CHAPTER 8
ALTERNATIVES TO PROPOSED ACTION

8. Alternatives to the Proposed Project

The following discussions center on four areas of alternatives. The first relates to the alternative gas sources, designs, and processes available and considered by ANGCGC. Second are the siting alternatives studied by ANGCGC. The third group of alternatives concerns alternative uses of the resources that would be committed to the proposed project. The last category relates to other possible sources of energy to supply the future energy needs of the Nation.

8.1 ANGCGC's Design and Source Alternatives

8.1.1 No Project

If production of the SNG from coal is not pursued, Michigan-Wisconsin might not be able to supply the long-term gas needs of its residential and industrial customers. Regionally and nationally, this would further strain already insufficient energy supplies. The resultant impact would either be the use of environmentally less desirable fuels, or in the case of some existing industries, curtailment of operations and the socioeconomic consequences of unemployment. Even if low sulfur fuel oil were available as a substitute for gas, such use would substantially increase sulfur emissions in the Michigan-Wisconsin market area.

Without development of the proposed coal gasification project, the physical and biological impacts discussed in Chapters 3 and 5 would not occur. If there were no other large scale industrial projects in the area, the population would probably decrease slowly and the community structure would likely remain rural and sparsely populated. However, it is probable that some coal-related development will take place; thus, many of the impacts discussed in Chapters 3 and 5 will occur in varying degrees.

8.1.2 Alternative Sources of Gas

8.1.2.1 Importation

Gas could be imported into the United States either as pipeline natural gas or as liquid natural gas at the expense of a further decline in the United States balance of payments. Natural pipeline gas is presently imported into the United States from Canada and Mexico. In 1972, 1.0 Tcf were imported, via pipelines, from Canada, while 8 MMcf came from Mexico. There may be some prospect of increased import. Mexico has a relatively small proven natural gas base and a policy of energy self-sufficiency which indicates that an adequate supply of new gas might not be available for export. Present Michigan-Wisconsin gas contracts with Mexico expire in 1982 thus creating the possibility that if no new supplies are released for export, natural gas imports from that country by Michigan-Wisconsin could cease.

Based on actions by the Canadian National Energy Board (NEB), it appears that future increases in natural gas imports from Canada may also be limited. In November 1971, the NEB rejected three license applications to export 2.7 Tcf of gas to the United States over a 15- to 20-year period. In addition, the Canadian Petroleum Association reported in 1973 that proven marketable reserves of natural gas experienced their first decline since 1954. These reserves dropped 4.5 percent, or 2.5 Tcf.

The impacts of pipelines carrying gas from Canada and Mexico would be essentially the same as those discussed for the product pipeline in this statement.

Liquified natural gas (LNG) is the other major potential source of gas imports. Plans are being made by the gas industry for base-load LNG imports under long-term contracts. Large scale shipping of LNG is a relatively new industry and the United States does not yet have facilities for receiving baseload shipments. The FPC recently approved two projects which together would deliver more than 1 MMcf/day of LNG. Various projections of LNG imports to 1985 (48) are:

	1975	1980	1985
	(Trillion cubic feet)		
Federal Power Commission	0.3	2.0	3.0
Department of Interior	0.5	0.9	1.6
National Petroleum Council	0.24	2.28	4.11

American Natural Resources is examining several possible locations for a LNG terminal; however, the need for LNG would be in addition to, not in place of, SNG from coal. The United States balance of payments would suffer as a result of extensive LNG imports. In addition, United States capital may be required for construction of foreign liquification plants. Further deficits could result from the purchase of tankers from a foreign source or the use of foreign tankers. The cost of the gas itself will, however, probably have the greatest influence on balance of payments. It is estimated that the f.o.b. price of gas would be $1.30 to $2.30/Mcf. Importing 1 Tcf could, therefore, result in a cash outflow of $1.3 to $2.3 billion (48).

Environmental impacts in the United States of LNG importation would largely be those of tankers, terminals, and regasification facilities, and transportation of the gas. The chance exists that a tanker might be involved in a collision or other mishap, but several studies have shown that the LNG would likely vaporize and escape into the air. An open flame could ignite the flammable gas-air mixture escaping from a rupture, however.

Facilities would be required to transfer the LNG from the tankers, store it, and regasify it for pipeline transport. Transfer methods for two proposed facilities (Cove Point, Maryland and Savannah, Georgia) would involve initial dredging, and possibly continued dredging, and result in increased turbidity of the water and disruption of marine organisms, particularly bottom-dwelling organisms.

Regasification plants use natural gas heaters or water to regasify the LNG, so very few pollutants are released into the air or water. Plants using water would lower its temperature about 5-15° F between intake and return. However, these plants could be combined with heat-producing plants to minimize the effect of both on water temperatures.

The potential for fire or explosion is always present during the transportation, transfer, or storage of LNG. Pipelines would be needed for transport and their impacts would be similar to those of the product pipeline associated with the proposed gasification plant.

8.1.2.2 Domestic Supplies

The American Natural Resources Company has attempted to purchase new reserves in the United States, is active in the Arctic Gas project, and has expanded their own efforts to explore for and produce new reserves in the lower 48 states, including offshore reserves. ANR officials have said that they find it hard to purchase new supplies from independent producers because of the price advantage intrastate purchasers can offer over the interstate price. New system reserves and the Arctic Gas project are not expected to keep pace with the decline in production from old reserves and an anticipated drop in pipeline gas deliveries from Canada of 158 MMcf in 1981.

There are no uncommitted reserves of any magnitude available to ANR from within the area covered by their system. Also, there is no assurance that reserves of any substantial nature will be available in the near term which would be a viable alternative to the proposed project. The net contribution to ANR gas supplies from expanded exploration and drilling activities has not been significant to date.

The environmental impacts of increasing domestic supplies are those associated with road-building, drilling and production facilities, and the construction of pipelines to deliver the new gas to existing transmission systems.

8.1.2.3 Liquid Hydrocarbon Gasification

Synthetic natural gas (SNG) can be produced from various petroleum feedstocks, notably naphtha, crude oil, and methanol. Processes being developed include (1) thermal cracking in steam, (2) thermal cracking in hydrogen-rich atmosphere, (3) catalytic cracking in steam, and (4) partial oxidation. Potential commercial processes involve gasification of naphtha; one process developed by the British Gas Council (catalytic-rich gas) operates at 93 to 95 percent thermal efficiency. The general process of converting liquid hydrocarbons to SNG is similar to that for the gasification of coal except desulfurization occurs first.

Some of the liquid hydrocarbons required for use in these SNG conversion processes are used by the petrochemical industry and are not currently available for gasification in the quantities needed. In 1973, nearly all the industrial-chemical naphtha was used as feedstock in olefin manufacture (49). In recent years this usage has substantially increased in response to the expected short supply of natural gas liquids. For example, 12.1 percent of ethylene manufacture in 1971 utilized this feedstock compared to 18.7 percent in 1973. Since petroleum refining in the United States is being oriented increasingly toward gasoline output, the resulting naphtha production has decreased considerably.

Oil gasification depends upon a crude oil feedstock, which is already in short supply in the United States. In 1973, the United States refining capacity was 690.1 million tons/year while the ever increasing rate of consumption was 829.3 million tons/year (50). From 1970-73, all imports have increased from 12.1 percent to 26.1 percent of annual consumption. Annual imports increased 26.9 percent in 1971, 31.9 percent in 1972, and 46.4 percent in 1973. Besides the question of reliability of foreign supply, use of foreign crude is not in conformance with the goals of energy independence.

The environmental impact of liquid hydrocarbon processes would be those of extraction and transportation of crude oil, the conversion processes, and transportation of product gas. Inasmuch as supplies of crude oil would be imported, the environmental impacts are likely to be those of importing oil. Transportation of the product gas would cause impacts essentially the same as those of the proposed product pipeline. Because coal-to-gas and liquid hydrocarbon-to-gas plants would be similar in most respects (boilers, gas scrubbers, etc.), the environmental impacts would be similar in nature. However, the intensity of the impacts of liquid hydrocarbon-to-gas plants would be less than coal gasification plants because they have a higher thermal efficiency than coal-based plants and would be relatively free of ash, char, and particulates.

After the SNG is removed, there remains solids and/or liquids that represent additional fuel supplies and/or waste.

8.1.2.4 Nuclear Stimulation

Nuclear stimulation is an experimental method of fracturing low permeability gas reservoirs otherwise incapable of sustaining commercial production. It has the potential to add significantly to United States recoverable gas reserves. ERDA is conducting research and development of underground nuclear explosions to recover natural gas locked in tight geological formations. Most reserves amenable to nuclear stimulation lie in thick, deep reservoirs in the Rocky Mountain Region.

The low permeability and heterogeneity of the reservoir rock in the Rocky Mountain basin require tremendous fractures over vertical intervals of 2,000 to 4,000 feet thick to provide adequate productivity. Two techniques are potentially capable of creating the underground fracture systems needed: (1) multiple nuclear explosive fracturing, and (2) massive hydraulic fracturing. Both systems are still in the experimental stage to determine if adequate and sustained gas production can be achieved (48).

Assuming experimental success, commercial development could begin by the late 1970's or early 1980's. A scenario developed by the Lawrence Radiation Laboratory predicts that 80 wells/year could be developed by 1980 resulting in the production of 600 Bcf/year by that time. Favorable conditions might allow development of 100 wells/year beginning in 1981. This would result in production of 1.50 Tcf/year (4.35 Bcf/day) by 1985.

Environmental effects of nuclear stimulation are those related to radioactivity and seismic disturbance, primarily subsurface but with some surface seismic disturbance. The chance of above ground contamination and disturbance is considered extremely unlikely. Most radioactivity remains underground, trapped in resolidified rock. Water produced with the gas from nuclear stimulated wells contains small amounts of tritium. Methods of disposal of this contaminant are being developed. Gas production from the wells can be delayed until the short-lived radionuclides decay. The first gas from the wells contains high CO_2 levels, but after production of a few chimney volumes, the gas composition is essentially the same as that from conventional wells.

Ground motion following the underground explosion is predictable; hence, damage to existing ground structures can be minimized. It has been suggested that residual stress from a number of detonations might accumulate and present an earthquake hazard not present in a single explosion. Data from seismic wave generation and stimulated fault motion at the Nevada Test Site indicate that the cumulative effect from many explosions is to reduce ambient stress levels rather than to increase them. Also, a recent series of high-precision geodolite measurements indicates that the residual strain field around a single explosion site tends to relax with time.

8.1.3 Alternative Designs, Processes, and Operations

8.1.3.1 Other Coal Gasification Processes

Presently, commercially proven technology for coal gasification has been demonstrated by Lurgi, Koppers-Totzek, and Winkler processes. ANGCGC selected the Lurgi process after detailed reliability, economic, and engineering studies of the three processes.

The Koppers-Totzek (K-T) process was developed in 1948 in cooperation with a German company. There are 16 K-T plants operating around the world, but none in the United States. The K-T process employs the partial oxidation of pulverized coal in suspension with oxygen and steam. A two-headed gasifier is capable of gasifying over 400 tpd of coal. Coal, oxygen, and steam are brought together in opposing gasifier burner heads. Reaction temperature at the burner discharge is 3,300 to 3,500^{o} F and the operating pressure of the gasifier is slightly above atmosphere. The coal is gasified almost completely and instantaneously. Carbon conversion is related to the reactivity of coal, approaching 100 percent for lignites.

The Winkler process is an atmospheric fluid-bed route in which the gasifying media are oxygen and steam. The fluid-bed operates at 1,500 to 1,850^{o} F, and most of the ash is carried over with the product gas. To prevent slagging of the ash, the gases are cooled by a radiant boiler section in the upper portion of the gasifier. The process is used at 16 plants in a number of countries, using a total of 36 generators.

The K-T and Winkler processes offer an advantage in not producing byproduct tars, oils, etc., due to their higher operating temperatures. The higher operating temperature, however, is also a disadvantage in SNG production. The SNG produced has a very low methane content ($<$ 1 percent) and the size of the methanation unit must almost be doubled. Their other disadvantages are greater oxygen consumption and low operation pressure. The resultant SNG has to be compressed to a final pipeline pressure of 1050 psig.

The environmental impacts of the alternate gasification processes would be essentially the same as those discussed in Chapter 3 for the proposed project.

8.1.3.2 Alternatives Within the Process

A major portion of the gasification plant is a Lurgi process package. The Lurgi process areas are (1) gasification, (2) gas shift conversion, (3) gas cooling, (4) Rectisol, (5) Phenosolvan, (6) methanation, and (7) gas liquor separation. Lurgi proprietary equipment is used in areas 1, 4, 5, and 6 above; thus, gas quality and other performance guarantees only apply if Lurgi designs the total system. For this reason, no alternative process units in the above areas were considered once the Lurgi process was selected.

In the area of ammonia recovery, the Lurgi CLL process was compared with the U.S. Steel Phosam-W process. Since both processes utilize the same feed stream and both produce commercial grade anhydrous ammonia, the Phosam-W process was selected for economic reasons.

In terms of sulfur conversion, a combination of Stretford, Claus, and IFP processes were considered at first. In the Sasol coal analysis at an existing gasification plant, however, it was learned that in processing lignite from the Beulah-Zap bed that the sulfur concentrations given off were too low to be effectively recovered by the Claus and IFP processes. As a result, a total Stretford system was selected.

Considerable testing and evaluation was also done by ANGCGC in the area of coal preparation. Tests were conducted in the areas of coal drying, crushing, and screening. The Sasol test showed that drying was not required. Crushing tests were used to provide data on final coal sizing and equipment selection. In a full scale screening test, a high probability screen, new to the American market, proved to be the best screen to use in the gasification plant.

8.1.3.3. Alternative Sources of Power

As an alternative to receiving power from the Basin Electric powerplant, ANGCGC could obtain some power from the existing grid system and provide the remainder from one of three internal systems: (1) low Btu fuel gas generation with gas-fired power boilers, (2) low Btu fuel gas generation with combined cycle power generation, or (3) direct firing of coal fines in a steam boiler with stack gas scrubbing.

Direct firing of coal fines would be preferable to low Btu gas generation for several reasons: low Btu gas generation involves high investment and operating costs, thus increasing SNG cost; it has lower thermodynamic efficiency than direct firing of coal fines because of conversion losses in the gasifiers; and, if the gas generation system malfunctions, product SNG would have to be used. Also, if Lurgi low Btu gasifiers were used, coal fines could not be used resulting in the need to purchase more coal and the creation of additional fines.

Obtaining power from the Basin Electric plant is preferable to the direct burning of coal fines because (1) burning coal fines would require investment in coal-fired steam boilers and SO_2 scrubbing equipment thus raising the cost of the SNG produced, (2) the process would not use all of the coal fines generated so the remainder would have to be shipped offsite by rail and sold, (3) emissions from the gasification plant would be increased, and (4) the cost of the facilities to be shared by ANGCGC and Basin Electric (i.e., water intake and pipeline, railroad spur) would have to be borne by ANGCGC alone thus adding to the cost of the product SNG.

8.1.3.4 Alternative Wastewater Treatment Methods

Alternative wastewater treatment methods considered by ANGCGC were (1) biological waste treatment; (2) solar evaporation ponds; (3) multiple effect evaporators, spray dryers, chemical landfill; and (4) deep-well disposal.

Biological waste treatment was discarded because several compounds in the wastewater may be either resistant or toxic to biological organisms, making complete biological treatment improbable. The solar evaporation ponds would require in excess of 1,000 acres of land and could not be justified on the basis of land commitment or cost.

Preliminary studies have shown that a combination of evaporators to remove organic wastes and deep-well injection of the inorganic brine to aquifers sufficiently below those used for water supplies would be feasible. Combined with a cooling tower which circulates and concentrates the process water, this method appears to provide the most efficient and complete method of handling plant wastewaters.

8.1.3.5 Other Water Intake Structures

Several alternate design configurations and construction methods for the water intake structure were evaluated by ANGCGC. The main methods considered were: (1) offshore tower with pumps and causeway to shore, (2) offshore tower with boat access instead of a causeway, (3) submerged pumps with buried pipeline, and (4) open channel cut to onshore pump station.

The offshore tower, with or without causeway, was discarded for environmental considerations (including high visual impact) and high maintenance costs. The submerged pump with buried pipeline alleviated the aesthetic problem, but reliability and accessibility would be poor. The open channel provided good reliability, accessibility, and low maintenance cost, but the visual impact and environmental problems associated with surface withdrawal were present. The submerged intake and tunnel to an onshore pump station, although having higher construction costs, provided good reliability and accessibility, low maintenance cost, low visual impact, and minimal operations impact.

8.1.3.6 Alternatives to Proposed Mining Plan

The Federal Government has retained extensive coal rights in the vicinity of the proposed project and these reserves are under the administration of the Bureau of Land Management (BLM). Prior to May 1971, leases to mine the coal were granted on a case by case basis without regard to total reserves under lease (87). From May 1971 until February 1973 no new leases were granted while the Department of the Interior reassessed Federal coal leasing policies. One result of the study was the recommendation to resume coal leasing under an Energy Minerals Activity Recommendation System (EMARS) which is a leasing system based upon expressed demands from the public and industry and a multiple use planning system for federally administered lands.

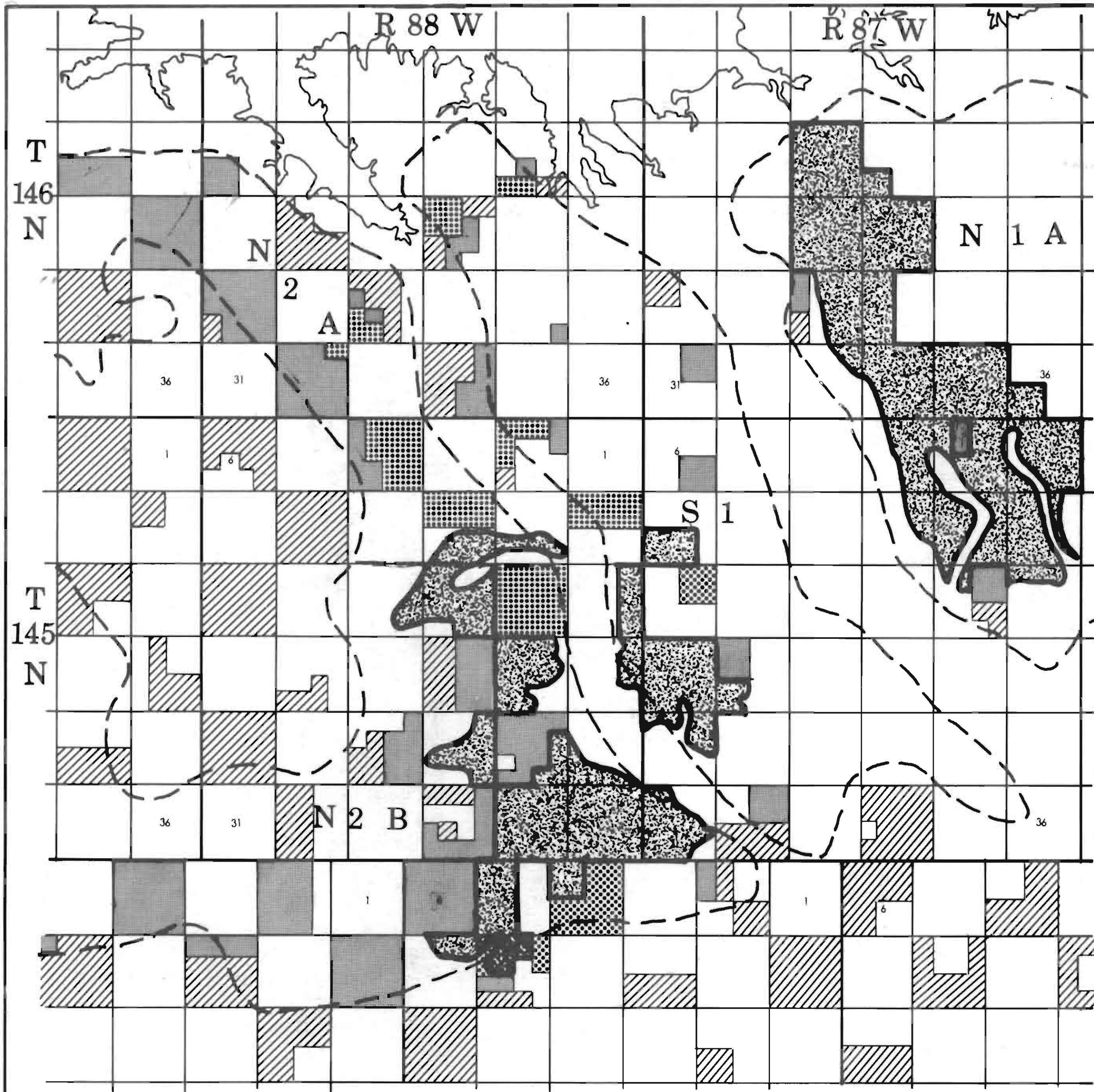
Figure 8-1 shows the Federal coal reserves and four proposed BLM lease tracts (designated N-1A, N-2A, N-2B, and S-1[1/]) near the proposed project. BLM intends to offer the lease tracts for competition bidding. Coteau Properties already has leases on several areas of Federal coal in these tracts and could obtain the rights to mine the remaining Federal coal, some of which could go to the proposed ANGCGC and Basin Electric projects. The mining plan for the proposed project (Figure 1-8) was based on privately owned coal and the project could proceed without Federal coal; however, use of a combination of Federal and private coal would allow more efficient mining and would result in a reduction of overall mining costs.

In formulating the Program for leasing of Federal coal tracts, BLM designed the tracts so that each tract would (114):

1. Contain sufficient reserves to provide the needs of gasification, power generation, and/or export,

2. Have a stripping ratio of less than 10:1 (overburden to coal depth) to result in low mining costs,

1/ "S" tracts are proposed for immediate leasing; "N" tracts are recommended for leasing before 1990.



FEDERAL COAL RESERVES
and
ANG CGC PROPOSED MINING PLAN

Figure 8 - 1

LEGEND

— — — FEDERAL LEASING TRACTS

ANG PROPOSED MINING AREA

EXISTING COAL LEASES (FEDERAL)

COAL LEASE APPLICATION (FEDERAL)

OTHER FEDERAL COAL

3. Be topographically amenable to mining and relatively easy to reclaim,

4. Be within areas classified as Known Recoverable Coal Resource Areas by the U.S. Geological Survey,

5. Be within reasonable distance of a sufficient water source,

6. Be reasonably close to existing rail lines and highways to facilitate movement of equipment or the coal itself,

7. Be near existing or proposed developments,

8. Have an identified immediate need for the coal,

9. Have low Federal coal ownership; thus, mining could readily proceed without it.

Federal coal reserves within the four lease tracts total 182.906 million tons broken down as follows:

Tract	Reserves (Million Tons)
N-1A	8.948
N-2A	65.135
N-2B	67.549
S-1	41.274

Privately owned reserves in these tracts total 717.918 million tons.

Of the total of 38,856 strippable acres of coal in the four proposed tracts, 8,257 acres are Federal; 798 are State; and 29,801 acres are private coal. Surface ownership of coal acreage is distributed as follows:

Tract	Federal	State	Private	Total
N-1A	0	0	11,956	11,956
N-2A	0	289	6,227	6,516
N-2B	0	484	9,619	10,103
S-1	0	0	10,281	10,281

The four proposed lease tracts lie within the study area described in Chapter 2, thus the description of the existing environment in that chapter would apply to the proposed lease tracts also. The impacts of mining the Federal coal would be essentially the same as those described in Chapter 3 related to mining privately owned coal except for the differences noted below:

1. About 570 acres of prime farmland lies within the four proposed lease tracts as follows: N-1A - 444 acres; N-2A - 126 acres; N-2B - 0 acres; S-1 - 0 acres. No unique farmland is found within the tracts (114).

2. Mining in the northern portion of tract N-1A would destroy the Weidner Campground adjacent to the Hille Game Management Area and lower the quality of the recreation experience at the Hille Game Management Area and the Beulah Bay Recreation Area. Tract N-2A is also close to the Lake Sakakawea shoreline and would lower the quality of the recreation experience at the lake.

3. Acreages of the various plant communities within the proposed tracts are as follows:

Tract	Cropland	Prairie	Woodland	Wetland
N-1A	15,409	5,946	154	64
N-2A	3,800	8,132	714	0
N-2B	12,960	12,864	104	25
S-1	12,576	5,931	18	0

4. The large amount of woodland in N-2A, if mined, would result in a higher-than-average loss of important winter cover for wildlife and populations of woodland associated wildlife (e.g., white-tailed deer, black-capped chickadee). The large amount of prairie in N-2A would result in higher-than-average losses of grassland species (e.g., sharp-tailed grouse, burrowing owl) if it were mined.

Since the Federal contribution to the total coal available in the proposed tracts is so small, and because of the random distribution of Federal coal within the tracts, not to mine the coal would result in the loss of the resource to future generations as it would not be economically feasible to try and extract such small, isolated pockets of coal. If the Federal coal were not mined, it would also result in higher costs and lower mining efficiencies to the proposed mining operations as Coteau Properties would have to mine around the Federal coal.

8.2 ANGCGC's Siting Alternatives

8.2.1 Plant Location Alternatives

a. North Dakota

ANGCGC in conjunction with Coteau Properties, studied 11 potential sites for the proposed gasification facility located near 5 coalfields in southwestern North Dakota. The coalfields studied were:

	Coalfield	Approximate Location	No. of Sites Studied
1.	Underwood	18 mi NE Hazen	1
2.	Otter Creek-Center	10 mi SE Hazen	3
3.	Beulah-Hazen	8 mi NNW Beulah	2
4.	South Beulah	12 mi SSW Beulah	2
5.	Dickinson	30 mi SE Dunn Center	3

The sites were rated according to socioeconomic, geotechnical, and meteorological factors (Table 8-1), and biological factors (Table 8-2).

Sites at the Underwood and South Beulah coalfields were eliminated because of potentially large impacts to terrestrial and aquatic organisms (Table 8-3), and undesirable geotechnical and hydrological factors. Desirable sites in the Otter Creek-Center and Dickinson coalfields were eliminated largely because of engineering and economic factors. Consequently, the currently proposed site (3B) was selected as being the least environmentally damaging and most economically feasible alternative.

b. Sites Nearer the Market Area

Locating the gasification plant nearer the market area (i.e., Michigan) was an alternative considered by ANGCGC. To feed such a plant, coals from Illinois, Iowa, Ohio, and West Virginia were evaluated. It was found that the Lurgi gasification process could not operate well on Eastern coals because of their high caking tendencies (see Section 8.1.3.1 for other gasification processes). Thus, Western noncaking coals were needed and North Dakota lignite reserves, being closest to the Michigan-Wisconsin market area, were selected by ANGCGC.

The possibility of mining the lignite in North Dakota and shipping it by rail to a point closer to the market was also considered by ANGCGC. Two logical plantsites tying into existing ANR system pipelines were at Thief River Falls, Minnesota, and Crystal Falls, Michigan. At current, unit train rates of 17 mils/ton mile, rail shipment of 36,767 tpd of North Dakota lignite would add $0.68/thousand cubic feet (Mcf) to the cost of gas produced in Minnesota, and

Table 8-1

Ranking of Various Alternative Sites According to

Socioeconomic, Geotechnical, and Meteorological Factors

Criteria Used	1A	2A	2B	2C	3A	3B	4A	4B	5A	5B	5C
					Socioeconomic Ranking						
Land Size	1	1	1	2	1	1	3	3	2	2	1
Dedicated Land Use	3	2	3	3	2	3	3	3	3	3	3
Traffic Disturbance	2	1	2	3	2	1	3	3	3	1	3
Labor Force/Unemployment	2	1	1	1	3	3	3	3	3	3	1
Proximity to Urban Area	1	2	2	1	3	3	3	3	1	1	3
Median Family Income	1	3	3	3	2	2	2	2	1	1	3
Aesthetics	2	2	2	1	3	2	2	2	1	1	2
Total	12	12	14	14	16	15	19	19	14	12	16
					Geotechnical Ranking						
Seismicity	3	3	3	3	3	3	3	3	3	3	3
Foundation	2	1	3	3	2	2	1	1	1	2	2
Drainage	2	1	2	2	2	2	1	1	3	1	3
Topography	2	3	3	3	2	2	1	1	3	3	3
Construction Material Avail.	1	3	3	3	3	1	3	3	2	2	1
Mineral Resource Avail.	1	2	2	2	3	1	2	2	1	2	2
Ground Water Avail.	2	2	2	2	3	2	2	2	2	2	2
Total	13	15	18	16	18	13	13	13	15	15	16
					Meteorological Ranking						
Population Center	3	3	3	3	3	3	3	3	1	1	3
Downwind Frequency	2	3	2	3	3	3	3	3	2	1	3
Sulfur Oxides	2	2	2	2	3	3	3	3	3	3	3
Particulates	2	2	2	3	3	3	3	3	3	3	3
Total	9	10	9	11	12	12	12	12	9	8	12

Note: Sites are ranked relative to one another. Score of 3 indicates better site; 1 a poorer site.

Source: Woodward-Envicon, Inc. Analysis, 1974.

TABLE 8-2

BIOLOGICAL RANKING

Most Desirable (no undesirable criteria affected)	Site 5C
Desirable (presence of natural prairie)	Site 3A
Less Desirable (some biological disturbance of a unique area)	Site 2A Site 3B Site 5A
Undesirable (disturbance of one or more unique areas)	Site 1A Site 2B Site 2C Site 4A Site 4B Site 5B

Source: Woodward-Envicon, Inc. Analyses, 1974.

TABLE 8-3

SITE EVALUATION SUMMARY

	SITES										
	1A	2A	2B	2C	3A	3B	4A	4B	5A	5B	5C
Socioeconomics, Land Use, & Demography	2	2	2	2	3	3	3	3	2	2	3
Geotechnical Factors & Hydrology	1	2	3	2	3	1	1	1	2	2	2
Meteorology & Air Quality	2	2	2	3	3	3	3	3	1	1	3
Terrestrial & Aquatic Biology	0	1	0	0	2	1	0	0	1	0	3
TOTAL	5	7	7	7	11	8	7	7	6	5	11

Note: As part of each evaluation, sites were placed into one of four judgment categories: 3 - Most Desirable, 2 - Desirable, 1 - Less Desirable, 0 - Undesirable. Judgment categories are based on approximate ranking values presented in Tables 8.3-1 through 8.3-4.

Source: Woodward-Envicon, Inc. Analyses, 1974.

$1.58/Mcf to gas produced in Michigan. Comparable costs for pipelining gas from North Dakota to these points is $0.20 and $0.39/Mcf, respectively.

Aside from the economic incentive for pipelining gas rather than rail-ship coal, there are other less obvious advantages. The shipment of coal by rail hopper car results in a 1 percent loss of fines, most of which is lost in the first 50 miles. This corresponds to about 370 tpd of particulate matter spread over the environment near the tracks. The particulate matter emitted by the gasification plant would amount to 2.8 tpd. An additional impact would be the disturbance caused by long coal trains passing through towns along their path every 6 hours.

A coal slurry pipeline was also considered as an alternative to rail shipment. While the effects on environment and communities along the route are less than those of rail shipment, other considerations make slurry transport undesirable: pipeline shipment requires particle size smaller than 1/10 inch, whereas the Lurgi gasification system cannot effectively handle coal particles smaller than about 3/8 inch; water requirements for the slurry would be about 6,100 gpm, or nearly the entire gasification plant requirement; and, finally, the energy requirement for slurry pipelining (including preparation, pumping, and dewatering) is about three times greater than that for rail shipment.

8.2.2 Alternative Product Pipeline Routes

An overriding constraint in the selection of the proposed product pipeline route was that a pipeline constructed to transport SNG would presumably not have the power of eminent domain. With this constraint in mind, the area was evaluated for location of existing utility corridors and other rights-of-way (ROW) that could accommodate the pipeline and minimize the crossing of private lands. The proposed route was selected as coming the closest to existing pipeline facilities while needing only a minor amount of trespass through private land. Other possible routes include (1) a direct route from the plant to the Thief River Falls compressor station, (2) a straight-line connection to the proposed Northern Border Pipeline, and (3) essentially the same route with a connection to an existing Mid-western Transmission Company pipeline (Figure 8-2).

a. Direct Route

The first alternate route is a combination of a nearly straight-line route from the proposed plant site to the Missouri River and a similar straight-line or great circle route from the Missouri River to the Thief River Falls compressor station. A major consideration west of the Missouri River was the avoidance of lignite deposits which are likely to be mined at a future date.

East of the Missouri River this alternative was first considered as a great circle and adjusted slightly to avoid urban areas and the many National Wildlife Refuges which are common in the region. But a major obstacle to this route was the Bureau of Reclamation's Garrison Diversion Unit, which is presently under construction in the area. Because multiple crossings of the irrigation system would be required, the great circle route was modified southward to completely avoid the Garrison project.

The proposed route was chosen over the great circle alternative primarily because it could be constructed on existing railroad ROW. In addition, Alternative 1 would cross numerous potholes,

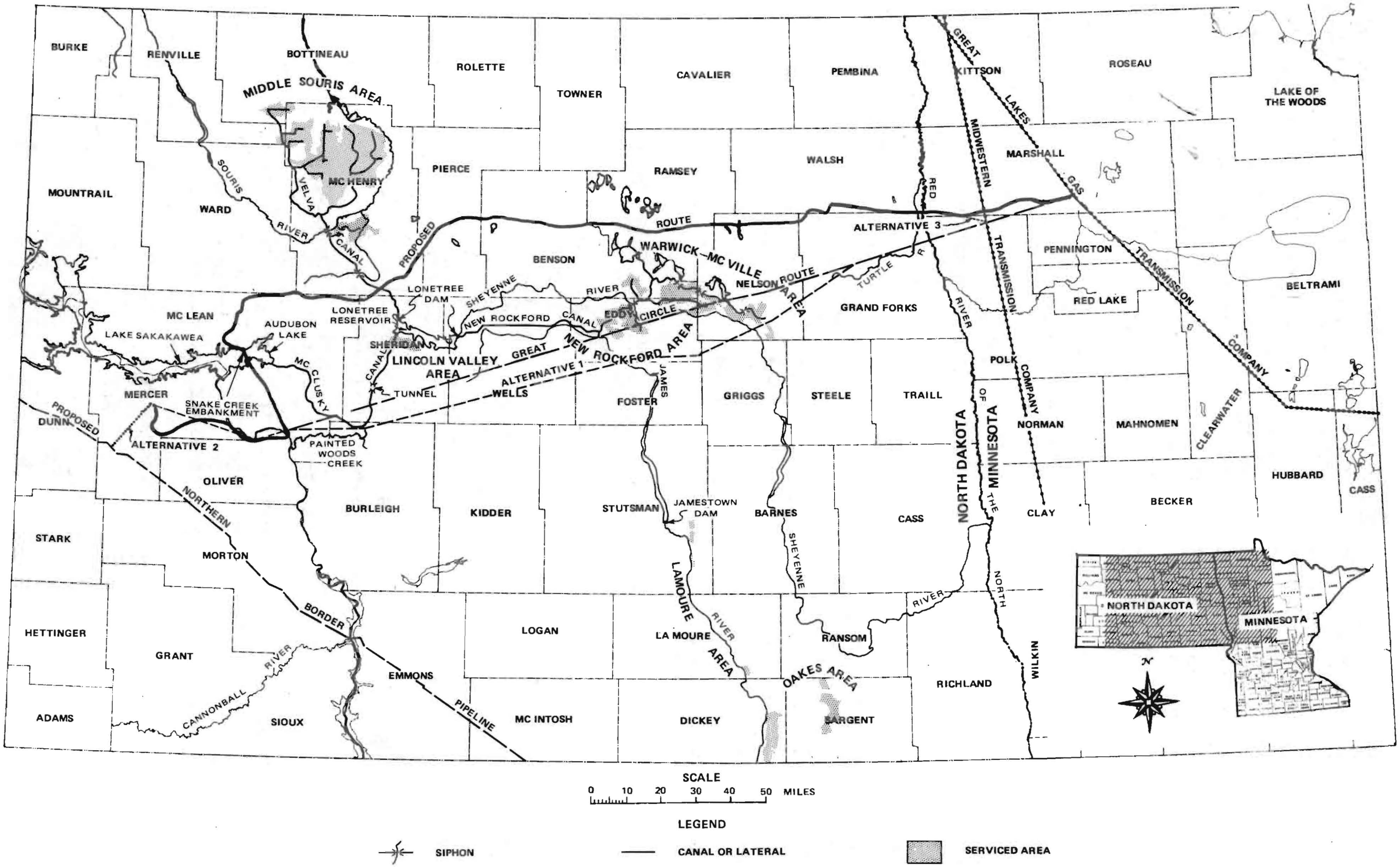


FIGURE 8-2

GARRISON DIVERSION UNIT* WITH PROPOSED ROUTE AND ALTERNATIVES FOR THE DAKOTA TRANSPORTATION PROJECT

*ADAPTED FROM: U.S. DEPT. INTERIOR, BUREAU OF RECLAMATION. 1973. GARRISON DIVERSION UNIT.

ponds, lakes, and wetlands which provide significant waterfowl habitat. The pipeline would have to be constructed so as to avoid many of these water areas, not only from environmental considerations, but from construction feasibility as well. While the proposed route crosses wetlands also, these are already crossed by the railroad. Potholes crossed by the railroad are interconnected with conduit to equalize water levels. Construction of the pipeline adjacent to the railroad may not be feasible at all pothole crossings, and some deviation from the ROW may be required.

Another significant difference between the proposed route and Alternative 1 is the amount of agricultural land impacted during construction. Since construction would occur during the summer and fall growing season, at least one season's crop would be lost on disturbed lands. The proposed route will be constructed within the railroad ROW and no cultivated areas will be crossed except for occasional parcels leased by farmers. Alternative 1 would be constructed primarily on agricultural land.

The total cost of the project and, thus, the cost of the delivered SNG, is increased by the increased length of the proposed route. Alternative 1 would be about 70 miles shorter and would require 8 perennial stream crossings to the proposed route's 12 (excluding the Snake Creek Embankment). The overall human hazard would also be less with Alternative 1 because of its rural location. A pipeline constructed in urban areas is more susceptible to accidental disruption by human activity.

b. Connect with Northern Border Pipeline

The shortest of the three alternatives studied would be a 25-mile pipeline to the closest point of intersection with the proposed Northern Border Pipeline (NBP) which would be bringing Alaskan natural gas into the 48 contiguous States. Because of the competetive proposals for transporting Alaskan gas, a question exists as to whether or not the NBP will even be built. Also, the NBP would require significant changes in capacity to handle the SNG on top of Alaskan gas. Add to these the problems associated with intermixing the lower Btu-rated SNG into a multicompany pipeline and this alternative does not appear viable at this time.

c. Connect with Mid-Western Pipeline Facilities

This alternative would require essentially the same pipeline route as either the proposed route or Alternative 1 to an intersection with an existing 24-inch-diameter gas pipeline in Polk County, Minnesota, owned by the Mid-western Pipeline Company. The environmental impacts, therefore, would be about the same as those for either the proposed pipeline or Alternative 1. There is some doubt that the 24-inch pipeline has the additional capacity to handle the volume of SNG produced without extensive modification.

8.2.3 Alternative Railroad Spur Routes

Five alternative routes were considered for the railroad spur from the existing Burlington Northern mainline to the plantsite (Figure 8-3). The fifth alternative was selected by ANGCGC because: (1) it is the shortest distance to existing track in the primary shipping direction, (2) it has only moderate grades, (3) it would involve the least amount of earthmoving, and (4) it would have the lowest construction and operating costs. In addition, about 25 percent of the proposed ANGCGC siding would involve the use of existing track, thus the degree of environmental impact would be less than that of the other alternatives because they would require longer lengths of new track.

8.3 Resource Use Alternatives

8.3.1 Local Use Alternatives

8.3.1.1 Coal

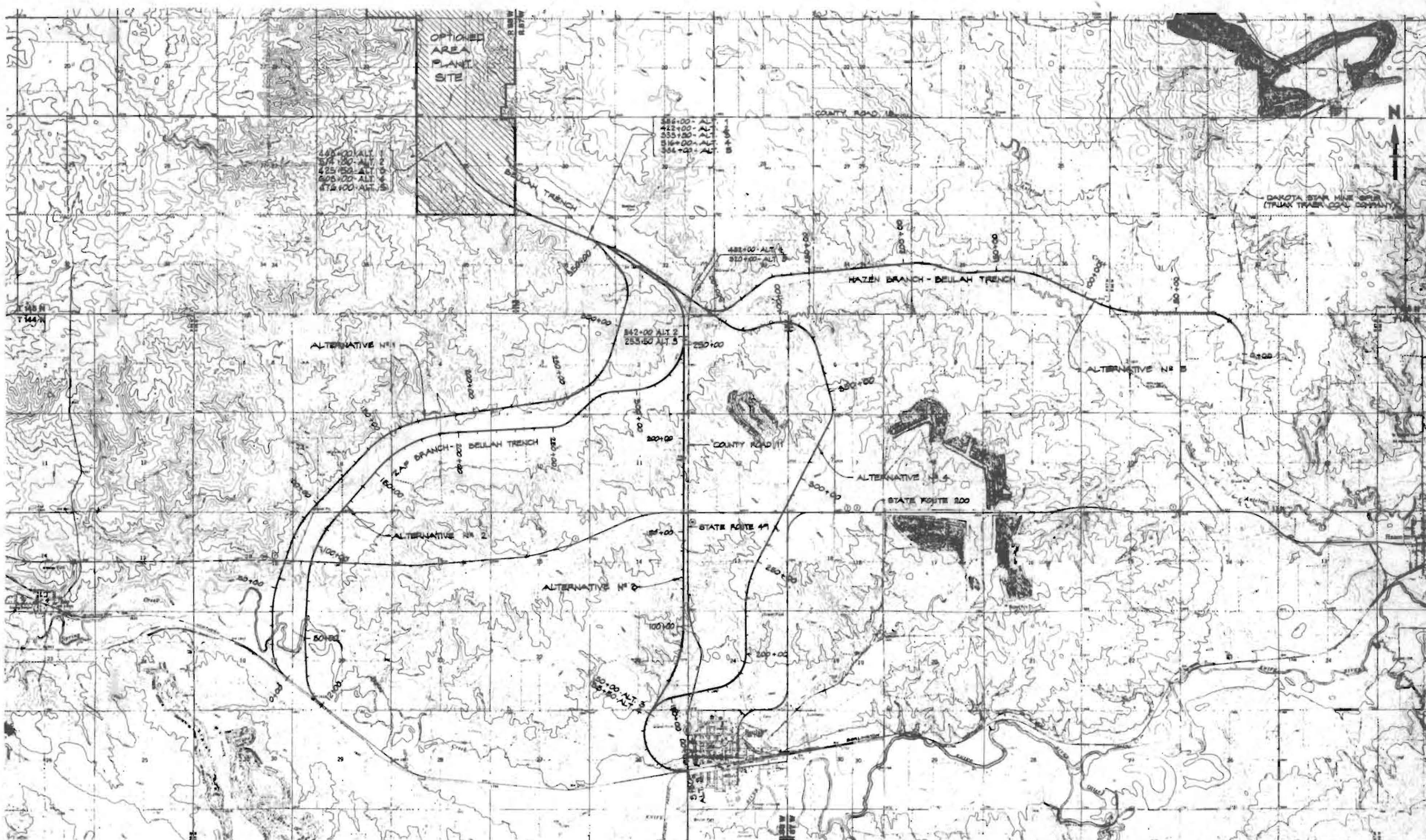
The two most viable alternative uses for energy production of the coal committed to the proposed project would be for liquefaction or steam electric generation.

a. Coal Liquefaction

As an alternative to gasification, coal may be converted, either by pyrolysis or by dissolution in a solvent, into a range of fuels. These include clean gas, low-sulfur oils, solid char, and solvent refined coal. All of the pyrolysis and dissolution processes are broadly referred to as "coal liquefaction," although the end products include gas and solid fuels as well as liquid fuels.

Pyrolysis involves heating the coal at pressures of about 10 psig to clean out the volatile hydrocarbons, and then catalytically hydrotreating the hydrocarbon liquids to desulfurize them. Relatively large amounts of gas and solid char are produced along with the hydrocarbon liquids. Some of the gas or char can be converted to supply the hydrogen needed for hydrotreating the liquid products, or the char can be gasified to produce additional clean gas. The heat required for pyrolysis can be obtained by burning some of the char with oxygen or air (55).

The dissolution processes actually dissolve coal in a hydrogenerated solvent oil at temperatures of 750 to 850° F and pressures of 150 to 2,500 psig. The end products (after recovery of the solvent



1. BACKGROUND MAP REPRODUCED FROM U.S.G.S. 7.5 MINUTE SERIES QUADRANGLE MAPS.

10-22-78 CHANGED PLANT SITE BOUNDARY

SCALE 1" = 2000'

J.P. TEMPLETON

C.F. VILLEGAS

FIGURE 8-3

ANG COAL GASIFICATION COMPANY

NORTH DAKOTA GASIFICATION PROJECT
PLANT ACCESS RAILROAD
ALTERNATIVE ALIGNMENTS

JOB No. 7381 DWG. No. 401-C

oil) include gas, oil, and char or a coking feedstock. In one process, solvent refined coal is produced.

None of the pyrolysis or dissolution processes have yet been commercially developed. Many small pilot plants are operating or planned, but unless funding and development are accelerated, it will be 4 to 6 years before a large commercial plant will be feasible. The overall thermal efficiency of the coal liquefaction processes is expected to be 65 percent -- which compares well with the 66 percent thermal efficiency of a Lurgi coal gasification plant.

Lacking detailed designs for liquefaction plants, it is not possible to detail particulate, NO_x, or SO_2 emissions. However, it has been estimated (47) that SO_2 emissions would be in the area of 13 to 20 tpd compared to about 30 tpd by a gasification plant. Generally speaking, all other environmental factors involved with coal liquefaction would be about the same as those associated with coal gasification. However, since liquefaction processes can use high-sulfur coal, the coal would come from underground mines in the Eastern and Mid-western States instead of being strip-mined on the surface. Underground mining generally has less environmental impact than strip-mining.

b. Steam Electric Generation

Producing electricity from coal involves feeding pulverized and blended coal into a furnace by fuel nozzles. In the furnace, the coal is mixed with preheated air and ignited. Heat energy given off during combustion is transferred through furnace walls to convert water into steam. The steam is then piped through superheaters, heated to 1,000° F, and piped to a turbine where its energy is used to rotate the shaft of an electric generator. The resulting electrical output is delivered to an exterior transmission system after being transformed to a higher voltage in an adjacent switchyard. The thermal efficiency of a coal-fired generating plant varies between 30 to 40 percent depending on the age of the plant, the type of plant, and the types of generators and boilers used.

Land use impacts of such a facility would be similar to those of the proposed gasification project. Land requirements of the two types of plants are comparable; water requirements for the generating plant would be somewhat greater.

Even with available emission control measures, a coal-fired powerplant would produce greater emissions of particulates, SO_2, NO_x, and heavy metals than those produced by the proposed gasification plant. This would result in a degradation of ambient air quality and possible damage to the adjacent flora and fauna.

8.3.1.2 Water

The water that would be used by the proposed gasification plant could be used to supply about 8 million kilowatt-hours (1 MW) of hydropower annually. It could also be used for navigation purposes to achieve a slight increase in the navigation season downstream. There would be no environmental consequences from either of these uses in regards to the present situation.

Because of the large amount of water available in the Missouri main-steam reservoirs, the use of 17,000 acre-feet annually for the coal gasification facility does not preclude irrigation, recreation, or other industrial use. Thus, the hydrogeneration of about 8 million kilowatt-hours of electricity is the only viable alternative in the foreseeable future to the use of the water that would be used by the gasification plant.

8.3.1.3 Land

The alternative uses of the land involved in the project would be for cropland, grazing land, and/or wildlife habitat. Again, the environmental impact of such use would not differ from present day levels.

8.3.2 Exportation Alternatives

8.3.2.1 Coal

Coal could be exported to almost any place in the United States for use in an industrial facility in or near the area to be serviced. The impacts of the mining operation in Mercer County would be similar to those of the proposed gasification project. Impacts of transporting the coal are discussed in Section 8.2.1. The major favorable aspect of using the coal in the service area is that the user of the finished product would have to bear some of the environmental costs. For example, air and water pollution would increase in the service area rather than the minesite. Social impacts of the work force would be less intense or entirely masked by locating the plants near large population centers, but larger numbers of potentially susceptible persons would be exposed to the pollutants.

8.3.2.2 Water

The water could be physically transported to another area for industrial, irrigation, municipal, or other uses. To transport the water, pipelines or canal systems and pumping facilities would have to be constructed. These facilities would cause land to be disturbed along the routes and could result in such impacts as habitat loss, erosion, reduced soil productivity, and decreased water quality. There would also be environmental impacts in the areas receiving the water depending on what type of facilities were constructed.

8.4 Alternative Energy Sources

8.4.1 Oil

Additional sources of oil could come from domestic or foreign supplies. United States crude oil production peaked in 1970 and reserves have fallen each year since 1966 (51). Only the discovery of the Prudhoe Bay field in the Alaskan North Slope was a temporary exception to the downward trend. Outer Continental Shelf (OCS) development could also add significantly to United States crude production, but the move into frontier areas and deeper waters will impose higher costs on oil production. Even with increased exploration and drilling, however, it is doubtful that United States crude oil production can even keep up with demands much less provide a reasonable alternative to coal development.

The availability of large volumes of foreign crude oil is by no means assured. World oil supplies are finite and the United States will increasingly find itself competing with the rapidly expanding economies of other countries for the foreign oil. The cartel of oil-producing countries has controlled the price of foreign crude and has threatened to use it to influence United States foreign policy. Foreign oil supplies will certainly become more costly and tenuous as competition for energy supplies increases.

Environmental impacts of oil production include those of drilling, extraction, transportation, and refining. Oil spills and discharges are the most notable hazards to offshore drilling and foreign crude importation.

8.4.2 Coal

Since coal is the most abundant fossil fuel in the United States, consideration should be given to its use in solid form. One advantage to using coal solids would be that the Btu loss in conversion processes would not occur. The major problems are those of air quality and substitutability. The problems are particularly significant for coal-fired electrical generation because the largest market for coal--and many severe air quality problems--are in the East and many major deposits of coal are in the West. Considerable research is being devoted to the development of economically feasible processes for the treatment of coal before burning to remove excess sulfur, to improve combustion processes, and to remove pollutants from stack gases after combustion. Where air quality standards can be met, coal can substitute for gas at facilities designed to use either.

Environmental impacts associated with increased use of solid coal would be those associated with mining, transportation of the coal or product (i.e., electrical transmission lines), and the construction and operation of coal-fired facilities.

8.4.3 Generation of Electricity

8.4.3.1 Hydroelectric

The total conventional hydroelectric power potential of the United States is estimated to be about 179,000 MW (53). The better hydroelectric sites are concentrated in areas of heavy precipitation and large topographic relief. Although most available sites for the economical production of hydroelectric energy have been developed, some additional capacity will be provided by new sites, expansion of existing facilities, and development of new technologies to obtain better operational efficiencies. Use of hydroelectric power to service peak loads enhances benefits, permitting consideration of possibilities that were formerly marginal or uneconomic under higher capacity factor standards.

The environmental impacts are primarily those of construction and the irretrievable commitment of the land resources beneath the dam and lake. Operation of the hydroelectric powerplant itself produces no air pollution, radioactivity, or waste heat. Studies conducted in 1971 indicate that high nitrogen levels in the Columbia and Snake Rivers pose a serious threat to the salmon and steelhead resources of the region. The Corps of Engineers and Bureau of Reclamation are actively engaged in studying and testing several approaches to solving the nitrogen problem.

8.4.3.2 Nuclear

The use of nuclear power as a commercial electrical energy source could increase considerably in the next 15 years. Installed capacity in June 1974 was 28,000 MW which represents about 6 percent of the Nation's electricity. Nuclear power development is presently being slowed by various siting, construction, and environmental problems. If nuclear facilities are not constructed, the equivalent of any one fossil fuel required annually to fill the existing gap by 1990 would be 26.9 Tcf of natural gas, 1.28 billion tons of coal, or 5.28 billion barrels of oil. Up to 10 years are required to construct nuclear powerplants; in the short term, nuclear development cannot be greatly increased.

Environmental impacts of nuclear powerplants are those of construction, waste heat disposal, radioactive waste disposal, and the small amounts of radionuclides discharged in the cooling water and gaseous plant effluents. The removal of vegetation and the creation of waste rock and overburden result from mining the uranium. To minimize the risks of accidents or their adverse effects if one does occur, plants are located away from high population areas and are designed to prevent accidents and to contain the effects of accidents if they do occur. Radioactive wastes must be isolated from the biosphere for hundreds of thousands of years if adverse effects to living organisms are to be totally avoided. Waste is presently disposed of in underground man-made facilities. Pilot studies of storage in salt beds are being conducted.

8.4.4 Geothermal Steam

The greatest potential for geothermal energy exists in the western third of the United States. The Geysers field in California was producing 552 MW of electrical energy by the end of 1974. Three areas planned for initial development soon are: Imperial Valley, Mono Lake-Long Valley, and Clear Lake Geysers, all in California. Within 20 years geothermal energy may account for 1 to 2 percent of the total United States energy, but in California, it could account for up to 5 percent of the State's energy consumption.

The major environmental objection to geothermal power development stems from the intrusion of industrial development into pristine areas. Other potential environmental impacts include those associated with construction, drilling, and transport. Air quality could be affected at sites where relatively large quantities of ammonia, hydrogen sulfide, and methane are associated with the steam. Generally, however, geothermal impacts on air quality are smaller than those associated with conventional fossil-fuel powerplants.

8.4.5 Oil Shale

Oil shales of the Green River Formation in Colorado, Utah, and Wyoming represent a very large energy resource. The deposits occur over a 17,000-mi^2 area (11 million acres), and contain an estimated 600 billion barrels of oil (52). The ultimate size of the oil shale industry will most likely not be determined by the size of the resource but will probably be limited by other factors, such as the availability of water and environmental considerations. In addition, since economics and technology are still uncertain and in the early stages, oil shale development could be severely affected by soaring costs and the general uncertainty in the energy situation.

Environmental impacts of oil shale development would be those of roads, mining, plantsites, waste disposal areas, utility and pipeline corridors, and associated services. These activities would change the existing patterns of land use, alter the existing topography, and affect natural vegetative cover until revegetation begins. Revegetation would be difficult because of the arid climate.

8.4.6 Solar Energy

Solar energy conversion systems which could work as an alternative energy supply are still in developmental stages. Conversion efficiencies of existing systems are relatively low averaging about 30 percent for conversion to heat and 5 percent for conversion to electricity. A 1,000 MW solar powerplant would require about 37 mi^2 of collector surface, assuming a normal solar climate and using presently available technology. The most promising method of using solar energy is a hybrid system for house heating and cooling. Such a hybrid system could use either gas, oil, or electricity as the auxiliary energy supply. Approximately 75 percent of the energy required for a home in the Southwest would be supplied by solar energy; the remainder would come from auxiliary systems. Development of such a hybrid system could extend the Nation's fossil-fuel reserves considerably.

Since solar energy systems are still experimental, the environmental impacts are not known. The largest potential impact is the large amount of land surface required for collector systems. If this problem could be solved, other impacts would probably be relatively minor.

8.4.7 Other Sources

Other possible sources of energy include tidal power, wind energy, and biological energy. The only practical opportunities for tidal power in the United States appear to be at Passamaquoddy Bay, Maine, and Turnagain Bay, Alaska. However, economic considerations have prevented development of this energy source in the past. Environmental problems would be considerable. Damming with alternative filling and draining of the bays would affect shipping, sport and commercial fisheries, wildlife, water quality, aesthetics, and numerous other uses of the bays and estuaries.

A fixed device could capture the kinetic energy of wind by rotation about an axis and, coupled to a generator or gears, convert it to mechanical or electrical form. The high cost of equipment, energy storage, and backup equipment coupled with the intermittent characteristics of the wind preclude a favorable cost benefit of wind energy at the present time. The chief environmental impact is the adverse aesthetic effect of large numbers of towers and assorted equipment.

Systems to use biological waste to make energy are still in the experimental or pilot stages (81). The potential energy that could be derived from this source could be of significant magnitude; an estimated 2 billion tons of organic waste is produced in the United States each year. This waste could be used to generate 147 trillion Btu's of energy within 10 years. Environmental impacts associated with this resource will be unknown until such time as specific systems are devised and developed.

Implementation of conservation measures could significantly help save energy and make our existing fossil-fuel resources last longer. In 1972, the Office of Emergency Preparedness estimated that a list of proposed conservation measures could reduce United States energy demands by 15.35 quadrillion Btu (QBtu) by 1980, and 34.9 QBtu by 1990. However, the proposed list of conservation measures included many admittingly with low "public acceptability" and "likelihood of implementations," so it is highly unlikely that such high energy savings could realistically be achieved.