Comment Draft Working Paper No. 3.1

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

March 1981

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

COMMENT DRAFT WORKING PAPER 3.1

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

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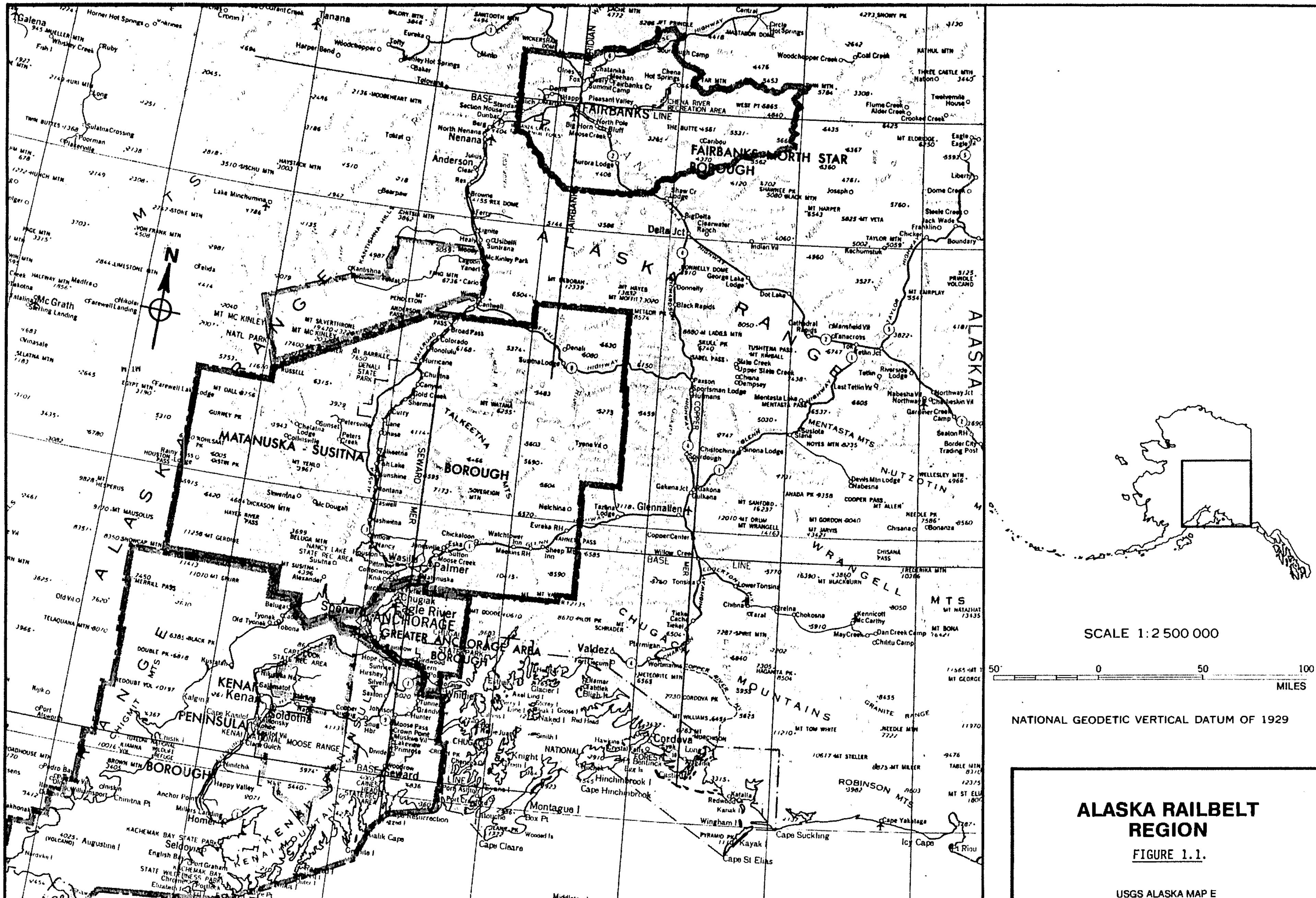
1.0 INTRODUCTION

The Railbelt region of Alaska includes Anchorage, Fairbanks, the Kenai Peninsula and the Valdez-Glenallen areas, which together account for about two-thirds of the population of the State (Figure 1.1). 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 a number of organizations including the Corps of Engineers, the Alaska Power Administration, The Alaska Power Authority, the Institute of Social and Economic Research, and the existing Railbelt utilities have all engaged in various aspects of electric power planning. None to date, however, has prepared a comprehensive electric power plan for the Railbelt region considering the overall electric energy needs for the region and considering 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-Northwest to perform a Railbelt Electric Power Alternatives Study. The primary objective of this study is to develop and analyze alternative long-range plans for electrical energy development for the Railbelt region. These plans will be used as the basis for recommendations to the Governor and Legislature for Railbelt electric power development, including whether or not the State should concentrate its efforts on development of the hydroelectric potential of the Susitna River or pursue other alternatives.

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



ALASKA RAILBELT REGION

FIGURE 1.1.

USGS ALASKA MAP E

The purpose of this report is to provide an overview of a number of candidate electric energy technologies for Railbelt electric power planning. This information will be used to support the selection of "viable" energy technologies for subsequent in-depth consideration in later stages of this study. In general, information is presented on the following aspects of each technology.

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

The remainder of this introduction discusses the selection of candidate electric energy technologies and provides an overview of the socioeconomic and environmental characteristices of the Railbelt and a description of the existing Railbelt electric energy systems. Profiles of the candidate technologies are presented in subsequent chapters. Summary comparisons among functionally similar technologies are provided at the beginning of each chapter. Descriptive material common to several technologies is presented in Appendices A through K.

1.1 CANDIDATE ELECTRIC ENERGY TECHNOLOGIES

A number of currently commercial, emerging, and advanced energy technologies was compiled for consideration as potential candidate electric energy technologies (Table 1.1). These technologies were classified into seven catagories generally based on the role they typically play in an electric energy system. The seven catagories include base load generation, cycling generation, fuel saver generation, energy storage options, electric energy substitutes, electric energy conservation and load shaping technologies.

Base loaded power plants operate 65 to 85% of the time and are designed to supply the continuous (base) portion of electric load at low cost. Cycling

TABLE 1.1. Candidate Electric Energy Technologies

Base Load Generation	Candidate Electric Energy Technology	Rejected Technologies: Commercial Availability	Rejected Technologies: Technical Feasibility
Coal-Fired Steam Electric	X		
Natural Gas/Distillate-Fired Steam Electric	X		
Biomass-Fired Steam Electric	X		
Combined Cycle	X		
Magnetihydrodynamic Generators		X	
Fission Reactors	X		
Fast Breeder Fission Reactors		X	
Geothermal Electric	X		
Fusion Reactors		X	
Ocean Current Energy Systems		X	X
Ocean Salinity Gradient Energy Systems		X	
Ocean Thermal Energy Conversion Systems			X
Space Power Satellites		X	
Cycling Generation			
Combustion Turbines	X		
Diesel Generation	X		
Hydroelectric	X		
Fuel Cells	X		
Fuel Saver (Intermittent) Generation			
Ocean Wave Energy Systems		X	X
Tidal Electric	X		
Central Wind Turbines	X		
Dispersed Wind Turbines	X		
Solar Photovoltaic Systems	X		
Solar Central Receiver Systems	X		
Cogeneration	X		
Energy Storage Options			
Pumped Hydro	X		
Compressed Air Storage	?		
Storage Batteries	X		
Electric Energy Substitutes			
Passive Solar Space Heating	X		
Dispersed Active Solar Systems	X		
Wood-Fired Space Heating	X		
Electric Energy Conservation			
Building Conservation	X		
Load Shaping			
Direct Load Control	X		
Passive Load Control	X		
Incentive Pricing	X		
Education and Public Involvement	X		
Dispersed Thermal Energy Storage	X		

technologies have more flexible operational characteristics and serve intermediate and peak loads, normally operating approximately 25 to 50% of the time. Storage technologies convert the electric energy production of base loaded power plants to a storable form of energy. The stored energy is reconverted to electricity during periods of peak demand. Fuel saver technologies include those generating devices which are available only on an intermittent basis. Fuel saver technologies displace base-load generation by contributing energy to a system, thus reducing overall fuel requirements. Unless provided with storage devices, these technologies normally are not credited as capacity credit since their availability is not assured on a continuous basis. Electric energy substitutes permit the direct substitution of other energy forms for electric power. Conservation technologies reduce the absolute demand for energy, including electric energy. Load shaping is used to reduce the need for peaking capacity. Load shaping is usually accomplished by shifting the use of electrical energy not dependent on a specific time of day to off-peak times.

In some cases a technology may have the potential for playing more than one role in an electric energy supply system. For example, combustion turbines, while commonly used in the "lower 48" as devices to meet cycling load requirements, are currently used to provide base load generating capacity in the Railbelt region partly because of the availability of inexpensive natural gas fuel.

Candidate electric energy technologies selected for the Railbelt Electric Power Alternatives Study are indicated in the second column of Table 1.1. Selection of candidate technologies was based on two criteria: commercial availability and technical feasibility.

Commercial Availability: A candidate technology should either be currently commercial or commercially available by year 2000. A technology which would be commercially available by year 2000 would have potential to significantly contribute to the electric energy needs of the Railblet during the planning period of this study (1980-2010). Energy technologies which were rejected for consideration because of commercial availability are indicated in the third column of Table 1.1.

Technical Feasibility: A candidate technology must demonstrate reasonable potential for technical feasibility in the Railbelt region. Technologies rejected for not meeting this criterion are indicated in the fourth column of Table 1.1. Technologies rejected as technically infeasible were typically technologies dependent upon nontransportable energy resources not found in the Railbelt region. Further discussion of technologies rejected from consideration as candidate electric energy technologies is provided in Appendix K.

1.2 OVERVIEW OF RAILBELT GEOGRAPHIC AND SOCIOECONOMIC CHARACTERISTICS

The Railbelt region, as shown in Figure 1.1, 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.

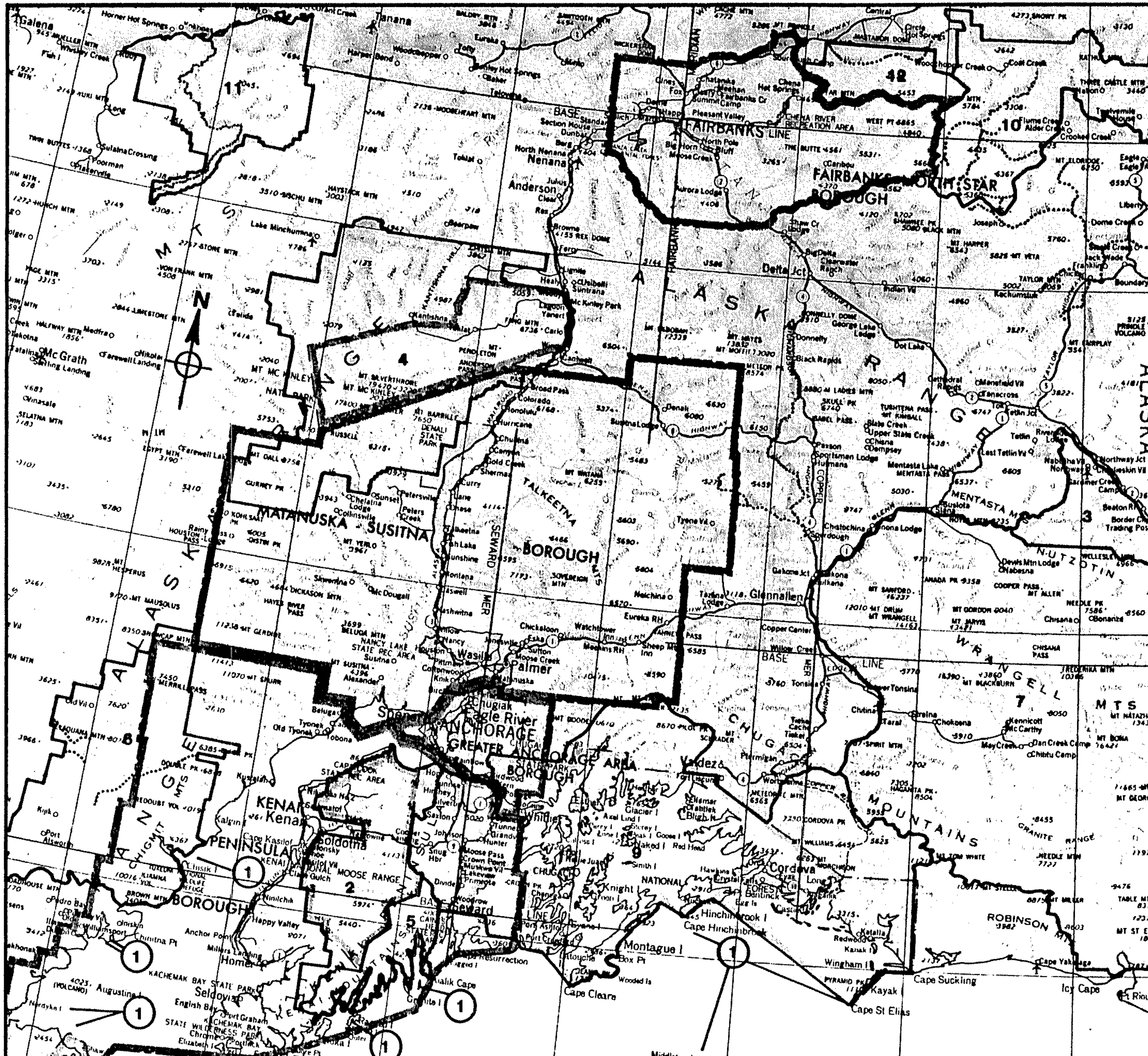
Geographically, the area is characterized by three major lowland areas separated by three mountain ranges. The lowland areas include the Tanana-Kuskokwim lowland, the Susitna lowland, and the Copper River lowland. The Alaska Range, the Chugach and the Talkeetna Mountains form boundaries to the three major lowland areas. Much of this land area in Alaska has recently been designated national interest land by the Alaska National Interest Lands Conservation Act of 1980 as shown on Figure 1.2.

Major industries in the Railbelt include fisheries, petroleum, timber, agriculture, construction, tourism, and transporation. The federal government provides employment in both the military and civilian sectors, although these sectors are presently 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).

1.3 ELECTRIC GENERATING CAPACITY

Eight utilities presently serve the region:

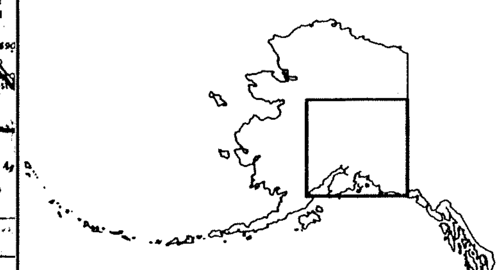
- Chugach Electric Association
- Anchorage Municipal Light and Power
- Homer Electric Association



ALASKA NATIONAL INTEREST LANDS CONSERVATION ACT

SOURCE: U.S. Geological Survey.

1. Alaska Maritime National Wildlife Refuge
2. Kenai National Wildlife Refuge
3. Tetlin National Wildlife Refuge
4. Denali National Park and Preserve
5. Kenai Fjords National Park
6. Lake Clark National Park and Preserve
7. Wrangell-Saint Elias National Park and Preserve
8. National Wild and Scenic Rivers System
9. Chugach National Forest
10. Yukon-Charley Rivers National Preserve
11. Nowitna National Wildlife Refuge
12. Steese National Conservation Areas



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NATIONAL GEODETIC VERTICAL DATUM OF 1929

ALASKA RAILBELT REGION

FIGURE 1.2.

USGS ALASKA MAP E

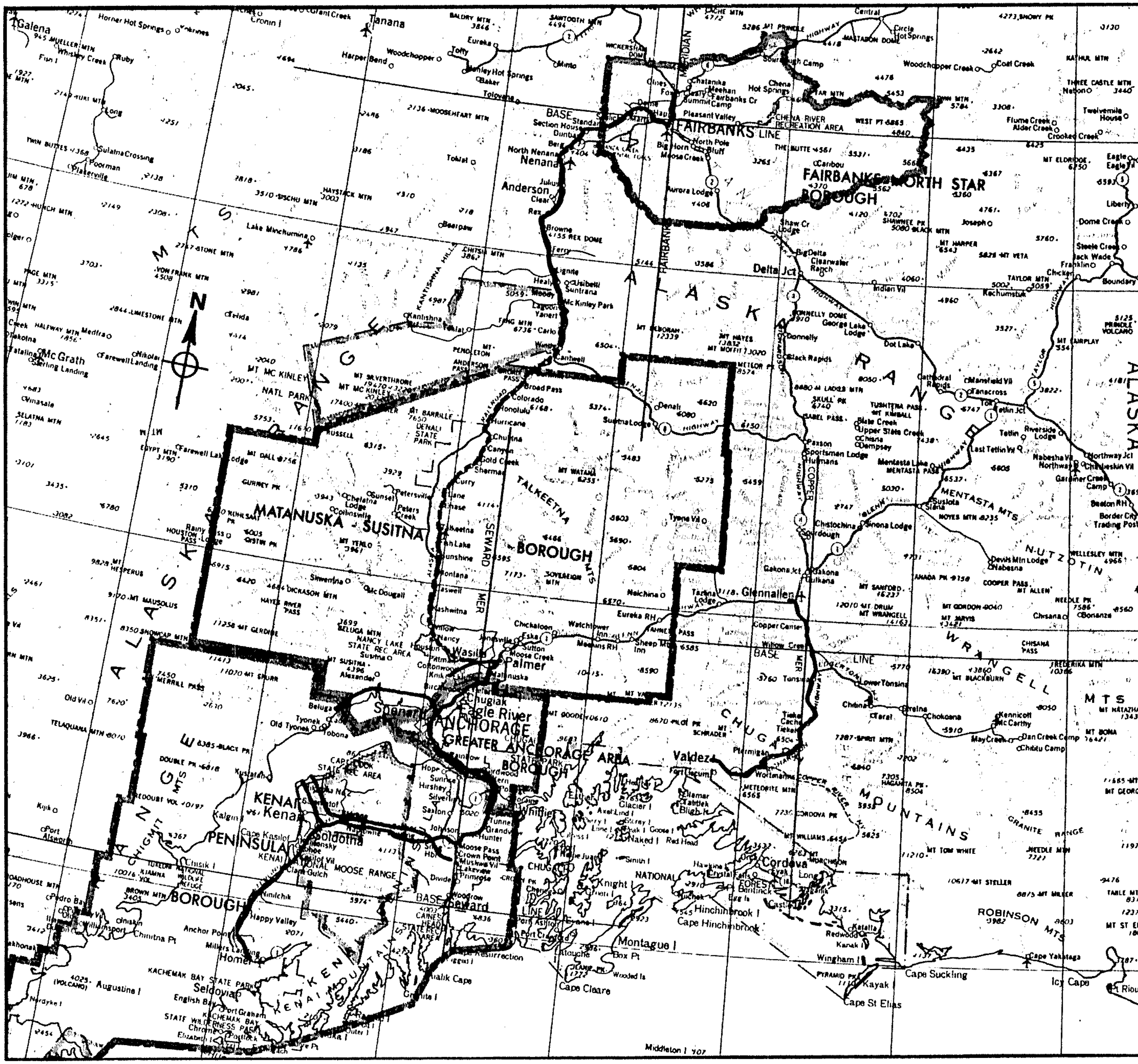
- Matanuska Electric Association
- Seward Electric System
- Golden Valley Electric Association
- Fairbanks Municipal Utilities System
- Copper Valley Electric Association

The City of Anchorage is served by Chugach Electric Association and Anchorage Municipal Light and Power. Most of the Kenai Peninsula is served by the Homer Electric Association while the area in the vicinity of Palmer and Talkeetna is served by Matanuska. Each of the aforementioned 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 1.3.

Existing electric generating capacity by major utility and type is shown in Table 1.2. Non-utility generating capacity is summarized in Table 1.3. In addition to the central generating systems, a number of smaller installations operated by individuals or small communities are found in the Region.

Planned expansions of utility system generating capacity are limited. Anchorage Municipal Light and Power is the only system currently considering expansion, by adding a 74-MW combustion turbine in 1982.

Current estimates indicate that over 20% of U.S. energy resources are located in Alaska. Coal deposits represent between 39 to 63% of the United States' totals; oil, natural gas, and hydroelectric potentials are greater than in any other single state (Alaska Dept. of Commerce and Economic Development 1978). Proper development of these resources is important to Alaska's future economic condition.

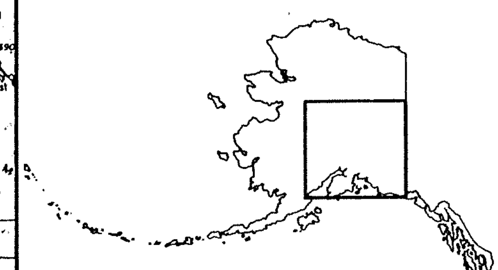


EXISTING AND PROPOSED TRANSMISSION SYSTEMS

SOURCE: Alaska Power Administration.

Existing

Proposed



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NATIONAL GEODETIC VERTICAL DATUM OF 1929

ALASKA RAILBELT REGION

FIGURE 1.3.

USGS ALASKA MAP E

TABLE 1.2. Generating Capacity: Railbelt Utilities (1980) (MW)

	Combined Cycle	Diesel Electric	Hydro Electric	Combustion Turbine[a]	Combustion Turbine[b]	Steam	Total
Alaska Power Administration	0	0	30	0	0	0	30
Anchorage Municipal Light and Power	139	2	0	0	90	0	231
Chugach Electric Association	0	0	17	120	287	19	443
Fairbanks Municipal Utility System	0	8	0	0	28	29	65
Golden Valley Electric Association	0	18	0	0	163	25	206
Homer Electric Association	0	3	0	0	0	0	3
Seward Electric System	0	6	0	0	0	0	6
TOTAL	139	37	47	120	568	73	984

Source: Battelle (1980).
(a) Regenerative Cycle Combustion Turbine
(b) Simple Cycle Combustion Turbine

TABLE 1.3. Generating Capacity (MW): Non-Utilty Railbelt Installations (1980)

Fort Richardson	Diesel Electric	Steam Electric	Total
Eielson AFB	0	9	9
Elmendorf AFB	2	32	34
Fort Greeley	2	0	2
Fort Richardson	7	18	25
Fort Wainwright	0	5	5
University of Alaska	6	13	19
	17	77	94

Source: Battelle (1980)

Energy resource consumption within the State of Alaska is currently as follows:

Energy Resource	Percent
Petroleum Liquids	69
Natural Gas	23
Coal	6
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.

1.4 LOAD CHARACTERISTICS OF THE RAILBELT REGION

The demand for electrical energy in the Railbelt as well as 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 facilities to meet the largest or peak hourly load. Therefore, the time-of-use characteristics of system and class loads have important implications for an electric utility system.

1.4.1 Seasonal Peak Load

The consumption of electricity is much greater during the winter season in the Railbelt region than in other seasons. The major reason for this is the need for energy for space heating. Monthly residential electric utility consumption data for 1979 is provided in Table 1.4. It is denoted in this table that the 1979 winter-summer ratio varied from 1.48 to 2.30 for the various utilities. The seasonal electricity consumption fluctuations are determined to a large extent by the change in heating degree days. The most recent heating degree day data available for a "normal" year for which electrical load data are also available are presented in Table 1.5. Note that heating degree day data corresponds with seasonal load fluctuations.

As noted in Table 1.4, electricity consumption during the months of November through January is very high, exceeding by far the consumption of other months. It would seem reasonable that modifying the seasonal load profile might be desirable to reduce the need for additional capacity expansion and obtain a better allocation of system resources.

1.4.2 Daily Peak Loads

Peak loads vary each day as well as from season to season. The daily variation reflects the living and working characteristics of the communities as well as ambient temperatures and other factors that influence time-of-use demands. To demonstrate this variation, the daily peaks for each month of 1975 are illustrated in Figure 1.4 for Anchorage Municipal Light and Power. The lowest daily peak was 38 MW which occurred in July and the highest daily load was 92 MW in December.

1.4.3 Load Duration Curve

Figure 1.5 illustrates the load duration curve for Anchorage Municipal Light and Power for 1975. The curve portrays the number of hours of annual generation that were a given percent of peak load. The curve indicates that

TABLE 1.4. Monthly Residential Electricity Consumption For 1979 (kWh/customer)

	CVEA	CEA	AMLP	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(a)	1.48	1.84	1.74	1.73	2.20	2.30
TOTAL	5,892	10,452	8,592	12,648	15,240	10,524
Nonspace Heat Load(b)	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
Percent Space Heat Customers(c)	0	14	15	30	33	6
Space Heat Average	--	4,457	5,907	4,063	9,545	34,333

(a) (December + January + February)/(June + July + August).
(b) Based upon the CVEA ratio of total annual sales to sales in the summer months of June, July, and August (4.79).
(c) Estimate.
(d) Fairbanks Municipal Utility System data were not available. Institute of Social and Economic Research.
Source: ISER 1980.

TABLE 1.5. Monthly Heating Degree Days for 1975

Month	Anchorage	Fairbanks
January	1,643	2,497
February	1,454	1,918
March	1,313	1,620
April	954	1,028
May	575	347
June	354	69
July	192	33
August	252	270
September	463	570
October	937	1,270
November	1,517	2,195
December	1,654	2,513

Source: Bair, F. E. and Ruffner, J.A. (eds.) 1977. The Weather Almanac, pp. 336, 340.

for almost all hours, actual loads were about 30 percent of the peak. Also, about 250 hours of the year had loads exceeding 80 percent 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 were the peak load to be experienced throughout the period. Low load factors indicate a "peaky" load while high load factors are characteristic of a flatter load profile. The 1975 load factor was about 0.55. Nationwide, load factors range from about 0.55 to 0.70 indicating that the AML&P load is rather peaky.

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.

1.4.4 Projected Load Growth

Table 1.6 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 3.7% annually with the load factor remaining essentially constant at about 62 percent. Overall peak load is forecasted to grow from

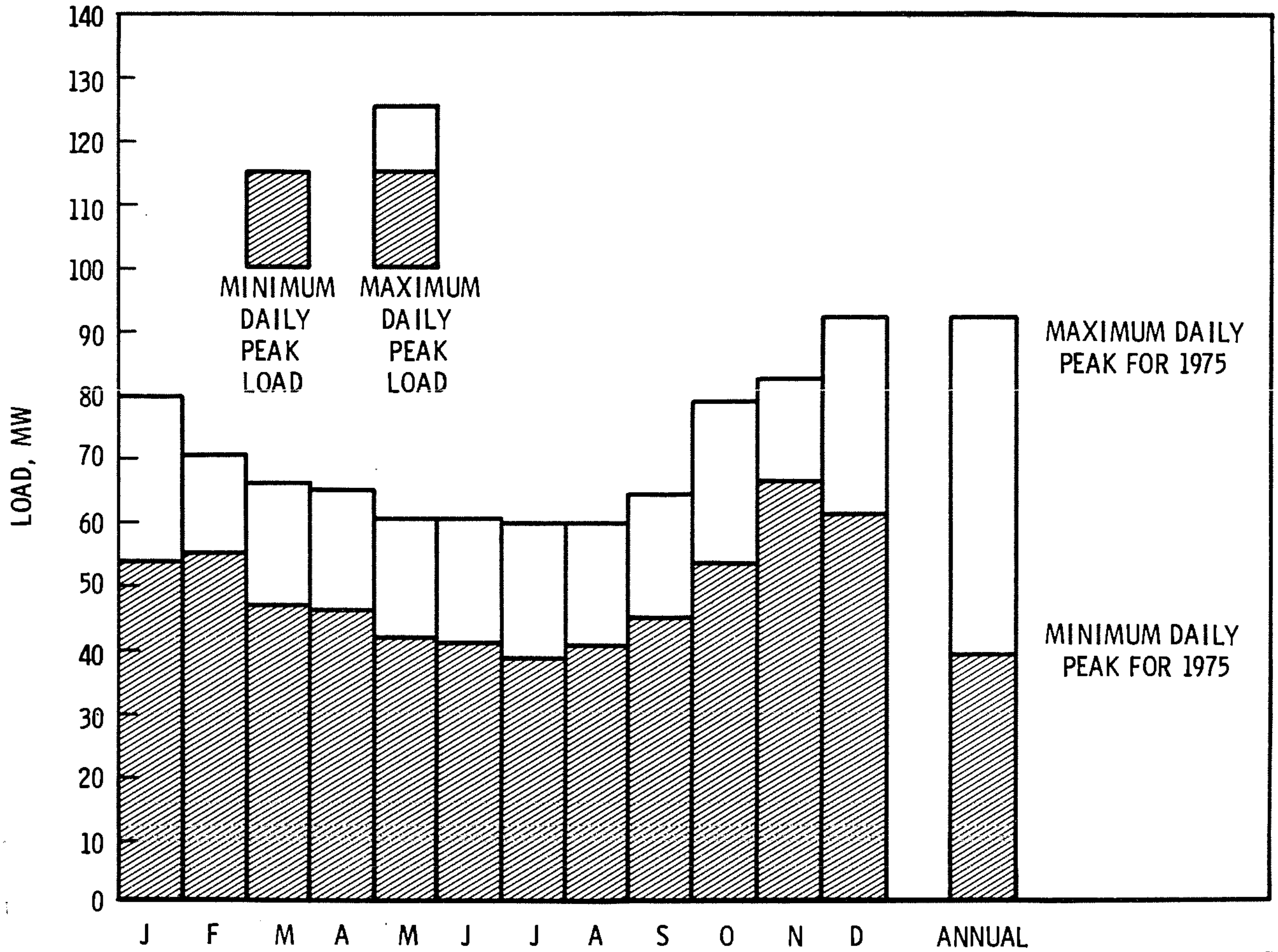


FIGURE 1.4. Anchorage Municipal Light and Power 1975 Daily Peak Loads

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.

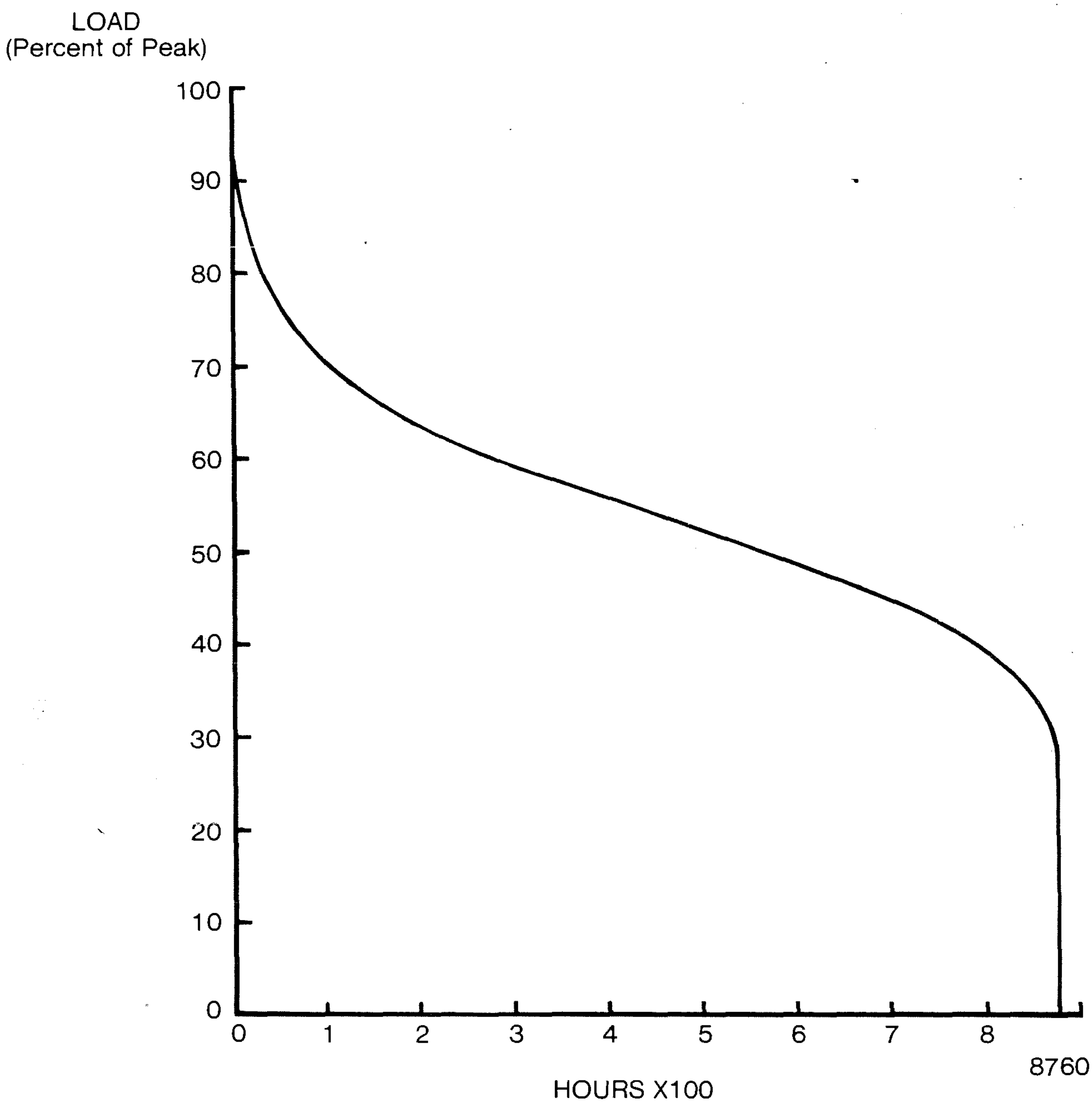


FIGURE 1.5. Anchorage Municipal Light and Power Load Duration Curve - 1975

TABLE 1.6. Yearly Estimated Load Growth (Total 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).

2.0 BASE LOAD TECHNOLOGIES

Three fundamental base load generating technologies are considered in this analysis: combustion-fired steam-electric generation, nuclear steam electric generation, and steam-electric generation supplied by geothermal energy. 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 these technologies, with the exception of geothermal, depend on the burning (fission in the nuclear cycle) of a fuel to produce steam, which is expanded through a steam turbine to produce electrical power in a generator. A schematic representative of the steam cycle of the three combustion-fired base load technologies is presented in Figure 2.1.

All of the base load technologies require: a fuel or energy source; site access facilities; power egress corridors (electrical transmission lines); environmental capabilities to support plant operation (e.g., cooling water and stable foundation); environmental capacity to absorb plant effluents such as liquid, gases, solids; institutional and social infrastructures 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 base generating technology. Salient characteristics of the base load technologies are compared in Table 2.1.

In the lower 48 states, base load installations have typically been large (200 MWe or more) oil, gas, coal, or nuclear fueled steam-electric plants. The Railbelt region of Alaska, because of its unique development and environmental characteristics, 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 constructon lead times, and lower capital costs of diesels and gas turbines have led to their use in the Railbelt region for base load capacity. Capacity has been added in small increments, with the

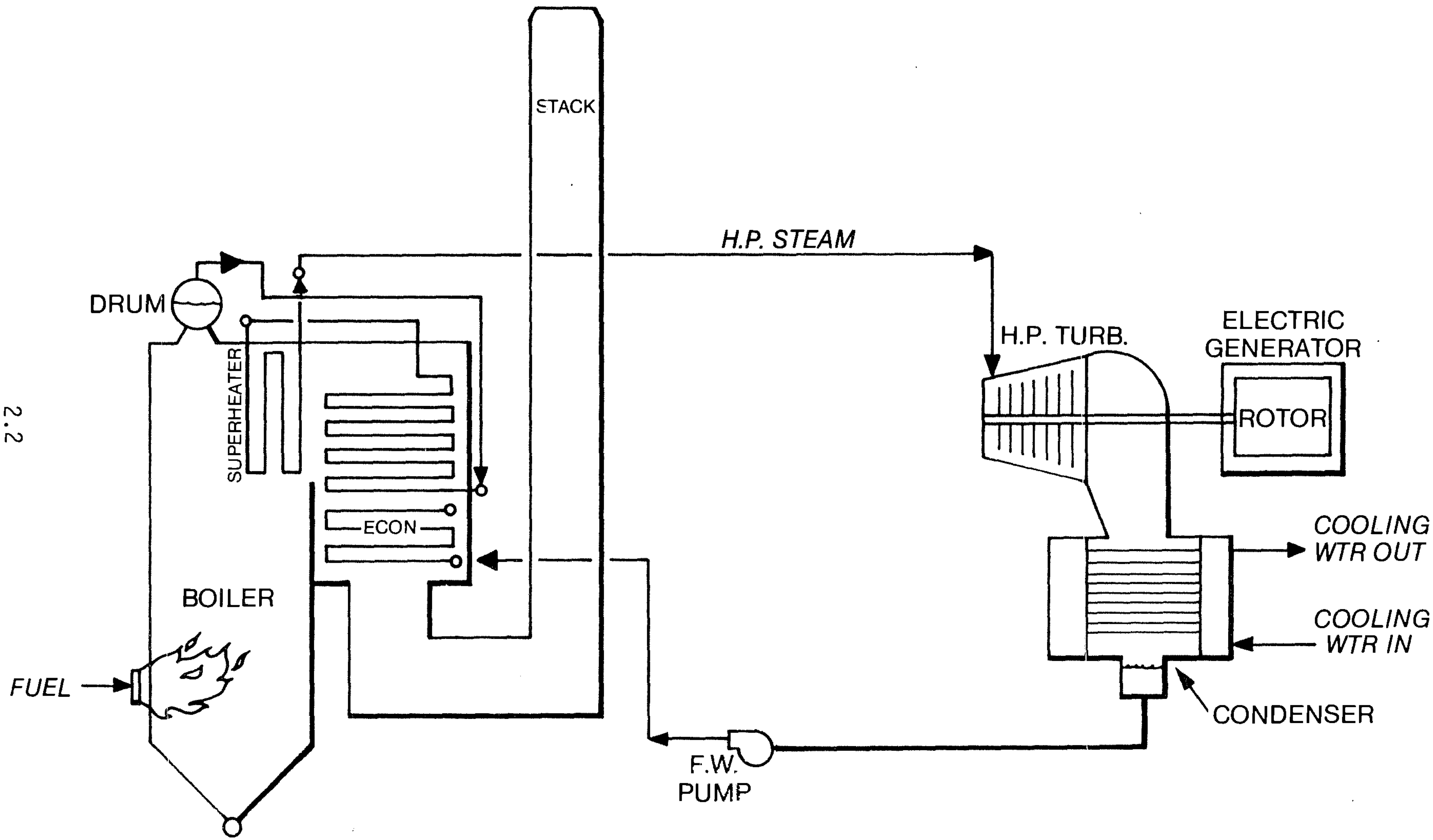


FIGURE 2.1. Typical Combustion-Fired Steam Electric System (Without Reheat)

TABLE 2.1. Comparison of Caseload Technologies on Selected Characteristics

First Stage Attributes	Biomass 25 MW	Coal 200 MW	Oil & Natural Gas 10 MW	Geothermal 50 MW	Nuclear 1000 MW
1. Aesthetic Intrusiveness					
A. Visual Impacts	Moderate	Significant	Minor	Significant	Significant
B. Operating Noise	Minor	Moderate	Minor	Moderate	Minor
C. Odor	Significant (Municipal Waste)	Minor	Minor	Significant	Minor
2. Impacts on Biota					
A. Aquatic/Marine (gpm)[a]	325	1800	90	750	11000
B. Terrestrial (acres)[b]	25	225	4	5 (Excluding Wells)	125
3. Cost of Energy					
A. Capital Cost ($/kW)	2160	2100	Oil 1920, Gas 1360	1500	1850
B. O&M Cost ($/kW)	68	38	Oil 60, Gas 56	1500	1850
C. Fuel Cost				N/A	
D. Cost of Power ($/kW)				0.035-0.151	
4. Health & Safety A. Public	Safe	No direct safety problems. Possible long-term air quality degradation.	No direct safety problems.	No direct safety problems. Possible air quality degradation in vicinity of plant.	No direct safety problems. Possible short- and long-term quality degradation or accidental radionuclide discharge.
5. Consumer Effort	Utility operated. No individual or community effort required.	Utility operated. No individual or community effort required.	Utility or community operated. No individual effort required.	Utility operated. No individual or community effort required.	Utility operated. No individual or community effort required.
6. Adaptability to Growth A. Adjustments in plant scale	Duplicate effort required.	Duplicate effort required.	Packaged units can be added relatively easily to existing site.	Increases possible but resource limited.	Duplicate effort including some licensing.
7. Reliability					
A. Availability (%)	85	85	85-90	65	70

TABLE 2.1. (contd)

First Stage Attributes	Biomass 25 MW	Coal 200 MW	Oil & Natural Gas 10 MW	Geothermal 50 MW	Nuclear 1000 MW
8. Expenditure Flow From Alaska					
A. Capital Cost (%)	60	60	75	55	60
B. Operation and Maintenance Cost (%)					
C. Fuel Cost					
9. Boom/Bust					
A. Ratio of Construction to Operating Personnel	65:25	600:85	60:20	90:30	1300:180
B. Magnitude of Impacts	Significant in very small communities. Minor to moderate in all other locations.	Severe	Significant in very small communities Minor to moderate in all other locations.	Severe	Severe with the exceptions of Fairbanks and Anchorage.
10. Control of Technology					
A. Utility	Primary Control	Primary Control	Primary Control	Primary Control	Primary Control
B. Individual	Limited through regulatory agencies and government.	Limited through agencies and government.	Limited through regulatory agencies and government.	Limited through regulatory agencies and government.	Limited through regulatory agencies and government.
Second Stage Attribute					
1. Commercial Availability	Mature	Mature	Little current utility experience, large industrial usage.	Experimental technology for Railbelt resources.	Moderately mature, some difficulties, no experience in Railbelt.
2. Railbelt Siting Opportunities	Limited to location fuel source.	Limited to coal regions and railroad or water transport.	Limited to fuel delivery considerations.	Limited to source.	Limited to port facilities or rail corridor, seismic influenced.
3. Product Type	Baseload	Baseload	Baseload	Baseload	Baseload
4. Generating Capacity					
A. Range in Unit Scale (MW)	5-60	10-1300	10-800	3 MW per well up to 50 MW	1000 nominal

(a) Recirculating cooling water systems.
(b) All facilities.

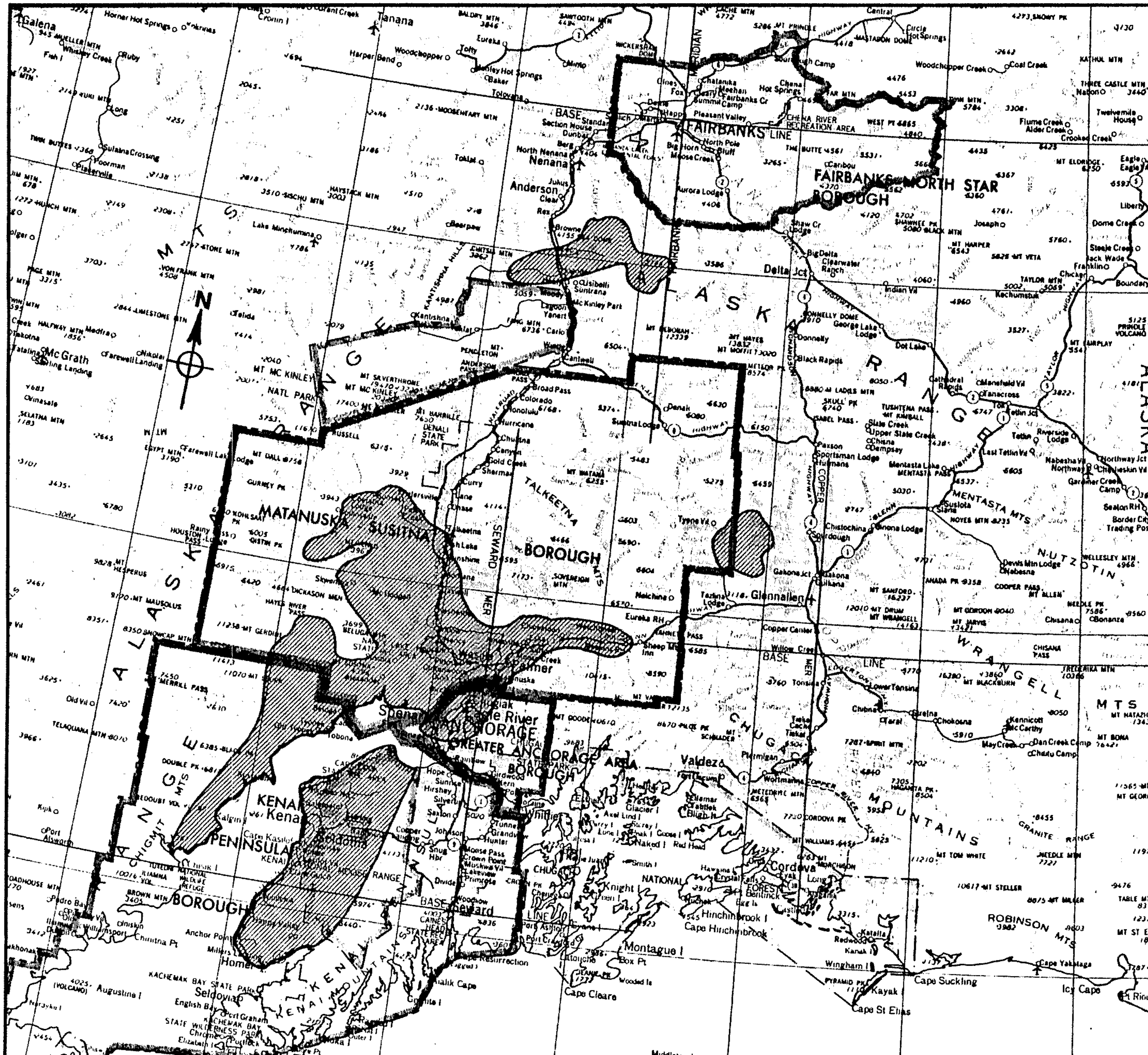
largest operating unit at approximately 68 MW. Of the approximately 1000 MW of nonmilitary power installed, only 86 MW is steam-electric. 20 MW of this is used as peaking capacity. The largest steam-electric unit currently found in the region is the 25-MW coal-fired Healy Plant.

The Railbelt region's projected load growth of approximatly 3 1/2% per year indicates that it may be possible to continue using individual generating units of approximately 10 to 25 MW 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.

2.1 COAL-FIRED STEAM-ELECTRIC GENERATION

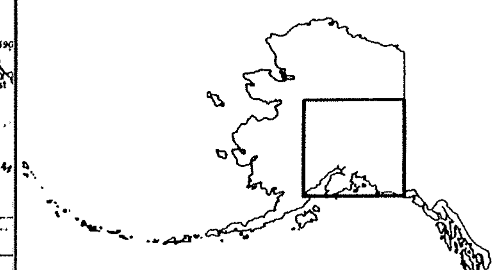
Coal-fired steam-electric generation is a mature, reliable, universally accepted technology which supplies more electric power in the United States than any other single fuel. Uncertainties in petroleum supply and rising petroleum prices are leading industry to return to a coal-based energy industry from one which had seen the rise of oil and natural gas use 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, leading to installation of flue gas clean-up equipment for 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 2.2.

Recent coal-fired power generation installations in the United States have been large units (greater than 200 MW). It is expected, however, that smaller users and producers of steam will look to coal as a fuel in the forseeable future because of its relatively abundant supply and lower cost when compared to competing fuels (Battelle 1980). In addition to economic factors promoting use of coal, the Powerplant and Industrial Fuel Use Act of



COAL RESOURCES

'Source: Joint Federal–State Land Use Planning Commission for Alaska, 1975.



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NATIONAL GEODETIC VERTICAL DATUM OF 1929

ALASKA RAILBELT REGION

FIGURE 2.2.

USGS ALASKA MAP E

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).

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

2.1.1 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.

The firing of coal imposes unique requirements on the design of steam-electric plants. First of all, it is necessary to provide for significant amounts of on-site fuel storage, resulting in large coal storage piles. The long-term storage area is usually sized for 60-90 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 limiting conditions. In addition to the long-term storage is a "live storage" area; this area is usually designed for a 7-day supply, from which the coal is fed to the plant.

Since coal combustion creates large quantities of ash, a location for final disposal of the ash must be provided. If a dry ash removal system is used, then only a small on-site storage area is required as 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; occasionally ash is returned to the mine for disposal.

Coal installations sited in cold-weather regions require special equipment, specifically thaw sheds at the unloading facility and frozen coal crushers at the reclaim area.

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 2.3). 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 and will be described in additional detail. The boiler plant includes coal handling and preparation facilities and the boiler itself.

Coal Handling and Preparation.

Coal handling and preparation facilities include facilities for receiving, handling and storing raw coal and equipment for preparing the coal for firing. Principal coal handling and preparation facilities include the following:

Unloading Station. The design of the unloading station depends on the mode of coal transportation. For transportation by rail, 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.

Stacking and Reclaiming. 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 retrieving for use in the plant.

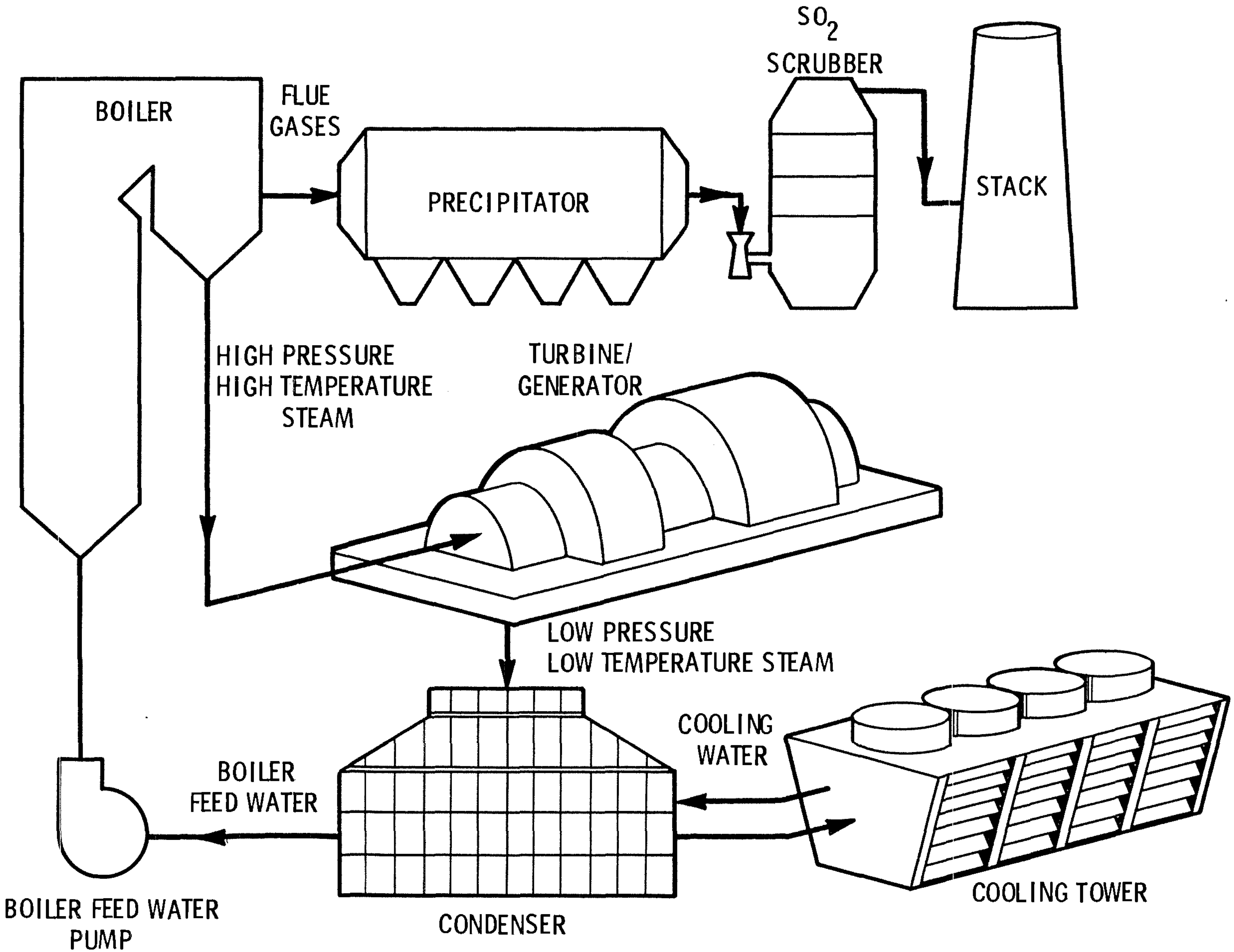


FIGURE 2.3. Power Plant Components

Conveying. Most coal-fired plants use some form of conveyor system to move the coal from the reclaiming area to the plant bunkers. Extreme environments will require climate protection equipment as well as dust supression systems to be used in the conveying.

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

Mills. The mills are generally located below the bunkers and serve to pulverize and dry the coal in preparation for burning. The mills are extremely large, heavy duty, slow speed, high energy-consuming pieces of equipment.

Air Pollution Control System

Combustion of coal produces a flue gas containing a number of environmentally harmful pollutants, notably particulate matter, oxides of sulfur (SO_x) and oxides of nitrogen (NO_x). Each of these requires control under the provision of the Clean Air Act of 1971 and subsequent amendments.

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

Oxides of Sulfur. The most common methods of removing sulfur from the flue gas is by use of 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 which are disposed of as solid waste. Removal efficiencies are on the order of 90% for single units. 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 has the advantage in a harsh winter climate--it reduces the freezing problem.

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.

Oxides of Nitrogen. Oxides of nitrogen (NO_x) are formed during the combustion process by the combination of atmospheric oxygen with atmospheric nitrogen at elevated firing temperatures. Oxides of nitrogen are currently controlled by special firing techniques.

Unit availability refers to the total amount of time that a particular piece of equipment was or could have been used divided by the total hours in the period in question. 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 percent
200-299 MW	84.8 percent
300-399 MW	77.6 percent
400-599 MW	74.1 percent

Additional information from the NERC survey indicates that in recent years the availability has decreased in every size range. The added complexity of flue gas clean-up 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 when one considers 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).

"Load factor" refers to the actual percent of time a unit is operated. Load factors for units in the above sizes range from 45 to 86%; however, for any particular unit the load 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.

2.1.2 Siting and Fuel Requirements

A complex decision process, which 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, available transportation facilities, and the size of the plant weigh more heavily in the siting of a coal-fired unit than with oil or gas-fired units because characteristics of the fuel vary so widely compared to oil or gas.

Coal-fired steam-electric plants require water for condenser cooling, emissions control, ash handling, boiler makeup, general cleaning, and for domestic purposes. Typically, boiler makeup, emissions control, domestic and other noncooling uses amount to approximately 5% of the boiler through-put. 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 this 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 F).

The acreage of sites required for coal-fired power plants of varying capacities are given in Table 2.2:

TABLE 2.2. Typical Land Requirements for Coal-Fired Steam-Electric Power Plants

Plant Size (MW)	Plant Site	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	550	670

These estimates account for the siting of not only plant facilities (including coal storage and handling facilities, power plant systems, and cooling systems) but also on-site housing facilities that would be necessitated by remote siting requirements.

Plant heat rate is a measure (in Btus) of the amount of fuel energy required to produce one kilowatt of electrical power, and is thus a measure of plant efficiency. Heat rates are a function of unit size, basic design, auxiliary equipment, heat sink temperatures, and operator attention. Fuel consumption (quantity) for coal-fired steam electric plants varies with heat rate and with the quality of the fuel. 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 (for power plant firing) and limestone for flue gas desulfurization if necessary. Siting coal-fired steam electric plants at the coal source (mine-mouth) eliminates the need for fuel delivery systems. Coal and limestone consumption are shown in Table 2.3 for four plant sizes.

TABLE 2.3. Fuel Consumption for Coal-Fired Steam Plants

Plant Size (MW)	Heat Rate Range (Btu/kWh)	Coal Consumption (Tons/hr)	Limestone (lb/hr)
20	10,600 to 13,000	16	150
200	10,200 to 13,000	145	1,400
400	9,800 to 12,200	275	2,750
600	9,500 to 10,600	400	4,000

2.1.3 Costs

Engineering costs vary from project to project and depend on the construction schedule, unit size, scope of work, and degree of standardization.

Operating and maintenance costs are difficult to estimate because of the wide variations in utility practice. The cost per kilowatt decreases substantially as unit size increases; this is because larger units require relatively fewer personnel than smaller units.

Estimated capital costs and operation and maintenance costs vary with plant size as shown in Table 2.4. The basis for these cost estimates are further discussed in Appendix I.

TABLE 2.4. Cost Summary of Coal-Fired Plants

Plant Size	Capital Costs ($/kW)	O and M Costs ($/kW)	Cost of Power ($/kWh)
20 MW	1600	45	
200 MW	1115	25	
400 MW	915	18	
600 MW	790	12.5	

2.1.4 Environmental Considerations

Coal-fired power plants generate large and problematic quantities of solid waste derived from both the combustion process (fly ash and bottom ash) and from atmospheric emissions (flue gas desulfurizaion wastes). These wastes require more extensive environmental monitoring and waste characterizaion 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 A).

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 will be the subject of an in-depth review by

Alaska and EPA authorities. The expected emissions from a coal-fired power plant and the regulatory framework are presented in detail in Appendix B, where emissions are compared to those of alternative technologies. Note that although impacts from coal combusion are generally greater than those of other fuels, a judicious siting analysis and the employment of 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.

Other significant, and difficult to mitigate, effects from coal-fired steam plants are associated with water supply and wastewater discharge requirments. 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 effects in the Railbelt region when the discharge is stopped. These effects are discussed in greater detail in Appendix C.

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

Many potentially suitable development areas for coal-fired plants border important aquatic resource areas (salmon in streams like the Copper and Susitna Rivers and other marine fish and shellfish in Cook Inlet); plants located in these areas would have to be designed to mitigate effects on these resources.

The greatest impact on the terrestrial biota is the loss or alteration of habitat due to the large amounts of land required for both construciton and operation. These land requirements (Table 2.2) are generally greater than those for other forms of fossil-fueled power plants.

Other impacts to the terrestrial ecology could result from gaseous and particulate air emissions, fuel or waste storage discharges, human disturbance, and the power plant facilities themselves, i.e., cooling towers. The effects of these plant characteristics on the biota are discussed in Appendix D. Impacts resulting from coal-fired plants on the terrestrial biota are best mitigated by siting plants away from important wildlife areas and by implementing appropriate modern pollution control procedures. Although certain impacts can be controlled, land losses are irreplaceable.

2.1.5 Socioeconomic Considerations

The construction and operation of a coal-fired plant has the potential to seriously affect localities and cause a boom/bust cycle. These effects are due to the remoteness of prospective sites. The magnitude of these impacts is a function of plant scale. A major contributing factor to this relationship is the variation in size of the construction workforce with plant size. Construction times, exclusive of licensing and permitting, will vary according to the size, type of equipment, and external factors such as weather and labor force. Construction schedules for coal-fired plants in the Railbelt will vary depending upon whether or not 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 auxiliary equipment is skid mounted. Larger units (above 50 MW) which are field constructed will take from 3 to 5 years. Because of site work involved with the fuel storage and ash disposal areas, it can be expected that a coal-fired unit will require an additional 3 months over a similarly situated oil or gas-fired plant.

Impacts would be most severe at the Beluga coal fields since the surrounding communities are small and the infrastructure is not devloped. 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 workforce, regardless of size, would disrupt the social structure of the community.

Impacts from development of the Nenana and Matanuska coal fields and construcion of a plant along the railroad corridor would depend on a scale of plant. Existing communities may be able to accomodate the requirements for constructing a 10 to 30-MW plant, but would be severely affected by a large-scale plant.

The area of Kenai-Soldatna on the Kenai Peninsula has a more developed infrastructure and a larger population to withstand the demands which accompany power plant construction. The impacts of a small-scale plant would be minor to moderate but the impacts of a large-scale plant could be significant, depending on the extent of local labor utilization.

The flow of expenditures both outside and within the Railbelt are expected to balance for a 200-MW field-erected project and 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 base load technologies because of the large construction workforce and extensive field preparation requirements.

2.1.6 Potential Application in the Railbelt Region

There are two major coal fields in the Railbelt region, the Nenana field and the Beluga field (Figure 2.2). Some development of coal-fired steam electric generation has occurred using 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 while the University of Alaska has three small units at their power plant. The Beluga fields have not been developed, although studies are underway to define the coal resource characteristics and markets (Battelle 1980).

The Beluga and Nenana fields would be potential sites. Mine-mouth siting has the advantage of being able to substantially reduce the coal storage area and transportation costs. Secondary sites may include deposits on the Kenai Peninsula as well as the Matanuska fields. The Matanuska fields have been worked in the past; the Kenai fields have not been developed. The next most logical siting choice is along the Alaska Railroad corridor. The area adjacent to the railroad from Seward, through Anchorage to Fairbanks, has existing transportation facilities which are adequate for coal transport from the Nenana coal fields.

If neither mine-mouth operation nor rail service is available at an otherwise attractive Railbelt site, then good roads would be essential for truck hauling. This type of operation would probably be limited to smaller plants (10 to 15 MW) requiring approximately 5 to 10 tons of fuel per hour. This siting option has at least two disadvantages: coal storage would have to be sized to handle plant operations during periods when deliveries are not made, and increased truck traffic would become a nuisance as well as a potential threat to highway user health and safety.

2.2 NATURAL GAS AND DISTILLATE-FIRED STEAM ELECTRIC GENERATION

The natural gas and distillate-fired (more generally oil-fired) steam-electric technologies are well known and widely used in the utility industry. However, the future application of these technologies is not promising because of the worldwide oil supply and pricing disruptions caused by the action of 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. Since this regulatory constraint severely limits new construction of oil- and gas-fired facilities, our evaluation of these types of units considers only units of 10 MW or less. Units of this overall size can be accommodated in either an interconnected or isolated Railbelt power system.

U.S. utilities have very little experience with gas and distillate-fired boilers in the 10 MW size range. Units of this size 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 can only give an indication of what can be expected for electrical generation.

2.2.1 Technical Characteristics

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 1-week supply is a common criterion for plants with a reliable source. Some means of heating the oil may be required, depending on oil type and ambient temperatures in the Railbelt region. Depending on the environmental regulations and the sulfur content of the fuel, flue gas desulfurization equipment may be required.

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

A 10-MW distillate-fired unit operating at rated capacity will consume approximately 20,000 gal/day of distillate, assuming a heat rate of 11,000 Btu/kWh (typical for this size unit). The consumption for a similarly sized natural gas fired plant will be approximately 2.9 million cu ft/day based on a typical heat rate of 12,000 Btu/kWh.

Industrial users frequently obtain availability of approximately 90%. This 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 units of this size based on industrial data and data from NERC on the smallest reported units (100 MW).

2.2.2 Siting and Fuel Requirements

The siting decision process for small gas- or distillate-fired steam-electric plants is similar to that for coal units with respect to water resources and air quality limitations (flue gas constituents will differ but the regulations, studies, and permits are similar). Both oil and natural gas 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, while 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. These estimates do not inlcude an allowance for employee housing, if such is required.

2.2.3 Costs

The estimated costs in 1980 dollars to construct, operate, and maintain a 10-MW distillate-fired or natural gas-fired unit in the Railbelt Region with construction starting in 1982 are shown in Table 2.5.

TABLE 2.5. Cost Summary for Gas and Distillate-Fired Plants

Fuel	Capital Costs ($/kW)	O and M ($/kW)	Cost of Power ($/kWh)
Distillate	1,920	60	
Natural Gas	850	56	

2.2.4 Environmental Considerations

Water resource impacts associated with the construction and operation of a natural gas or oil-fired power plant are generally mitigated through appropriate plant siting and a water, wastewater, and solid waste management program (refer to Appendix A). These steam cycle facilities present the least adverse impacts of the combustion technologies; significant, or difficult to mitigate, water resource impacts are not anticipated, especially in light of the small power plant capacities that are considered likely.

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 form a natural gas or oil-fired power plant and the associated regulatory framework are presented in detail in

Appendix B. Emissions of sulfur dioxide from the burning of residual fuels will be signficiant and will require conventional scrubbers for large systems. In addition, emissions of nitrogen oxides resulting from high-temperature combustion may also be significant and may 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 C). 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. Because these plants use the same or less water per megawatt than any steam cycle plant except the combined cycle, and because of federal restrictions on maximum plant size (10 MW), these plants would use less water than any other steam plant (approximately 4,500 gpm for once-through cooling and 90 gpm for recycling cooling systems). As a result, if properly sited and constructed, impacts from these plants would be less than other steam cycle plants.

The greatest impact on the terrestrial biota resulting from natural gas or distillate-fired steam electric would be loss or alternation of habitat. However, since these plants are limited to 10 MW, land requirements for plant development should be approximately 6 acres. Thus, these plant types encompass considerably less land area than other steam cycle plants and impacts are not expected to be significant. Also, natural gas and distillate-fired power plants would probably be placed near existing developments, thus avoiding environmental problems associated with plants sited in remote areas.

2.2.5 Socioeconomic Considerations

Because plant size is limited to 10 MW, socioeconomic impacts will vary with location rather than with scale of plant. Primary sites for oil-fired plants occur near existing refineries or along distribution pipelines. Secondary sites are located along the railroad, and major highway corridors. Sites for gas-fired plants would be located near the gas transmission line that links Soldatna to Anchorage.

The flexibility of siting a power plant, particularly an oil-fired plant, results in numerous potential sites. Assuming good access, a 10-MW unit could be constructed in 18 working months. This estimate is based on a packaged boiler and skid mounted auxiliary equipment. 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 the boiler and turbine installation. The construction work forces are estimated to peak at 60 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. Operational manpower on the two types of firing are basically the same and are estimated at 20 workers. In order to mitigate a boom/bust cycle caused by the influx of workers, sites should be constrained by the population size of the nearby communities. While very small communities would be significantly affected by the influx of construction workers, small communities should not be, assuming that temporary housing is provided for the workers (see Appendix). Primary locations meeting this criterion which are near a distribution pipeline include Anchorage, Soldatna, and Fairbanks. Secondary locations include Kenai, Seward, Wasilla, and Palmer.

Expenditures that would flow out of the region due to the development of these facility types would include investment in equipment and employment of specialized supervisory personnel. Due to the moderate-sized construction workforce and relatively short installation period, it can be expected that 25% of the project expenditures would be made within the region while 75% would be sent outside Alaska.

2.2.6 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. There are plans for adding refinery capacity in the Valdez area, the point of termination of the Alaska pipeline. 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. To supply a 10-MW plant operating at capacity, approximately two to three tank truck deliveries per day would be required.

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 system.

2.3 BIOMASS-FIRED STEAM-ELECTRIC CONSRATION

Biomass fuls potentially available in the Railbelt region for power generation include sawmill residue and municipal waste. Biomass fuels have been used in industrial power plants for many years. Biomass plants are distinct from fossil-fired units in that maximum plant capacities are relatively small; in addition, they have specialized fuel handling requirements. The generally accepted capacity range for biomass-fired power plants are approximately 5 to 60 MW (Bethel et al. 1979; Jamison 1979). The moisture content of the fuel, as well as the scale of operation, introduces thermal inefficiencies into the power plant system.

2.3.1 Technical Characteristics

The core of the biomass-fired power plant is the boiler and the turbine-generator. Like the coal-fired power plant, ancillary systems exist for fuel receiving, storage and processing, stack gas cleanup, bottom and fly-ash handling, and condenser cooling. Fuel processing equipment is particularly critical if spreader-stoker firing is used. Tramp iron[a] must be removed from the biomass fuel usually by magnetic means. Preferably, municipal waste will be shredded and classified, and sorted to minimize contamination by metals and glass objects. Mass burning (firing of unsorted

(a) Foreign objects of iron and steel

refuse), while practical in some cases, requires less efficient operation of the equipment. Research in such areas as fuel preparation and fuel gasification is underway to improve upon and overcome limitations in the efficiency of biomass power plant systems caused by moisture content, low bulk densities, and modest heating values.

Biomass plant efficiencies improve rapidly as the scale of a plant increases. Conversion efficiencies as a function of plant size are shown in Table 2.6 (Tillman 1980). The equivalent heat rates are also shown.

TABLE 2.6. Conversion Efficiencies

Plant Size (Megawatts)	Thermal Efficiency (Percent)	Heat Rate (Btu/kWh)
5	17	20,000
15	23	15,100
25	24	14,200
35	24	14,100
50	24	14,000

Biomass facilities, which would be operated as base-load 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. Plant reliability is a function of the individual reliability of the numerous parts of the system, including fuel receiving, preparation, and handling systems; the boiler itself; the turbine-generator and associated steam equipment; and pollution control system (Jamison 1979). Increasing the complexity of any system has a tendency to diminish reliability.

Fuel handling systems in the Railbelt area will have to be designed to accommodate cold conditions and frozen fuel.

2.3.2 Siting and Fuel Requirements

Biomass fuels are generally inexpensive but are characaterized by high moisture content, low bulk densities, and modest heating values. Typical net heating values of biomass fuels are compared to coal below:

Fuel	Btu/lb
Municipal Waste	4000
Peat	5000
Wood	4500
Coal	9000

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 (e.g., wood and municipal waste). For example, the estimated supply of both wood and municipal waste biomass fuel in Greater Anchorage will support a 19-MW power plant operating 24 hr/day at a heat rate of 15,000 Btu/kWh (see Section 2.4.6).

The rate of fuel consumption is a functon of efficiency and plant scale. Fuel consumption as a function of plant capacity is presented in Table 2.7 (Tillman 1980).

TABLE 2.7. Fuel Requirements by Plant Size

Plant Size (Megawatts)	Hourly Fuel Requirements (tons)	Truck Loads Per Hour
5	11	--
15	25	1
25	40	2
35	55	3
50	80	4

Siting requirements for biomass-fired power plants are dictated by the condition of the fuel, location of the fuel source, and cooling water requirements. Because biomass fuels are high in moisture content and low in bulk density, economical transport distances do not exceed 50 miles (Tillman 1978). Biomass power plants are thus typically sited at, or close to, the fuel source and may function as part of a cogeneration system. Sites must be accessible to all-weather highways since biomass fuels are usually transported by truck. (Approximately four trucks per hour would be required, for example, for a 50-MW plant.)

While proximity to the fuel source may be the most limiting factor, sites also must be accessible to water for process and cooling purposes. Land area requirements are a function of scale, extent of fuel storage, and other design parameters. Typically, a 5-MW stand alone power plant will require 10 acres; a 50-MW stand-alone plant will require 50 acres.

Plants that use peat will require additional land for air drying the fuel. A 1 to 3-month fuel supply should be provided to assure fuel availability during prolonged periods of inclement weather.

2.3.3 Costs

Biomass-fired power plants, particularly of a small scale, are expensive to construct. Construction periods range from 18 months to 3 years (not including permitting). Capital and operation and maintenance costs for relevant scale biomass facilities in Alaska are presented in Table 2.8.

TABLE 2.8. Cost Summary for Biomass-Fired Plants

Plant Size	Capital Costs ($/kW)	O and M Costs ($/kW)	Cost of Power ($/kWh)
15 MW	2,400	68	
25 MW	2,160	68	
35 MW	1,280	68	

Biomass-fired facilities require relatively small labor forces to construct and operate. For a 15 to 30-MW plant, the construction workforce would comprise 65 people; operating and maintenance will require approximately 25 people.

2.3.4 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 in light 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 B. Impacts arise largely from particulate matter and nitrogen oxides emitted by the system. The emissions of particulates can be well-controlled by using techniques such as electrostatic precipitators or baghouses. The tradeoff between emission controls and project costs must be assessed at each facility, but wood burning facilities larger than about 5 MWe will require the application of these air pollution control systems.

Potentially significant impacts to aquatic systems from biomass plants are similar to other steam cycle plants and result from the water withdrawal and effluent discharge (refer to Appendix C). Although these plants are second only to geothermal facilities in rate of water use (730 gpm/MW), their total use for a typical plant would only exceed that of oil and natural gas-fired plants because of the small size of prospective plants. Approximately 18,250 gpm and 362 gpm would be required for once-through and recirculating cooling water systems, respectively. Proper siting and design of intake and discharge structures could reduce these 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 coal-fired plants, and are generally intermediate between those for nuclear and the other steam cycle power plants (see Table D.1).

Potential primary locations of biomass-fired power plants in the Railbelt region are near Fairbanks, Soldatna, Anchorage, and Nenana. Lands surrounding these five areas contain seasonal ranges of moose. Waterfowl also inhabit these areas with high use occurring along the Matunuska and Susitna River deltas near Anchorage, and areas around Nenana. The Soldatna region also contains populations of black bear and calving, migration corridors, and seasonal ranges of caribou. Populations of mountain goats, caribou, and Dall sheep occupy habitats in the Susitna and Matunuska River drainages near Anchorage. Impacts on these animal populations will depend on the characteristics of the specific site and the densitites 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.

2.3.5 Socioeconomic Effects

Impacts of biomass-fired plants will vary among the primary locations identified as well as with plant size. Anchorage, Fairbanks, and Soldatna 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.

The impacts of plant construction on Nenana may be significant and will increase with plant size. The cause of these impacts would be the small population size and undeveloped infrastructure. Neana, which is an Alaskan native village, has a population of 471 and the surrounding area has an aggregate population of approximately 1,000. The transfer of workers and their families for a period of 3 to 5 years may cause a strain on the social fabric of Nenana and create demands for infrastructure in the nearby community of Anderson (pop. 390). These impacts can be mitigated by limiting the scale of the plant.

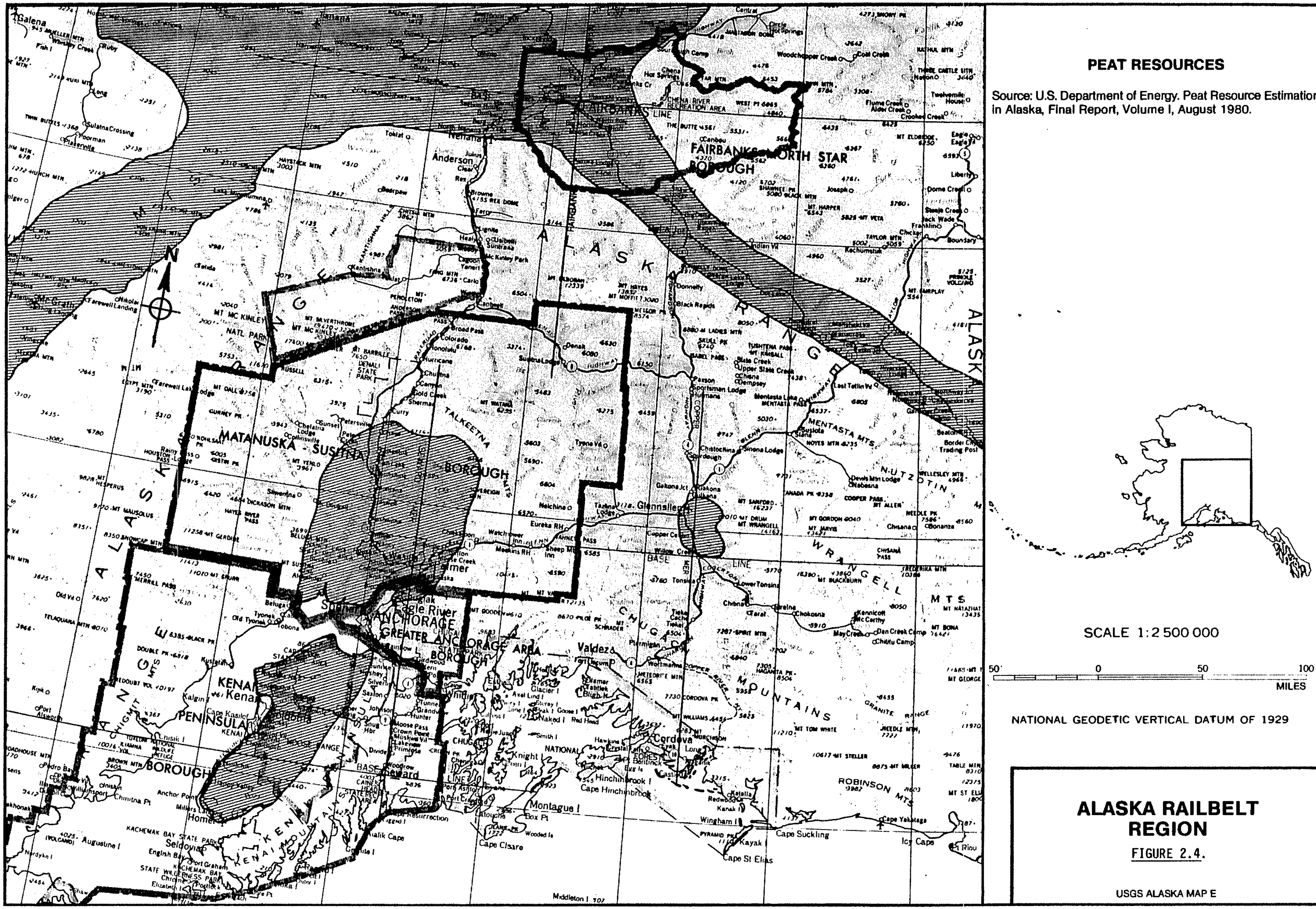
The breakdown of project expenditures is expected to be 60% outside the Railbelt and 40% within the region. Expenditures due to a large capital investment will be offset by employment of an Alaskan labor force.

2.3.6 Potential Applications in the Railbelt Region

Potential sources of biomass fuels in the Railbelt region include peat (Figure 2.4), mill residue from small sawmills (Figure 2.5), and municipal waste from the cities of Fairbanks and Anchorage.

Fuel availability for wood residue and municipal waste in the Railbelt region is shown in Table 2.9 (Alaska Sawmill Directory).

Only broad ranges of wood residue availability have been developed since little information is available on lumber production as a function of markets, lumber recovery, and internal fuel markets. Volumes of municipal waste have been identified from studies of refuse recycling in the Anchorage area (Nebesky 1980). Fuel supplies for a wood or municipal waste-fired biomass



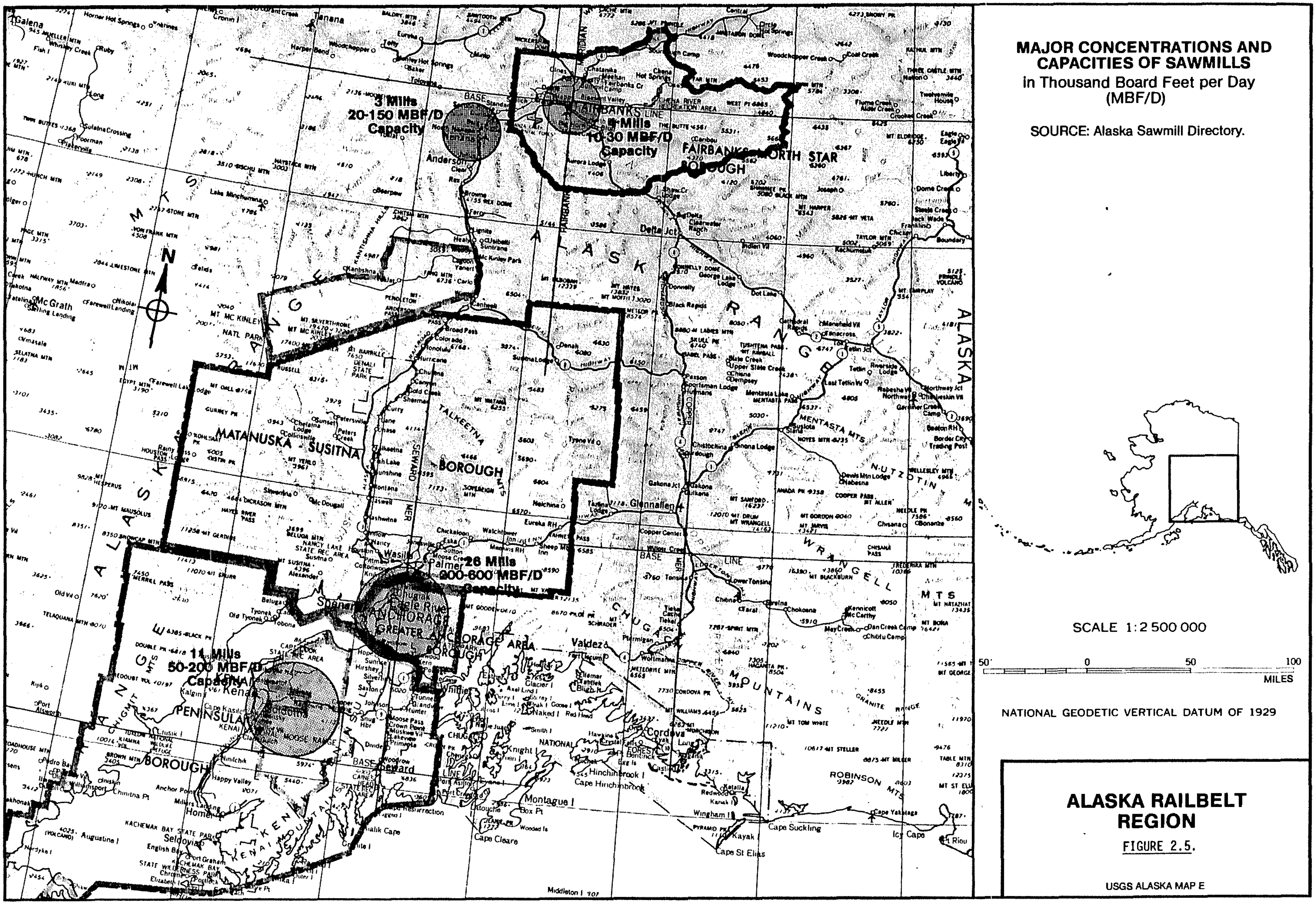
PEAT RESOURCES

Source: U.S. Department of Energy. Peat Resource Estimation in Alaska, Final Report, Volume I, August 1980.

ALASKA RAILBELT REGION

FIGURE 2.4.

USGS ALASKA MAP E



ALASKA RAILBELT REGION

FIGURE 2.5.

TABLE 2.9. Fuel Availability for Wood and Municipal Wastes

Railbelt Region	Daily Tons Wood Fuel (Tons/Day)	Municipal Refuse (Tons/Day)
Greater Anchorage	200-600	400
Kenai Peninsula	60-180	--
Fairbanks	10-30	150
Nenana	40-140	--

plant may be sufficient in greater Anchorage, but marginal in Fairbanks or the Kenai Peninsula. Peat deposits are substantial as shown on Figure 2.5 but many other fuels are available which compete economically with peat.

Biomass power plants in the Railbelt region may potentially contribute 0.5% to 5% of future power needs. As such, the biomass-fired units would be centrol 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 forecast for the Railbelt region.

2.4 NUCLEAR STEAM ELECTRIC

Nuclear steam electric generation is a mature, commercially available technology. At present, some 73 units with a total installed capacity of 54,000 MWe are operable in the United States. An additional 104 units representing approximately 116,000 MWe 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 impressive backlog of 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 are thus of significance 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 support at the highest political levels have all resulted in no new domestic orders for nuclear units since 1977. The industry is currently maintaining its viability through completion of backlog work on domestic units and by pursuing new foreign orders.

2.4.1 Technical Characteristics

Nuclear power plants produce electricity using a steam cycle similar to fossil fuel-fired power plants. However, in a nuclear power plant the heat used to raise steam is obtained by fissioning of uranium fuel in a nuclear reactor. A schematic of a typical reactor is shown on Figure 2.6. Heat to produce the steam is generated from nuclear fission of uranium fuel in the reactor core. In Boiling Water Reactor (BWR) designs, coolant water circulates through the core and is heated to form steam, at about 1,100 psi, above the core for use in the turbine. Pressurized Water Reactor (PWR) designs include two coolant loops (Figure 2.6). The primary (reactor) loop is operated at approximately 1,700 psi, so that the cooling water remains in liquid form at all times. The hot 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, and thus are not discussed here.

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 MWe range. This magnitude of electric power and costs means that nuclear power is a viable option for only those utilities with a high system demand. (There are nuclear units operating in the lower 48 states with generating capacities ranging from 50 MWe to 700

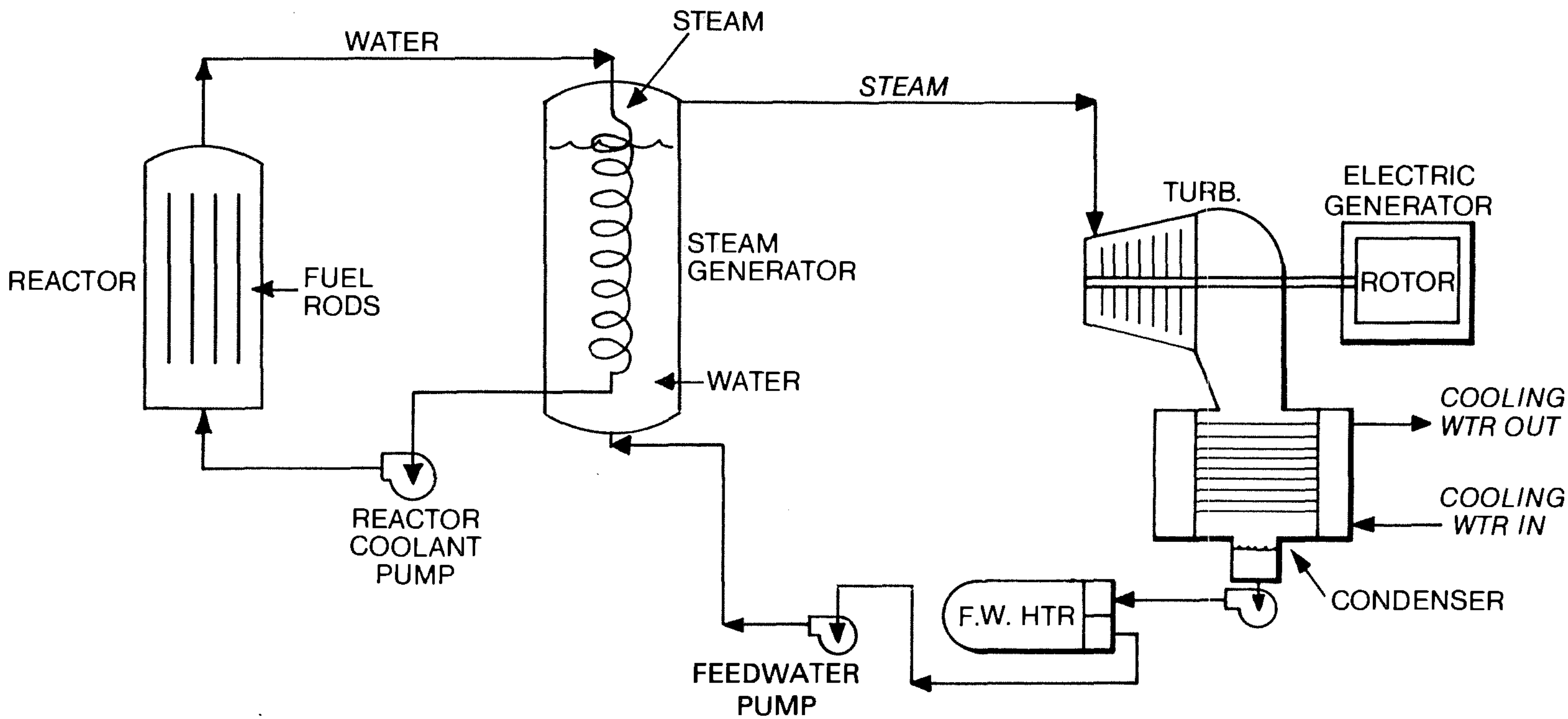


FIGURE 2.6. Steam Electric System using Pressurized Water Reactor

MWe. However, these are demonstration and first and second generation nuclear facilities and represent unit sizes not currently available from vendors.)

Nuclear power generating plants are typically designed for operation as base load units (for a 40-year commercial life) because of their characteristically high capital costs and low operating costs. The more power produced from the plant, the lower cost per unit of electricity delivered. Since nuclear plants are designed as base-load units, they are not able to follow load changes readily.

The day-to-day operations of a nuclear plant are less affected by environmental conditions than many other technologies. The plants are constructed to withstand high wind loads, tornadoes, storms, earthquakes, etc. In addition, the containment building (housing the reactor) is designed to withstand large, internally generated loads resulting from system failure. These requirements result in heavy, strong structures relatively unaffected by ambient conditions.

Nuclear plants require periodic replacement of the uranium fuel assembly. Typically, plants can operate for over a year on a single refueling. Because the plants must be shutdown for refueling, refueling is normally accomplished during periods of low electrical demand.

To a large degree, plant availability is dependent upon the performance of cooling equipment and electrical transmission lines, facilities which are not significantly different from those employed in other large scale generation technologies. The availability of nuclear plants is reported to be approximately 70%, with the upper end about 85%, and is expected to rise as more operating experience is gained.

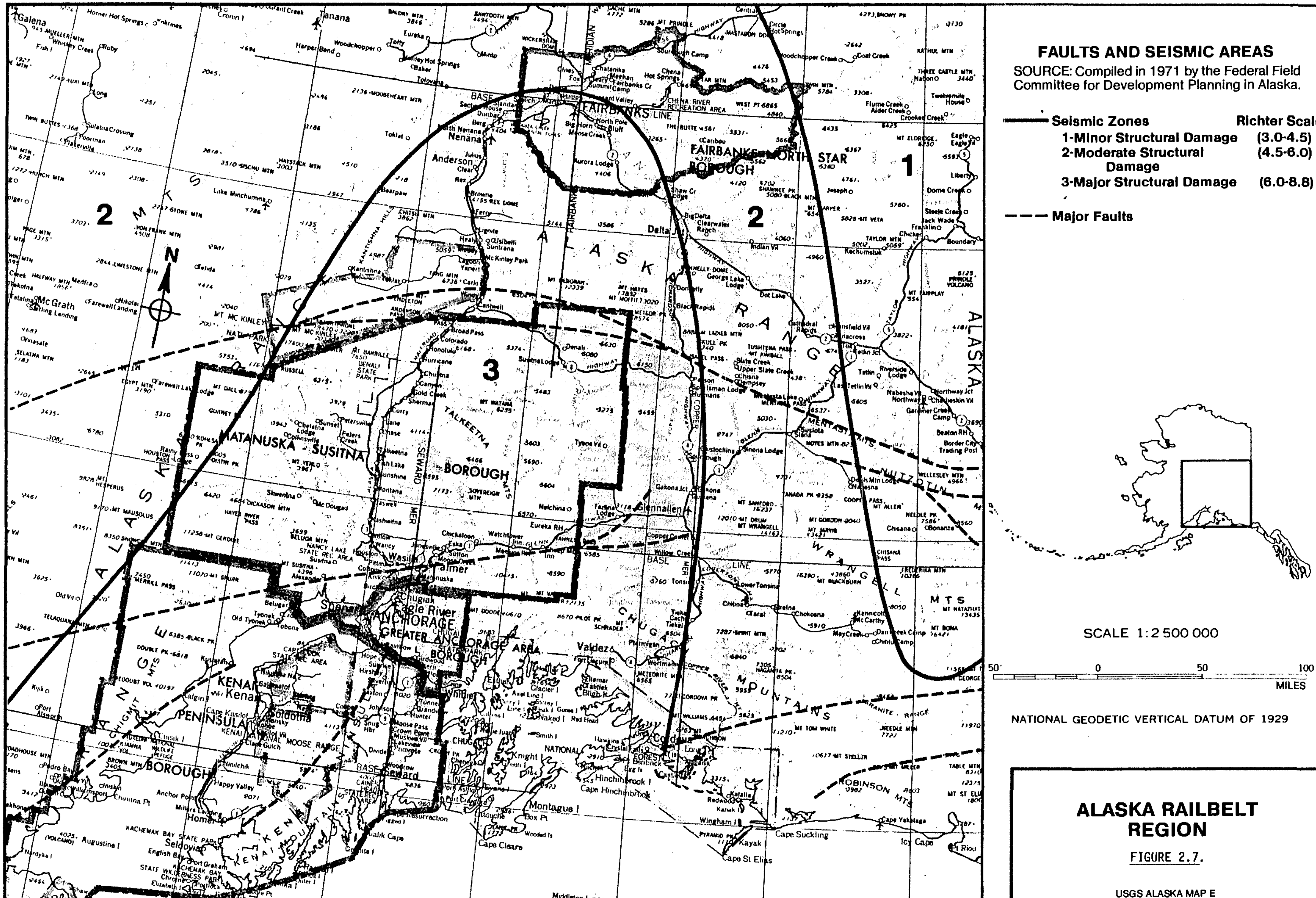
2.4.2 Siting and Fuel Requirements

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

Under the siting criteria of the Nuclear Regulatory Commission (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 feet to the nearest site boundary (encompassing areas of 250 to 2,000 acres) are typically sufficient to meet the first criterion for almost any sized nuclear facility. Additionally, a physical separation of 3 to 5 miles from areas of moderate population density allows compliance with the second criterion. These requirements are of little real consequence in the present case considering the low population densities existing in the Railbelt region. In the Railbelt region land required for location of the construction force campsite could serve as an exclusion area around the plant perimeter upon completion.

Seismic characteristics of a potential site are a major factor in plant siting since 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 2.7. Construction of a nuclear plant in the Railbelt in Zone 3 would very likely require expensive plant designs and a lengthy permitting process. Siting a plant in Zone 2 is less difficult. In either case, extensive preapproval geotechnical investigations will be required. Total exclusion of nuclear plants on this basis is not indicated since nuclear plants have been designed and constructed on a worldwide basis in each of the seismic zones found in the Railbelt region.

In addition to meeting the specific nuclear safety requirements of the U.S. Nuclear Regulatory Commission (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. Means of transportation capable of handling these items limit the potential Railbelt sites to the corridor along the Alaska Railroad and port areas of Cook Inlet and Prince William Sound. As noted previously, it is necessary to site a nuclear plant in an area of low population density. This requirement for remote siting must be balanced against the cost of transmission facilities required to deliver power to high-density population areas and load centers.



ALASKA RAILBELT REGION

FIGURE 2.7.

The heat rejected by a 1,000-MW plant is substantial; a potential site must thus have a sufficient supply of cooling water to remove the heat in a manner complying with environmental criteria for thermal discharges. Once-through cooling of a 1000-MWe facility requires a water flow of approximately 3,000 cfs and would almost certainly require coastal siting. Closed cycle systems require less water than once-through systems (probably less than 100 cfs), thus expanding the range of siting options to some of the rivers of the region (Appendix G).

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 United States. The proximity of the nuclear plant to the fuel source is relatively unimportant compared to fossil-fired and geothermal plants. 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 occur during periods of low electrical demand.

Current estimates indicate known uranium supplies are sufficient to fuel only those reactors now in service or under construction for their estimated lifetime. However, the latest nuclear designs are capable of being fueled by plutonium as well as uranium, and assuming that breeder reactors, producing surplus fuel-grade plutonium, become commercial, then 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.

2.4.3 Cost

The capital cost of a nuclear plant is high relative to other base load 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 is offset by the higher costs of the BWR's containment building and shielding.

Estimated nuclear power plant costs, adjusted for Alaska, are shown in Table 2.10.

TABLE 2.10. Cost Summary for Nuclear Power Plants

Capital Costs	\$1850/kW installed capacity
Operation and Maintenance	\$13/kW/yr

2.4.4 Environmental Considerations

Water resource impacts associated with the construction and operation of a nuclear power plant are generally mitigated through appropriate plant siting and a water and wastewater management program (Appendix A). It should be noted, however, that due to the large capacities required for nuclear power stations (1000 MW), the magnitude of water withdrawal impacts associated with a given site may be greater than 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 experienced in other combustion steam cycle technologies.

Nuclear power plants cause no deterioration in the air quality of the locale, other than the routine or accidental releases of radionuclides. To assess the potential dosages of these radioactive materials, a complex meteorological monitoring program is required. 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 optimal from a meteorological point of view. Large amounts of heat are also emitted by nuclear power plants. Some modification of microclimatic conditions onsite will be noted, but these modifications will be imperceptible offsite. The U.S. Nuclear Regulatory Commission 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 at many locations in the Railbelt region.

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. The minimum size for a nuclear facility (1,000 MW) indicates that these plants would be the largest water user of any steam cycle plants, using approximately 310,000 gpm for a once-through cooling system and 6,200 gpm for a recirculating cooling water system. Their rate of use (gpm/MW) is also higher than many other technologies (Table A.1) because of somewhat lower plant efficiencies. Potential impingement and entrainment impacts would therefore be somewhat higher than for other base load technologies of comparable size. Detrimental effects of discharge may also be high because of the large quantity of water used. But the discharge water may have fewer hazardous compounds than may be found in other steam cycle wastewaters.

The predominant biotic impact on terrestrial biota is habitat loss. Nuclear power plants require land areas (100-150 acres) second in size to those of coal- and biomass-fired plants. Furthermore, lands surrounding the plant island are at least temporarily modified by ancillary construction activities (i.e., laydown areas, roads, etc.). Partial recovery of these lands could possibly be accomplished through revegetation. 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, proper plant design and construction should prevent these emissions. One positive feature of nuclear power is the absence of air pollution emissions and resulting effects on biota.

2.4.5 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 base load technologies, a nuclear power plant has the greatest potential to adversely affect localities. 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 operating phases, adversely affecting regional participation in the labor 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. However, 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 for accommodating the workers and their families. At the termination of the construction, 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.

The proportion of project expenditures sent outside the Railbelt would be approximately 60% since all equipment and most of the labor would be imported from the lower 48 states. Expenditures on site improvements, with the exception of purchasing cement and reinforcing steel outside the region, would be made within the Railbelt.

2.4.6 Potential Application in the Railbelt Region

As discussed in Section 2.4.2 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 of the need to deliver large amounts of construction material and very large and heavy components to the site. Interior siting would have 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

Railbelt region. The Railbelt System, with a forecasted interconnected load of 1,800 MW in 2010 (see Chapter 1), will probably be too small to accommodate even the smaller nuclear power plants, primarily from the point of view of system reliability. If nuclear power were available to the Railbelt System, significant reserve capacity would still have to be available to provide generating capacity during scheduled and unscheduled outages.

In addition, the large capacity of most current nuclear units limits the adaptability to growth to very large increments, which are not characteristic of projected Railbelt demands. Nuclear capacity is not added easily, as a strict licensing, construction, and operation process must be followed.

2.5 GEOTHERMAL

Geothermal energy is defined as the heat generated within the earth's interior. If this heat is close to the surface, it may be tapped as an energy source. Geothermal energy may be utilized for electricity generation, which usually requires temperatures of at least 280^{o}F, or for direct applications at temperatures less than 280^{o}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. Approximate required temperatures of geothermal fluids for various applications is presented in Table 2.11.

Three types of geothermal resources hold potential for development: hydrothermal, geopressured brine, and hot dry rock. Only hydrothermal systems are in commercial operation today. 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 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 approximatly 450^{o}F.

Liquid-dominated systems may be subdivided into two types, those producing high enthalpy fluids greater than 200 calories/gram (360 Btu/lb),

TABLE 2.11. Approximate Required Temperature of Geothermal Fluids for Various Applications

	°C		
	200		
	190		
	180	Evaporation of highly concentrated solutions Refrigeration by ammonia absorption Digestion in paper pulp (Kraft)	
Saturated Steam	170	Heavy water via Hydrogen sulphide process Drying of diatomacious earth	
	160	Drying of fish meal Drying of timber	Conventional Power Production
	150	Alumina via Bayer's process	
	140	Drying farm products at high rates Canning of food	
	130	Evaporation in sugar refining Extraction of salts by evaporation and crystallistation Fresh water by distallation	
	120	Most multi-effect evaporation; Concentration of saline solution	
	110	Drying and curing of aggregate slabs	
	100	Drying of organic materials, seaweeds, grass, vegetables, etc. Washing and drying of wool	
	90	Drying of stock fish Intense de-icing operations	
	80	Space-heating (buildings and greenhouse)	
Hot Water	70	Refrigeration (lower temperature limit)	
	60	Animal husbandry Greenhouses by combined space and hotbed heating	
	50	Mushroom growing Balneology	
	40	Soil warming	
	30	Swimming pools, biodegradation, fermentations Warm water for year-round mining in cold climates De-icing	
	20	Hatching of fish. Fish farming.	

Source: Armstead, H. 1978.

and those producing low enthalpy fluids less than 200 calories/gram. The high enthalpy fluids may be used to generate electrical power; the lower enthalpy fluids may be useful for direct heating applications (Considine 1976).

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.

2.5.1 Technical Characteristics

The specific type of plant which could be selected to develop the Alaskan geothermal resources will depend on the temperature, pressure, and quality of the geothermal fluid. Four geothermal generating technologies are currently used: 1) dry steam; 2) flashed steam in either single or multiple flash units; 3) binary plants which use secondary working fluids because the direct use of the geothermal resource is either impossible or undesirable; and 4) a combination of flashed steam and binary fluids. A fifth plant type, not yet in use, is a hybrid in which geothermal resources are used in conjunction with fossil fuels, solar energy, or biomass for electrical generation.

In a dry steam plant the 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 injected back into the reservoir.

Flashed steam plants operate on steam flashed from de-pressurized hot water brought to the surface. Utilization efficiency can often be increased by flashing at decreasingly lower pressures (multiple flashing) to obtain as 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 systems is more technically demanding for the liquid-dominated than for vapor-dominated systems. Certain difficulties would be encountered in developing liquid-dominated systems: larger masses of fluids must be produced to generate a given amount of electrical energy; corrosion of well casing and piping may be excessive;

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 2.8, use secondary working fluids such as freon, isobutane, or isopentane to drive turbines. The use of a binary cycle plant allows for the generation of electricity with geothermal fluids that are below the flashing temperature of water. Binary plants may also use geothermal fluids whose direct use would be impossible 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 turbo-generators, and condensed for reuse.

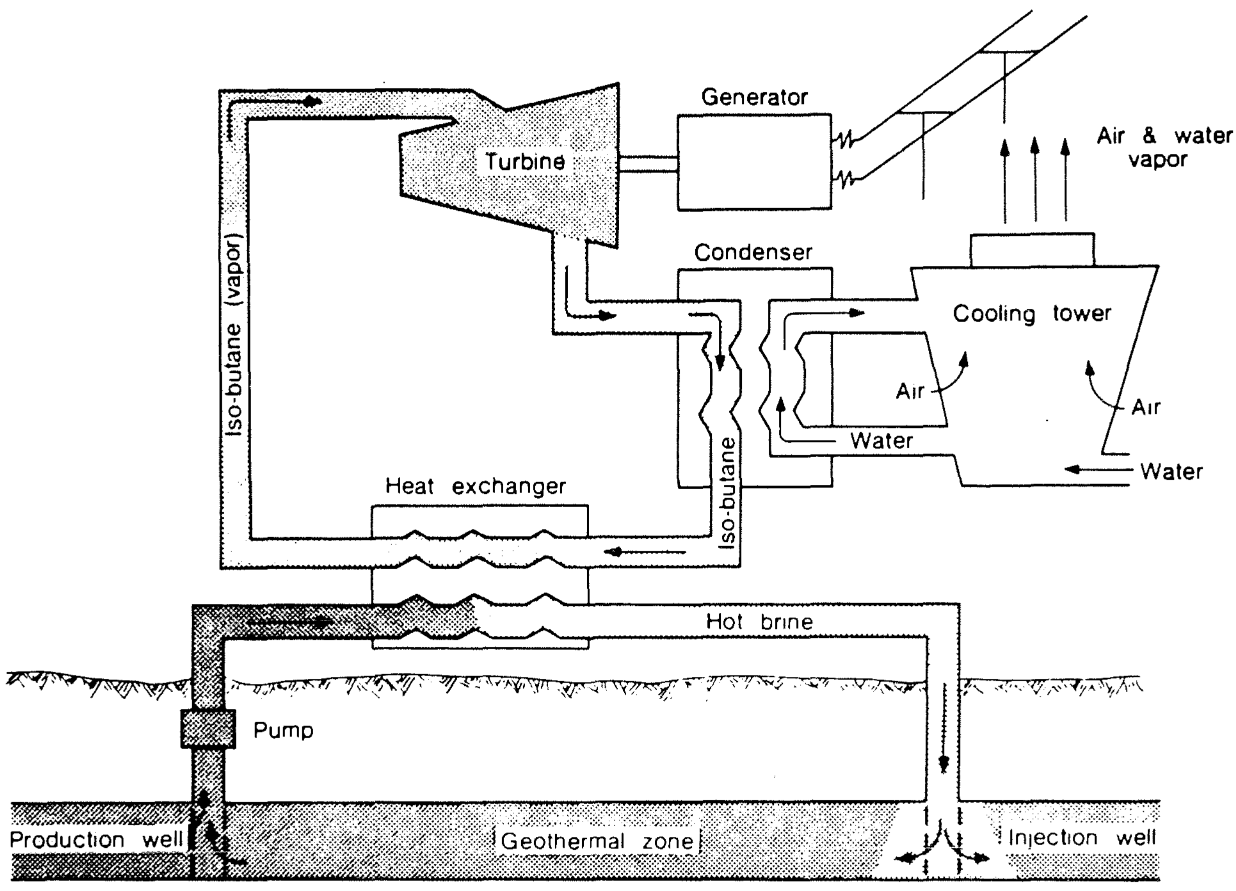


FIGURE 2.8. Binary Cycle Geothermal Power Plant

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, thus extracting additional energy and making for more efficient use of the resource.

Hybrid plants make use of geothermal resources together with ancillary energy sources such as coal, biomass, or solar energy. The geothermal resource is used as preheated feed water for a boiler fired by the ancillary fuel. In some cases, such as with the use of biomass, the geothermal resource can also be used to dry the organic fuel, thus increasing the burning efficiency. The hybrid plant can utilize geothermal resources that are below the temperature required to produce usable amounts of steam.

In a conventional geothermal electric generating plant, the working fluid is withdrawn from the geothermal source, enters the turbine, is condensed, and is either evaporated from the cooling tower, or reinjected into the reservoir.

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 of between 50 and 60%. Plants receiving lower quality geothermal energy 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 rates of the turbine are on the order of 22,000 Btu/kWh. This is equivalent to a thermodynamic efficiency of 16%, which means that it would require twice as much cooling water 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, maintenance and source reliability. It is estimated that a geothermal plant in the Railbelt region would be available approximately 65% of the time. Hot dry rock resources would be used by injecting a working fluid, probably water, into the hot rock using injection wells. The heated water would then be brought to the surface using production wells where it would be flashed to steam and used to drive turbo generators.

The low thermal conductivity of rock controls the rate of heat transfer to the circulating fluid. Large surface areas are thus required for geothermal utilization. Los Alamos Scientific Laboratory (LASL) is field testing a rock-fracturing method based on conventional hydraulic fracturing. By pumping high pressure water 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 from which the heated working fluid is drawn.

2.5.2 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:

1. Fluid temperatures in excess of approximately 140^{o}C (280^{o}F)
2. Heat sources at depths less than 10,000 ft with a temperature gradient at 25^{o}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 power station's long term viability is dependent on the prediction of reservoir energy capacity and management of reservoir development.

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 electrical generating and auxiliary equipment portion of a geothermal 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.

2.5.3 Costs

Estimated capital costs and operation and maintenance costs of several types of geothermal developments, including well field development, are shown in Table 2.12. These are all 50-MW plants.

2.5.4 Environmental Impacts

A problem unique to geothermal steam cycles involves the water quality characteristics of the geothermal fluid and the subsequent disposal method. This fluid is generally saline and, because of this characteristic, most geothermal plants in the United States mitigate this potential problem through 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 Cool Inlet shoud not prove to be too difficult. The interior fields, however, could require extensive wastewater treatment facilities to properly mitigate water quality impacts to

TABLE 2.12. Cost Summary for Geothermal Developments

System Type	Capital Costs ($/kW)	O and M Costs ($/kW/yr)	Cost of Power[a] ($/kW)
Vapor-dominated cycle	900	-	0.035
Binary cycle	1550	-	0.052
Hot dry rock	2550	90	0.150
High-temperature water	3400	-	0.101
Low-temperature water	5300	-	0.151
General Average - All Types	1100	65	0.040

(a) Cost of power calculated using general average O&M cost except for hot dry rock case.

freshwater resources and comply with all relevant Alaska regulations. Depending upon a specific field's water quality characteristics, the costs associated with these treatment facilities could also preclude development.

Geothermal plants have the highest per megawatt use of any steam cycle plant (845 gpm/MW). A maximum size plant for the Railbelt region (50 MW) would use less water than only nuclear or coal fired- plants, with a total water use rate of 42,200 gpm or 750 gpm for once-through and recirculating cooling water systems, respectively.

Emissions of gases and particulates into the atmosphere from the development of geothermal resources will consist primarily of carbon dioxide and hydrogen sulfide (H_2S). Other emissions may consist of ammonia, methane, boron, mercury, arsenic compounds, fine rock particles, and radioactive elements. There is considerable variability in the nature and amount of these emissions, and this uncertainty can be removed only by testing wells in the proposed project area. Emissions are also a function of operational techniques. If the reinjection of geo-thermal fluids is used, emissions into the atmosphere may be reduced to nearly zero. Even when reinjection is not used, H_2S emissions can be controlled by oxidizing this compound to sulfur dioxide (SO_2) and subsequently 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.

In addition to major potential impacts associated with water withdrawal and effluent discharge that are similar for all steam cycle plants, geothermal plants have some unique problems that may have hazardous effects on the aquatic environment. 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 toxic nature of the brine. Current regulations require reinjection of spent geothermal fluid; however, entry of these brine solutions into the aquatic environment either by discharge, accidental spills, or ground water seepage, could cause acute and chronic water quality effects.

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 geothermal fluids into this system may have significant impacts on these fish, and other aquatic organisms, depending on the size and locaton 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.

The primary impact resulting from geothermal plants on the terrestrial biota is habitat loss. Land requirements for geothermal plant facilities, on a per-kW basis, are comparable to those for oil and natural gas plants. Biomass, coal, and nuclear plants require larger tracts of land than geothermal, either from the standpoint of capacity or kW production. However, geothermal lands are more likely to be located in remote areas than other steam cycle power plants. Disturbances to these areas could be extensive depending on the land requirements of the geothermal well field.

Primary geothermal development locations are within the Wrangell and Chigmit Mountains. The latter area is remote and is inhabitated 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. Impacts could 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 impose additional disturbances to wildlife and vegetation from increased accessibility to people.

2.5.5 Socioeconomic Effects

The construction of a 50-MW geothermal plant would require approximately 90 workers over a 7-year period. Although the construction workforce is moderate in size, the remoteness of the geothermal resources will 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. Semi-permanent 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 rather than from an influx of workers.

Impacts to communities from development of the Wrangell Mountain resource could be expected to be more severe since Glennallen (pop. 360) is a community of sufficient size to attract workers and their families. The in-migration of the workforce to Glennallen would place a strain on community infrastructure. Similar to the Chigmit Mountain geothermal resources, haul roads would have to be built from the Glennallen-Gakona-Gulkana area. Secondary impacts to the communities would be associated with the transportation of equipment to the site.

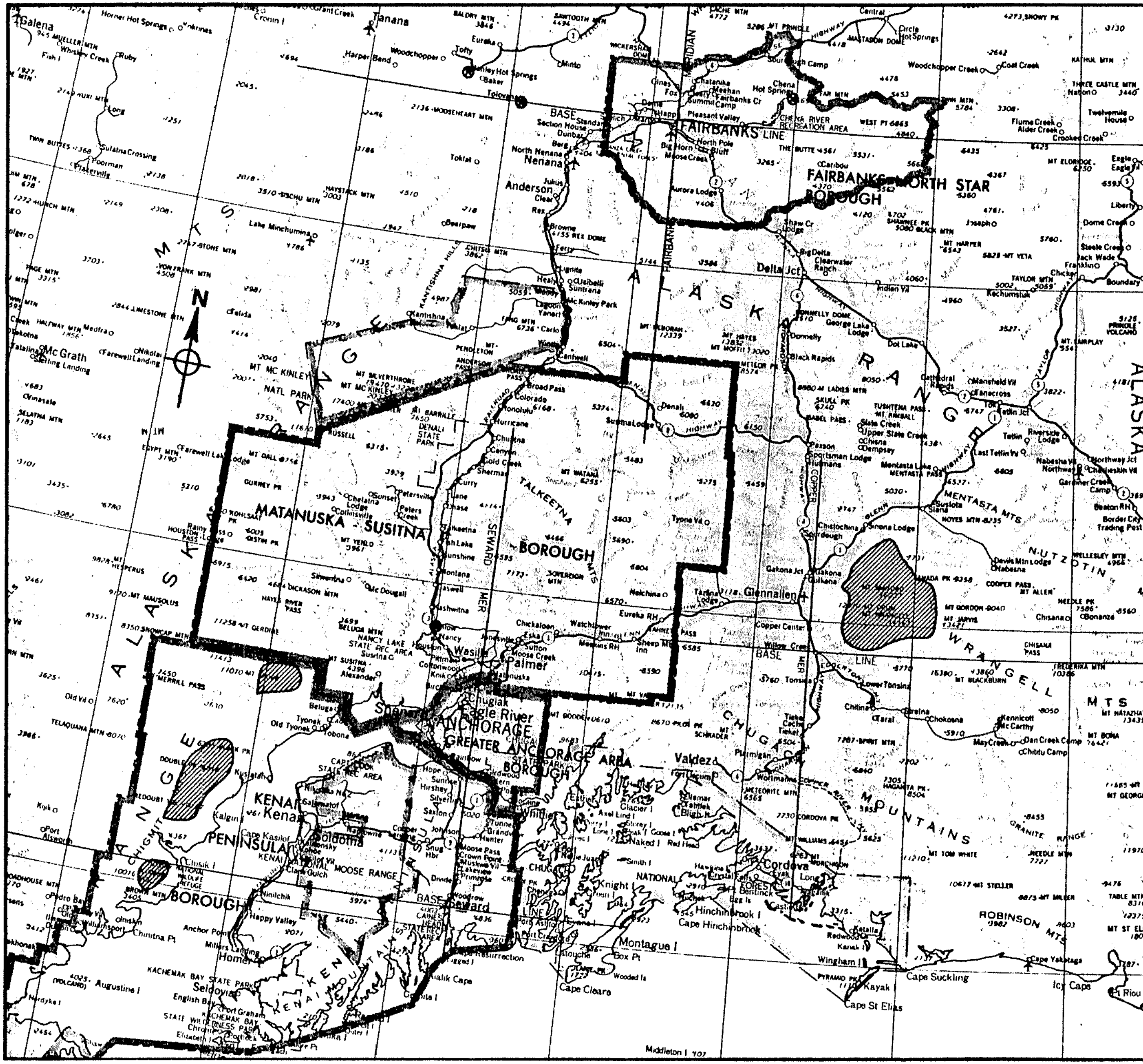
Project expenditures is estimated to be 55% outside the region and 45% within the Railbelt. The large investment in production and reinjection wells and equipment will be offset to some extent by the moderate-sized construction workforce and long construction period.

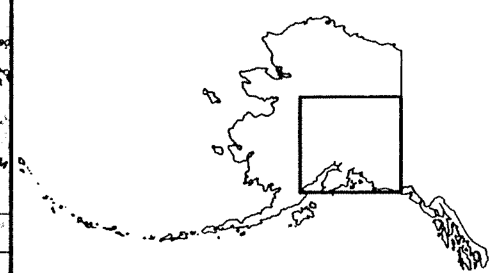
2.5.6 Potential Application in the Railbelt Region

Only hot dry rock (hot igneous) and low-temperature, liquid-dominated hydrothermal convection systems have been identified in or near the Railbelt region (Figure 2.9). 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 space heating. 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, located approximately 200 miles from Anchorage, has subsurface temperatures exceeding 1200°F. The Chigmit System, 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.

A geothermal 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.

The geothermal areas (with the exception of Mt. Spurn) of both Wrangell and Chigmit Mountains are located in lands designated as National Parks (Figure 2.2). The federal Geothermal Steam Act prohibits leasing and developing National Park lands. If, however, townships within these areas are





GEOTHERMAL RESOURCES

Source: U.S. Geological Survey Circular 726, Assessment of Geothermal Resources of the United States, 1975.

Hot Igneous System

⊗ Hot Springs

SCALE 1:2 500 000

50 0 50 100
MILES

NATIONAL GEODETIC VERTICAL DATUM OF 1929

ALASKA RAILBELT REGION

FIGURE 2.9.

USGS ALASKA MAP E

selected by a Native corporation under the Alaskan Native Claims Settlement Act, and if the surface and subsurface estates are conveyed to private ownership, then the federal government jurisdiction would not apply, and development could be possible. The Alaska National Interest Lands Conservation Act of 1980 allows the granting of rights-of-way for pipelines, transmission lines and other facilities across National Interest Lands for access to resources surrounded by National Interest Lands.

3.0 CYCLING TECHNOLOGIES

The primary characteristic of cycling technologies is the capability to start and stop generating units on a daily 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 growth pattern of the Alaska Railbelt have resulted in technologies traditionally considered cycling (certain combustion turbine and combined cycle units) being used for base load service. This can be expected to change as the area grows and especially if an interconnected system is developed.

Four currently available technologies and one emerging technology have been identified as cycling technologies for purposes of this study:

- Combustion Turbines
- Combined Cycle
- Diesel Electric
- Hydroelectric
- Fuel Cells

The first four of these technologies already exist within 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 3.1.

3.1 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 plants, and the

TABLE 3.1. Comparison of Cycling Technologies on Selected Characteristics

First Stage Attributes	Combustion Turbines 70 MW	Combined Cycle 200 MW	Diesel 12 MW	Hydroelectric 50 MW	Fuel Cells 10 MW
1. Aesthetic Intrusiveness					
A. Visual Impacts	Minor	Moderate	Minor	Moderate to Significant	Minor
B. Operating Noise	Moderate	Minor	Minor	Minor	Minor
C. Odor	Minor (Municipal Waste)	Minor	Minor	Minor	Minor
2. Impacts on Biota					
A. Aquatic/Marine (gpm)[a]	0	600	0	Site-Specific	20[c]
B. Terrestrial (acres)[b]	6	12	4	Site-Specific	2
3. Cost of Energy					
A. Capital Cost ($/kW)	560	960	700	4000	650
B. O&M Cost ($/kW)	40	42	35	13	3.30
C. Fuel Cost					
D. Cost of Power ($/kW)					
4. Health & Safety A. Public	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 air quality degradation	Safe	Safe
5. Consumer Effort	Utility operated. No individual or community effort required.	Utility operated. No individual or community effort required.	Utility, community or individual operated.	Utility operated. No individual or community effort required.	Utility operated. No individual or community effort required.
6. Adaptability to Growth A. Adjustments in plant scale	Packaged units can be added relatively eaily to existing site.	Additional units can be added.	Additional units can be added.	Additional units can be added.	Additional units can be added
7. Reliability					
A. Availability (%)	88	85	90	90	95
8. Expenditure Flow From Alaska					
A. Capital Cost (%)	80	70	80	65	80

TABLE 3.1. (contd)

First Stage Attributes	Combustion Turbines 70 MW	Combined Cycle 200 MW	Diesel 12 MW	Hydroelectric 50 MW	Fuel Cells 10 MW
B. Operation and Maintenance Cost (%)					
C. Fuel Cost					
9. Boom/Bust					
A. Ratio of Construction to Operating Personnel	30:12	45:15	25:2	200:6	90:10
B. Magnitude of Impacts	Minor to moderate in all locations.	Minor to moderate in all locations.	Minor in all other locations.	Severe in small communities. Moderate to significant in Fairbanks & intermediate sized communities. Minor in vicinity of Anchorage.	Significant to very small communities. Minor to moderate in all other locations.
10. Control of Technology					
A. Utility	Primary Control	Primary Control	Primary Control	Primary Control	Primary Control
B. Individual	Limited through regulatory agencies and government.	Limited through regulatory agencies and government.	Potential for individual control.	Limited through regulatory agencies and government.	Limited through regulatory agencies and government.
Second Stage Attribute					
1. Commercial Availability	Mature	Mature	Mature	Mature	Emerging
2. Railbelt Siting Opportunities	Limited to fuel delivery considerations.	Limited to fuel delivery considerations.	Limited to fuel delivery considerations.	Numerous sites available.	Numerous sites available.
3. Product Type	Baseload Intermediate Peaking	Baseload Intermediate Peaking	Baseload Intermediate Peaking	Baseload Intermediate Peaking	Baseload Intermediate Peaking
4. Generating Capacity					
A. Range in Unit Scale (MW)	3-80	15-150	30 KW - 15 MW	50 MW - 700 MW	>40 KW

(a) Recirculating cooling water systems.
(b) All facilities.
(c) Water produced and discharged.

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 J).

3.1.1 Technical Characteristics

The combustion turbine power plant uses a gas turbine engine as the prime mover. This engine, which is similar to a typical 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 power turbine. The power turbine drives the inlet air compressor and the electric power generator, as shown in Figure 3.1. The fact that hot gas is the working fluid in a combustion turbine gives rise to the gas turbine.

Combustion turbine powerplants have traditionally been less efficient than conventional fossil-fired generating stations. However, recent advances in combustion turbine technology, particularly improvements in blade metallurgy and cooling and improvements in combustor efficiency, have significantly increased combustion turbine output and efficiency.

Heat rate and conversion efficiency of combustion turbines are presented below for different plant sizes.

Plant Size (MW)	Heat Rate (Btu/kWh)	Conversion Efficiency (Percent)
20 - 100	10,000 - 11,000 (LHV)[a]	34
0.5 - 20	12,000 - 14,000 (LHV)[a]	28

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

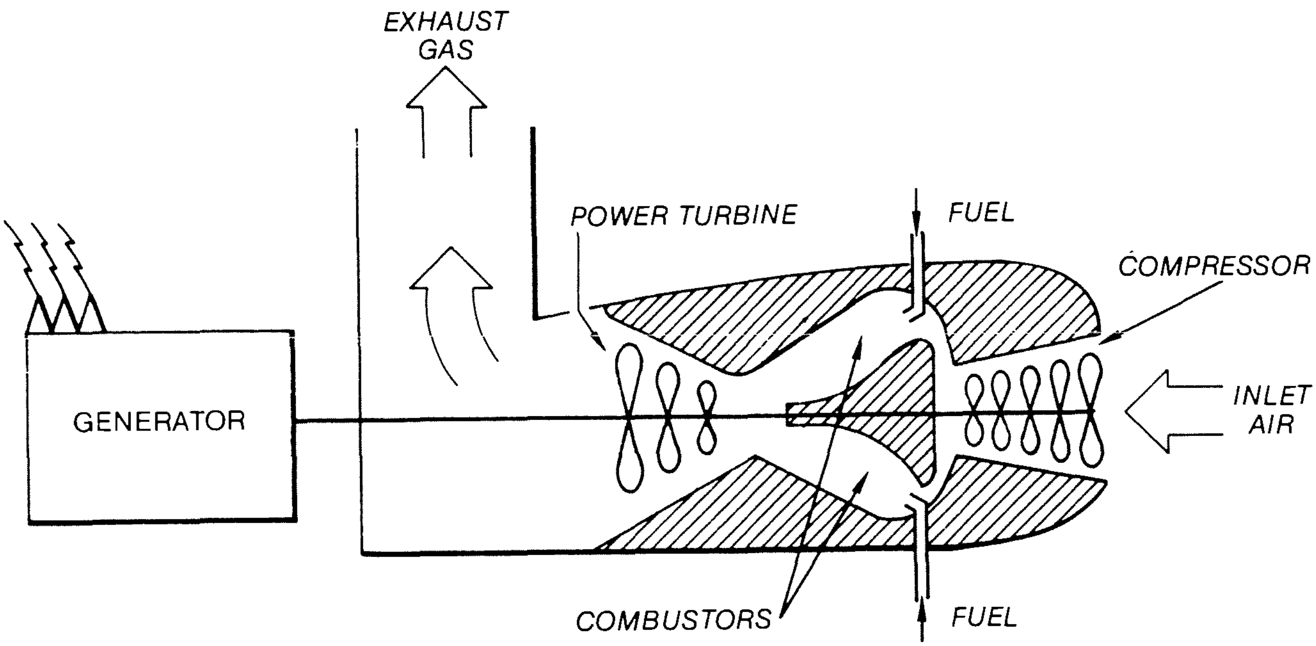


FIGURE 3.1. Simple Cycle Combustion Turbine

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 have been developed which utilize a portion of this exhaust gas heat to improve efficiency. Combined cycle and cogeneration, which are discussed in separate technology profiles, are two examples. A regenerative cycle is another example. In the regenerative cycle, 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 can increase 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 powerplants.

A minimum economical plant size for combustion turbines is 500 kW, which could serve a community of 80 to 100 households. Combustion turbine power plants are not complex to build since most of the equipment arrives at the site assembled. The machines are reliable; they are available to meet demand approximately 88% of the time.

3.1.2 Fuel Requirements

Combustion turbines can use a wide variety of natural and synthetic fuels, from heavy residual oils to medium Btu synthesis gases. Combustion turbines operating in the Railbelt use natural gas produced in Alaska, or distillate oil similar to grade DF-2. The performance of the turbine varies slightly with each fuel. While 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 from the standpoint of performance and operating simplicity. Heat rates are generally better and exhaust emissions, especially for sulfurous oxides and particulates, are almost non-existent. 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 utilized, 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 with appropriate treatment. 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. Thus is may be more economic to use even with treatment costs.

Combustion turbines are capable of burning a variety of synthetic fuels, although little operating experience with synthetics has been gained to date.

This is due mainly to the high cost and limited availability of synthetic fuels. However, certain synthetic fuels, notably gas synthesized from coal, is approaching economic viability. Potential application of synthetic fuels to Railbelt power facilities are described in Appendix J.

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, with only a minimum of modifications to existing hardware required.

Methanol produces fewer emissions than petroleum-based fuels. Methanol 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. Carbon monoxide (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.

A fuel transportation system must be provided to use any of these fuels. 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 gas is impractical, which thus requires the combustion turbine power plant to be located adjacent to the gasification plant. Medium-Btu gas can be transported economically via pipeline to distances up to approximatly 100 miles. This removes the limitation of locating the combustion turbines at the gasification plant, and in fact, 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.

3.1.3 Siting Requirements

The simple cycle combustion turbine power plant has fewer siting constraints than conventional fossil-fired or nuclear plants. Only limited space is required, no cooling water is required, and operating personnel are not necessary. The primary siting constraints relate to atmospheric emissions and fuel supply.

One of the primary siting constraints of the combustion trubine technology is environmental. The exhaust from combustion turbines typically contains oxides of sulfur (SO_x) when residual fuels are used, as well as oxides of nitrogen (NO_x) with residual fuels or natural gas. These constituents comprise the main 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 utilized. 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 conversion 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.

3.1.4 Costs

Combustion turbine powerplants 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, there is some economy of scale 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 capital costs are presented in Table 3.2.

TABLE 3.2. Estimated Costs for Combustion Turbine Power Plants

Plant Size (MW)	Capital Cost ($/kW)	O and M Cost ($/kW/yr)	Cost of Power ($/kW)
50 - 100	60	40	
50 and under	20	40	

Operation and Maintenance costs vary drastically and published costs can often be misleading. Even with identical combustion turbines, many operators report significantly different O and M costs. One reason for this is because 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. Improper fuel selection and inlet air contamination can also have detrimental effects. Also, maintenance practices differ significantly among utilities. Some utilities rely heavily on preventative maintenance, while others only perform maintenance as necessary. In addition, the methods of recording O and M costs are not uniform, and differences in reported costs may result purely from accounting practices.

3.1.5 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 fuel combustion technologies. This comparison is provided in Appendix B along with a detailed discussion of the regulatory framework and various siting considerations. Sulfur emissons can be controlled through use of low-sulfur oils or natural gas. Emissions of the oxides of nitrogen can be controlled by use of water or steam injection techniques. These emissions will not preclude the siting of combustion turbines anywhere in the Railbelt region, except that it may be difficult to justify their operation within the Fairbanks or Anchorage non-attainment areas. Optimum siting would involve a consideration of these areas as well as nearness to fuel lines, fuel ports, and load centers.

Because cooling water is not required for combustion turbines, there would be no impacts on aquatic biota associated with operation of combustion turbines. The only potential impacts would be from construcitn runoff (refer to Appendix C). The use of proper construction techniques would eliminate any potential for impacts on the aquatic environment.

Land losses and human disturbance represent the most significant impacts on the terrestrial biota resulting from combustion turbine power plants. Land losses, however, will generally be small (3 acres for 170 MW plant). 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 smaller than those for combined cycle, fossil fuel, or other conventional power plants.

In addition to land losses, combustion turbine power plants fueled by fossil-or syn-fuels release gaseous and particulate matter that could afffect the terrestrial biota. Depending on the fuel type, SO_2 and certain trace elements 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 are described in Appendix D. In the Railbelt region, these impacts could be minimized by siting plants away from sensitive ecological communities and installing effective pollutant control devices.

3.1.6 Socioeconomic Effects

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

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

3.1.7 Potential Application to Railbelt Region

Combustion turbine power plants found in the Railbelt vary from 3 MW 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 Railbelt. The main reasons for their wide use in the Railbelt have been their low capital costs, relatively small unit size, and the availability of gas and distillate fuels.

The potential for future application of this technology is somewhat clouded by the provisions of the Fuel Use Act, which restricts the use of petroleum fuels and natural gas. Simply stated, new units that use petroleum fuels or natural gas may operate 1500 hr/yr as peak load units. After 1990 the use of natural gas is prohibited. It is possible however, to use combustion turbine power plants that are integrated with a coal conversion plant or fueled by a product from such a plant such as low or medium Btu gas, methanol, or distillate oil.

3.2 COMBINED CYCLE

The combustion turbine combined cycle power plant relies on two proven technologies, the combustion turbine and conventional steam cycle power generation. This is an efficient and reliable generating resource which has been in commercial operation well over a decade. These plants are capable of closely following growth in demand since generating capacity can be added in relatively small increments, especially compared to technologies such as coal-fired or nuclear steam electric.

3.2.1 Technical Characteristics

The combined cycle power plant uses two different thermodynamic cycles simultaneously to produce electricity. (This differs from cogeneration, which produces two forms of energy, electricity and process heat.) A combustion turbine combined cycle consists of a conventional combustion turbo-generator (as described in the combustion turbine profile) with a heat recovery boiler supplying a steam turbo-generator. The heat recovery boiler utilizes 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 which would otherwise go to waste, 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 3.2.

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-seventies, several utilities converted 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 3.2). 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 allows a combined cycle plant considerable flexibility in terms of electrical output.

Combined cycle power plants can be erected more rapidly than conventional large power plants of equivalent capacity, with 2 to 4 years a typical construction time for a new plant. They are usually constructed in phases,

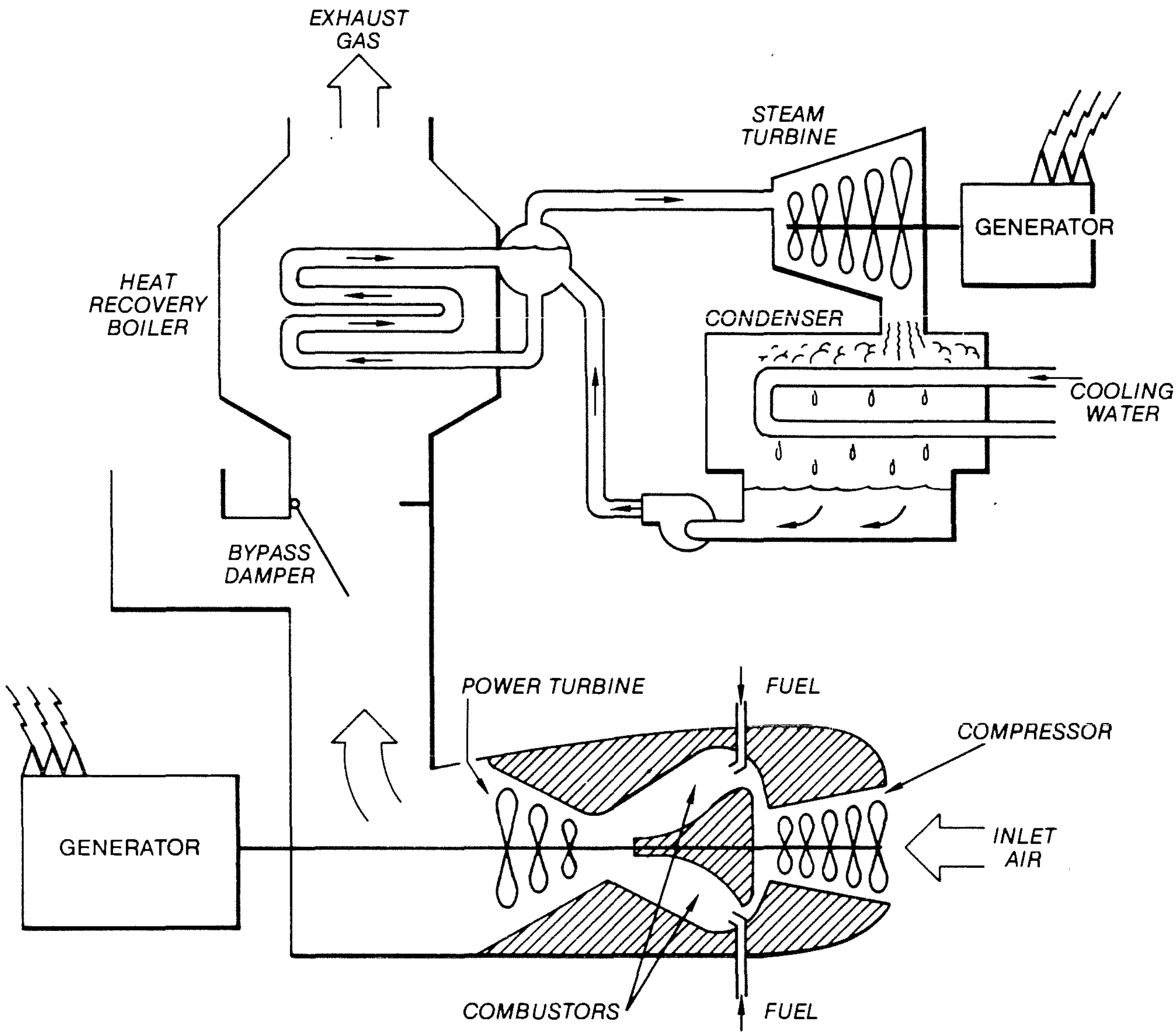


FIGURE 3.2. Combined Cycle Combustion Turbine

with the combustion turbine portion erected first. This allows the combustion turbines to generate power while the balance of the plant is still under construction. Combined cycle plants have therefore traditionally been used where generation is needed to fill critical shortages.

The minimum size of a large-frame combustion turbine combined cycle plant is 90 MW. This is slightly larger than a large combustion turbine plant (60 MW). A 90-MW combined cycle plant can economically serve a community of

26,000 households. Anything smaller would not be economically viable. The reliability of combined cycle compares favorably with other technologies based on combustible fuels. Combined cycle power plants are available, on average, 88% of the time, compared to nuclear steam electric 78% and natural gas-fired steam electric 92%. The response time to changes in load is very good, making a combined cycle useful for load following applications.

Combined cycle plants are considerably more efficient than simple cycle combustion turbine plants, since turbine exhaust heat is converted into useful electrical energy. Whereas a simple cycle plant may have a heat rate in the 11,000 to 12,000 Btu/kWh range, a combined cycle heat rate may be as low as 8,500 Btu/kWh (a thermal efficiency of approximately 40%). Compared to other conventional fossil generation technologies of comparable capacity, a combined cycle plant would use less fuel and reject less heat to the environment.

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

3.2.2 Siting and Fuel Requirements

Like the simple cycle combustion turbine plant, a combined cycle plant has siting constraints related to air emissions (see Section 3.1). In addition, the combined cycle plant has further constraints imposed by the steam cycle, which requires water for condenser cooling and boiler make-up. However, because the combustion turbine portion of the total combined cycle plant (approximately two-thirds) requires essentially no cooling water, water requirements are much less than a similar sized conventional steam electric plant.

Fuel storage and handling requirements are the same as those described in Section 3.1 for combustion turbines. 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.

3.2.3 Costs

Capital costs 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 3.3.

TABLE 3.3. Estimated Costs for Combined Cycle Facility

Capacity (MW)	Capital Cost ($/kW)	O and M Cost ($/kW/yr)	Cost of Power ($/kW/yr)
90	$1000	$1.60	
200	920	1.60	

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 presented below:

Capacity (MW)	Capital Cost ($/kW)
90	$240
200	320

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.

Operation and maintenance costs for combined cycle plants are fairly constant over a large range of plant sizes. Operation and maintenance costs for combined cycle plants seem to suffer the same recording and reporting disparities as simple cycle combustion turbines. Reported operation and maintenance costs vary considerably as a result of different operating and maintenance practices as well as accounting practices.

It is interesting to note that reported operation and maintenance costs for combined cycle plants are generally about 1 mill/kWh less than those for simple cycle combustion turbine plants. This may be due to the fact that base load operation typical of combined cycle plants is less demanding of machine life than is the cyclic duty typical of combustion turbines.

3.2.4 Environmental Considerations

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

Air quality impacts are similar to those associated with combustion turbines (see Appendix B). Emissions of nitrogen oxides can be controlled through water or steam injection techniques while SO_2 emissions can be reduced by using low sulfur fuels. Additional water vapor is added to the air from the waste heat rejection system of the boiler unit. The formation of plumes can be eliminated by the use of a wet or wet/dry cooling tower system (Appendix F). No offsite meteorological effects of system operation will be detectable.

Potentially significant impacts from water withdrawal and effluent discharge which are common to all steam cycle plants would be the lowest on a per megawatt basis for combined cycle plants. The water use rate of these facilities is only one-third that of the next lowest plant type, requiring 150 gpm/MW or 3 gpm/MW for once-through or recirculating cooling water systems, respectively. Other potential impacts can be avoided by proper siting, design, and construction techniques.

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 200-MW plant), but can be larger if plants are fueled by distillate oil or certain types of synfuels which require on-site fuel storage (12 acres). Distillate oil-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 certain trace element emissions probably have the highest potential for terrestrial impacts; this potential, however, is highly dependent on the fuel type. Distillate oil-fired plants produce the highest levels of SO_2 emissions while natural gas-fired plants produce almost none. The specific impacts of these emissions and those associated with land loss and human disturbance on the terrestrial biota are described in Appendix D. In the Railbelt region, these impacts on soils, vegetation, and wildlife could be minimized by siting plants away from sensitive ecological areas and installing effective pollution control devices.

3.2.5 Socioeconomic Considerations

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

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

3.2.6 Potential Application to The Railbelt Region

Use of the combined cycle technology is rather recent, with plants currently operating in Anchorage and Fairbanks. However, prospects for further use of this technology in Alaska would not appear good because of provisions of the Fuel Use Act, which restricts new plants that use natural gas or petroleum-based fuels. However, exemptions can be obtained for such a plant if it is designed to use synthetic fuels derived from coal (Appendix J). If coal gasification plants are built in the Alaska Railblet, then large, base-loaded combined cycle plants could be integrated with the gasification plant.

Sixty four percent of the installed capacity in the Railbelt region is currently met by combustion turbine electric generation. Combustion turbine plants serve most of the load in the Anchorage area and are used primarily to meet peak loads in the Fairbanks area. The widespread use of combustion turbines in the Railbelt area may provide an opportunity to increase generating capacity through conversion to combined cycle plants. Heat recovery boilers and steam turbines would be added to simple cycle plants to provide more generation with no additional fuel use.

3.3 DIESEL GENERATION

Diesel generation accounts for approximately 5% of the Railbelt electric generating capacity. Approximately 36 MW of utility capacity exists, while 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 when there is a power outage), peaking units, and standby units. They also are used as load following units in remote locations and small communities in the Railbelt. Diesel installations in the Railbelt region range in size from 2 to 18 MW, although a much larger range 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 utilizing slow-speed, two-stroke diesels are under construction.

3.3.1 Technical Characteristics

A diesel generating plant consists of a diesel cycle internal combustion engine driving a standard electricity generator. 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 during combustion. Expansion of the products of combustion 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 are typically 12:1 to 15.1 contrasted with spark ignition ratios ranging from 6:1 to 10:1 and can reach 20:1. It is these higher compression ratios which contribute to the relatively high thermal efficiencies of diesel units.

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 8,500-9,700 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 3.4).

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 Alaskan locations may have a much shorter life because of poor maintenance.

TABLE 3.4. Fuel Consumption Rates and Equivalent Heat Rates for a Diesel Generator Operating at Various Loads

Kilowatts	Fuel Consumption (gas/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 able to quickly respond to start-up and shut down. These units are used in the Railbelt as black start units when other generating units fail. They also serve in conjuncton with larger generating base load systems as an emergency power source. Further, diesels can be used to augment fuel saver technologies such as wind or tidal power when natural conditions preclude power generation from the fuel saver technologies.

3.3.2 Siting and Fuel Requirements

Diesels are well-suited for generation throughout the Railbelt region. The small high-speed units are compact, usually 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. Medium and low-speed units are larger, usually 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 2-5 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. Air shipment of units has been used in remote locations such as communities in the interior of Alaska.

Ancillary systems associated with diesel units are minimal. Fuel storage is required, particularly in remote locations where fuel deliveries may be as infrequent as once a year. Waste heat boilers may be attached for cogeneration (see Section 5.1). The small size of diesel units, and the relatively clean fuels consumed, generally eliminate the need for extensive pollution control systems, although sound suppression is 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, have also been proposed for diesel units, and their adaptation to diesel generation cycles is under study.

3.3.3 Costs

Diesel power is expensive, but not in comparison to other options in Alaska. Most of the capital cost expenditure is for the equipment, purchased outside Alaska, and the transportation of that equipment to Alaska. Only a small amount of on-site 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 the lower 48 states. In remote areas, consumers may play a role in diesel maintenance and have a direct role in the decision to supply electricity.

Estimated capital, operation and maintenance, and estimated levelized costs of power (in 1980 dollars) for various diesel plant capacities are provided in Table 3.5.

TABLE 3.5. Estimated Costs for Diesel Electric Generation

Capacity (MW)	Capital Cost ($/kW)	O and M Cost ($/kW/yr)	Levelized Cost of Power ($/kWh)[a]
3	850	55	
6-9	800	45	
12	700	35	

(a) Based on a fuel cost of $8.00/MMBtu (Appendix G).

3.3.4 Environmental Considerations

Diesel electric generating systems do not require cooling water or continuous process feedwater for their efficient operation. They also 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 associated with diesel engines will be confined mainly to carbon monoxide and particulates. Residual, high sulfur fuels are generally not used in these engines. Carbon monoxide (CO) emissions can be controlled through the use of catalytic converters, and particulate emissions can be controlled through optimizing engine operation. In the Railbelt, these facilities may be sited almost anywhere, but if they are prposed for the carbon monoxide non-attainment areas (Anchorage and Fairbanks), regulatory agencies may require the consideration of alternate viable sites.

Impacts on the terrestrial biota 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. Other possible impacts due to noise and fuel storage can generally be resolved through noise-suppression devices and the avoidance of prime wildlife habitat during the siting process.

3.3.5 Socioeconomic Considerations

The impacts of siting diesel generators in the Railbelt are expected to be minimal due to the inherent limitation of scale of plant (0.05-15 MW) and absence of major siting constraints. Installation of a large diesel generator would require a small construction crew of 5 to 25 workers for periods of 1 month to 1 year, depending upon unit size. One or two people on a part-time basis could fulfill the operating and maintenance 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 to the lower 48 states. Approximately 80% of the capital investment of the project would be made outside of the Railbelt while 20% would be spent inside the region.

3.3.6 Potential Application for Railbelt Region

Because small increments of capacity are available and because diesel generators can be installed quickly, they can be used to provide base load 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.

3.4 HYDROELECTRIC ENERGY

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 economic viability of hydroelectric developments depends on the arrangement of project features, 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. In fact, for decades thermal plants served primarily as standby in case of equipment failure or to supplement hydroelectic power during peak demand hours. The more recent trend has been toward the use of thermal power to carry base load with hydropower supplementing thermal generation for peak loads.

Of the 610 million kilowatts of installed capacity for the United States (U.S. DOE 1979), about 11.5% or 70.4 million kilowatts is hydroelectric capacity. Most of this installed capacity and associated energy generation are produced by conventional hydroelectric developments. 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.

3.4.1 Technical Characteristics

There are two basic types of hydroelectric plants: conventional and low head.[a] 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. There are, however, many conventional and small high-head sites.

Small hydroelectric developments can be characterized as either complete "scaled down" conventional developments or as additions of hydropower generating facilities to existing dams. In remote areas, small hydropower developments can provide a steady and reliable source of electricity, given hydrologic conditions that would provide an adequate supply of water on a year-round basis. Commonly, this development is a run-of-river type project with little or no reservoir storage capacity. Small hydro projects are likely to be less complex; thus, federal licensing and permit granting programs are simpler, as are the physical facilities.

(a) "Head" is the difference between reservoir elevation and tailwater elevation.

The major components of a conventional hydroelectric development include a dam or diverison structure, a spillway for excess flows, turbines, a conduit called a 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 3.3). 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 (channel into which water is discharged after passing through the turbines). No two hydro power 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.

There are four types of dams, 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 containing spillway and low level outlets may be constructed across the main river section with earth or rock-fill wing dams extending to either abutment. 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 of transportation facilities.

A spillway is provided to discharge major floods without damaging the dam and other components of the project. 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 spillway design flood (the largest flood that statistically might be expected), normal discharge capacity of outlet works, and the available reservoir flood storage.

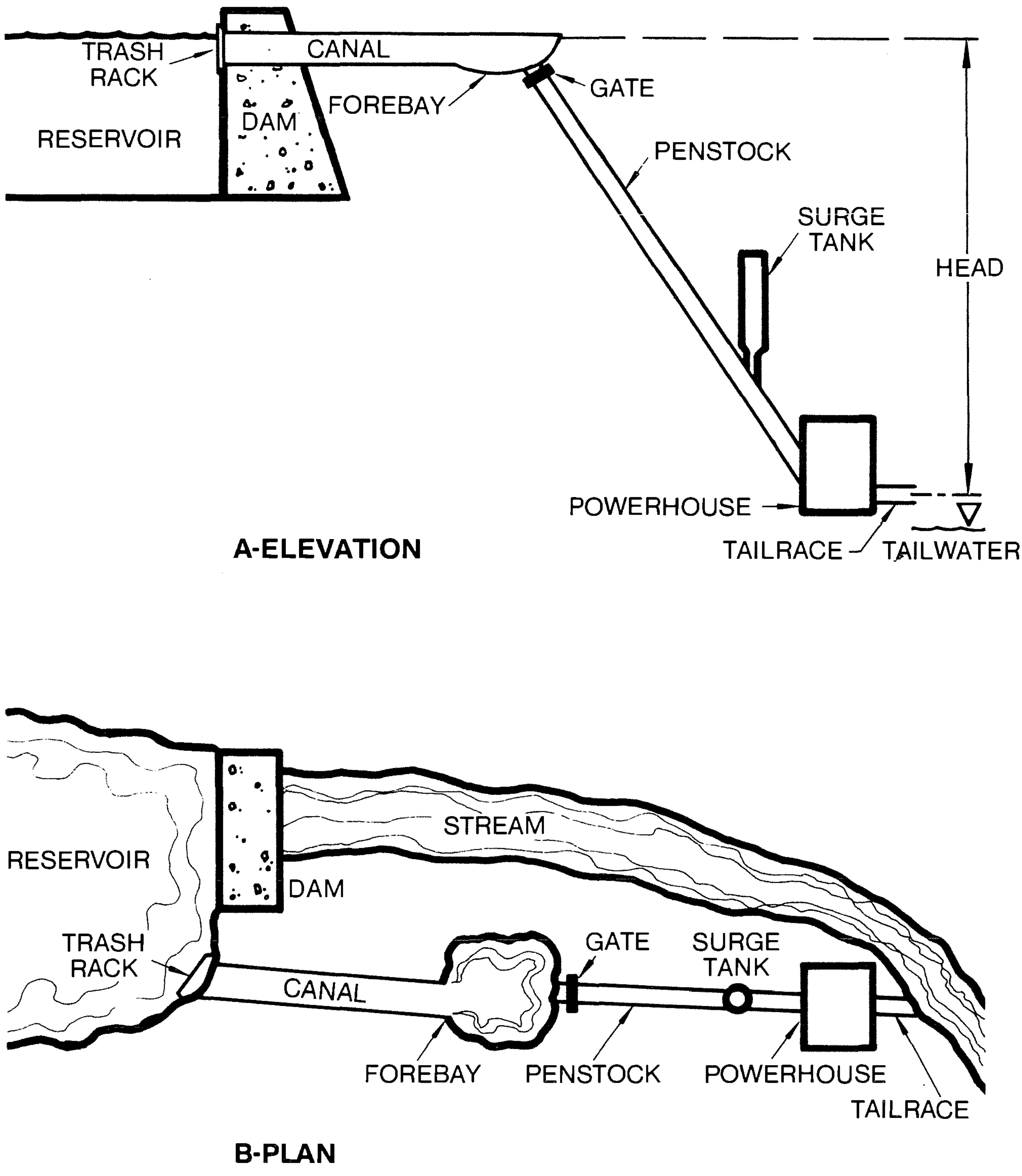


FIGURE 3.3. Schematic Diagram of Typical Components of a Hydropower System

If the turbines and generators are not 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 terrain. However, penstocks are used for the major portion of the elevation drop between the reservoir and the powerhouse.

A hydraulic turbine transforms the kinetic energy of flowing water into mechanical energy that, when harnessed to a generator, performs useful work. There are three basic types of hydraulic turbines: 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 and with hydraulic heads in the range of 100 to 2,400 ft (medium range). Propeller-type reaction turbines are used for hydraulic heads up to 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. The underground powerhouse is constructed in a natural or man-made cavern. This arrangement is used in certain topographic conditions, particularly narrow canyons, which preclude the convenient siting of a surface powerhouse.

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 base load, cycling, or standby unit. It is capable of assuming full load in a matter of minutes, and to follow 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 includes generator, turbine, and transformer efficiencies and hydraulic friction losses. Transmission losses are not included in this estimate. The response time for hydroelectric generators is very good. When start-up 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. This characteristic improves overall integrated generation and transmission system reliability of hydroelectric generating facilities.

3.4.2 Siting Requirements

The power potential of a hydroelectric development is a function of the head and streamflow available at a given 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 in order to provide storage and seasonal regulation without discharging water over a spillway. Smaller, or low head, hydroelectric projects must be operated as run-of-river, and therefore, are dependent 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. Flow duration data (and head) are used to calculate average annual energy and dependable capacity for the site.

The geophysical conditions at a site 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 for the project. Fault lines, sedimentary deposits, potential seismic activity, and extensive depth to hard rock can cause construction costs to soar, thus eliminating otherwise suitable sites.

3.4.3 Costs

Hydroelectric development capital investment costs 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 and waterways vary considerably and may have little relationship to the installed generating capacity. There is less variation in the costs of powerhouses, but it is not unusual for two plants of the same capacity to have a cost differential of 50%.

Civil components (dams, spillways and other nonmechanical or nonelectrical) of low head and small hydro developments usually carry a smaller percentage of the total development costs than features for conventional hydro developments.

Capital cost information for hydroelectric development constructed in the Railbelt area is scarce. Based on information from the 1976 Alaska Power Survey Vol. I by the Federal Power Commission, we estimated hydro project development costs were estimated for more favorable sites. Operation and maintenance costs are determined primarily by plant size. Other factors include the type of operation (base load or peaking), annual generation, number and size of units, operating head, and other conditions peculiar to individual plants. Estimated capital costs and operation and maintenance costs for a 50-MW and a 200-MW hydro development are shown in Table 3.6.

TABLE 3.6. Estimated Costs of Hydroelectric Facilities

Capacity (MW)	Capital Costs ($/kW)	O and M Costs ($/kW/yr)	Cost of Power ($/kW)
50	4000	13	
200	1750	5	

3.4.4 Environmental Considerations

The physical configuration and operation of a hydroelectric facility can cause a number of hydrologic impacts, the most obvious of which 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 incur 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. Fluctuations that are too large and rapid can adversely affect aquatic biota, and for the more accessible small river projects, 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 the reservoir is so operated, it can have positive impacts by attenuating flood flows, thereby helping prevent flood damage to property downstream. By augmenting low river flows, the reservoir can improve water quality and aquatic habitat. Flow attenuation can be a significant positive impact in light of the fact that many rivers in the Railbelt region exhibit wide natural flow variations.

Reservoir operation affects four parameters of water quality: temperature, dissolved oxygen (DO), total dissolved gases, and suspended sediment. Adverse impacts on temperature and DO can occur during the summer months when the reservoir is stratified. The large water surface area of the reservoir allows the upper layer of water (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, elevated river water temperatures downstream can result, causing adverse impacts on aquatic biota (especially cold water fish). If all water released from the reservoir is from the lower layer of water (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 can result in fish mortality. Supersaturation can be minimized by various spillway designs and operating measures.

As water flows into a reservoir, its velocity is reduced, and it deposits much of its suspended sediment. Therefore, when the water is released from the reservoir, it is relatively free of sediment load. A potential exists, then, for this water to initiate scour downstream to re-establish equilibrium between the erosive energy of the flowing water and its sediment loads. 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. The latter scour problem can be mitigated by proper engineering design.

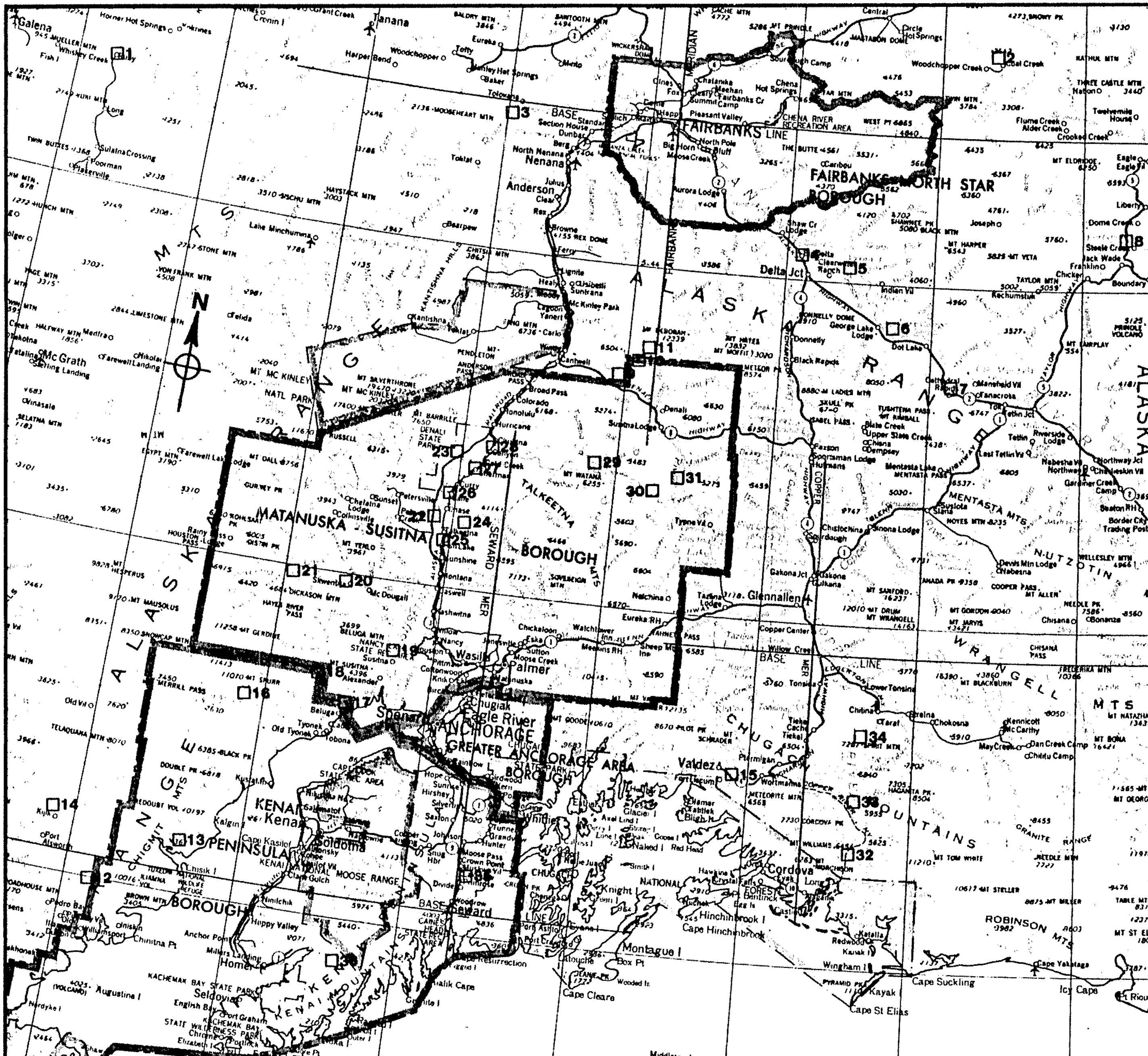
The construction of dams and the development of fairly large bodies of water (at least several square kilometers) will cause some variation in meteorological conditions. Conditions will generally be less extreme near an unfrozen reservoir, resulting in warmer nights and cooler days. There will be no perceptible change in precipitation patterns. 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 will generally 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. Potential major effects in the Railbelt that will be most difficult to mitigate are: 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 shown on Figure 3.4 indicates that these major impacts could occur at many locations, especially for anadromous fish (U.S. Department of Energy 1980). Many of these potential sites are located on major anadromous salmon streams such as the Tenana, Beluga, Skwentna, Susitna, and Copper Rivers.

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

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

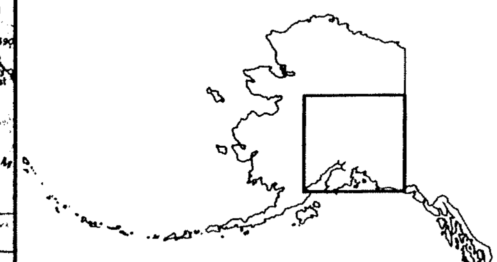
With the exception of run-of-the-river projects, hydroelectric energy projects require large amounts of land for water impoundment. Although the amount of land required varies with the energy-producing capacity of a plant and the characteristics of a river basin, they generally exceed those of other energy types. Because of this feature, 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 in particular are critical



POTENTIAL HYDROELECTRIC RESOURCES

Source: Alaska Power Survey, 1976.

(Refer to Table 3-2 for Site Identification)



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NATIONAL GEODETIC VERTICAL DATUM OF 1929

ALASKA RAILBELT REGION

FIGURE 3.4.

USGS ALASKA MAP E

habitats for migratory big game animals. Large reservoirs could also cause genetic isolation of migratory big game animals and other wildlife. Aquatic furbearers could be adversely affected by the loss of riparian or other riverine 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 water levels associated with 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 bear could be further affected by the loss of anadromous fish if fish passage is prevented or reduced by the dam.

In the Railbelt region, 36 potential hydroelectric dam sites have been identified (Figure 3.4). These sites occur in seven major drainages or general geographic areas including: 1) West side of Cook Inlet; 2) East side of Cook Inlet; 3) Susitna River Drainage; 4) Copper River; 5) Yukon River; 6) Nenana River; and 7) Lowe River. All of these areas contain important wildlife areas that could be affected by hydroelectric developments. Those sites on the West side of Cook Inlet support moose and waterfowl populations. The Crescent River site is an area for black bears. Key waterfowl areas are located at the Beluga River sites. The Chakachatna and Beluga River sites also contain seasonal moose range. Caribou are present at the Kijik River location.

Potential dam sites in the areas on the east side of Cook Inlet have mountain goat, Dall sheep, and moose ranges. The Bradley River site is also used by black bears. Seasonal ranges for moose occur in both the Snow and Bradley River sites. Waterfowl use on these areas is generally low.

The greatest number of potential dam sites occur in the Susitna River Drainage. Moose range occurs at all 13 sites and caribou at all sites except those on the Yenta and Skwenta Rivers. The Denali Project on the Susitan River may cross a major caribou migration route. Waterfowl use of the sites over the entire drainage is low to moderate.

The Copper River dam sites could affect a variety of wildlife primarily because of their close coastal locations. These sites contain key waterfowl use areas including trumpeter swan nesting areas. Dall sheep, mountain goat, and, to a lesser degree, moose ranges are also present. Other important wildlife are black bears, brown bears, and raptors, which utilize, at least in part, the anadromous fish runs of the river.

The Yukon River Drainage dam sites possibly represent some of the most remote locations. All eight sites contain moose seasonal ranges. Caribou utilize ranges at each of these areas except at the Ruby Project on the Yukon River and the Junction Island, Big Delta, and Gerstle Projects on the Tanana River. The Woodchopper Project on the Yukon River is a key area for waterfowl and for peregrine falcon breeding. Other project-specific locations of important wildlife include bison at the Gerstle Project site and possibly Dall sheep at the CAthedral Bluffs project site. Waterfowl occur throughout the two tributaries of the drainage in low to moderate abundance.

The three project sites of the Nenana River drainage include seasonal ranges of moose and caribou. The Bruskasna and Carlo Projects occur in areas utilized by brown bears for denning. Waterfowl occur in moderate numbers throughout the drainage. Wildlife use of the Lowe River area is low. It does not appear to be a key area for game animals.

In addition to the losses of wildlife habitats resulting from inundation, those projects located in remote areas will cause other impacts. Access roads to remote locations will cause extensive disturbance to wildlife. Not only will habitat be replaced by roads, but isolated wildlife populations will be adversely affected by increased human activity and numbers. This could result in disturbance of wilderness species like grizzly bears. 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 like islands used by waterfowl for nesting could be created through placement of spoils or channels. Trees and other natural features used by raptors could be retained instead of removed as is usually done prior to inundation. While these relief measures are somewhat specific, impacts on all wildlife could be minimized by selecting only those sites where wildlife disturbances would be least. It should be noted that one benefit to wildlife from creation of a reservoir would be that waterfowl tend to use them as resting areas during migration.

3.4.5 Socioeconomic Considerations

The construction and operation of a large hydroelectric plant has a high potential to cause a boom/bust cycle, but a small-scale project will have a minor to moderate impact on community infrastructure. The primary reason large projects create adverse effects is the remoteness of the larger sites. All of these sites are located at or near communities with a population of less than 500. An in-migration of 250 to 1,000 workers, depending on scale of plant in the range of communities, could more than quadruple the population. The installation of a construction camp would not mitigate the impacts on the social and economic structure of a community. Estimated manning requirements for hydroelectric projects are summarized in Table 3.7.

TABLE 3.7. Estimated Manning Requirements for Hydroelectric Projects

	Construction Period (years)[a]	Construction Personnel (number of persons)	Operation Personnel (number of persons)
Small Hydro (5 MW)	2	25-35	2-3
Conventional Hydro (100 MW)	3-5	200-400	10-12
		3-30	

(a) To first power.

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 while

65% would be made within the Railbelt. Sixty-five percent of the investment in a small-scale hydro project would be made in the lower 48 while 35% would be contained within the Railbelt.

3.4.6 Potential Application for 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 WW 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. Two significant hydro projects are operational in the Railbelt, Cooper Lake (15 MW) on the Kenai Peninsula and Eklutna (30 MW) near Anchorage. The Solomon Gulch (19 MW) project near Valdez is under construction and will serve Valdez and Glennallen when finished.

Due to its flexibility, hydropower is generally used for peaking power in a large power grid. It can also provide intermediate and base load power. In the Railbelt region, hydroelectric power can be used to provide base load for remote communities, intermediate load for any community, and peaking for larger communities with existing base and intermediate generation.

A number of siting opportunities for hydro development in the Railbelt region have been identified (Table 3.8 and Figure 3.4). Bradley Lake, a 94-MW project, has been authorized (1962) for development by the Corps of Engineers, and Grant Lake (7.3 MW) has been studied at the feasibility level. The 1,600-MW Susitna project is being studied. About 8,400 MW have been identified at 23 potential "more economical" sites in the Railbelt region. It is not yet known how many smaller hydro installations are possible in the Railbelt region, although such studies are underway by the U.S. Army Corps of Engineers, Alaska District.

3.5 FUEL CELLS

The fuel cell is fundamentally composed of two electrodes (an anode and a cathode) separated by an electrolyte (see Figure 3.5). Electrical energy is

TABLE 3.8. Potential Hydroelectric Resources in the (2.5 MW or greater)Railbelt Region

Project	Stream
1. Ruby	Yukon River
2. Woodchoper	Yukon River
3. Junction Island	Tanana River
4. Big Delta	Tanana River
5. Gerstle	Tanana River
6. Johnson	Tanana River
7. Cathedral Bluffs	Tanana River
8. Fortymile	Fortymile River
9. Bruskasna	Nenana River
10. Carlo	Nenana River
11. Healy	Nenana River
12. Tazimina	Tazimina River
13. Crescent Lake	Lake Fork of Crescent River
14. Ingersol (Lackbuna Lake)	Kijik River
15. Lowe (Keystone Canyon)	Lowe River
16. Chackachamna	Chackachamna River
17. Coffee	Beluga River
18. Upper Beluga	Beluga River
19. Yentna	Yentna River
20. Talachulitna (Shell)	Skwentna River
21. Skwentna (Hayes)	Skwentna River
22. Lower Chulitna	Chulitna River
23. Tokichitna	Chulitna River
24. Keetna	Talkeetna River
25. Whiskers	Susitna River
26. Lane	Susitna River
27. Gold	Susitna River
28. Devils Canyon	Susitna River
29. Watana	Susitna River
30. Vee	Susitna River
31. Denali	Susitna River
32. Million Dollar	Copper River
33. Cleave	Copper River
34. Wood Canyon	Copper River
35. Snow	Snow River
36. Bradley Lake	Bradley Creek

Note: Project numbers correspond to numbered boxed on the Potential Hydroelectric Resources location map, Figure 3.4.

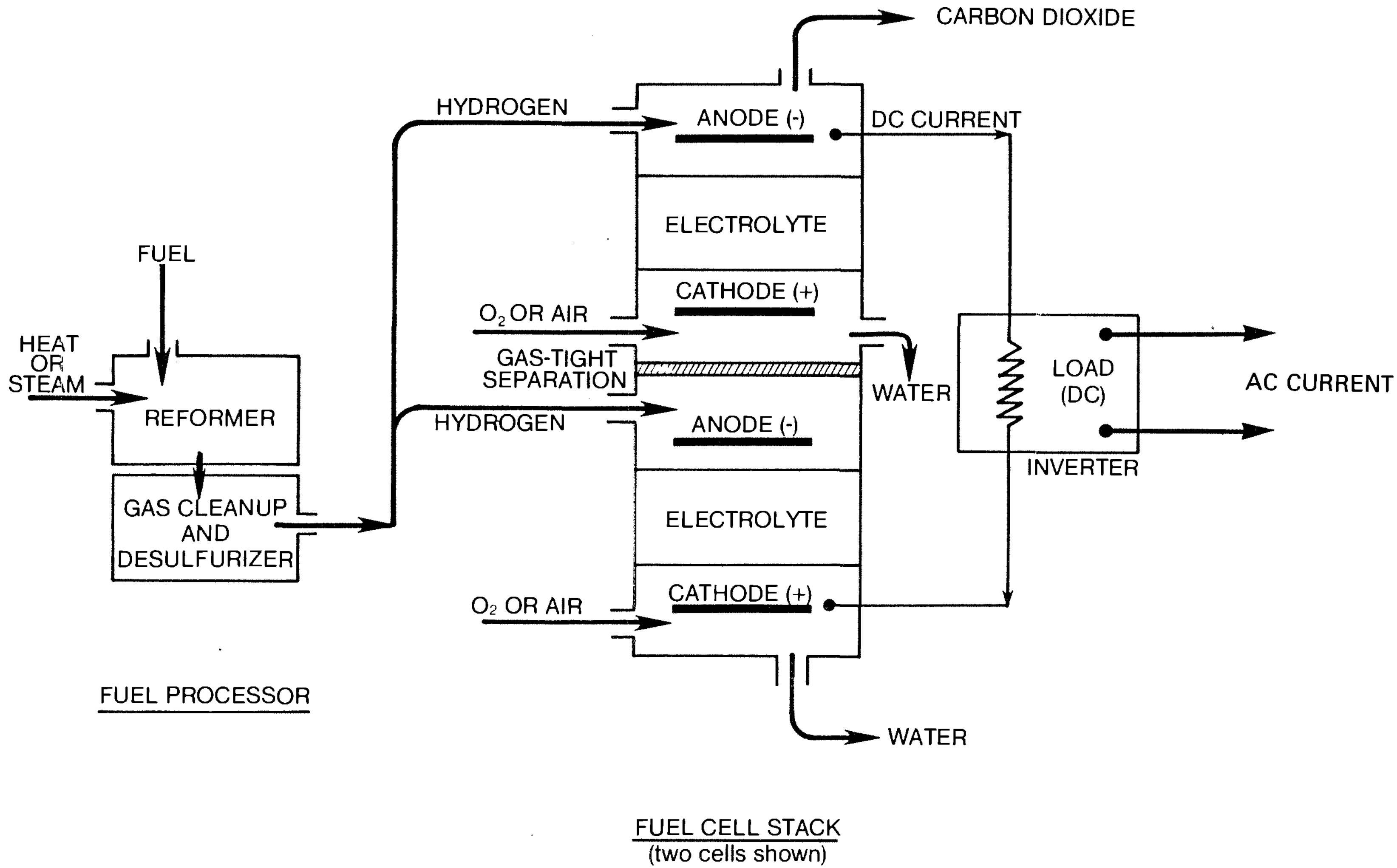


FIGURE 3.5. Fuel Cell Plant

extracted from the cell by a process whereby fuel and oxygen are electrochemically combined in the electrolyte. The fuel and oxidant must be in the gaseous form, but the electrolyte may be an aqueous acid, an aqueous alkaline, a molten salt, or a solid type. Electrodes are thin, porous, and electrical-conducting. Catalysts are included to speed up the reaction.

3.5.1 Technical Characteristics

Most of the cells currently being produced use phosphoric acid as the electrolyte, and hydrogen-rich fuel and oxygen (or air) as the reactant gases. 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 supplying a utility distribution grid.

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 easily attainable. Cogeneration with such fuel cells is also a possibiity for the utility interested in supplying district heat or industrial process heat.

A third-generation fuel cell utilizing the 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 in power generation during the 1990s.

A complete fuel cell plant typically consists of a fuel processor, a fuel cell section, and an inverter and power conditioner. The individual fuel cell produces an output of about 0.8 V under load. Individual cells may be connected in series to provide greater output voltage and connected in parallel to provide greater output current. Current fuel cell designs utilize 456 cells stacked in a cell stack assembly to produce 300 VDC at a current of 500 amps. The cell stacks can be connected in series or parallel to produce megawatt quantities of power at 2000-3000 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 mass production techniques in a factory environment, unit costs may be reduced. Using the modular arrangement, it is conceivable that modules can be added and/or shifted to new locations, depending upon changes in local load conditions.

Fuel cells consume several types of fuel, depending upon the type of electrolyte. Present-day 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. In the molten-carbonate and solid-oxide fuel cells, carbon monoxide acts as a 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 carbon dioxide 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.

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. The electrolytes have efficiencies as follows:

Electrolyte	Efficiency (Percent)	Heat Rate (Btu/kWh)
Phosphoric acid	37	9,200
Moltan Carbonate	50	6,820

Advanced fuel cells operating at higher temperatures may be used with a steam bottoming cycle, resulting in efficiencies of more than 60%. The overall efficiency of the fuel cell steam bottoming cycle system using coal gasification is at about 50%.

The efficiency of fuel cell plants is practically constant over wide ranges of loads. This means that they are suitable for partial load operation to meet "spinning reserve" requirements of a utility grid.

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 hydrogen generating equipment is the control factor. As an example, a demonstration plant has been built which is designed to follow a load change between 35% and 100% of full power within 2 seconds.

Molten-carbonate cells using fuel from coal gasification 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, then surplus of fuel will be available from the gasifier when the 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 high electrical load periods, thus reducing the required capacity of the gasification plant.

One other difficulty with using the carbonate cell in cycling service is adverse effects of thermal cycling. Because of the high operating temperature, 1200°F, it is difficult to accomplish thermal cycling a number of times without the probability of cracking the electrolyte tile. For these reasons, the molten carbonate cell is more suitable for base load operation.

The reliability of a fuel cell plant depends to some extent on the type of fuel which is used; plants are expected to be extremely reliable when a clean fuel is used. An availability of 95% is predicted for first generation plants. At present fuel cell manufacturers recommend a re-work of the cells every 10,000 operating hours. Scheduled outages for maintenance will therefore be less than the more conventional coal or gas-fired plants.

3.5.2 Siting and Fuel Requirements

The modular design of the fuel cell offers considerable flexibility in siting. Because of the small size of the early commercial plants (40 KW to 10 MW), fuel cell plants 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 system.

The principal siting constraint for such plants would be the source of fuel supply. 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.

A fuel cell plant were integrated with the synthetic fuel plant, the same siting requirements that apply to the synthetic fuels conversion plant would prevail. A medium Btu gas fuel could be transported by pipeline for moderate distances, allowing remote or dispersed siting of the fuel cell generation plants.

Demonstration fuel cell plants vary in size from 25 KW to 11 MW. Assuming no on-site fuel storage, small fuel cell installations would have the following general area requirements: a 40-KW plant would require less than one acre; a 4.8-MW plant would require one to two 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 500 MW molten-carbonate plant, will probably take more than the 120 acres for the same size conventional fossil steam plant. But as new coal-fired plants are required to have more and more air pollution control equipment and require solid waste disposal areas, the fuel cell plant of the mid 1990s (which is inherently free from needing air pollution controls) will likely require less area than the future coal plants.

Little, if any, external water is required for the fuel cell plant as the water formed by the fuel cell process is usually sufficient for cooling and heat recovery systems. The fuel stacks are normally cooled by the process gases passing through the structure, although forced air cooling has also been satisfactorily tested.

In order to provide the fuel cell with hydrogen, 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. The New York City fuel cell will use either naphtha or methane gas as its fuel supply.

The shortage of liquid and gaseous fossil energy (required to obtain hydrogen) has prompted some research in developing fuel cells that would use coal-derived gaseous fuels directly. Coal can supply hydrogen and carbon monoxide as gaseous fuels, but the carbon monoxide cannot be used in hydrogen-oxygen 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 cell fuel processor.

3.5.3 Costs

Capital costs for phosphoric acid fuel cell plants are not yet competitive with conventional power plants now being installed in the United States. In addition, the high cost of suitable fuel for the fuel cell, contributes to costs of power currently exceeding that of conventional coal plants. However, currently, conventional fossil-fuel plants are undergoing a dramatic cost increase, due in part to emission controls required by the New Source Performance Standards required by the Clean Air Act Amendments of 1977. Since the fuel cell produces virtually no air pollution, fuel cell capital cost should become increasingly more competitive with the conventional fossil plant. Furthermore, mass production of phosphoric acid cells should result in a decrease in "real" (i.e. adjusted for inflation) capital cost. Estimated costs, in 1980 dollars, for phosphoric acid power plants using naphtha as fuel are given in Table 3.9.

TABLE 3.9. Estimated Costs of Fuel Cell Generation Facilities

Plant Type	Capacity	Capital Cost ($/kW)	O and M Cost ($/kW)	Cost of Power ($/kW)
Phosphoric Acid	Greater than 500 MW	$650	$3.30	
Moltan Carbonate				

3.5.4 Environmental Considerations

Fuel cell systems operate at approximately 20 to 1200°C depending upon the electrolyte, thus product water at elevated temperatures will be produced. For aqueous hydroxide systems, characteristic cell operating temperatures are 20 to 90°C. A typical value given for waste heat disposal is about 30% of the heat of reaction, to avoid electrolyte decomposition. 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 1-MW and 10-MW plant, this corresponds to a water production rate of approximately 2,700 gal/day and 27,000 gal/day, respectively (Davis and Rozeau 1977). Depending upon the specific fuel cell type, this product water can either be discharged from the plant, or if in the form of steam, utilized to drive a conventional steam turbine in a bottoming cycle or utilized in the fuel processor to reform the hydrocarbon fuel. Additional makeup water may also be utilized 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 implemented 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 technologies. Sulfur and nitrogen will be gasified, not oxidized, and can easily be recovered from process streams. Fuels which are essentially free of such pollutants, such as hydrogen or natural gas, will not lead to any pollutant emissions. Carbon dioxide and water vapor will be formed in large quantities, similar to that associated with combustion, 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 impacts over combustion technologies. Heat rejection must be considered in fuel cell technologies, but these design considerations will avoid any adverse environmental impacts.

Fuel cells will produce heated water and may require additional makeup water for cooling. The quantity of intake water, 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 from intake and discharge of water. Because water use requirements vary, no direct per megawatt comparison can be made with another plant. Due to the small plant size (10 MW), 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 small land areas are required. Noise and other potential disturbance factors are also relatively low. Furthermore, these plants would be sited within or adjacent to developed areas where access road requirements would be minimal.

3.5.5 Socioeconomic Considerations

Sites for fuel cell plants would be determined by fuel type and source. Locations should be constrained by the population size of the community since construction work force requirements are large and may cause significant impacts in small communities. Approximately 90 persons would be required to construct a 10 MW plant for a period of less than 1 year. Impacts would be minor to moderate in Anchorage, Fairbanks, Soldatna, Kenai, Valdez, Wasilla, and Palmer. An estimated five workers would be required to operate such a plant.

Expenditures that would flow out of the region due to development of a fuel cell facility would include investment in high-technology equipment. It can be expected that 80% of the project expenditures would be made outside the region, with 20% spent within the Railbelt.

3.5.5 Application to Railbelt Energy Demand

Fuel cells represent an emerging technology. It is not yet commercially available and has thus not been applied in Alaska. Present-day prototype fuel cells, which generally use phosphoric acid as the electrolyte, are expected to be commercially available in the next few years. The molten-carbonate cell has been under development at a modest level for about 25 years. Since good progress and accelerated effort have characterized the past few years of this development, this second-generation fuel cell could be generating multi-megawatt power on a demonstration basis within 3 to 4 years. Commercial availability is not anticipated until after 1990, however.

The phosphoric acid fuel cell in electric power generation has been developed to the point of satisfactory operation in several small demonstration 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 4.5 MW output is under construction in New York City and one with an output of 10-MW is under construction in Tokyo, Japan. Commercial production facilities are being built by a major electrical equipment manufacturer, with 11-MW modules to be available around 1985.

The molten-carbonate cell is about 5 years behind the phosphoric acid cell technology. The U.S. Department of Energy is funding a significant effort to achieve a molten carbonate system demonstration in the 1986 to 1987 time frame. Fabrication processes are being developed with current funding from DOE and EPRI.

Potential obstacles to commercialization of fuel cells for electric power generation are threefold: insufficient orders, national fuel policy, and technical development.

Enough orders must be generated to take advantage of the economies of scale which are needed to produce fuel cells at a cost that utilities can afford. No one utility is currently in a financial position to sponsor the potentially high cost of developing production facilities for fuel cells, so it is assumed that the development timetable will 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 tap a slipstream 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 which 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.

4.0 STORAGE TECHNOLOGIES

The utilization of energy storage techniques has, within the last 25 years, become an important component in serving the nation's overall electric energy needs. This technology does not, by itself, add to the overall generating capacity of a system, but it does utilize otherwise unused capacity available from base load plants during off-peak hours. This energy is stored and subsequently reused during the peak demand hours.

Although many energy storage methods are technically feasible, the only energy storage system in widespread commercial use is hydroelectric pumped-storage. Battery storage systems. Although not currently in commercial use may become commercially available within the next ten years. Selected characteristaics of hydroelectric pumped storage and battery storage systems are compared in Table 4.1.

4.1 HYDROELECTRIC PUMPED-STORAGE

Hydroelectric pumped-storage plants provide a unique solution to the problems of increasing base-load plant factors and providing peaking capacity. Water is pumped from a lower reservoir to an upper reservoir during the 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. The system pumping losses and generating inefficiencies are more than compensated for by the differential power production costs of the baseload plants used to fill the upper reservior and the cycling plants whose operation is displaced by operation of the pumped-storage plant as a operating facility.

Pumped-storage plants had their commercial origins in the United States in 1929. The first domestic installation was the 7-MW Rocky River Plant near New Milford, Connecticut. This 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

TABLE 4.1. Comparison of Storage Technologies on Selected Characteristics

First Stage Attributes	Pumped Storage 25 MW	Battery Storage Battery Storage
1. Aesthetic Intrusiveness		
A. Visual Impacts	Significant	
B. Operating Noise	Minor	
C. Odor	Minor (Municipal Waste)	
2. Impacts on Biota		
A. Aquatic/Marine (gpm)(a)	Site-Specific	
B. Terrestrial (acres)(b)	Site-Specific	
3. Cost of Energy		
A. Capital Cost ($/kW)	950	
B. O&M Cost ($/kW)	7.40	
C. Fuel Cost		
D. Cost of Power ($/kW)		
4. Health & Safety		
A. Public	Safe	
5. Consumer Effort	Utility operated. No individual or community effort required.	
6. Adaptability to Growth	Units can be added easily if planned.	
A. Adjustments in plant scale		
7. Reliability		
A. Availability (%)	85	
8. Expenditure Flow From Alaska		
A. Capital Cost (%)	55	

TABLE 4.1. (Contd)

First Stage Attributes	Pumped Storage 25 MW	Battery Storage Battery Storage
B. Operation and Maintenance Cost (%)		
C. Fuel Cost		
9. Boom/Bust		
A. Ratio of Construction to Operating Personnel	250:10	
B. Magnitude of Impacts	Minor in vicinity of Anchorage. Moderate to severe in allother locations.	
10. Control of Technology		
A. Utility	Primary Control	
B. Individual	Limited through regulatory agencies and government.	
Second Stage Attribute		
1. Commercial Availability	Mature	1988-1992
2. Railbelt Siting Opportunities	None identified	None identified
3. Product Type	Peaking	Peaking
4. Generating Capacity		
A. Range in Unit Scale (MW)	1.5-400	

(a) Recirculating cooling water systems.
(b) All facilities.

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 (1,800 feet).

Changes in the needs of the total electrical generating system further contributed to the development of the pumped-storage technology. The early 1950s saw the use of pumped storage for energy trading purposes among relatively small utility companies. In some areas, as energy consumption grew, conventional hydro capacity was no longer sufficient to satisfy peak power demands; pumped storage was a relatively economical way of filling the gap. With the advent of today's large base-load thermal generating plants, pumped storage complements these plants, maximizing use of these efficient plants.

4.2.1 Technical Characteristics

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, for example, 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.

Man-Made Upper and/or Lower Reservoir. As the name implies, this approach consists of constructing the complete reservoir using perimeter containment dikes. This type of 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. This approach would use underground natural rock caverns or an underground rock excavation for the lower reservoir and would have an underground powerhouse associated with it. The upper reservoir may be either natural or man-made, as described above, or it may use the storage reservoir of an existing conventional hydro plant.

Conversion of Existing Hydro Plant. 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. A modification of this approach has a seasonal pumped-storage arrangement built in conjunction with a conventional hydro project. During periods of high river flow, the excess water normally discharged over the spillway of the existing structure could, during off peak hours, be used to run pump/turbines to pump water to an off-site 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 existing river.

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 4.1.

Several dam types are used to form the reservoir, generally dependent on the valley conditions, local geology, availability of construction materials, and cost. Typical dams may include concrete gravity, concrete arch, or an earth and rockfill dam with an impervious central core. Typically, perimeter dikes are constructed of earth and rockfill with an impervious central core or an impervious liner.

Upper reservoirs are provided with an emergency spillway. This structure conveys excess water caused by accidental overpumping away from the reservoir in a controlled manner. A when formed by a dam structure lower reservoirs also includes 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 associated with the existing waterway. Water conductors between the reservoirs may be rock tunnels or above-ground steel 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

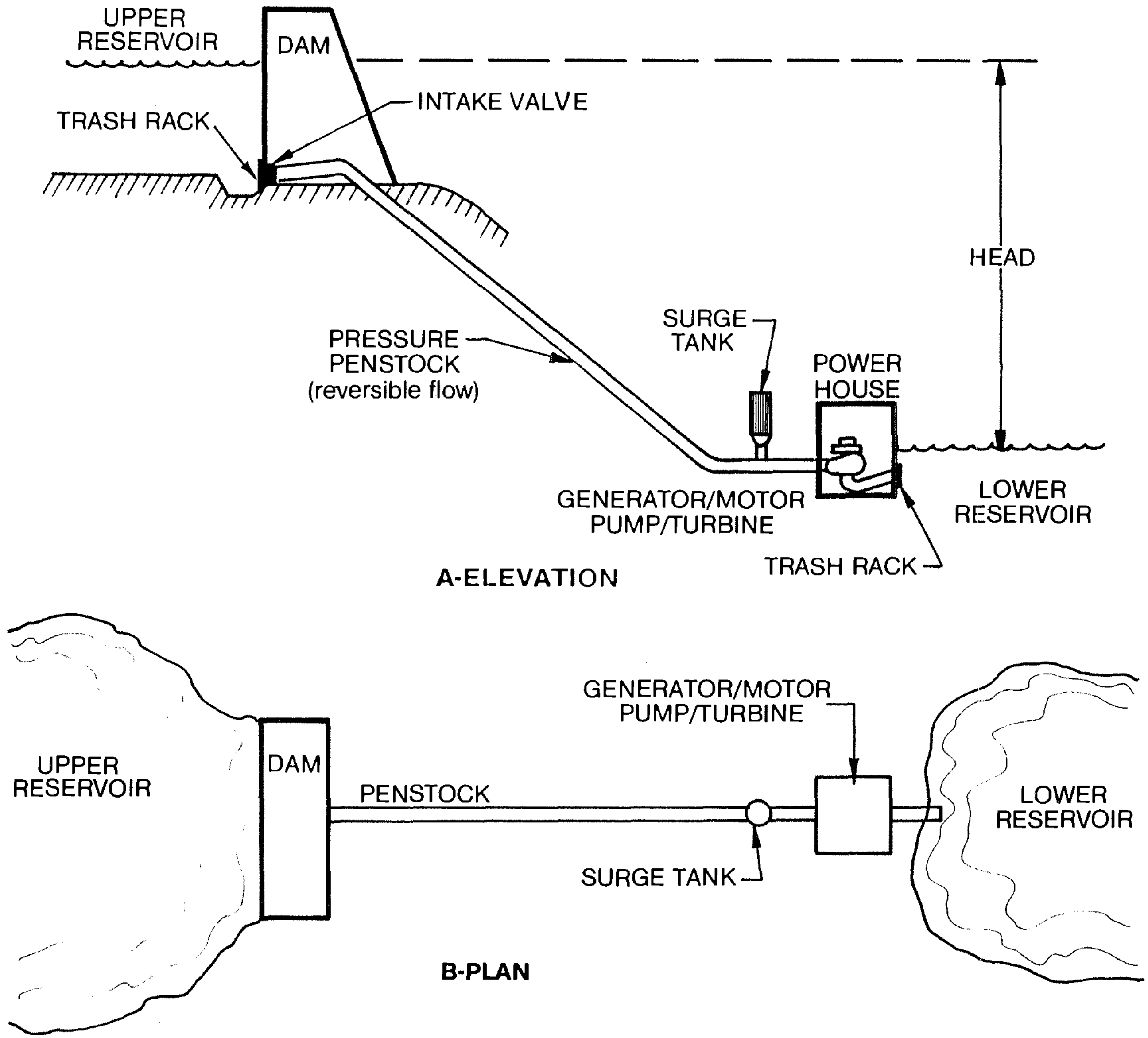


FIGURE 4.1. Schematic of a Pumped Storage Hydro Plant

lower to the upper reservoir. During peak demand hours, the pump/turbine units 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 protect this equipment. Underground powerhouses are constructed in natural or man-made caverns. This scheme is used in certain topographic conditions, particularly narrow canyons, for which there is no convenient site for a conventional powerhouse. Its use is also dependent on site geology and cost. Underground powerhouses would also be required for underground pumped-storage concepts.

4.2.2 Siting and Fuel Requirements

The operation and success of a pumped-storage project are influenced primarily by site characteristics. Availability of water, land, transmission lines, and access roads is an important consideration 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 utilization of natural embankments is desired. The length of the water conductors is, to a large extent, dependent on topography. A longer line of flow will add to construction costs and result in larger generating losses and pumping costs. It is desirable to have the shortest possible horizontal distance between the upper and lower reservoirs.

Geologic conditions have the potential for affecting 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 above ground 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 increase in cost. Embankment slopes would have to be built flatter; additional restrictions would be placed on fill materials; and structures would be more massive.

Availability of construction materials 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 could also 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.

All siting considerations must be evaluated in conjunction with the overall project power needs. It is unlikely that any single site will ideally satisfy all requirements, and it will therefore be necessary to evaluate the relative technical and economic merits of several candidate sites 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.

4.2.3 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 and waterways vary considerably and may have little relationship to the installed generating capacity. An installed capacity cost of $950/kW (1981 dollars) is generally accepted for low capacity pumped-storage projects (less than 100 MW). Installed costs in dollars per kW are a function of capacity, and generally decrease as plant capacity increases; however, for very large pumped-storage plants (greater than 100 MW), installed costs begin to rise.

Plant size, number of pump/turbine units, annual generation, operating head, and site-specific conditions for individual plants are major 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.

Historical data (U.S. DOE 1979) indicate weighted annual operating and maintenance costs to be $7.40/kW-Yr in 1981 dollars. This information is tabulated in Table 4.2.

TABLE 4.2. Estimated Costs of Hydroelectric Pumped Storage Facilities

Plant Capacity	Capital Cost ($/kW)	Operating and Maintinance Cost ($/kW/yr)	Cost of Power ($/kW)
Less than 100 MW	950	$7.40	
500 MW	500	$7.40	
Greater than 1000 MW	600 plus	$7.40	

4.2.4 Environmental Considerations

The impacts of a hydroelectric pumped storage facility on the water resources associated with both the upper and lower reservoir can be similar to those of a conventional hydroelectric facility, which are discussed in Section 3.4.4. 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 there are differences in the water quality characteristics of the upper and lower reservoirs (i.e., from introduction of lower quality water from the 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 will also affect the lower reservoir, again depending upon site-specific characteristics and whether the lower reservoir is a natural or man-made water body.

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

Creation of a man-made reservoir, either upper or lower, may affect the local hydrologic regime because of increased groundwater seepage and evaporation. Proper site selection criteria and design should minimize these impacts.

Underground caverns used for water storage, whether natural or man-made, may experience adverse impacts on water quality due to the potential solvation or reaction with the local rock media. These impacts are site specific, and can be minimized by proper site selection and design.

No impacts on air quality result from the use of pumped storage techniques. Development of an artificial reservior may produce some changes in the microclimate. 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. Potential effects most difficult to mitigate are: 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 from increased access. Plant operation may result in: altered nutrient movement, affecting primary production; water flow pattern changes, modification of 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, possibly resulting in fish mortalities. Competition and predation between and within species may also be changed.

Mitigative procedures are possible for many impacts and are frequently incorporated into the design of the facility. Fish hatcheries are commonly used to replace losses in spawning habitat. Screening or diversion structures are used to direct fish away from critical areas. 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 terrestrial impacts of pumped storage facilities are similar to those of conventional hydroelectric developments (see Section 3.4.4) 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. Pumped storage reservoirs can be developed in dry basins such as timber areas using perimeter containment dikes.

Pumped storage sites in the Railbelt region have not been identified. It is quite likely, however, that primarily lowland (versus mountainous) wildlife populations, particularly moose and caribou, would be negatively affected by inundation of habitat.

The primary action to be taken to reduce terrestrial impacts would be to site pumped storage facilities in areas of low wildlife value. Other actions could include enhancing the value of a reservoir to certain wildlife.

4.1.5 Socioeconomic Considerations

Since pumped storage is a labor-intensive technology, impacts will vary with both plant scale and location. The construction workforce requirements range from 250 for a 100 MW Plant to 1,500 for a 1000 MW Plant, for a period of 5 to 7 years. Plant operation and maintenance requires a staff of approximately 10, regardless of plant size. The large differential in construction and operating personnel may cause a boom/bust cycle in remote areas.

More specifically, a 100-MW Plant would have minor socioeconomic impacts if located near Anchorange. 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 immigrants. Small and very small communities would be severely affected by a 100-MW Plant because of the substantial increase in population.

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 semi-permanent settlement by the workforce dependents and secondary inmigrants.

It is estimated that approximately 55% of the project expenditures would flow out of the region while 45% would remain within the Railbelt.

4.1.6 Potential Application to Railbelt Region

The commercial availability of pump/turbines is comparable to the availability of conventional hydroelectric machinery. Commercially operating pump/turbines have been built with capacities ranging from 1.5 MW up to 400 MW at TVA's Raccoon Mountain project, with larger units anticipated for the future.

There are currently 28 pumped storage projects in operation in the United States, with an installed capacity of 12,900 MW. No pumped-storage hydroelectric plants, however, have been constructed in the Railbelt region. The outlook for their continued use and expansion in some areas of the United States is bright, assuming favorable site conditions and a significant, well-integrated generating power base and distinct peaking power requirements. These requirements are not entirely satisfied in the Railbelt region at present. Site conditions in the Railbelt are suitable for pumped-storage development but there is not significant base load generating capacity. As of 1976 the state's total generating capacity was approximately 940 MW; however, the generating stations are not incorporated into a well-integrated system as would be required for the pumped-storage concept to work effectively. No pumped-storage hydroelectric plants have been constructed in the Railbelt region.

4.2 STORAGE BATTERIES

Battery storage systems could be used in electric utility service to serve in a load leveling capacity. In hours of low demand, electricity would be converted from high-voltage a.c. into lower voltage d.c. and stored in the batteries. During peak hours the process would be reversed to carry part of the utility's load.

4.2.1 Technical Characteristics

Several new types of storage batteries are under development for utility application. Among these are the sodium-sulfur battery, the zinc-chlorine battery, zinc-bromine battery, and the Redox fluid battery. Table 4.3 gives some performance parameters for four battery types.

The most important criterion for storage in electric power systems is long life: the ability to undergo 2,000 to 3,000 cycles of charge and discharge over a 10-to-15 year period (Kathammer 1979).

TABLE 4.3. Battery Performance Parameters (Kalhammer 1979)

Battery Type	Operating Temperature (Degrees Celsius)	Estimated Cycle Life	Estimated Cost (Dollars Per Kilowatt-Hour)	Estimated Availability (Year) (Prototypes or Early Commercial Models)
Lead-Acid Utility Design Improved	Ambient	2,000	80	1984
Zinc-Chlorine Utility Design	30-50	2,000(?)	50	1984
Solium-Sulfur Utility Design	300-350	2,000	50	1986
Redox	100 or less	(a)	?	?

(a) 20 years estimated (Thaller 1979)

EPRI has indicated that three criteria must be met in order for a 100 MWh battery plant be acceptable to the utility industry. These criteria are:

1) installed cost less than $25/kWh plus $75/kW (in 1977 dollars),
2) overall plant efficiency greater than 65%, are to a-c conversion, and
3) Minimum siting restrictions (Energy Development Associates 1979).

Sodium-sulfur batteries, under development by General Electric use molten sodium as the negative electrode, molten sulfur/sodium polysulfide as the positive electrode and beta alumina as the solid electrolyte separator (Bast and Mitoff 1980). A nitrogen blanket is required, to prevent spontaneous ignition of the 300oC sodium and sulfur. The sodium-release problem is under investigation (Bast and Mitof 1980).

The zinc chlorine battery is being developed by Energy Development Associates. The cell consists of a zinc electrode, a chlorine electrode, and aqueous zinc chioride electrolyte. Important safety and environmental impact considerations revolve around accidental release and dispersion of toxic amounts of chlorine (Energy Development Associates 1979).

The zinc-bromine battery developed by Gould is based on a cell design of titanium electrodes, permeable microporous cell divider, and two electrolyte pumping systems that circulate aqueous zinc bromide solution. Two problems inherent to the system are low coylombic efficiency resulting from reaction of zinc with dissolved bromine, and the tendency for zinc to electro deposit dendritically, which can lead to short-circuiting of the cell (Putt, 1979).

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 a 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.

This system has advantages of relatively low pressure and temperature, independent sizing of energy-storage capacity, (tank sizes), and reactants that stay in solution, and minimal environmental impact from accidental spill or equipment failure (Pruce, 1979). Cost is also potentially lower because of system simplicity and predicted long component life.

Battery prototypes are to be tested in the Battery Energy Storage Test Facility (BEST), sponsored jointly by DOE and EPRI. In order 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 30,000 kWh lead acid battery coupled to a 10,000 kW ac-dc converter (Kalhammer (1980).

4.2.2 Siting and Fuel Requirements

TO BE SUPPLIED

4.2.3 Costs

TO BE SUPPLIED

4.2.4 Environmental Considerations

TO BE SUPPLIED

4.2.5 Socioeconomic Considerations

TO BE SUPPLIED

4.2.6 Applicability to Railbelt Region

Battery-storage systems may be applicable to Railbelt electrical system for road leveling.

The data in Table 4.3 indicates that prototype or early commercial battery systems will be in operation before 1990. Commercialisation of the technology may depend on utility acceptance. This could put battery storage systems in the proper time frame for consideration in the Railbelt Electric Alternatives Study.

The need for load leveling facilities such as battery storage systems is greatly dependent upon the load and generation characteristics of the utility system. In general, battery storage systems would be considered for utility systems having substantial daily peaking characteristics, inexpensive baseload capacity and relatively little hydroelectric capacity. The current Railbelt electric energy system, although not having substantial hydroelectric capacity, exhibits only modest daily peaking characteristics and does not have low cost baseload generating capacity.

5.0 FUEL SAVER TECHNOLOGIES

Candidate fuel saving technologies for Railbelt application include cogeneration, tidal power, wind power, and solar power. These technologies supply energy to the power grid but typically cannot be assigned capacity credits because of the intermittent availability of the energy source. Capacity credit can be assigned 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.

For cogeneration cycles, source of energy is the thermodynamic potential available from the simultaneous generation of electricity and process heat. Electrical power is produced from cogenerating installations only when there is a demand for heat. Wind power is available only when wind speeds are sufficient to support generation. Solar power is available only when solar radiation is available. Tidal power is dependent upon tidal patterns. All of these technologies can augment an electrical supply system, but they can not form the basis of such a network unless substantial energy storage capacity is provided. Consequently, these technologies are normally regarded as fuel saver technologies. Each of these fuel saving technologies is described in the following four sections. A comparison of selected characteristics of the fuel saver technologies discussed in this chapter is provided in Table 5.1.

5.1 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 may 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 in association with industrial or commercial development. Cogeneration capacity can be expanded simultaneously with increases in industrial capacity. A major barrier to the development of

TABLE 5.1. Comparison of Fuel Saver Technologies on Selected Characteristics

First Stage Attributes	Cogeneration 20 MW	Tidal	Wind 2.5 MW		Solar 10 MW	
1. Aesthetic Intrusiveness						
A. Visual Impacts	Minor to Moderate	Moderate to Significant	Minor		Significant	
B. Operating Noise	Minor	Minor	Minor		Minor	
C. Odor	Minor (Municipal Waste)	Minor	Minor		Minor	
2. Impacts on Biota					Solar-Thermal	Photovoltaic
A. Aquatic/Marine (gpm)[a]	180	Site-Specific	0		150	0
B. Terrestrial (acres)[b]	8	Site-Specific	2		200	50
3. Cost of Energy			Oil	Gas		
A. Capital Cost ($/kW)	850	3000	800		1500	11000
B. O&M Cost	2.50	--	7		40	
($/kW)			60	56		
C. Fuel Cost						
D. Cost of Power ($/kW)						
4. Health & Safety						
A. Public	Safe. Possible long-term air quality degradation	Safe	Safe		Safe	
5. Consumer Effort	Utility operated. No individual or community effort required.	Utility operated. No individual or community effort required.	Utility or community operated.		Utility operated. No individual or effort required	
6. Adaptability to Growth						
A. Adjustments in plant scale	Duplicate effort required.	Additional units can be added.	Additional units can be added.		Duplicate effort required for solar-thermal. Photovoltaic units can be added easily.	
7. Reliability						
A. Availability (%)	Baseload	Provides intermittent power.	Provides intermittent power.		Provides intermittent power.	

TABLE 5.1. (Contd)

First Stage Attributes	Cogeneration 20 MW	Tidal	Wind 2.5 MW	Solar 10 MW
8. Expenditure Flow From Alaska				
A. Capital Cost (%)	67	33	80	80
B. Operation and Maintenance Cost (%)				
C. Fuel Cost				
9. Boom/Bust				Solar-Thermal / Photovoltaic
A. Ratio of Construction to Operating Personnel	30:15	300:30	12:0	Solar-Thermal 60:25 / Photovoltaic 100:10
B. Magnitude of Impacts	Minor to moderate in all locations.	Minor in vicinity of Anchorage. Significant to severe in all other locations.	Minor in all other locations.	Minor in vicinity of Anchorage & Fairbanks. Moderate to severe in all other locations.
10. Control of Technology				
A. Utility	Primary Control	Primary Control	Primary Control	Primary Control
B. Individual	Limited through regulatory agencies and government.	Limited through agencies and government.	Limited through regulatory agencies and government.	Limited through regulatory agencies and government.
Second Stage Attribute				
1. Commercial Availability	Mature	Commercially available but not mature.	Commerically available but not mature.	Photovoltaic cells are commercially available but not through mass production
2. Railbelt Siting Opportunities	Oil refineries, military & academic installations	Knik Arm, Turnagain Arm, Upper Cook Inlet	Coastal locations; along ridgelines or hills in the interior.	No sites identified
3. Product Type				
4. Generating Capacity				
A. Range in Unit	2.5-100	400 KW - 240 MW	1-45	

(a) Recirculating cooling water systems.
(b) All facilities.

cogeneration was removed with the passage of the Public Utility Regulatory Policies Act of 1978. The Act essentially allows industries and other non-utility generators to sell power to a utility at a fair market value.

The size of a cogeneration system generally ranges from 25 to 100 MW, although it is becoming economic to build systems in the 5 to 25 MW range where high electricity costs prevail, such as those encountered in small communities in the Railbelt region. 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.

5.1.1 Technical Characteristics

Cogeneration facilities are classified into those using "topping" thermodynamic cycles and those using "bottoming" cogeneration cycles. Both exist commercially although the topping cycles predominate. Topping cycles are used at installations whose primary purpose is to produce low quality heat for process or space heating applications. Topping cycles capture available energy at temperatures above those required for process or space heat applications. Bottoming cycles are used to capture otherwise rejected low-level heat and to convert this heat into useful work. Three topping cycles are available: 1) steam turbine topping cycle, 2) combustion turbine topping cycle, and 3) diesel generator topping cycle. Cycle selection is usually determined by relative power and steam demand; fuel availability and cost; and process heat utilization system designs.

Steam Turbine Topping Cycle

In the steam turbine topping cycle, as depicted in Figure 5.1, high pressure/high temperature steam is raised in the boiler, passed through a non-condensing turbine, and 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 decreased, the power generation/steam production ratio is increased.

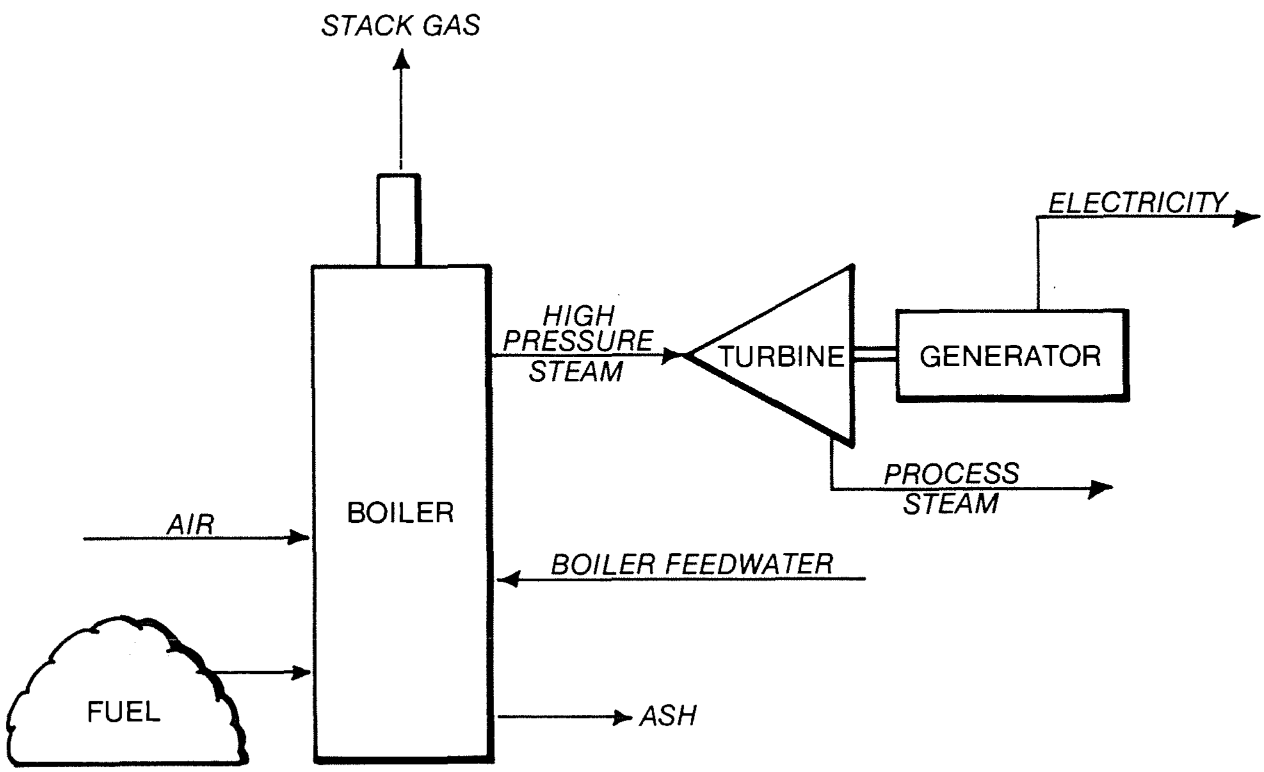


FIGURE 5.1. Simplified Schematic of Steam Tubrine Topping Cycle

System capacity is generally determined by manufacturing or space heat steam needs. Manufacturers with requirements for only one steam quality 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 generation is determined by boiler efficiency plus turbine-generator heat rates. A typical small-scale, wood-fired cogeneration system 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 4200-4500 Btu/kWh, and an overall efficiency of about 85%.

The primary advantage of the steam cycle is its ability to utilize 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 5.2, integrate a combustion turbine and a waste heat boiler in order to simultaneously produce electricity and steam. Alternatively, the exhaust from the combustion turbine may be passed through a exhaust gas lair heat exchanger for warm air for process purposes. This cycle is ideal for oil refineries.

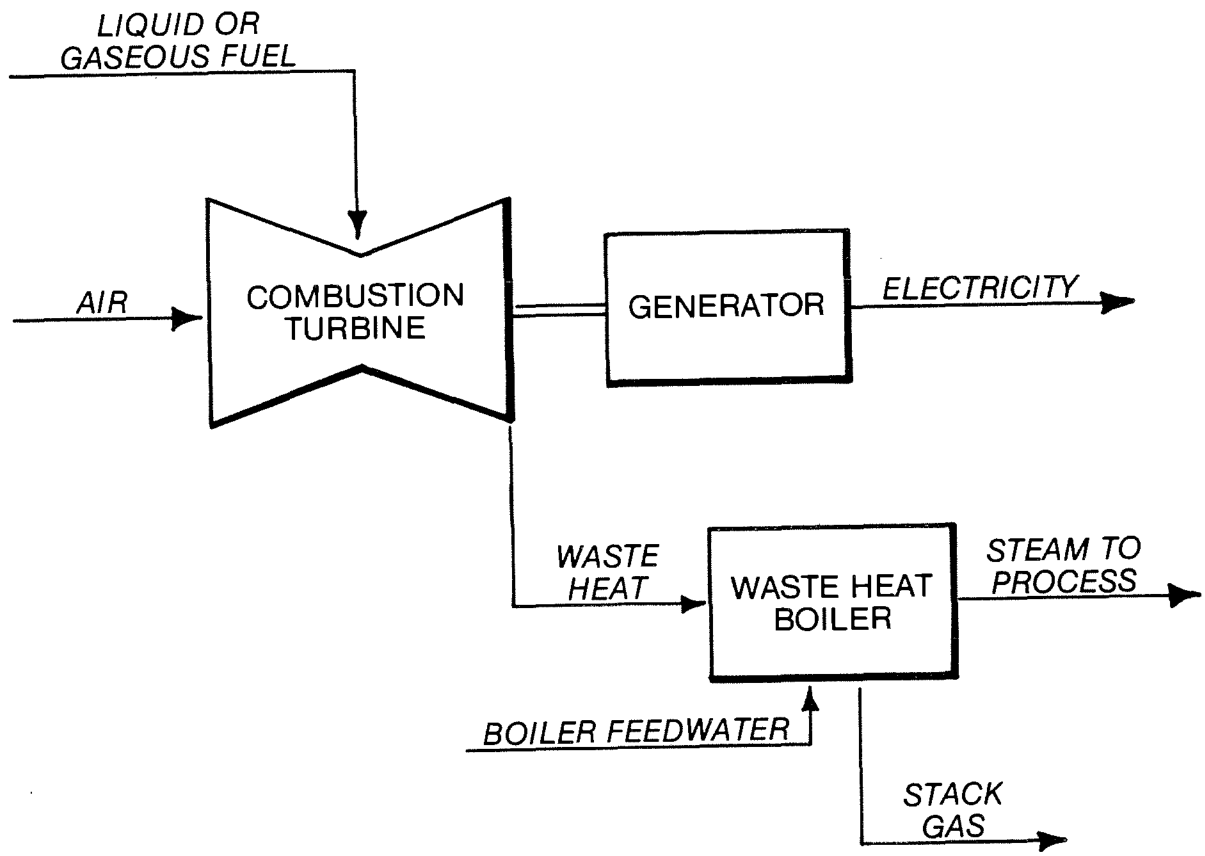


FIGURE 5.2. Simplified Schematic of Combustion Turbine Topping Cycle

The combustion turbine technology is described in Section 3.1. The second major component of the system is the waste heat 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 the quantity of SO_2 in the exhaust stream. An economizer for feedwater heating is typically added to remove heat from the stack gas.

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 associated with 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 is about the same as that associated with steam turbine topping cycles. Typical heat rates are in the 5000-6000 Btu/kWh range.

A potential drawback of combustion turbine topping cycles is the petroleum based 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., 500 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 in order 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 in waste heat boilers. Diesel cycles are appropriate for institutional and high-density residential installations. They may be appropriate for smaller manufacturing establishments such as seafood processing plants or where power costs dictate their use.

Diesel generation, which has been described in Section 3.3, has three potential advantages over combustion turbine-based systems: 1) the highest power/steam ratios, typically twice those associated with 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 gas from coal and biomass has been used successfully in diesel generation; however, this results in substantial derating of the equipment.

Bottoming Cycles

Currently available bottoming cycle technology converts reject steam into electricity by use of large, specially designed condensing turbines which can handle saturated steam. The concept of this form of cogeneration is illustrated in Figure 5.3.

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 70-80% of capacity.

5.1.2 Siting and Fuel Requirements

All cogeneration systems must be located at or close to 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 in close proximity 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

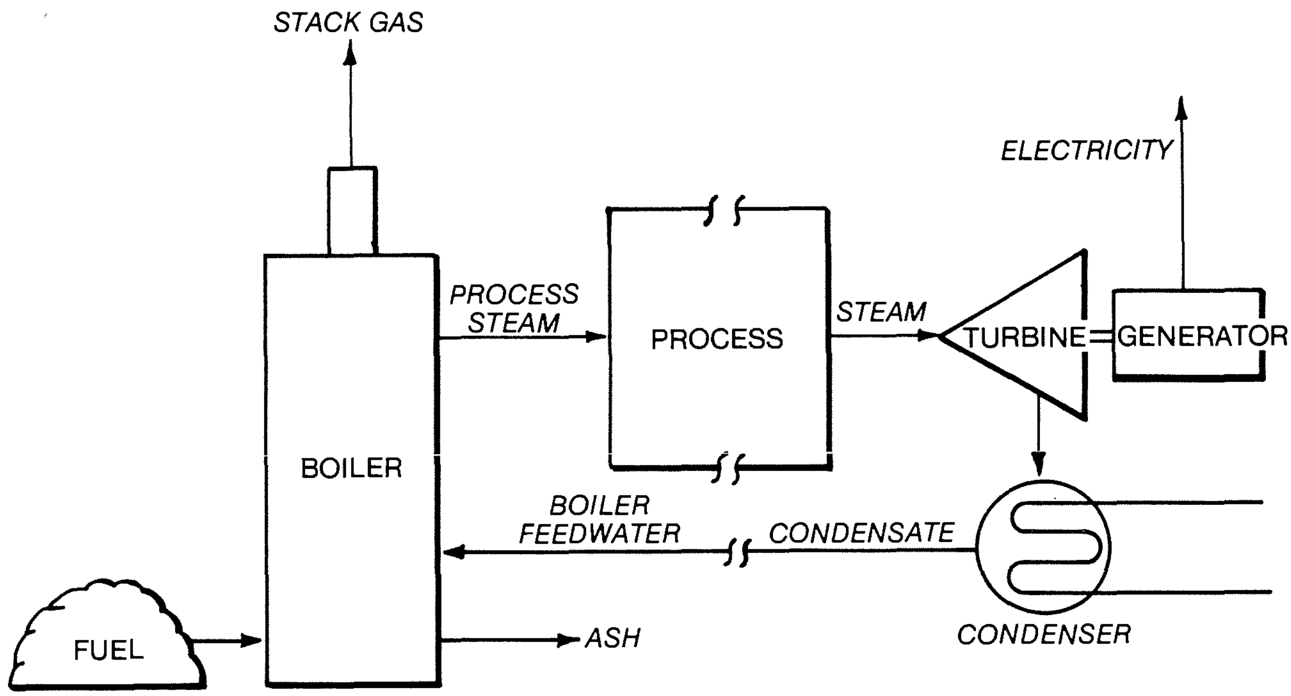


FIGURE 5.3. Simplified Schematic of a Bottoming Cycle

are also located near electrical load centers. Proximity to fuel sources is not required unless the fuel is 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 as discussed in Section 5.1.1. 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 a number of site-specific variables. Typical values for cogeneration facilities are normally in the 4500-6500 Btu/kWh range depending on cycle, power/steam ratio, process steam conditions, and other parameters.

5.1.3 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 5.2.

TABLE 5.2. Cost Summary for Steam and Combustion Turbine Cycles

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.

Operating and maintenance costs depend on cycle, capacity, degree of complexity, and the type of operators otherwise required at the site. For example at refineries, maintenance can be accomplished by plant crews. A maintenance crew must be hired for other applications. Labor and maintenance costs are somewhat higher for steam turbine systems than for combustion 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 a combustion turbine cycle would be about $2.50/kW/yr.

Despite the complexities and costs associated with cogeneration, the price of power from such systems is generally lower than that associated with condensing power stations. This is 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. It is also significant that 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.

5.1.4 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.

With a steam topping cycle, a minimal 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 3-4 times per kW-hr when compared to a conventional condensing plant. Cooling water requirements would correspondingly increase. Boiler feedwater and blowdown would remain essentially unchanged from the original facility.

All potentially adverse water resourace impacts associated with the construction and operaion of a cogeneration facility are generally minimized through appropriate plant siting and water, wastewater, and solid waste management program (refer to Appendix A). 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.

A variety of atmospheric impacts may be associated with the development of cogeneration facilites. This variety arises from the fact that many different fuels, processing systems, facility sizes, and combustion techniques may be used. For existing facilities the incremental impacts on air quality resulting from cogeneration systems are probably negligible unless a great deal of additional fuel is consumed. These systems use heat or power that have already been generated for other purposes, and they extract a portion of the available energy for electric power generaton. Cogeneration may then be characterized as having a very low atmosphere 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 associated with oil and gas combustion facilities. As with existing systems, the impacts may be construed to be minimal because the emissions are basically associated with the industrial process or system to which the cogeneration facility is attached.

Conversion of an existing steam production facility to a cogeneration system is not expected to result in significant incremental impacts on aquatic or marine ecosystems. This is attributable to minimal additional water requirements and, for steam topping cycles, the elimination of waste heat dissipation to the aquatic environment.

Aquatic ecosystem impacts associated with the construction and operation of a complete cogeneration facility would be dependent upon fuel and process type and would be similar to those experienced with comparable steam cycle facilities (refer to Appendix C).

Incremental terrestrial ecosystem impacts associated with the addition of electrical generating facilities to an existing steam plant will be minimal. Generally, less than a 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. Biological effects of construction and operation of a complete cogeneration facility would be dependent upon fuel and process type, but would be similar to those experienced with comparable steam cycle facilties (refer to Appendix D).

5.1.5 Socioeconomic Considerations

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

The size of the construction work force will vary from 25 to 250 depending on scale of plant. 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 (3,173 and 4,326, respectively). A boom/bust cycle can be avoided in these communities through the installation of construction camps.

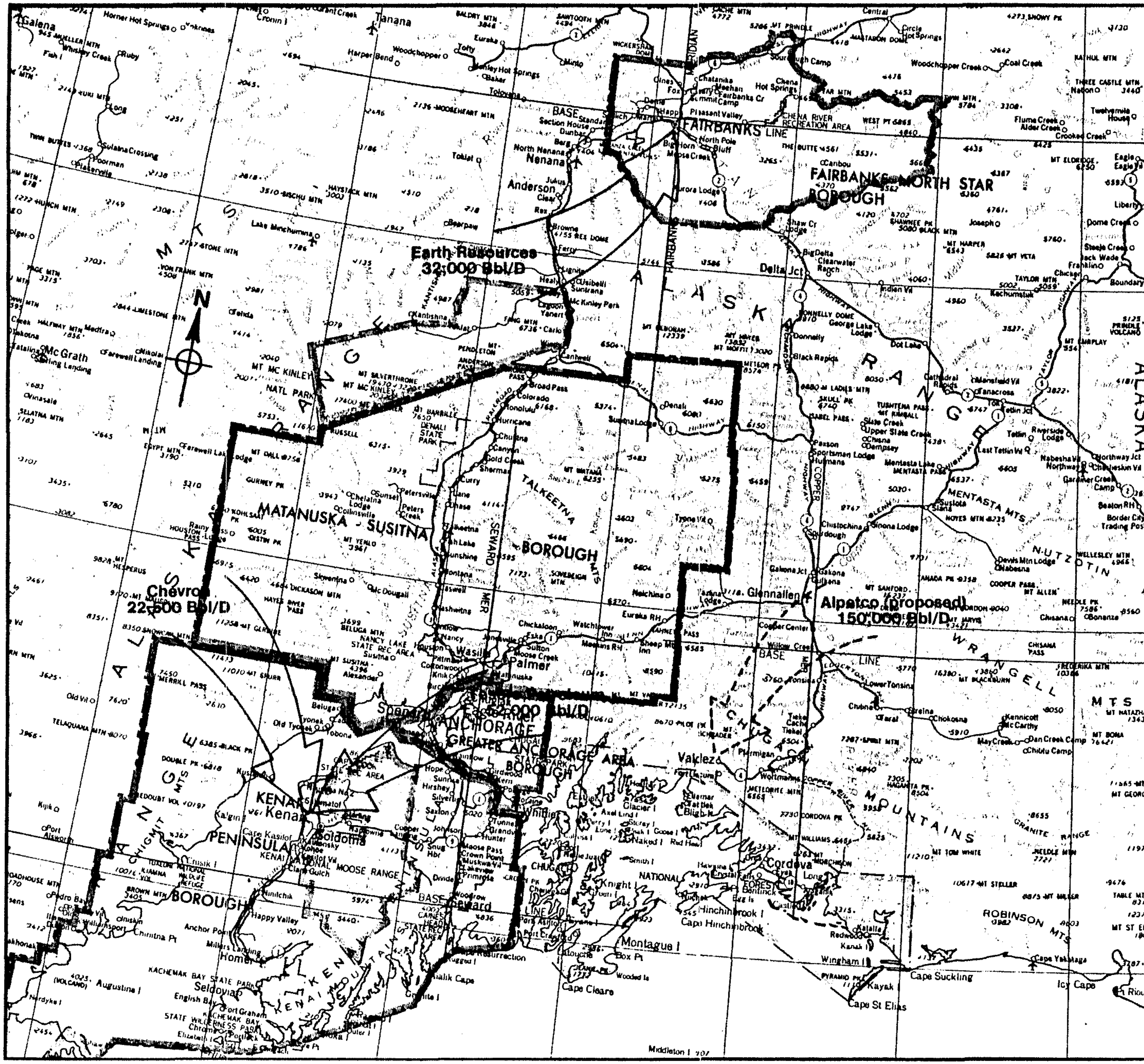
Expenditures on a cogeneration facility would flow primarily out of Alaska. This is because of the amount of equipment compared to the moderate sized workforce and relatively short construction time. The estimated percentage breakdown of project investment is approximately 67% outside of Alaska and 33% made within the state.

5.1.6 Potential Application to 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 5.4), 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 available for distribution outside of the producing industry's needs (Gyftopoulos, Lazrridis, and Widner 1974). Existing oil refining capacity has a potential for approximately 50-MWe of generating capacity. About 210 million kWh/yr of saleable energy could be produced refinery annual load factor of 80%. The proposed Alpetco refinery has the potential to generate approximately 300 million kWh/yr.

Other petroleum-related activities in the Railbelt region with cogeneration potential include oil pipeline pumping stations, natural gas pipeline pumping stations, and natural gas liquefaction (LNG) facilities if such plants are developed.

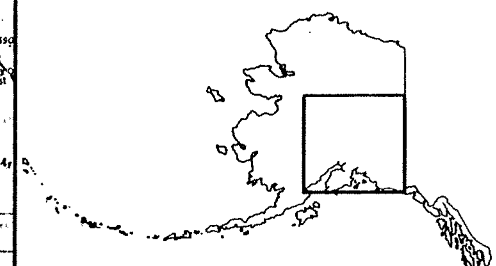
Outside the petroleum industry, manufacturing focuses on lumber and fish processing. The 51 lumber mills in the region are small (e.g., 1 MBF/D), and



PETROLEUM REFINING IN THE RAILBELT AREA

in Barrels Per Day
(Bbl/D)

SOURCE: "Petroleum Refineries in the U.S. and U.S. Territories." DOE/EIA 0111 (80)



SCALE 1:2 500 000

50 0 50 100
MILES

NATIONAL GEODETIC VERTICAL DATUM OF 1929

ALASKA RAILBELT REGION

FIGURE 5.4.

USGS ALASKA MAP E

are well below the scale required for cogeneration. The fish processing industry has a low potential for cogeneration (Resource Planning Associates 1977), although some cogeneration may be occurring in these industries (Census of Manufacturers 1976).

Industry in the Railbelt currently generates 414 million kWh/yr and military installations generate 334 million kWh/yr. This 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.

5.2 TIDAL POWER

Tidal 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 turbo-machinery is still being developed. In its present state of technology, 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 identified with significant tidal power potential. Estimates indicate that up to 2,600 MW of tidal power energy may be available on the Knik Arm and Turnagain Arm of Cook Inlet. Studies sponsored by the State of Alaska will more thoroughly define potential project costs and environmental effects. The preliminary results of the studies may be available by Spring 1981.

The underlying principles of tidal power plants are similar to those of hydropower, but instead of water flowing in one direction, water flows back and forth between the basin and sea through reversible turbines. The electrical energy that can be developed at any tidal site depends on a number of interrelated factors, including usable head, which varies continuously with tidal fluctuations, area of the tidal basin, capacity of sluiceways to fill or empty the basin, capacity of turbine and generating units, and the mode of operation.

Tidal power's major benefit is that, like hydropower, the operation of the plant utilizes a renewable energy resource. The primary disadvantage is that the generation of electricity is dependent on the cyclical pattern of tides. Since the 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 demand.

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 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.

5.2.1 Technical Characteristics

Tidal power projects consist of one or more reservoirs (or basins), a barrage, and a transmission link to a system grid. A typical plan of a tidal power project is depicted in Figure 5.5. 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,

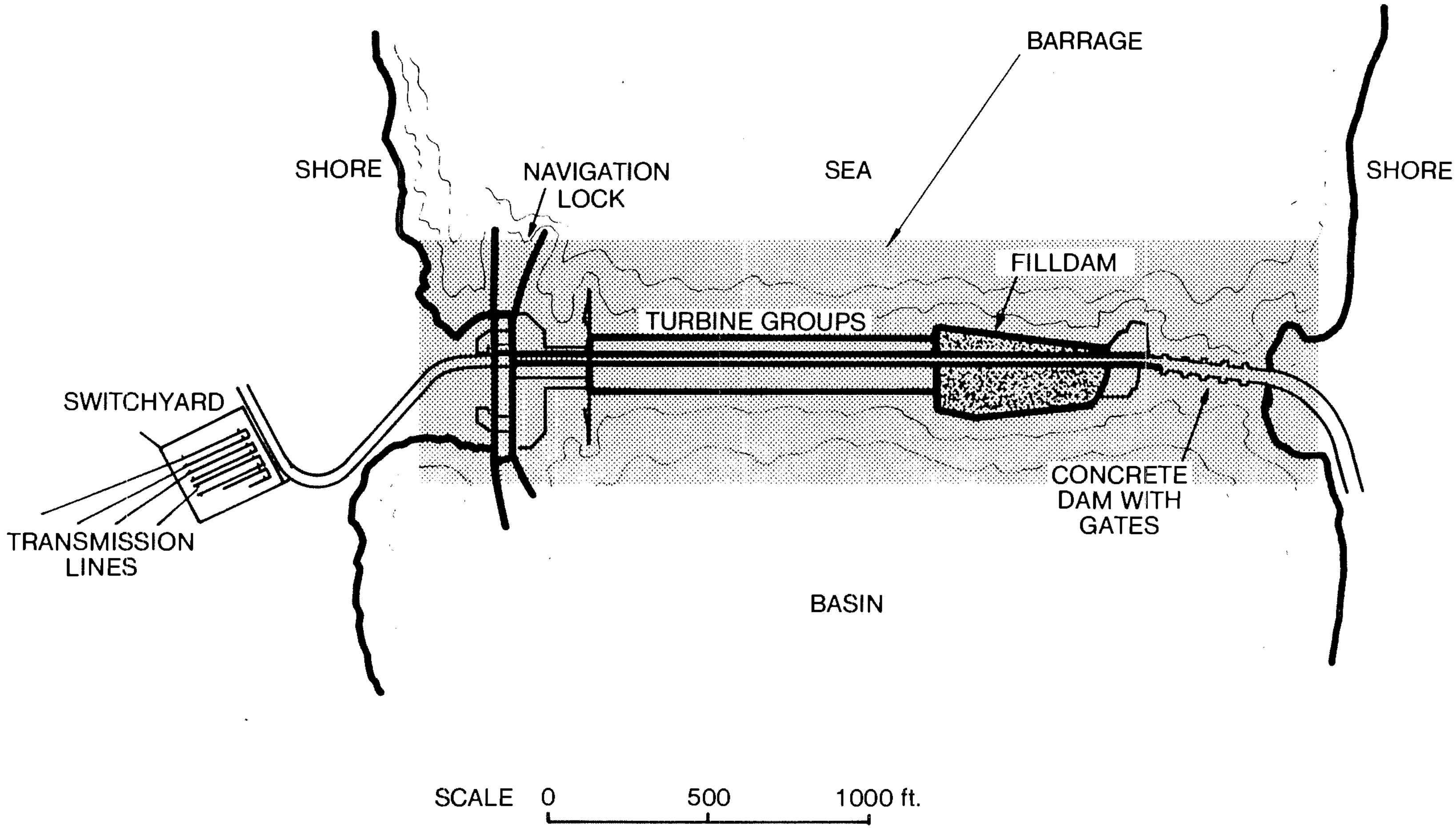


FIGURE 5.5. Plan of a Tidal Power Plant

generators, control and switching apparatus, and transformers. Additional components may include trash racks on both sides of turbine water passages, concrete forebay, and tailrace approaches.

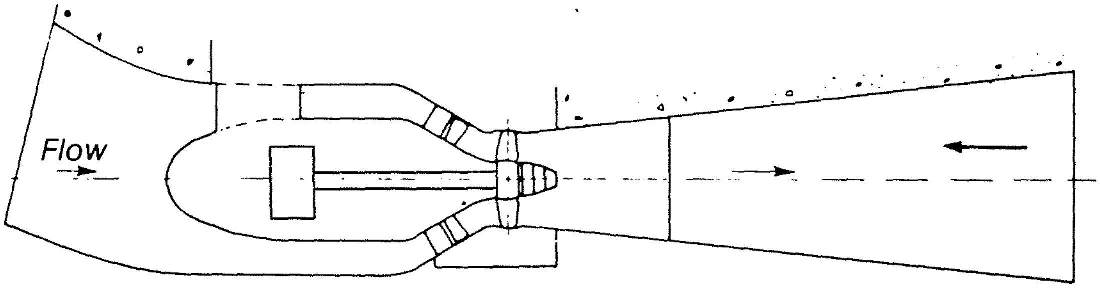
Existing tidal generating plants range in size from less than 1 MW to 240 MW. Generating efficiencies are on the order of 60%.

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

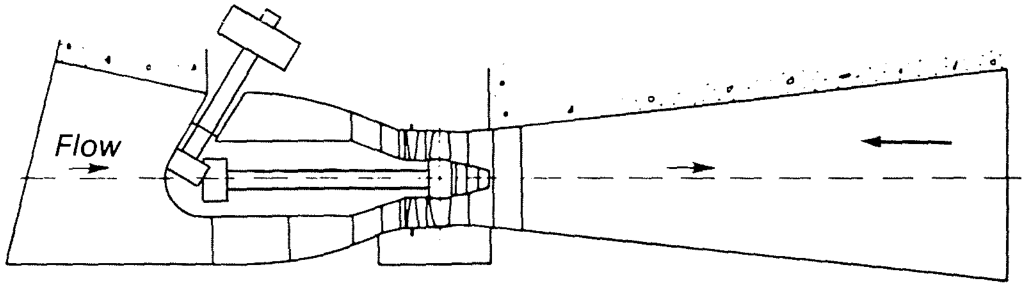
- Because power generation is a function of cyclical tidal characteristics, there is no way to accommodate demand occurring out of phase with the tides.
- Full power is only available at maximum tide levels
- Tidal power plants have no dependable capacity in the sense that the plant can serve a continuous load over extended intervals of time.

Due to these characteristics, tidal power developments must be used in conjunction with complementary cycling generating capacity or energy storage systems. An alternativae approach to compensate for the intermittant characteristics of tidal power generation would be to design and operate the project to include pumped-storage 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.

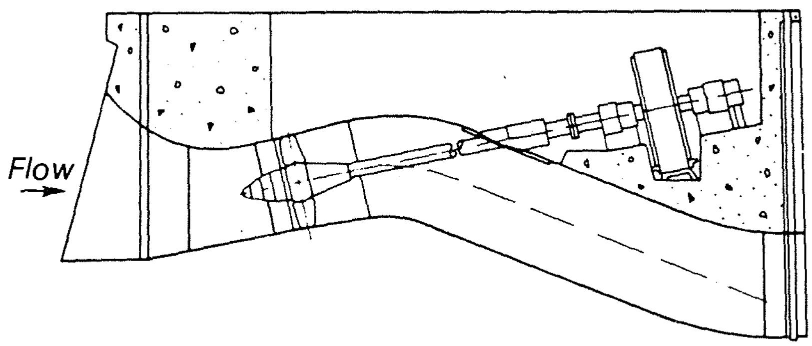
Refinements in the areas of equipment technology and construction procedure are necessary to accelerate commercialization of this technology. Specific obstacles to the development of tidal power technology have included limited availability of low-head turbo-generator units and the difficulties and expense of barrage construction. Recent renewed interest in low head hydropower development is helping to spur the manufacture of necessary equipment. In addition, the cost of cofferdams construction can be brought down through the development of prefabricated barrage sections. State-of-the-art barrage construction methods involve prefabrication of the power station in sections, in drydocks, or on slipways. Each caisson section includes a horizontal water duct incorporating an intake, space for a turbo-generator set, and draft tube (Figure 5.6). Provision for two or more



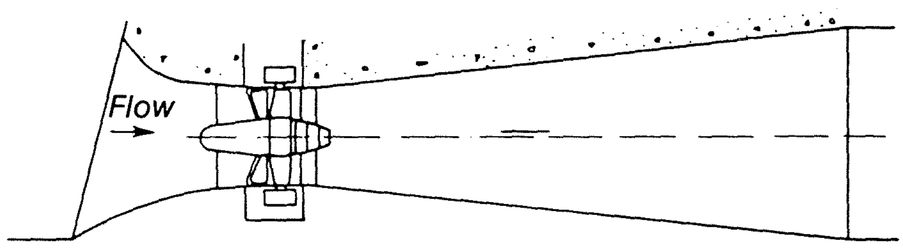
TYPE A—BULB TYPE TURBINE, DIRECTLY COUPLED GENERATOR



TYPE B—BULB TYPE TURBINE, GEAR COUPLED GENERATOR



TYPE C—TUBE TURBINE, DIRECTLY COUPLED GENERATOR



TYPE D—STRAIGHT-FLOW TURBINE WITH RIM GENERATOR

FIGURE 5.6. Types of Turbine/Generator Sets for a Tidal Power Plant

turbo-generater sets might be incorporated in a single caisson. Sections are then floated to the barrage site and sunk at slack water level onto dredged, level, rock-rubble foundations. This caisson method has been used to build a tidal-power station at Kislaya Bay, USSR.

5.2.2 Siting Requirements

Ideal sites for a tidal power plant should have large tidal ranges and large water areas capable of being dammed by a short barrage. Three site conditions are necessary for an economically viable tidal power development: 1) a mean tidal range of about 20 ft; 2) an estuary or coastal indentation that, when dammed, will not substantially reduce the tidal range; and 3) an interconnected electrical generating system with surplus off-peak power which can provide 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.

5.2.3 Costs

Detailed cost information on tidal power facilities is not yet available, but will be provides later based on the findings of two current studies: Acres American Cook Inlet Study and Retherford's Angoon Study. Based on information from preliminary studies, Cook Inlet installed 1980 capital costs could range from $2,660 to $3,460 per kilowatt (Stone and Webster 1977). Estimated operation and maintenance costs are not yet available.

5.2.4 Environmental Considerations

The placement of a barrage to harness tidal power separates a natural embayment into two artificial basins. This separtion 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 basin. Because of this characteristic, waters are well-mixed laterally, longitudinally, and vertically with each tidal cycle. In summer, there is a net outward movement of inlet waters caused by large inflow of glacial meltwater from tributary streams, while in winter with reduced runoff, there is practically no net outflow (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. There would also be a reduction in the amount of water exchanged between the Knik Arm and the Upper Inlet. 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. The magnitude of this impact, however, 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 large freshwater discharge of the Susitna River. If, however, the tidal power project encompasses both the Knik Arm and the Turnagain Arm of if the project is coupled with a Susitna River energy development project in the future, significant Cook Inlet circulation pattern changes 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 cause an increase in pollutant concentrations. Constricting the water flow to a few intake and outlet conduits would also 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 one of low energy. 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 which obstruct navigable waters. This can be overcome through the construction of locks, which then places constraints on the volume of boats traveling to and from an estuary. This could be significant to the traffic entering the Port of Anchorage, but is dependent upon the specific location of the barrage.

There will be no impacts on air quality or meteorological resources resulting 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 the restriction of movement of aquatic organisms, such as salmonids, 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 a number of 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 discharge by the Matanuska River and other Knik Arm tributaries, resulting in habitat destruction and increased benthic organism mortality. Flow patterns may be altered outside the tidal barrier, resulting in changes in 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 may occur if a tidal power development were to occur on Turnagain Arm because of the many similarities between the two areas. Salmon, though 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 manuel habitat reduction will result from 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 negataively 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 during seasonal migration periods on these areas. 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 reduce their value to waterfowl and various shorebirds.

Both tributaries are also used by harbor seals. Establishment of 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. Losses to marine mammals could, however, not be relieved. Waterfowl and various shorebird habitats could be kept relatively unchanged by maintaining tidal cycles similar to normal ones. This would not be possible if tidal energy production was 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, provided densities of fish-eating raptors on these streams are not at saturation levels for reasons other than food availability. If this were the case, then losses could not be mitigated.

5.2.5 Socioeconomic Considerations

A tidal power plant requires a large construction workforce and a small operating workforce, creating the potential for a boom/bust cycle. During a period of 7 years a workforce of 200 to 500 would be required for a 240-MW plant. The size of the construction workforce would not vary greatly with plant scale since excavation and barrage construction are general requirements independent of generating capacity. A staff of 20 to 50 would be required during the operating phase.

Since the two tidal sites 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 siding in Anchorage and the upper Kenai Peninsula. Therefore, a workforce would not have to be brought in from other areas of Alaska, which would avoid increasing the demand for housing or services.

Since tidal power is a labor-intensive technology and participation by the Anchorage and upper Kenai Peninsula labor force is expected, the expenditures for labor should be kept primarily within the region. Some of the expenditures for capital, 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.

5.2.6 Application to Railbelt Energy Demand

The Railbelt region has one significant area for tidal power development--Cook Inlet, which has 35-ft tidal fluctuations. Up to 2,600 MW of potential, including 750 MW from an identified site on Knik Arm just north of Anchorage, could be developed. However, Cook Inlet sites also has the disadvantage of shallow water, deep sediment layers, and icing conditions.

Severe ice conditions in Knik Arm and Turnagain Arm will complicate the design and operation of a tidal development for Cook Inlet. The tide fluctuation prevents formation of solid ice sheet on Cook Inlet, as the rapid rise and fall in water level tends to continuously break up the ice. These broken ice sheets form ice floes which tend to move back and forth within the estuary. Experience at the Port of Anchorage Marine Terminal, for example, indicates that ice builds up in thick layers on piles supporting the wharf until a non-uniform honeycomb has been formed under the entire structure. This ice layering lasts for about 3 months. Scouring action of the ice flows will damage concrete surfaces unless these are protected by steel armoring.

An additional problem is presented by cold winter air temperatures in combination with repeated submergence and exposure of concrete surfaces by tidal action. Each cycle of the tide becomes a freeze-thaw cycle under these conditions. Concrete surfaces become scoured and spalled as a result of the combination of frost action and falling ice. Steel piles and sheet steel armoring of concrete surfaces will be necessary to ensure surface and structural integrity of normally exposed concrete surfaces.

5.3 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 come to play a significant role in electric power generation in rural areas, small communities, and possibly for large interconnected energy systems.

Large wind turbines are being developed in response to this renewed interest and are in a demonstration phase. In 1979 a MOD-1 2-MW, 200 ft diameter turbine was completed at Boone, North Carolina. Three MOD-2 wind turbines, rated at 2.5-MW capacity, are under construction near Goldendale, Washington by the Bonneville Power Administration, U.S. Department of Energy, and NASA. These and other wind turbines in the 1-MW range of rated output are available for production, but benefits of assembly line production have not been realized. Commercially available, mass produced wind machines are at present quite small and only available in unit sizes of about 5 kW, with the maximum at 45 kW. This section will focus on large wind turbines of 0.1 MW rated capacity or more such as might by employed as centralized power generating facilities by a utility.

5.3.1 Technical Characteristics

Wind energy is characteristically a diffuse source of energy in which the theoretical output of an individual wind machine is a function of the third power of the speed of the wind, wind machine efficiency, and area intercepted by the turbine blades. Wind is converted to electric power in two steps. The first involves the conversion of the kinetic energy in the flowing wind to rotational energy. The flow of the wind past an aerodynamically designed blade moves it around its axis of rotation, extracting energy from the wind. The second step is the conversion of rotational energy to electric energy through the use of a generator.

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: 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 is the design being used for development of the megawatt-size systems and is illustrated in Figure 5.7. Vertical axis rotor systems have a

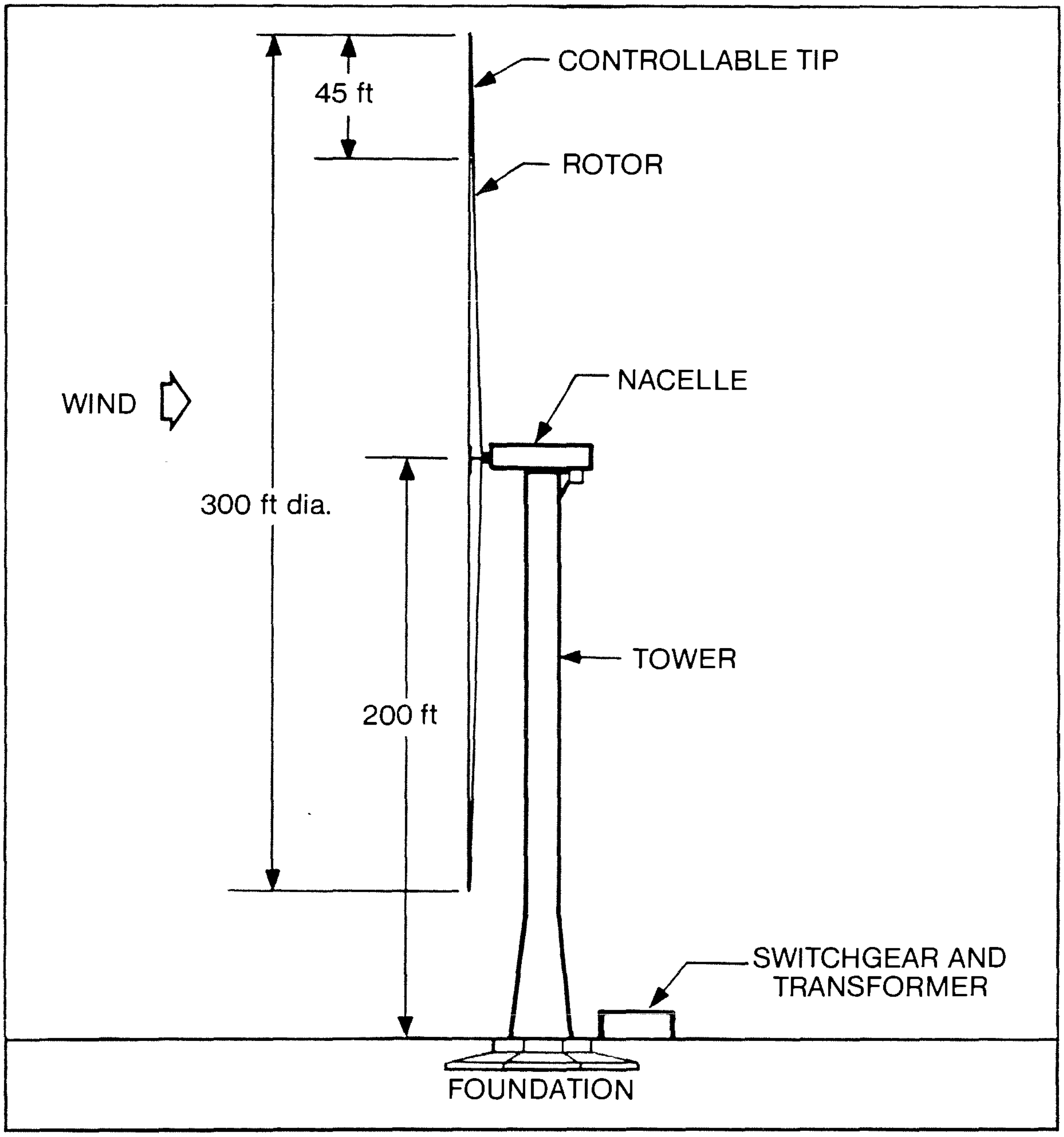


FIGURE 5.7. Schematic of a MOD-2 Wind Turbine Generator

vertical axis of blade rotation. The most common representatives of this system are the Savonius and Darrieus machines (Figure 5.8). Vertical axis systems are generally less efficient than the horizontal rotor systems, but since they do not need a tower, their construction costs are less and have the added advantage of being insensitive to wind direction. Cross-wind horizontal

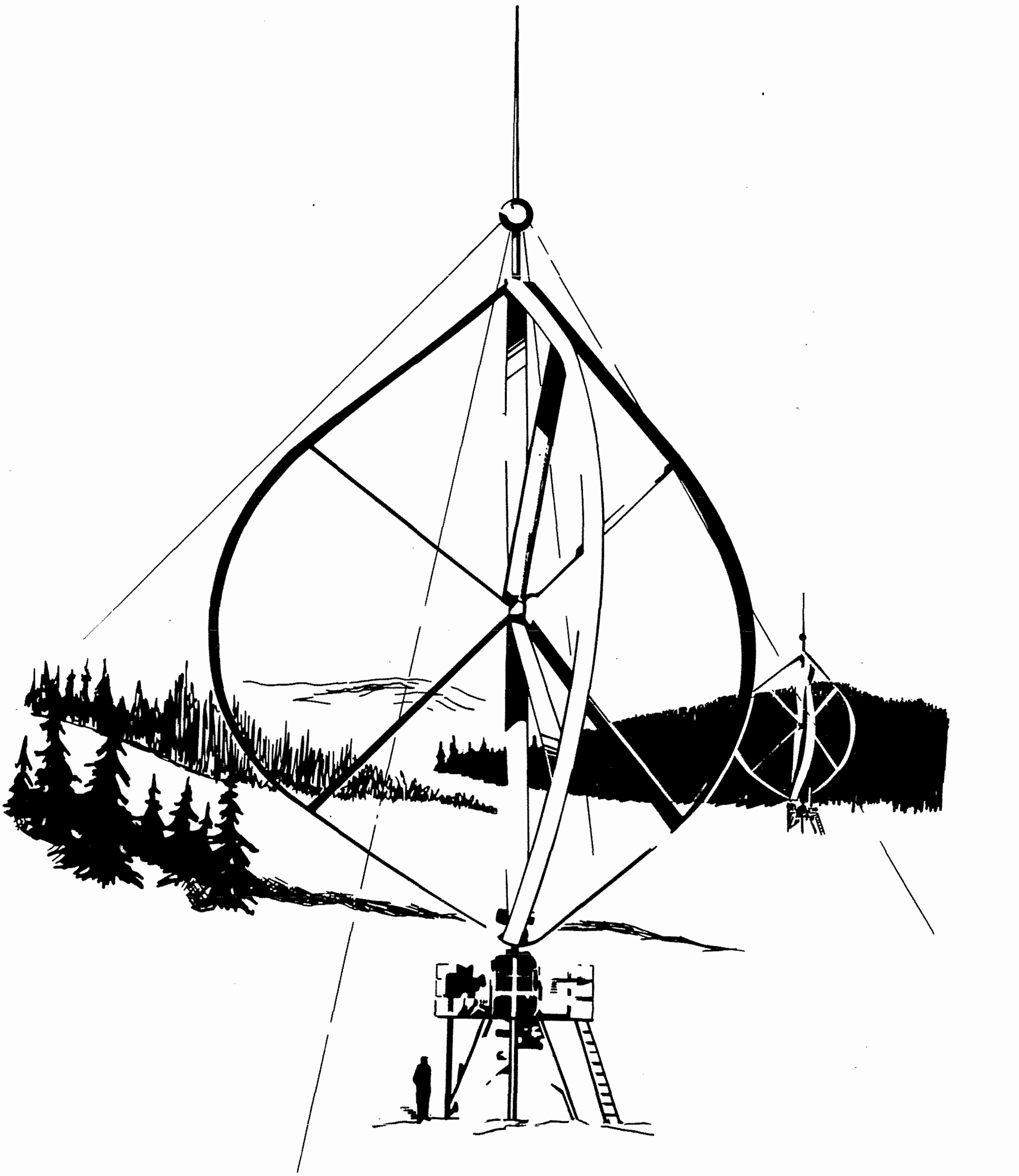


FIGURE 5.8. A Vertical Axis Wind Turbine (Darrieus Type)

axis systems are of the familiar paddle-wheel design and do not represent an improvement over either of the other two designs (Inglis 1978). At the current stage of development it appears that horizontal axis designs will be preferred for megawatt-scale machines.

Wind generators operate within well-defined wind speed ranges. The "power output profile" depicts the power output of the turbine as a function of the wind speed. The power profile for the MOD-2 (Figure 5.9) indicates the cut-in speed (14 mph), rated speed (28 mph), and cut-out speed (47 mph). Since wind turbines must be designed to fit load system and wind conditions, in some cases a smaller wind turbine with a lower cut-in speed, a lower rated speed, and a lower power rating may be preferred to a larger machine with higher cut-in wind speeds.

The production of wind power electricity is an intermittent process owing to 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 capacity factor, for wind turbines will probably range between 30 and 50%, but this factor is extremely sensitive to the wind pattern at the site.

Weather factors such as icing or high winds act to reduce the machine reliability. Equipment life in the harsh climate of the Railbelt region may pose a problem, which requires careful study. 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 sub-zero temperatures.

Grouping of wind turbines into "wind farms", as at Gambell, Alaska, can reduce problems associated with equipment failures. Any one turbine could be shutdown for repair or maintenance without greatly affecting the farm's output. The overall reliability of the farm 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

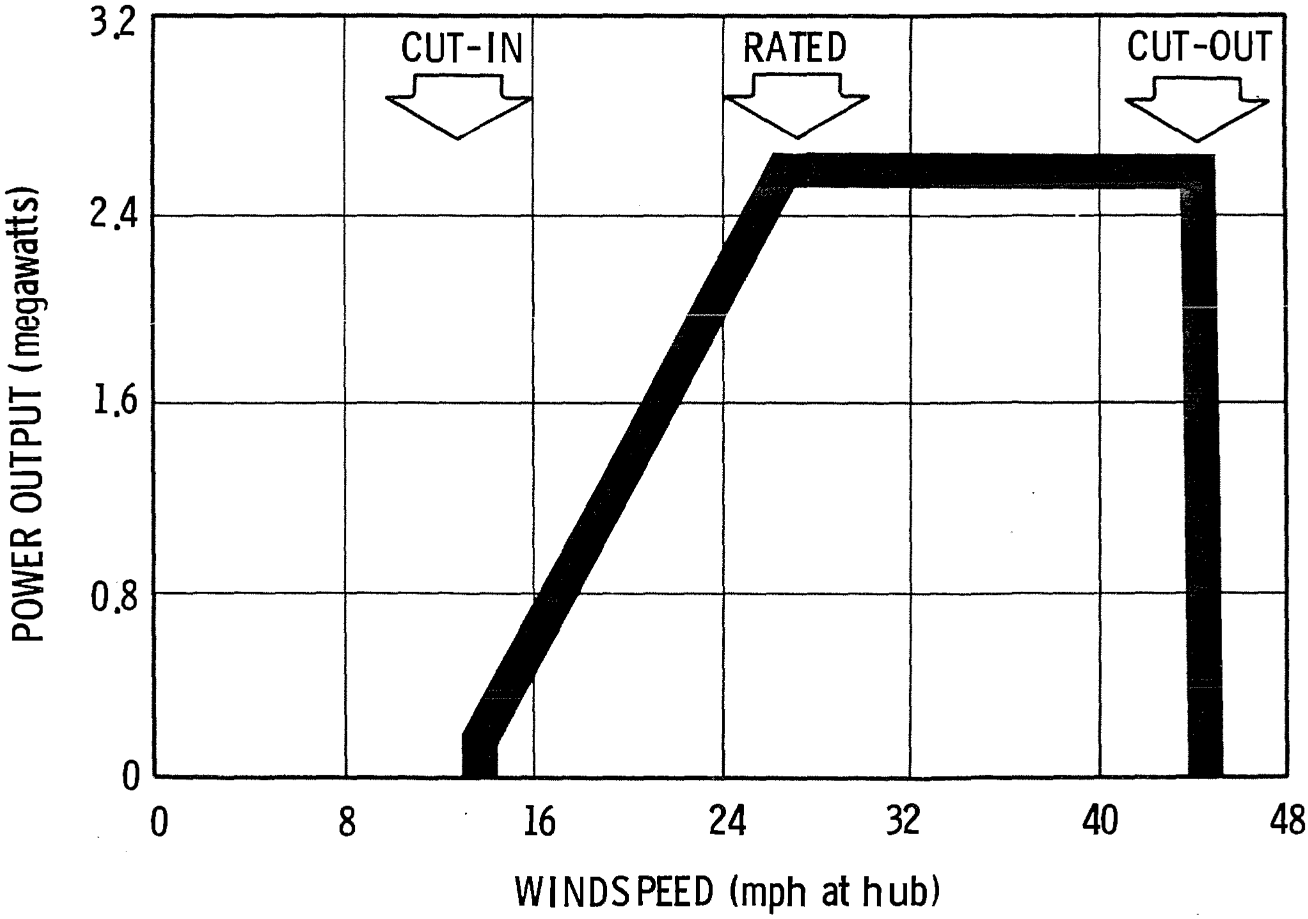


FIGURE 5.9. Power Profile of the MOD-2 Wind Machine

or a wind farm may be developed at sites where the wind pattern closely approximates the load pattern. This helps alleviate storage requirements and load management difficulties.

In a grid with existing hydro capacity, storage can be accomplished by displacement of hydro production, that is, by simply not using as much water 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 in a manner similar to hydro power.

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.

5.3.2 Siting Requirements

The siting of the wind turbines is crucial in wind energy conversion systems. The most significant siting consideration is average wind speed and variability. These 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 incremental increases in wind speed is important (Hill 1977). Extremely high winds and turbulance may damage the wind turbines, and any 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.

5.3.3 Costs

The major costs associated with the development of wind power are the equipment and erection costs. The operations and maintenance (O and M) costs are difficult to project because of a lack of standardization and little operating experience. Consequently, the O and M costs are uncertain but are projected to be small when compared to the 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. Boeing also estimates that the cost of power produced by these turbines will be in the range of 4 to 5 cents per kilowatt-hour. Costs of installation at remote locations are uncertain, particularly if there is considerable difficulty in shipping the units or installing them onsite. Because of the remoteness of prime locations, the costs of installed wind turbine power capacity are expected to be significantly higher than those associated with more accessible locations (Inglis 1978; BPA 1981; Hill 1978).

5.3.4 Environmental Considerations

Wind turbines extract energy from the atmosphere and therefore have the potential of causing slight modifications to the surrounding climate. Wind speeds will be slightly reduced at surface levels and to a distance equivalent to 5 rotor diameters which for a single 2.5-MW facility would be approximately 1500 ft. 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 associated with 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.

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. This can range from approximately 2 acres for one 2.5-MW generating unit to over 100 square miles for a 1000 MW wind farm. These developments, due to requirements for persistent high-velocity winds, would probably be established in remote areas.

Because of the land requirements involved, the potentially remote siting locations and the possible need for clearing of vegetation, the greatest impact resulting from wind energy projects on terrestrial biota would be loss or disturbance of habitat. Wind generating structures could also affect migratory birds by causing collisions. 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, however, are presently unclear.

Environmentally sensitive areas in the Railbelt region presently proposed for wind energy development are exposed coastal areas along the Gulf of Alaska, and possibly hilltops and ridgelines in the interior. Alteration of coastal bluffs could negatively 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 utilize 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 (endangered species), and other birds, if situated in migratory corridors. Inland development of wind energy could negatively affect Dall sheep, mountain goat, moose, and caribou if situated on critical range lands.

These terrestrial impacts can generally be mitigated. Habitat lost through development is irreplaceable. However, these losses can be minimized by siting plants in areas of low wildlife use. This would include avoiding 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. The feasibility of mitigation will, of course, depend on the size of the wind energy development.

5.3.5 Socioeconomic Effects

Construction of a 1 to 2 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 on-site 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, population size of a community is not a siting constraint. Individual wind turbines should therefore be compatible with communities of all sizes.

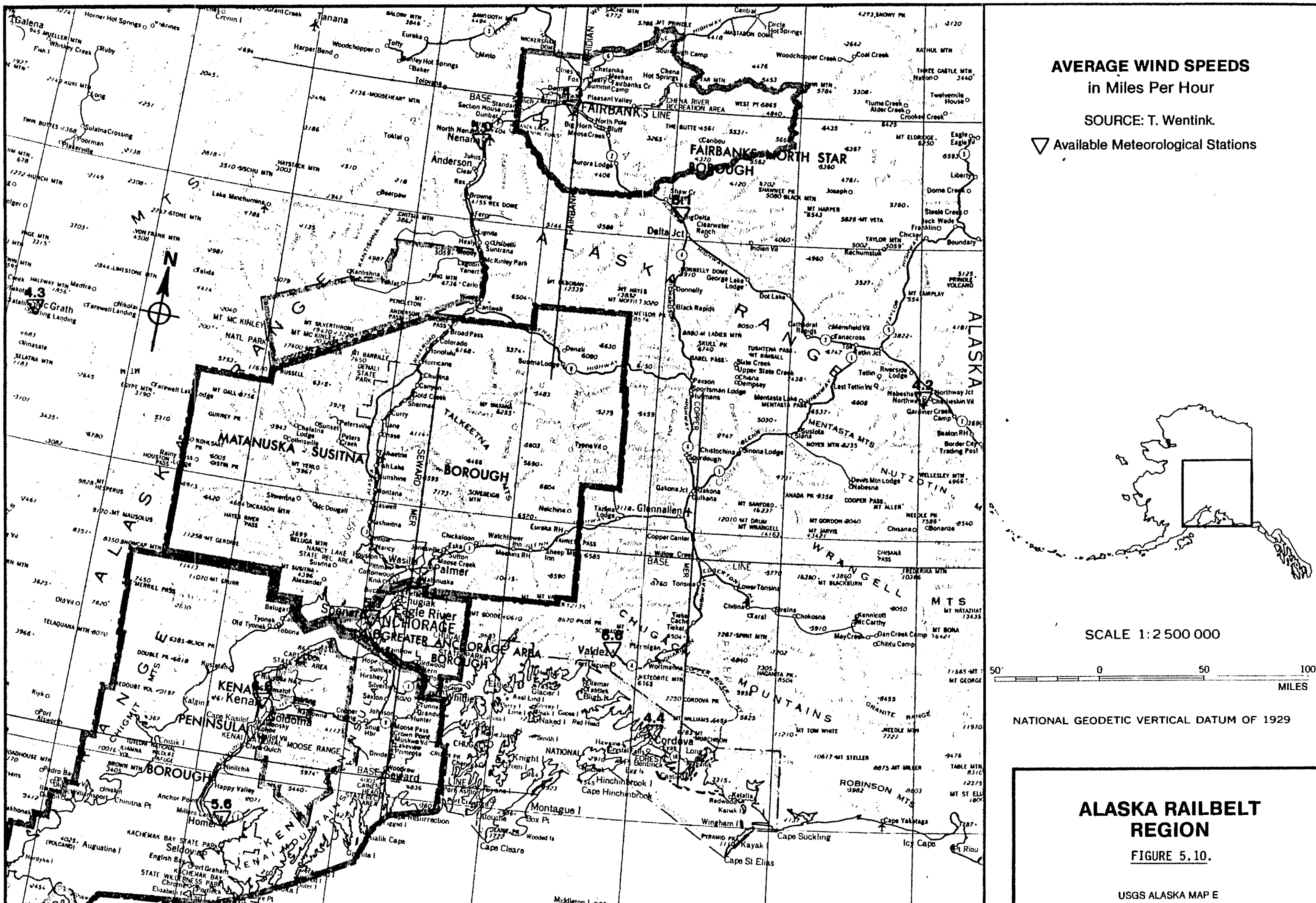
Installation of a 100-MW wind farm would require a construction work force of approximately 60 over a period of a few years. The impacts of constructing a wind farm on small communities may be significant because of the increase in work force size and length of construction period.

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. Therefore, approximately 80% of the expenditures would be sent outside the region while 20% would remain within Alaska.

5.3.6 Potential Application to Railbelt Energy Demand

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.

Studies to identify wind energy resources in the Railbelt would require a significant data base. Such a data base is currently lacking, as can be seen on Figure 5.10, which shows mean wind speeds from available monitoring



ALASKA RAILBELT REGION

FIGURE 5.10.

stations in the Railbelt region. Currently available literature is not adequate to comprehensively identify potential wind energy conversion system sites in the Railbelt region. Studies necessary to assess wind energy potential include: preparing and examining detailed contour patterns of the terrain, modelling selected sites, monitoring meteorological conditions at prime sites for at least 1 year (preferably 3 years), analyses using modelled and measured data, developing site-specific wind duration curves, and selecting final sites.

Wentink and his colleagues at the University of Alaska have conducted a preliminary assessment of wind power potential in Alaska. The results of these studies indicated a potential for favorable sites for wind energy development at exposed coastal locations and possibly along ridgelines or hills in the interior (Wentink 1979). A Battelle-Northwest study that addressed the nature of wind patterns in the Cook Inlet area generally concluded that sites with marginal potential exist in this area.

5.4 SMALL WIND ENERGY CONVERSION SYSTEMS

Small wind energy conversion systems (SWECS) are wind machines with rated output of 100 kW or less. Typically these machines would be sited in a dispersed manner, at individual residences or in small communities, as compared to the large wind energy conversion systems (Section 5.3) which would be sited, generally in clusters, as centralized power production facilities.

Small wind energy conversion systems are available in horizontal and in vertical axis configuration. The horizontal areas machines (Figure 5.11) 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 revolve in conformance with changing wind direction, requiring provision of head bearings and slip rings and machine orientation devices.

Although of lower efficiency than horizontal axis machines. The vertical axis generator (Figure 5.8) is located in a fixed position near the grounmd, minimizing tower structure and eliminating. 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.

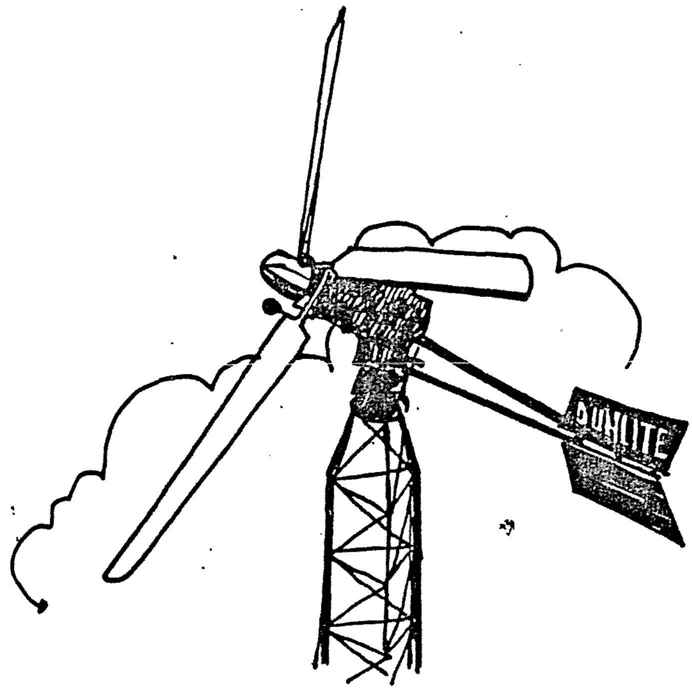


FIGURE 5.11. A Typical Horizontal Axis Small Wind Machine

A number of small wind machines are now in commercial production in sizes ranging from 0.1 to 37 kW (A.D. Little, 1979).

Historically, battery-charging systems have been the primary application for Small Wind Energy Conversion Systems in Alaska; however, this is beginning to change. Figure 5.12 shows some of the many possible ways of using SWECS, a few of which are used in Alaska.

The subject of this study is concerned with SWECS which interface directly with the utility grid. Off-grid installations are not considered.

5.4.1 Technical Characteristics

The three most common types of small wind generator systems are induction (AC) generators, synchronous (AC) generators, and DC generators. SWECS using induction generators are designed to operate in parallel with an existing utility grid. The induction generator is actually an induction motor. With the wind blowing at a velocity that causes the rotor to turn faster than the induction motor's rated rpm, the device acts like a generator and produces

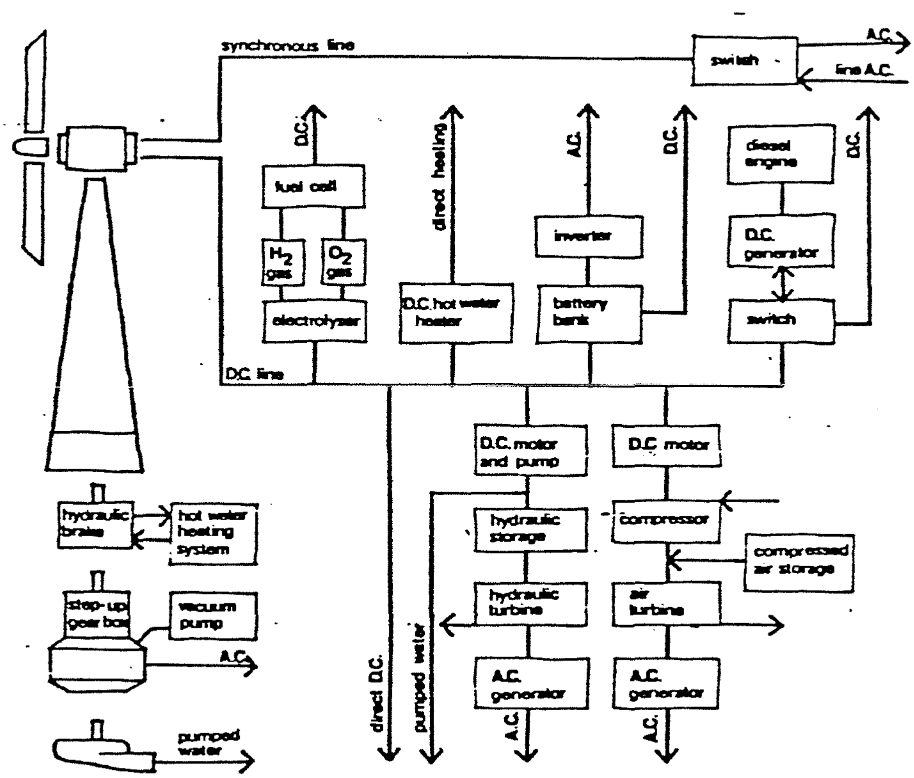


FIGURE 5.12. Block Diagram of SWECS configurations presently being used and under study.

energy. The resulting power will be synchronized with the local utility power frequency allowing power to be supplied to the utility system. The utility power source provides the reference frequency.

SWECS using synchronous alternators are capable of generating 60-cycle alternating current with or without a synchronizing utility grid. This capability is possible because of synchronizing microprocessors controls incorporated innto the wind machine.

SWECS which generate DC power are typically used for charging batteries in remote sites. Either a brush-type DC motor or an alternator and DC rectifier is 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.

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).

The maximum heat loss from a building occurs in extreme, cold weather with high winds. Since winter months are typically windier than summer in most parts of Alaska, any electricity used for space heating, either directly or indirectly, (furnace motor, fans, circulating pump) would coincide with power available from the wind. Also, in periods of high wind, people's activities are usually limited to indoors where lighting and appliance usage is increased.

On-grid SWECS are usually not considered as base load units and are given little capacity credit, operating only in a fuel-saver mode. However, in regions as diverse climatically as the Railbelt, studies have shown (Timm 1980) that with simple load management techniques, wind machines can be given significant capacity credit in grids without storage.

If SWECS are added to an existing hydroelectric grid, storage is built into the grid system: when the wind is blowing, less water is run through the turbines; during periods of calm, that water is then used to follow load, much like a large battery storage system (BPA 1980). If enough grid-connected wind generated capacity were installed, hydroelectric pump-storage could be used to store surplus energy.

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 their small size allowing for incremental additions, SWECS are extremely adaptable to any growth pattern.

Historically, the market for SWECS has been remote sites where power costs were very high. Because of the extreme environmental condition they are subjected to, wind generators must be properly designed and installed to provide adequate reliability with little maintenance. The availability of wind energy depends on the site and the application, and it cannot be answered without better wind data.

5.4.2 Siting Requirements

A wind speed of 7 to 10 mph is required to start most SWECS producing power. An annual average of 10 mph is usually considered a lower economic cut-off for most applications; however, this is very dependent on the site, energy costs, and particular wind generator design.

Turbulence is the worst energy of SWECS. It can be caused by trees, buildings, and topography. Because wind acts like a fluid in that it slows down when it encounters an object or rough terrain, the higher up from the ground, the stronger the wind. Thus each site must be evaluated for terrain (Figure 5.13) and what affect that may have on wind speeds at different heights (Figure 5.14).

A small wind machine which 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 becauase of the high transmission line losses.

5.4.3 Costs

Depending on the application, the cost of money, tax credits, and the type of system, installation of 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 5.3). A operation and maintenance figure of 1% of installed costs equal to $50-$200/year would be representative, but depends on the system.

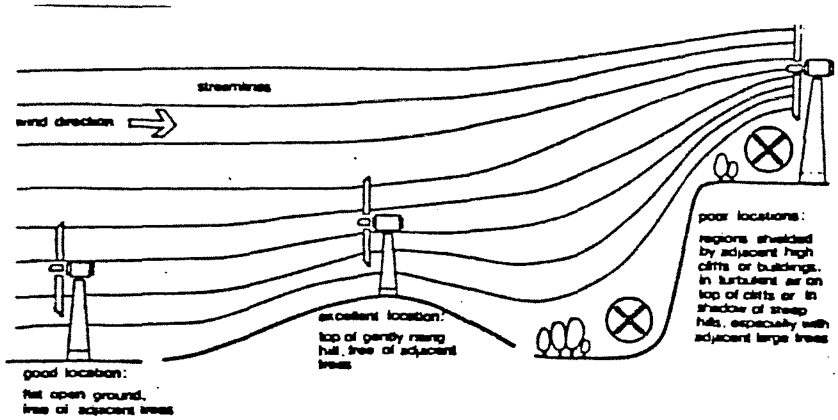


FIGURE 5.13. Local Terrain Can Significantly Affect the Performance of a Wind Machine

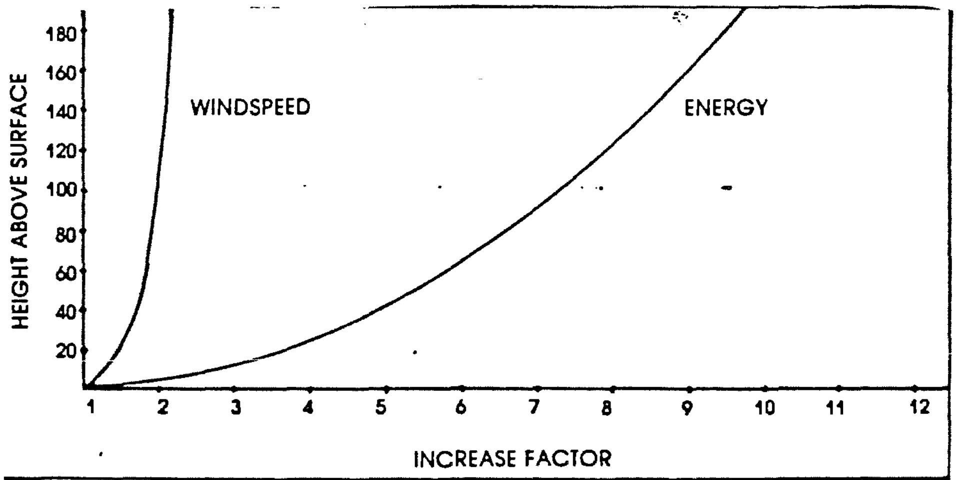


FIGURE 5.14. Example of Increase In Energy Available In the Wind with An Increased Tower Height

TABLE 5.3. Estimated Costs of Small Wind Energy Conversion Systems

Rate of Capacity (kW)	Capital Costs ($/kW)	Operation and Maintenance Costs ($/kW/yr)	Cost of Power ($/kW)[(a)]
2	2500	25	0.09-0.15
10	2500	20	0.09-0.15

(a) Ranges given based on capacity factors of 0.3 to 0.5.

5.4.4 Environmental Impacts

Studies have shown some enhancement of local wildlife due to downwind shelters, as well as a possible adverse impact on low flying night migratory birds in bad weather. However, the kill rate is not significant.

Aesthetic intrusiveness is difficult to assess and highly subjective. Many people surveyed have found small wind machines to be visually pleasing. Small generators noise is not significant with proper blade design.

Small wind machines mounted on towers require no more than 100 sq ft at the base plus any exclusion area which the owner wishes to fence off for safety reasons (usually no more than about 5 blade diameters).

Radio frequency interference can be mitigated with proper blade design (nonmetallic) and siting.

Potential safety risks involve the possibility of tower or blade failure 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.

5.4.5 Socioeconomic Impacts

By siting SWECS in "wind farms," rows of generators can be lined up as a wind break for combined utilization 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 resulting from construction or operation of a facility is foreseen. The necessary manpower, talent, and expertise is 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.

How convenient this technology is to the consumer depends on the system. Induction generator systems require only an annual inspection and lubrication of the wind generator. Synchronore generator systems being installed today are totally microprocessor-controlled and need no maintenance other than periodic generator inspection and lubrication. Maintenance contracts are presently available which would free the consumer from any maintenance responsibilities.

The individual consumer's level of control can range from a totally manual system to a totally automatic SWECS. Most installations do allow the individual to be considerably closer to the actual source of power and gives him the ability to exercise more control over his production and consumption than if the power were generated off-site by a utility.

5.4.6 Potential Application to the Railbelt Region

Until recently there were only a handful of SWECS manufacturers. Today there are over 50 with a half dozen mass producing generators at a respectable rate (20-200/month). The demand, however, is far outpacing the supply, and several manufacturers report back orders of 120, or more, days. However, 60-90 days is generally quoted as delivery time and the major manufacturers hope to be selling from inventory by the end of 1981.

A dealership and repair network is already in existence in the Railbelt region and would grow as the number of installed WECS increases. Engineering and design expertise is also present in the region. Five system design organizations, four suppliers and one installer are currently operating in the Railbelt (Energactions 1981).

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 the market penetration and mass production has brought the unit cost down and manufacturers have internalized major R&D efforts, then widespread use of SWECS may become a reality.

Wind data have historically been collected from airports at a height usually no greater than 30 ft. Wind generators are typically not located near airports (which are usually sited in locations protected from winds) and are placed at least twice as high as conventional meteorlogical stations. A few examples will illustrate the problem:

- 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 is recorded as 4 mph, yet as one climbs out of the valley the average wind speed almost triples near Murphy Dome.

This suggests that existing data are not very helpful in determining the potential of SWECS in the Railbelt. The number of mountain passes with channeling effects, glaciers with their constant source of winds, and coastal regions with the windy maritime influences yield thousands of potential SWECS sites in the Railbelt. A recent study done by Battelle-Northwest 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 any candidate sites to be selected or site specific costs to be identified for large wind systems.

Because of the lack of data taken for siting small wind machines there is no quantitative means for assessing the possible contribution SWECS would have in the Railbelt region. However, since most of the population lives in two known areas of low winds (Anchorage and Fairbanks), it is reasonable to assume that without large-scale utilization of "wind farms," only a small percentage of the total Railbelt load could be met by wind power (less than 10%) in the next 5 years. If a decision were made to develop clusters of SWECS then this contribution could become significant in the midterm (5 to 10 years).

5.5 SOLAR ELECTRIC

Two basic methods for generating electric power from solar radiation are under development, solar thermal conversion and photovoltaic systems. Solar thermal systems convert solar radiation to heat in a working fluid. This working fluid can include water, steam, air, various solutions, and molten metals. Energy is realized as work when the fluid is used to drive a turbine. Photovoltaic systems is a more direct approach. Solar energy is converted to electric energy by the activation of electrons in photosensitive substances.

At present, commercially available photovoltaic cells are made of silicon wafers and 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 have been proposed capable of converting 30 to 40% of the sunlight falling on them to electricity.

Both solar technologies suffer from the same constraints. Available solar energy is diurnally and seasonally variable and is subject to uncertainties of cloud cover and precipitation. Solar energy resources must be employed as a "fuel saving" option or they must be installed with adequate storage capacity. In addition, if the diurnal and annual lead cycles are out of phase with solar energy potential cycles, the inducements for development of this resource are further reduced. The energy demand and solar availability cycles are out of phase in the Railbelt region, where demand generally peaks in winter and at night.

5.5.1 Technical Characteristics

Solar Photovoltaic Systems

Photovoltaic cells operate by transferring the energy in light to electrons in a semiconductor material. Transfer occurs when a light photon collides with an atom in the same conductor material with enough energy to dislodge an electron from a fixed position and 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 then created, which then induces a voltage specific to the cell material.

Photovoltaic cells commonly come in modular units with voltages of 3 to 24 volts and current outputs from the milliamp range to around 3 amps. The cells are load-sensitive; as the load is increased, the voltage decreases.

These cells, being modular in nature, can be easily added together, up to the limits of various ancillary systems. Ancillary systems include voltage conversion, energy storage systems, and backup electricity generating systems (Hill 1977). In general, photovoltaic system conversion efficiencies range from approximately 2 to 13%.

These cells are well-suited for outer space, application in remote locations such as navigational aids, and irrigation pumps, where their high cost per kilowatt-hour can be justified.

Two of the most developed photovoltaic devices are concentrated sunlight photovoltaic systems and cogeneration photovoltaic systems.

Concentrated Sunlight Photovoltaics. Parabolic reflectors are used for concentrating sunlight onto an array of solar cells in order 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. It is believed that design improvements will result in cells that have an efficiency of at least 20%, with slight increases in costs. Parabolic reflectors have one specific disadvantage: in order to work well, automatic tracking mechanisms must be provided to keep the reflectors focused at the sun as the sun moves across the sky. With the sun low in the sky during the winter months in Alaska or in early and late afternoon, these systems would be very 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, it is preferable to accept these losses of efficiency and to use the thermal output from the cells directly rather than to maximize cell performance. The use of these systems could be more efficient than using straight photovoltaic systems for certain applications. But, even in the "lower 48" states these are expensive options.

Solar Thermal Systems

Solar thermal systems use focused sunlight to provide concentrated thermal energy. This energy is then used to raise steam or impart heat to some other working fluid, which is then used to drive turbo-generaters to produce electricity. The two most advanced solar thermal systems are described below.

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 the best way to generate high temperatures using solar energy is with a point-focusing array of mirrors that track the sun (a heliostat). The solar insolation is focussed on a boiler set atop a large tower. Heliostats that concentrate sunlight 1,000 times are used to raise the temperature in the boiler to 500^{o}C, and the resulting steam can be used to produce electricity and process heat through cogeneration.

The first 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 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. The best sites for commercial-scale towers would be in the desert because of the high solar flux. These systems are still experimental and will not be available until possibly the late 1990s. A typical density packed 60-MW tower would cover roughly 160 acres (Metz and Hammond 1978). Efficiencies are climate-sensitive and can range from 10 to 70%.

Parabolic Dish Collectors. Solar energy systems can provide a regime of intermediate operating temperatures 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 simple low-temperature collectors used for space and water heating. These types of collectors could be used for process heat, crop irrigation, and decentralized generation of electricity.

One such system is the parabolic tracking dish. This 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).

5.5.2 Siting Requirements

Solar electric generating systems are optimally located in areas with 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 high 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 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 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.

5.5.3 Costs

Costs of photovoltaic systems are extremely high compared to other technologies, mainly because of technical dificulties associated with developing efficient cells. The costs of photovoltaic cells are much higher than what they were projected by previous research and development progress.

Today's 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/watt of capacity. Costs as low as $11 per watt of capacity have been reported by the federal government when buying in large quantities. DOE expects these costs to be $2/watt in 1982 and $.50/watt in 1986, and as low as $.10-.20/watt in the mid-1990s.

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.

The construction of residential or district photovoltaic systems should not be labor-intensive, since photovoltaic arrays can be easily assembled into large units, and ancillary systems are also modular in nature.

Cost estimates for solar thermal systems in the 10 to 100 MW capacity range, are provided in Table 5.4. Construction time is estimated at 5 years, and the system life is projected for 30 years.

TABLE 5.4. Estimated Costs for Solar Thermal Systems

Capacity	Capital Costs ($/kW)	Operating and Maintenance Costs ($/kW/yr)[a]	Cost of Power ($/kW)[b]
10 MW	1500	30-40	0.10
100 MW	1200	27-36	0.08

5.5.4 Environmental Considerations

Photovoltaic systems do not require cooling water or other continuous process feedwater for their efficient 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. In light of the small plant capacities that would be considered for the Railbelt and the absence of cooling water requirements, water resource effects should be minimal.

The development of solar thermal conversion systems would produce water resource effects similar to other of steam cycle facilities. Boiler feedwater and condenser cooling water will be required and will necessitate proper management techniques (refer to Appendix A). Water requirements are extremely site-specific as efficiencies ranging from 10 to 70% are possible depending upon climatic factors. However, in light of the small capacities considered, impacts should not be significant.

Solar thermal conversion systems may also be operated utilizing a working fluid other than water. Fluids such as liquid sodium, sodium hydroxide, hydrocarbon oils, and sodium and potassium nitrates and nitrites 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 spill risk and properly mitigate potential impacts.

Water resource impacts would also occur if pumped storage facilities were utilized as the energy storage technology for either photovoltaic or solar thermal conversion systems. Pumped storage impacts are discussed in Section 4.1.

Solar thermal and photovoltaic electric power conversion systems have no impact on ambient air quality because they do not emit gaseous pollutants. Water vapor plumes may emanate from cooling systems associated with solar thermal processes, however. These plumes will be substantially reduced because solar thermal systems operate best in full sunlight when the air tends to be well below saturation. The water droplets are quickly evaporated into a dry atmosphere. The plumes can also be mitigated by using dry or wet/dry cooling tower systems.

Some modification 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 climatic response of these facilities will be similar to that of any comparably large construction project.

Due to minimal water requirements, the operation of photovoltaic systems will have insignificant impacts on fresh or marine aquatic biota but solar thermal conversion plants may have impacts similar to those of other steam cycle plants (refer to Appendix C). These impacts, however, should be small and easy to mitigate in light of the small plant capacities considered.

The major terrestrial impact associated with photovoltaic or solar thermal conversion systems is habitat loss. If these systems are located in remote areas, the potential for wildlife disturbance through increased human access may also be significant. Spills of non-water working fluids if used, could adversely affect local ecosystems. In general, however, impacts to the terrestrial biota of the Railbelt region should be minimal, since power plant capacities for both photovoltaic and thermal conversion systems will be small.

5.5.5 Socioeconomic Impacts

Both solar photovoltaic and solar thermal conversion systems require a large construction work force and a small operating and maintenance staff. The work force for a photovoltaic plant would be larger because of the construction of solar arrays. A 10-MW photovoltaic plant would require a construction work force of 100 and an operating and maintenance work force of 10. A 10-MW central receiver would require a construction work force of 60 and an operating and maintenance staff of 25. The impacts of either 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, both solar electric generating options require large investments in high technology equipment. The percentage breakdown of project investment is 80% spent outside Alaska, and 20% would remain in Alaska.

5.5.6 Potential Application to the Railbelt Region

To estimate the availabilty of solar energy in Alaska, insolation data collected at Fairbanks and at Matanuska, near Anchorage, was 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 1,969 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. In comparsion, in the arid 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 there is an abundant supply of solar energy on a horizontal surface in midsummer in Alaska, the mid-winter values are an order of magnitude less than those of even poor sites in the remainder of the country. The obvious lack of sunshine in the winter restrains the development of solar energy in the Railbelt region. 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 siting constraint.

None of the existing or developing solar photovoltaic technologies represents an economically viable form of large-scale electric power generation in the Railbelt. Current systems provide only a few watts of output and are not currently planned for large-scale application.

6.0 LOAD SHAPING

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 facilities to meet the annual peak load. Activities which reduce the magnitude of load peaks will thus reduce the investment in generating capacity required to meet peak load.

Load shaping refers to electric utility industries' attempts to improve load factors. Generally, an increase in load factors result in loads being satisfied more economically. The economies are due to decreased use of intermediate and peaking units, which are more expensive to operate relative to base-load units.

Load shaping is effected through load management and supply management alternatives. 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, shed, or shave peak loads to derive a more economical load profile. Supply management refers to attempts to use generating units, especially intermediate and peak loaded units, and available energy storage units in the most economical manner, including the storage of off-peak energy for use during peak periods (EPRI 1979, 1980).

6.1 LOAD MANAGEMENT TECHNIQUES

Load management procedures involve changes in equipment and/or consumption patterns on the customer-side of the meter. The customer may be either an end user of electric power (e.g., residential or industrial) or utility distributing power from a wholesaler to end-use consumers. Any technique considered, however, must be assessed in terms of its effect on the existing load profile and on the utility's planning and operating systems.

This section summarizes five general load management methods that may be applied to the Railbelt region. The five general methods are:

1) Direct Control by the Utility of Customer Loads
2) Passive Control of Customer Loads
3) Incentive Pricing of Electricity
4) Education and Public Involvement Programs
5) Thermal Energy Storage.

6.1.1 Direct Load Control

Direct load control is the control by electric utilities of specific customer loads. These loads are cycled or deferred during periods of local or system peak loads or emergencies. Residential loads associated with the use of space and water heaters can be controlled by direct means, but interruptions in this type of service can result in customer inconvenience or discomfort. Economic incentive (i.e., lower rates) may be provided to compensate for customer inconvenience (IEEE 1980). The effectiveness of these incentives depends on their operating parameters and importance to customers.

Studies evaluating loads that can be controlled have been conducted primarily in urban areas in states with load characteristics different from those found in the Railbelt. Such nationwide studies constitute the most complete set of data on load shaping. To present these data in their complete context, it is necessary to show a variety of load shaping experiences including some not applicable (e.g., air conditioning) to the Railbelt. Such general data are presented in this section while a more specific discussion of applications affecting the Railbelt region can be found in Section 6.1.3.

The types of electrical loads that have been selected most frequently for direct load control are as follows (ERA 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	S		
Nonessential Loads		X	X

A recent Electric Power Research Institute (EPRI) study summarized another study which surveyed 2,000 U.S. households and obtained electrical consumption by major appliance from August 1976 to July 1977 (EPRI 1979). Tables 6.1 and 6.2 contain information cited by EPRI in their 1979 study. Table 6.1 shows market penetration for major electric appliances. Table 6.2 presents daily electric consumption by appliance per month. Unfortunately, the study did not contain data on time-of-day characteristics. Nevertheless, the information in Tables 6.1 and 6.2 indicates the importance of the residential loads listed above for direct control.

Unfortunately, appliances currently used for lighting, cooling, and refrigeration in residences are not designed to permit load management. In time, refrigeration should have potential for load management if thermal storage can be economically incorporated into the design. Electric clothes drying is a substantial load that usually can be shifted to off-peak hours. In the commercial sector, water heating and space heating offer the most potential while other potentially controllable loads include lighting, air

TABLE 6.1. Regional Market Penetration for Major Electric Appliances (Western U.S.)

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

Source: EPRI 1979, p. B-42.

TABLE 6.2. Average Daily Electric Consumption by Appliance Per Month (kW-hr/day)

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

Source: EPRI 1979, p. 43-44.

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. Irrigation pump motors, as well as space heating of animal dwellings, grain drying, feed grinding, and specific dairy cooling operations have a potential for load management (Arthur D. Little 1979).

Control devices to implement direct load control entail switching of specific circuits or appliances are listed in Table 6.3. Clock-based controls have been applied as well as remote control of customer loads by the utility through a communication system. Communication technologies for direct load control are: communication via power lines, including ripple systems, power-line carrier, and waveform modification; telephone and coaxial cable; an radio systems. Special or separate meters are not necessary for direct load control (Institute of Electrical and Electronic Engineers 1980).

TABLE 6.3. Direct Control and Communication Systems

Local Control Equipment	Communication System
Clock Timer Switches	Ripple Control Systems
Temperature Sensing Controllers	Power Line Carrier Control Systems
Photocontrollers	Line Wave Alternation Systems
Load Levelers	Radio Control Systems
	Telephone Control Systems

Source: Economic Regulatory Administration 1980.

The chief distinction between control systems is whether or not the control is local or remote. Local systems depend on the use of a timing or physical sensing device to determine when end-use devices should be employed. Remote systems permit a utility to control loads through direct communication.

Clock-timer switches are electrically driven controls which automatically turn external circuits on or off at a preset time of day. These switches have been in use for a number of years, in particular, for off-peak electric water heater control. Temperature sensing controllers are outdoor thermostat-cycle timers which can be employed to control heating or air conditioning loads. In a test case run by Georgia Power Co. on central air conditioners, the results indicated a reduction in the diversified peak demand of 1.4 kW per central air conditioner unit controlled by the thermostat. Photocontrollers are light-sensitive controllers which 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. A single circuit load leveler removes one circuit or load from service when a predetermined current load in 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 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 percent average reduction of kW demand (Economic Regulatory Administration 1980).

Ripple control systems use the utility's existing transmission and distribution network to transmit control signals. Although bi-directional ripple systems have been recently developed, most systems employed over the years are uni-directional 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 (200-1500 Hz). Radio control systems utilize 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 likely potential for telephone control systems would be for meter reading.

6.1.2 Passive Controls

Passive controls are those load-limiting devices that are owned by the customers themselves and installed on their property. From the utilities' standpoint, these types of control systems are less reliable than the more active forms of demand control because they are controlled by the owner, not the utility. A major advantage exists, however, because there is no direct investment in the control equipment by the utility. These controls are similar to direct controls except that the customer, not the utility, retains the ultimate control over their operation.

These controls are often implemented through the use of 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.

6.1.3 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: There are two fundamental types of time-differentiated rates. 1) rates based on time-differentiated accounting costs (TDAC); and 2) rates based on time-differentiated marginal costs (TDMC). Accounting costs include capital and operating cost components consistent with cost definitions used to meet revenue requirements (PHB 1979). These accounting costs are average costs of producing power. As opposed to accounting costs, marginal costs refer to incremental costs incurred to supply additional increments of electrical output.

The allocation of costs to specific time (rating) periods enables the design of rates that give explicit signals to customers about the costs they impose for use at various times. TDSAC rates may be determined by methods analogous to those used in designing embedded cost rates. The use of TDUC (marginal), costs, results in higher incremental costs for the use of electricity during peak periods. This provides greater disincentives 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 (Electric Utility Rate Design Study 1979).

If demand is very price sensitive, time-of-day pricing can cause changes in load shapes. Moreover, time-of-use pricing should promote efficiency in the allocation of resources to the extent that consumers are willing to pay prices that reflect marginal costs. In a nation-wide survey (Elrick and Lavidge, Inc. 1977) conducted for the electric Utility Rate Design Study to measure residential response to time-differentiated rates, the following conclusions were reached:

1. majority of residential customers who had not experienced time-differentiated pricing or load controls preferred voluntary reductions and/or more power as ways to handle growth in peak load;

2. residential customers, when faced with limited power, preferred voluntary reductions to time-differentiated pricing or controls;
3. almost 80 percent of the residential users and more than 50 percent of the commercial and industrial customers stated that they would reduce energy consumption to save money or avoid higher charges when faced with time differentiated peak use charges four times as great as 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 straight forward rate of this type is exemplified by a discount or credit to customers who agree to have some portion of their loads reduced under system conditions as identified above. Special rates might also be available to customers whose loads are regulated by control devices or other means.

The implementation of 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 cause price increases as consumption of electrical energy rises. The rationale behind this aproach is the notion that new capacity tends to be more costly than existing capacity. Therefore, the growth in electricity consumption which tends to increase costs over time should be dampened by the price mechanism.

At the present time, incentive pricing measures are in effect in the Railbelt area (e.g., Anchorage Municipal Light and Power has an elective time-of-day rate schedule for residential customers). One advantage of incentive pricing is that requirements for capital equipment are relatively low, and, through an educational program, customers can be informed of the benefits of modifying their consumption patterns. Also, for larger customers, the costs of metering represent a relatively small percent of their total electric bill. Meters would permit large customers who monitor their energy consumption to determine cost savings realized by altering energy consumption patterns.

6.1.4 Education and Public Involvement

The need in all load management options to alter individuals' electricity consumption patterns makes effective communication with customers a prerequisite to successful implementation of any load management echnique. This means that 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 current relationship between the utility and its customers and the attitude and awareness of the public. In areas where people pride themselves on their individualistic lifestyles, it is doubtful that appeals to the general need to modify consumption patterns will be effective. This method of load management is also not as reliable as the other ones in that the utility has virtually no control over the exact amount of load that will be shifted.

Under present 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 actually strive through the promulgation of information and incentive programs to retard the growth in use of electrical energy.

Today utilities foster conservation and load management in their advertising whether in public newspapers or in informative materials included with the electrical bill--for example, 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, insulating, etc. These and other public involvement techniques merit consideration in pursuing load management objectives.

Although some state regulatory commissions may prohibit utilities from promoting electrical consumption and now require the utility 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 on the part of utilities and their customers. However, APUC does not monitor the loads of various utilities in Alaska.

6.1.5 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. In most applications, customers purchase storage equipment to obtain the operating cost reduction through low, off-peak rates for service. If the storage devices are appropriately sized, the customer should not experience inconvenience or discomfort irrespective of the fact that the storage unit might be controlled by the utility.

On-off switching of storage heating elements or compressors may employ the same communication and control technologies as direct and voluntary load control. A separate meter is usually used to distinguish the power requirement of the storage system from the balance of customer load. Thermal energy storage is a useful method used to smooth out or reduce the disparity in supply and demand periods of various energy systems

Similarly, energy produced by solar collectors, industrial waste, or base loaded generators during off peak periods is used to heat a fluid, which is pumped to storage for use at a later time. Presently, water is the fluid which is commonly considered because of its abundance, low cost, nontoxic nature and relative ease of handling.

Storage systems include deep sea insulated bags with steel reinforcing nets, flexible bags under non-cohesive overburden, fixed volume tanks with separating disks, or underground porous rock formations (aquifers). The Alaska coastline at the Railbelt area has been identified as suitable for undersea storage, the criteria being at suitable depth a short distance from shore (Powell and Powell 1980). A recent study has concluded that a large bag system (4.5×10^6 ft^3) storing water at a pressure of 420 psi, a temperature of 450^oF and at 900 ft will cost about $1/$ft^3$ for storage only. The stored hot water can be used for feed water 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 is the residential and commercial sectors are listed in Table 6.4.

A room electric storage heater consists 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 and foyers and for heating small rooms such as bathrooms. Dynamic storage heaters are similar in construction to static room storage heaters, but the dynamic heaters utilize fan forced convection to achieve better control of room temperature. Dynamic room storage heaters can be used for heating single- or multi-family dwellings and office buildings (ERA 1980).

Central ceramic storage heating units adjust thermal charging of ceramic brick core with off-peak power and have thermostatically controlled fan-forced convective discharge. An average size heater, e.g., 20 kW size, weighs over 3000 pounds. Central storage heating systems of the ceramic brick type have potential in the residential housing sector. In the industrial sector. a stored heat installation in a large warehouse has been undertaken.

Hydronic central storage systems 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 used to heat air or

TABLE 6.4. Thermal Energy Storage Equipment

1. Storage Heaters
   - Static Room Storage Heaters
   - Dynamic Room Storage Heaters
   - Central Ceramic Storage Heaters
   - Hydronic Central Storage Heaters
   - In-Ground Heat Storage
2. Storage Air Conditioners
3. Storage Domestic Hot Water Heaters
4. Multiple Reservoir Storage
5. ACES - Annual Cycle Energy System
6. SESS - Supplemental Electric Storage System
7. CEIS - Constant Energy Input System

Source: ERA 1980.

water that is circulated through the space to be heated. Hydronic storage units for moderate size residential homes are available. The units consist of a sealed and insulated water tank of 212 gallons heated to 265^{o} - 280^{o}F and 50 psig and with a weight of about a half ton. Hydronic storage can be used for commercial heating (and cooling) as well. In-ground heat storage beneath a building can be convenient. This thermal reservoir can be charged with resistance heat which is radiated to the building at different times depending upon building temperature (Economic Regulatory Administration 1980).

Storage air conditioning utilizes chilled water or a mixture of water and ice which is produced by the operation of the air conditioner compressor during off-peak periods to supply cooling load during peak periods. Central storage air conditioning using chilled water is currently used in the commercial sector but little data is available in the residential area. The combination ice and chilled water storage system appears to be better suited for residential use. Storage domestic water heaters can be managed by cycling loads or off-peak operation. A clock-timer switch or remote controlled switch is used to break the hot water tank circuit. The control of water heating is the simplest and most often used approach of residential 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 a number of storage media which 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 permits 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 (Economic Regulatory Administration 1980).

6.2 LOAD MANAGEMENT APPLICATIONS

Load management techniques are in current use in many industrialized countries. The earliest use of load management was found in Europe. In the

United States, there are many load management programs that have been completed or are in various stages of development by electric utilities. 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 (1980). These load management strategies range from time-of-day pricing to direct control over customer appliances and have been undertaken by large investor-owned utilities and small public utilities. Many of these programs have proved to be cost-effective, although in general, they are in experimental or demonstration phases and findings are not conclusive.

It is also important to recognize that the feasibility of load management techniques depends on a specific electric utility's planning and operating system, load profile, type of loads, and other socioeconomic factors. Therefore, although favorable results have been obtained by some winter peaking utilities outside Alaska, implementation of such programs should be attempted only after detailed utility-specific studies.

At present, the opportunity for load management in the Railbelt region appears to be limited mainly because only a few loads are controllable. For example, in the AMP&L residential class, less than 10% of the customers have all-electric homes and even less 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. New opportunities for load management in the commercial sector appear to be limited because of the present use of energy-saving devices in most of the office buildings. Potential areas for load management could be found in the Anchorage municipal dock area and local military bases.

Anchorage Municipal Light and Power has a time-of-day rate in effect. The AMP&L rate structure reflects energy conservation and load management objectives. The "all-electric" rate schedule has been eliminated, and a rate schedule with a 12-month ratchet[a] clause has been adopted.

(a) 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.

Although there appear to be few additional opportunities for applying load management techniques in the Railbelt region, further shaving of winter peaks is possible and might be more beneficial than other generation options. 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. The control of water heaters might be economical although AMP&L considered unit water heaters with some thermal storage but determined, based on preliminary economic analysis, that they were not cost-effective. During the winter, the heating load is uniform all day. This does not leave room for shifting 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.

In the Fairbanks area, load management possibilities also appear to be limited. Like Anchorage, there is little or no industrial load. The commercial load is relatively flat from 8:00 a.m. to 5:00 p.m. Fairbanks Municipal has built into their rate structure load and energy-conserving features. In Fairbanks, 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 the nature of this load makes it difficult to control even though it contributes significantly to load peaks.

In summary, load management is an option that the Railbelt utilities are employing at the present time. In the future, it will continue to be a useful technique 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. Should low-cost power become widely available in the future, resulting in expansion of space and water heating electrical loads. Then implementation of aggressive load management programs may become desirable. The need for such a program, however, 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.

6.3 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. In addition, customer acceptance and technical feasibility need to be considered in making an assessment of a load management technique (Baron 1979).

6.3.1 Capital Costs

Two types of capital costs need to be considered when evaluating a load management option. First, the costs that are expended in acquiring any hardware for implementing load management should be determined. Table 6.5 presents cost information for various direct control load management techniques. A summary of payback period calculations for thermal energy storage systems is contained in Table 6.6.

The second type of capital costs to consider in evaluating load management options are those costs that are deferred or eliminated as a result of load management programs. The capital costs for new electric generating facilities are high and any savings realized by delaying such construction should be compared to the cost of implementing a load management program.

6.3.2 Changes in Revenue

Load management techiques in conjunction with conservation programs might affect a utility's revenue significantly. The potential effect of this on a utility's revenue requirements should be assessed. Of particular consequence is the potential effect of incentive pricing on a utility's revenue, at least in the short term. For utilities subject to regulation, approval by the Alaska Public Utilities Commission would be necessary.

6.3.3 Timing

An advantage of load management programs is that they can be implemented rather quickly. Therefore the cost of pursuing this option is not incurred

TABLE 6.5. Load Control Cost Summary

System	Average Per Point Installed Hardware Cost ($)	Installed Control and Transmission Cost ($1,000)	Total Per Point Installed Cost as a Function of Total Customers						
			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

Source: EPRI 1980.

TABLE 6.6. Thermal Energy Storage Systems Summary of Payback Period Calculations

Thermal Storage System	Base System	Potential kW Savings Winter/Summer		Percent IC ($)[a]	Payback Period (Con Ed Percent R) Years[b]	Payback Period (Jersey Central Percent R) Years[b]	Percent IC ($)[a]	Payback Period (Con Ed Percent R) Years[b]	Payback Period (Jersey Central Percent R) Years[b]
Room Ceramic	Electric Baseboard	8		2,210	3.1	8.8	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	3,920	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	12,500	18.13	50.95
Daily Cycle Energy Systems	Heat Pump	12	3	5,130	8.8	24.8	7,694	13.2	37.2
Dual Heating System	Electric Furnace	10		675	0.95	2.7	1,000	1.4	4.0

(a) Includes maintenance.
(b) Percent R is presently offered time-of-day rate.

Source: EPRI 1980.

over a long period of time prior to realizing any benefits. This is unlike the situation typically experienced when constructing a major power plant.

In spite of the fact that load management programs can be implemented more rapidly than many generation technologies, it should not be assumed that it can be accomplished in a very short period of time. For example, EPRI concluded that it takes two to three years to conduct a small load management test (EPRI 1980).

6.3.4 Operation and Maintenance Costs

Once installed, the operation and maintenance costs associated with the active or passive load management techniques should be minimal. Such activities include ongoing assessment of the effectiveness of the program and the routine maintenance associated with the equipment. In addition, as new buildings and new facilities are constructed, they will be incorporated into the load management program. For this reason, the load management system will expand with the load.

6.4 ENVIRONMENTAL, INSTITUTIONAL, AND REGULATORY CONSIDERATIONS

Successful implementation of a load management program may present certain institutional and regulatory benefits. Several broad areas of environmental, institutional, and regulatory concerns should be evaluated in assessing the merit of a load management option. In particular, a successful load management program will defer and possibly eliminate the need for certain energy facilities. Any delay or elimination of the need for such facilities will have environmental benefits. The extent of benefits to the environment are assessed by comparing the load management plan to the specific generation option that is foregone. In general, air and water emissions will be alleviated and all impacts associated with resource extraction will be avoided.

6.4.1 Changing Consumption Impacts

The idea of controlling an individual's use of energy, although prudent from an energy standpoint, can arouse concerns regarding individual choice and freedom. In the case of direct control load management techniques, the individual homeowner or commercial customer relinquishes considerable control of personal energy use. Such control measures do not rely on the supply and demand mechanism, but rather on overall economic considerations and the belief that a fair program will be developed for all customers.

Pricing and other less active control measures will not give the utility as much control over individual customer loads as the direct measures, but they will alter individual consumption patterns nevertheless. In most areas where load management has been tried, programs have been well accepted. With an effective public communications program by the local utilities, it is expected that similar results could be expected in the Railbelt region.

6.4.2 Rate Design Activities: State and Federal Regulation

Reent activities on the part 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. It is significant, however, that some states have made major advances in this regard. Of particular importance to the electric utility industry is the Public Utility Regulatory Policies Act (PURPA) of 1978.

The Public Utility Regulatory policies Act of 1978, part of the National Energy Act, set standards for electric utilities with respect to: 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 be designed 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 it is demonstrated that the costs of providing electric service 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 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 and cost-effective; reliable; and provide useful energy or capacity management advantages to the electric utility.

7.0 ELECTRIC ENERGY CONSERVATON IN BUILDINGS

The majority of buildings constructed in the Railbelt reflect 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 towards design of a building's thermal envelope.

While the technology is available, most people still do not understand the economic benefits of energy conservation. A certain resistance to the concept of conservation remains. To many, the term implies a return to a lower standard of living. This is unfortunate, and stems from a misunderstanding of the term.

Conservation technologies as defined in this profile do not consist of turning back the thermostat and wearing an extra sweater in the evenings. Nor do they describe the myriad of gadgets and devices purported to save energy. Some of these devices are worthwhile; many are not. Collectively, the good ones will benefit the individual homeowner or building user. It is difficult, however, to quantify their impact on energy use in Alaska's Railbelt.

It is much easier to imagine the benefits of significantly reducing a structure's overall heating load; this is the type of conservation addressed in this study. A handful of individuals in the Railbelt have reduced their fuel bills by as much as 70% simply 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.

The measures addressed in this report, if implemented on a large scale, would contribute to reducing fuel demands in the Railbelt region. While relatively little electric space heating is currently found in The Railbelt, building conservation could significantly reduce the demand for electricity if low cost electricity became widely available and electrical space heating became common.

7.1 METHODS OF CONSERVATION

Conservation, or thermal efficiency, is not difficult to achieve in most buildings. It is in fact the end product of applied current knowledge and of techniques already commonly used. The following four factors determine the efficiency of any building, and through proper implementation 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 with regard to 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 enhance thermal efficiency. The design could and should become even more specific with regard to location. For instance, a structure in Fairbanks would be more heavily insulated than one in Anchorage, to accommodate the more severe Interior climate.

7.1.1 Conduction

Conduction is the transfer of heat through a solid material. In buildings this occurs through the "envelope," which is made up 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," a unit of thermal resistance--the greater the R-value, the greater the resistance. 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. (1) Structures should be built multi-story rather than spread out with a large roof area (California "ranch" style), and (2) the simpler the shape, the more energy-efficient. 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 is offset by solar gain it is able to use as a result of its orientation.

Window area is critical since 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 without jeopardizing aesthetics or livability of the interior space--granted, a subjective judgement. The orientation of windows is also important. Southerly or easterly orientation can gain heat during most of the year, and thus contibute 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 a wooden frame, and by incorporating multiple glazing; the more panes, the greater the savings. Conductive losses through multiple glazing will remain high, but can be further reduced by using thermal shutters or movable insulation that can be placed over the windows at night or during cloudy periods.

There is considerable disagreement, and not much practical information, on the best window insulation system for Alaska. Several manufacturers are making shutters, most at fairly high cost. None have yet been proven effective in Alaska, though there is a significant amount of product testing going on. Some quantifiable answers should be available in the next year.

Walls, floors, and ceilings can become more resistant to heat loss by adding more insulation than has been recommended in the past. However, the structural design must provide for 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 wall is made up of wooden studs and plates, which contribute significantly to conductive heat loss. Because wood is a poor insulator, it provides a direct heat transfer between the interior and exterior.

Several methods (Figure 7.1) 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. This increases the R-value of the stud wall, while radically slowing down 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.

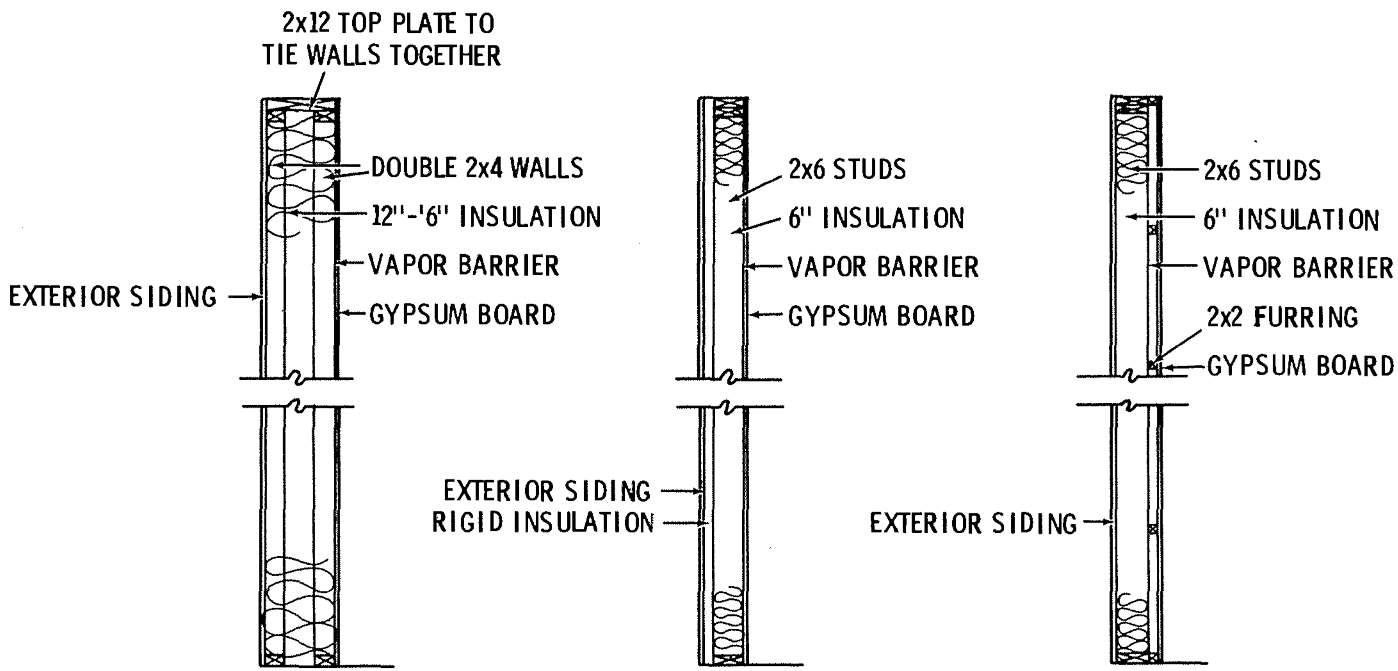
A second approach, known as the "cross-hatch" method (Figure 7.1), is to nail 2x2 or 2x4 furring strips perpendicular to the wall studs, usually on the inside of the wall. The horizontal members are placed usually at 2 feet on center, and the interior finish nailed to them. This results in reducing the 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 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 R-value and leaving the structural integrity of the exterior wall intact.

The third wall system employed is the double wall, where two 2x4 walls are set a specified distance apart, and joined only at the top plate. The space between is filled with insulation. The main advantage to this approach is that the walls may be set any distance apart and filled with relatively inexpensive fiberglass or cellulose insulation. Conduction losses may be reduced to a minimum.

How cost-effective these wall systems are varies throughout the region, and further study is needed. It is important, however, to note 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. While urethane insulation can be used to give high R-values in thinner 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 R-values in excess of R-60, which is adequate in most of the Railbelt. The problem lies at the



1. DOUBLE WALL 2. RIGID FOAM WALL 3. "CROSS-HATCH" WALL

FIGURE 7.1. Energy Conserving Wall Systems

point where the roof meets the wall. Here, the available space for insulation becomes too thin to accommodate sufficient insulation and still provide for air circulation. Ample air circulation must be provided to prevent "sweating" or condensation and subsequent deterioration of the insulation and surrounding wood.

The solution lies in using an "arctic" or "Arkansas" truss (Figure 7.2). The arctic truss is constructed with raised ends so that a constant line of insulation can extend to the roof edge, while still allowing room for ventilation. Even if extra insulation is not applied at the time of construction, this strategy allows for future upgrading over the entire roof area.

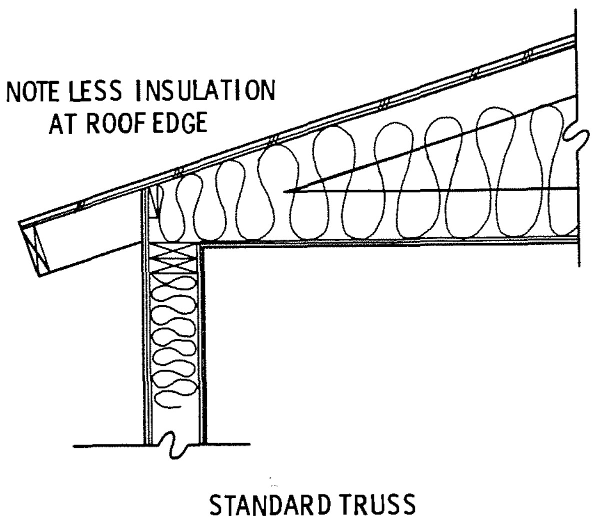
In the past, designers and builders mistakenly believed that floor insulation could be minimized, and the extra applied to the ceiling. Recent studies are showing that adequate floor insulation minimizes stratificaton of air temperatures between floor and ceiling. The hypothesis is that the colder floor in standard construction drives warmer air to the ceiling, adding to heat loss.

Conductive heat loss can also be reduced by using insulated headers over wall openings rather than solid wood, and 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.

7.1.2 Infiltration

"Infiltration is air leakage through cracks and interstices, around windows and doors, and through floors and walls, into a building; its magnitude depends on type of construction, workmanship, and condition of the building, and cannot be effectively controlled by the occupants" (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 caulking critical areas such as the sole plate and around window and door casings. Texas Power and



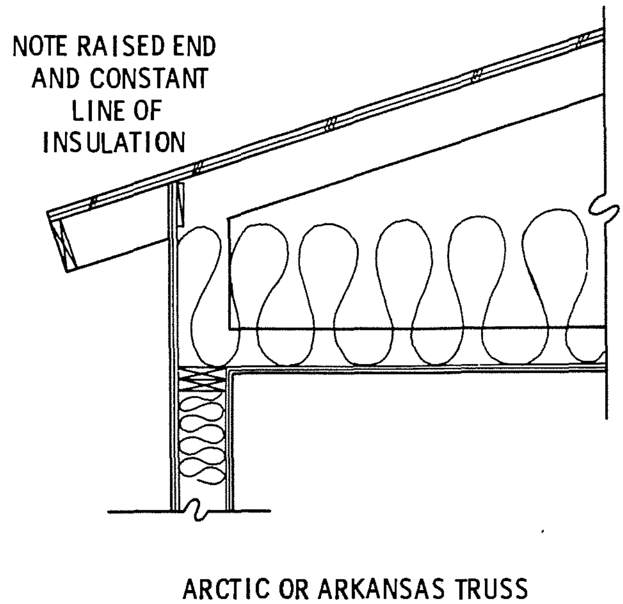


FIGURE 7.2. Energy Conserving Roof

Light Co. have found that the sole plate of the walls, which is seldom caulked in conventional construction, accounts for 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 should be sealed as tightly as possible. Caulking should be used freely, to close all holes in the envelope. 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 the addition of an arctic entry, which is basically an enclosed porch. The outer door provides for 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 combustion air for any furnace 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 should also 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, this 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, the figure can be as high as one ACH.

The problem is 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. An air exchanger unit is inexpensive and manufacturers claim an efficiency rate of 65 to 70%. These units have some operating problems in colder climates. Condensation tends to form on the coils, resulting in ice formation and subsequent failure of the unit. This problem is not insurmountable, and more testing is being done to further develop these units. It is likely that they will become an integral part of the Alaska-specific house.

All of these measures are fairly inexpensive when compared to the resulting reduction in the number of air changes per hour (the standard measure for infiltration) and the subsequent fuel savings.

7.1.3 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 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 with care towards the warm side of the insulation. While a vapor barrier is installed in most new Alaskan buildings, they are often poorly installed, resulting in leaks and penetrations that allow moisture transfer.

7.1.4 Space Heating and Hot Water System Efficiency

Hot water heaters account for about 15% of the fuel consumption in many homes. It is pointless to fix a number to the exact load that hot water systems add to overall demand since there are so many variables, such as lifestyle, perferred 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 insulation--resulting in an insulation factor of approximately R-6. By covering the unit with an insulation jacket, the R-value can easily be raised to R-20 or 25. Such an improvement can provide savings of approximately 1.2 MMBtu/yr on a 52-gallon tank maintained at 120^{o}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 pre-heaters are all worthy of implementation. Collectively, they may result in considerable savings.

Primary heating units can consume excessive amounts of energy due to improperly maintained burners, dirty stacks, and even dirty intake filters. All of these are easily fixed by a service person at a reasonable cost.

A more difficult problem might arise if a furnace is larger than necessary. This can result from an improper judgement in initial design or following an extensive retrofit of a building wherein the heat load is reduced dramatically. This furnace will be operating at less than design efficiency, and consequently using more fuel than necessary. At current fuel prices, it is difficult to justify replacement of expensive furnace equipment. 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.

7.1.5 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--it is more difficult, and often more costly, to rebuild, particularly when adding additional insulation to existing walls.

Much depends on the design and condition of the existing structure. It may not be cost-effective to do a total upgrade on a fairly new building; caulking and other simple measures may be best here. On the other hand, an older structure with little or no insulation could easily incorporate a total upgrade, and pay back the investment in a few years.

If the structure has an attic space, additional insulation can be added. It may be desirable to use a rigid insulation at the junction of the roof and wall, 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 finish surfaces on both sides. If additional insulation is desired, it is usually necessary to add a second wall either outside or on the interior. This is often done using rigid insulation and applying a new skin. It is labor-intensive and thus costly; usually it is considered after other retrofit measures, if at all. In an older building with high fuel bills, it may well prove cost-effective.

It is relatively easy to upgrade windows in older buildings 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, a most 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%.

An 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.

The potential effectiveness of these retrofit measures is demonstrated in Tables 7.1 and 7.2.

7.2 TECHNICAL CHARACTERISTICS

7.2.1 Conversion Efficiencies

How energy-efficient a structure will be depends on the extent of conservation measures employed; this should not be confused with conversion efficiency. Conservation technologies as defined within the context of this profile can be said to be 100% efficient in that once installed they are working to their full potential. The amount of energy saved by building conservation measures depends upon the lifestyle of the occupants and weather conditions.

7.2.2 Coincidence to Load/Reliability

The relationship of conservation to load/reliability is different from those of technologies that generate power. The ability to quickly adapt to or affect peak loading is negligible since conservation is static. However, if conservation were implemented on a fairly large scale, the base load would be so reduced that generation facilities would be capable of handling peak loading with little or no strain on their systems.

In some northwestern states, utilities provide refunds and 'no interest' loans to incorporate conservation technology in an effort to offset demand. It is becoming increasingly clear to utilities that the implementation of conservation measures provides an attractive alternative to construction of costly new facilities.

In terms of reliability, the advantages of energy conservation are obvious. Once insulation, weatherstripping, and the like are installed, they will generally last as long as the structure with little or no maintenance. They are unaffected by disruptions in fuel supply or other outside factors. Conservation will continue to reduce the heating load of a structure at a constant level, relative to the differential between indoor and outdoor temperature, throughout the useful life of the insulation and scaling techniques employed.

7.2.3 Adaptability to Growth

Conservation technologies are easily adapted to growth patterns because of its simplicity and dispersed nature. However, like all construction, it is site-intensive and is thus as sensitive to sudden 'boom' growth situations as new construction. The inherent danger is that 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.

7.2.4 Type of Demand Serviced

Electricity for space heating does not currently comprise a large percentage of the Railbelt's heating demand. Electric heat generally tends to serve as a supplemental heat source during extremely cold periods through the use of portable radiant heaters. Thus, conservation measures as defined herein will have little overall effect on the immediate electrical demand. However, should changing relative fuel prices result in a future shift to use of electricity for space heating in the future, building conservation may have a significant impact on future electrical demand.

7.2.5 Complementary Technologies

Once conservation technologies are applied, they are an inherent part of the building's character and as such are applicable and complementary to all other space heating technologies. Conservation complements 'hard technologies' such as fossil fuel heaters in that it lessens their work load.

In general the 'soft technologies,' such as active and passive solar, cannot be effectively applied in Alaska unless conservation measures are first applied to reduce the total heating load in both new and retrofit structures. Once this is done, solar can supplement the heating load of many structures. Much depends on correct building orientation and availability of good solar access.

7.3 COSTS

The cost of conservation is difficult to define on a large scale at this point, due to its dispersed nature. Retrofit costs for each existing structure will vary substantially depending on its 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 ranged between \$1.30/MMG for simple caulking and weatherstripping to \$16.50/MMBTU for a full wall/roof insulation upgrade on an existing building.

The example of the Alaska-specific design cited earlier in the profile (Tables 7.1 and 7.2 demonstrates the cost per million Btu (MMBTU) of a typical installation. It is estimated that this "superinsulated" house will cost an additional \$7,000 over a standard structure. Extra costs include 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 AKREA show an additional investment of 5 to 7% for these measures. Adding the high ened cost of 7% to

TABLE 7.1. Effects of Conservation on Heat Loss for Retrofit of House and for Alaska-Specific Design

Thermal Storage System	Base System	Potential kW Savings Winter/Summer		Percent IC ($)[a]	Payback Period (Con Ed Percent R) Years[b]	Payback Period (Jersey Central Percent R) Years[b]	Percent IC ($)[a]	Payback Period (Con Ed Percent R) Years[b]	Payback Period (Jersey Central Percent R) Years[b]
Room Ceramic	Electric Baseboard	8		2,210	3.1	8.8	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	3,920	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	12,500	18.13	50.95
Daily Cycle Energy Systems	Heat Pump	12	3	5,130	8.8	24.8	7,694	13.2	37.2
Dual Heating System	Electric Furnace	10		675	0.95	2.7	1,000	1.4	4.0

(a) Includes maintenance.
(b) Percent R is presently offered time-of-day rate.

Source: EPRI 1980.

a $100,000 conventional house. It must be reaffirmed that these figures are very rough and may be high. Assuming that the investment results in the estimate of $70000 is financed for 30 years at 15% interest, cost per million Btus would be $7.80. State of Alaska home loan programs at 10% would bring this figure down, as would the conservation loan program at 5% interest. As a comparison, fuel oil in the region averages a cost of $11.60 per million Btu at present.

Conservation in both new and retrofit generally require no additional maintenance once installed.

7.4 ENVIRONMENTAL IMPACTS

Building conservation technologies have few detrimental environmental impacts. The materials employed are by and large non-toxic. Air, water and land are unaffected by conservation. The technology need not have any impact on community aesthetics; indeed, the "styles" of buildings do not have to change at all. It is the building envelope that is affected, not necessarily the exterior of the structure.

TABLE 7.2. Comparative Annual Heating Loads and Costs: Retrofit of Representative House and Alaska-Specific Design

Location/Case	Annual Heating Load (MMBtu)	Annual Savings (MMBtu)	Original Load Saved (%)	Annual Savings: Oil[a,b] ($)	Annual Savings: Electricity[c] ($)	Annual Costs: Oil[a,b] ($)	Annual Costs: Electricity[c] ($)
Homer: 10364 Degree days				Cost/MMBtu $8.69[b]			
Case 1 - Before retrofit	179.4	--	--	--	--	2081	3014
Case 2 - After retrofit	104.3	75	4.18	870	1260	1211	1754
Case 3 - Alaska-Specific Design	54.1	125.3	69.8	1453	2105	628	909
Anchorage: 10911 Degree days				Cost/MMBtu $8.40[b]	$1.60[c]		
Case 1 - Before retrofit	189	--	--	--	--	646	1852
Case 2 - After retrofit	110	79	41.8	270	774	376	1078
Case 3 - Alaska-Specific design	57	132	69.8	451	1294	195	558
Fairbanks: 14345 Degree days				Cost/MMBtu $8.20[b]			
Case 1 - Before retrofit	248.1	--	--	--	--	2879	8340
Case 2 - After retrofit	144.4	103.8	41.8	1204	3488	1675	4852
Case 3 - Aaska-Specific design	74.9	173.3	69.8	2010	5823	869	2517

(a) 138,000 Btu/gal, 70% furnace efficiency with the following January 1951 oil prices = Homer - $11.60/MMBtu; Fairbanks - $11.60/MMBtu.
(b) Anbchorage case is for gas @ $3.42/MMBtu.
(c) Electricity at the following prices: Anchorage - $0.035/kWh; Fairbanks - $0.10/kWh; Homer - $0.06/kWh.

The possibility of injury or death to either the consumer and installer is negligible, and would most likely not result in any increase beyond what is now experienced in the light construction industry.

7.5 SOCIOECONOMIC IMPACTS

Since conservation technologies require little or no operational maintenance other than that already necessary in the home, there is little inconvenience to the individual after the initial installation with the exception of movable insulation/shutters. However, this would seem to be a relatively minor inconvenience when compared with the control an individual gains over heat loss.

The individual further reduces his dependence on outside fuel sources, over which there is no control in terms of cost and availability. In times of disruption of fuel supplies to the dwelling, a wood stove will normally supply all of the dwelling's heating needs.

As conservation measures become more widely implemented, new business opportunities will result and existing business will be vitalized. 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 create local jobs and enhance local economies.

It is difficult to determine the impact of conservation on employment because many homeowners will probably do their own work, but retrofitting jobs should 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 a variety of services. For example, materials used in conservation can easily complement the inventories of local hardware and general mercantile stores or entirely new "conservation specialty" stores that would likely 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. Since these revenues will remain in the hands of the consumer, they are effectively dispersed within the private sector and will ripple through local economies as spending power.

Community and Regional governments could also have smaller expenditures for fuel, with a resultant reduction in operation costs and taxes to the community. 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 investments in generating facilities, proper long-range planning could result in significant economic benefits throughout the region.

7.6 POTENTIAL APPLICATION IN THE RAILBELT REGION

It is difficult to address and quantify the effectiveness of conservation technologies because it is influenced by the quality of the existing structure, its use, and its occupants. Lack of a regional data base assessing 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.

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 7.1. Each of the three cases were then considered for three population centers of the Railbelt--Homer, Anchorage, and Fairbanks--and summarized in Table 7.2. 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%. The costs of retrofits and dollar savings are discussed in Section 7.3.

7.7 COMMERCIAL MATURITY

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. Indeed, nothing more exotic than standard insulations and caulking compounds are needed for most application. Those items not readily available will soon be, as interest and understanding grows. Given that the "state of the art" is here, it is up to the designers, builders and consumers to understand the benefits of conservation from an economic standpoint. It is lack of knowledge as to the ratio between dollars spent on conservation and dollars saved from reduced fuel billsrather than the availability and level of development that has led to the relative slow growth of conservation technologies.

The lack of public awareness is perhaps the greatest impediment to the expanded commercialization of conservation measures. Education of consumers is needed to debunk the notion that conservation means a return to pre-industrial revolution lifestyles. Education is equally important for designers, planners and installers, who must understand the care and subtle differences with which different conservation measures must be employed to achieve maximum effectiveness.

Additional obstacles resulting from building codes and policies of financial institutions will need to be addressed as public demand for conservation increases. The problem of outdated and conflicting codes has never been addressed in Alaska, and needs more research to determine whether indeed they might pose a problem.

Developers and financial institutions have historically attempted to reduce the front end costs of construction in order 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. While this phenomenon has not yet become the standard in Alaska, it is doubtful that such factors can be ignored in the future in light of escalating fuel prices.

8.0 ELECTRIC ENERGY SUBSTITUTES

8.1 PASSIVE SOLAR FOR SPACE HEATING

In the purest sense, passive solar uses no mechanical means such as fans or pumps to distribute heat from the sun into the living space. It relies on a combination of a thermally efficient building envelope to contain heat, south glazing to capture solar energy, some form of thermal mass to store this energy for release at night or during cloudy periods, and design techniques to distribute heat by convection. Essentially, the building is the system.

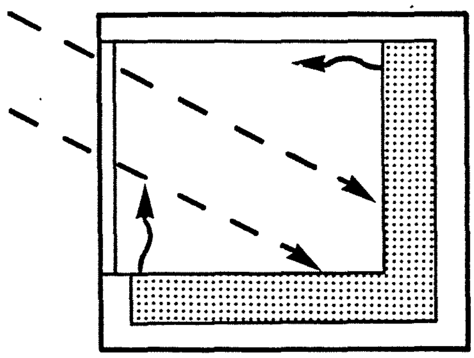
8.1.1 Types of Systems

Three different strategies (see Figure 8.1) of passive solar heating have been studied or implemented in the Railbelt region. Although other options are available, none have been seriously considered to date, and are not discussed here.

The simplest of solar strategies, direct gain, uses south facing windows to bring sun directly into the living space. Because of the potential for significant heat loss through these windows at night or during cloudy periods, multiple glazing and insulated sash should be used in window construction. In addition, thermal shutters should be placed over the windows during periods of potential heat loss.

Indirect gain (greenhouse/sunspace) is achieved by attaching a solar greenhouse to the living unit. This system 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 energy enters the greenhouse through south glazing. A portion is transferred by various means of venting into the main living area. At night, or during cloudy periods, heat loss from the house is buffered by the greenhouse.

Several factors will affect the performance of indirect gain installations. A poorly insulated or inefficient greenhouse design will not allow much heat transfer into the house; most of the energy from solar gain will be used up in the greenhouse. And like direct gain installation, a significant amount of heat is lost back out the glass without night

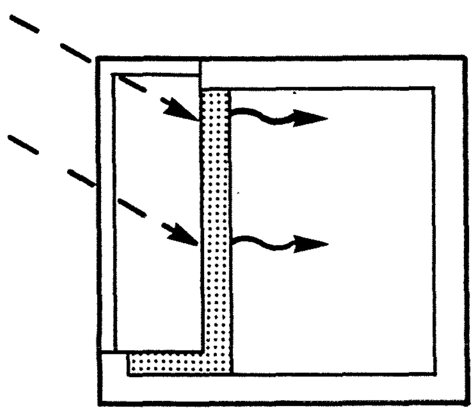


DIRECT GAIN

DEFINITION: THE BUILDING SPACE IS DIRECTLY HEATED BY THE SUN, THE SOLAR HEAT IS STORED IN THE MASS OF THE HOUSE.

REQUIREMENTS: SOUTH FACING GLASS WALL USUALLY DOUBLE OR TRIPLE GLAZED TO PREVENT HEAT LOSS.

WALL FLOOR TO CEILING MASS WITH SOLAR EXPOSURE AND SIGNIFICANT CAPACITY FOR THERMAL STORAGE



INDIRECT GAIN

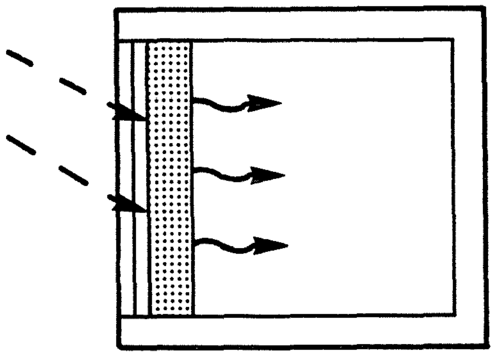
DEFINITION: SOLAR COLLECTION AND STORAGE FORM A SPACE THAT IS THERMALLY ISOLATED FROM THE BUILDING SPACE AS IN A LEAN-TO GREENHOUSE, A GLAZED ATRIUM, OR A SUN PORCH. THE BUILDING DRAWS FROM THIS SPACE AS THE COMFORT REQUIREMENTS DICTATE.

REQUIREMENTS: SOUTH FACING, GLASS ENCLOSED COLLECTION SPACE THERMALLY LINKED TO A THERMAL STORAGE MASS: FLOOR WALLS, BENCHES, ROCK BEDS, WATER TANKS.

THIS SOLAR COLLECTION SPACE MUST BE ATTACHED TO THE HOUSE, YET DISTINCT.

OPTIONAL REFLECTANCE DEVICE TO CONCENTRATE SOLAR RADIATION ON GLASS.

INTERFACE TO BUILDING FOR RADIATION, CONVECTIVE OR CONDUCTIVE HEAT GAIN.



MASS WALL

DEFINITION: A GLASS COVERED MASS COLLECTS AND STORES SOLAR HEAT DIRECTLY FROM THE SUN AND THEN TRANSFERS HEAT TO THE BUILDING SPACE AT A TIME LAG, e.g., TROMBE WALL.

REQUIREMENTS: SOUTH FACING GLASS WALL USUALLY DOUBLE OR TRIPLE GLAZED TO PREVENT HEAT LOSS.

A THERMAL STORAGE MASS DIRECTLY BEHIND THE GLASS WALL.

OPTIONAL REFLECTIVE DEVICE TO CONCENTRATE SOLAR RADIATION.

FIGURE 8.1. Passive Solar Systems Appropriate for Alaska

insulation. Even so, the greenhouse will have higher temperature than the outside air, thus tempering heat loss from the south wall of the house. To be truly effective, however, solar gain must be trapped for use at night.

In the mass wall concept, sunlight passes through the glazing and strikes a water or concrete mass. Some of the heat passes directly into the living space; how much depends on the particular design. The remainder is transmitted to the storage mass, to be released to the living space when the sun is not shining. As in the other concepts, the glazing must be well insulated and thermal shutters should be installed for night time or cloudy periods.

8.1.2 Design Considerations

Several important considerations must be taken into account when designing a passive solar building.

The proper amount of south facing glass varies in relation to the square footage of the building and the thermal efficiency of the structural envelope. Placing glazing to the south indiscriminately will not ensure an effective solar design; indeed, overglazing may result in a total heating load higher than the "standard" home constructed today. During the coldest and darkest parts of the winter, the amount of solar radiation available may not be enough to offset heat losses through the glass.

Movable insulation is an important factor in the optimum performance of solar in the region. Although benefits can be derived from south facing glass without shutters, the truly effective system will use insulation to retard heat loss through glass, the weakest point in the building's envelope.

Some form of storage mass should be applied in all systems to soak up excess solar gain and to dampen the wide swings in the interior temperatures, which can result from the variation of available solar radiation. In direct gain and sunspace applications, concrete floors and walls, water drums and containers are all used to provide mass. Even adding an additional layer of gypsum board to walls receiving insolation will help regulate temperatures.

Finally, the thermal efficiency of the structure will have an overwhelming impact on the performance of solar heat. Obviously, solar is less effective in Alaska than in the southern United States; a structure built to the same specifications as those in more temperate climates will gain little benefit from the sun. A building heavily insulated in recognition of Alaska's severe climate will have a reduced heating load. Once this load is reduced, passive solar becomes much more attractive as a heating source.

8.1.3 Technical Characteristics

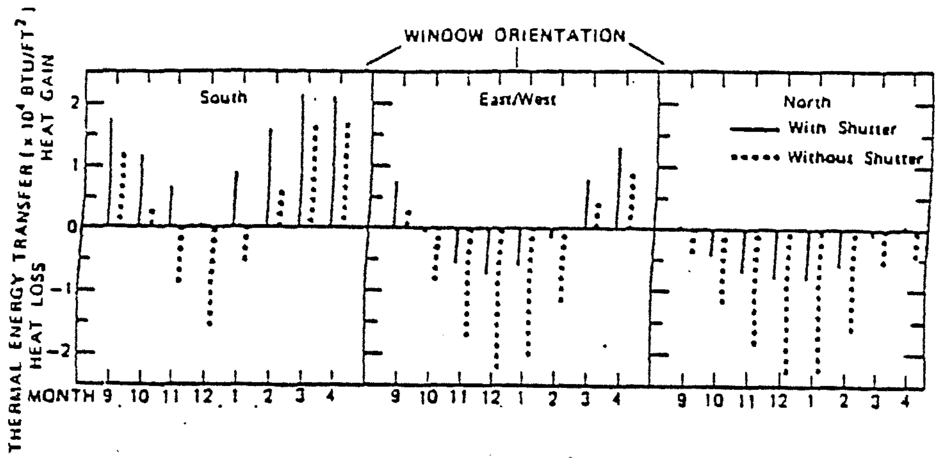
Solar Conversion Efficiencies

Passive solar applications are a prime example of a site intensive technology. Since they rely on the sun, they do not produce a constant amount of energy as a central fuel-fired plant might. The conversion efficiencies of passive solar technologies vary with the type of system (direct gain, greenhouse, etc.) used. Other factors that can also affect efficiency include, but are not limited to: orientation, obstructions and shading, exterior temperatures, building heat loss, and angles of incidence.

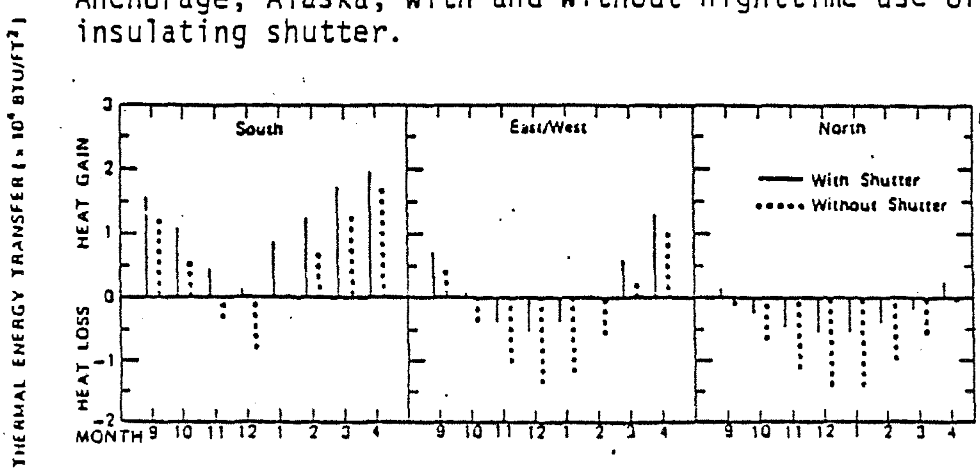
Because the amount of energy produced will vary with each installation, it is impossible to quantify actual efficiencies until some existing systems in the Railbelt region are monitored. Some examples will help illustrate the broad range of possibilities.

A direct gain system using vertical glass (double pane), 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 (see Figure 8.2) for percentages of efficiency at the different angles of incidence. The direct gain system offers the highest efficiency of any solar approach, as the only variable affecting the solar gain is irregularities in the glazing itself. The disadvantage is that the benefits can be eradicated by heat loss back out the windows at night and during cloudy periods. Movable insulation will alleviate the problem, and indeed, is necessary for optimum performance.

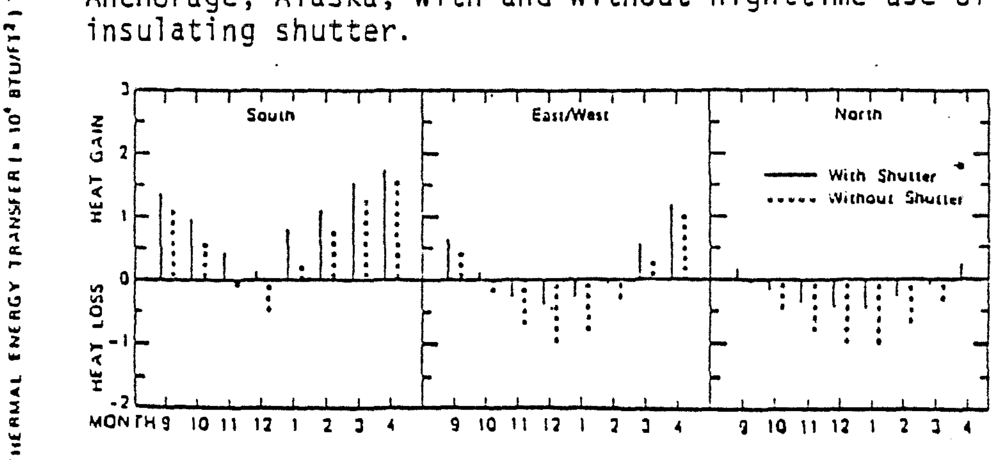
The efficiencies of the greenhouse/sunspace are much the same as those of direct gain, with one major difference. Since solar heat must be transferred from the sunspace to the house, the thermal efficiency of the greenhouse itself will have a sizeable impact on usable heat for the main structure. A



1. Monthly thermal performance of double glazed windows in Anchorage, Alaska, with and without nighttime use of R-9 insulating shutter.



2. Monthly thermal performance of triple glazed windows in Anchorage, Alaska, with and without nighttime use of R-9 insulating shutter.



3. Monthly thermal performance of quadruple glazed windows in Anchorage, Alaska, with and without nighttime use of R-9 insulating shutter.

FIGURE 8.2. Solar Gain Versus Heat Loss with Various Windows

minimally insulated greenhouse will use most or all of the solar gain to maintain ambient temperature within it. A thermally efficient application using night insulation over the windows will provide a significant amount of heat to the living area. Table 8.1 gives some examples.

The conversion efficiencies of the mass wall (concrete/water) concept is the most difficult to quantify. To our knowledge, no applications exist in the Railbelt.[a] Thus far, only one study of Trombe walls in residential applications in the Railbelt has been generated (AREA 1980). This study has used computer simulation to model performance using 150 cu ft wall sizes.[a] While these results listed in Table 8.2 show that the mass wall has merit, they are computer models and not actual tested installations.

The space between the glazing and the Trombe wall can reach temperatures as high as 130 to 200^{o}F. Since 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 Trombe wall and the glazing. The efficiency of Trombe walls in Alaska is still uncertain, and no real projections can be made without further study.

Water as a storage medium when placed directly behind south glazing is approximately 50% more efficient than concrete. The most common containments include 55-gallon drums, steel culverts, and commercially manufactured large volume plastic tubes. There is some concern that water placed close to exterior glazing, without night insulation at the windows, might freeze and burst its containment. There are therefore no known water wall applications in the region. With proper design techniques to alleviate this problem, water walls may prove to be efficient.

Two other storage mediums used for passive solar systems include rock bed storage and phase change materials (PCM). In rock bed storage solar heated air is moved through a container of rocks which provide heat storage. Since air will not move readily through the rock bin by convection, some type of fan

(a) Energy Alternatives for the Railbelt, Alaska Center for Policy Studies, 1980.

TABLE 8.1. 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	-30.5%
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) Asumes an 8' x 20' greenhouse with 130 ft^2 south glazing, opaque end walls and roof, one insulated door in end, full solar access with due south orientation.
(b) Assumes shutters closed 12 hours per day during the heating season (September-May).

TABLE 8.2. Comparative Heating Needs of Home Built to ASHRAE 90-75 vs. Passive Solar Design

Heating Needs	Location: Homer	Matanuska Valley	Fairbanks
ASHRAE 90-75 Annual Heating Load(a) (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)(b)	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) Based on 1,500 square foot home
(b) Assumes 150 cu ft trombe wall.
Source: Alaska Renewable Energy Associates

is used in almost all cases. The disadvantage of rock storage is that it requires a large amount of material. In most retrofits it will not be economically feasible to incorporate storage adjacent to collection surfaces. While more cost-effective in new construction, the sheer volume of material and space needed will likely make other options more attractive.

Phase change materials incorporate a chemical compound, encapsulated in containers, that is capable of storing the latent heat associated with the change from solid to liquid. PCMs change from a solid to a liquid at a temperatures (81^{O}F in several models) within the range of warm air temperatures commonly encountered in passive solar installation. Fully charged, they release this heat back to the space, slowly changing from a liquid to a solid as they give up energy.

Phase change materials offer several advantages. They are relatively lightweight and provide more Btu stored per volume needed than other storage mediums. They therefore are useful in retrofit applictions, where concrete or water systems may prove too costly and heavy for the existing structure. They can also be incorporated into benches or planting boxes near south glazing, minimizing aesthetic impact.

Their major disadvantage is that they are costly and enjoy no long-term track record of success, since they have been on the market only a short time. Even so, they may offer significant benefits in terms of utilizing excess solar gain. The potential of these new products in passive solar for the Railbelt should be studied further.

<u>Type of Demand Serviced</u>

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 heating demand of structures that solar would have little effect on the immediate demand for electricity.

The ability of passive solar to affect the load curve will hinge directly 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 in order to alleviate wide swings in temperature inside the dwelling. The addition of storage mass will help dampen these swings and 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 affect on demand would be to reduce the base load. 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.

Complementary Technologies

A thermally efficient building is necessary for optimum performance of solar. The amount of heat available from the sun does not equal heat loads in "typical" buildings during much of the winter months. By reducing the heating load through conservation, solar becomes much more attractive as a heat source.

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 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 act as a preheater for the main system during much of the spring and fall months.

Finally, even with a combination of solar and conservation, a backup space heating system is required. A typical large home in Anchorage might use between 100 and 150 thousand Btu/hr during the colder winter months to maintain ambient temperature. A super-insulated passive solar home of the same size will use only 35-45 thousand Btu/hr. This figure falls well within what a quality wood stove can supply.

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.

8.1.4 Siting Considerations

Insolation

Insolation is the determining factor in the success of any solar application. Insolation is "the total amount of solar radiation--direct, diffuse and reflected--striking a surface exposed to the sky. This incident solar radiation is measured in langleys per minute, or Btu per square foot per hour or per day" (Mazria 1979).

Insolation varies throughout the Railbelt region, depending on local factors such as latitude and percentage of cloud cover throughout the year. A very broad average figure for the Railbelt would be 300,000 Btu/sq ft on a horizontal surface. Compare this with insolation at Albuquerque, New Mexico, with approximately 700,000 Btu/sq ft available on a horizontal surface.

A factor not yet adequately quantified is the amount of solar radiation available on a vertical surface. The sun is so low in the Railbelt region during the winter as to be a possible disadvantage because of obstructions in the sun's path (see later section). On the other hand, the relatively horizontal orientation of winter time solar radiation is an advantage in maximizing efficiency of solar applications. The greatest amount of energy is intercepted when the sun's rays strike the collector surface at a perpendicular angle. The greater the variance from this, the more radiation is reflected away from the glazing surface, unusable as heat in the structure. Because of the low sun angles prevalent during the heating season in the Railbelt, vertical glass becomes an excellent collector.

Research shows that the difference in percentages of solar gain between vertical glass and tilted glass is minimal.[a] It is obviously cheaper to install vertical glass, particularly stock manufactured window units, than to custom design and install tilted glazing. This is particularly true when retrofitting existing building stock for passive solar.

Only Anchorage and Fairbanks are currently measuring vertical insolation. Longer term data gathering, at several additional sites, is necessary to form a scientific base of solar radiation available. Until this data base exists, designers are severely limited in their ability to "fine-tune" actual applications.

(a) A general rule of thumb for optimum tilt of glass is latitude plus 15°. Thus, in Anchorage: 61° latitude plus 15° = 76°--very close to vertical.

Orientation

Most of the solar radiation usable for space heating is found in the southern sky. The collection area should therefore be oriented as close to due south as possible, although a variance of 20^{o} or so from true south in either direction will not seriously affect performance (see Table 8.3). New construction can, of course, be easily oriented correctly, provided that the topography of the building site will allow siting to the south.

Site planners in residential and commercial development have generally failed to consider the advantages of proper orientation when designing subdivisions and building sites. It is thus impossible for some existing

TABLE 8.3. Percentage of Radiation Striking a Surface at Given Incident Angles[a]

Incident Angle[a] (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. In other words, at 0o, the sun is absolutely perpendicular to the collection surface.

structures to realize the benefit of solar heat. However, many existing buildings could justifiably be retrofitted using various solar gain methods.

Solar Obstruction/Shading

The sun is low on the horizon during much of the winter in the Railbelt. It rises to a high of only 6^{o} in Anchorage and 4^{o} in Fairbanks at noon on December 21, the shortest day of the year. Because of this, objects of even insignificant height can block solar radiation. The shadow cast behind a 10 ft high object in Fairbanks on December 21 will reach a length of 128 ft (see Figure 8.3).

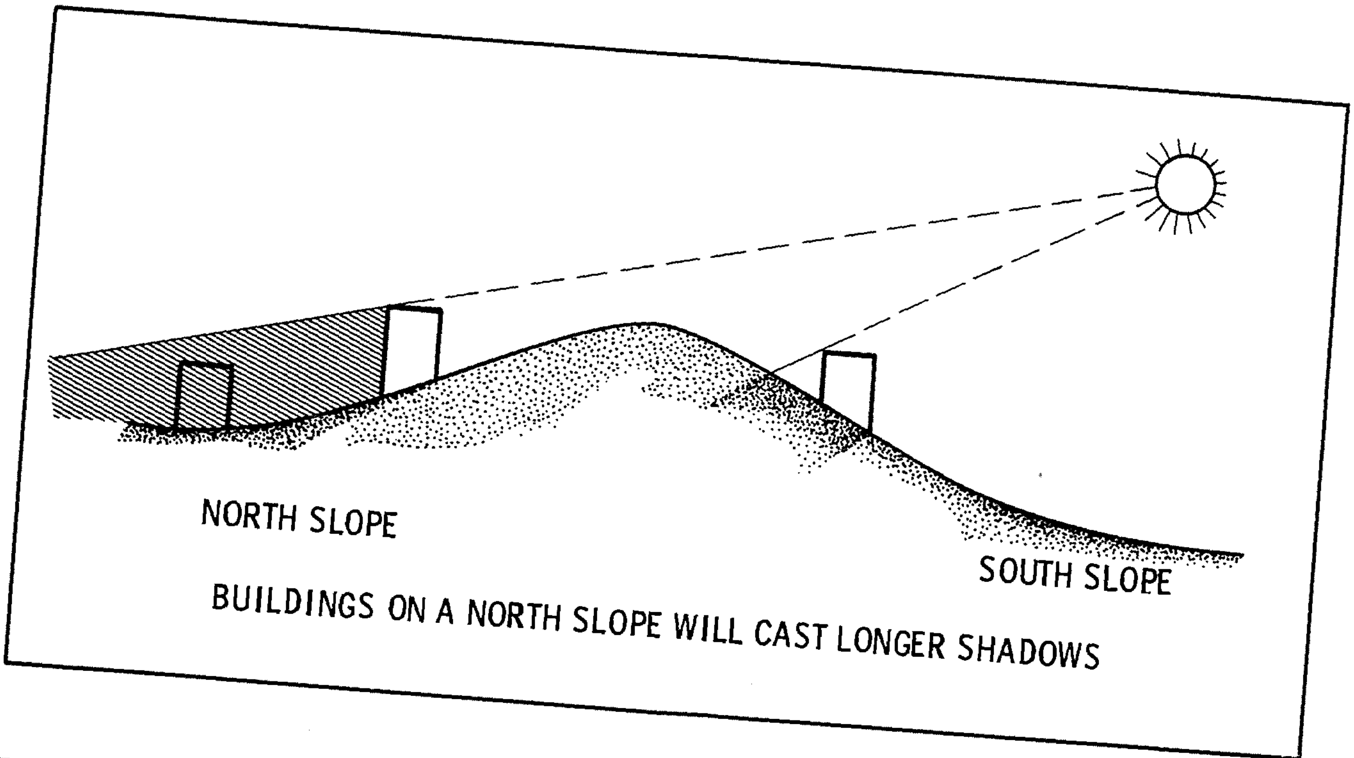
The problem is less significant in low density areas, particularly rural sites. The lack of large trees and tall buildings in the region helps minimize obstructions and shadows, but the mountainous terrain causes some solar obstruction.

8.1.5 Costs

There has been virtually no work done in the Railbelt on capital costs for passive solar, mainly because there have been so few actual installations. In addition, most solar buildings in the region rely on heavy insulation and efficient thermal envelopes to first reduce heat load and it is often difficult to differentiate between costs for solar and those general building costs.

Our preliminary studies show an increase of anywhere between 6 to 10% above normal construction costs for a passive solar, superinsulated home (AREA 1980). Thus, in a $100,000 "typical" home, an added expenditure of $6 to 10 thousand could be expected. Total heating load would be reduced by 65 to 75% through conservation and solar measures.

This particular example is an "extreme" case. Capital costs will be less with structures employing lesser degrees of insulation, scaling 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. Some broad examples will help to illustrate the possibilities. They are by no means concise or all-encompassing.



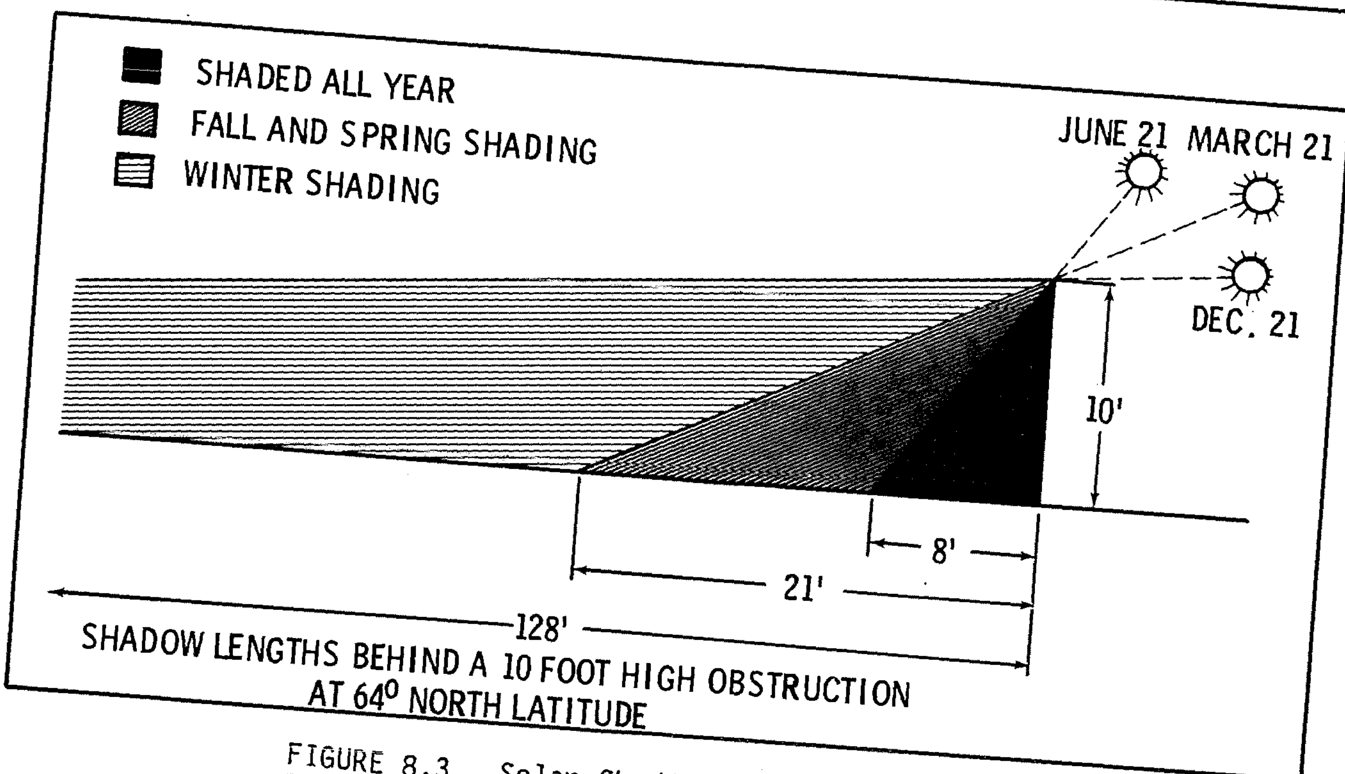


FIGURE 8.3. Solar Shading Considerations

Assumption 1: A 1500-ft^2 home in Fairbanks built to ASHRAE 90-75 standards with a 218-MMBtu heating load.

Assumption 2. Conservation (superinsulation) and passive solar gain with concrete storage mass (150 ft^3) will cut the heat load to 71 MMBtu, a savings of 147 MMBtu.

Assumption 3. Operation and maintenance costs are $25.00/yr.

With the above assumptions, cost per MMBtu are presented for several variables:

A. $6,000 capital cost--

1.	15% interest, 30-yr term, conventional	$6.38/MMBtu
2.	10% interest, 30-yr term State Loan	$4.49/MMBtu
3.	5% interest, 20-yr term, Alternate Energy Loan	$3.58/MMBtu

B. $10,000 capital cost--

1.	15% interest, 30-yr term, conventional	$10.53/MMBtu
2.	10% interest, 30-yr term State Loan	$ 7.38/MMBtu
3.	5% interest, 20-yr term, Alternate Energy Loan	$ 5.86/MMBtu

By comparison, the cost ot fuel oil in the region as of January 1981 is:

Anchorage	$8.40/MMBtu
Homer	$8.69/MMBtu
Fairbanks	$8.20/MMBtu

It is worth noting here that conservation and solar technologies are virtually inflation proof once installed. Fuel oil is not.

These examples constitute broad averages only, and represent only one particular case, a superinsulated new house with maximum solar considerations. Until further study is done, particularly with solar retrofits (no assessment has been done in the Railbelt), these figures should be received with caution. Even so, they show economic potential in many parts of the region, particularly in view of the fact that the examples do not reflect added tax incentives nor address future fuel inflation costs.

In the examples a figure of $25 dollars per year was set aside for operation and maintenance costs. This reflects a "worst case;" in reality these costs may approach zero, as passive systems are extremely simple, with few or no moving parts. Much depends on the particular system, but it can be generally stated that passive systems will last the life of the building with little added cost beyond initial construction.

8.1.6 Environmental Impacts

Environmental impacts from passive solar tecnologies are minimal, almost non-existent. No traceable air or water pollution has been recorded in dispersed application. Solar is an ideally benign fuel source with regards to the environment.

The potential detriments of solar on the environment center on two factors: aesthetics and reflected glare. Aesthetic appeal is of course subjective, and not quantifiable here. It is however, an important factor. Since the concept of passive solar centers on the building and its components, it is in the hands of the designers to 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, there are just as many or more examples of successful installations. 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, save for the expanse of south facing glass.

Reflected glare off south glazing is a potential problem in solar application. How much of a problem it might be in the Railbelt is not known at this point. Glare is more prevalent when the sun strikes the glazing at an acute angle; i.e., the less perpendicular the sun's rays to the collector surface, the more glare encountered. During the winter, vertical glass will not cause excessive glare problems. In summer, proper design of the roof overhangs will ensure that enough of the glass is shaded to alleviate most glare. It is during the spring and fall that the phenomenon could cause problems to passing motorists and pedestrians. The small number of solar system installation in the Railbelt region precludes answers at this time.

Consumer safety poses no real problem with passive solar. As most systems are simple and benign, danger to the consumer is far less than, say, 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 the sphere of those the worker might encounter in standard construction.

8.1.7 Socioeconomic Impacts

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 in order 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 subdivisions 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 statment 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 which 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 there have been studies done in the southern parts of the United States, 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 will be chosen unanimously. But, shadows would probably negate solar gain during December and early January in such cases. However, because of the long heating season, solar would still be beneficial during a large part of the winter.

Consumer Convenience and Control

Passive solar offers the following advantages. It

- requires virtually no maintenance or replacement of parts during the building's lifetime, as the components are a part of the structure
- requires little or no operator attention with the exception of thermal shutters
- is safe
- can provide a significant portion of heating needs in case of power failure or fuel shortages
- reduces dependence on uncontrollable factors affecting fossil fuel pricing and availability
- reduces fuel expenditures and thus provides more income to the individual.

Potential disadvantages include:

- necessity of operating shutter
- wide temperature swings within a heated space if no storage mass is present to regulate the variance in available solar radiation.

Regional Economics

As passive solar is a decentralized technology, it will create jobs and new capital ventures at a local as well as at a regional level. Since the skills required to design and install systems are relatively straight forward, using standard materials and techniques, it is likely that most of the human resource needed exists in the region. If pursued on a fairly widespread scale, the potential for long-lasting jobs in new and existing businesses is promising. Though 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 very likely result in an increase in the amount of capital staying in the region, further providing economic benefits outside the construction sector. Certainly, the extra income available to the consumer by reduced fuel expenditures will find its way into the region's economy. While an in-depth economic analysis cannot be done until the degree of penetration of the solar technologies in the marketplace can be better assessed, preliminary study and common sense indicate that solar will indeed have a positive impact on the economy.

8.1.8 Potential Application to the Railbelt Region

A combination of energy conservation and passive solar in new construction can cut energy demands by 60-70% 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 30-50% reduction in the heating load is conceivable combining these two technologies. Without an assessment of existing building stock, it is difficult to make an aggregate projection.

Passive solar is an emerging technology in the Railbelt. At this point, only a handful of structures have been designed specifically to take advantage of the maximum amount of available solar radiation.

Passive solar technologies use materials and building techniques common to the building trades--an important attraction. The fact that passive solar in the Railbelt is best exemplified by an energy-efficient house coupled with south glazing makes it easily accessible to the present skills of the designer and builder.

Development of a thorough understanding of the economy 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 a number of techniques: a thermally efficient building envelope, south glazing, a completely unbroken 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. There are a few components not stocked in the state that would help to 'fine-tune' passive system; they are available on fairly short notice from suppliers in the lower United States.

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, educated field work will be necessary to implement successful systems. Interest among builders in the region toward passive solar technology appears to be high; it will be necessary to educate the trades to the details of implementing systems to ensure that they work to their designed efficiency.

Existing financial practices present an additional obstacle to the development of 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; operation and maintenance costs (i.e., fuel) over the life of the building must be integrated into the overall cost. It is not clear how widely accepted the concept of life cycle costing is among lending institutions. There have been scattered reports of bankers' resistance to extra costs for solar. On the other hand, of six passive solar houses designed by this author in 1980, not one was refused a loan by the several lending institutions in the Anchorage area, 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. This quote by an appraiser taken from the First Railbelt Alternatives Study[a] illustrates the problem:

> "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 ovvurrences and, unfortunately, there haven't been enough fact occurrences to give a true and accurate answer."

(a) Energy Alternatives for the Railbelt, Alaska Center for Policy Studies, 1980.

Most Alaskan appraisers of solar homes did not understand the value of 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 there have been several administrative problems in the first year of the loan program operation, consumer interest is high, and work continues on ironing out the flaws. It is an important step toward solving some of the financial obstacles listed herein.

8.2 DISPERSED ACTIVE SOLAR TECHNOLOGIES

"Active" solar systems require auxilliary pumping energy to function properly. These systems differ from "passive" solar energy application, 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.

Three varieties of dispersed active solar systems are currently available for use in Alaska: liquid-based flat-plate collector systems for space heating, liquid-based flat-plate collector systems for hot water heating, and hot air systems for space heating. 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 the sheet metal unions or plumbing shops are available, particulary in the Fairbanks area.

8.2.1 Types of Systems

The flat-plate solar collector (Figure 8.4) is the most common configuration used today in active solar energy systems. Active systems employing flat-plate collectors are the most common type used to retrofit

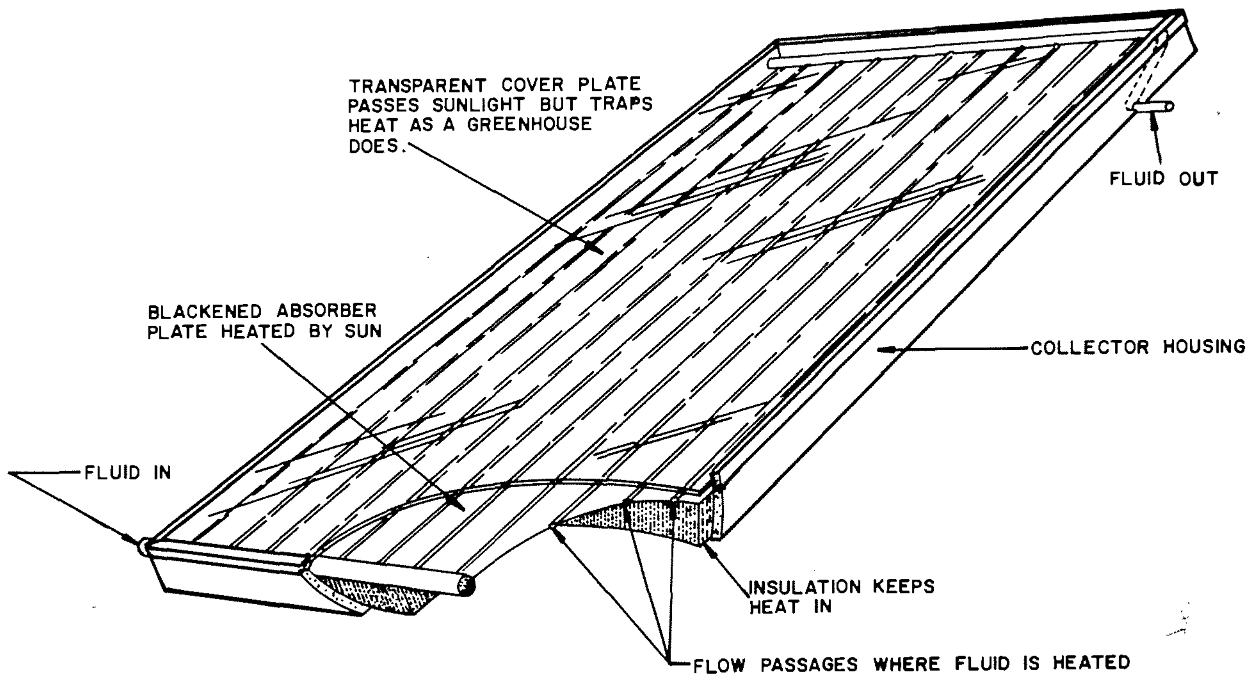


FIGURE 8.4. Schematic of a Typical Liquid Flat-Plate Collector

homes and businesses with solar energy 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, or both.

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 loss of heat, 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 true efficiency of double glazing needs further research.

There are currently less than 20 operating systems in the Railbelt area, and none have been monitored to determine efficiency of double glazing.

For year-round use in the Railbelt, a liquid-type flat-plate collector must incorporate antifreeze in the heat exchange fluid to prevent freezing. Figure 8.5 shows a typical Alaskan installation for an active space heating system.

A version of the flat-plate collector which may be applicable for Alaska is called <u>SolaRoll</u>.

> "The system consists of a unique exchanger/absorber plate made of a flexible elastic monomer which can withstand freezing and has an anticipated 30-year lifetime. It is a black material, and

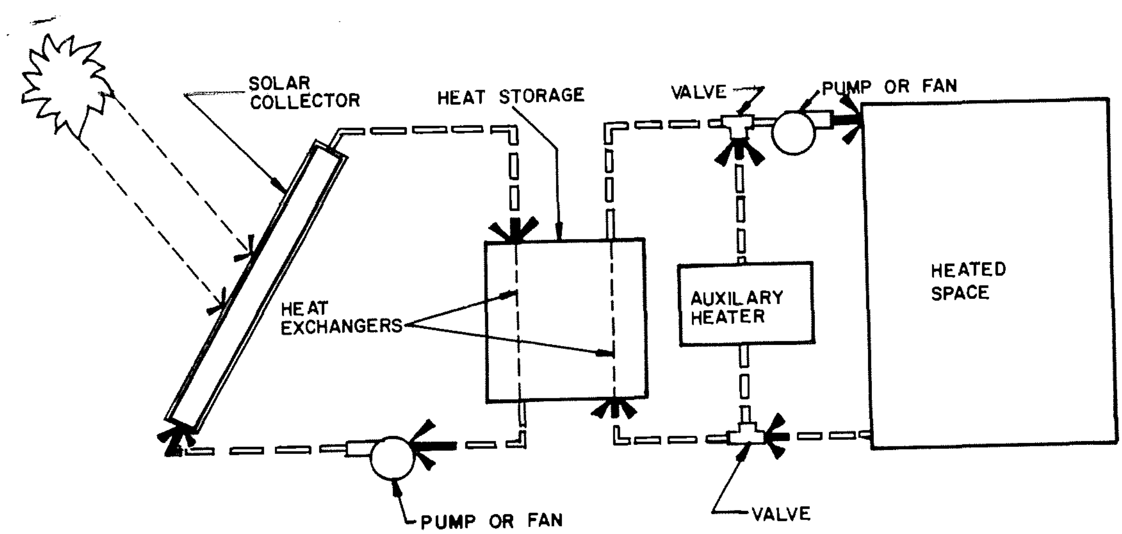


FIGURE 8.5. Typical Active Space Heating System

performance tests indicate that SolaRoll encased in a standard site built or locally manufactured insulated collector frame performs better than average metal solar collectors. It is tailored for do-it-yourself installation. No nails, screws, plumbing elbows or tees, or battens are needed for assembly. There is also no need for soldering, welding, sealant, or paint. SolaRoll is an example of the types of technological advances which continue to make solar collectors cheaper and better."[a]

Active systems require an energy storage system to be truly effective. 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 8.5).

Active solar systems for Domestic Hot Water (DHW) systems use the same type of collectors used for space heating systems. Figure 8.6 shows a typical DHW 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 there is a much closer match between resource availability and end-use 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 for a great portion of midwinter needs, during fall and spring months it will supply a large portion of the load. During summer, 100% of hot water can be had from the sun.

Systems Using Air As The Working Fluid

Active air collectors (see Figure 8.7) are usually thicker than liquid-based collectors because they handle higher volumes--that is, a given volume of air absorbs fewer Btu than a similar volume of liquid. In order to keep the collector temperature low, thus improving efficiency, more air must

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(a) Richard Seifert, Energy Alternatives for the Railbelt, Alaska Center for Policy Studies, 1980.

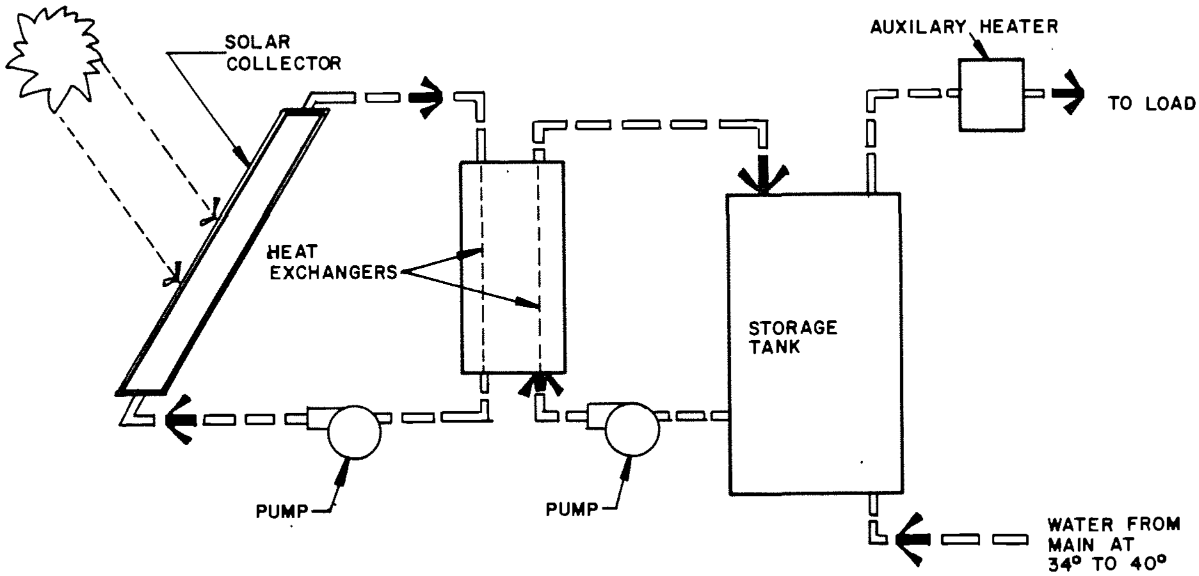

FIGURE 8.6. An Active Domestic Hot Water System (From Seifert, Alaska Solar Design Manual, 1980, Draft

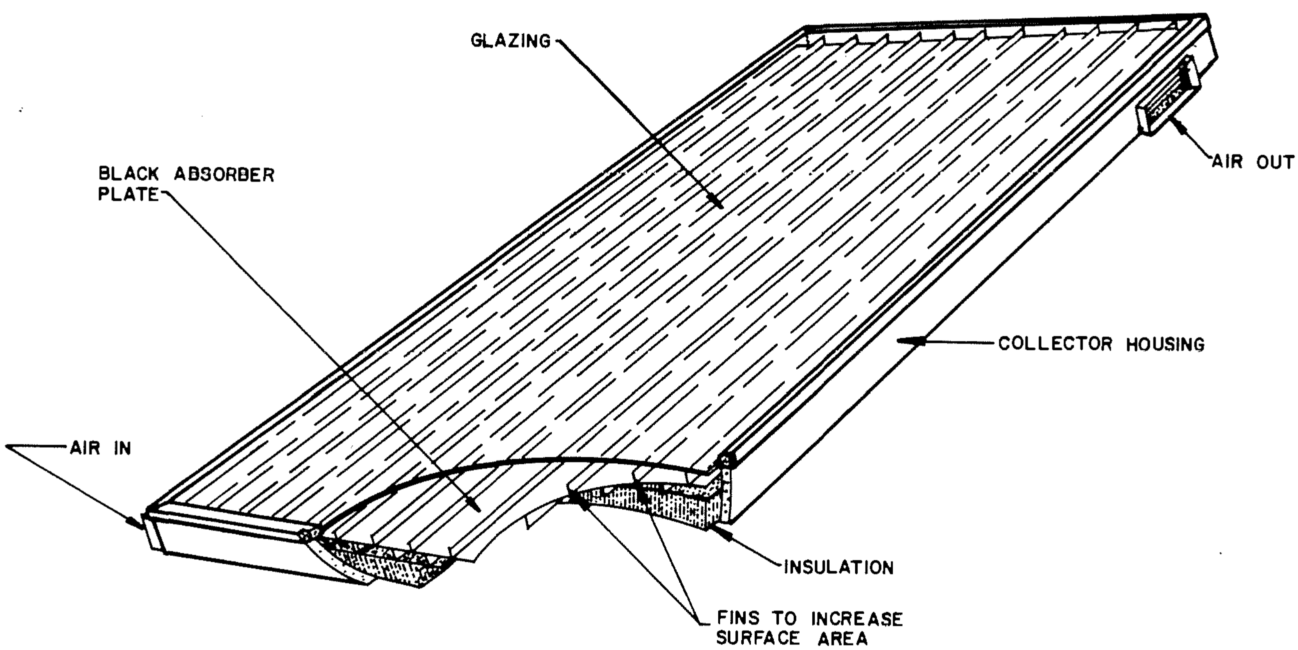

FIGURE 8.7. Schematic View of a Typical Air Collector

pass through the system. One approach to this technology (untested in Alaska) is to pump the hot air directly into the living space. Preliminary calculations show this to be effective when combined with a thermostatically controlled fan. A more common approach used in the lower United States involves ducting the heated air from the collector into a rock bed to provide storage for use at a later time. 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.

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 9-10 months of the year; in fact, 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 500-600 solar homes. This 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.

8.2.2 Technical Characteristics

Active Solar Conversion Efficiencies

In the Railbelt, active solar collectors make effective use of 30-40% 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 collector tilted perpendicular to the sun on an average annual basis (usually at the latitude angle for domestic hot water, and latitude plus 10-15^{o} 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 100-180^{o}F is generally acceptable. The "optimum" situation described above assumes that the temperature of the collecton fluid is about 140^{o}F.

A collector's efficiency can only approach 30-40% if the heated medium is used directly, 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 8-12%. 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 8-12% loss can occur.

Until some monitoring of installed systems in the Railbelt is undertaken, actual performances cannot be fully quantified.

Coincidence to Load

The ability of an active solar installation to supply heating loads (whether it be space or hot water) depends to a great degree 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 there is little existing data, it is believed that active solar will 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, but we do not yet know how much. 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 active solar system is limited.

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 go hand in hand with 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.

Active solar ranks alongside the rest of the dispersed technologies in terms of adaptability to future growth. The simple fact that it is dispersed means that solar can be put into place quickly, with little lead time, by installers with a minimum of training. Whether active solar will be cost-effective on a large scale is impossible to determine at this point; the fact that the technology is available and could be implemented is well-known.

8.2.3 Siting Considerations

The same meteorological considerations apply to active solar systems as were discussed for passive solar systems. See Section 8.1.3. 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 8.1.3 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 southern United States indicates that active solar hot water systems will still perform very well when oriented as much as 90° off of south.[a] No testing has yet been done to verify this phenomenon in the Railbelt, but the potential ramifications may be significant from the perspective of retrofit of active solar systems to existing housing. Most housing in the region has been oriented haphazardly in relation to solar access. Collectors can be mounted 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, it is simpler, less costly, and generally more aesthetically pleasing to mount the collector "in line" with the roof of an existing structure.

The number of existing structures adaptable to active solar space and/or hot water heating in the Railbelt is not yet known. Actual 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 8.1.3.

(a) Collector Location: No Taboos on East or West, Solar Age Magazine, page 26, December 1980.

8.2.4 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 what is probably the best cost analysis to date on active solar in Alaska. They used several models of houses: a standard home, a retrofitted structure, and a "superinsulated" house for cost comparisons. In addition, they looked at hot water heating. Assuming a collector cost of $15/ft^2 (including storage) with financing at 9.5% interest over 20 years with nothing down, they formulated results based on several different collector sizes, in an attempt to define the "optimum" investment. As can be expected, hot water heating was the best investment, at unit costs ranging from $12.53/MMBtu for 15% of the load, to $24.30/MMBtu for 61.6% of the load. These figures are for the Fairbanks area. The standard house case was the worst, ranging from $12.83 to 34.16/MMBtu, for 5.2% to 37.3% of the heating load, respectively. The retrofitted home's unit cost ranged from $12.60 to $32.31/MMBtu, for 6.3% to 39.1% respectively. Finally, the costs for superinsulated homes ranged from $12.61 to $31.10/MMBtu, for 7.5% to 41.9%, respectively. These cost figures are projections only; there have not been enough installations to know actual initial capital costs.

Operation and maintenance costs will be a part of every active solar system; just how much 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 there is little precedent in Alaska. An average figure of $25-50 dollars per year over the life of the system seems likely, for such items as burned out pumps, piping or ducting repairs, and glycol solution once a year if the system is drained down annually.

8.2.5 Environmental Impacts

The environmental effects of active solar energy utilization are almost entirely positive. Once the system is manufactured and installed, it should supply 10-20 years of pollution-free energy at an average rate of

400 Btu/SF-day in the Railbelt. Early concern over the aesthetic devaluation of neighborhoods due to large numbers of roof-mounted solar collectors has been supplanted in the southern United States by the increased real estate appraisal values for homes with solar systems.

Injuries and deaths accredited to the solar technologies are rare; since most installations tend to be small and relatively simple to install, the hazard rate is no higher than that involved in standarad light construction.

8.2.6 Socioeconomic Impacts

Were active solar to be employed on a widespread basis, it is likely that it would enjoy the same socioeconomic benefits that the other dispersed technologies enjoy. 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. There would, however, be an outflow as both manufactured collectors and components for job-built collectors would be shipped in from the continental United States to a large degree.

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. How positive the benefits would be depend on the amount of market penetration, but in general, the socioeconomic impact of active solar would likely 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 ambient temperatures in the dwelling (or hot water supply) during times of fuel disruption is an additional advantage. Finally, the investment is inflation proof, something that cannot be said for most traditional fuel 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 (EPDM) absorber can eliminate this requirement.

As so few systems have been installed in the region, it is difficult to estimate how much time the consumer would spend on maintenance and operation. A figure of 3 to 6 hours per month for a well-defined system is a reasonable estimate.

8.2.7 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, there are many constraints on the use of active solar energy in Alaska. The low winter sun angle coupled with extreme, low temperatures make 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 there are no currently available definitions of solar access angles for the state. Until latitude-specific, economic-based definitions of solar access data are gathered, it must be assumed that for a site with unobstructed south view, the collector will not be useful between December 1 and January 15 at the southern extreme of the Railbelt, and December 15 to February 1 in Fairbanks.

Though no in-depth studies have been done, preliminary work in various Anchorage neighborhoods has shown that as much as 35-45% of the existing building stock may be adaptable to retrofits for active and/or passive solar.[a]

It would be extremely difficult to determine the overall potential of active solar at this point. The number of dwellings with solar access is

(a) Alaska Renewable Energy Associates, in-house study, 1980.

unknown; the actual performances of active systems are undocumented; market penetration of active solar technologies is difficult to assess as availability is still fairly low in the region.

In a study performed in 1980 by the Alaska Center for Policy studies, Richard Seifert 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 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 percent of the maximum possible.

Even 20-25% 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 will remain so until and unless front end costs come way down.

Active hot water heating on the other hand could conceivably provide for a significant reduction for electric power demand. Prospects for offsetting load year-round 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. Assuming that 40-50% of the building stock had good solar access, 20-25% 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 weak. Further work needs to be done to define active solar's impact in the region.

Several dealers sell active collectors, most of them for hot water heating and as 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 how effective their particular systems were, and 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. There simply has not been enough demand for active solar for many to have 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 scare off a banker looking at a solar investment. 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.

8.3 WOOD FUEL FOR SPACE HEATING

A number of 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 utilization. This profile examines the nature and extent of wood usage for home heating in the Railbelt area, including the potential for demand growth and adaptability of the alternative to increased demand.

8.3.1 Technical Characteristics

Table 8.4 lists mechanical and physical properties of tree species found along the Railbelt (USDA 1974). For the consumer, the column representing millions of Btu per cord is the important consideration. This column illustrates the relative superiority of birch (prevalant in the Railbelt area) over other species by a significant margin. Wood containing 20% moisture (MC) is considered acceptable for good combustion.

Types of Units

This report does not assess the relative merits of specific wood-fired heating units now available for home use. Many types and styles of varying quality are on the market, and though consumer sophistication has grown with the popularity of using wood as an alternative heat source, choice of units is often governed by personal subjectivity and economics to a degree that makes it difficult to analyze the factors leading to the purchase of particular types.

Fireplaces are still in use for some home heating needs, chiefly as a secondary source. Few, if any, masonry fireplaces are being incorporated in new residential construction; most new installations have fireboxes and chimneys of steel. Fireplaces do not permit any draft control and generally have little capability to radiate what heat they do produce.

Fireplace inserts provide an opportunity to utilize an installed fireplace while incorporating some of the advantages of wood stoves, such as draft control, baffling for secondary combustion, and improved heat

TABLE 8.4. Railbelt Wood Characteristics[(a)]

Area	Species	Moisture Content, (%) for Green Wood: Heartwood	Moisture Content, (%) for Green Wood: Sapwood	Specific Gravity (Green)	Weight/Cu Ft, 20% MC[(b)]	10^6 Btu Cord 20% MC[(b)]
Coast:	Sitka Spruce	41	142	.37	27.7	15.2
	Hemlock	85	170	.42	31.4	17.2
Interior:	White Spruce	34	128	.37	27.7	15.2
	Black Spruce	34	128	.38	28.4	15.6
	Aspen	95	113	.35	26.2	14.1
	Birch	89	72	.48	35.9	19.3
	Cottonwood	162	146	.31	23.3	12.5

(a) Values are given for a standard 128-cu ft cord, containing 90 cu ft of solid wood and bark.
(b) Derived from Galliet, Marks, and Renshaw (1980).

radiation. Many of these units draw combustion air from the outside, thus cutting the loss of warm air from the structure.

Box or chunk stoves are the simplest and most common type available. They come in many forms, including kitchen, Franklin, potbelly and parlor stoves. These 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.

Air-tight 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. Some designs preheat incoming combustion air. Others incorporate thermostatically-controlled heat exchangers to recapture heat for space heating.

Base-burning airtight stoves take the principles of the controlled draft 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 still need frequent tending.

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. 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 its proper burning position. Thus, even a fresh load of fuel will not cool to the fire below. Volatile gases from the new fuel wood are also released more slowly for more efficient burning.

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.

Mixed fuel systems are also available, they incorporate many of the features described above while providing the advantage of flexibility in fuel choice. Estimates of conversion efficiencies for these eight stove types, and for standard fireplaces, are given in Table 8.5.

Conversion Efficiencies

For wood fuel to reach combustion temperatures, its inherent moisture must be heated and turned to steam. Therefore, the moisture content is

TABLE 8.5. Conversion Efficiencies for Wood-Fired Units

Wood System Type	Conversion Efficiency	Typical Heat Output (Btu)	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 stove	50 - 60%	112,000	6000

Source: Matson/Oregon State University Extension Service.

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 and a oxygen deficiency will result, leading to incomplete combustion, which results in a plume of dense black smoke.

Inherent moisture values vary according to species, as shown in Table 8.4. Moisture content of 20% is considered acceptable by most technical sources and wood stove manufacturers.

Consumers have considerable control over moisture content of wood. The type of wood used and the length of drying time are two factors. In addition, cutting wood during the dry seasons will usually ensure a lower moisture content.

It should be remembered that 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 cause the introduction of unwanted air, as well as signal the end of the stove's useful life. Also note that 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.

In some respects, the effectiveness of converting to wood heating as either backup or 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 house or building.

<u>Reliability</u>

Wood as an alternative fuel is generally reliable year-round, although consumers must plan for harvest or purchase of a wood supply. Important factors include wood type and quality and storage. Reliability is also governed by the condition or nature of the heated structure. Design features which 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.

8.3.2 Siting Considerations

Most wood used in the study area (see Table 8.6) for fuel is harvested by small operators or individuals using chainsaws and pickups or snowmachines. It appears that wood is gathered year round and is typically gathered from areas accessible by public roads.

TABLE 8.6. Survey of Wood Suppliers(a)

Anchorage:		Distance Traveled (mi)	Public Land	Private land	# Cords Annually	Primary Wood Type	Delivered Price
Supplier:	1	50 to 90	X	X	6	Birch	$85
	2	90	X		N.A.	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

(Note:) Primary Anchorage commercial supplier will not reveal data.

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.

There is only one fully committed commercial firewood supplier in Anchorage who considers his operation to be full-time and relies on it as a sole source of income. He will not disclose any data concerning wood sources or volume as he feels it to be 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 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. Birch is the most common wood in the Anchorage area and ranges from $75 to $95 per delivered cord.

Spruce is most common in Fairbanks and ranges from $80 to $90 per cord. Distances traveled range from 25 to 50 miles (one-way) and State land is the primary source.

All suppliers stated that their sales were limited only by accessibility to harvest areas, and not to resource shortage.

8.3.3 Costs

Wood fuel compares very favorably with other sources, especially when harvested by the dispersed, individual method. This will continue to be the case, unless transportation fuel costs rise dramatically.

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-$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 proceed in the Railbelt area.

The unit cost for wood heating is difficult to assess over the life of the structure, as several assumptions must be made. These 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 woodburning unit will vary, dependent on the intended end use and quality of the unit. Simple box stoves can be put into place for as little as $350-400, though the useful life will in almost all cases be under 10 years. Well built airtight stoves will range in cost from $700-$1600, and will last 20-30 years with a significantly higher heat output than the type listed above. The wood furnace units with full ductwork can run $3000-$6000, particularly if a multipurpose unit is purchased (e.g., oil/wood).

Two useful units for expressing wood fuel cost values are "cost per cord" and "cost per (10^6) million Btu." Table 8.7 lists typical costs for both figures. These figures are based on costs quoted by commercial suppliers in each area and do not take into consideration the efficiency and combustion units.

TABLE 8.7. Relative Wood and Oil Costs for Railbelt Area

Location		Costs/Cord[a]/Gallon[b]	Cost/MBtu
Wood:			
	Fairbanks	$80.00	$5.48
	Anchorage	$90.00	$6.30
Oil:			
	Fairbanks	$ 1.13	$8.20
	Anchorage	$ 1.16	$8.20

(a) 90 ft^3 of wood within 128 gross cubic feet (4'x4'x8') used for standard cord.
(b) At January 1981 prices, assuming 138,000 Btu/gallon.
(c) Does not consider combustion efficiency.

Operation and maintenance costs are difficult to assess as 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 which accumulate creosote in the stack with lower burn temperatures. Professional stack cleaning ranges from $60-$85 in the region. Obviously, the homeowner could do this work himself and save considerable expense.

Other items of maintenance 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/yr. Again, this is hypothesis, and will vary with the individual.

8.3.4 Environmental and Socioeconomic Impacts

The two primary potential environmental impacts of wood fuel center on safety issues and air quality. The use of wood for heating poses two safety issues: fire hazards, and air quality effects. House fires resulting from the use of 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 the use of a spark arrestor screen in the flue, proper use of the stove itself, and burning a hot fire with well seasoned wood.

Table 8.8 summarizes data on residential fires attributed to "failures in heating systems". Anchorage data refer to heating systems in general; "wood specific" data is 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 occurance of

TABLE 8.8. Wood Heat Fire Hazards

Area	Year	Total Residential Fires	Fires Attributable To 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				
	1979	166			7	(4)
	1978	66			4	(6)
	1977	81			5	(6)
	1976	107			9	(8)
	1975	119			4	(3.4)

(a) John Fullenwider-Deputy Fire Marshall, Fire Protection Division, Municipality of Anchorage
(b) Eric Mohromon, Fire Inspector, Municipality of Fairbanks

chimney fires suggests that safety is not a problem. Furthermore, chimney fires have decreased while wood consumption has increased.

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 combustable 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 particulate 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 ever been made to quantify public perception of woodburning aesthetics. Certinly, wood smoke creates a visual and odor impact which is not pleasing to all. However, there is as yet no indication that this is of major concern to many.

Socioeconomic impacts associated with the use of wood fuel for space heating center on four areas: 1) consumer convenience, 2) adaptability to growth, 3) land use, and 4) regional economic impacts.

Convenience/Control for Consumer

Wood fuel provides an independent source of heat in case of power failure. Heating systems are available in the Railbelt which accommodate wood as well as other fuels (coal, oil and/or gas), and are capable of rapid and easy changeover should the need arise. Firewood is also a relatively inexpensive heat source, particularly if the labor for producing the wood supply is provided by the user. 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, in order 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, this would require up to 120 hours per year. 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 are capable of meeting considerably greater demand for both primary and secondary heating systems. Available systems include a number of models which can accommodate other fuels (coal, oil, gas) and which 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 8.9 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 the cutting from private lands is not monitored. In the case of commercial cutters this is significant because a large portion of their annual take 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)/ 28% for the North Central District (Fairbanks).

(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.

TABLE 8.9. Summary of State Firewood Permits

North Central District

Year	Personal Use Permits: No. of Permits	Increase (%)	No. of Cords[a]	Commercial Sales: No. of sales[b]	No. of Cords
Jan 1981	400		4,000(a)	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

Source: Dept Nataural Resource, Div of Forest, Land & Water Mgt.

South Central District

Year	No. of Permits	Increase (%)	No. of Cords	No. of sales	No. of Cords
Jan 1981	74		222(c)	(unknown at this time)	
1980	960	49	3,000(c)	14	1,175
1979	643		1,829(c)	0	0
1978	Not available				
1977	Not available				

(a) Estimated at 10 per permit
(b) Issued by bid to commercial suppliers
(c) Estimated at 3 cords per permit
Source: Dept Natural Resources, Division of Forest, Land & Water Mgt. South Central District Office

It has been stated that approximately 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[a] 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 shows that in 1979 6.5% or approximately 910 of the

(a) Source: Heather Stockard, Environmental Technician, Fairbanks North Star Borough homeowners in the municipality possessed permits to cut firewood. It is also known that 36% of the 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. It is possible that 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, it is clear that 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 distinction between wood cutting and deadwood gathering. Pressure will probably be brought to bear 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 utilization of other sources of fuel such as driftwood along rivers, streams and coastal areas. Additionally, wood is now being recovered from the lands being disposed of by the state for development of agricultural sites.

Land Use

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.

Long-time government policy requiring "primary" manufacture of Alaskan wood harvested for commercial export was directed at boosting local economics. On the state level, this policy was recently declared unconstitutional.

Although federal and state government and Native corporations own the largest areas of commercially viable timber, future plans for these areas are not known at this time.

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.

8.3.5 Application to Railbelt Energy Demand

The Railbelt region contains large reserves of commercial and non-commercial grade timber.[a] 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 is provided in Table 8.4) Regeneration of these forests is slow, but could be improved with mechanical seeding techniques.

A large number of site-specific or small-scale forest studies and inventories have been conducted in the Railbelt area, though 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 8.10 provides a summary of forest resource data, including total wood volume, standing wood energy, and annual potential wood energy figures.

In general, there is an abundant supply of wood of several types 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 utilization by Native corporations, the State of Alaska, and 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.

(a) Commercial timber stands are those having a potential wood formaton rate of 20 ft^3/acre or more.

TABLE 8.10. Wood Energy Summary/Railbelt Area

Forest Type and Unit Number[a]	Total Wood Volume (million cu ft)		Standing Wood Energy (Billions Btu)		Annual Potential Wood Energy (Billions Btu)	
	Commercial[b]	Non-commercial	Commercial[b]	Non-commercial	Commercial[b]	Non-commercial
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 USFS (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.
Source: Calvin Kerr, Reid Collins, Inc.

Private ownership is increasing because of state lands disposal programs and land transfers under the Alaska Native Claims Settlement Act. Preliminary indications are that most Native land with commerical forest potential will be placed under long-term management. Most small-lot private landowners prefer 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 but 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.

8.3.6 Commercial Availability of Wood Burning Units

The relative simplicity of wood stove installation and operation, the adaptability of units to a variety of structural heating requirements, combined with the aesthetic attraction of wood heating to many people have made wood popular in an area where wood has long had a foothold as a practical heat source.

Figures in recent studies point to a dramatic increase in wood burning in the residential sector. There are many people, usually outside the larger urban areas, depending on wood for their sole heating source. In the larger population centers, wood heat tends to be more of a secondary source, although it appears that this may be changing to some degree.

Based on a relatively casual comparison of wood-burning systems available in the Railbelt area with data on systems available nationwide, it appears local suppliers have kept pace with recent developments in wood system technology. Technological improvements have been made without greatly complicating wood burning for the average consumer, while at the same time increasing the variety and performance of available units.

How much heat can be provided by wood 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.

While it is difficult to determine the amount of space heating energy that would contribute to the region, a figure of 10-15% of total demand is quite realistic if favorable market penetration is assumed.

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APPENDIX A

WATER RESOURCE IMPACTS ASSOCIATED WITH 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 use impacts, water quality impacts, and hydrologic impacts. Most of the potential impacts can be satisfactorily mitigated through the 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 identified, the discussion generally applies to all steam cycle facilities.

WATER CONSUMPTION EFFECTS

Since the operation of any steam cycle power plant requires a substantial water supply for cooling and other plant uses, consumptive water losses associated with the plant 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 the hydraulic conductivity of the aquifer serving as the supply. It should be noted that th Railbelt region's surface water supplies are plentiful, and therefore the use of groundwater 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 to mitigate entrainment of aquatic organisms and impingement impacts; and 2) the possible use of groundwater in coastal areas to supply a plant's freshwater 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 steam cycle employed, the site, and the specific water management techniques used to maximize water reuse and minimize power plant makeup requirements. Estimates of these water requirements are presented in Table A.1 for various steam cycles and plant capacities.

To comply with existing federal and state regulations, once-through cooling water systems will likely be limited to coastal areas employing salt water cooling and interior sites will utilize some form of recirculating cooling water system (see Appendix F).

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 A.2. Selected USGS streamflow data for these resources are presented in Table A.3.

Since water withdrawal impacts are relative to the flow of the river, a comparison of the information presented in Tables A.1 and A.3 can provide an overview of potential effects. If it is assumed that all water demand represents total consumption (as it would for a zero discharge plant), then the maximum water consumption for any of the plants identified in Table A.1, using a recirculating cooling water system would be less than 1% of the average flow for rivers identified in Table A.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, say 200 MWe, total plant demand (again for a zero discharge plant) represents less than 10% of minimum flow for all but the smallest streams of Table A.3. These conclusions suggest that impacts on water flow should not be significant.

WATER QUALITY EFFECTS

Construction and operation of all steam cycle facilities can 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 wastes, concrete batch plant wastewaters, construction dewatering, and dredge spoil. The development of geothermal fields requires large quantities of drilling mud, which require

TABLE A.1. Estimated Water Use Associated with Various Steam Cycle Facilities

Steam Cycle	Approximate Thermal Efficiency (Percent)	Plants Utilizing Once Through Cooling Water Systems: Cooling Water (gpm/MW)[a]	Total Plant Demand (1000 gpm)[b] 20 MW	50 MW	200 MW	400 MW	600 MW	Plants Utilizing Recirculation Cooling Water Systems: Cooling Water (gpm/MW)[c]	Total Plant Demand (1000 gpm)[d] 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 A.2. Power Plant Water Supply 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 plant operation are greatly dependent upon the type of steam cycle and the size of the plant. Potential spures of water pollution include cooling system blowdown, fuel pile runoff, demineralizer regeneration wastewater, ash handling and flue gas disulfurization waste, geothermal fluid discharges (geothermal technologies only), fuel oil releases, radioactive wastes (nuclear plants only) and miscellaneous cleaning wastes.

Cooling Water Blowdown:

In general, the operation of all steam cycles require substantial amounts of cooling water and therefore produce cooling water blowdown. The quantity and quality of this wastewater 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 A.3. Streamflow Data for Selected Railbelt Locations

Station Name and Location	U.S.G.S. Number	Years of Record	Average Flow		Maximum Flow		Minimum Flow	
			cfs	1000 gpm	cfs	1000 gpm	cfs	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 utilizing solid fuel, i.e., coal and various forms of biomass, require management of fuel pile runoff. For coal, this wastewater is generally low in pH, 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, for example, metals in municipal solid waste.

Demineralizer Regeneration Wastewaters

All steam cycle facilities except geothermal power cycles produce demineralizer regeneration wastewaters which 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 byproduct 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 are associated with oil-fired power plants and other facilities which may use oil as an auxiliary fuel. These include fuel storage areas and the accidental release of oil through spillage or tank rupture. Potentially significant impacts which may result from oil releases are generally mitigated through the mandatory 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 complete 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 from the release of radioactive wastes with nuclear facilities are generally mitigated through compliance with Nuclear Regulatory Commission guidelines. However, accidental releases are possible; therefore, all potential transmission media, including ground and surface water resources, are extensively studied during project development to minimize any impacts related to such releases.

Miscellaneous Wastewaters

All steam cycle plants have many other miscellaneous wastewaters that are 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, SS, and metals are the effluents of most concern.

All of these enumerated wastewaters are strictly managed within a specific steam cycle facility. The management vehicle is generally termed a "water and wastewater management plan" and in some technologies is developed in conjunction with a "solid waste management plan". The purpose of these studies is to balance environmental, engineering, and cost considerations, and develop a plant design and operational procedures operation that ensures plant reliability and environmental compatibility, and minimizes costs.

For plants developed in the Railbelt region, relevant regulations would include the 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 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, as receiving stream standards are rarely identical to the existing site-specific water quality regime 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 avoided if the plant is designed to operate in a "zero discharge" mode. This is technically possible for all steam cycle facilities, but can be extremely costly.

Values for selected rivers in the Railbelt region are given in Table A.4. Based on these values, there does not appear to be any extraordinary or unusual water quality characteristic which would preclude construction or operation of a properly designed steam cycle facility. 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 a number of wastewater streams, most significantly cooling tower blowdown. "Standard" power plant water management technologies will be required to mitigate any adverse water quality impacts. Also, based on the sufficiently high bicarbonate levels and alkaline pH values, appears these natural waters to have sufficient assimilative capacity to mitigate effects from potential acid rain events.

HYDROLOGIC IMPACTS

Impacts to the hydrological regime of ground and surface water resources can result from the physical placement of the power plant and its associated facilities, and from the specific location and operation of a generating plant's intake and discharge structures. The siting of the power plant may

TABLE A.4. Water Quality Data for Selected Alaskan Rivers[a]

River/Location	U.S.G.S. Station No.	flow cfs	silica mg/l	iron mg/l	manganese mg/l	calcium mg/l	magnesium mg/l	sodium mg/l	potassium mg/l
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 A.4. (Contd)

River/Location	U.S.G.S. Station No.	flow cfs	silica mg/1	iron mg/1	manganese mg/1	calcium mg/1	magnesium mg/1	sodium mg/1	potassium mg/1
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

necessitate the elimination or diversion of surface water bodies and will modify the areas's 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. If, after siting, localized impacts remain a concern, various 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 power plant's 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 facility siting and structure orientation. Discharge of power plant wastewaters may create localized disturbances in the flow regime and velocity characteristics of the receiving water body. This potential problem is 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. Hydrologic impacts due to reduced streamflow should therefore not be significant.

APPENDIX B

AIR EMISSIONS FROM FUEL COMBUSTION TECHNOLOGIES[a]

Air pollution is the presence of contaminants such as undesirable gases or particles in the outside (ambient) atmosphere in quantities and of sufficient 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, combined cycle plants, and diesel generators are potentially major sources of energy-induced air pollution because they discharge potentially polluting products of combustion into the atmosphere.

The discussion addresses the general nature of air pollution arising from fuel combustion, the broad regulatory framework that has been implemented to control air pollution, and the regulatory considerations which apply to the Railbelt region. The appendix also compares the emissions of the different fuel combustion technologies used in electric power generation, and finally, discusses the general nature of siting requirements which affect the construction of combustion-fired generating facilities in the Railbelt region.

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.

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. Man-made particulate matter includes smoke, metal fumes, soil-generated dust, cement

(a) Technologies fueled by coal, petroleum distillates and residuals, synthetic and natural gases and biomass.

dust, and grain dust. On the basis of data collected by the U.S. Environmental Protection Agency (EPA), total suspended particulate matter (TSP) 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 non-combustible minerals. Particulate matter would be emitted in large quantities from fuel combustion plants which use solid fuels (coal, peat, wood, municipal waste) or residual oil, if high-efficiency control equipment were not used. Particulates are removed from flue gas by use of electrostatic precipitators or fabric filters (baghouses). They are routinely required, however, and collection efficiencies can be very high (in excess of 99%).

Sulfur Dioxide

Sulfur dioxide (SO_2) is a gaseous air pollutant which 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, while pipeline natural gas, wood, and most municipal wastes contain relatively little sulfur. Sulfur dioxide, like particulate matter, has been identified as being harmful to human health, and it appears to be particularly serious when combined with high concentrations of particulate matter. It is damaging to many plant species, including several food crops such as beans.

Nitrogen Oxides

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

Pollution control technology for nitrogen oxides has developed more slowly than for most other air pollutants. Lack of chemical reactivity 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. CO emissions are regulated under the Clean Air Act because of their toxic effect on humans and animals.

Unburned Hydrocarbons

TO BE SUPPLIED

Water Vapor

Plumes of condensed water vapor will emanate from a wet cooling tower as its exhaust is cooled below its saturation point. The plume will persist downwind of the tower until the water vapor is diluted to a level below saturation. In cold or cool, moist climates the plumes are particularly long because the ambient air can hold little added moisture. Formation of these plumes is particularly hazardous during "fogging" conditions when a high wind speed causes the plume to travel along the ground. During freezing conditions, such plumes may lead to ice formation on nearby roads and structures. Plume generation, fogging, and icing can be controlled or virtually eliminated through the use of 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 can be anticipated if municipal wastes or some biomass fuels are to be used. Generally noise and odors are not as great a concern as the air pollutants contained in exhaust gasses.

Acid Precipitation

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

On initial assessment, it appears that Alaskan lakes are not so sensitive to acid rain as lakes in eastern Canada and the northeastern United States. Furthermore, the total emissions into the Alaska environment are much less than emissions from industrialized areas of the midwest and northeastern United States (Galloway and Cowling 1978). It is unlikely that acid rainfall will ever present problems in Alaska similar to those in the eastern portion of the continent. There is currently no basis for assessing the impacts of acid rainfall which might develop because of increased fuel combustion in Alaska. In the development of any of these technologies, however, the planning agencies must be aware that a significant researach effort is being mounted against acid rainfall and that a regulatory framework may be developed within the next 2 to 10 years to analyze and mitigate the impacts of acid rainfall.

COMPARISON OF PROJECTED EMISSIONS

The critical comparison of fuel combustion technologies for their impacts on air quality is determined by the anticipated rate of emissions of each of the pollutants. Emission levels for the various technologies are presented for sulfur dioxide in Table B.1, for particulates in Table B.2, and for nitrogen oxides in Table B.3. Data are taken from EPA publications or the

TABLE B.1. Sulfur Dioxide Emissions for Various Technologies

Technology	Emission Rate ($lb/10^6$ Btu)	Annual Emissions at 75% Load Factor (Tons/Yr) Facility Size (MWe) 20	50	200	400	600
Steam Electric						
Coal[a]	0.10	67	169	674	1348	2022
Oil[b]	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[c]	--	--	--	--	--	--

(a) 70% scrubbing of 0.18% S Coal.
(b) New Source Performance Standard.
(c) Negligible.

enforced New Source Performance Standards. Emissions from wood-fired boilers, though officially published, are felt to be estimated somewhat high, especially for sulfur dioxide.

The development of these tables are based on various assumptions. A 33% efficiency of conversion is assumed for steam electric plants, and a 25% efficiency for combustion turbines. For the power plant sizes provided in the tables, emissions are directly proportional to the heat rate input for a given technology. The following heat input factors were assumed: for coal 10,000 Btu/lb; for oil 20,000 Btu/lb, for wood 5,000 Btu/lb; and for natural gas 1,000 Btu/standard cubic foot.

REGULATORY FRAMEWORK

In 1970, the federal Clean Air Act established the national strategy in air pollution control. The Act established New Source Performance Standards

TABLE B.2. Particulate Matter Emissions for Various Technologies

Technology	Emission Rate ($lb/10^6$ Btu)	Annual Emissions at 75% Load Factor (Tons/Yr) Facility Size (MWe) 20	50	200	400	600
Steam Electric						
Coal[a]	0.03	20	49	197	394	591
Oil[a]	0.03	20	49	197	394	591
Gas[b]	0.01	7	16	66	131	197
Wood[c]	0.02	131	329	--	--	--
Combustion Turbine						
Oil	0.05	46	125	--	--	--
Gas[d]	--	--	--	--	--	--

(a) New Source Performance Standard
(b) Typical.
(c) Assumes mechanical collection. Using electrostatic precipitators or baghouse, emissions may be reduced by 90%.
(d) Negligible.

(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 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 is capable of burning any amount of coal, or if such use is planned, is

(a) "The term standard of performance means a standard for emissions of air pollutants which reflect the degree of emissions limitation achievalbe through the application of the best system of emission reduction. . ." (Pub. L. 91-604, HR 17255, Dec. 31, 1970).

TABLE B.3. Nitrogen Oxides Emissions for Various Technologies

Technology	Emission Rate ($lb/10^6$ Btu)	Annual Emissions at 75% Load Factor (Tons/Yr) Facility Size (MWe) 20	50	200	400	600
Steam Electric						
Coal[a]	0.6	394	986	3942	7884	11826
Oil[a]	0.3	197	493	1971	3942	5913
Gas[a]	0.2	131	329	1314	2628	3942
Wood[b]	1.0	657	1643	--	--	--
Combustion Turbine						
Oil	0.59	530	1272	--	--	--
Gas[c]	--	--	--	--	--	--

(a) New Source Performance Standard
(b) Probably significantly overstated.
(c) Comparable to oil.

subject to the coal-fired power plant standards. Standards of allowable emissions for each fuel combustion technology for each major pollutant for a range of sizes for power plants are presented in Tables B.1 through B.3. The standards are being enforced for both newly constructed and significantly retrofitted 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 (SO_2 and TSP) throughout the United States. Pristine areas of national significance, (Class I areas), were set aside with very small increments in allowable deterioration. The remainder of the country was allowed a greater level of deterioration. 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 programs through the development of a state implementation plan acceptable to the EPA. See Table B.4 for National Ambient Air Quality Standards and allowable PSD increments.

The PSD program is currently administered by the U.S. 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 sulfur dioxide and suspended particulates) 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 on-site monitoring of air quality and meteorological conditions prior to the issuance of a permit to construct. 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 the construction of 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 the development of nearby facilities.

A potentially important aspect of the PSD program to development of electric power generation in the Railbelt region is that Denali National Park (Mt. McKinley National Park prior to passage of the 1980 Alaska Lands Act) is Class I, and it lies close to Alaska's only operating coal mine and the

TABLE B.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-h[a]	24-h[a]	Annual	3-h	24-h	Annual	30-h	24-h	Annual
Total Suspended Particulate Matter ($\mu g/m^3$)	None 260	150[b] 75	60[b] 3[c]	None	37	19	None	10	5
Sulfur Dioxide ($\mu g/m^3$)	1300[b]	365[d]	80[d]	512	91	20	25	5	2
Nitrogen Dioxide ($\mu g/m^3$)	None	None	100[d]	N/A	N/A	N/A	N/A	N/A	N/A
Carbon Monoxide[e] (mg/m^3)			None	N/A	N/A	N/A	N/A	N/A	N/A

N/A - Not applicable (no standards have been issued).
(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-h period per year is 10 mg/m^3.

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 man-made air pollution. The impact of visibility requirements on Class I areas are not yet fully known.

SITING STRATEGY

Based on information on emissions and regulations, several general conclusions can be drawn that bear on the siting 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 at least 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 non-attainment areas surrounding Anchorage and Fairbanks. In addition, the major fuel burning facilities should be located away from large hills and outside of narrow valleys or other topographically enclosed areas. Facilities should be developed in open, well-ventilated sites 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 Glenallen areas, near the available coal fields. Since Alaska coal is generally low in sulfur content, the siting constraints will be less stringent than those normally encountered in the eastern United States. 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 C

AQUATIC ECOLOGY IMPACTS ASSOCIATED WITH STEAM CYCLE POWER PLANTS

The construction and operation of steam-electric plants have three potential areas of impacts on aquatic ecosystems: water quality effects from construction stormwater runoff, water withdrawal for power plant use, and process water discharge. The degree of each potential impact will depend on the size, location, and operating characteristics of the plant. Unless a specific cycle is identified, the 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. For inland waters where steam cycle facilities could potentially be sited, including the Susitna, Copper, and Tanana Rivers, the main effect of this siltation could be the destruction of these productive aquatic ecosystems. Spawning areas could be eliminated by inundating gravel with fine sediment particles that smother eggs or inhibit fry emergence (especially for salmonids); benthic organisms could be smothered and light penetration reduced, thereby inhibiting the growth of aquatic plants. Salmon, trout, char, grayling, burbot, sheefish, and whitefish species, which are common in many of the major rivers of the Railbelt region (ADFG 1978), could be affected.

Runoff into the marine environment, especially where existing suspended sediment levels are typically low like outer Cook Inlet or Prince William Sound, could also smother benthic organisms and reduce light penetration. Organisms potentially affected include scallops, clams, crabs, shrimp, trout, char, salmon, herring, smelt, halibut, and other bottom fish (ADFG 1978). Silt laden runoff, if severe, may also clog or damage the gills of these organisms. Organisms such as razor clams, which live in the intertidal area, may be the most susceptible to being smothered. Populations of important food chain organisms like zooplankton and zoobenthos may be reduced because of decreased algae production resulting from reduced light penetration.

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

Intake structures, by virtue of their function, have the potential to impinge or entrain aquatic organisms. Entrainment is the incorporation of small organisms, like plankton, fish eggs, larvae, and small fish, into the plant's water supply flow. Entrainment in once-through cooling water systems can often result in acute and chronic effects to organisms through thermal shock, pressure change, mechanical damage, or chemical additions. Organisms entrained in closed cycle cooling systems would have a greater chance of mortality because of continued cycling within the system. Impingement refers to the interception, often injurious, of larger organisms, especially juvenile fish by intake screens. Impingement can cause injury or death from abrasion, increased predation, or exhaustion of the organisms.

The sport and commercially important fish of inland waters could be adversely affected by impingement and entrainment. Larval forms are particulary susceptible to entrainment while juvenile salmon are susceptible to impingement. Important marine species with larval forms that could be damaged by entrainment or impingement include crab, shrimp, clams, scallops and many marine fish.

Entrainment and impingement effects are dependent on type and location of the intake and the rate of water withdrawal. The use of adequately designed screening equipment and proper velocity characteristics at the intake structure will help minimize impacts by reducing numbers of organisms impinged or entrained. The proper location of intakes away from known migratory routes of important species will also help reduce these impacts. The use of subsurface intakes, like Ranney wells, at sites not prone to permafrost, should eliminate impingement and entrainment of freshwater or marine organisms. Other factors being equal, the plant that requires the most water will have the greatest impact (see Table A.1, Appendix A for comparison).

WATER WITHDRAWAL

Withdrawal of water in significant amounts from inland streams can alter flow patterns and reduce aquatic habitat downstream. This may be partially offset by the amount of water discharged, if both the intake and discharge are on the same body of water. The loss of habitat is highly dependent on the size, type, and location of the steam plant. Considering the most probable locations (Appendix A) for the types and sizes of plant considered for the Railbelt region, the effects on habitat loss would probably not be very significant (worst case is 10% of minimum flow estimates; see Tables A.1 and A.3, Appendix A). If other areas in the Railbelt region are chosen as plant sites, the impacts of withdrawals could be more severe. If all other factors are equal, the plant that uses the most water will most contribute to habitat loss.

WATER DISCHARGE

Attraction of organisms to thermal discharges may interfere with normal migration patterns. A particular concern in Alaska would be a situation in which marine organisms are attracted and become acclimated to a heated discharge from a once-through cooling water system which is then interrupted or stopped; the almost instantaneous temperature change back to ambient levels can result in thermal shock and subsequent mortalities to these organisms. In Cook Inlet or Prince William Sound migrating or feeding salmon, herring, crabs, shrimp and other important marine organisms could be affected (ADFG 1978). In inland waters this problem would not be as significant because of the use of recirculating cooling water systems, which would eliminate or greatly reduce any heated water discharge. Proper plant siting and cooling system design could reduce or eliminate thermal impacts. With other factors constant, the plant that utilizes the most water would have the greatest impact.

The chemical composition of the intake water is altered during its passage through the steam plant. The changes in the composition are generally dependent on the specific steam cycle and its capacity (see Appendix A), but general alterations include: 1) chemicals, such as chlorine, are added to control biological fouling and deposition of materials on cooling system components; 2) constituents of the intake water are concentrated during recirculation through evaporative cooling systems; and 3) corrosion products from structural components of the cooling system are present. Other potential pollutants from steam cycles include: low pH, high metal concentrations, biochemical oxygen demand, radionuclides, and petroleum products. When discharged in sufficient quantity, these can cause immediate impacts such as death of organisms or long-term changes in the aquatic ecosystem. Of particular concern would be the effects on the commercial and recreationally important fish and shellfish species that reside in both the fresh and marine systems of the Railbelt region.

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

The discharge water is often treated to remove many of those potentially hazardous compounds before discharge (e.g., dechlorination can be accomplished with SO_2 gas). Also, proper diffuser location and a large receiving water system like the Copper or Susitna Rivers can help mitigate negative effects. If the area is highly sensitive, a "zero discharge" system can be designed.

Acid rain, resulting from SO_x emissions (Appendix B), can cause significant changes in the pH level of a water body 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, and the sensitivity of the aquatic organisms to pH change. Acid rain would have no effect on the marine environment because of its buffering capacity. Most freshwater systems in the Railbelt region are also well buffered (see Table A.4, Appendix A), and significant impacts would not be expected. Generally, coal-fired plants would have the greatest potential for contributing to acid rain, and natural gas the lowest for similar sized plants. Emissions of this type can be reduced by proper plant design (e.g., appropriate flue gas desulfurization techniques).

APPENDIX D

IMPACTS OF STEAM CYCLE POWER PLANTS ON TERRESTRIAL ECOLOGY

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 D.1.

TABLE D.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
Giomass-Fired	5 to 60	10 to 50	0.8-2.0
Natural Gas-Fired	10[a]	3	0.3
Distillate-Fired	10[a]	4	0.4
Nuclear	800 to 1,200	100 to 150	0.1
Geothermal	10	5 (excluding wells)	0.5

(a) The Fuel Use Act limits the maximum electrical generating capacity to approximately 10 MW.

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 D.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 for financial reasons.

AIR EMISSION EFFECTS

The release of toxic chemicals into the air can negatively affect vegetation and subsequently wildlife. Sulfur and nitrogen oxides 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 sulfur and nitrogen oxides 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: 1) decreased aerial growth; 2) direct injury to foliage of coniferous and

TABLE D.2. Possible Watersheds Associated with the Development of Steam Cycle Power Plants in the Railbelt Region and Prominent Wildlife Found at these Locations (Wildlife Information was Taken from Alaska Regional Profiles 1974)

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									
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.

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 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, particulates 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 particulates ($<1 \mu m$) are difficult to control. Small particulates can cause greater impacts on soils, plants, and wildlife than larger particulates because they contain a greater fraction of potentially toxic trace elements (e.g., mercury, selenium, arsenic, bromine, chlorine, and others) in a state more readily available for chemical interaction (Dvorak 1978).

Trace elements would primarily enter the soil through direct deposition, plant litter decomposition, and the washing of particulates 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.

Particulates 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 particulates, which can interfere with the diffusion of CO_2, O_2, and water vapor between the leaf air spaces and air. In addition, particulates 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 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 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 steam cycle plant types, human disturbance impacts are probably greatest with geothermal plants, since these are more likely to be sited in isolated locations near their fuel sources. In addition to human disturbance impacts, 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 byproduct of human intrusion; however, the severity of this disturbance is uncertain. Potential impacts from noise could be related to hearing loss and stress in animals. Noise could 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 impacts 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 associated with 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 significance of this impact. Bird collision impacts, 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 E

SOCIOECONOMIC IMPACTS ASSOCIATED WITH ENERGY DEVELOPMENT IN THE RAILBELT REGION

Two types of decisions made during the overall Railbelt energy development process will result in community and regional impacts. The decision to site a facility at a particular location will affect the people living in that area. 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 workforce, and the duration of the construction period. The bust occurs with the out-migration of a large construction workforce, 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 workforce to community size. These two measures are provided for each technology in the attribute matrix.

The secondary effect of power plant construction is impact on the growth of the local and regional economies. The increase in number of permanent residents will usually cause the introduction of new businesses and jobs to the community. This may be perceived as either a positive or negative effect, 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; this 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 workforce, 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 1980). The population of boroughs and census areas within the Railbelt is presented in Table E.1. Anchorage (Figure 1.1) 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,

TABLE E.1. Population of the Railbelt (1980) Incorporated Areas

	1980	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. 1980 Census of Population and Housing Preliminary Reports.

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 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, has 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 well as 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 are 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 workforce, and their dependants are summarized according to population size of communities in Table E.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 workforce. 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 sizeable Fairbanks 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

TABLE E.2. Magnitude of Impacts from Powerplant 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	.01 or less
Moderate	.02 - .10
Significant	.11 - .39
Severe	.40 or greater

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 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 specialized in heavy construction are located (Alaska Department of Labor 1989).

Rapid growth due to power plant construction will be most dramatic in the interior Railbelt 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 which 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 a homogenous economic base. The size of the operating and maintenance workforce, although usually substantially smaller than the construction workforce, is another factor contributing to the permanent population.

REGIONAL IMPACTS

The Railbelt region should not be affected by the boom/but cycle in population since power plant siting is location-specific. 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 which capture all costs associated with power plant construction. The assumptions made regarding the flow of capital for each category are presented in Table E.3. The proportion of expenditures allocated to the site improvement, equipment, and labor catagories will vary with each technology and is presented in the detailed description of the individual technology.

TABLE E.3. Flow of Expenditures Sent Outside and to the Railbelt

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, would be purchased within the Railbelt, as well as tools, light machinery, and supplies. Cement and rebar would be purchased outside of Alaska; these are estimated to average approximately 15% of site improvement expenditures. Construction supervisory and engineering personnel are normally provided by the project developers while skilled labor may be provided fully from the local workforce. For estimation purposes, it was assumed that 20% of the workforce would be derived from outside Alaska, while 80% would be Alaska residents. In compliance with Alaska State labor laws, 60% of the labor force must be Alaska residents, if 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.

APPENDIX F

WASTE HEAT REJECTION SYSTEMS IN STEAM CYCLE PLANTS

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 from 0.01 to 0.1 cfs/MW. Appendix A presents more detailed 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). Figure F.1 presents a schematic diagram of the typical features of a condenser cooling water system.

ONCE-THROUGH SYSTEM

A once-through system is one in which the total water requirement for the condenser is pumped from the supply source through the condenser on a single pass basis 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 power plant sites located within the coastal region. The water resources of Cook Inlet and Prince William Sound are prime candidates for this technology, if not precluded by environmental or regulatory constraints.

RECIRCULATING SYSTEMS

In a recirculating cooling water system, an additional heat sink is used to lower the spent condenser cooling water's elevated temperatures to permit the reuse of the condenser cooling water. Recirculation can be accomplished with various heat dissipation systems which transfer the absorbed heat to the atmosphere primarily by evaporation. The heat dissipation systems usually

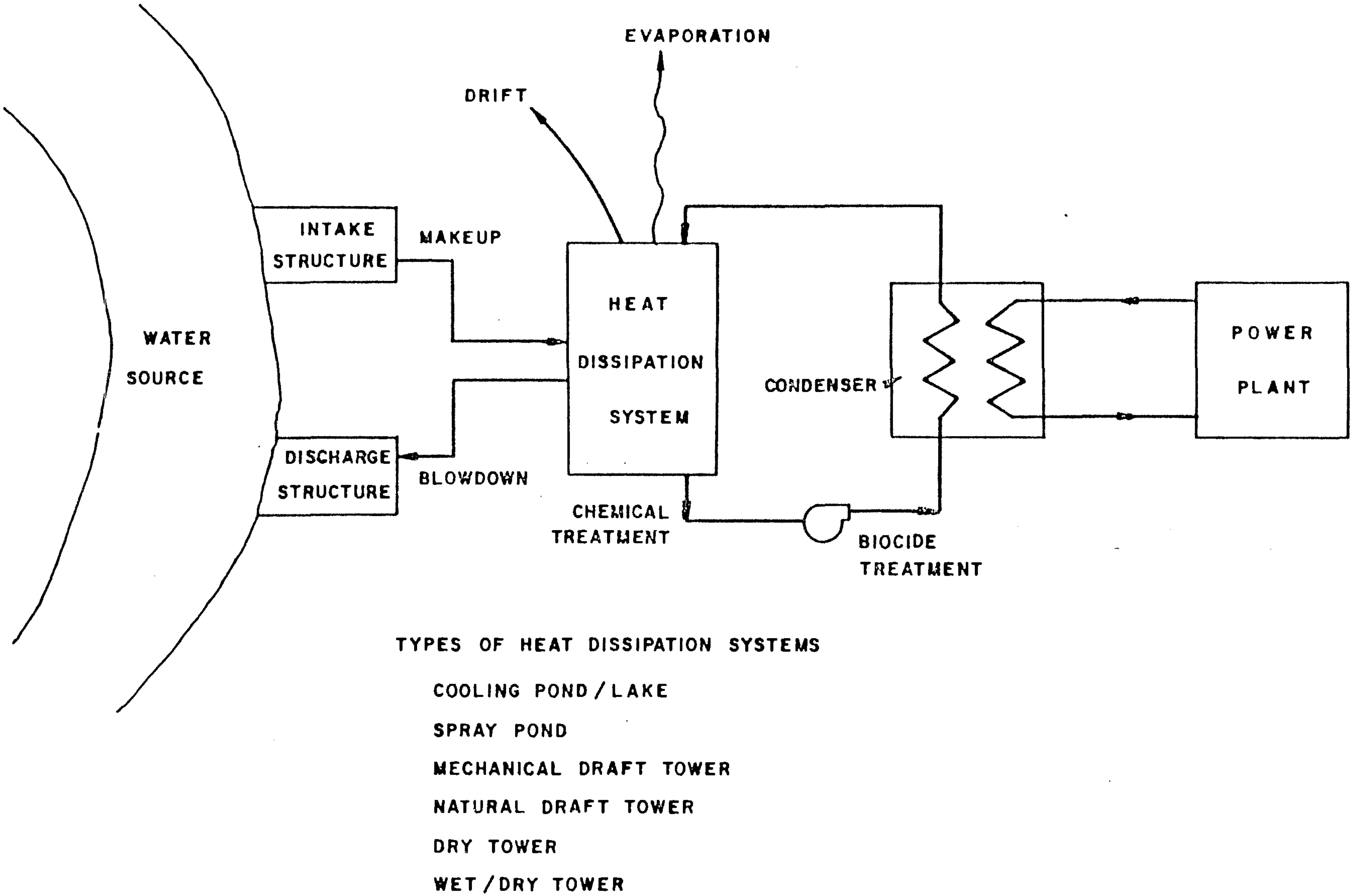

FIGURE F.1. Typical Condenser Cooling Water System considered for a recirculating cooling water system include cooling ponds/lakes, spray ponds, and wet cooling towers (natural draft and mechanical draft), dry cooling towers and wet/dry cooling towers.

Cooling Ponds and Lakes

A cooling pond operates in a manner similar to once-through cooling, except the body of water used is largely isolated from natural waters. Heat is transferred from the heated water in the cooling pond by radiation, conduction and evaporation prior to the water being recirculated from the pond to the condenser inlet. Area requirements for dissipation of waste heat from a cooling lake or pond are on the order of 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 also required to eliminate the effects of fog to off-site roads, buildings, etc. 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 Railbelt's cold weather will cause these localized icing conditions and thus will severely limit the development of cooling ponds. Even at Anchorage over half the days during the year will have temperatures at or below freezing.

The cooling pond is a proven, effective and economical heat sink in areas where suficient level land can be purchased at reasonable cost. The rugged topography of much of the Railbelt presents an obstacle to development of cooling ponds because abundant, inexpensive level land is not readily available.

Spray Ponds and Spray Canals

Land requirements of cooling lakes can be reduced, by a factor of up to 20, by use of sprays. As with cooling ponds, however, a buffer zone of about 1,000 to 1,500 ft 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. However, spray ponds are similar to cooling ponds in that their cooling effectiveness depends upon local temperature, relative humidity and wind conditions.

In order 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 will be derived based upon comparative cooling efficiency and cost.

Cooling Towers

There are two basic types of cooling towers: the wet tower that carries away heat by evaporation and sensible heat transfer, and the dry tower that relies on air to carry away heat and, in principle, functions like an automobile radiator.

Wet Cooling Towers:

The two types of wet cooling towers, mechanical and natural draft towers, differ in the method of inducing air flow from the heated water to the ambient air.

When operated in the closed cycle mode, wet cooling towers require makeup water to compensate for losses sustained through evaporation and drift (the carryover of small water droplets by air). As evaporation occurs, the natural salts in the cooling water become concentrated; to prevent buildup and deposition on the components of the system, they are continuously returned to the source of cooling water supply as blowdown or recycled to other water users within the plant.

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.

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 Btu to the atmosphere.

Natural Draft Cooling Towers. A wet natural draft cooling tower consists of the familiar large reinforced concrete chimney (Figure F.2) which 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 ft. 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 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 compared to 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

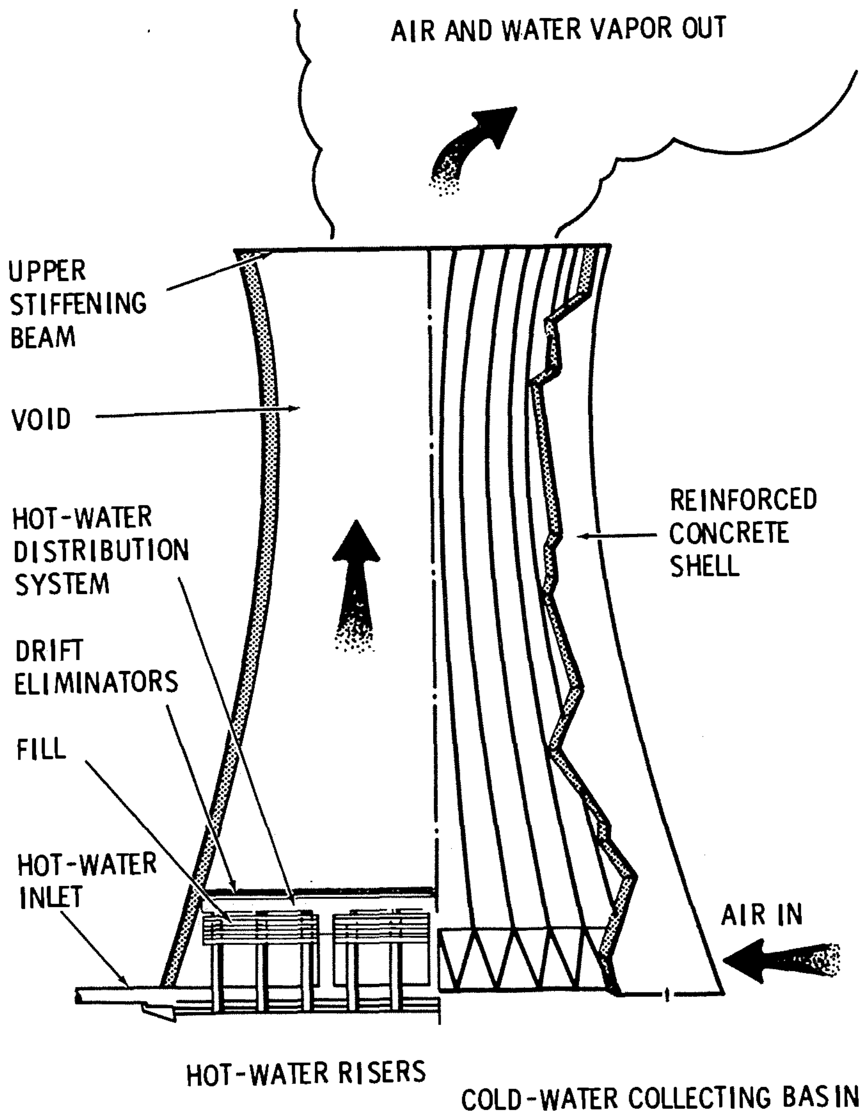

FIGURE F.2. Natural Draft Cooling Towers

an 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.

In a relatively new design, a fan-assisted natural draft cooling tower, fans assist the natural airflow to increase 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.

Mechanical Draft Cooling Towers. Mechanical draft cooling towers and natural draft cooling towers operate on the same basic thermodynamic principle--that is, cooling takes place by evaporation and sensible heat transfer. In mechanical draft towers, fans are used to pull air through the fill section. Mechanical draft towers are of modular construction. Figure F.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 of the structure due to its lower profile. However, 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 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 these mechanical draft units places a severe restriction on their use in cold environments, which includes the entire Railbelt region. The effects of ice fog formation and icing can be mitigated by purchasing large amounts of land surrounding the cooling towers or by siting them in non-sensitive areas.

Dry Cooling Towers

Dry cooling towers remove heat from a circulating fluid through conduction to the air being circulated past the heat exchanger tubes. In contrast to wet towers there is no direct contact between the circulating

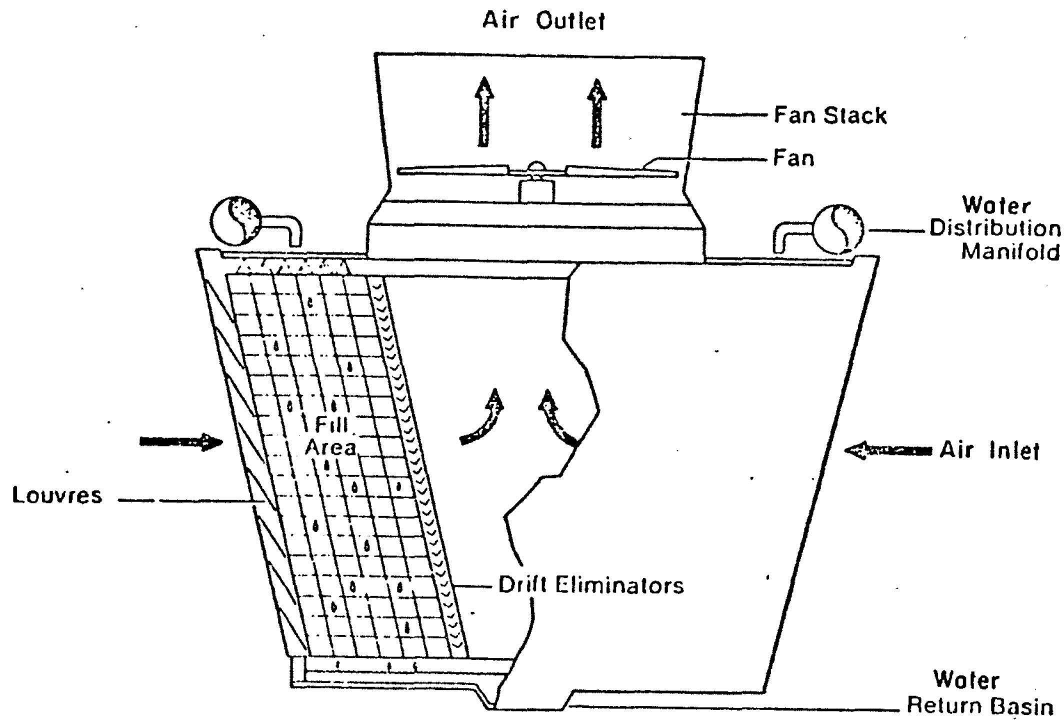

FIGURE F.3. Mechanical-Draft Wet Cooling Tower (Cross Flow)

cooling water and the ambient air. The heat exchanger tubes are generally finned to increase the heat-transfer area. The theoretically lowest temperature that a dry cooling system can 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 theoretically lowest temperature that a wet cooling tower 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. Turbine warmer condenser cooling water will increase turbine back pressures, resulting in reduced station capacity for a given size generating facility.

The advantage of a dry cooling tower system is its ability to function without large quantities of cooling water. Theoretically, this allows power plant siting with minimal consideration of water availability, and eliminates thermal/chemical pollution from blowdown. From an cost/benefit standpoint, dry cooling towers can permit optimum siting with respect to environmental, safety, and load distribution criteria without fogging or dependence on a supply of cooling water. Other advantages, compared to wet cooling towers, include elimination of drift, elimination of fogging and icing problems, and elimination of blowdown disposal. Thus, dry cooling towers present an environmental advantages 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 problems may be encountered. Noise generation problems for mechanical draft dry towers will be more severe than those of wet cooling towers because of increased air flow requirements. And, the aesthetic impact of natural-draft dry towers, which would be much taller than a wet natural draft 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 in the order of 20% more than a once-through system and 15% more than a wet cooling tower system. Dry cooling towers now being used for European and African steam cycle plants of 200 MW or smaller capactities in areas of cool climates and winter peak loads. The use of dry towers to meet cooling requirements of larger facilities with summer peak loads requires new turbine designs to achieve optimum efficiencies at the higher backpressures imposed by use of dry cooling systems.

Wet-Dry Mechanical Draft Cooling Towers

In this combination tower, a dry cooling section is added to 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 F.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 temperatures (e.g., 35^{o}F). Such are expected to operate as "wet only" units in summer. Thus, water would be conserved only in winter. The units would be operating efficiently throughout the year and aesthetic and environmental impacts would be reduced.

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. This combined wet-dry system can be of great advantage to plants in geographical locations where the incremental contribution of cooling tower moisture to the atmosphere could increase the occurrence of fog 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 alternative from an environmental point of view for the Railbelt.

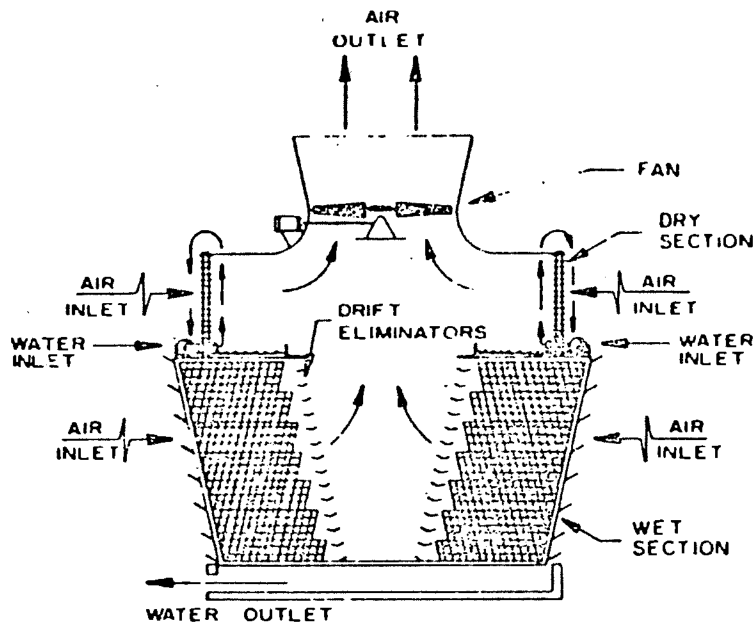

FIGURE F.4. Mechanical Draft Wet-Dry Cooling Tower

APPENDIX G

FUEL AVAILABILITY AND PRICES

Many of the technologies discussed in the report rely on fossil fuels (oil, gas, coal, peat) and renewable fuels such as municipal waste and biomass. The future availability and prices of these fuels is essential to assessing each technology from the standpoint of both supply and conservation.

Each of the various fuels now have different prices, even if reduced to dollars per/million Btu (MMBtu). Price differentials are expected to continue in the future, although the differentials between fuels may change markedly with time.

Each fuel must be addressed separately, with recognition of the Railbelt region's geographic differences and appreciation of the factors that determine prices. A set of preliminary reports on these issues is planned for completion in June 1981, with the expectation of minor modifications in subsequent months. This appendix summarizes preliminary findings.

NATURAL GAS

Natural gas is currently the predominant non-transportation 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 24 to 109¢/MMBtu for use in combustion turbines and from $1.55 to $2.46 per MMBtu for residential direct end-use. These prices are the lowest in the United States primarily as a result of long term contracts signed when there was an excess of natural gas and the producers, lacking a major market outlet, faced a "buyer's market."

This price situation is not expected to continue in the future. Under the most optimistic (from the consumer's point of view) conditions, rapid increases in natural gas prices may occur about 1990, although it is quite possible that gas prices will increase markedly in the mid-1980s.

Natural gas is not currently available in the Interior regions (Fairbanks, Ternana Valley). Should North Slope gas become available in the mid to late 1980s, its city gate cost (made up of well head price plus conditioning cost plus a share of transmission tarrifs) is expected to be far higher than in Cook Inlet--somewhere near $6.00/MMBtu. Depending on many variables, its cost may be competitive with liquid fuels.

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.

Petroleum products are generally sold under short-term contracts on a lot bid basis. Long term contracts are virtually nonexistent. Recent fuel oil prices in $/MMBtu are as follows:

	Anchorage	Fairbanks
Utility Combustion Turbine Fuel	6.99	6.22
Home Heating Oil (#2)	8.00	8.36

Unlike natural gas and coal, which are subject to either regulation or marketability constants, petroleum product prices are now directly related to the world price of crude oil with appropriate adjustments for locational transportation and refining costs.

We believe the price of petroleum products will increase in real terms (i.e., over and above inflation) at about 3% per year on the average, and a sound body of economic theory (that OPEC seems to be acting on or at least striving toward) seems to support this forecast. This forecast of an annual 3% increase assumes that the Persian Gulf or other major producing regions do not become involved in major political upheavals or war.

PROPANE AND BUTANE

If a petrochemical plant is constructed in Alaska based on natural gas liquids (ethane, propane, butane) extracted from North Slope natural gas, then large quantities of propane and butane would become available. These products, known as low-pressure or liquified petroleum gases (LPGs) or "bottle gas," are generally not shipped in large quantities except by pipeline or by rail and truck. Specially designed ships have recently been developed for international trade. Since the quantity of these products originating in Alaska would be large, shipment out of the state would be required and the price in Alaska will be rough by equivalent to the price paid in the final market (ca. California) less the cost of ocean shipment.

COAL

Sub-bituminous coal is a major resource in Alaska. It currently supports electrical power generation and some direct space heating in the Interior. The only current major coal mining activity is located near Healy, supplying the Fairbanks utilities as well as military installations. Coal reserves in that region appear ample for many decades to come. Coal from the Healy mine is currently priced at about $1.25/MMBtu.

Little coal appears to be used in the Cook Inlet region. However, research conducted at Battelle-Northwest suggests that there is an excellent chance for a "world scale" mining operation to develop in the next few years in the Beluga region, with the primary impetus being the rapidly growing coal market in East Asia. Such a large-scale development could make coal available at mine mouth at about $1.00/MMBtu for power generation in the Cook Inlet region. If an export mine at Beluga is not developed, then coal sufficient to support a mine-mouth generation plant could still be provided, but at a substantially higher cost. Coal from the Healy mine could be supplied to the Cook Inlet region via the Alaska Railroad. The cost of such a supply system will be estimated as part of the Railbelt Electric Power Alternatives Study.

Alternative sources of coal in the Railbelt exist in the Natanuska Valley (Evans Jones Mine now abandoned) and on the Kenai Peninsula. The Natanuska 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.

Future coal prices are not expected to escalate substanitally in real terms and will be established under long-term contracts probably with provisions for labor cost adjustments.

PEAT

Peat is an abundant resource in the Matanuska and Susitna Valleys, on the Kenai Peninsula and in the Fairbanks region. 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.

At the present time, no estimates of peat costs including harvesting and preparation have been developed for Alaska conditions.

WOOD

Wood is used extensively in the non-metropolitan areas of the Railbelt for space heating. It is also used as a reliable back-up fuel.

Wood costs are currently on the order of \$5.00 to \$6.40/MMBtu.

Wood is generally not regarded as a primary fuel for electric power generation unless substantial quantities of wood wastes are available from logging and sawmill operations. The main deterrent is the relatively high cost of harvesting and transporting a high bulk, low Btu content fuel.

MUNICIPAL WASTE

Municipal waste is a candidate for central station fuel in urban areas where collection already takes place and disposal occurs at relatively few landfill sites. The solid waste materials currently generated in Greater Anchorage have been estimated to contain sufficient energy to fuel a 20-MW power plant. However, the economics appear marginal relative to coal-fired plants. This will be further investigated.

SYNTHETIC FUELS

There is considerable interest in the development of synthetic fuels derived from low-cost and abundant reserves of coal and, to a lesser extent, peat. A number of processes are in the research and development stage and a few (e.g. low Btu gasification of coal) are nearing the commercial demonstration scale. These are capitally intensive projects and their economic success is primarily dependent on their ability to displace oil and natural gas at world prices and to achieve economies of scale in large installations. In order to reduce transportation costs, such plants are expected to be located at mine mouth or near the location of the basic resource.

Two firms, Placer Amex Inc. and Cook Inlet Region Inc., are studying the possibility of gasification of Beluga's low-Btu 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 gasificaton operation.

HYDROGEN

If surplus electrical generating capacity from underwater conventional hydroelectric or tidal systems is available, hydrogen could be produced by electrolysis of the surplus electrical energy that might otherwise be lost. New hydrogen could be stored and used at a later date in fuel cells to generate electrical energy.

Alternatively, hydrogen could be supplied as a gas in a manner similar to natural gas for direct end use. Due to the physical and chemical nature of hydrogen, it is unlikely that existing natural gas distribution systems or appliances could 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 there is little research and development activity aimed at commercial applications.

APPENDIX H

AESTHETIC CONSIDERATIONS

This appendix presents methodologies for assessing aesthetic considerations, specifically visual, noise, and odor impacts. The objective of these methodologies is to provide a comparison of the typical aesthetic impacts of the candidate electric energy technologies. The magnitude of aesthetic impacts from the candidate electrical generating technologies are assessed in this appendix.

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 man-made 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 of the landscape such as form, line, color, and texture of the landscape 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 should be developed to assess visual sensitivity and may include viewing distance, viewer location, and viewing frequency. The visual quality of each landscape unit should be evaluated with attention paid to areas that are vulnerable to any man-made changes.

The third phase involves identification of the elements of the project that cause impacts and their effect on viewers. The various attitudes and values of the individual viewers should be 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 through mapping the areas from which the power plant and associated project elements could be viewed, and evaluating these areas with respect to 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 should address 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 the introduction of a power plant into the landscape 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 H.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 H.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 man-made 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, it can be concluded that off-site impacts will be significant for coal-fired steam electric, geothermal, nuclear, pumped-storage, solar, large-scale hydroelectric and tidal, and wind farms (Table H.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, identifying potential sources of noise impacts, predicting of noise levels, and determining of 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 should be collected throughout one year in order to account for seasonal variation. In addition, data are collected throughout the day in order to determine day/night average sound levels. Isolines are drawn to indicate the decibel levels at various distances. Other data that should be collected from the survey include wind speed, temperature, and relative humidity, as these affect noise levels.

Potential sources of noise impacts from power plants should be identified, including pre-construction, 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 should be determined in a controlled environment without wind attenuation or topographical shieldings.

Noise impact criteria should be 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 on-site sources of noise to protect personnel. Off-site 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.

An increase in noise levels due to power plant construction and operation should be calculated at various receptor areas. The noise levels of the various power plant components should be evaluated for their cumulative impact. Mitigation measures should be identified as well as noise sources that are difficult to mitigate. Receptors and noise levels should then be 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 impacts. Noise related impacts generally associated with each of the various technologies are summarized in Table H.2. For those facilities in which noise could be a potential problem, it may be necessary to site the vents and turbines well away from residential or commercial areas in order to comply with ambient noise regulations. Consideration should be made 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 (U.S. Environmental Protection Agency 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.

TABLE H.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
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

TABLE H.2. (contd)

Technology	Visual	Noise	Odor
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 basin design.

Since an odorant may be a complex mixture of many components in extremely high dilution of air, a chemical analysis is not a sufficient measurement of odor. Noxious odors must be diluted in order 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 should 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 should be 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 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 needed to be rid of the odor may be considerably greater than is predicted by the calculations.

Since the dispersal of gas from a stack can be calculated theoretically, it should be possible to predict the maximum level of odor that can be emitted from a stack without causing a nuisance. If the actual rate is higher than the calculated value, then the dispersal should be increased (by raising the stack) or the concentration should be decreased (by an abatement device), or both.

Off-site 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 while the odor impacts of the other technologies should be minor.

APPENDIX I

COST ESTIMATING METHODOLOGY

The conceptual capital cost estimates and operating and maintenance 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 and then applying a location adjustment factor 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 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. In light of the fact that only a few of the technologies are presently represented in the Railbelt region, costs for facilities developed in the contiguous U.S. were utilized to maximize the use of the large available data base and to ensure cost comparability among technologies.

Location adjustment factors were developed based upon an analysis of considerations which contribute to higher Alaskan construction costs. Cost adjustment factors developed by the Department of the Army (1978) were also used. Factors which are the prime contributors to the higher construction costs in Alaska include remoteness, limited accessibility, short construction season, and severe climatic conditions. In the Railbelt region, for example, there is but 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 receive overtime pay for working a 60-hour week instead of the traditional 40 hours.

The Department of the Army has developed cost adjustment factors for numerous locations within the United States and many foreign countries. The data was developed from bid experience and is intended for use as a guideline in the preparation and review of conceptual cost estimates for budgetary purposes. Adjustment factors identified for specific Railbelt locations include:

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 and is assumed to have a factor of 1.00.

Based upon these considerations, location adjustment factors of 1.4 to 1.9 were utilized in this study to develop capital cost estimates while a factor of 1.5 was used for operating and maintenance cost estimates. Values at the upper end of the range were utilized 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 a consideration of the potential site locations of the technology in the Railbelt region.

While the costs generated through the use of these adjustment factors provide order of magnitude estimates suitable for a comparative decision making process, it should be realized that limitations exist when using only a single adjustment factor. For capital cost estimates associated with the construction of a power plant facility, there are actually three factors involved (equipment, material, and labor) and a different multiplier 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, operating and maintenance 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 catagories.

The development of adjustment factors associated with each of the above categories requires additional, more detailed study which is beyond the level associated with these technology profiles. The use of a single adjustment factor provides conceptual, order of magnitude cost estimates suitable for a comparative decision-making process.

APPENDIX J

SYNTHETIC FUEL TECHNOLOGIES

A number of the 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 liquid or gaseous 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 which synthesize liquid or gaseous hydrocarbon fuels from coal. These processes are considered within the scope of this study because of the availability of substantial coal resources in the Railbelt region (see Appendix G).

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 500-600 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 process types and products has been developed.

The principles employed are conceptually simple, and 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. In order to accomplish conversion of 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. While some of the coal conversion reactions are exothermic (heat releasing), most are endothermic (heat consuming). 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 (e.g., 150 Btu/ft^3), medium Btu gas (e.g., 350 Btu/ft^3), and high Btu gas or substitute natural gas (e.g., 900-1000 Btu/ft^3). Coal 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. Details of these processes are presented in subsequent paragraphs.

SITING REQUIREMENTS

Synthetic fuel plants are, for the most part, similar to large petrochemical complexes. Table J.1 gives scale factors for such plants by syn-fuel type. Due to the large scale of these plants, siting requirements are strongly dependent upon the economic availability of the coal resource.

Land requirements for typical synthetic fuels plants are measured in thousands of acres (not including the coal mine). The land must provide 30-90 days coal storage, land for the primary facility itself, land for ancillary facilities such as an on-site power plant and/or a cryogenic oxygen separation plant, and land for product storage. The Modderfontain site in South Africa (Sasol II), for example, exceeds 12,000 acres.

The site must have transportation facilities for moving coal to the facility if mine-mouth sites are not available, and for transporting the

TABLE J.1. Typical Sizes of Coal Conversion Facilities

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 106 SDCF
Substitute Natural Gas	20,000	250,000	250 x 106 SDCF
Synthetic Crude Oil	20,000-22,000	330,000	50,000 bbl
Methanol	28,000	2[illegible]0,000	11,000 tons
Synthetic Motor Fuels (Fischer-Tropsch)	35,000	250,000	42,000 bbl

Source: Sliepcevich et al. 1977.

product from the facility. The only exception to the latter requirement is low Btu gas, which must be used on-site due to the expense of transporting the low energy content gas.

The site must have access to copious quantities of water for process cooling and other requirements. Water serves as a source of hydrogen for altering the H/C ratio in the water gas shift reaction. Water also is the sink for waste heat generated by the exothermic reactions. Table J.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; however, they can be minimized by use of air-to-air heat rejection systems. However, water requirements of 4 million gal/day may be considered typical values, and sites must be selected with such quantities (or more) being available.

Electricity should be available, unless on-site generation is used as would probably be the case in the Railbelt area. Where on-site generation is used, land and water requirements will escalate accordingly.

TABLE J.2. Water Requirements for Coal Conversion Processes

End Product	Water Requirements (gal/10^6 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.

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.

Gasification

In low Btu gasification, coal is fed into a fixed bed, entrained bed, or fluidized bed reactor. There it is reacted with air and steam. The air is used to combust a portion of the coal, thus supplying heat for the endothermic pyrolysis and gasification reactions. Steam is used to drive key gasification reactions such as the steam-carbon, water-gas shift, and methane reformation reactions. The steam-carbon reaction converts solid carbon molecules to carbon monoxide, while also generating hydrogen gas. The water-gas shift increases the hydrogen concentration at the expense of carbon monoxide. Methane reformation converts methane (CH_4) to 1 CO and 3 H_2.

The gas resulting from this process contains about 50% nitrogen due to the use of air and has a heating value of approximately 150 Btu/SDCF. It is "wet" and "dirty", and must be burned immediately in a boiler to preserve the sensible heat of the gas.

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. Thus, nitrogen gas is not part of the product 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 on-site. While it may be burned as a fuel, it may also be used as a feedstock for the production of chemicals. Figure J.1 shows a schematic of a medium Btu gas plant. By way of comparison, low Btu gasifiers do not have the oxygen plant with its attendent energy expenditures. Table J.3 shows typical product gas composition for various gasifiers producing low and medium Btu gaseous fuels.

Thermal efficiencies for gasification can be defined as fuel value of product gas divided by total energy and fuel input (including electricity used for O_2 production). Typical values are in the 75-90% range depending upon gasifier design, product type, and extent of waste heat recapture.

<u>Liquefaction</u>

Indirect liquefaction begins with medium Btu gas, as shown in Table J.3 for O_2 blown gasifiers. 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 J.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 J.3.

The thermal efficiencies of indirect liquefaction are in the 40 to 45% range depending upon severity of treatment, final product, plant design, and the specifics of coal composition.

Direct (hydrogenation) liquefaction processes treat coal under elevated temperatures and pressures with hydrogen. Catalysis may or may not be employed to aid in fracturing the molecule and, more importantly, donating

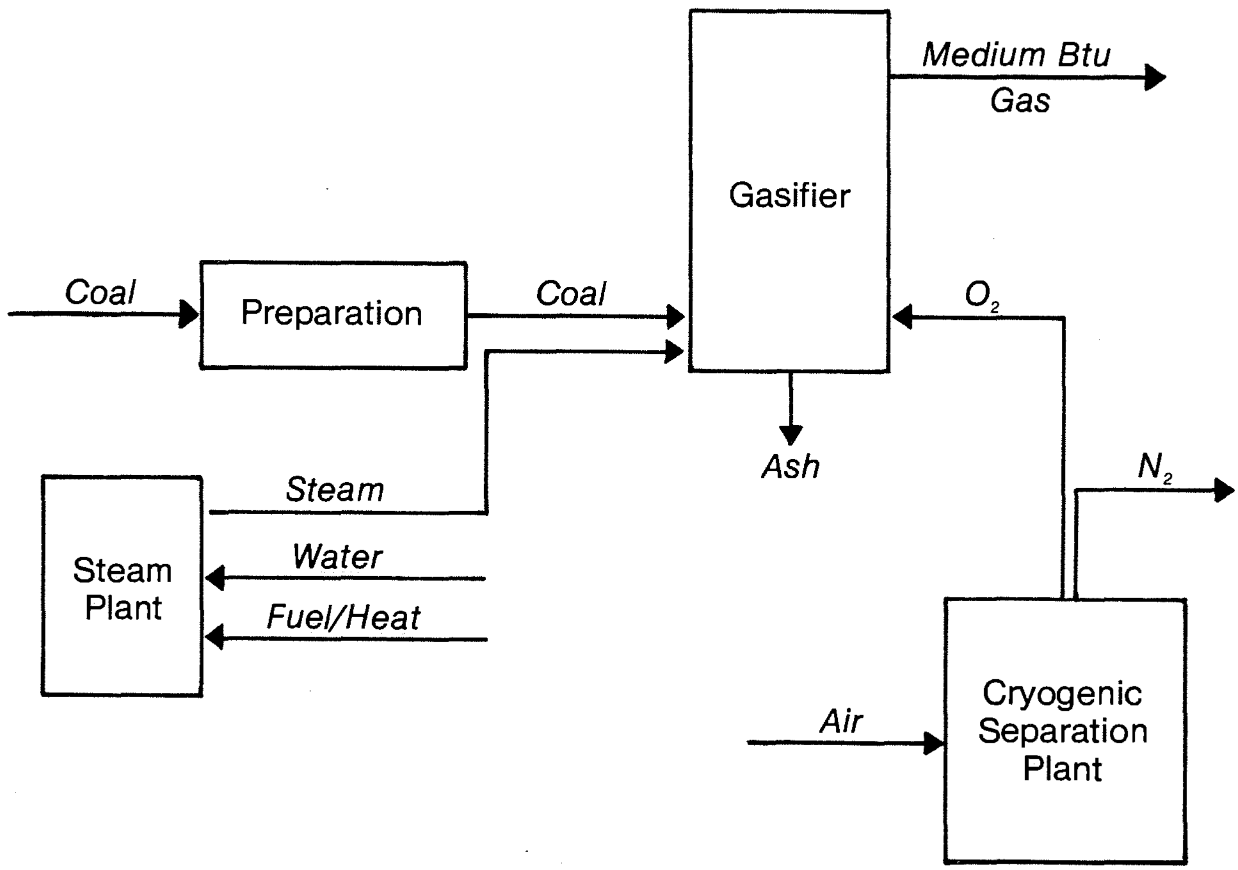

FIGURE J.1. Flowsheet of Medium Btu Gas Plant

hydrogen to the fragments. Figure J.4 shows direct hydrogenation by the solvent extraction process; Figure J.5 shows a flow sheet for catalytic hydrogenation.

Products resulting from direct hydrogenation include syn-crudes, boiler fuels, and naptha. Thermal efficiencies are typically in the 60-65% range.

Direct hydrogenation is at the pilot plant scale of development and commercialization is expected within the next 10-15 years.

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 South Africa and other countries, and from pilot plant experiences. Costs are, therefore, highly uncertain. Estimated capital costs are presented in

TABLE J.3. Gas Composition and Higher Heating Values from Various Coal Gasifiers

Gasifier	Composition (Percent Volume)						Higher Heating Value
	CO	CO_2	H_2	CH_4	N_2	Other	(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

Table J.4. 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 operation and maintenance costs are estimated at about $330 million (not including depreciation) for a 50,000 bbl/day refinery (Tillman 1981).

World oil prices would have to rise to $60/bbl ($10/10^6 Btu) for coal liquifaction preocesses to be economicly competitive at current estimates of capital and O&M costs of liquifaction plants (Tillman, 1981). This is about double the current world price of oil (Perry, 1980). Because of the higher thermal efficiencies and lower capital costs of coal gasification costs, coal gasification would be competitive at much lower prices. Values frequently quoted range from $5-6/$10^6$ Btu.

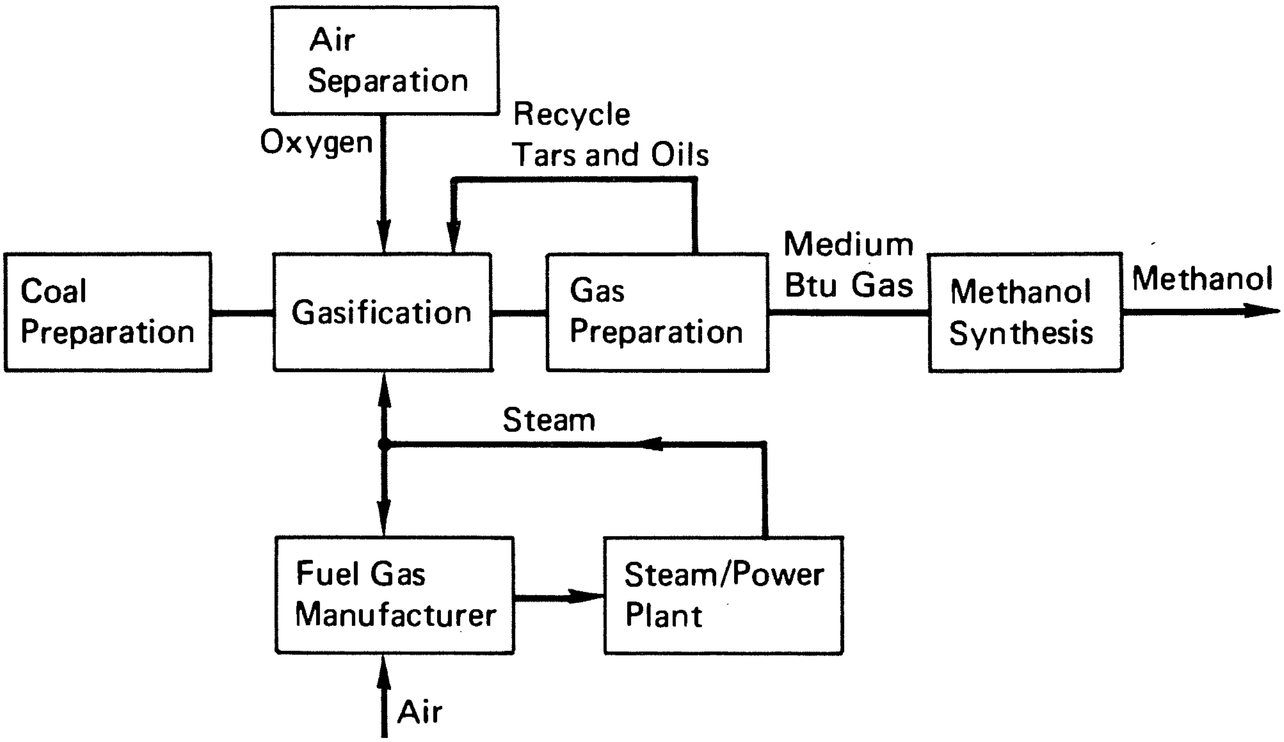

FIGURE J.2. Methanol Production Flowsheet

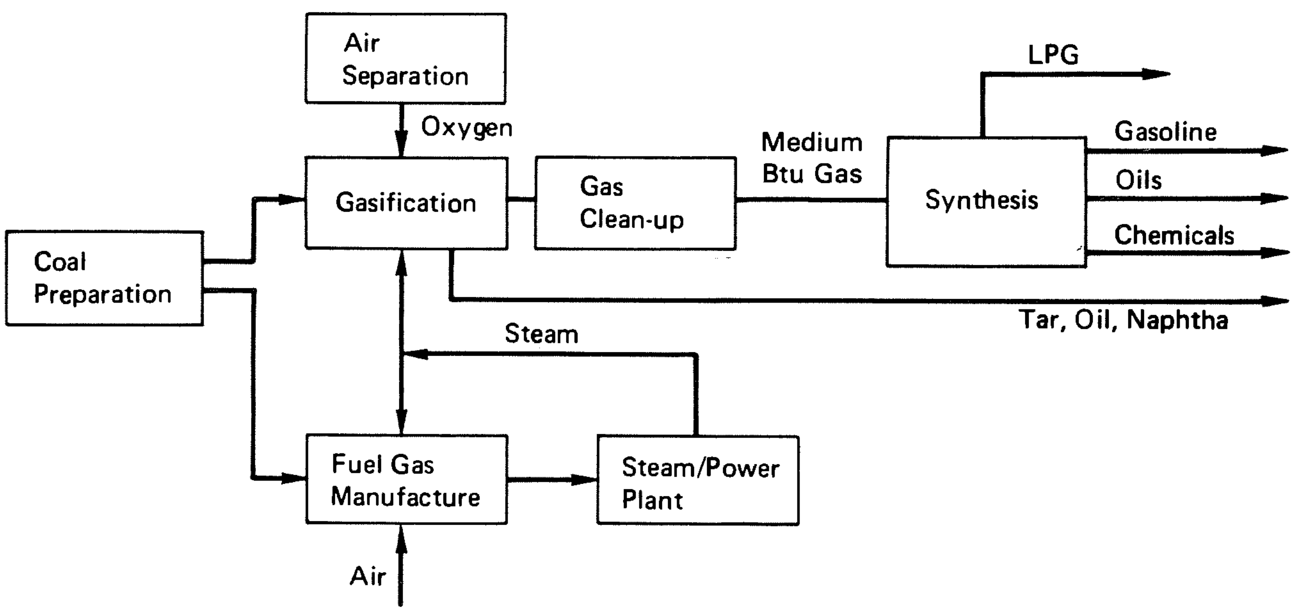

FIGURE J.3. Fischer-Tropsch Synthesis Flowsheet

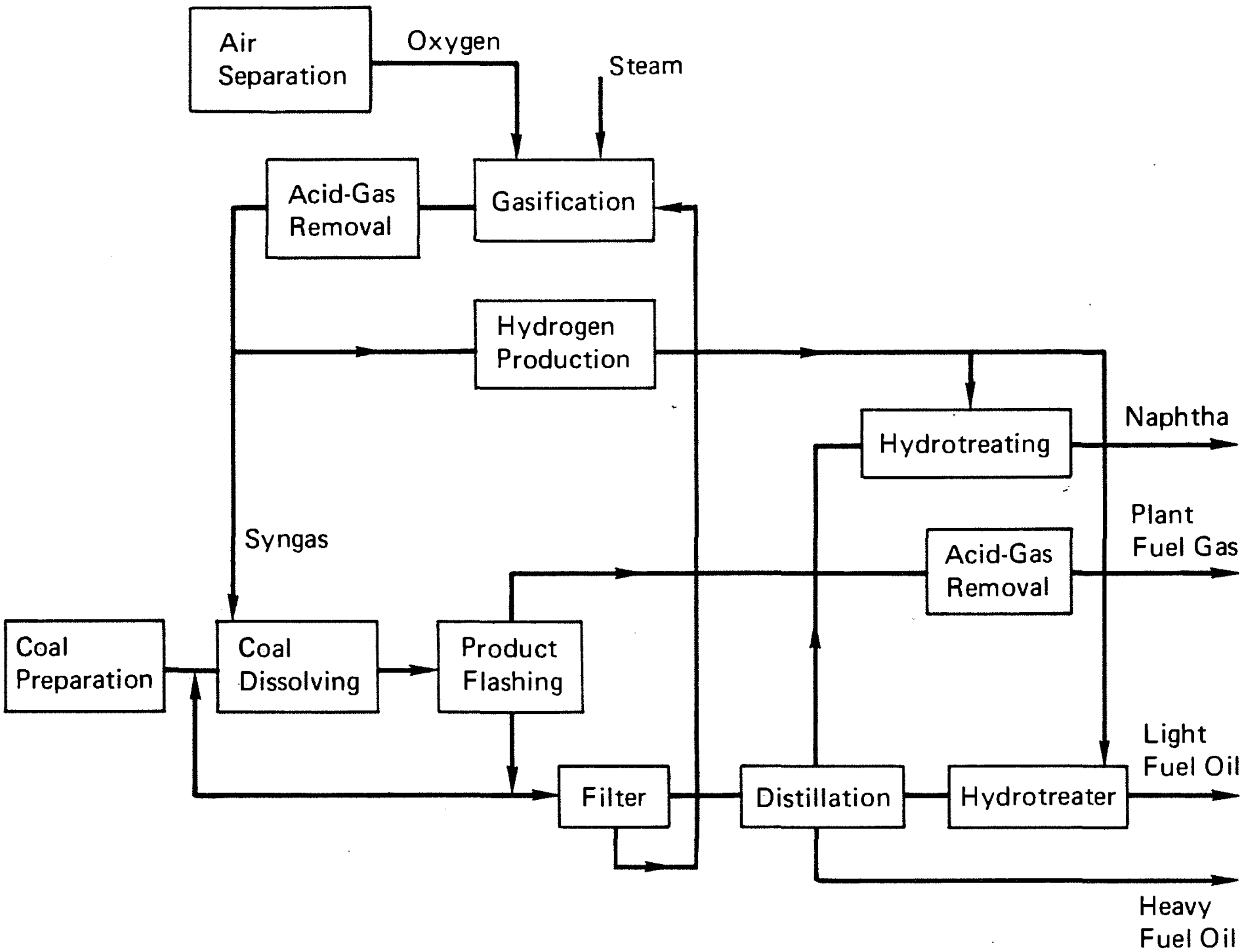

FIGURE J.4. Solvent Extraction Process Flowsheet

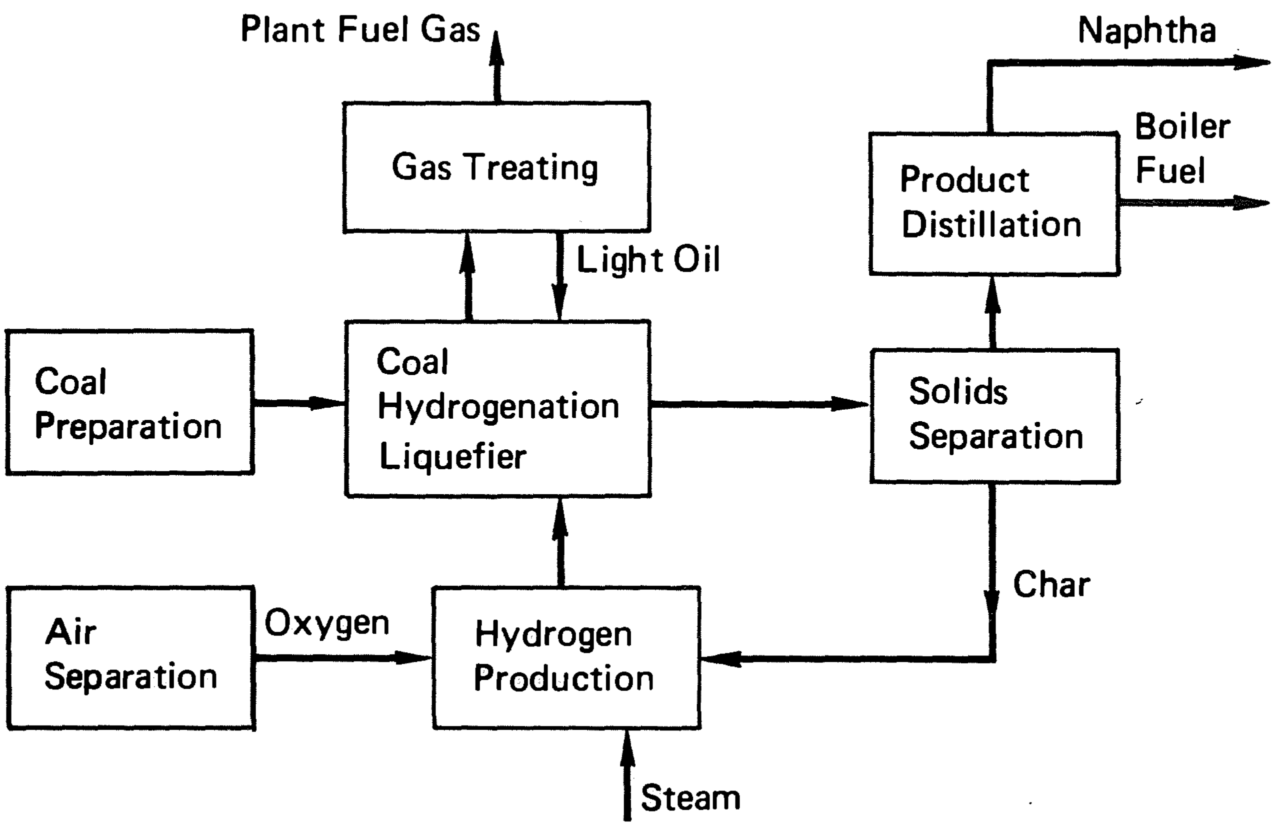

FIGURE J.5. Catalytic Hydrogenation Flowsheet

TABLE J.4. Capital Costs for Coal Conversion Facilities (1977 Dollars)

Process	Capital Cost
Low Btu Gas	$200/10^6 Btu Capacity
Medium Btu Gas	$350/10^6 Btu Capacity
Methanol	$23,000-$30,000/Bbl-Day
Fischer-Tropsch	$21,500-$28,000/Bbl-Day
Solvent Extraction	$16,500-$21,500/Bbl-Day
Catalytic Hydrogenation	$15,500-$20,000/Bbl-Day

Sources: Sliepcevich et al. (1977); Anderson and Tillman (1979).

APPENDIX K

SELECTION OF CANDIDATE ELECTRIC ENERGY TECHNOLOGIES

MAGNETOHYDRODYNAMIC GENERATORS

Technology and Siting Requirements

Magnetohydrodynamis (MHD) is an energy conversion technology that has the potential to increase the efficiency of electrical generation plants from about 84% to 48% (Corman & Fox 1976).

In an open cycle MHD generation system, fossil fuel is burned at a sufficiently high temperature so the product gases are ionized (4000-5000^oF). Electrical conductivity of the hot gases is increased by "seeding" with readily ionized material (salts of cesium or potassium).

When passed through a magnetic field, this produces an electric current in the gas. The current (DC) can be removed directly with metal rods or "electrodes."

The d-c output of the MHD channel is converted to ac in solid state inverters (Corman & Fox 1976). The gases exit through a series of heat exchangers and a steam generator, which drives an a-c generator.

Seed material K_2CO_3 is used to both increase conductivity and tie up sulfur as K_2SO_4. The seed recovery system and integral clause plant converts K_2SO_4 to seed material plus elemental sulfur. Problems which may delay implementation of MHD technology include predicted poor forced outage rate, short life expentancy, inflexible operation (difficult at minimum load), difficult operation and control, corrosion problems, poor potential for retrofit (Corman and Fox 1976).

Current Status of Development

A 250 hr 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 Bute, Montana.

It was estimated in 1976 that a commercial MHD facility could be operational by 2003 (Corman and Fox 1976). In an International Energy Agency study, the reference start year for a coal-fired MHD electric power plant was 2005 (IEA). However, funding of MHD has been cut from $60.5 million in FY 1981 to zero in 1982. Confirmation of the engineering feasibility of MHD and commercial demonstration will become the reasonability of the industry (DOE 1981).

Applicability to the Railbelt Region

The time scale for development of commercial MHD conversion systems is not consistent with the time frame of the Alaska Railbelt Electric Alternatives study.

An open cycle MHD facility would be located at a large central fossil-fired power plant. Gaseous emissions of NO_x and 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 consume only 60% as much make-up water as a conventional steam plant, and use less than 40% of the total water requirement of a conventional plant (Corman and Fox 1976).

FAST BREEDER FISSION REACTORS

Technology and Siting Requirements

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. When isotope ^{238}U (which constitutes 99.3% of natural uranium) in the fuel absorbs a neutron, it decays to ^{239}Pu, which is the main energy source for the breeder. The heat generated by fission is removed by the liquid sodium coolant in the primary loop. Heat is exchanged to an intermediate sodium loop. From the intermediate coolant loop, heat is exchanged to water coolant in the steam generator. At that stage, the steam cycle is similar to that of any other conventional thermal power plant (fossil or nuclear).

The overall thermal efficiency of an FBR is slightly higher than that of a light water reactor (LWR) because it operates at higher temperature. The product of a comercial breeder facility would be about 1000 MWe, baseload power.

Siting considerations are the same as those for conventional nuclear plants. These include adequate water available for cooling, geologic and seismic stability, and 100-400 acres of land remote from a large population center. In addition, access to reprocessing facility is required by an FBR. Impacts from a breeder plant, like any large thermal power plant include local impacts during construction, heat release to the environment and fog created by cooling towers.

A principal problem for breeder development is in the fuel cycle. Reprocessing and facrication facilities for breeder fuel must be built for continuing breeder operation. Fuel reprocessing provides for recovery and purificaton of plutonium contained in the spent fuel, so it can be recycled. Fuel fabrication prepares the recovered fuel for recycle in a power plant.

Current Status of Development

Current U.S. experiene with breeders is being acquired at the Fast Flux Test Facility (FFTF) which achieved full power in December 1980. The reactor capacity is 400 MW thermal, approaximately equivalent to 133 MWe, but is not being used for generation of power. The Clinch River Breeder Reactor (CRBR) will generate 350 MWe. The CRBR has been restored to the FY-1982 DOE budget (DOE 1981).

The conceptual Design Study reactor (CDS) is a 1000 MWe gross 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 time frame (DOE 1979).

Applicability to the Railbelt Region

Breeder reactors will not be established on the commercial market by the year 2000, and are thus out of the time considerations of this project.

FISION REACTORS

Technology and Siting Requirements

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:

$$ {}^{2}_{1}D + {}^{3}_{1}T + \text{plasma energy} \quad {}^{4}_{2}He + {}^{1}_{0}n + \text{fusion energy} $$

Deuterium is present in water in sufficient quantities to be available for millions of years. The other fuel atom, 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 (Dingee 1979) via an intermediate heat extra or possibly closed-cycle MHD. 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 fission plant. A site should be near a load center, with cooling water available, satisfactory geology and seismology, transportation facilities to burrial site for solid radioactive wastes. In addition, large land area is required to preclude effects on the public of magnetic fields, and interference on electtrical and communication systems.

The inventories of tritium 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. But large heat releases and fog acreated by cooling towers may have significant impact on the siting of the plant.

Current Status of Development

Energy breakeven requires the product of confinement time (sec) and density (ions/cc) to be greater than 200 trillion at a temperature over 100 million^{o}F. No fusion device has yet to reach "breakeven" -- where fusion energy release is just equal to the energy supplied to run it. It is expected that breakeven will first be reach by Tokamak Fusion Test Reactor sometimes in 1983 (Blake, 1980).

Applicability to the Railbelt Region

This time scale is not consistent with the Railbelt Electric Energy Alternative Study.

OCEAN CURRENT ENERGY CONVERSION

Technology and Siting Requirements

There have been a number of proposals for the extraction of power from ocean currents. These are, in principal, relatively simple installations--such as turbines and paddle wheels (Isaacs and Schmitt 1980).

DOE has supported preliminary studies of a large ducted turbine for ocean current energy conversion. The device is an undersea, moored, ducted turbine, driven by current flow kinetic energy, which drives electrical generators and transmits power to shore with a sea-floor cable. The structure envisioned is on the order of 200 to 300 feet in diameter, and has a rotational speed of 1 RPM. The proposed structure would be of hollow aluminum construction. 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.

The Florida current of the gulf stream is the only candidate for U.S. Production of Energy from ocean currents (Booda 1978). Even a major current has very low energy density, equivalent to about 5 cm of water head, or about 1000 times lower than for thermal gradients. 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 6 to 8 times that of the Alaska current.

The Impacts of ocean current power extraction include

(No serious impacts identified --look for ref.)

Status of Development

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 it was projected that ocean turbines could be commercialized by 1999. However, that assumed that DOE_funded work would continue and a full-scale prototype would be complete in 1985. Since Ocean Energy systems has no funding for FY1982 and beyond (U.S. DOE 1981) the development of ocean current energy conversion is in doubt.

Applicability to the Railbelt Region

The future of ocean current power in the U.S. Is uncertain at this time. Apparently, it will not be commercial in the U.S. by the year 200, which puts it out of the time scale of this study. 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 TECHNOLOGY AND SITING REQUIREMENTS

Salinity gradient energy conversion is a large potential source of power. The concept involves converting the energy of mixing of high and low saline waters into usable energy.

The energy density of this process is equivalent to about 240 m of water head, or an OTEC Plant with a temperature difference of 23^{o}F (Isaacs and Schmitt 1980). The energy available represents a theoretical power of 2 MW for a flow rate of 1 m^3/sec for a freshwater river flowing into the sea (Olsson, Wick and Isaacs 1979).

There have been three approaches for extracting power from salinity gradients: 1) osmotic exchange against a hydrostatic pressure, or pressure-retarded osmosis; 2) the dialytic batter, or inverse electrodialysis (Isaacs and Schmitt 1980). and 3) vapor exchange between two solutions or 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 freshwater. To convert the osmotic pressure, one releases the pressurized solution through a hydroturbine (McCormick 1979). This concept requires large amounts of fresh water, and must be sited at a river.

The dialytic battery is made of anionic-permeable and cationic-permeable membranes in a battery type 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, prefereably 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).

The third scheme uses no membranes, but 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 concentration differences. The energy density of a system of saturated brine (260 partys per thousand) and fresh water is about 20 times greater than a seawater (35 parts per thousand) and fresh water system (Isaacs and Schmitt 1980).

Energy densities for Alaskan salinity gradient resources would be slightly lower than values presented because lower salinity of the sea water. The salinity of sea water off alaska is 31.5-32 parts per thousand most of the year (U.S. Department of the Interior 1970, p. 83) about 10% less than salt water in the referenced experiments.

Status of Development

Salinity gradient energy conversion is in the experimental stage. Salinity gradient research was conducted by DOE Under Ocean Energy System, which will no longer be funded as of FY1982 (U.S. DOE 1981). Therefore, the commercialization of this technology is uncertain at best.

Applicability to the Railbelt Region

Considering the current low state of development of salinity gradient energy conversion technology and the funding situation, this will not be an option in the time frame under consideration to meet Railbelt power requirements.

SPACE PWER SATELLITES

Technology and Siting Requirements

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 consists of an array of inclined planar solar panels 3 m wide in long continuous rows. Power is converted from dc to ac and stepped up to 500 kV for transmission (Brown et al. 1980, p. 328). The microwave power transmission link cannot be scaled down economically to powers less than a gigawatte (1000 megawatts) (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 capacity of 5 gigawatts.

The rectenna requires a large area of relatively flat land with an area of low population density. Variables which exclude rectenna siting include inland water, military reservations, population density, marshland, or perennially flooded areas, interstate highways and unacceptable topography. Potential exclusion areas include Indian reservations, national forests and wild and scenic rivers. Other variables which impact 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, p. 127).

The Ground Receiving Station (GRS) should be near the load center, but located to avoid radio interference. An optimum location would be a desert area. A prototype assessment or environmental impact of siting and construction of a GRS Used the California desert about 250 km north of Los Angeles for baseline data (Bachrach 1980, p. 525).

The land area required is about 400 km^2 at 35^o latitude. At the latitude of the Railbelt area, about 63^o, an area of about 1200 km^2 would be needed (Reinhartz 1980). Construction of a Ground Receiving Station in a desert area at 36^o is expected to require 25 months, with an average work force of 2500. Approximately 450 workers would be required for 24-hours, 365 days per year operation (Bachrack 1980, p. 525). 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 dispoace existing land uses, totally disrupt the ecology of the stie, and have great socioeconomic impact from the immigration of construction workers. The most significant environmental issue from satellite power transmission is long term exposure to low level microwaves on telecommunication, particularly interference with defense requirements (Valentino 1980).

Current Status of Development

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. There is no SPS funding for TY1981 or FY1982 (Riches 1981). 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).

Prospects for Railbelt Application

An SPS system does not currently 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 generation system, 5 GWe (5000 MWe) is much larger than demand forecasts for the Railbelt region.
- The northern latitude location 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.

OCEAN THERMAL ENERGY CONVERSION

Technology and Siting Requirements

Ocean thermal energy conversion (OTEC) uses the temperature difference between surface water and ocean depths to generate electricity. A schematic diagram of a closed-cycle OTEC Plant is shown in Figure 1. A conventional thermodynamic cycle is used with ammonia or propane as the working fluid. The working fluid is boiled by the warm sea water, 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^{o}F. Cold water from about 3000 to 6000 feet deep originates in the ARctic or Antarctic, and has a temperature of 39 to 44^{o}F (Booda 1978).

The efficiency of the OTEC closed-cycle is limited by Carnot efficiency of a heat engine. The ideal heat engine working at upper and lower temperatures of 80^{o}F and 40^{o}F (540^{o}R and 500^{o}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 hhave to pump 30,000 cubic feet of sea water per second (Forbes et al. 1979).

OTEC powerplants are suitable for tropical or subtropical seacoasts or offshore regions. A minimum temperature difference of about 30°F and depth of about 2000 ft is required. Power would be transmitted to the load center by dc electricity in 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.

Status of Commercial Development

A demonstration of the feasibility of OTEC Has been performed by DOE. The DOE budget for OTEC has been reduced from $34.6 million in FY81 to zero in FY82. DOE considers it the responsibility of the private sector to develop marketable systems once technical feasibility is established (U.S. DOE 1981).

A commercial prototype OTEC powerplant was envisioned about 1990 (Richards 1979). The reference start year for a commercial operation a 100 MWe ocean thermal gradient electric powerplant was taken to be 2000 in an International Energy Agency study (IEA 1980). The commercial sector will determine the actual development schedule for OTEC.

Railbelt Feasibility

Sites for OTEC plants are generally restricted to 20° north and south of the equator (Booda 1978). OTEC power cannot be considered in alaska because the concept depends on warm (80°F) tropical ocean surface temperatures. 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, p. 83).

OCEAN WAVE ENERGY SYSTEMS

Technology and Siting Requirements

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 International Energy Agency (IEA). The apparatus, known as "Kaimei," is a cavity resonator system, shown in Figure 1. There are three air turbines on the deck of Kaimei which have been designed and constructed in Japan, the United Kingdom, and the United States. The turbines are excited by the air motions above the rising and falling of the internal surface of the water, as shown in Figure 2. Each turbo-generating system is designed to deliver 125 kW in a 2 meter sea with a period of 6 seconds (McCormick 1979).

Another DOE-sponsored effort has been in wave-focusing systems. Wave focusing is accomplished by four techniques: 1) radient wave interaction, 2) Fresnel-type focusing, 3) refraction, and 4) channeling.

Radient wave interaction occurs when a body is in resonance with the incident wave. Fresnel-type focusing is done by a lens type structure which causes wave diffraction or refraction. A refraction wave energy device called DAM-ATOLL, which was developed at Lockheed, is shown in Figure 3. The device is a submerged dome which causes incident waves to refract and focus on a vertical axis turbine located at the center of the dome. The device, a lenticular hump on the sea floor, could be produced 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). The U.S. wave energy program has concentrated on wave focusing systems and the cavity resonator because larger structures are not justified by the low energy density. Also, large structures undergoing significant motions while moored at sea is the opposite of standard ocean engineering practice (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^{o}F temperature difference (Isaacs and Schmitt 1980). Siting requirements will include location in the ocean with consistent waves, near a load center. Such a facility would probably be used as a "fuel saver."

The DOE considers only the northern half of the Pacific coast a promising area. It is estimated that between 5 and 50 megawatts per kilometer of coastline could be generated (Booda 1978). The northern California and Oregon coasts have waves of height 5 feet and over 20 to 30% of the time in spring and winter, and 30 to 40% of the time in summer and autumn. Off the Alaskan coast, the frequency of waves of height 5 feet and over varies from less than 5% in the spring to 10 to 20% in the fall (U.S. Department of the Interior 1970).

The potential impact impediment is navigation. How about scientific effects, effects on marine life?

Status of Commercial Development

Currently, wve energy systems are in the developmental stages. Problems requiring resolutin include the need to withstand large storm waves, corrosion and fouling, energy storage and/or transmission, capital costs of fabrication and installation (Forbes et al. 1979).

An International Energy Agency study assumed 1990 as the reference starting year for commercial operation of a 2 MWe wave powerplant (IEA 1980). Wave energy research programs have been supported by DOE and are dependent 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 FY1982 (U.S. DOE 1981), the fate of wave energy development is uncertain.

Applicability to the Railbelt Region

The coast of Alaska is not an optimum location for wave energy powerplants, 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.