	--	54	7.0
		140	13	2.1	0.52	--	--	165	6.6
Tanana River at Nenana	15515000	173	33	2.4	0.30	--	--	212	7.5
		72	34	2.5	0.10	--	--	113	7.2
Nenana River near Healy	15518000	102	51	5.0	0.11	--	--	169	7.0
		57	14	1.1	0.09	--	--	74	7.0
Gulkana River at Sourdough	15200280	110	--	--	0.15	0.03	10.1	--	7.5
		40	--	--	0.04	0.15	11.0	--	7.1
Talkeetna River near Talkeetna	15292700	52	10	12	--	0.00	14.1	91	7.7
		28	2.8	2.6	0.20	0.08	11.7	37	6.8
Yukon River at Ruby	15564800	94	1.4	0.2	0.04	--	--	113	7.6
		165	25	1.3	0.23	--	--	183	--
Chakachutna River near Tyonek	15294500	26	12	2.0	0.00	--	--	46	7.1
		26	11	1.4	0.03	--	--	51	7.5
Skwentna River near Skwentna	15294300	52	20	6.0	0.05	--	--	91	7.4
		77	24	12	0.18	--	--	130	7.1
Lowe River near Valdez	15226500	57	3.2	0.8	0.32	--	--	100	7.6
		46	22	1.2	0.34	--	--	77	7.3
Fortymile River near Steel Creek	--	65	37	0.5	0.47	--	--	116	7.4

TABLE D.4. (Contd)

River/Location	Bicarbonate mg/	Sulfate mg/	Chloride mg/	Nitrate mg/	Total Phosphorus mg/	Dissolved Oxygen mg/	Total Dissolved Solids mg/	pH Units
Copper River near Chitina	116	26	18	0.09	--	--	174	7.2
	78	15	3.2	0	--	--	98	7.6
Matanuska River at Palmer	61	29	2.5	0.2	--	--	94	7.0
	100	41	13	0.25	--	--	169	8.1
Susitna River at Gold Creek	36	6.0	4.0	0.14	--	--	52	6.8
	98	12	29	0.11	--	--	152	8.0
Susitna River at Susitna Station	82	15	13	0.24	0.0	--	116	6.9
	59	13	2.2	0.05	1.1	11.3	64	8.1
Chena River at Fairbanks	30	10	0.7	0.27	--	--	54	7.0
	140	13	2.1	0.52	--	--	165	6.6
Tanana River at Nenana	173	33	2.4	0.30	--	--	212	7.5
	72	34	2.5	0.10	--	--	113	7.2
Nenana River near Healy	102	51	5.0	0.11	--	--	169	7.0
	57	14	1.1	0.09	--	--	74	7.0
Gulkana River at Sourdough	110	--	--	0.15	0.03	10.1	--	7.5
	40	--	--	0.04	0.15	11.0	--	7.1
Talkeetna River near Talkeetna	52	10	12	--	0.00	14.1	91	7.7
	28	2.8	2.6	0.20	0.08	11.7	37	6.8
Yukon River at Ruby	94	1.4	0.2	0.04	--	--	113	7.6
	165	25	1.3	0.23	--	--	183	--
Chakachutna River near Tyonek	26	12	2.0	0.00	--	--	46	7.1
	26	11	1.4	0.03	--	--	51	7.5
Skwentna River near Skwentna	52	20	6.0	0.05	--	--	91	7.4
	77	24	12	0.18	--	--	130	7.1
Lowe River near Valdez	57	3.2	0.8	0.32	--	--	100	7.6
	46	22	1.2	0.34	--	--	77	7.3
Fortymile River near Steel Creek	65	37	0.5	0.47	--	--	116	7.4

quartite, and quartz sandstone, none of which are extensively prevalent in the Railbelt region (USGS 1978). These rock types are highly resistant to dissolution through weathering and are therefore generally low in dissolved solids and have a low buffering capacity (a low ability to neutralize additions of acids or alkalis). Hence, when acid precipitation falls on such an area, the acids are not fully neutralized in the watershed, and so streams and lakes become acidified.

Working with water chemistry data from more than 1,000 lakes in Norway, the Norwegian Institute for Water Research has recently developed an empirical relation by which the sensitivity of a given fresh-water system to inputs of acid precipitation can be estimated (Likens et al. 1979). For example, the relationship predicts that a soft water lake with about 80 microequivalents of bicarbonate (corresponding to about 4.8 mg/l of bicarbonate, 1.7 mg/l of calcium and a pH of about 6.5) will lose its buffering capacity to the point where the pH drops below 5, a critical level for fish, if the long-term average pH of precipitation is below about 4.3.

A review of the available water quality data (Table D.4) for various water resources in the Railbelt region indicates that bicarbonate and calcium concentrations are, in general, an order of magnitude greater than these critical levels, and pH values are generally alkaline (greater than 7.0). Based upon these values, there appears to be sufficient assimilative capacity in these natural waters to mitigate effects from potential acid rain events.

HYDROLOGIC EFFECTS

Impacts to the hydrological regime of groundwater and surface water resources can result from the physical placement of the power plant and its associated facilities, and from the location and operation of water intake and discharge structures. The siting of the power plant may necessitate the elimination or diversion of surface water bodies and will modify the site runoff pattern. Stream diversion and flow concentration may result in increased stream channel erosion and downstream flooding. Proper site selection and design can minimize these impacts. Mitigative techniques such as runoff flow equalization, runoff energy dissipation, and stream slope stabilization may be employed.

Other hydrological impacts can result from the siting and operation of the makeup water system and wastewater discharge system. The physical placement of these structures can change the local flow regime and possibly obstruct navigation in a surface water body. Potential impacts associated with these structures are generally mitigated, however, through site selection and structure orientation. Discharge of power plant wastewaters may create localized disturbances in the flow regime and velocity characteristics of the receiving water body. These effects are minimized through proper diffuser design, location, and orientation. Consumptive water losses associated with the power plant may also affect hydrological regimes by reducing the downstream flow of the water resource. However, as discussed previously, surface water supplies in the Railbelt region are plentiful, and hydrologic impacts due to reduced streamflow should not be significant.

APPENDIX E

AIR EMISSIONS FROM FUEL COMBUSTION POWER PLANTS

APPENDIX E

AIR EMISSIONS FROM FUEL COMBUSTION POWER PLANTS

Air pollution is the presence of contaminants in the atmosphere in sufficient quantities and duration to be harmful to human, plant or animal life or property. Fuel-burning electric generating plants, including coal, distillate and gas-fired steam-electric plants, combustion turbines, combinedcycle plants, and diesel generators, are potentially major sources of air pollution because they discharge potentially polluting products of combustion into the atmosphere.

In this appendix, the discussion addresses the general nature of air pollution that arises from fuel combustion, the broad regulatory framework that has been implemented to control air pollution, and the regulatory considerations that apply to the Railbelt region. The emissions of the different fuel combustion technologies used in electric power generation are compared also. Finally, the general nature of siting requirements affecting the construction of combustion-fired generating facilities in the Railbelt region are discussed.

POTENTIAL POLLUTANTS

Several kinds of air pollutants are normally emitted by fuel-burning power plants. These include particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, unburned hydrocarbons, water vapor, noise and odors. Of particular concern is acid rainfall, a secondary effect of air pollutants.

Particulate Matter

Particulate matter consists of finely divided solid material in the air. Natural types of particulate matter are abundant and include wind-borne soil, sea salt particles, volcanic ash, pollen, and forest fire ash. Manmade particulate matter includes smoke, metal fumes, soil-generated dust, cement dust, and grain dust. On the basis of data collected by the U.S. Environmental

Protection Agency (EPA), suspended particulate matter in sufficient concentrations has been determined to cause adverse human health effects and property damage.

Fuel combustion power plants produce particulate matter in the form of unburned carbon and noncombustible minerals. Particulate matter would be emitted in large quantities from fuel combustion plants that use solid fuels (coal, peat, wood, municipal waste) or residual oil, if high-efficiency control equipment were not used. Particles are removed from flue gas by using electrostatic precipitators or fabric filters (baghouses). They are routinely required and collection efficiencies can be very high (in excess of 99%).

Sulfur Dioxide

Sulfur dioxide (SO_2), a gaseous air pollutant, is emitted during combustion of fuels that contain sulfur. Coal and residual oil contain sulfur in amounts of a few tenths of a percent to a few percent, whereas pipeline natural gas, wood, and most municipal wastes contain relatively little sulfur. Sulfur dioxide, like particulate matter, has been identified as harmful to human health, and it appears to be particularly serious when combined with high concentrations of particulate matter. It is damaging to many plant species, including several food crops such as beans. Sulfur dioxide may, in addition, result in acid rainfall.

Nitrogen Oxides

Nitrogen oxides (NO_x) (NO_2 and NO, primarily), gaseous air pollutants, form during the combustion process by oxidation of fuel-bound or atmospheric nitrogen. Nitrogen oxides damage plants and play an important role in photochemical smog. Fuel combustion plants and automobiles are significant contributors to these emissions.

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

Carbon Monoxide

Carbon monoxide (CO) emissions result from incomplete combustion of carbon-containing compounds. Generally, high CO emissions result from suboptimal combustion conditions and can be reduced by using appropriate firing techniques. However, CO emissions can never be eliminated completely, using even the most modern combustion techniques and clean fuels. Carbon monoxide is toxic to humans and animals.

Unburned Hydrocarbons

Unburned hydrocarbons are emissions of vaporized unburned fuel or partially burned products that escape combustion. Generally, they are produced during periods of startup or shutdown or during faulty unit operation. For combustion turbines they may also be emitted during periods of very low load. Unburned hydrocarbons play a role in photochemical smog formation. They are generally well controlled by employing efficient combustion techniques or operational controls. Emissions of hydrocarbons in the Railbelt region should not adversely affect the selection of any of the fuel burning options, nor will they affect the selection of one option over another.

Water Vapor

Plumes of condensed water vapor are discharged from wet cooling towers as the tower exhaust is cooled below the saturation point. The plume will persist downwind of the tower until the water vapor is diluted to a level below saturation. Under cold, moist conditions the plumes are particularly long because the ambient air can hold little added moisture. Formation of these plumes may be hazardous during "fogging" conditions when a high wind speed causes the plume to travel along the ground. During freezing conditions, such plumes may lead to ice formation on nearby roads and structures. Plume generation, fogging, and icing can be controlled or virtually eliminated by using wet/dry or dry cooling towers.

Noise and Odor

Noise levels beyond the plant property line can be controlled by equipment design or installation of barriers. Odors may be produced by municipal wastes or some biomass fuels.

Acid Precipitation

The SO_2 and NO_x emissions from fuel-burning facilities have been related to the occurrence of acid rainfall downwind of major industrial areas. Acid rain results from the conversion, in the atmosphere, of gases such as SO_2, H_2S and NO_x to sulfuric and nitric acids. Congress may soon enact laws to restrict these emissions because of the effects of acid rain. The mechanisms of acid rain formation, subsequent acidification of lakes and effects on soils, vegetation, wildlife and structures, and the relationship to specific source emissions are not yet fully understood. Much research is in progress in this area, and recent research indicates that some remote areas of the western United States have been affected by acid rain.

On initial assessment, Alaskan lakes do not appear to be so sensitive to acid rain as lakes in eastern Canada and the northeastern United States. Furthermore, the total emissions into the Alaska environment are much less than emissions from industrialized areas of the midwest and northeast United States (Galloway and Cowling 1978). Acid rainfall most likely will never present problems in Alaska similar to those in the eastern portion of the continent.

Currently, no basis exists for assessing the impacts of acid rainfall that might develop because of increased fuel combustion in Alaska. In developing any of these technologies, however, the planning agencies must be aware that a significant research effort is being mounted against acid rainfall and that a regulatory framework may be developed within the next several years to analyze and mitigate its impacts.

REGULATORY FRAMEWORK

The 1970 federal Clean Air Act established the national strategy for air pollution control. The Act established New Source Performance Standards

(NSPS)[a] for new stationary sources, including fuel combustion facilities. Levels of acceptable ambient air quality (National Ambient Air Quality Standards) were also established, and the regulations were promulgated to maintain these standards or to reduce pollution levels where the standards were exceeded.

New source performance standards (NSPS) have been promulgated for coal-fired steam-electric power plants and for combustion turbines. In addition, any combustion facility designed to burn coal or coal mixtures, or capable of burning any amount of coal, or if such use is planned, is subject to the coal-fired power plant standards. Standards of allowable emissions for each fuel combustion technology for a range of sizes for power plants are presented in Table E.1 for SO_2, Table E.2 for particles, and Table E.3 for NO_x. Data are taken from EPA Publications or the New Source Performance Standards. The standards are enforced for both newly constructed and significantly retro-fitted facilities and represent the expected level of controlled emissions from these power plants.

In Alaska, the Department of Environmental Conservation enforces regulations regarding ambient air quality standards and source performance standards. A permit to operate will be required for all fuel-burning electric generating equipment greater than 250 kW generating capacity.

Major changes were made to the Clean Air Act in 1977 when the Prevention of Significant Deterioration (PSD) program was added by Congress. The PSD program has established limits of acceptable deterioration in existing ambient air quality for SO_2 and total suspended particulates (TSP) throughout the United States. Pristine areas of national significance (Class I areas) were set aside with very small increments of allowable deterioration. The remainder of the country was allowed a greater level of deterioration. Other regulatory factors apply to areas where the pollution levels are above the national standards. State and local agencies may take over the administration of these

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(a) "The term standard of performance means a standard for emissions of air pollutants which reflects the degree of emissions limitation achievable through the application of the best system of emission reduction. . ." (Pub. L. 91-604, HR 17255, Dec. 31, 1970).

TABLE E.1. Controlled Sulfur Dioxide Emissions for Various Technologies

Technology	Emission Rate ($lb/10^6$ Btu)	Annual Emissions (tons/yr)[a] Facility Size (MW) 20	50	200	400	600
Steam Electric						
Coal[b]	0.10	67	169	674	1348	2022
Oil[c]	0.20	131	329	1314	2628	3942
Gas	0.0006	0	1	4	8	12
Wood	0.15	99	246	--	--	--
Combustion Turbine						
Oil	0.30	269	673	--	--	--
Gas[d]	--	--	--	--	--	--

(a) 75% capacity factor.
(b) 70% scrubbing of 0.18% sulfur coal.
(c) New Source Performance Standard.
(d) Negligible.

programs through the development of a state implementation plan acceptable to the EPA. Table E.4 gives the National Ambient Air Quality Standards and allowable PSD increments.

The PSD program is currently administered by the U.S. Environmental Protection Agency (EPA). A PSD review will be triggered if emissions of any pollutant are above 100 tons per year for coal-fired power plants or above 250 tons per year for the other power plants. This review entails a demonstration of compliance with ambient air-quality standards, the employment of best available control technology, a demonstration that allowable PSD increments of pollutant concentrations (currently promulgated for SO_2 and suspended particles) will not be violated, and a discussion of the impact of pollutant emissions on soils, vegetation, and visibility. It also generally includes a full year's onsite monitoring of air-quality and meteorological conditions prior to the issuance of a permit to construct.

TABLE E.2. Controlled Particulate Matter Emissions for Various Technologies

Technology	Emission Rate ($lb/10^6 Btu$)	Annual Emissions (tons/yr)[a] Facility Size (MW) 20	50	200	400	600
Steam Electric						
Coal[b]	0.03	20	49	197	394	591
Oil[b]	0.03	20	49	197	394	591
Gas[c]	0.01	7	16	66	131	197
Wood[d]	0.02	131	329	--	--	--
Combustion Turbine						
Oil	0.05	46	125	--	--	--
Gas[e]	--	--	--	--	--	--

(a) 75% capacity factor.
(b) New Source Performance Standard.
(c) Typical.
(d) Assumes mechanical collection. Emissions may be reduced by 90% using electrostatic precipitators or baghouse.
(e) Negligible.

In the near future, PSD control over other major pollutants, including NO_x, CO, oxidants, and hydrocarbons, will be promulgated. Obtaining a PSD permit represents one of the largest single obstacles to constructing a major fuel-burning facility.

Alaska has two permanent Class I areas in or near the Railbelt region, Denali National Park and the pre-1980 areas of the Tuxedni Wildlife Refuge. The new national parks and wildlife preserves have not been included in the original designation, but the state may designate additional Class I areas in the future. New major facilities located near Class I areas cannot cause a violation of the PSD increment near a Class I area; this requirement presents a significant constraint to developing nearby facilities.

TABLE E.3. Controlled NO_x Emissions for Various Technologies

Technology	Emission Rate ($lb/10^6$ Btu)	Annual Emissions (tons/yr)[a] Facility Size (MW) 20	50	200	400	600
Steam Electric						
Coal[b]	0.6	394	986	3942	7884	11826
Oil[b]	0.3	197	493	1971	3942	5913
Gas[b]	0.2	131	329	1314	2628	3942
Wood[c]	1.0	657	1643	--	--	--
Combustion Turbine						
Oil	0.59	530	1272	--	--	--
Gas[d]	--	--	--	--	--	--

(a) 75% capacity factor.
(b) New Source Performance Standard.
(c) Probably significantly overstated.
(d) Comparable to oil.

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

In the Fairbanks and Anchorage areas, the levels of CO exceed the primary National Ambient Air Quality Standards. The state regulatory agencies are

TABLE E.4. National Ambient Air-Quality Standards and Prevention of Significant Deterioration Increments for Selected Air Pollutants

Pollutant	National Ambient Air Quality Standard			Prevention of Significant Deterioration Increments					
				Class I			Class II		
	3 hr[a]	24 hr[a]	Annual	3 hr	24 hr	Annual	30 hr	24 hr	Annual
Total Suspended Particulate Matter ($\mu g/m^3$)	None	150[b] 260[c]	60[b] 75[c]	None	10	5	None	37	19
Sulfur Dioxide ($\mu g/m^3$)	1300[b]	365[d]	80[d]	25	5	2	512	91	20
Nitrogen Dioxide ($\mu g/m^3$)	None	None	100[d]	None	None	None	None	None	None
Carbon Monoxide[e] (mg/m^3)			None	None	None	None	None	None	None

(a) Not be to exceeded more than once per year.
(b) Secondary or welfare-protecting standard.
(c) Annual geometric mean, advisory indicator of compliance.
(d) Primary or health-protecting standard.
(e) Carbon monoxide primary ambient air quality standards are as follows: the value not to be exceeded more than 1 hr/yr is 40 mg/m^3 (may be changed to 29 mg/m^3); the value not to be exceeded more than one 8-hour period per year is 10 mg/m^3.

required to reduce CO emissions in these two airsheds to attain the standards. This goal will be accomplished by requiring any new or modified major source to install the lowest achievable emission rate for CO emissions and to obtain offsets for the actual CO emissions. Consequently, the construction of a major combustion facility in or near the nonattainment areas will entail the most demanding pollution controls, as well as a lengthy and detailed regulatory review.

COMPARISON OF PROJECT EMISSIONS

The comparison of fuel combustion technologies for their impacts on air quality is determined by the anticipated rate of emissions of each pollutant. Emission levels for the various technologies are presented in Tables E.1 through E.3. Estimated emissions from wood-fired boilers, although officially published, are felt to be somewhat high, especially for SO_2.

These tables were developed based on various assumptions. A 33% conversion efficiency is assumed for steam-electric plants and a 25% conversion efficiency for combustion turbines. For the power plant sizes provided in the tables, emissions are directly proportional to the heat rate of a given technology.

SITING STRATEGY

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

Many acceptable sites should exist for coal-fired power plants in the Beluga, Kenai, Susitna, Nenana, and Glennallen areas, near coal fields (McNaughton 1979). Since Alaska coal is generally low in sulfur content, the siting constraints will be less stringent than those normally encountered in the eastern United States. Smaller biomass-fired plants could generally be sited in broad valleys as well. Generally, emissions from natural gas and fuel oil combustion are below the threshold of significance, and the siting of such facilities is therefore less critical. If high-sulfur residual oils are used, however, siting will become a more important factor.

APPENDIX F

AQUATIC ECOLOGY IMPACTS FROM STEAM-CYCLE POWER PLANTS

APPENDIX F

AQUATIC ECOLOGY IMPACTS FROM STEAM-CYCLE POWER PLANTS

The Railbelt region encompasses many marine and freshwater habitats that provide spawning, rearing, and migration paths for a wide variety of commercially and recreationally important species. Several of these species are listed in Table F.1. These habitats may be impacted by steam-electric plant construction and operation in several major ways, including construction area runoff, water withdrawal for power plant use, and process water discharge. In addition, air emissions (e.g., SO_2 and NO_x) from fossil-fuel plants can impact the aquatic ecosystem through the creation of acid rainfall. The degree of all potential impacts will depend upon the size, location, water requirements and operating characteristics of the plant. Unless a specific facility type is identified in the following sections, this discussion generally applies to all steam-cycle facilities.

CONSTRUCTION AREA RUNOFF

Construction area runoff can increase turbidity and siltation in receiving waters adjacent to site construction. Siltation in freshwater habitats can eliminate fish spawning areas by inundating gravels with fine sediment that smothers eggs and embryos. It can also block emergence of young fish from the gravel (especially salmonids). Similarly, silt can smother benthic organisms, alter their habitat, and reduce benthic primary production by decreasing light penetration. Species of major concern in the Railbelt region include salmonids, burbot, sheefish, and whitefish. Silt-laden runoff, if severe, may also clog or damage the gills of these organisms.

If silt reaches the marine environment, especially areas where turbidity is naturally lower (e.g., outer Cook Inlet or Prince William Sound), it could smother benthic organisms and reduce benthic and pelagic primary production. Potentially affected organisms in these areas include the marine vertebrates and invertebrates listed in Table F.1. Especially susceptible are species

TABLE F.1. Some Commercially and Recreationally Important Aquatic Species in the Alaska Railbelt Region

Fresh Water Organisms
- Salmonids
  - Arctic grayling (*Thylmallus arcticus*)
  - Lake trout (*Salvelinus namaycush*)
  - White fish (*Coregonus spp.*)
  - Inconnu (*Stenodus leucichtys*)
- Other fish
  - Burbot (*Lota lota*)
  - Northern pike (*Esox lucius*)

Marine Organisms
- Fish
  - Herring (*Clupea harengus pallasi*)
  - Halibut (*Hippogossus stenolepis*)
- Invertebrates
  - Crab
    - Tanner (*Chionectes spp.*)
    - King (*Paralithodes spp.*)
    - Dungeness (*Cancer magister*)
  - Shrimp
    - Pink (*Pandalus borealis*)
    - Humpy (*Pandalus goniurus*)
    - Coonstrip (*Pandalus hypsinotus*)
    - Spot (*Pandalus platyceros*)
    - Sidestrip (*Pandalopsis dispar*)
  - Bivalves
    - Razor clam (*Siliqua patula*)
    - Pacific scallope (*Patinopecten caurinus*)

Anadromous Fish
- Chinook salmon (*Oncorhynchus tshawytscha*)
- Chum salmon (*Oncorhynchus keta*)
- Coho salmon (*Oncorhynchus kisutch*)
- Pink salmon (*Oncorhynchus gorbuscha*)
- Sockeye salmon (*Onchrohynchus nerka*)
- Steelhead/rainbow trout (*Salmo gairdneri*)
- Cutthroat trout (*Salmo clarki*)
- Arctic char (*Salvelinus alpinus*)
- Colly vardin (*Salvelinus malma*)
- Smelt (*Thaleichthys pacificus*)

Source: Alaska Department of Fish and Game 1978.

inhabiting areas of low current and wave energy near the mouth of silt-laden rivers. In these low-energy environments suspended solids are ultimately deposited. Clam beds, rearing habitats for juvenile fish, and spawn of Pacific herring would be especially vulnerable.

The impact from construction runoff would depend on the effectiveness of erosion control measures, location and size of the plant, and the existing soils. Potential problems to both fresh and marine waters can be minimized by implementing appropriate site runoff and erosion control measures, including runoff collection and treatment systems, soil stabilization techniques and scheduling of earthmoving activities to coincide with seasons of low precipitation.

WATER WITHDRAWAL EFFECTS

The principal impacts of water withdrawal include entrainment, impingement and reduction in downstream flow.

Entrainment and Impingement

Intake structures associated with water withdrawal have the potential to impinge or entrain aquatic organisms. Impingement occurs when aquatic biota are caught against screens and grates placed in intakes to keep organisms out of the cooling system. Impingement of organisms on inadequately designed screening or diversion structures can cause mortalities due to abrasion, increased predation, or exhaustion. Entrainment occurs when aquatic biota are caught in a cooling system's intake water. Entrainment can acutely and chronically affect organisms by thermal shock, pressure change, mechanical damage, or toxic chemicals added to the recirculating cooling water. Most organisms identified on Table F.1 can affected by these processes at some stage in their life cycle. Larvae of fish, crabs and clams are particularly susceptible to entrainment, whereas larger forms such as juvenile salmonids are susceptible to impingement.

Adequately designed screening equipment and proper approach velocities at the intake structure will reduce the number of organisms impinged or entrained. Locating intakes away from migratory routes or holding areas of important species will also help reduce these impacts. The use of subsurface water sources, like Ranney wells, would eliminate impingement and entrainment of fresh-water and marine organisms.

Streamflow Reduction

Withdrawal of water in sufficient amounts from streams can also alter flow patterns and reduce aquatic habitat downstream. Process water discharged to the same body of water may partially compensate for withdrawals.

PROCESS WATER DISCHARGES

The characteristics of the intake water are altered during passage through the plant. Changes include increases in temperature, and addition of potentially toxic chemicals and corrosion products from the cooling water system. Depending on the temperature and chemical composition of the process water discharges, organisms may be attracted to the vicinity of the discharge structure, thus increasing the mortality of organisms, or causing long-term changes in the aquatic ecosystem.

Thermal Shock

Warm water discharges may attract aquatic organisms to the vicinity of the outfall. This attraction may interfere with normal behavior patterns (migration, feeding, etc.). Of particular concern in Alaska would be a situation in which marine organisms are attracted and become acclimated to a heated discharge with the potential for flow reduction or interruption. The resulting rapid change to ambient levels can result in severe thermal shock that can be lethal. Fish can also be entrained in the mixing zone of a power plant's effluent, and if this effluent is hot enough, the fish can experience thermal shock. Heated effluents may also alter community structure and rate of species succession, depending upon the respective temperatures and flows of the effluent and receiving water.

Chemical Changes in the Process Water

The chemical composition of the intake water is altered during its passage through the power plant. Changes in the composition generally depend on the specific steam cycle and the power plant's capacity (see Appendix D), but general alterations that occur in most plants are as follows: 1) addition of chemicals (e.g., chlorine) to control biological fouling and deposition of materials on cooling system components; 2) concentration of impurities in the intake water during cooling system recirculation; and 3) incorporation of corrosion products from structural components of the cooling system. Other characteristic effects of certain steam cycles include lowered pH, increased biochemical oxygen demand, and discharge of radionuclides (nuclear facilities) and petroleum products.

One of these changes, such as the addition of heavy metals and radionuclides, could have negative effects far from the site of their initial discharge, whereas others like low pH and increased BOD will have the greatest impact close to the discharge. Some constituents would have less impact on marine systems than on fresh-water systems due to the buffering and chemical complexing capacity of saline waters. High concentrations of dissolved solids, which occur to some extent in most power plants but can be especially high in geothermal plants, would have little effect on the marine environment, which already posseses much higher concentrations of dissolved solids than fresh water. Most other changes could have negative effects on both the marine and fresh-water environment, but the marine environment's much larger volume diminishes the probability of adverse effect because of dilution.

Proper siting, design, and location of discharge structures, discharge pretreatment (e.g., dechlorination with sulfur dioxide), use of cooling towers or other heat dissipating systems, and cooling system optimization can reduce or minimize effects from process water discharges. Also, siting on large receiving water systems (e.g., the Copper or Susitna River, Cook Inlet) will reduce impacts. Futhermore, if an area is highly sensitive, a "zero discharge" system design can be implemented.

ACID RAINFALL

Emissions of SO_x may occur from combustion of fuels such as many coals and petroleum products containing sulfur. These emissions may result in the production of acid rainfall. This production can cuase significant changes in the pH level of receiving water bodies, which, if severe, can reduce or eliminate certain species. The severity depends on the amount of acid rain, the size and buffering capacity of the receiving water, the chemical composition of the soil, and the sensitivity of the aquatic organisms to pH change. Acid rain would not affect the marine environment because of its great buffering capacity. Most fresh-water systems in the Railbelt region appear well buffered (see Table D.4, Appendix D) and significant detrimental impacts would not be expected. Generally, the potential for production of acid rainfall depends upon plant size, sulfur contact of the fuel, SO_x control systems and meteorological patterns. SO_x emissions can be reduced by incorporating SO_x control facilities and selecting low sulfur control fuel. Alaskan coals are of very low sulfur content (∿0.25%).

APPENDIX G

TERRESTRIAL ECOLOGY IMPACTS FROM STEAM-CYCLE POWER PLANTS

APPENDIX G

TERRESTRIAL ECOLOGY IMPACTS FROM STEAM-CYCLE POWER PLANTS

Impacts on terrestrial biota resulting from steam-cycle power plants will vary according to the type, size, and location of a specific plant. Plants requiring large land areas in remote or sensitive locations will generally exert the greatest impacts on vegetation and animals. Most impacts, however, can usually be minimized through careful power plant siting.

In general, habitat loss represents the most significant impact on wildlife. Other terrestrial impacts include those resulting from air emissions, fuel and waste storage areas, and human intrusions. Approximate land area requirements for various types of steam-cycle facilities are compared in Table G.1.

TABLE G.1. Approximate Land Requirements of Steam-Cycle Power Plants

Steam-Cycle Power Plants	Electrical Generating Capacity (MW)	Land Area (acres) (all facilities)	Land Area Per Unit Capacity (acres)
Natural-Gas-Fired	20 to 600	8 to 670	0.4-1.1
Biomass-Fired	5 to 60	10 to 50	0.8-2.0
Natural-Gas-Fired	10 to 200	3 to 13	0.3
Distillate-Fired	10 to 200	4 to 20	0.4
Nuclear	800 to 1,200	100 to 150	0.1
Geothermal	10	5 (excluding wells)	0.5

HABITAT LOSS

While any steam-cycle facility will cause a reduction or alteration of habitat, the most significant impacts typically result from coal, biomass, and nuclear plants because these technologies generally require the largest land areas for development. In the Railbelt region, probable watersheds suitable for development of steam-cycle facilities contain seasonal ranges of moose, caribou, brown and black bear, mountain goat, and Dall sheep (Table G.2). Disturbance of these range areas will lower the carrying capacity of the land to support these species. Moreover, power plant development, if in remote areas, can adversely affect certain wildlife sensitive to disturbance, such as Dall sheep and brown bear. Wildlife impacts, however, can be minimized by siting plants outside of important wildlife areas. This form of mitigation will be most difficult to accomplish with geothermal plants and, in some cases, with biomass and coal-fired plants, which may need to be sited at the fuel resource sites to be economically viable.

AIR EMISSION EFFECTS

The release of toxic chemicals into the air can negatively affect vegetation and, subsequently, wildlife. Sulfur and nitrogen oxides (SO_x and NO_x) are the major gaseous pollutants; of these, SO_2 has the greatest potential for affecting the terrestrial biota. The mechanism of SO_2 injury to plants is largely physiological. Damage results when plant tissues accumulate SO_2 and produce sulfurous acids and sulfate salts faster than these compounds can be oxidized and assimilated. At this point, sulfur compound concentrations become toxic, resulting in chlorophyll destruction and cell collapse. Plants in the Railbelt region that may be sensitive to SO_2 include lichens. These plants are often an important food for wildlife, especially for caribou.

Acid rain, which can be formed from SO_x and NO_x emitted from fossil fuel and biomass plants, can further affect the terrestrial biota. This phenomenon can modify the chemical properties of soils and affect the aerial portions of plants, which intercept precipitation. Some of the impacts on soils and vegetation known to result from acid rain include the following: 1) decreased aerial growth; 2) direct injury to foliage of coniferous and deciduous trees; 3) changes in the physiology of foliar organs; 3) alteration of root functions; 5) poorer germination of seeds; 6) accelerated leaching of nutrients from foliage, humus, and soils; and 7) inhibition or stimulation of plant disease (Dvorak 1978). The degree to which soils are changed will

TABLE G.2. Possible Watersheds Associated with the Development of Steam-Cycle Power Plants in the Railbelt Region and Prominent Wildlife Found at These Locations

Energy Technology Species	Watershed: Cook Inlet	Prince William Sound	Susitna River	Matanuska River	Copper River	Gulkana River	Tanana River	Nenana River	Chena River
Energy Technology									
Coal-Fired	X[a]	X	X	X	X	X	--	X	--
Oil-Fired	X	X	X	X	--	--	--	--	--
Gas-Fired	X	X	X	X	--	--	--	--	--
Biomass-Fired	X	X	X	X	--	--	--	--	--
Nuclear	X	X	X	X	--	--	X	X	--
Geothermal	X	--	X	--	X	--	X	--	X
Species[b]									
Moose	X	X	X	X	X	X	X	X	X
Caribou	X	--	X	X	X	X	--	X	--
Bison	--	--	--	--	X	--	--	--	--
Mountain Goat	--	X	--	X	X	--	--	--	--
Dall Sheep	--	--	X	X	X	--	--	X	--
Black Bear	X	X	X	--	X	--	--	--	--
Grizzly/ Brown Bear	--	X	--	--	X	--	--	X	--
Sitka Deer	--	X	--	--	X	--	--	--	--
Marine Mammal	X	X	X	--	X	--	--	--	--
Waterfowl	X	X	X	X	X	X	X	X	X
Colonial Nesting Birds	X	--	--	--	--	--	--	--	--

(a) X signifies potential power plant development and wildlife species/group present.
(b) Wildlife information was taken from Alaska Regional Profiles 1974. (Selkregg 1974)

vary with the buffering capacity of the soils. Impacts on wildlife will largely be indirect and result from modification of habitat.

In addition to gaseous emissions, particles and associated toxic trace elements may affect soils, plants, and wildlife. In steam-cycle plants, these substances are released in stack emissions and cooling tower drift. While mitigative measures are generally employed, small particles (<1 μm) are difficult to control. Small particles can cause greater impacts on soils, plants, and wildlife than larger particles because they contain a greater fraction of potentially toxic trace elements (e.g., mercury, selenium, arsenic, bromine, chlorine, fluorine and others) in a state more readily available for chemical interaction (Dvorak 1978).

Trace elements will primarily enter the soil through direct deposition, plant litter decomposition, and the washing of particles from plant materials and other surfaces by precipitation. The impacts of these elements on soils are difficult to predict, but soils already at the tolerance limits of existing trace element concentrations will generally experience more severe effects. Conversely, soils deficient in various trace elements (i.e., copper, molybdenum, boron, zinc, and manganese) may benefit from their addition.

Particles and trace elements can also affect plants through direct injury to aerial plant parts and through material uptake and accumulation. Stomates (small openings in leaf surfaces used for gas exchange) may be blocked by particles, which can interfere with the diffusion of CO_2, O_2, and water vapor between the leaf air spaces and air. In addition, particles may adversely affect plant absorption and reflectance of incident solar radiation. Plant uptake of trace elements may result in reduced growth rate since many trace elements affect various metabolic processes and enzymatic reactions, such as photosynthesis and respiration. Trace element uptake will vary with plant species, element, and many environmental conditions.

EFFECTS OF FUEL AND WASTE PRODUCT STORAGE

Storage of fuel and waste products from steam-cycle plants can have potentially important impacts on terrestrial biota. Uncontrolled runoff from these materials can be toxic to soils and vegetation. Spoil piles and fuel piles require large land areas, which result in the loss of vegetation and wildlife habitat. Wildlife use of waste ponds as drinking water sources can also have adverse effects if concentrations of various elements reach toxic limits. Windblown dust from storage piles, if deposited on vegetation, may block leaf stomates, which may lower photosynthetic rates and may provide a pathway for ingestion of particles by herbivores. Exposure of vegetation to dust over long time periods could change vegetation community structure. These impacts, however, can be minimized in the Railbelt region by designing storage facilities to prevent runoff, seepage, dust, and access by wildlife.

HUMAN INTRUSION EFFECTS

Wildlife populations can be adversely affected by increased human activity resulting from power plant construction and operation. Wildlife populations in areas adjacent to power plant sites or access roads may be subjected to greater hunting pressure, poaching, road kills, and other forms of human disturbance. This situation may be particularly severe for power plants located in isolated areas. Wildlife populations in these areas are not only more sensitive to disturbance but also more vulnerable to exploitation. Of the various types of steam-cycle plants, human disturbance is probably greatest with geothermal plants because these are more likely to be sited in isolated locations near their fuel sources. Power plants sited in remote areas may require many miles of new road construction resulting in an even greater loss of habitat.

Noise associated with power plant construction and operation is a by-product of human intrusion; however, the severity of this disturbance is uncertain. Potential impacts from noise can be related to hearing loss and stress in animals. Noise can also interfere with the auditory cues for communication among certain wildlife. Auditory cues can include those for territorial defense, mate attraction, alarm calls, and nesting behavior of passerine birds. Stress on wildlife will be largely physiological. Terrestrial impacts from noise in the Railbelt region can largely be avoided through installation of proper noise suppression equipment at the power plants.

COLLISION EFFECTS

Another wildlife impact results from birds colliding with the cooling towers for waste heat rejection systems. The significance of this impact is highly dependent on cooling tower design and location in relation to daily and seasonal migratory routes. Locations subject to frequent fogging may also increase the severity of this impact. Bird collision, however, can be mitigated through proper siting. In the Railbelt region, major migratory bird corridors occur within the Susitna, Copper, Nenana, and Gulkana River Basins, as well as throughout Cook Inlet and Prince William Sound.

APPENDIX H

SOCIOECONOMIC IMPACTS FROM ENERGY DEVELOPMENT IN THE RAILBELT REGION

APPENDIX H

SOCIOECONOMIC IMPACTS FROM ENERGY DEVELOPMENT IN THE RAILBELT REGION

Two types of decisions made during the energy development process will result in community and regional impacts in the Railbelt region. First, the decision to site a facility at a particular location will affect the people living in that area. Secondly, the specific technology adopted for generating electric power will affect both the community and the larger region defined as the Railbelt. These decisions can result in both beneficial and adverse socioeconomic impacts. Positive impacts will include employment opportunities and revenues generated by the project, which will stimulate growth of the local economy in the short term and, in the long term will contribute to the expansion of the regional economy. Adverse impacts include the in-migration of temporary workers to a community, potentially causing a boom/bust cycle.

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

Two indicators of a boom/bust cycle have been developed. Since the permanent staff required to operate a plant is typically much smaller than the construction labor force, the population will decrease dramatically following construction. A measure of the potential for a bust, independent of community size, can be inferred from the ratio of construction to operating personnel. The probable magnitude of the boom/bust cycle can be determined by relating the size of the work force to community size. These two measures are provided for each technology in the attribute matrix.

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

COMMUNITY IMPACTS

The most pronounced impact on the community is the boom/bust cycle. The potential for a boom/bust cycle is a function of the existing population of the area and characteristics of the regional labor market. Existing population size reflects the ability of the community to meet new demands for housing, roads, and public and community services. Characteristics of the labor market include the size of the work force, skills, and unemployed persons available for work.

The 1980 Railbelt population was 284,822 and comprised 72% of the State's 400,142 residents (U.S. Bureau of Census 1981). The population of boroughs and census areas within the Railbelt is presented in Table H.1. Anchorage is the Railbelt's major population center; remaining population is distributed widely in small cities and towns among several regions including the Fairbanks North Star Borough, Kenai Peninsula Borough, Matanuska-Susistna Borough, and the Valdez-Cordova area. With the exception of Fairbanks, all communities having populations exceeding 1,000 persons are located in the Anchorage area, on the Kenai Peninsula, and along the southern coast. The rail corridor

TABLE H.1. Population of the Railbelt's Incorporated Areas (1980)

Area	Population	Percent
Anchorage	173,992	61
Fairbanks North Star Borough	53,610	19
Kenai Peninsula Borough	25,072	9
Matanuska-Susitna Borough	17,938	6
Valdez-Cordova Census Area	8,546	3
Southeast Fairbanks Census Area	5,664	2
Total	284,822	100

Source: U.S. Bureau of Census 1981.

between Wasilla and Fairbanks is characterized by a string of communities with population sizes of less than 500 persons.

The population of the southern Railbelt has expanded significantly during the 1970-1980 decade; the central and northern regions of the Railbelt have grown at a slower rate. The Matanuska-Susitna Borough, and Wasilla in particular, have seen rapid growth over the last decade. Since 1970, the population of that area has increased by 64% from 6,500 to 17,938 persons. This significant rate of growth is explained by the proximity of the southern part of the region to the Anchorage labor market. The Kenai Peninsula has also grown rapidly during the last decade (37%), as has Anchorage itself (27%).

The reason for the large increase in population in the southern portion of the Railbelt has been the expanding state economy, which has attracted people from the lower 48 states. During the 1975-79 period, employment opportunities were greatest in Anchorage, Valdez-Chitina-Whittier, and the Cordova-McCarthy areas where unemployment rates were lower than the state average. Unemployment has been higher than the state average in other areas of the Railbelt, particularly in the Matanuska-Susitna Borough, Fairbanks area, and the Kenai Peninsula.

Small communities (500-1,000 population, including North Pole and Delta Junction) and very small communities (less than 500 population) should be able to accommodate the demands for services resulting from installation of a small-scale project, but will have more difficulty in absorbing the impacts of large projects, particularly labor-intensive projects. Intermediate-sized communities with a population size ranging from 1,000 to 5,000 (Homer, Kenai, Soldotna, Seward, Palmer, Wasilla, Cordova, Valdez) would be affected by the influx of a large population (250 or more) but would be able to meet the demands created by a smaller influx, particularly if construction camps were used to reduce the need for new housing. Large communities (Fairbanks, population 22,521) and very large communities (Anchorage, population 173,992) should be able to absorb the impacts caused by an influx of a population of 500 or less, but could be significantly affected by the in-migration of a population of 1,000 or more. The magnitude of impacts from the in-migration of the work force and their dependents are summarized according to population size of communities in Table H.2.

The magnitude of the boom depends on the number of workers, their marital status, and the number of dependents who relocate to the site. The potential for a boom/bust cycle is also highly dependent on the local labor market since available labor would reduce the influx of the construction work force. Because of the relatively sparse population of the Interior, a boom/bust cycle will likely occur if a large facility is located in the northeastern region of the Railbelt. If the site is located within an approximate 50-mile radius of Fairbanks, a boom is less likely, since many workers could commute to the site from Fairbanks. The impact of project construction will also be mitigated by the Fairbanks' sizeable labor market and high unemployment rate.

A boom/bust cycle would be less probable in the Anchorage and upper Kenai areas. Labor requirements for power plant construction should be met by the Anchorage labor market and may even attract the unemployed labor pool in the upper Kenai Peninsula. In 1979 the occupational classification of craft workers, operators, and laborers represented 32% of the labor force statewide. This category includes maintenance repairers, carpenters, heavy equipment operators, and truck drivers, among other occupations. Employment in these

TABLE H.2. Magnitude of Impacts from Power Plant Construction as a Ratio of Population Increase to Community Size

Population Increase	Community Size: Very Small (~500)	Small (500-1,000)	Intermediate (1,000-5,000)	Large (Fairbanks)	Very Large (Anchorage)
1000+	Severe	Severe	Severe	Moderate	Minor
500-999	Severe	Severe	Significant	Moderate	Minor
250-499	Severe	Severe	Moderate-Significant	Moderate	Minor
100-249	Severe	Significant	Moderate-Significant	Minor	Minor
50-99	Significant	Moderate	Moderate	Minor	Minor
0-49	Moderate	Minor-Moderate	Minor	Minor	Minor

KEY:

Magnitude of Impact	Ratio of Population Increase to Community Size
Minor	0.01 or less
Moderate	0.02 - 0.10
Significant	0.11 - 0.39
Severe	0.40 or greater

occupations is predicted to increase by 3,550 per year through 1985. Most of these jobs are expected to be located in the Anchorage labor market area, where over 50% of the firms specializing in heavy construction are located (Alaska Department of Labor 1979).

Rapid growth due to power plant construction will be most dramatic in the Railbelt's interior region, which is delineated by the railroad from Wasilla to Fairbanks, the Alaska Highway from Fairbanks to Tok, and the Glenn Highway from Tok to Palmer. This vast area of the Railbelt is characterized by few and very small towns that would have difficulty in meeting the demands created by the influx of workers to construct moderate to large-scale power plants.

The local economy will grow in the long term if a population bust does not occur, which is more likely when construction periods are long and new job opportunities develop during that time. The creation of new businesses and jobs is more likely to arise in communities with a diverse economic base rather than in those with a homogeneous economic base. The size of the operating and maintenance work force, although usually substantially smaller than the construction work force, is another factor contributing to the permanent population.

REGIONAL IMPACTS

The Railbelt region as a whole should not be affected by the local boom/bust cycles resulting from power plant construction. It will, however, be affected by the project expenditures that are made within the region.

The regional economy may be stimulated by power plant construction through expenditures on equipment, supplies, and fuel, direct project employment, and through indirect employment arising from expenditures on goods and services supplied to the project. Indirect employment will result from projects requiring a large work force over a long period of time.

The degree of economic growth is a function of the capital spent in the region as opposed to necessary expenditures that must be made outside of the Railbelt. The methodology used here for estimating the flow of capital into the Railbelt for each technology is based on a standard code of accounts used to calculate power plant costs. This code of accounts has been simplified to three general categories that capture all costs associated with power plant construction. The assumptions made regarding the flow of capital for each category are presented in Table H.3. The proportion of expenditures allocated to the site improvement, equipment, and labor categories will vary with each technology and is presented in the detailed description of the individual technology.

TABLE H.3. Flow of Capital Expenditures

Category	Subcategory	Percent of Expenditures Spent Outside the Railbelt	Percent of Expenditures Spent Within the Railbelt
Site Improvements	Land Grading Foundation Concrete	15	85
Equipment	Mechancial Instrumentation Electrical Piping	100	0
Labor	Supervisory Engineering Skilled Laborers	20[(a)]	80

(a) Expenditures on labor for a nuclear power plant would be higher since highly skilled workers are required.

The extent to which project construction expenditures can be contained within the region will be largely determined by the proportion of labor, equipment, and site improvements required for each technology. Virtually all high-technology equipment, heavy machinery, and electronic components would be purchased outside of Alaska. Most construction materials, including sand and gravel aggregate, as well as tools, light machinery, and supplies, would be purchased within the Railbelt. Cement and rebar, estimated to average approximately 15% of site improvement expenditures, would be purchased outside of Alaska. Construction supervisory and engineering personnel are normally provided by the project developers, whereas skilled labor may be provided fully from the local work force. For estimation purposes, 20% of the work force was assumed to be derived from outside Alaska, whereas 80% would be Alaska residents. In compliance with Alaska State labor laws, 60% of the labor force must be Alaska residents, if they are found qualified.

Capital-intensive technologies that require a small or highly skilled labor force will have a less beneficial effect on the regional economy. Conversely, labor-intensive projects (e.g., hydropower and tidal power) have the potential to positively affect the regional economy, particularly through direct employment.

Expenditures on operation and maintenance will be less significant than the expenditures on capital and labor for project construction. Some technologies, such as combustion turbine, wind electric, solar electric, fuel cells, diesel, and hydroelectric, can be operated by a small work force on a part-time basis. The other technologies do not require a very large operating and maintenance staff. Therefore, once construction is completed, plant operation will have little effect on the regional economy through direct employment.

The allocation of operating and maintenance expenditures have been calculated for each generating technology based on a set of assumptions. One hundred percent of operating and maintenance personnel is assumed to be derived from the Alaska labor pool; 20% of supplies and other materials would originate in Alaska; and 50% of outside maintenance costs would be for the purchase of goods and services in Alaska.

APPENDIX I

WASTE HEAT REJECTION SYSTEMS

APPENDIX I

WASTE HEAT REJECTION SYSTEMS

Cooling water is required in all steam-cycle plants to condense the spent steam to obtain increased pressure differential across the turbine and to cool auxiliary system equipment such as seals, bearings, and pumps. As an order of magnitude estimate, the quantity of condenser cooling water is approximately 1 cfs/MW of capacity. Auxiliary cooling systems may require an additional 0.01 to 0.1 cfs/MW. Appendix D presents estimates of the cooling water requirements required by each of the technologies discussed in this study. In general, cooling systems can be characterized as either once-through or recirculating (closed cycle).

ONCE-THROUGH SYSTEM

In once-through system the total water requirement for the condenser is pumped from the source through the condenser and is then discharged into the receiving water body. The heat sink for this type of system is the receiving water body. In the Railbelt area, once-through cooling water systems will probably be considered only at coastal locations, if they are not precluded by environmental or regulatory constraints.

RECIRCULATING SYSTEMS

In a recirculating cooling water system the atmosphere is used as a heat sink for waste heat rejection. Several types of heat dissipation systems are available for use, including lakes, spray ponds, wet natural draft cooling towers, wet mechanical draft cooling towers, dry cooling towers and wet/dry cooling towers. Figure I.1 is a generalized schematic diagram of a recirculating waste heat rejection system.

Cooling Ponds and Lakes

A cooling pond operates similarly to once-through cooling, unless the body of water used is largely isolated from natural waters. Heat is

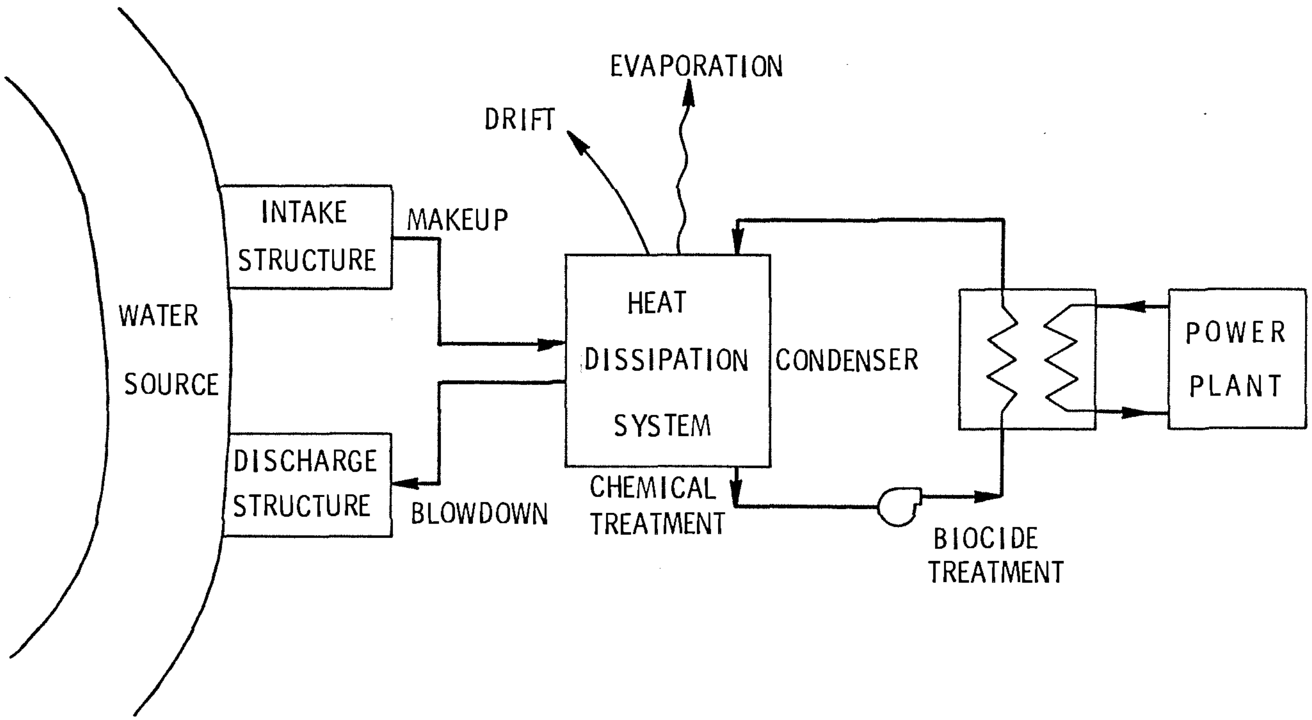

FIGURE I.1. Typical Recirculating Waste Heat Rejection System transferred from the heated water in the cooling pond by radiation, conduction and evaporation before the water is recirculated from the pond to the condenser inlet. Area requirements for dissipation of waste heat from a cooling lake or pond are about 1 to 3 acres per MWe. Water vapor rising from the surface of the pond will, in cool weather, condense to form fog. Additional land is required to eliminate the offsite effects of fog. A typical buffer zone of 1,000 to 1,500 ft is normally maintained.

During freezing conditions, fog will form layers of ice on nearby structures, roads, and other surfaces. The fog plumes also tend to be long during extremely cold conditions. The cooling pond is a proven, effective and economical heat sink in areas where sufficient level land can be purchased at reasonable cost. However, the Railbelt's cold weather will cause these localized icing conditions.

Spray Ponds and Spray Canals

Land requirements of cooling lakes can be reduced by a factor of up to 20 by sprays. As with cooling ponds, however, a buffer zone of about 1,000 to 1,500 feet is needed to confine fogging and drift effects to the site. In a spray pond, waste heat is dissipated to the atmosphere by sensible and latent (evaporative) heat transfer. The circulating water is cooled by spraying it via floating spray modules. Spray ponds are similar to cooling ponds in that their cooling effectiveness depends upon local temperature, relative humidity and wind conditions.

To maximize cooling by reducing recirculation of air between sprays and to minimize fogging, spray modules are generally placed in a long meandering canal. The efficiency and drift loss from spray modules are a function of the spray height and spray drop size, which are a function of the design of the spray pump system. At higher pressures, the drops become very fine. Although this results in high heat transfer, the finer drops can also be transported readily by the wind, causing more local fogging in cooler months.

Spray ponds could find application in the coastal, maritime climate areas of the Railbelt region. A decision regarding their use would be based upon comparative cooling efficiency cost and problems resulting from potential fogging and icing.

Cooling Towers

Two basic types of cooling towers exist: the wet tower that carries away heat by evaporation and sensible heat transfer, and the dry tower that relies on sensible heat transfer alone and, in principle, functions like an automobile radiator.

Wet Cooling Towers

In wet cooling towers, about 75% of the average annual heat transfer is due to evaporation, and 25% due to sensible heat transfer. The fraction due to evaporation varies with weather conditions; values of 60% in winter and 90% in summer are typical.

Makeup water is provided to wet cooling towers both to replenish water lost through evaporation and drift and to compensate for water lost through system blowdown. Periodic or continuous system blowdown is required to control the concentration of dissolved solids in the recirculating cooling water. As evaporation occurs, the natural salts in the cooling water become concentrated. To prevent buildup and deposition on the components of the system, those salts are continuously returned to the source of cooling water supply as blowdown or are recycled to other water uses within the plant.

Wet cooling towers can be designed as counterflow or crossflow towers. Counterflow towers maximize the air-water heat transfer time, thereby resulting in a thermally more efficient tower. Crossflow towers offer less resistance to air flow and therefore result in lower energy consumption for mechanical draft cooling towers.

The size of the cooling tower will depend upon certain design parameters, such as the cooling range (the decrease in temperature of the water passing through the tower), approach to wet-bulb temperature (difference in temperature between the water leaving the tower and the ambient wet-bulb temperature), and the amount of waste heat to be dissipated. Typically, evaporation of one pound of water will transfer about 1,000 Btus to the atmosphere. Wet towers may be of natural draft or mechanical draft design.

Natural Draft Cooling Towers

A wet, natural draft cooling tower consists of the familiar large reinforced concrete chimney (Figure I.2) that induces an upward flow of air through the falling drops of the water to be cooled. The chimney, or shell, is hyperbolic in shape to decrease resistance to air flow. The shell is characteristically built to heights of 400 to 600 feet. The condenser cooling water is sprayed into baffles, or fill material, in the lower part of the tower, where the water is cooled by evaporative and conductive heat transfer

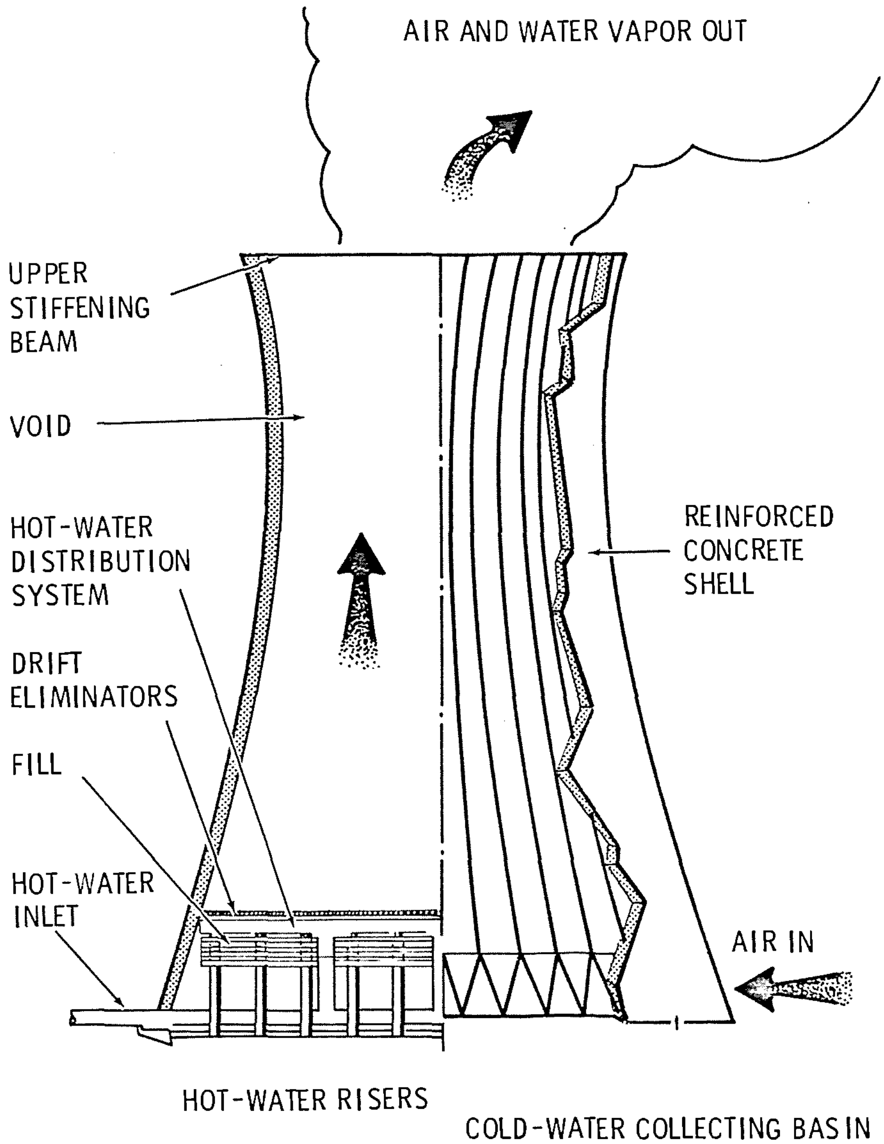

FIGURE I.2. A Natural Draft Cooling Tower to the air. The differential density between the heated air inside the tower and the air outside creates the natural draft; the warm, vapor-laden plume will usually continue to rise for some distance after leaving the top of the tower because of its momentum and buoyancy.

Natural draft towers have several advantages over mechanical draft units: operating costs are lower since fans are not needed to move the air, noise levels are relatively low, and the discharge height above the terrain greatly reduces the possibilities of ground-level drift deposition, fogs, and icing problems. Major disadvantages include relatively high capital costs and aesthetic intrusion, since the large structures and visible plumes tend to dominate the surroundings. The aesthetic impact of the plume is reduced in normally cloudy areas, such as the coastal areas, because the plume tends to blend into the background cloud cover.

Natural draft towers tend to operate most effectively in cool, humid climates, however. A relatively new design, the fan-assisted natural draft cooling tower, uses fans to assist the natural airflow, increasing the efficiency of heat dissipation. The cost of operation and construction is somewhat higher for this design. Drift rates are slightly higher with the fan-assisted systems, but the potential for downwash, fogging, and icing is the same as that for other natural draft systems. Natural draft towers could operate efficiently in the Railbelt region, although unacceptable fogging or icing problems may result.

Mechanical Draft Cooling Towers

In mechanical draft towers, fans are used to pull air through the fill section. Mechanical draft towers are typically of modular construction. Figure I.3 shows a cross section of a typical cell. The cells may be arranged in rows or in circular configuration.

Mechanical draft towers have been used for several decades for power plant cooling and are proven, reliable, and economical heat sinks. They have several advantages when compared to natural draft units, including lower capital costs, greater flexibility, greater control of cold-water temperature, and less visual impact because of the structure's lower profile. However,

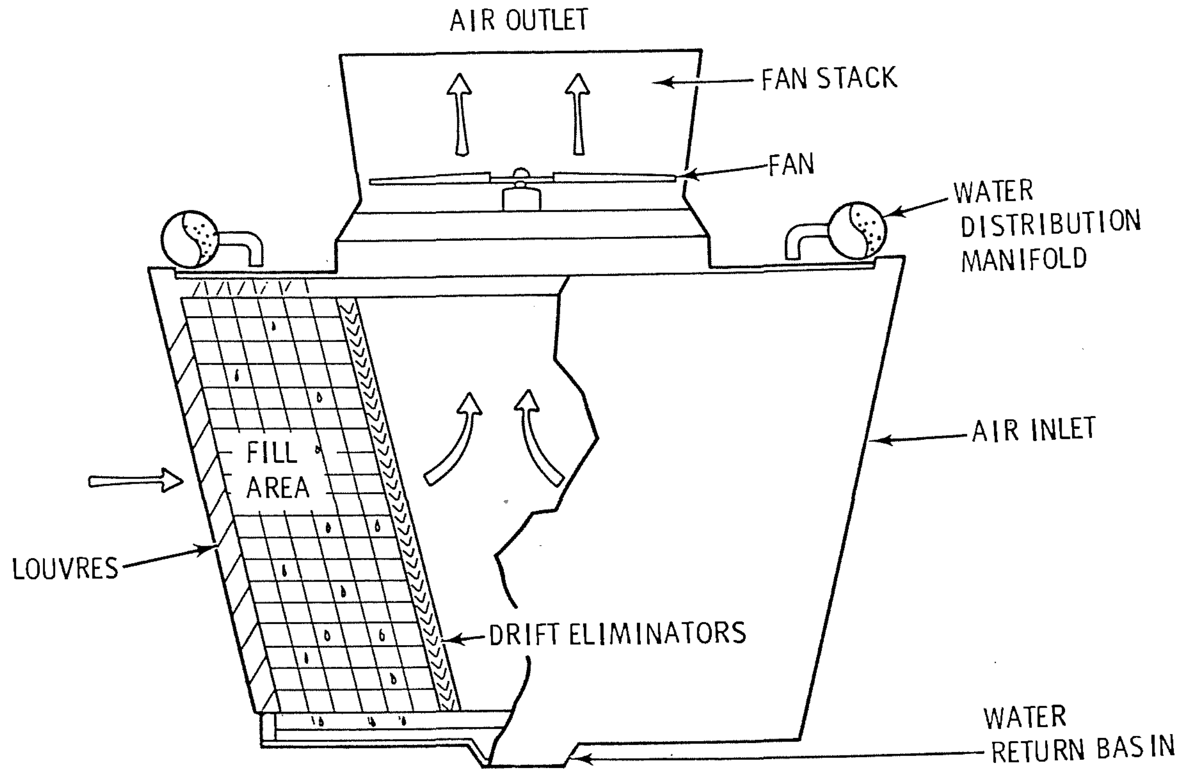

FIGURE I.3. Mechanical-Draft Wet Cooling Tower (Cross Flow)

the mechanical draft cooling towers have more potential for ground-level fogging and icing than the natural draft units. This phenomenon is caused by the relatively low discharge elevation for the water vapor from the mechanical draft towers, with aerodynamic downwash being the primary cause of fogging at such towers. Experience indicates that the fog either evaporates or lifts to become stratus clouds within about 1,500 ft of the towers. Drift rates from such towers are somewhat higher than for natural draft units; however, almost all of the drift that strikes the ground will do so within 1,000 ft or so of the towers. The remaining drift droplets will evaporate and their salts will remain airborne. Circular configurations tend to have reduced downwash, fogging, and icing because of the concentrated buoyancy of the multiple plumes from individual cells.

The formation of ice fog from mechanical draft units places a severe restriction on their use in cold environments, including the entire Railbelt region. The effects of ice fog formation and icing can be mitigated by creating a large buffer zone around the cooling towers or by siting them in insensitive areas.

Dry Cooling Towers

Dry cooling towers remove heat from the circulating cooling water through conduction to air circulated past heat exchanger tubes. In contrast to wet towers, direct contact does not occur between the circulating cooling water and the ambient air. The heat exchanger tubes are generally finned to increase the heat-transfer area. The lowest temperature that a dry cooling system can theoretically achieve is the dry-bulb temperature of the air. The dry-bulb temperature is always higher than (or equal to) the wet-bulb temperature, which is the lowest temperature that a wet cooling tower theoretically can achieve. Thus, cooling water returning to the turbine condenser will generally be at a somewhat higher temperature for dry cooling towers than for comparable wet towers. Warmer condenser cooling water will increase turbine back pressures, resulting in reduced station capacity for a given size generating facility.

A major advantage of a dry cooling tower system is its ability to function without large quantities of cooling water. This ability allows power plant siting in areas of restricted water availability. Other advantages, compared to wet cooling towers, include elimination of drift, elimination of fogging and icing problems, and elimination of thermal and changing pollution from blowdown. Thus, dry cooling towers present an environmental advantage over the wet system for the Railbelt region.

The environmental effects of heat releases from dry cooling towers have not yet been quantified. Some air pollution may be encountered. Noise generation for mechanical draft dry towers will be more severe than that of wet cooling towers because of increased air flow requirements. And, the aesthetic impact of natural-draft dry towers, which are taller than natural-draft wet towers, will increase despite the absence of a visible plume.

The principal disadvantage of dry cooling towers is economic: for a given plant size, plant capacity can be expected to decrease by about 5 to 15%, depending on ambient temperatures and assuming an optimized turbine design. Bus-bar energy costs for a dry cooling system are expected to be about 20% more than a once-through system and 15% more than a wet cooling tower system. Dry cooling towers are now being used for European and African steam-cycle plants of 200 MW or smaller capacities in areas of cool climates and winter peak loads.

Wet-Dry Mechanical Draft Cooling Towers

In this combination tower, a dry cooling section is combined with a conventional evaporative cooling tower. Most design concepts and all operating units are of the mechanical draft type, although a wet-dry natural draft tower is feasible. The design is an attempt to combine some of the best features of both wet and dry cooling towers. These towers cause little or no fogging in winter, less water consumption, and more economical cooling by using water evaporation.

Four basic tower designs are possible: air flow in series or parallel, and water flow in series or parallel. In the one design currently in use, the hot water first passes through the dry section of the tower and then the wet; air flow is passed through either the wet or the dry section, or both, with adjustable louvers used to control the two air flows (Figure I.4). The two air flows mix inside the tower before discharge. The discharged air has a higher temperature and a lower absolute humidity than it would have from a standard mechanical draft tower, thus reducing the potential for fogging, icing, and long plumes. The amount of reduction of fogging and plumes will depend on the relative sizes of the two cooling sections.

Wet-dry towers can be designed to operate with "dry only" cooling below a given design ambient temperature (e.g., 35°F). Such units are expected to operate as "wet only" units in summer. Thus, water would be conserved only in cool seasons.

Since more cooling surface is required for a dry section than for a wet section of equal cooling capacity and since excess surface may be required to achieve operating flexibility, wet-dry mechanical draft cooling towers would be larger than pure wet towers and more costly to build and operate than either natural draft or mechanical draft units.

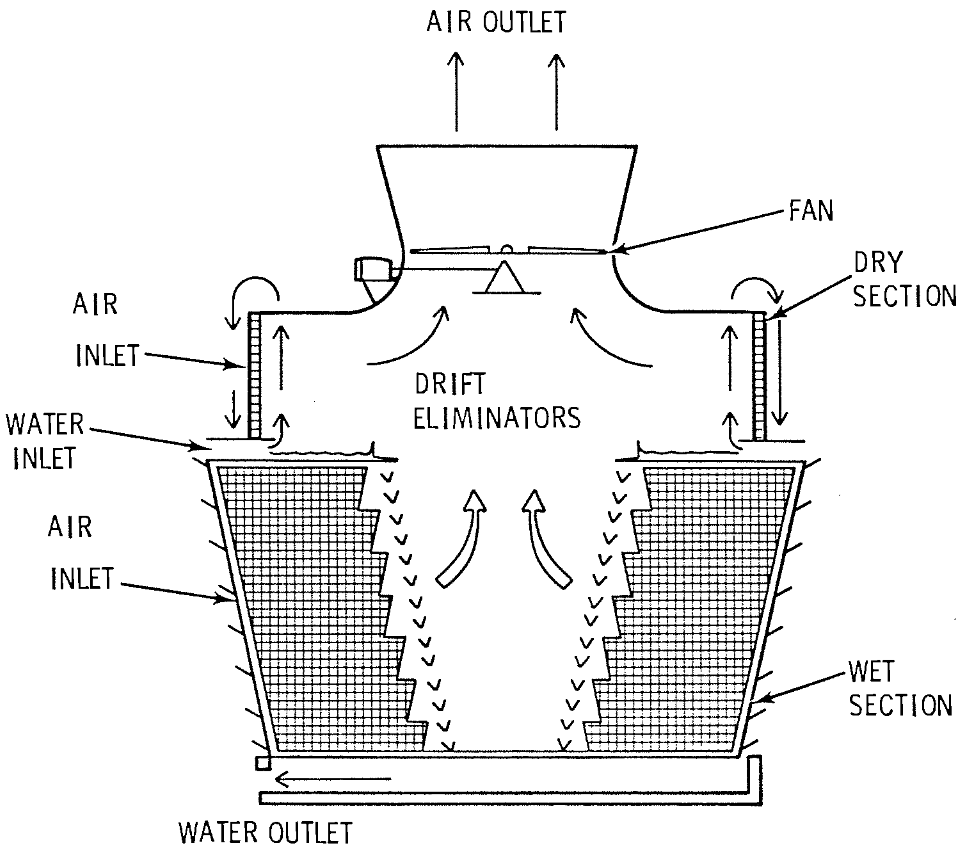

FIGURE I.4. Mechanical Draft Wet-Dry Cooling Tower

Wet-dry mechanical draft cooling can be of great advantage to plants in geographical locations where the contribution of cooling tower moisture to the atmosphere could increase the occurrence of fog or icing to an unacceptable degree. The potential for fogging and icing conditions exists throughout the Railbelt region. The wet/dry cooling towers therefore represent the preferred waste heat rejecting system alternative from an environmental point of view.

APPENDIX J

AESTHETIC CONSIDERATIONS

APPENDIX J

AESTHETIC CONSIDERATIONS

In this appendix methodologies for assessing aesthetic considerations, specifically visual, noise, and odor impacts, are presented. The objective of these methodologies is to provide a comparison of the typical aesthetic impacts of the candidate electric energy technologies. At this level of study the magnitude of aesthetic impacts from the candidate electrical generating technologies are discussed, assessed, and summarized in the sections below.

VISUAL

The study of visual considerations involves a three-step process: an assessment of the present visual quality of a study area, a determination of the viewer's sensitivity to modification of the landscape, and an assessment of the visual impacts caused by the construction of a power plant. Several methodologies can be used to conduct a visual impact study. The primary objective of these methodologies is to translate concerns that are often subjective into a common basis for a systematic evaluation.

The first phase involves a definition of the study area as well as visual units within the study area. The inventory of the visual quality of the study area can be completed through the analysis of topographic maps, a series of ground and air observations, and photographs of the site. The landscape components should be defined, including both manmade and natural features. A description of the landscape components that define the characteristics of each visual unit should include boundary definition, general form, terrain pattern, distinctive visual features, vegetation patterns, water presence, and cultural and land-use patterns. Dominant factors, such as form, line, color, and texture, should be used as a basis for description. Visual quality criteria should be developed to assess the baseline characteristics of the study area.

In the second phase, the existing landscape units that are most sensitive to change are identified. The visual sensitivity related to the landscape components is caused by the way change is exposed to the viewer. Criteria are generally developed to assess visual sensitivity and may include viewing distance, viewer location, and viewing frequency. The visual quality of each landscape unit is then evaluated with attention paid to areas that are vulnerable to any manmade changes.

The third phase involves identification of the project elements that cause impacts and their effect on viewers. The various attitudes and values of the individual viewers are taken into account as well as differences in the location and duration of the view. Project elements may include site preparation activities as well as the physical features of the power plant. The effect of the project on viewers can be determined by mapping the areas from which the power plant and associated project elements can be viewed and by evaluating these areas' vulnerability to visual change.

Assessment of how a project element visually affects the viewers is based on the evaluation of whether a project element either conforms to or disrupts the visual qualities of a landscape unit. The assessment addresses whether the power plant elements visually contrast or complement the environment, dominate or are consistent with the visual perceptions of the viewers, and degrade or enhance the setting.

Assessing visual impacts in the manner described above is not feasible at the level of candidate electric energy technologies because visual impacts from a power plant are site dependent. The impacts will be a function of plant scale, components, dimension of the components, acreage requirements, terrain, and land use in the vicinity of the site. Structural components that should be assessed for visual impact include the plant and related facilities, fuel storage facilities, and water intake facilities. Ancillary components that apply to all technologies are transmission lines and substations. Visual considerations of the candidate electric energy technologies are summarized in Table J.1. A comparison of visual impacts among these technologies can be made to some extent without knowledge of the site, but a detailed visual impact assessment can be made only once the plant scale and site are known.

TABLE J.1. Visual Considerations for Assessment of Power Plant Impacts

Technology	Visual Concerns
Coal	Large land requirements; landscape dominated by gray and black tones; components that may visually alter the landscape include stacks, cooling towers, coal stockpiles, boiler plant, ash pond, coal storage area and fuel handling system and ash slurry pipelines. Cooling tower and stack plumes may disrupt visibility and be visually offensive.
Oil and Natural Gas	Relatively clean technology with small land requirements; components that may be obtrusive include stacks, cooling towers, and boiler plant. Cooling tower plumes may disrupt visibility and be visually offensive.
Biomass	Powerplant components that may affect the visual quality of the landscape include stacks, cooling towers, and fuel storage area. Cooling tower plumes may disrupt visibility and be visually offensive.
Geothermal	Land-intensive technology with dispersed wells; visually intrusive components include extensive piping system, boiler plant and cooling towers. Large quantity of escaping steam and cooling tower plumes may impair visibility and be visually offensive.
Nuclear	Large land requirements; landscape may be dominated by tall cooling towers and reactor building. Cooling tower plumes may disrupt visibility and be visually offensive.
Combustion Turbine	Small land requirements; compact facility; low stacks.
Combined Cycle	Visual impact on landscape varies with plant scale; scene may be dominated by cooling tower and stack. Cooling tower plumes may disrupt visibility and be visually offensive.
Diesel	Small land requirements; small units; few support facilities.
Fuel Cells	Visual impact on landscape varies with scale; compact facility.
Hydroelectric	Altered waterscape; large land requirements; effects of drawdown can be visually significant.
Pumped Storage	Altered waterscape; large land requirements; effects of drawdown can be visually significant.
Cogeneration	Visual impacts generally minimal since industrial setting is required.
Tidal	Introduction of linear manmade structure into seascape. Altered wave pattern.
Wind	Large land requirements for wind farms; height of turbine may form silhouettes against the sky.
Solar Thermal	Large land requirements; field of tracking mirrors may impair visibility.

Based on the visual concerns of each technology, offsite impacts will be significant for coal-fired steam-electric, geothermal, nuclear, pumped storage, solar, large-scale hydroelectric and tidal, and wind farms (Table J.2). Visual impacts can be mitigated or avoided by siting power plants in less visually attractive areas and through screening and camouflaging measures.

NOISE

Noise impacts are assessed by collecting baseline noise level data, by identifying potential sources of noise impacts, by predicting noise levels, and by determining the incremental noise levels due to plant construction and operation. Although the methodology described below cannot be used at this level of study, it contains the significant elements that should be identified in a generic assessment of noise impacts.

Baseline data of ambient noise levels are generally collected throughout one year to account for seasonal variation. In addition, data are collected throughout the day to determine day/night average sound levels. Isolines are drawn to indicate the decibel levels at various distances. Other data that are collected from the survey include wind speed, temperature, and relative humidity because they also affect noise levels.

Potential sources of noise impacts from power plants are then identified, including preconstruction, construction, and operating activities. Noise predictions are generally based on models that calculate the transmission of sound from project sources to various receptors. The noise levels of equipment and plant operations are determined in a controlled environment without wind attenuation or topographical shieldings.

Noise impact criteria are estabished based on the objectives of protecting people from hearing loss and from negative health and welfare effects. The Occupational Health and Safety Act (OSHA) regulates onsite sources of noise to protect personnel. Offsite noise, which is regulated through the Noise Control Act, can affect residences, commercial activities, wildlife habitats, and domesticated animals. Maximum noise levels that are established for various categories of land uses should be considered in the siting and plant design processes.

TABLE J.2. Magnitude of Off-Site Aesthetic Impacts from Power Plant Construction

Technology	Visual	Noise	Odor
Coal			
(20 MW)	Moderate	Minor	Minor
(200 MW)	Significant	Moderate	Minor
Oil and Natural Gas			
(10 MW)	Minor	Minor	Minor
(200 MW)	Significant	Moderate	Minor
Biomass			
(25 MW)	Moderate	Minor	Significant (Municipal Waste)
Geothermal			
(50 MW)	Significant	Moderate to Significant	Significant
Nuclear			
(1000 MW)	Significant	Minor	Minor
Combustion Turbine			
(70 MW)	Minor	Moderate to Significant	Minor
Combined Cycle			
(200 MW)	Moderate	Minor to Significant	Minor
Diesel			
(50 KW)	Minor	Minor to Significant	Minor
(15 MW)	Minor	Minor to Significant	Minor
Fuel Cells			
(10 MW)	Minor	Minor	Minor
Hydroelectric			
(2.5 MW)	Moderate to Significant	Minor	Minor
Pumped-Storage			
(100 MW)	Significant	Minor	Minor
Cogeneration			
(25 MW)	Minor to Moderate	Minor	Minor
Tidal			
(N/A)[a]	Moderate to Significant	Minor	Minor
Wind			
(2 MW)	Minor	Minor	Minor
(100 MW)	Significant	Moderate	Minor
Solar			
(10 MW)	Significant	Minor	Minor

(a) Rated capacity will not alter basic design.

An increase in noise levels due to power plant construction and operation is calculated at various receptor areas. The noise levels of the various power plant components are evaluated for their cumulative impact. Mitigation measures should be identified as well as noise sources that are difficult to mitigate. Receptors and noise levels are then identified.

At this level of study, site-specific impacts cannot be addressed. Noise impacts will be a function of plant scale, fuel transportation requirements, fuel type, terrain, wind conditions, and land use in the vicinity of the site. Generally, the impacts of noise-producing technologies can be mitigated by siting the power plant in an area away from receptors, enclosing the equipment in structures, and installing mufflers on the turbine-generator set.

The noise impacts of most technologies can be either mitigated or confined to the site. Impacts of certain technologies, however, may be significant irrespective of sites. Geothermal, wind turbines (several, as in wind farms), combustion turbines, and coal-fired power plants have the potential to produce substantial noise. Noise-related impacts generally associated with each of the various technologies are summarized in Table J.2. For those facilities in which noise could be a potential problem, the vents and turbines may have to be sited well away from residential or commercial areas to comply with ambient noise regulations. Consideration should be given to keep these facilities out of narrow, sheltered valleys where wind speeds are light or vegetation is sparse.

ODOR

The study of odor impacts involves a sensory evaluation of the odor source after it has been diluted (Turk 1973). Most gases and vapors that are not one of the normal components of air are odorous in some ranges of concentration. Odors that are by-products of fuel combustion or the bacterial or thermal decomposition of organic matter are objectionable to the majority of people.

Since an odorant may be a complex mixture of many components in an extremely high dilution of air, a chemical analysis is not a sufficient measurement of odor. Noxious odors must be diluted to be evaluated by a panel of judges. Since odor is a logarithmic function of the stimulus, it is appropriate for the concentrations of the odorous substance to be distributed along an exponential scale. The substance can be appraised in terms of its quality intensity profile by a panel of judges. Odor intensity can be measured on an ordinal scale, using descriptions such as "slight," "moderate," "strong," and "extreme." The quality of an odor can be described by using specific odor quality descriptors that are represented by odor quality reference standards. The odor quality to be judged is defined in terms of a few qualities that have associations with subjective perception and chemical analysis. Each reference standard may then be expanded into a dilution scale using an odorless dilutant.

After the odorous substance has been evaluated for its quality and intensity, conditions under which the substance will be odorous or odorless are specified. This prediction can be accomplished through the collection of odor threshold data. The odor threshold is the minimum concentration of a substance that can be distinguished from odor-free air. Such predictions provide a basis for calculating the required degree of dilution by ventilation or outdoor dispersal to avoid adverse impacts.

The approach to odor control of inorganic gases such as hydrogen sulfide and organic vapors such as hydrocarbons is to reduce the odorant in concentration through diluting the odor by ventilation or dispersal, or through removing the odorant by adsorption, scrubbing, or chemical conversion to odorless, or nearly odorless, products. Dispersal and scrubbing are most widely practiced in power plant emission control technology.

When odors are dispersed from an elevated source such as a stack, the maximum concentration at ground level can be calculated as a function of the stack geometry, concentration of the odorant in the plume, the effluent temperature, and meteorological conditions. These calculations predict average concentrations over a specified time interval. Since even a short exposure to a foul odor may be unacceptable, the degree of dispersal required to reduce the odor may be considerably greater than is predicted by the calculations.

Since the dispersal of gas from a stack can be calculated theoretically, the maximum level of odor that can be emitted from a stack without causing a nuisance can be predicted. If the actual rate is higher than the calculated value, then the dispersal is increased (by raising the stack) or the concentration is decreased (by an abatement device), or both.

Offsite odor impacts from power plants are primarily a function of fuel type. Geothermal brines and municipal waste are the two major sources of odoriferous substances that cannot be mitigated easily. In a geothermal power plant, steam from leaks and pressure vents contains inorganic gases, including hydrogen sulfide. In a municipal waste-fired plant, the decay of organic matter produces putrescible substances that are not easily controlled. The impacts of these two technologies are considered to be potentially significant, whereas the odor impacts of the other technologies should be minor.

APPENDIX K

SYNTHETIC FUEL TECHNOLOGIES

APPENDIX K

SYNTHETIC FUEL TECHNOLOGIES

Many technologies described in this report operate only on liquid or gaseous hydrocarbon fuel. Among these technologies are combustion turbines, combined-cycle plants and diesel-electric plants. Other technologies, including steam-electric plants and fuel cells, will accept synthetic liquids or gases as alternative fuels and may exhibit superior economic and environmental operating characteristics using these fuels.

Because of the limited supply of natural liquid and gaseous hydrocarbons and the relative abundance of coal, increasing interest is being shown in processes that synthesize liquid or gaseous hydrocarbon fuels from coal.

The conversion of coal to gaseous and liquid hydrocarbons is not a new science. Coal gases, produced as a by-product of the coking process, were introduced to the English economy in the 18th century. These distillation gases contained about 500 to 600 Btu/ft^3 and were used for street lighting and other applications. Improvements in gasification were introduced during the 19th and early 20th century. Two general classes of gasifiers emerged: "town gas" systems, run by utilities to serve residential and commercial needs of communities; and "producer gas" systems, designed to serve the needs of industry. Liquefaction processes emerged in the 20th century. As a result of the pioneering efforts of chemists such as Friederich Berguis, Franzo Fischer, Hans Tropsch, Mathias Peer, and other notable German scientists, a range of processes and products has been developed.

The principles employed are conceptually simple, but are varied depending upon the products sought. Coal is a heterogeneous solid substance with hydrogen/carbon (H/C) ratios of about 0.5 to 0.8, depending upon rank. This contrasts with crude oil and natural gas where H/C ratios are about 1.5 and 4.0, respectively. Further, the macromolecules of coal are considerably larger than the molecules of liquid or gaseous fuels. To convert coal to gaseous or liquid fuels, then, the H/C ratio is increased by carbon removal (pyrolysis, coking), hydrogen addition (direct hydrogenation), or total reformation (indirect liquefaction through the production and reaction of synthesis gas, a mixture of CO and H_2). Simultaneously, the coal molecule is fragmented into smaller units. Whereas some of the coal conversion reactions are exothermic (heat releasing), most are endothermic (heat consuming). Fuel synthesis processes, therefore, have different thermal efficiencies depending upon the extent to which endothermic reactions are required and the degree to which waste heat produced by exothermic reactions can be recaptured.

Coal gasification systems employing these principles produce low Btu gas (100 to 150 Btu/ft^3), medium Btu gas [(250 to 350 Btu/ft^3), or high Btu gas (substitute natural gas) 900 to 1000 Btu/ft^3]. Coal liquefaction systems produce synthetic crude oils, alcohol fuels, and gasoline and diesel oil liquids. Alcohol and most vehicle fuels are currently produced by indirect liquefaction, such as the Sasol I and Sasol II plants using the Fischer-Tropsch process. These processes are described below.

SITING REQUIREMENTS

Synthetic fuel plants are, for the most part, similar to large petrochemical complexes (Table K.1). Due to the large scale of these plants, siting strongly depends upon the economic availability of the coal feedstock.

Land requirements for typical synthetic fuel plants are measured in thousands of acres (not including the coal mine). Land is required for 30 to 90 days of coal storage, for the conversion facility itself, for auxiliary facilities such as onsite power plants and cryogenic oxygen separation plants, and for product storage. The Modderfontain site in South Africa (Sasol II), for example, exceeds 12,000 acres.

If not located at mine mouth, the site must have transportation facilities for moving coal to the facility and for transporting the product from the facility. An exception to the latter requirement is low Btu gas, which must be used onsite because of the expense of transporting the low- energy-content gas.

TABLE K.1. Typical Sizes of Coal Conversion Facilities (Sliepcevich et al. 1977)

Facility Type	Daily Coal Consumption (tons)	Daily Output	
		10^6 Btu	As Product
Producer Gas (Low Btu Gas)	40 - 800+	680-12,800	4.5-85+ x 10^6 SDCF[(a)]
Substitute Natural Gas (SNG)	20,000	250,000	250 x 10^6 SDCF
Synthetic Crude Oil	20,000-22,000	330,000	50,000 bbl
Methanol	28,000	230,000	11,000 tons
Synthetic Motor Fuels (Fischer-Tropsch)	35,000	250,000	42,000 bbl

(a) Standard dry cubic foot.

The site must have access to copious quantities of water for process cooling. Water also serves as a source of hydrogen for altering the H/C ratio in the water-gas shift reaction. Table K.2 identifies water requirements as a function of end product. Water requirements for indirect liquefaction (methanol, Fischer-Tropsch) are similar to those for SNG production. Cooling water requirements are the most significant, although they can be minimized by atmospheric heat rejection systems. However, water requirements of 4 million gal/day may be considered typical values, and sites must be selected where such quantities (or more) are available.

Electricity should be available, unless onsite generation is used, as would probably be the case in the Railbelt area. Where onsite generation is used, land and water requirements will escalate accordingly.

DETAILED PROCESS DESCRIPTIONS

The most appropriate processes for synthetic fuels production in the Railbelt region include low and medium Btu gas production and liquefaction by indirect and direct means.

TABLE K.2. Water Requirements for Coal Conversion Processes

End Product	Water Requirements (gal/MM Btu) Process	Cooling	Blowdown
Low and Medium Btu Gas	2-5	20	4
Substitute Natural Gas	3-13	16	3
Synthetic Crude Oils	1-2	9	2

Source: Anderson and Tillman 1979.

Low and Medium Btu Gasification

In low Btu gasification, coal is fed into a fixed bed, entrained bed, or fluidized bed gasifier. There it is reacted with air and steam. The air is used to combust part of the coal, thus supplying heat for the endothermic pyrolysis and gasification reactions. Steam is used to drive key gasification reactions as follows:

$$C + H_2O \rightarrow H_2 + CO$$

$$2C + H_2O \rightarrow CH_4 + CO_2$$

The gas resulting from this process contains about 50% nitrogen because of the use of air and has a heating value of approximately 150 Btu/SDCF (standard dry cubic foot). The gas is "wet" and "dirty" and must be burned immediately in a boiler to preserve the gas's sensible heat.

The fundamental difference between low and medium Btu gas production is the oxidant used to generate heat for driving endothermic reactions. Medium Btu gasifiers employ cryogenically separated pure oxygen as an oxidant instead of air. Thus, nitrogen gas is not part of the product gas stream and the heating value is increased to approximately 300 Btu/SDCF. Medium Btu gas may be cleaned, cooled, and transported up to about 40 miles economically, although it is ideally used onsite. Whereas it may be burned as a fuel, it also may be used as a feedstock for producing chemicals. Figure K.1 shows a schematic of

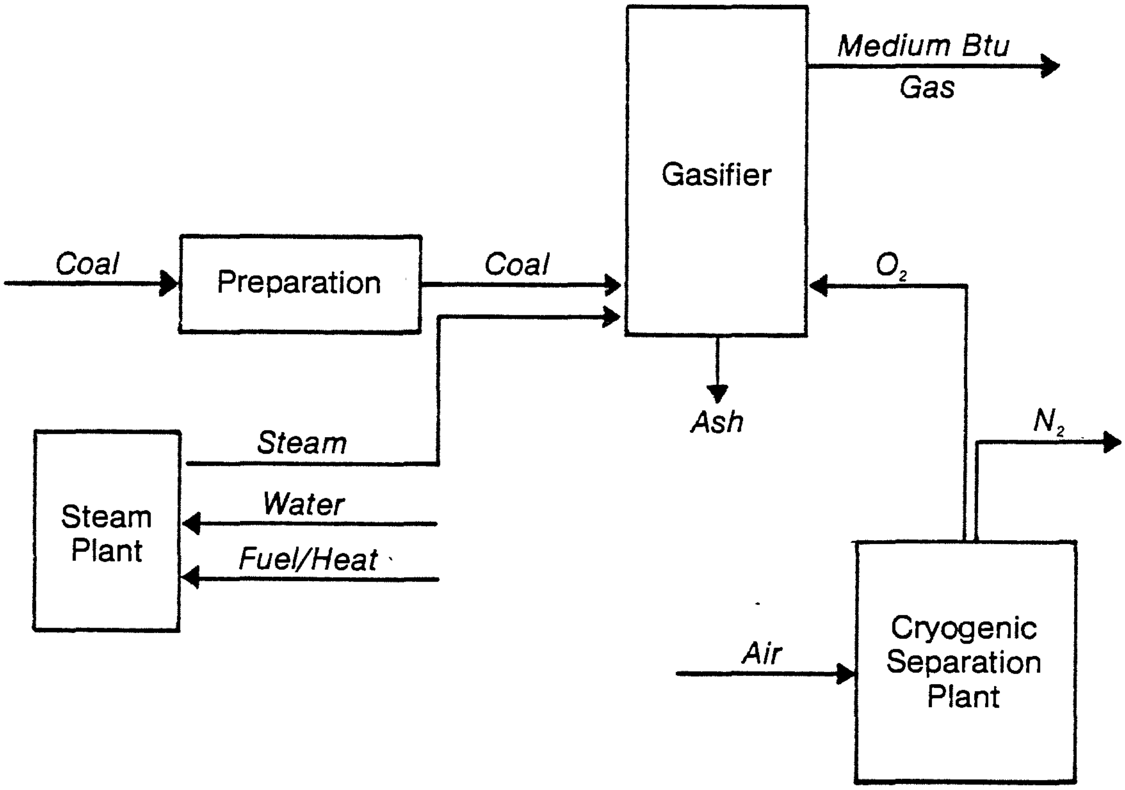

FIGURE K.1. Flowsheet of Medium Btu Gas Plant

a medium Btu gas plant. (In comparison, low Btu gasifiers do not have the oxygen plant). Table K.3 shows typical product gas composition for various gasifiers producing low and medium Btu gaseous fuels.

TABLE K.3. Product Gas Composition and Higher Heating Values from Various Coal Gasifiers

Gasifier	Product Gas Composition (Percent Volume) CO	CO_2	H_2	CH_4	N_2	Other	Higher Heating Value (Btu/SDCF)
Wellman-Galusha (Air Blown)	28.6	3.4	15.0	2.7	50.3	--	150
Lurgi (Air Blown)	13.3	13.3	19.6	5.5	48.3	--	150
Koppers-Totzek (O_2 Blown)	52.2	10.0	36.0	--	1.5	--	300
Lurgi (O_2 Blown)	16.3	31.5	39.4	9.0	2.4	0.8	350

Thermal efficiencies for gasification can be defined as the fuel value of product gas divided by total energy and fuel input (including electricity used for O_2 production). Typical values are in the 75 to 90% range, depending upon gasifier design, product type, and extent of waste heat recapture.

Liquefaction

Indirect liquefaction begins with medium Btu gas. The gas can be shifted to a volumetric H_2/CO ratio of 2:1 and reacted over a catalyst to produce methanol (CH_3OH). This process is essentially commercial today and is shown in Figure K.2. Alternatively, the Fischer-Tropsch process employed by Sasol I and Sasol II can be used to catalytically react medium Btu gas into gasoline and diesel oil. This process stems from the original work of Fischer and Tropsch in the 1920s and 1930s in Germany and is shown in Figure K.3. The thermal efficiencies of indirect liquefaction are in the 40 to 45% range depending upon the process used, final product, plant design, and coal composition.

Direct liquefaction processes (hydrogenation) treat coal under elevated temperatures and pressures with hydrogen. Catalysis may be employed to aid in fracturing the molecule and, more importantly, in donating hydrogen to the fragments. Figure K.4 shows direct hydrogenation by the solvent extraction process; Figure K.5 shows a flow sheet for catalytic hydrogenation. Products resulting from direct hydrogenation include syncrudes, boiler fuels, and naptha. Thermal efficiencies are typically in the 60 to 65% range.

Direct hydrogenation is at the pilot plant scale of development and commercialization is expected within the next 10 to 15 years. Major pilot plants under construction or in operation are shown in Table K.4. Others, such as the gasoline pilot plant in Cresap, West Virginia, and the COED Pyrolysis pilot plant in Princeton, New Jersey, have been built, operated, and decommissioned. Numerous other processes (e.g., Toscoal, University of Utah, Synthoil) are or have been under intensive, although smaller scale study.

COSTS

No major coal gasification or liquefaction plant has been built in the U.S. since World War II. Costs are typically extrapolated from experiences in

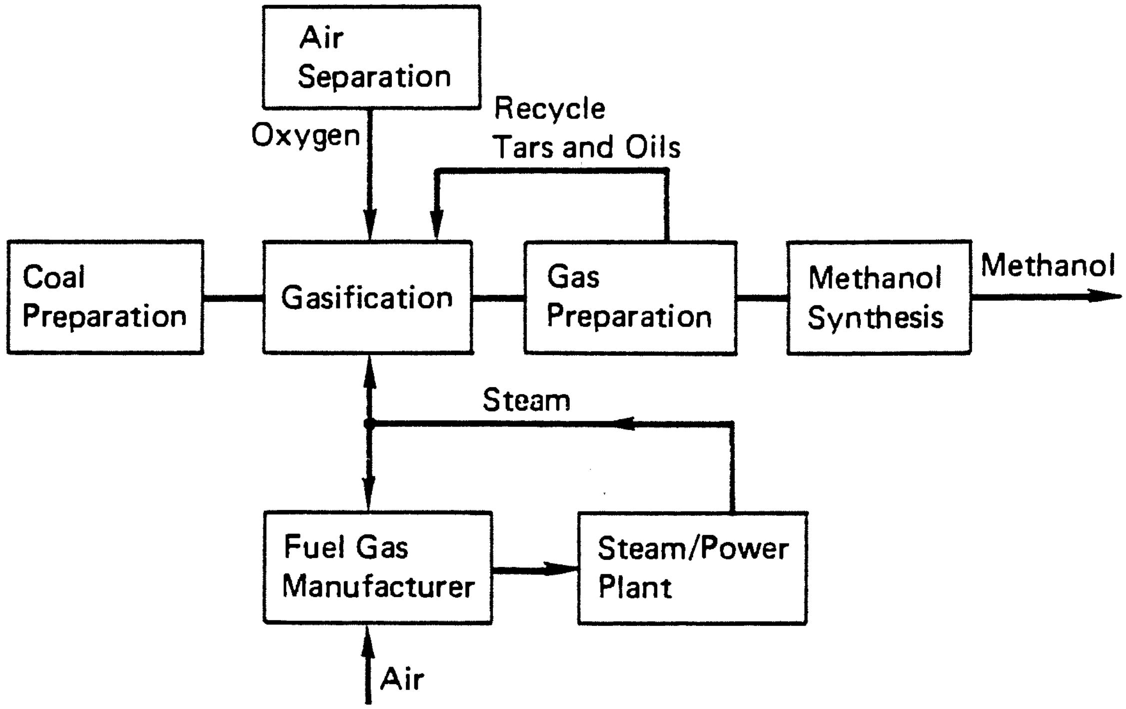

FIGURE K.2. Methanol Production Flowsheet

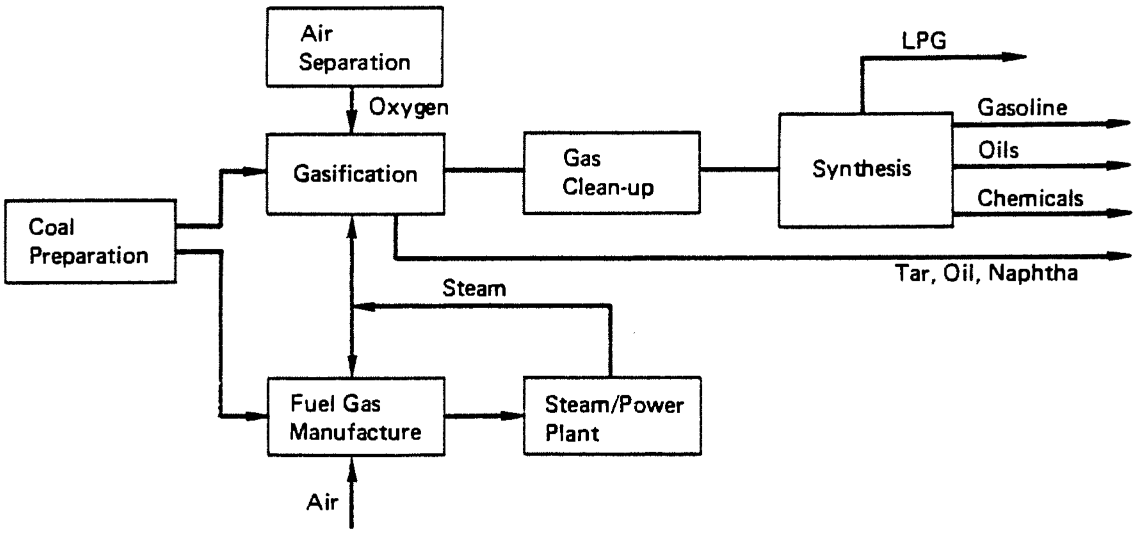

FIGURE K.3. Fischer-Tropsch Synthesis Flowsheet

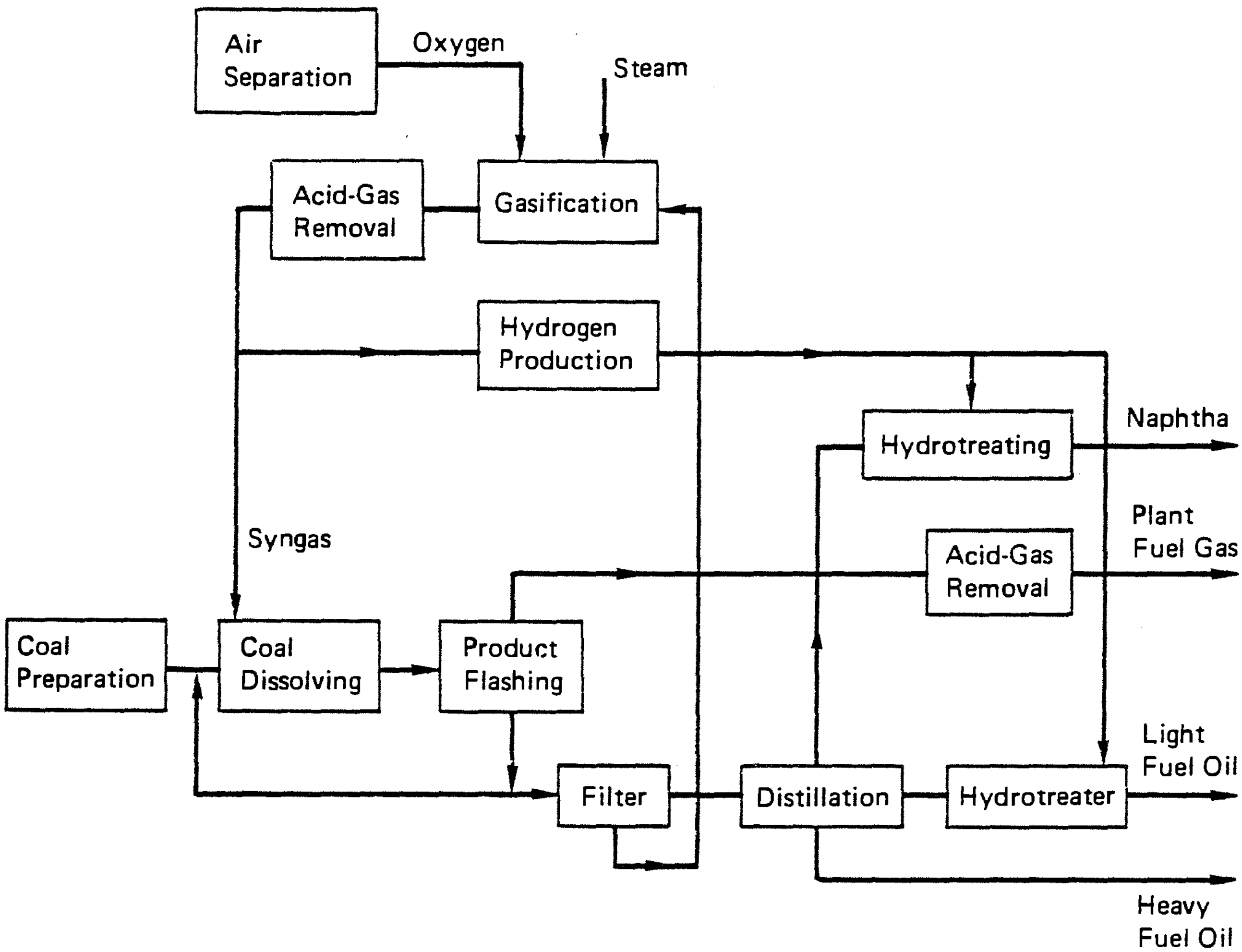

FIGURE K.4. Solvent Extraction Process Flowsheet

South Africa and other countries, and from pilot plant experiences. Costs are therefore highly uncertain. Estimated capital costs are presented in Table K.5. Total 1980 capital costs for a 50 x 10^3 bbl/day coal liquefaction plant are estimated to be approximately $1.3 billion (Tillman 1981).

Operating costs are also uncertain. For gasifiers they are totally dependent upon plant configuration and practices. For liquid fuels, such as direct hydrogenation, annual O&M costs are estimated at about $330 million (not including depreciation) for a 50,000 bbl/day refinery (Tillman 1981).

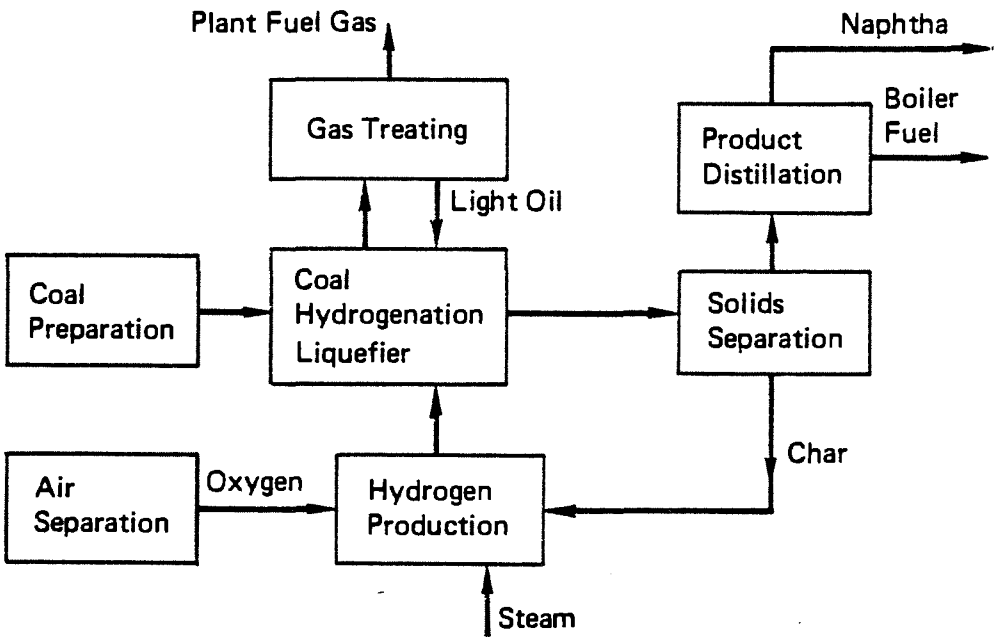

FIGURE K.5. Catalytic Hydrogenation Flowsheet

TABLE K.4. Major Coal Liquefaction Pilot Plants in the United States

Pilot Plant (Process)	Primary Industry Sponsor	Capacity (T/D)[a]
Solvent Refined Coal	Gulf Oil	50
H-Coal	Hydrocarbon Research	600
Exxon Donor Solvent	Exxon Corporation	250

(a) T/D = tons per day.

World oil prices would have to rise to $60/bbl ($10/MMBtu) for coal liquefaction processes to be economically competitive at current estimates of capital and O&M costs of liquefaction plants (Tillman 1981). This price is about double the current world price of oil. Because of higher thermal efficiencies and lower capital coal gasification's costs, it would be competitive at much lower prices. Values frequently quoted range from 5 to $6/MMBtu.

TABLE K.5. Estimated Capital Costs for Coal Conversion Facilities (1980 Dollars)[a]

Process	Capital Cost
Low Btu Gas	$250/Btu/day Capacity
Medium Btu Gas	$450/Btu/day Capacity
Methanol	$30,000-40,000/bbl/day
Fischer-Tropsch	$28,000-36,000/bbl/day
Solvent Extraction	$21,500-28,000/bbl/day
Catalytic Hydrogenation	$20,000-26,000/bbl/day

(a) These costs have not been adjusted to Alaskan conditions.
Sources: Sliepcevich et al. (1977); Anderson and Tillman (1979).

ENVIRONMENTAL CONSIDERATIONS

The principal environmental effects of synthetic fuel plants include water consumption, water-quality impacts, air emissions, and habitat disturbances.

Water Resource Effects

Synfuel processing plants may have a significant water requirement, which can restrict their location to regions of abundant water supply. The specific water requirements vary by conversion process and individual plant design, and by the extent of water recycling and the ratio of air/water cooling employed. Davis and Wood (1974) have made the following estimates for minimum water demands:

SNG production:	72 gal/MMBtu for 90% water cooling
	37 gal/MMBtu for 90% air cooling
Coal liquefaction:	31 gal/MMBtu produced as fuel.

These values compare with Davis's and Wood's estimate of 146 gal/MMBtu equivalent to electricity from fossil fuel based generating stations. As a general guideline, a minimum of 4 million gallons per day are required by a synfuel plant. This requirement could have significant impacts in regions with limited water supplies and could preclude development of a synfuel plant at water-scarce locations.

If a total requirement of 14 million gallons per day for a synfuel plant and its associated power plant, cryogenic oxygen plant, and other associated facilities is assumed, a plant location in the Beluga coal fields would require approximately 4% of the entire Susitna River flow during minimum flow conditions, or almost 10% of the Matanuska River flow.

In addition to water supply impacts, synfuel plants may have significant water-quality impacts. Most current synfuel technologies use process water streams that come in direct contact with the intermediate products. Hence, wastewater streams typically contain high concentrations of dissolved solids, suspended solids, and dissolved organics (e.g., phenols). These effluents are typically not significant in low or medium Btu gasification (e.g., Koppers-Totzek process), but become a major concern in high Btu gasification (e.g., Lurgi process) or liquefaction processes. Extensive treatment facilities are required to mitigate adverse impacts associated with the discharge of these effluents. One existing facility using a Sasol II process that had been designed as a zero wastewater discharge facility has proven ineffective in practice in avoiding all adverse water-quality impacts.

In certain site-specific cases, water-quality problems can also arise from leaching and surface runoff from fuel/coal storage. These impacts are similar to those of a coal-fired steam-electric facility and are discussed in Appendix D.

Air Resources Effects

The production of synthetic fuels creates the potential for large amounts of atmospheric emissions. These emissions are similar to those of conventional combustion processes and include primarily particulate matter, sulfur oxides, nitrogen oxides, hydrocarbons, and carbon monoxide. These emissions are a function of both process configuration and process efficiency (Anderson and Tillman 1979). Specific emissions estimated on the basis of the heat content of product fuels were made by the U.S. Energy Research and Development Administration (1975). Projected emissions for a range of products and various coal types are shown in Table K.6. These data indicate that a synfuel's facility that produces fuel for a 15-MW power plant conservatively could be considered a major source of air pollution and would require a complete air-quality review.

Other emissions will be associated with the onsite use of the synfuels. Although little practical experience with the use of these fuels exists, their impacts roughly could be projected to be similar to those of oil or natural gas. Viable mechanisms exist to remove sulfur and nitrogen from the product stream and their extraction for sale as by-products enhances the economic feasibility of a synfuel's project.

Aquatic and Marine Ecosystem Effects

The most difficult to mitigate effects from synthetic fuel production plants are associated with water supply and wastewater discharge requirements. In addition, the large land area requirement could result in large construction runoff. Water withdrawal is associated with impingement and entrainment of aquatic organisms (refer to Appendix F). Chemical and thermal discharges may have acute or chronic effects on organisms living in the discharge plum area. Thermal discharges can also cause lethal thermal shock effects in cold climate regions when the discharge is stopped. The degree of these impacts will depend on many factors, such as the location of the intake and discharge structure,

TABLE K.6. Range of Controlled Air Emissions from Coal Conversion Facilities

Pollutant	Emissions Range (lb/MMBtu)
Particulates	0.01 - 0.04
Sulfur Oxides	0.01 - 0.30
Nitrogen Oxides	0.07 - 0.40
Hydrocarbons	0.001 - 0.01
Carbon Monoxide	0.006 - 0.03

Source: U.S. Energy Research and Development Administration (1975).

the chemical composition of the water supply and effluent, the plant's water and wastewater management plan, and the type and quantity of aquatic organisms present in the receiving water. In general, however, the magnitude of impacts can be related to a plant's makeup water requirements.

Synfuel plants most likely would be located near the Beluga coal field. Many important aquatic resources are located near these areas, including salmon in the Susitna River and shellfish, salmon, and other marine fish in Cook Inlet. Due to the large water requirements as compared to many of the river systems in the Railbelt, extensive mitigation efforts will be required to avoid adverse impacts.

Terrestrial Ecosystem Impacts

The major impact on the terrestrial biota resulting from synfuel plants is the loss of habitat. Synfuel plants require land areas that are two to five times that of coal-fired plants for a given energy generating capacity. In terms of land area, the synfuel plant, electrical generating facility, and support facilities can occupy approximately 1000 to 3000 acres. In addition, the work force needed to support this facility can create further disturbances to local terrestrial ecosystems.

Terrestrial impacts can also result from air emissions. These impacts will be similar to those of gas- and oil-fired plants. Whereas sulfur and nitrogen oxides are generally retained as a plant by-product, particles and other pollutants are released into the environment. Such particles can have adverse effects on local soils, vegetation, and animals. A detailed discussion of these impacts and possible mitigative measures are presented in Appendix G.

As noted earlier, in the Railbelt region sites for synfuel plants will most likely be at or near the Beluga coal fields. Specific terrestrial impacts at this site are presented in Appendix D and in Section 4.1 of this report (Coal-Fired Steam-Electric Generation). Impacts primarily include the loss or disturbance of moose, mountain goat, Dall sheep, and black bear habitat.

Socioeconomic Impacts

Because a synthetic fuel plant in the Railbelt most likely would be located in the Beluga area, this site would present the advantage of mine-mouth siting and would allow direct ocean shipment of products. Electricity generated at the site could be readily transmitted to the Anchorage area or could be fed to the proposed Anchorage - Fairbanks intertie. Use of Nenana coal would be less desirable because of the expense of transporting product fuels by rail and concerns regarding air-quality ethics on Denali National Park.

The socioeconomic impacts of a synthetic fuels production plant are difficult to predict since no United States experience exists from which to extrapolate employment levels. Due to the large scale of these plants, however, the construction work force requirements can be assumed to be at least equal to those of a large coal-fired power plant. The work force requirements for mining the coal would increase the impacts of a mine-mouth synthetic fuels plant by an order of magnitude of at least two. The cumulative impacts of a coal mine, synthetic fuels plant, and onsite power plant would be severe.

The construction and operation of a synthetic fuels plant (including the coal mine and power plant) would cause a permanent boom due the large cumulative operating work force requirements. While the construction work force would be substantially larger than the operating staff, the impacts caused by the out-migration of the construction workforce would not be as great as the initial boom. These effects would be due to the large scale and intensity of a plant development and the remoteness of the Beluga sites.

The communities in the vicinity of the Beluga coal field are small in population. The largest community in the area, Tyonek, is an Alaskan native village with a population of 239. The influx of a construction work force would severely disrupt the social structure of the community.

APPENDIX L

PERFORMANCE OF PASSIVE SOLAR OPTIONS

APPENDIX L

PERFORMANCE OF PASSIVE SOLAR OPTIONS

The performance of several passive solar options was assessed using a 1500 ft^2 representative house.

OPTION A - USE EXISTING GLASS

In this first example, the 130 square feet of glazing on the model structure is assumed to be distributed equally to all four orientations. This distribution is rare; it is assumed here for illustrative purposes, since most housing in the last several decades has paid very little attention to orientation for solar.

Dividing the total glass area by 4 results in 32.5 square feet of south glazing, worth approximately 5.5 MMBtu (million Btus) per year. Although all free heat is beneficial, this is a very small percentage of the annual heat load.

OPTION B - RELOCATE GLASS

In the second example, the same amount of glass is kept, but most of it is relocated to the south orientation. Not all the glass can be put there, as most likely bedrooms will be located in other parts of the building without access to the south wall glazing. Most solar home designs take advantage of the south glass by putting living areas there, with bedrooms towards the north wall. By fire codes, each bedroom must have a window for emergency egress; therefore, all glass cannot be placed to the south.

Forty square feet of glazing is assumed to be required for the bedrooms, leaving 90 square feet that can be placed to the south. These windows are "free" in the sense that there is no additional cost for them above and beyond that included in the model house. They are simply being relocated for this scenario. Likewise, no additional heat loss occurs through the windows. By relocating the glazing, a total of 15.1 MMBtu is now available through solar gain to heat the house.

OPTION C - ADD ADDITIONAL GLAZING

In this third example, south glazing is added to equal 10% of the floor area. This addition requires an investment of 60 additional square feet of double pane glazing, at a cost of approximately $725 in materials. (There generally will not be added framing charges in new construction for the added glass, unless it is excessive or involves a different construction system.)

With 150 square feet of south glazing, yearly solar gain is approximately 25.3 MMBtu. However, an additional heat loss of 7.8 MMBtu occurs through the extra 60 square feet of window. This loss is in addition to the heat loss previously calculated for the base-case windows. Adding this loss to that for the original 90 square feet gives a total net gain of 17.5 MMBtu yearly, or just 2.4 MMBtu better than the "free" glass in Option B.

OPTION D - ADD ADDITIONAL GLAZING

In the fourth example, 50 square feet of glazing is added to the level found in Option C, for a total of 200 square feet. Total solar gain for the year[a] is approximately 33.7 MMBtu. However, additional heat loss through the 110 square feet of glazing (200 minus the original 90) is about 14.4 MMBtu, for a net gain of 19.3 MMBtu annually. This gain amounts to a net of 4.2 MMBtu over Option B, the free glass. The 110 square foot of glazing costs approximately $1330.

The above examples are somewhat deceiving, in that an annual averaging of solar gain is an unfair method to evaluate performance in the Alaskan climate. Solar has little benefit in the midwinter months and can have a great deal of impact on home performance in the spring and fall months. In addition, actual performance of solar houses appears to exceed the calculated percentages. As mentioned earlier, solar data are poor and suspect.

Once a large portion of the heating load has been reduced through conservation, solar gain is able to take up a fair amount of the heating needs. Since the solar gain of the windows is offset largely by the heat lost back

(a) "Year" in this and all other examples denotes the heating season - approximately late September to early May.

out through them at night and during cloudy periods, movable insulation over the windows is necessary for an optimal solar performance. Little hard data are available on installed costs of shutters because they are a new development in the region. One Anchorage store sells a kit for fabric shutters (Roman shades) for a material cost of about $3.50 per square foot. The shades must then be sewn and installed by the owner. Resistive value is about R-7. A very preliminary estimate of rigid shutters with wood facing (R-10) done by J.A. Barkshire from Alaska Renewable Energy Associates, with assistance from a local contractor, indicates an installed cost of around $7.50 per square foot. Solar performance in Option D would increase by about 7 MMBtu net gain per heating season if the shutters were used diligently during night and other periods of no sun.

OPTION E - ADDING STORAGE MASS

Because solar radiation is not static, a space with large windows to the south will experience a large variety of temperature ranges throughout the year and even throughout the day. Storage mass is a common and accepted way both to temper these swings in interior temperature and to store excess solar gain coming through the glazing for later use.

In Alaska for much of the year, most of the available solar radiation is used up immediately as it enters the space. Although little modeling has been done, results show that only during the spring and fall months does storage mass become effective to any degree. As such, it is the last investment a homeowner is likely to make in passive solar applications. Nonetheless, it is important in a structure with significant south glazing. Overheating by solar gain as early as February in structures with no mass present has been reported. However, the addition of storage mass most likely will be limited to new housing that is solar oriented in design.

Many types of storage mediums exist; water is the most effective for its installed cost. However, very few installations use water. Consumer acceptance of water as a storage medium appears to be very low, mainly because few if any architecturally pleasing containers are available to store it in.

Concrete walls and floor slabs appear to be the most popular storage mediums. The slab need have no additional cost if designed into the house as a structural system. If designed into the house, the slab generally can be credited as a free investment for solar performance. The installed cost of a 4" thick concrete slab is approximately $3 per square foot.

A concrete wall is popular among some as a storage medium. Placed at the rear of the room exposed to southern sun, it has the added advantage of acting as a structural element and serves to break up the often boring interior finishes of gypsum board. A concrete wall is expensive, about $30 per lineal foot for an 8 foot high wall (including structural footing) or about $1000 for a 32-foot-long wall. Such a wall presents about 250 square feet of surface to the south and will increase the solar performance of Option D by about 5 to 7%. As such, it cannot be justified in life-cycle costs alone. As mentioned earlier, the homeowner is making an investment in comfort and ease of control of the solar system during those months when the mass is required. All cost and solar performance results for this section were calculated for Anchorage. Performance figures should be viewed with some caution until further studies can be done.

Normally, passive solar is associated with new construction. Retrofitting existing structures for solar applications is somewhat difficult and costly. Tearing out walls to add solar windows is not easy, although it may be desirable if the proper orientation and site access exists. Adding a greenhouse onto the south wall of a home is by far the most popular solar retrofit in the Railbelt region. This retrofit offers many advantages above and beyond thermal performance, such as plant and food production, addition of pleasant living space, etc. However, repeated testing shows the greenhouse to be the lowest performer in terms of thermal energy supplied to the home. The greenhouse space itself must use solar gain to maintain ambient temperature before supplying heat to the household. Each installation will be markedly different, depending on type and care of construction, whether night insulation is used over glazing, and desired temperature in the greenhouse. Early calculations show that a well-managed solar greenhouse will supply net benefit to the house of 10 to 15% of the load.

Costs of greenhouse construction will reflect those of current building costs, $30 to $40 per square foot. These costs assume a well-built structure with heavy insulation in the end walls and roof, and double-glazed glass windows on the south.

A review of conservation and passive solar costs will show that the investment in passive solar is not as attractive an investment as one in conservation. Study after study shows that conservation measures offer the fastest payback. Conservation is the first and most practical step, particularly in the North, where housing stock does not reflect the cold climate in construction techniques. Passive solar is best suited to new construction, in harmony with increased conservation. Nonetheless, increased understanding of use of the sun increases retrofitting of existing structures for passive solar gain.

All cost figures contained in this appendix were taken from suppliers and contractors in the Anchorage Bowl area. Although cost increases in outlying areas of the Railbelt do not reflect those of remote Bush construction, they are higher than they would be in Alaska's largest commerce center.

The following cost multiplier was prepared for the entire state by an Anchorage professonal cost estimating firm (HMS, Inc.). Excerpts for Railbelt locations are listed here. The last update on this multiplier was March 1981.

Anchorage (base)	100.00
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

APPENDIX M

PERFORMANCE OF ACTIVE SOLAR WATER HEATING SYSTEMS IN FAIRBANKS

APPENDIX M

PERFORMANCE OF ACTIVE SOLAR WATER HEATING SYSTEMS IN FAIRBANKS

Not much research has been done in Alaska on the performance of active solar hot water heating systems. The bulk of research has been from Fairbanks, particularly the work of Rich Seifert from the Institute of Water Resources at the University of Alaska, Fairbanks.

The effectiveness of an active system will obviously depend on the amount of solar radiation available and the type and effectiveness of the system installed. Somewhat less tangible is the load for water heating, which varies with every household.

In a September 1980 article in Solar Age magazine, J. Carter noted an average yearly load of approximately 22 MMBtu for a family of four. An approximation to this figure has been used for the calculations in Table M.1. In Table M.2 a family of six is assumed to use 36.5 MMBtu per year (100,000 Btu per day). Eighty and 120 square feet of collector have been assigned to these loads, respectively.

In both cases, almost 50% of the annual load can be met with an active solar system. These figures differ little from Seifert's work over the past several years and tend to further confirm this phenomena. One column shows the percentage of load supplied by the 120-square-foot section. Although the system is drained down during the mid-winter months, the high percentage of performance results because a hot water load occurs year round.

Costs for active systems are estimated to run from 25 to $80 per square foot contractor installed, depending on the system design. The high end cost reflects copper-tube flat-plate collector systems by major manufacturers. Most of those systems are not readily available in Alaska. The low end reflects the newer Solaroll® product Seifert has been experimenting with. These prices are estimates, not quotes from Mr. Seifert.

(a) A trademark from the Bio-Energy Systems, Inc., Ellenville, New York.

TABLE M.1. Solar Hot Water Heating System Performance: Household of Four[a,b]

Month	Load[c] (MMBtu)	Insolation Factor[d]	Ref. Temp (°F)	Load Supplied by Solar (MMBtu)[e]	Percent Solar Supplied
January	2.07	0	0	0	0
February	1.87	0	0	0	0
March	2.07	1925	8.6	1.697	82
April	2.00	1904	30.2	1.700	85
May	2.07	1806	46.4	1.734	84
June	2.00	1797	57.2	1.700	85
July	2.07	1559	59.0	1.5	76
August	2.07	1588	53.6	1.53	74
September	2.00	1040	42.8	0.96	48
October	2.07	836	26.6	0.68	33
November	2.00	0	0	0	0
December	2.07	0	0	0	0
Annual	24.36			11.57	

(a) Fairbanks - Lat. 64°49' N; El. 436 ft.
(b) 80 ft^2 collector area.
(c) 80 GPD, Tin 40°F, Tour 140°F.
(d) 50° collector tilt.
(e) System drained during mid-winter months.

TABLE M.2. Solar Hot Water Heating System Performance: Household of Six[a,b]

Month	Load[c] (MMBtu)	Insolation Factor[d]	Ref. Temp (°F)	Load Supplied by Solar (MMBtu)[e]	Percent Solar Supplied
January	3.102	0	0	0	0
February	2.802	0	0	0	0
March	3.102	1925	8.6	2.544	82
April	3.002	1904	30.2	2.552	85
May	3.102	1806	46.4	2.606	84
June	3.002	1797	57.2	2.552	85
July	3.102	1559	59.0	2.358	76
August	3.102	1588	53.6	2.295	74
September	3.002	1040	42.8	1.441	48
October	3.102	836	26.6	1.024	33
November	3.002	0	0	0	0
December	2.07	0	0	0	0
Annual	36.524 Btu/yr	Total Hot H_x0 Load		17.372 x 10^6 Btus/year	Solar - 47

(a) Fairbanks - Lat. 64°49' N; El. 436 ft.
(b) 80 ft^2 collector area.
(c) 80 GPD, Tin 40°F, Tour 140°F.
(d) System drained during mid-winter months.
(e) 50° collector tilt.

The following are estimated installed costs at a contractor price of $25 per square foot of collector:

80 square foot @ $25 = $2000.00
120 square foot @ $25 = $3000.00

Actual square footage cost will vary with type of system (drain down, anti-freeze, one or two tanks), and final installed cost is difficult to determine except on a case-by-case basis. Note, however, that the above costs also are for a complete system with a single hot water tank and short, simple plumbing runs.

Reports from Fairbanks of home-built collectors using the Solaroll indicate that construction costs of as little as $8 dollars per square foot is possible. This figure is for the collector area only and does not include associated costs.

Expected life of the Solaroll system averages 15 to 20 years if properly installed. O&M costs are difficult to determine; a hypothetical estimate of $25 to $50 per year is made. Replacement cost is largely restricted to the pump(s) during the systems life. Pump replacement might occur at 7 to 10 years.

Man-hours required for an installation will vary; on a simple application, 5 to 6 man-days might be required for collector assembly and installation. If the collector is shop built and simply has to be installed, 2 to 4 man-days generally will be required.

APPENDIX N

POWERPLANT AND INDUSTRIAL FUELS USE ACT

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POWERPLANT AND INDUSTRIAL FUELS USE ACT

An objective of the Powerplant and Industrial Fuels Use Act (FUA) of 1978 is to curtail the use of natural gas and petroleum-derived fuels for the generation of electricity where acceptable substitutes for these fuels are available. Pursuant to the FUA, natural gas or petroleum-derived fuels may not be used as a primary fuel in new electric generating plants except under special conditions subject to approval of the Department of Energy (DOE).

Thirteen conditions are set forth in the FUA, one of which is a potential basis for an exemption. The conditions are as follows (10 CFR 503.30-503.43):

503.31 An alternative fuel supply to natural gas or petroleum would not be available within the first ten years of plant life.

503.32 An alternative fuel supply is available only at a cost that substantially exceeds the cost of using imported petroleum.

503.33 Site limitations are present that would impede the use of alternate fuels to natural gas or petroleum. Qualifying site limitations include: a) physical inaccessibility of alternate fuels; b) unavailability of transportation facilities for alternate fuels; c) unavailability of land or facilities for storing or handling alternate fuels; and d) unavailabiity of land for controlling and disposing of wastes resulting from use of alternate fuels.

503.34 Inability to comply with applicable environmental requirements except by use of petroleum or natural gas.

503.35 Inability to obtain adequate capital for plant construction except by use of petroleum or natural gas.

503.36 State or local requirements (except for building codes, nuisance or zoning laws) rendering use of alternate fuels infeasible.

503.37 Use of cogeneration, where electricity would constitute more than 10% and less than 90% of the useful energy output of the facility.

503.38 Use of mixtures of natural gas or petroleum and alternate fuels.

503.39 Use of the plant for emergency purposes only.

503.40 Need for the plant to maintain reliability of service due to timing considerations.

503.41 Use of the plant for peakload purposes (not greater than 1500 equivalent full power hours per year).

503.42 Use of the plant for intermediate load purposes (not greater than 3500 equivalent full power hours at a heat rate of 9500 Btu/kWh or less). This exemption is applicable to petroleum-fired units only.

503.43 Use of the plant to meet scheduled outages (less than or equal to 28 days-per-year on average over three-year periods.)

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