THE POTENTIAL FOR
HIGH-BTU COAL GASIFICATION
IN ADAMS COUNTY, COLORADO

by

Richard Michael Stanwood

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A Thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science, Mineral Economics.

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ABSTRACT

Project feasibility analysis in the United States can no longer consist merely of technical and economic feasibility because of the Congressional mandate for consideration of the environmental and socio-economic factors of development, and the practical necessity in today's world to consider policy factors. Decision-makers from the diverse interested parties (industry, government, special interest groups, etc.) which will be involved as development plans are formulated and progress, must be aware of these critical variables in the preliminary planning stages so that rational decisions are made through consideration of all relevant information, and so that costly delays do not occur if development is deemed appropriate.

This report applies this concept to a site-specific case by assessing those factors which are currently affecting, and those that may affect in the future, the potential for high-Btu coal gasification development in Adams County, Colorado. These critical factors consist of the rationale

for development, along with physical, technological, economic, environmental, socio-economic, and policy variables. Each must be carefully examined before a realistic determination of overall project feasibility can be made. It is clear that many of these variables, under current circumstances, consist of constraints to development, which must be overcome by potential developers before strip mining and gasification operations could begin in Adams County. Information contained in this report should be of value to the many decision-makers who will be involved in determining if, when, and how, development will occur.

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CHAPTER 1. INTRODUCTION

Coal gasification is one of a number of energy alternatives currently being considered in the effort to meet future energy demand. Adams County, Colorado has generated considerable interest as a possible coal gasification site because of its lignite and other available resources necessary for development.

To determine overall project feasibility (or the potential for development), a wide variety of factors affecting development must be considered. These factors include the rationale for high-Btu gasification along with physical, technological, economic, environmental socio-economic, and policy variables.

The following study is a comprehensive assessment of the potential for coal strip mining and high-Btu gasification development in Adams County. Information contained in this report should be of value to the many decision-makers who will determine if, when, and how development will occur. These decision-makers are currently hampered by a lack of available information on many of these factors which must be considered in the pre-planning and planning stages of development. This document is intended to fill this gap.

CHAPTER 2

THE RATIONALE FOR HIGH-BTU COAL GASIFICATION

U.S. Energy Situation and Brief Review of Past Use

The era of low-cost clean energy sources in the form of petroleum and natural gas is coming to an end. In 1977, the United States consumed approximately 75.9 quads (quadrillion Btu's) of energy, as shown in Table 1, and although oil and natural gas were still the primary sources of fuel, domestic reserves (economically and technologically recoverable today) of these two sources of energy cannot keep pace with the ever increasing demand in this country.

Today, the United States relies heavily on foreign sources of crude oil and liquefied natural gas (LNG), but these sources are unreliable (as shown by the Arab oil embargo and resulting "energy crisis" of 1973-74) and contribute to the balance of payment and inflation problems facing this nation. The natural gas and oil physical resources have been rapidly depleted in a short period of time, and the United States is now forced to develop alternative sources of energy to gain energy reliability and independence from foreign sources. Research and development efforts in both government and private industry are exploring all possible sources including the gasification of coal.

However, the use of gas produced from coal is certainly not new. Manufactured gas from coal was first used for illumination in England in 1802 and in the United States in 1813. Illumination was the major use for this synthetic gas until the 1900's when it began to be used in the residential cooking and space heating markets. Manufactured gas was the principle supplier to the eastern residential gas market as late as 1932 (1). But easy availability and cost advantages forced the rapid development of the oil and natural gas industries, and the science of coal gasification has been all but forgotten until recent years.

Table 1

U.S. Energy Consumption for 1977

Primary Energy Source	Energy Use in Quads	Percent Use
Petroleum	36.9	48.7
Natural Gas	19.6	25.8
Coal	14.1	18.6
Nuclear	2.7	3.5
Hydroelectric	2.5	3.3
Geothermal Power	0.1	0.1
Total Consumption	75.9	100.0

Source: Shimoda and Dew, 1978, p. 6.

Natural Gas

Natural gas demand has nearly reached the limit of available supply. It is a convenient, clean-burning source of energy, and a large portion of residential energy end-use is equipped to handle natural gas as its main source of energy. Natural gas price regulation (begun with the Natural Gas Act of 1932) by the United States government had encouraged use of this fuel, and with this sufficiently low price, there were no incentives for increases in production or for conservation of natural gas by the consumer.

However, consumption of this premium fuel has been falling since 1972, when consumption reached a peak of 22 trillion cubic feet. Domestic production has been on the decline since 1971, and the only recent significant addition to natural gas reserves has been the Alaskan North Slope in 1970. The shortfall in supply has been filled with imports of natural gas from Canada and Mexico and of LNG from Algeria. Imports from these sources plus LNG from Indonesia can be expected to increase in the coming years if these supplies remain available on the international market. The United States government has adopted a policy of incremental (or marginal) pricing of LNG to the user. This is a significant barrier to expanding these sources of fuel when considering the existing policy of rolled-in (or average) pricing where the additional cost is shared by all consumers and the impact upon any one consumer is reduced (2).

The Natural Gas Policy Act of 1978 (part of the National Energy Act of 1978) has eased the critical natural gas shortage somewhat in early 1979 by increasing the allowable price of natural gas and removing market distortions of the interstate market. Unregulated intrastate markets had accumulated major surpluses of natural gas, and this legislation has allowed the movement of this surplus from the intrastate market to the interstate market and increased the incentive for domestic exploration and production. This mitigation of the natural gas supply problem is only temporary, however, and cannot continue as long as the limited physical resource is rapidly being depleted.

Coal

In contrast to natural gas, coal supplies in the United States are plentiful. On the basis of a weighted analysis of data on resources of fossil fuels in the country (as of January 1, 1974), recoverable resources of coal are estimated to contain approximately ten times more heat value than the United States' combined recoverable resources of petroleum and natural gas (3). If the 1977 coal production rate of 688 million short tons were to continue at the same pace, the nation would have a coal supply for the next 375 years. A demand growth factor of three percent per year applied to the 1977 base-year production reduces this supply estimate to 84 years. A growth factor of five percent per year (which may be unattainable because of the many constraints on coal production) would still supply coal for the next

60 years. The United States coal reserves, then, appear to be large enough to satisfy a large portion of the nation's foreseeable future energy needs.

However, the fact remains that this country is tied to the use of petroleum and natural gas today because of their liquid and gaseous forms, respectively, for use in existing equipment. Additionally, the direct burning of coal is a dirty process which produces a number of environmental problems, so other uses of coal must be found if this abundant resource is to be used in increased quantities in the future.

Alternatives to Domestic Natural Gas

There are several alternatives to the use of domestically-produced natural gas. One of those previously mentioned is increased imports of natural gas and of LNG. These sources of energy are unreliable because of political influences, growing world energy needs and increased international competition. Both Europe and Japan can afford to build a gas economy based on imported LNG, and they may lay claim to the supplies from their geographical areas. Additionally, LNG importation is a potentially dangerous process because of explosion if exposed to air, the United States is very inefficient in the importation of LNG because of the lack of adequate harbor facilities to handle supertankers in the east coast ports, and large-scale importation would impose great strains on the ability to consume energy at the incremental prices (4). Even with these problems, some LNG importation can be expected; however, it is clear that this alternative is not a solution to replacing domestic natural gas.

Imports of natural gas, even from the neighboring countries of Canada and Mexico, are unreliable. Canada has threatened to shut off contracted supplies to the United States several times to meet their own needs. With respect to Mexican natural gas, the Department of Energy did not allow a consortium of American companies to complete an agreement with Mexico to purchase gas at $2.60/MCF in the summer of 1978 (5). Political uncertainties with Mexico appear to be a major stumbling block to increasing Mexican imports.

The second major alternative to natural gas is domestic production of substitute (or synthetic) natural gas (SNG) from coal. The goal of high-Btu (approximately 1000 Btu/MCF) coal gasification is to produce an end product indistinguishable from natural gas. The SNG would be of pipeline (transportable) quality and suitable for any use which is accomplished by natural gas. Although this source of energy would be reliable, it is very expensive and has not been tried on a commercial basis in the United States.

The last major alternative to natural gas use would be an increased use of electricity, which can perform the residential end-uses of cooking and space heating now accomplished on a large-scale basis by natural gas. Electricity, like natural gas, is clean and efficient at its end-use and is available to almost all consumers with currently installed equipment. Electricity can be produced from many different sources of fuel, but it is clear that any large increase in its use will have to be met by coal and/or nuclear power plants. Nuclear power is confronted with a number of environmental, economic, social and regulatory problems today, and the predicted rapid development of this industry may never take place. Electricity from coal is also facing a number of problems, but these may be resolved more easily and sooner than the nuclear problems, so it is anticipated that as natural gas availability declines, the major sources of domestic natural gas replacement and increases in residential energy demand will be SNG from coal and an increase in electricity production from coal. Even with rapid electricity growth from nuclear and/or coal plants, there will be a need for SNG to supplement dwindling natural gas supplies during the 1985-2000 period.

Comparison of SNG and Electricity from Coal

Although electricity end use is somewhat more flexible and convenient than natural gas or SNG end-use, the American Gas Association (AGA) reports that in comparing coal consumption for electricity generation and coal consumption for production of high Btu SNG, the gasification of coal appears to have several advantages over electricity generation. The following results were obtained by the AGA(6) in their study of these two alternatives:

1) On the basis of efficiency of the utilization of the energy content of the coal, gasification of coal is estimated to considerably more efficient than coal electrification. Using conventional technologies at the residential end-use, the overall system efficiency is 36 percent for coal gas and 25 percent for electricity. Using advanced technologies at the end-use (heat pumps), the efficiency advantage of coal gas is substantially higher in almost all regions of the country with the greatest advantage for coal gasification in the most northern parts of the continental United States (62 percent for coal gas versus 35 percent for electricity).

2) From an environmental standpoint, coal gasification plants would result in significantly less air pollution, would generate less solid wastes, and would use far less water than a coal-fired electric power plant producing the same amount of useful energy. For comparable size plants, air emissions are between nine and twelve times less for coal gasification, depending on the category. With respect to water use, a coal gasification plant is estimated to consume 88 percent less water than a comparable coal-fired electric plant (see Table 2).

3) With respect to the cost of the energy to the end-user, coal gasification has substantial advantage over coal electrification, even when advanced end-use technologies are employed.

Table 2

Comparison of Environmental Impacts of Gasification and Electrification of Coal (energy equivalent projects)

Environmental Impact	High-Btu Gasification (250 MM CF/d)	Electricity (3,000 MWe with scrubbers)
Air Emission (lb/hr)		
Particulates	180	1,070
Sulfur Dioxide	450	4,300
Nitrous Oxides	1,780	20,830
Carbon Monoxide	90	1,200
Hydrocarbons	30	360
Water Requirements (acre-ft/yr)	6,300	54,300
Solid Wastes (tons/day)	1,400	5,100

Source: American Gas Association, 1977, Comparison of Coal Use for Gasification Versus Electrification, p. 7.

> For current technologies (i.e., using electric resistance heating and conventional gas furnaces), the average residential cost of energy used would be about $7/MM Btu (million Btu) for coal gasification versus about $14/MM Btu for electricity from coal. Using advanced space heating technologies (i.e., heat pumps), the cost of energy from gas produced from coal is between $4 and $5/MM Btu depending on the geographical area compared with $7 and $10/MM Btu for electricity for the same area (1976 dollars).

Summary of Rationale

From the previous perspectives and analyses, the following benefits (in addition to the advantages over electricity generation from coal) may be attributed to high-Btu coal gasification production as reported by Edwards, et al (7):

1) Coal gasification permits utilization of the United States' enormous coal reserves at a time when reserves of oil and natural gas are declining.

2) The fuel produced will be environmentally sound; that is, SNG can be used anywhere throughout the country without contributing significant quantities of pollutants to the air.

3) SNG production will reduce the dependence on politically unstable foreign fuel supplies, thereby increasing energy self-sufficiency.

4) This shift away from foreign fuel supplies and toward energy self-sufficiency will both increase national security and decrease the inflationary balance of payments deficit.

5) The fuel produced will be easily storable and transportable, a decided advantage over raw coal.

6) The fuel produced will allow continued useful access to natural gas lines, precluding the expense and necessity for converting to electric home heating and coal-fired industrial processes.

7) Reduced importation of oil will reduce any potential adverse environmental impacts of shipping, e.g., ocean spills or other accidents.

Status of Commercial Development in the United States

Ten to fifteen high-Btu coal gasification facilities have been proposed at various sites across the United States, although no plant has even come close to beginning production on a commercial scale. Those area with the highest potential for gasification development as designated for the

U.S. Bureau of Mines by Lindquist are shown in Table 3. Area numbers 6 and 8 from this table have been the sites of the most activity.

In the San Juan County area of New Mexico, both the El Paso Natural Gas Company and WESCO (Texas Eastern Transmission Corporation and Pacific Lighting Corporation) have proposed sites for gasification facilities. Both groups have completed extensive engineering design and planning for their plants and associated coal mines and have prepared final environmental impact statements, but their status is now in limbo because of difficulty in obtaining Federal Power Commission (now the Federal Energy Regulatory Commission) approval and problems with financing and obtaining coal and land rights on Navajo Indian lands.

In the Dunn and Mercer County area of North Dakota, both the American Natural Resources Company (a consortium of five pipeline companies) and the Natural Gas Pipeline Company of America have made plans to construct gasification facilities and associated coal mines. Again, extensive engineering design and planning have been completed and the environmental impact statement and environmental impact report, respectively, have been prepared and released to the public, but neither project has received Federal Energy Regulatory Commission (FERC) approval.

Table 3

Areas of High Potential for Gasification Development*

Area Number	State and County	Type of Reserve Base
1	Ohio (Jefferson, Harrison, Belmont); Pennsylvania (Washington, Greene); West Virginia (Marshall, Marion, Monongalia)	Deep
2	Kentucky (Hopkins, Muhlenberg, Webster, Union, Henderson); Illinois (Hamilton, Williamson, Saline, Gallatin)	Strip-deep
3	Illinois (St. Clair, Washington Perry, Madison, Sangamon, Christian, Macoupin, Montgomery, Bond)	Deep-strip
4	Illinois (Vermilion, Edgar)	Strip-deep
5	Illinois (Knox, Fulton, Peoria)	Strip
6	New Mexico (San Juan)	Strip
7	Montana (Big Horn, Rosebud, Powder River, Custer); Wyoming (Campbell, Johnson)	Strip
8	North Dakota (Dunn, Mercer)	Strip

*Author's note: There are several other areas of the United States (including Adams County, Colorado) which show high potential for development on a smaller scale than those areas listed here.

Source: Lindquist, 1977, p. 32.

The American Natural Gas project in Mercer County (which would produce gas at approximately $5.50/MCF) was awaiting final approval from FERC after obtaining Department of Energy support when six states announced that they opposed the financing plan for this project. This plan would have increased the monthly utility bills of consumers in the area during the construction phase (before SNG was actually being produced) and consumers would help to pay for the project even if the plant failed. The status of these projects is temporarily in limbo, although the North Dakota area represents the best chance of constructing the first commercial size high-Btu coal gasification plant in the United States.

Adams County, Colorado is not listed in Table 3 as an area of high potential for large-scale gasification development. However, discussion and planning of such a facility began in 1969. If development were to have been seriously considered in that year, most likely only technical and economic studies would have been completed to determine the potential for coal gasification. Today, however, this determination of potential must include analyses of the site-specific environmental, socio-economic, and policy parameters in addition to the technical and economic studies. Attention must now be given solely to the Adams County and to the

Denver metropolitan area for an examination of the physical, technological, economic, environmental, socio-economic, and policy considerations of development to determine the potential for coal gasification in Adams County.

CHAPTER 3

THE CONCEPT OF SNG PRODUCTION IN ADAMS COUNTY

Regional Setting and Description

The five counties of Adams, Arapahoe, Boulder, Denver, and Jefferson form the Denver Standard Metropolitan Statistical Area. This region encompasses approximately 3,660 square miles and ranked 27th in metropolitan population in the United States in the 1970 census with a population of 1,227,529. The five county population is forecast to increase to 2,350,000 by the year 2,000. Adams County is located north and east of the city and county of Denver, and covers an area of approximately 1,240 square miles, extending 72 miles east to west and 18 miles north to south. Rapid urbanization is occurring in the western section of Adams County because of its close proximity and easy access to Denver. However, the vast majority of land in the county has maintained a rural-agricultural character, with only six percent of the land area devoted to urban uses, while 45 percent is in dry land farming, 14 percent in irrigated cropland, and 30 percent in grazing and native grass (8).

The Denver Basin Coal Region

The Denver basin coal region consists of coal-bearing strata in eastern Colorado. Portions of Adams, Arapahoe, Boulder, Douglas, Elbert, El Paso, Morgan, and Weld counties are included within the region. Physiographically, the basin is in the dissected Colorado Piedmont of the Great Plains province of the Western United States. Topographically, the region is characterized by undulated plains, locally dissected by stream erosion. The northern portion of the basin is drained by the North Platte River and its tributaries; the southern part of the Arkansas River and its tributaries. Structurally, the region is a major synclincal depression, the axis of which trends from north to south; the deepest portion if located directly below Denver. The strata are near-vertical on the west flank where the basin sediments about the Front Range; they are moderately inclined on the north, east, and south sides, where the Laramie Formation outcrops in the plains. Coal of both Late Cretaceous and Early Tertiary (Paleocene) ages occurs in the Denver Basin, the Crateceous coal being in the Laramie Formation and Tertiary coal being in the Dawson Arkose or its lateral equivalent, the Denver Formation. Laramie coal ranges from subbituminous B rank in the western and northern portions of the basin to subbituminous C or lignite in the east and southeast. Tertiary coals are all lignite in rank. A range of analysis for all coals (as received) in the Denver basin, undifferentiated as to formation or location is shown in Table 4 (9). In any coal analysis, high moisture, sulfur and ash contents are considered undesirable, while a high volatile matter and fixed carbon content provide most of the energy in the combustion of coal.

It is estimated that approximately 13 billion tons of coal or lignite may be mined by surface methods on 912,341 acres. Figure 1 shows those areas considered to have some strippable coal resources (10). Additionally, more than 400 million tons of kaolin are contained in the lignite. Kaolin and bauxite are mineral bases used for production of aluminum and certain ceramics. This vast kaolin resource in the Denver basin may be competitive with the supply of bauxite imported to the United States from the Caribbean if developed along with the strippable coal resource (11).

The Watkins Project Concept

A reconnaissance drilling program was conducted by Jenkins and Bailey in 1965 which delineated a large strip-mineable lignite resource in the Denver basin trending 60 miles from Watkins, Adams County to Ramah, El Paso County. Private leases, State of Colorado leases and Federal

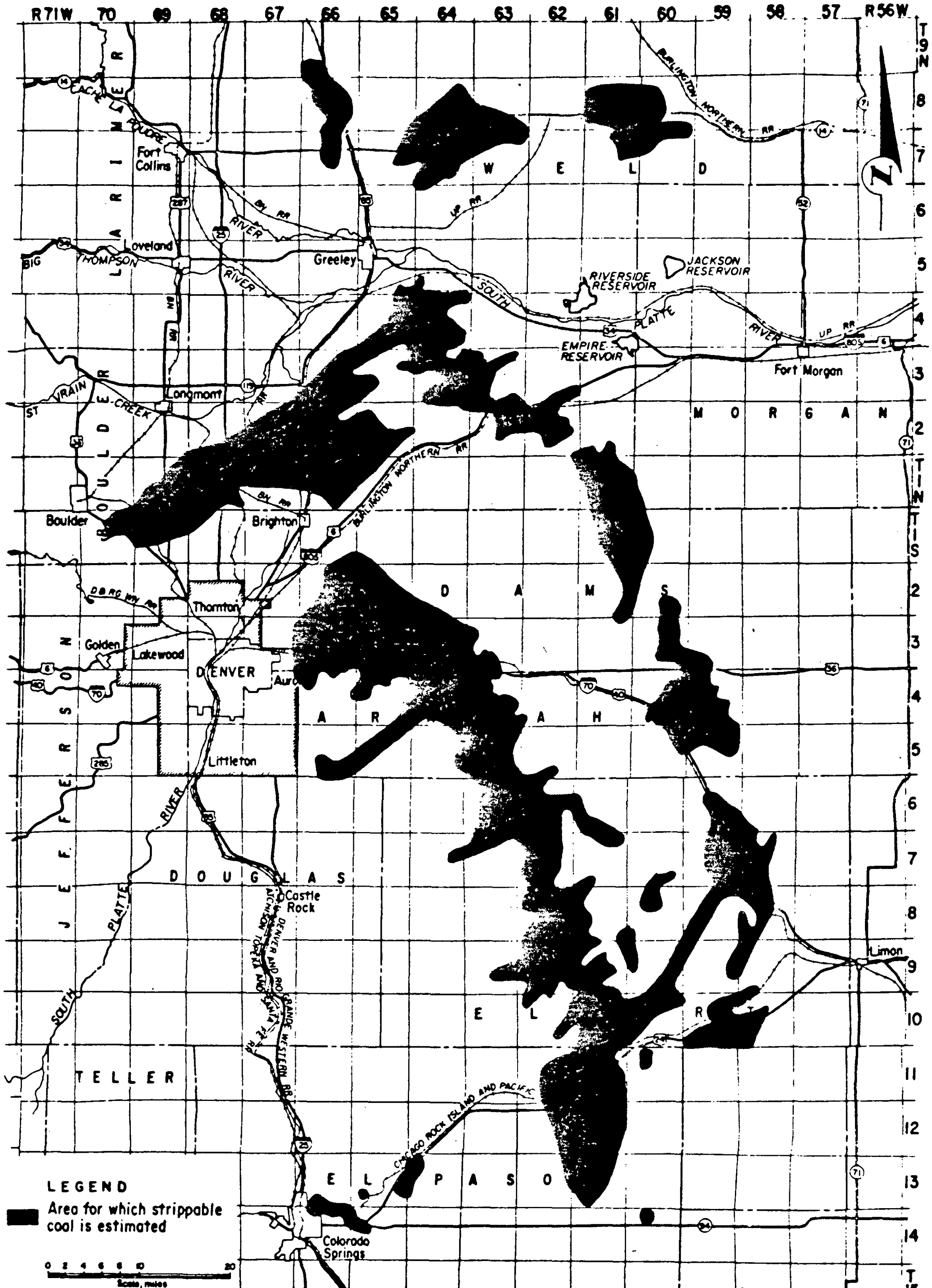


Figure 1. Strippable Coal Resources in the Denver Basin.

Source: Speltz, 1976, p. 43.

Table 4

Coal Analysis in the Denver Basin

Coal Constituent	Low	High
Moisture (%)	6.6	35.0
Ash (%)	4.3	14.6
Sulfur(%)	0.2	2.2
Volatile matter (%)	36.3	44.6
Fixed carbon (%)	49.3	54.9
Btu/lb	6330	12130

Source: Speltz, 1976, p. 42.

prospecting permits in the area were taken by Bailey, et al, in 1969 and 1970. Further exploration conducted by Cameron Engineers, Inc., for Mintech Corporation and Marathon Oil Company, successors to Bailey, et al, resulted in the selection of the Watkins area as the prime site for a commercial lignite gasification project producing 250 MMcfd (million cubic feet per day) of synthetic pipeline quality gas. The development was to be located in Township 3 South, Range 65 West in Adams County 17 miles east of the center of Denver. This area is presently used for dry land wheat farming. Since 1969, the concept, planning, and preliminary development of a lignite and solid waste high-Btu gasificationplant to be located near Watkins has been extensively studied by Cameron Engineers (12).

The basic lignite resource for the project would be an indicated 337 million ton recoverable reserve under 7,400 acres. This lignite is in one seam ranging in thickness from ten to thirty feet averaging 24.2 feet. The overburden stripping ratio averages 3.8 cubic yards per ton of lignite. The average heating value is 4,430 Btu per pound. Additional deposits exist two miles east of the primary deposit with reserves on the order of 200 million tons (13). The best use of this low-grade lignite does appear to be on-site coal gasification because of its low heating value and inability to be transported economically. This site in Adams County is especially attractive because of the availability of resources (in addition to the coal resource) such as water from Denver and Aurora uncommitted waste water or aquifers beneath the mine and plant sites; the Colorado Interstate Gas Company's gas produce pipeline one mile southwest of the mine site; transportation from Interstate Highway 70, the Union Pacific Railroad Company main line and Stapleton International Airport; labor supply from the Denver metropolitan area; existing community infrastructure and services; and power from the Public Service Company of Colorado (if the plant is not self-sufficient in site power generation)(14). Interest in this area has been shown by a number of other organizations.

An August 1975 listing of energy projects proposed in Federal Region VIII listed three gasification proposals in Adams County. Companies involved in these projects were Mintech Corporation, Kerr-McGee Corporation, and Cameron Engineers (15). An update of this document in 1978 (16) lists only one coal gasification facility planned for Adams County (Mintech Corporation listed as the operating company). Additionally, AMAX Coal Company has developed a potential mining scenario for use in identifying potential environmental impacts associated with surface mining in the area (17).

Strip Mining Application

A brief description of strip mining technology is given in Appendix A. The mining plan developed by Cameron Engineers for the Watkins project consists of a 27-year operation, with a 12.5 million tons lignite per year production schedule. As shown in Figure 2, the operation would exist exclusively on the west side of Box Elder (Running) Creek, a major watershed in the area, and progress east to west across the coal deposit (18). A potential mining scenario developed by AMAX envisions two mining areas, one on each side of Box Elder Creek. Mining of each area will be undertaken in each field separately, one field being mined out before instituting mining in the other field. Each coal

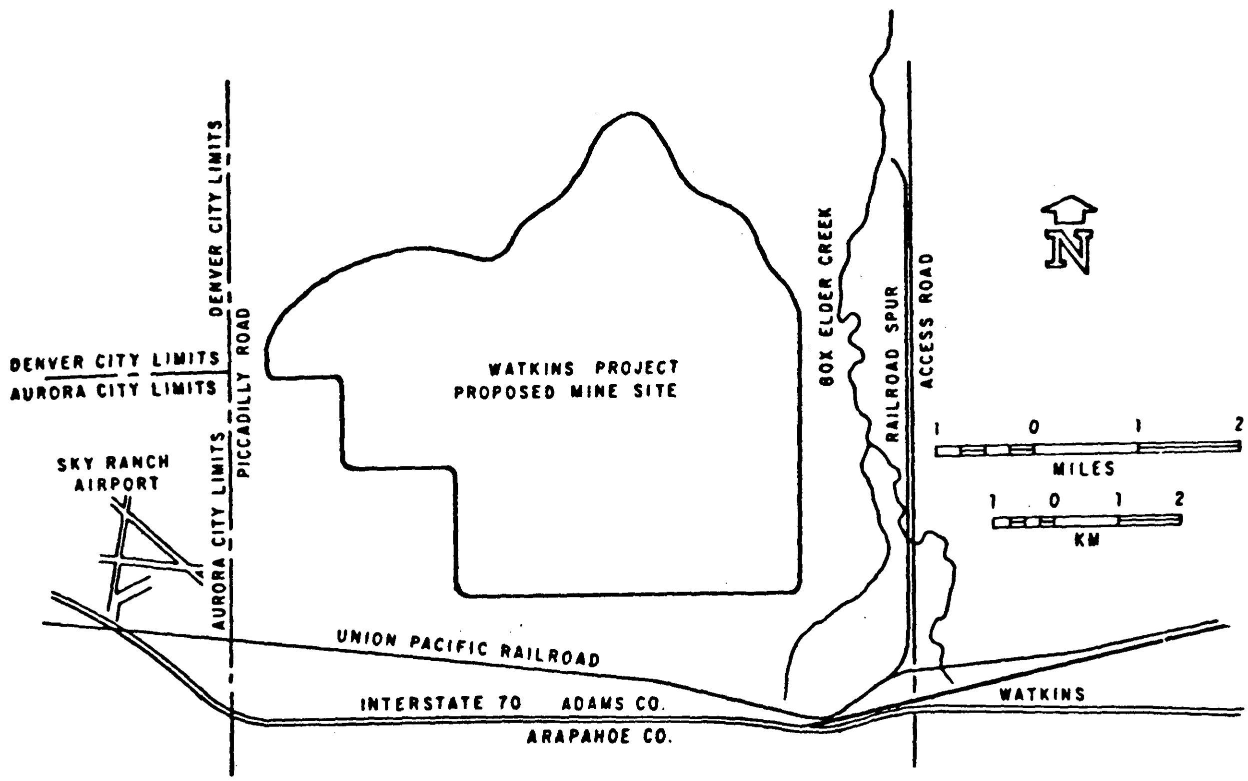


Figure 2. Watkins Project Proposed Mine Site.

Source: Argonne National Laboratory, 1978, p. 3.

field would have a 20-year life at a production schedule of five million tons lignite per year (19). It is uncertain if either of these plans represents the optimum mining strategy.

Surface ownership in the Watkins area is held by private individuals and real estate development companies. There has been considerable speculation by these companies in the last few years in the purchasing of land for future housing developments. Danford-Champlin Farms is the single largest private owner controlling about 10,000 acres on the eastern edge of and beyond the Watkins areas. Mineral ownership is split between private individuals, State, Rocky Mountain Energy Company (Union Pacific Railroad), and the Federal government. Rocky Mountain Energy is the largest owner, controlling approximately 50 percent of the minerals. Private individuals control the next largest amount, approximately 25 percent, with the remaining land split between the State and Federal governments. As of 1977, Cameron Engineers had control of 5,980.6 acres of private leases and 320 acres of Federal Preference Right (noncompetitive) Lease Applications in the Watkins area. The only other lessee in the area was United Electric Coal Company, which held a 640 acre State Lease (20).

If all necessary land in the Watkins area could be purchased or the right to mine gained through leasing the properties, a logical mining unit (LMU) would be formed. A LMU is an area of land in which the coal resource can be mined by a single operator in an efficient, economical, and orderly manner as a unit with due regard to the conservation of coal reserves and other resources (21).

Coal Gasification Application

A general review of coal gasification technology is given in Appendix B. There are many high-Btu gasification processes which are in the commercial and/or research stages of development today. All major proposed SNG projects to this point in time have considered only the Lurgi process (using fixed-bed gasifiers) for use in their facilities. Figure 3 shows an overview of the fixed-bed gasification process, which involves the upgrading of lower grade gas to pipeline quality SNG. The Lurgi process has been in use for many years (it is known as a "first generation" gasification process) in the production of medium Btu (approximately 300-500 Btu/cubic foot) gas, but with the addition of the methanation step to gasification technology in recent years, the Lurgi process has come to the forefront in high-Btu plant proposals because it is the most thoroughly demonstrated and researched process and has been successfully tested in its high-Btu form with American coals in Westfield,

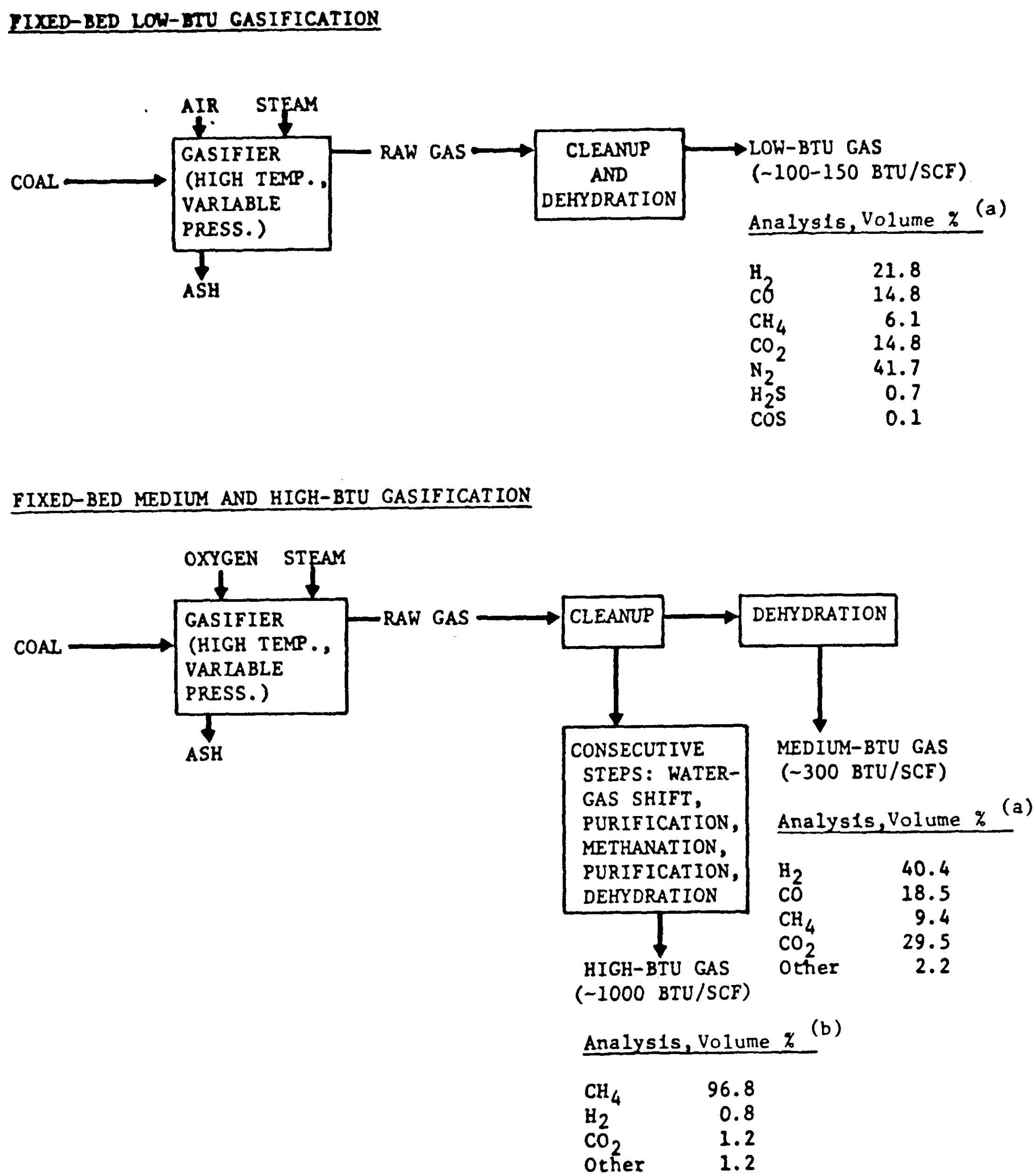


Figure 3. Fixed Bed Gasification Process Flow

Source: Energy Research and Development Administration, 1977, p. II-3.

Scotland and Sasolburg, South Africa. SNG was introduced into the Scottish gas system with no noticeable effects in 1974. Disadvantages of using this process include higher capital costs (resulting in higher gas costs to the consumer) and lower process efficiency. Appendix C gives a brief discussion of second-generation gasification technology and commercialization.

The Cameron Engineers gasification plant proposal called for use of the Lurgi high-Btu process, and coals from the Watkins area of Adams County were deemed acceptabel for use with Lurgi gasifiers by Lurgi Mineralotechnik in West Germany (22). The Watkins facility was also designed to use solid waste (5000 Btu/lb as received) and sewage solids (6500 Btu/lb as received) to be obtained from sources throughout the Denver Metropolitan area. The overall material balance for the Watkins gasification facility is shown in Table 5. Net energy considerations of coal gasification are discussed in Appendix D.

Table 5

Lurgi Gasification Process Material Balance

Basis: 250 million cubic per day SNG (954 Btu/cubic foot)

Inputs	Short tons per day
Lignite	34,300
Granulated Waste	5,870
Steam and Water	20,540
Oxygen	5,620
Total	66,330

Outputs	Short tons per day
Product Gas	5,530
Water	26,690
Ash	11,425
Phenols	95
Tar Product	820
Tar Oil Product	350
Naphtha	170
Ammonia	125
Elemental Sulfur	125
Off Gases (CO_2 and N_2)	31,000
Total	66,330

Source: Cameron Engineers, 1975, p. 47.

CHAPTER 4. ECONOMIC CONSIDERATIONS

SNG Market

The SNG supply produced in Adams County should have a ready market in the Denver Metropolitan area. The 1976 peak daily supply available for the entire Public Service Company of Colorado system was 1,282 million cf/day. This peak daily available supply is not expected to significantly increase or decrease in the next ten years (although there will be slight variations such as the new underground gas storage facility in Morgan County which will add about 25 million cubic feet of gas per day to supply capability in 1979 and a comparable amount the following year). Projections of the peak daily demand for the Denver area alone for 1985 and 2000 are 1,213 million cf and 1,585 million cf, respectively, which indicates a serious shortfall of natural gas supply occurring in the Public Service Company system sometime between 1985 and 2000 (23). The 250 million cf/day (approximately equal to 45,000 barrels of oil) SNG production in Adams County would help to offset this expected shortfall during this critical period of time. Table 6

Table 6

Projected Denver Area Annual Demand for Natural Gas (MCF)

Sector	1985	2000
Residential	99,498,000	130,043,000
Commercial	71,315,000	93,208,000
Industrial	62,493,000	81,677,000
Public Authorities	1,225,000	1,602,000
Other Utilities	10,538,000	13,773,000
TOTAL	245,069,000	320,303,000

Source: U.S. Department of Housing and Urban Development, 1978, Volume III, p. 57.

shows the projected metro area demand for natural gas by sector, while Table 7 displays the residential demand by urban service area for 1985 and 2000. Using these projected demand figures, an SNG facility in Adams County could supply 83 percent of the anticipated Denver area residential natural gas market or 34 percent of the entire Denver area market in 1985, and 63 percent of the residential market or 26 percent of the overall market in 2000.

Several factors may affect this anticipated SNG demand in the coming years, including the increasing price of natural gas and other conservation incentives (such as rate structures which penalize those using larger amounts of natural gas), and most notably, SNG pricing policy. It is uncertain if, in reality, consumers would be willing to pay the incremental (or marginal) price of SNG, which would be significantly higher than the price of natural gas for at least the next ten years. The arguments in favor of incremental pricing include the feeling that supplemental sources of energy should be priced at its true (higher) cost of production to encourage wise use of this fuel through conservation. In contrast to marginal pricing is rolled-in (or average) pricing. Oil and electricity have been priced this way for many years, and SNG would be at a great market disadvantage if it were forced to use marginal pricing while

Table 7

Projected Denver Area Annual Residential Demand for Natural Gas (MCF)

Urban Service Area	1985	2000
Adams Co. Urban	3,421,000	4,435,000
Arapahoe Co. Urban	3,395,000	4,280,000
Arvada	5,245,000	6,931,000
Aurora	8,437,000	13,257,000
Boulder	5,333,000	7,490,000
Bow Mar	68,000	72,000
Brighton	941,000	1,386,000
Broomfield	1,562,000	2,750,000
Cherry Hills Village	313,000	393,000
Columbine Valley	31,000	33,000
Commerce City	941,000	1,108,000
Denver	37,668,000	41,172,000
Edgewater	277,000	328,000
Englewood	2,137,000	2,544,000
Erie	10,000	28,000
Federal Heights	502,000	676,000
Glendale	455,000	482,000
Golden	919,000	1,441,000
Greenwood Village	443,000	826,000
Jefferson Co. (A-P)	606,000	843,000
Jefferson Co. Urban	3,118,000	6,192,000
Lafayette	533,000	776,000
Lakewood	8,548,000	12,202,000
Littleton	1,656,000	2,323,000
Longmont	2,685,000	4,114,000
Louisville	523,000	755,000
Northglenn	2,011,000	2,251,000
Sheridan	360,000	632,000
Superior	21,000	28,000
Thornton	2,220,000	3,405,000
Westminster	3,108,000	4,452,000
Wheat Ridge	2,011,000	2,440,000
TOTAL	99,498,000	130,040,000

Source: U.S. Department of Housing and Urban Development, 1978, Volume III, p. 56.

oil and electricity continued to use rolled-in pricing. Ultimately, the Federal Energy Regulatory Commission, which has Federal regulatory authority over power rates and sales, and the Colorado Public Utilities Commission, which has a similar State regulatory authority, will have to decide the SNG pricing issue.

Capital and Operating Costs

The Adams County coal gasification facility would almost certainly use the Lurgi process if it is built in the next fifteen years, barring an unforeseen technological breakthrough or incentives to use other processes. A summary of capital and operating costs for a Lurgi facility is shown in Table 8 (1976 dollars). Appendix E shows a comparison of capital costs, operating costs, and price estimates for six SNG processes including the Lurgi process. As discussed in Chapter 2, the Lurgi technique is the most thoroughly tested process and appears to be technologically viable now, while other processes are undergoing further testing and refinements in the pilot plant or early commercial stages of development.

The most recently available estimate of the capital cost of the Lurgi facility designed by Cameron Engineers for the Watkins Project was $660 million in 1976 dollars (24). This figure appears to have been grossly underestimated and

Table 8

Lurgi Process Capital and Operating Costs
(thousands of 1976 dollars)

Capital Costs, $ million	
Total Plant Investment	$1,060.00
Initial Charge of Catalysts and Chemicals	20.82
Allowance for Funds Used During Construction	166.95
Paid-Up Royalties	0.97
Start-Up Costs	33.56
Working Capital	26.21
TOTAL CAPITAL REQUIREMENT	$1,308.51
Operating Costs, $ Million/Year	
Raw Materials	73.31
Catalysts and Chemicals	9.05
Purchased Water	0.46
Labor	
Process Operating Labor	3.34
Maintenance Labor	18.93
Supervision	4.45
Administration and General Overhead	16.03
Supplies	
Operating	1.00
Maintenance	12.62
Local Taxes and Insurance	28.62
TOTAL GROSS OPERATING COSTS/YEAR	$167.81
TOTAL BY-PRODUCT CREDITS	54.25
TOTAL NET OPERATING COSTS/YEAR	$113.56

Source: Detman, 1976, p. 73.

made with very optimistic assumptions. Total capital costs for a Lurgi facility in early 1979 would be approximately \$1.5-\$1.6 billion.

Financing

Potential developers of the Watkins area SNG facility are confronted with setting aside large portions of their net worths and borrowing an equal or greater amount from an external source to obtain the necessary capital for development. Even a utility such as Public Service Company of Colorado, which has several financing advantages in its favor compared to private financing, will be unable to finance a facility in Adams County on its own. Traditional sources of external financing have been unwilling to provide capital for the SNG facility because of this large percentage of developer debt and lack of assurance of repayment to the lender.

This problem of capital exposure, or the amount of money the lender could lose if the project fails, is a significant barrier to industry development as well as development in Adams County. Recently, the American Natural Resources Company tried to solve this problem by proposing a financing plan which would have customers of the five natural gas companies involved in the project made liable for three-fourths of the financing if the project failed. However, this plan has been rejected by the Federal Energy Regulatory Commission (25). Additional problems hindering traditional external financing include uncertainties about future economic conditions in the United States and Colorado; future labor, equipment, and other resource availability; and unforeseen technological problems. It can be expected that traditional money markets will continue to turn down requests from project sponsors in the near future because of the many uncertainties confronting developers and the high risks confronting lenders.

The only possible action which may get the SNG industry moving appears to be governmental participation of some type. Many types of involvement including price guarantees, tax credits, construction subsidies, and governmental plant ownership, are being discussed, but the best option for governmental participation may be a non-recourse loan guarantee for approximately 75 percent of the capital requirements. This type of loan guarantee would greatly lessen the risks of financial commitment, as the developer would be liable only for its portion of the inital capital (25 percent), while the Federal government would be liable for repayment of loan money that private lenders have put into the project.

In fact, the Department of Energy is now starting to write rules for a loan guarantee program for high-Btu coal gasification plants (26). However, the projected 1980 budget for the program is only $235 million, which is approximately 15 percent of the capital cost of one commercial facility.

SNG Price Estimation Methods and Current Estimates

There are three methods which can be used to estimate the SNG cost at the gasification facility (before delivery costs have been added on). The accuracy of these methods range from rough (the gas send-out price method) to fairly accurate (the Synthetic Gas-Coal Task Force method) to very accurate (the discounted cash flow breakeven price method). The gas send-out price method is acceptable for purposes of this report, and will be used for cost estimation. A description of the other two methods is included in Appendix F. In comparing changes in capital investments ($ million change in capital requirements), coal costs ($/ton price changes), and operating costs ($ million in annual operating costs), the price of SNG will generally be most sensitive to feedstock costs, less sensitive to operating costs, and least sensitive to capital costs (27).

Gas Send-Out Price Method (28), as modified by the author. This method uses only the estimated capital cost for the plant, the heating value of the coal, and the cost to mine (or obtain) the coal feedstock to calculate the SNG price/MM Btu. (The price per million Btu (MM Btu) can be considered the same as price per thousand cubic feet (MCF) assuming a 1,000 Btu/CF (cubic foot) SNG product). The gas send-out price (P) consists of the feedstock cost (F) and the service cost (S) so that

$$P = F + S$$

where P, F, and S, and all in ¢/MM Btu. The feedstock cost (F) is calculated from the cost of the coal (C) in cents/ton and the heating value of the coal (HV) in Btu/pound according to the relationship

$$F = \frac{C}{HV} \cdot (714.29),$$

assuming a gasification efficiency of 70 percent. The service cost (S) is calculated from the plant capital cost (PC) according to the relationship

$$S = (.00000031) \cdot (PC),$$

Assuming a 330 day/year operation, production of 250 MM CF/day, and a 1,000 Btu/CF SNG product. Overall, then,

$$P = \left(\frac{714.29\ C}{HV}\right) + (.00000031)(PC).$$

A definite advantage of this method is that it can immediately take into account specific information about the coal to be used in the process.

Using the gas send-out price method, a series of rough cost estimates can be made for SNG produced using the Watkins area coal (4,430 Btu/pound), and assuming possible plant capital cost (not total capital cost) of $1.3, 1.5, and 1.7 billion, and coal mining costs of $7.50, 10, 12.50, and 15/ton. This series of cost estimates is summarized in Table 9. Costs of transmission and delivery must be added to these costs to determine the price to the consumer.

A realistic assumption in early 1979 would be coal costs of $10/ton and a plant capital cost of $1.3 billion, yielding a SNG cost of $5.64. By 1982, costs would be approximately $12.50/ton and $1.5 billion, yielding a SNG cost of $6.59; while in 1985, costs would be approximately $15/ton and $1.7 billion, yielding a SNG cost of $7.29. Again, it must be emphasized that these are only rough estimates. More accurate price determinations can only be made when detailed design plans and cost analyses have been performed. However, it is clear from these estimates that SNG costs can not even come close to competing with the regulated natural gas and oil prices.

Table 9

Sensitivity Analysis of SNG Cost to Coal Cost and Plant Capital Cost

Coal Cost ($/ton)	Plant Cost (billion $)	SNG Cost ($/MM Btu)
7.50	1.3	5.24
7.50	1.5	5.86
7.50	1.7	6.48
10.00	1.3	5.64
10.00	1.5	6.26
10.00	1.7	6.88
12.50	1.3	5.97
12.50	1.5	6.59
12.50	1.7	7.29
15.00	1.3	6.45
15.00	1.5	7.07
15.00	1.7	7.69

Source: Author.

Environmental Costs

There has been increasing concern in recent years over the impact of environmental and regulatory costs on the developer. Appendix G gives a brief summary of important Federal and State laws, the regulations from which will affect strip mining and coal gasification development in Adams County.

Regulations are, in effect, an attempt to protect health and welfare by internalizing into the market system all externalities and social costs, which have for many years been excluded from the cost of production and the associated price of goods. Regulations, in their optimal form, will determine the point where marginal costs of externality control (such as pollution control) equal the marginal benefits of control. Of course, this optimization rarely, if ever, occurs because of the difficulty in measuring these overall costs and benefits. There is no doubt that regulations may pose significant constraints to development in some instances; however, there exists no better method of internalization at the present time. When externalities are internalized into the market system, it is the producer and/or the consumer who pays the true cost of production rather than having costs borne by the public and society at large. The public must, however, bear the cost of regulation and enforcement through governmental agencies established for that purpose. It can be anticipated that developers of a strip mine and gasification development in Adams County will be confronted with a complex and confusing maze of regulations, permits, and clearances from all levels of government. This will result in environmental costs to the developer.

Environmental costs borne by the developer can be grouped into three distinct categories: those incurred before the development begins (which are either sunk costs or capital costs), costs of delay, and those incurred when the facility is in operation (which can be considered as operating costs). Examples of costs incurred before development begins include environmental baseline studies and preparation of environmental impact assessments and/or impact statements (in accordance with the National Environmental Policy Act of 1969). These are sunk costs (which occurred in the past and cannot be altered by present or future action) and are not relevant to economic decision-making in any investment evaluation study, but represent considerable expense to the companies involved with no monetary return on these environmental investments. Capital costs incurred before development take the form of pollution control engineering and equipment in order to meet all applicable environmental regulations and standards. Costs of delay occur when litigation or delays in the issuance of required permits are experienced by the developer, which tend to increase capital costs through escalation and inflation. Environmental operating costs include reclamation efforts and environmental monitoring. Although there is no doubt that many of these costs are necessary and represent significant benefit to society, the overall impact of existing and uncertain future environmental costs may significantly affect the profitability and risk of an untried industry.

For a brief look at the effect of probable environmental costs on the price of the SNG product, the costs of pollution control equipment and environmental operating costs can be examined. Using the realistic 1979 assumptions of $10/ton coal cost and $1.3 billion plant capital cost, the SNG product cost was found to be $5.64/MM Btu. If 10 percent of this plant capital cost is assumed to be for pollution control equipment (a fairly realistic assumption, although it is many times very difficult to separate pollution control equipment from other plant equipment), the plant capital cost without this equipment would be $1.17 billion ($1.3 billion less $130 million). Additionally, the cost of the coal feedstock will be increased through environmental operating costs of the reclamation process and environmental monitoring. Assuming these costs to be \$15,000 per acre, the effect on coal price can be calculated as follows.

1) Approximate density factor for Watkins area coal "in place,"

$$\left(\frac{2{,}200 \text{ tons}}{\text{acre-foot}}\right)$$

2) For the average 24.2 foot coal seam being mined,

$$(24.2 \text{ feet}) \cdot \left(\frac{2{,}200 \text{ tons}}{\text{acre-foot}}\right) = \left(\frac{53{,}240 \text{ tons}}{\text{acre}}\right)$$

3) For a total reclamation and monitoring cost of \$15,000/acre,

$$\left(\frac{\text{acre}}{53{,}240 \text{ tons}}\right) \cdot \left(\frac{\$15{,}000}{\text{acre}}\right) = \left(\frac{28.2¢}{\text{ton}}\right)$$

The price of coal (without these environmental costs) then becomes \$9.72/ton (\$10 less \$.28). Using the gas send-out price formula for the 1.17 billion plant capital cost and \$9.72 coal cost,

$$P = \frac{(714.29) \cdot (972)}{(4430)} + (.00000031)(1{,}170{,}000{,}000),$$

The cost of SNG will be \$5.20/MM Btu. This is 44 cents less than the product price which included these environmental costs, and as mentioned previously, there currently is no way to accurately assess whether the additional cost is "worth" it when considering overall costs and benefits.

CHAPTER 5. ENVIRONMENTAL CONSIDERATIONS

Anticipation of Impacts

It must be emphasized that while a coal gasification facility tends to bring benefits to the nation as a whole and to the region, it has the potential to bring major problems on both a local and regional scale which must be balanced against the national and regional benefits. Adverse environmental impacts can be classified into those that are primary (which basically occur on-site) or those that are secondary (which occur off-site and tend to be regional in nature). Both primary and secondary impacts must be anticipated and taken into consideration by decision-makers.

Emissions, which can take the form of air, water, solid waste, or other pollution, result from the extraction and use of the coal resource. Only a part of the coal is actually used to produce SNG; its other constituents must be admitted to the environment in some manner. This means that any environmental analysis which predicts these pollutants in their various forms requires a knowledge of the coal characteristics and constituents. Those constituents which cause pollutants, or the pollutants themselves, must be dealt with at some point during the mining, processing and/or SNG conversion processes so that the regulations and standards enacted to protect the natural environment are met. Their mode and magnitude of entry into the environment can be managed and significantly mitigated by proper planning and abatement procedures. Appendix H gives an overview of expected environmental problems from any coal gasification plant and associated strip mine.

Environmental Planning

Planning to mitigate the environmental impacts from any type of development has become an accepted part of overall business planning, but its potential is still not used to its fullest extent. The planning process involves considerable time, effort, and expense, but careful and thorough environmental planning completed in the early stages of design will save additional time, effort, and expense later, as well as protect the integrity of natural ecosystems. The importance of planning carried out by industry with regards to coal gasification development in Adams County can be summed up by this paragraph from the U.S. Energy Research and Development Administration (29):

> "Planning is potentially the most valuable mitigating measure because it would be used to eliminate or reduce the conditions which could lead to adverse impacts before they occur. Planning should be broadly interpreted to include the acquisition of reliable and comprehensive data pertinent to each locality in which development could cause a disturbance to the existing environment; the formulation of objectives, priorities, plans and schedules for application of each mitigation measure; and a review of the plans by competent parties. In addition, planning should provide for monitoring and surveillance to insure the continued and full compliance with all mitigating requirements and laws. The lead times required to develop synthetic fuel projects of the magnitude considered would, in most instances, offer considerable opportunity for planning."

Governmental or institutional planning will also be important in the effort to minimize impacts. Two State plans, the Air Quality State Implementation Plan (SIP) and the Clean Water Plan (also called the 208 Plan) are especially relevant.

The SIP, adopted by the Colorado Air Pollution Control Commission and submitted to the Environmental Protection Agency in December 1978, was formulated in response to the requirements of the Clean Air Act Amendments of 1977. States (such as Colorado) in which there are areas which did not meet the National Ambient Air Quality Standards were required by those 1977 amendements to prepare a plan which would assure compliance with the air quality standards by

December 31, 1982, although under certain circumstances, attainment of the standards for carbon monoxide and ozone may be extended until December 31, 1987. Regional plans were prepared for each of the five non-attainment areas in Colorado. The plan for each area includes an assessment of the nature and sources of the area's air pollution problem and the definition of the specific program of actions to be implemented to meet the air quality standards by the required dates. The Denver Regional Council of Governments (DRCOG) was designated by the Governor as the principal participating agency for preparation of the Denver Region Element of the SIP.

The Denver area 208 Plan was formulated by DRCOG in response to requirements of the Federal Water Pollution Control Act Amendments of 1972, which required an area-wide approach to planning for the abatement of water pollution. It is a plan based upon a comprehensive and integrated approach to water quality improvement, and extended consideration of pollutants to include non-point sources along with point sources. The objectives of the 208 study are to determine technical solutions to regional water pollution problems and establish a management system for implementing a plan to maintain clean water for a variety of uses. A classification system which defines the suitability of a given body of water and sets effluent discharge limitations is one of the major elements in regional water quality planning.

These two plans are meant to be dynamic in nature and will be updated when needed in the attempt to provide the necessary planning so that the goals of clean and healthful air and water are achieved. Implications of these plans with regards to Adams County strip mining and coal gasification development are still largely uncertain as discussed later in this chapter in the Air Quality and Water Quality portions of the Site-Specific Concerns section.

Site-Specific Concerns

The environmental consequences of a SNG facility and associated strip mine in Adams County will require extensive analysis and study before serious thoughts of development begin. An Environmental Assessment Report concerning possible coal strip mining in Adams and Arapahoe counties has been prepared by Dole (30). This report discusses many of the environmental impacts associated with mining, but does not discuss gasification impacts. Another study which has briefly considered the environmental consequences of development in the study area was completed by Claire (31). A complete analysis of potential problems is not necessary here, but an assessment of the critical concerns facing developers and decision-makers is relevant in the determination of the potential for development in Adams County. Brief summaries of those critical concerns which may prevent, delay, or halt development if not thoroughly and carefully evaluated are given below. It must be emphasized that all of these concerns are interrelated, and a holistic and interdisciplinary approach to the environmental considerations of development should be taken.

Air Quality. The front range of the Rocky Mountains, including the Denver area, has suffered from deteriorating air quality in the last ten years. The main source of pollutants in the area is from automobiles, with industrial point sources adding very little in comparison. Serious problems may occur when inversion episodes occur (usually in the winter months) within the South Platte River Valley (SPRV) in which much of the Denver area is located. These inversions normally trap airborne pollutants up to an average height of 300 feet above the approximately 5,200 foot altitude of downtown Denver. To the east (towards Adams County from Denver), a gradual rise of terrain is evident. The probable site where strip mining and coal gasification would occur in Adams County is roughly 5,600-5,700 feet in elevation, which is out of the SPRV and above the inversion layer height.

The airborne pollutants from the development should not interact with the SPRV pollution under most circumstances (32).

The only currently existing sources of pollution in the immediate Adams County study area are from farm equipment, automobiles, and fugitive particulates from cultivation and dirt roads. Anticipated air pollutants from a 250 MM CF/day high-Btu coal gasification facility are shown in Table 10. Key permits for the gasification plant which will have to be obtained under current circumstances include an emission permit from the State (under authority granted by the Environmental Protection Agency (EPA)) and a New Source Performance Standard (a standard which is, as of February 1979, still not established, but will be by the time the first commercial facility comes on line) permit (maximum emissions from a point source) from the EPA. The mine will also require at least one emission permit from the State, and a New Source Performance Standard permit from EPA. Extensive monitoring, data acquisition, and computer modelling will be necessary before these permits are issued. More information on the types of required permits will be necessary if and when detailed plans for development are formulated because of probable further changes in the standards and permitting system. A preplanning conference with the Colorado Department of Health and EPA is strongly recommended.

As mentioned in Chapter 1, coal gasification has decided air pollution advantages over electrification of coal, and all evidence to this point in time indicates an SNG facility and strip mine would meet all applicable air pollution regulations and standards.

There is, however, one major uncertainty. The Denver region (including Adams County) has been designed by the State of Colorado and the EPA as a non-attainment area (not meeting National Ambient Air Quality Standards (NAAQS)) for four pollutants: carbon monoxide, ozone, total suspended particulates, and nitrous dioxide. Under the provisions of the 1977 Clean Air Act Amendments, a full analysis must be made of each new or modified large stationary source to determine its likely impact on ambient air quality. Additionally, a new source must use the best available control technology for pollution control, and pollution emissions from a new or modified source must be offset for each pollutant by reductions in emissions from existing sources in the non-attainment area. The implications of these provisions with respect to coal gasification in Adams County are still unclear; however, it appears that industrial growth in the Denver region will be restricted to at least some extent until the NAAQS are met.

If the Denver region were to be redesignated as an attainment area before gasification and mining development actually began, a Prevention of Significant Deterioration (PSD) permit (maximum allowable increments added to the ambient air quality) would definitely be required by the EPA for the gasification facility itself, with another PSD permit necessary if coal cleaning is included in the coal preparation phase of SNG production. PSD permits are granted on a case-by-case basis, depending upon the existing conditions and extent of expected impacts.

Watershed. The primary drainage basin of the study area is Box Elder (Running) Creek, with a number of additional (intermittent) creeks also in the area. Table 11 shows the major streams and drainage areas in the Watkins lignite resource area, while Figure 4 displays the Box Elder watershed location and surrounding land uses. The importance of Box Elder Creek cannot be overlooked. Disruption of this watershed would severely alter existing drainage patterns in the area, leading to primary and secondary hydrological impacts. Efforts in mining and in gasification plant siting must be made to protect this critical area. One of the two alternative plant sites for the Cameron Engineer Watkins Project design was located immediately

Table 10

Expected Air Pollutants from a 250 MM CF/d High-Btu Gasification Plant

Type	Amount (lb/hr)
Particulates	180
Sulfur dioxide	450
Nitrous oxides	1,780
Carbon monoxide	90
Hydrocarbons	30

Source: American Gas Association, 1977, Commercializing High-Btu Coal Gasification, p. 10.

Table 11

Major Streams and Drainage in the Watkins Area

Stream	Drainage Area (square miles)
First Creek	7.4
Second Creek	19.1
Third Creek	18.4
Lost Creek	34.8
Box Elder Creek	64.3

Source: Dole, 1977, p. 42.

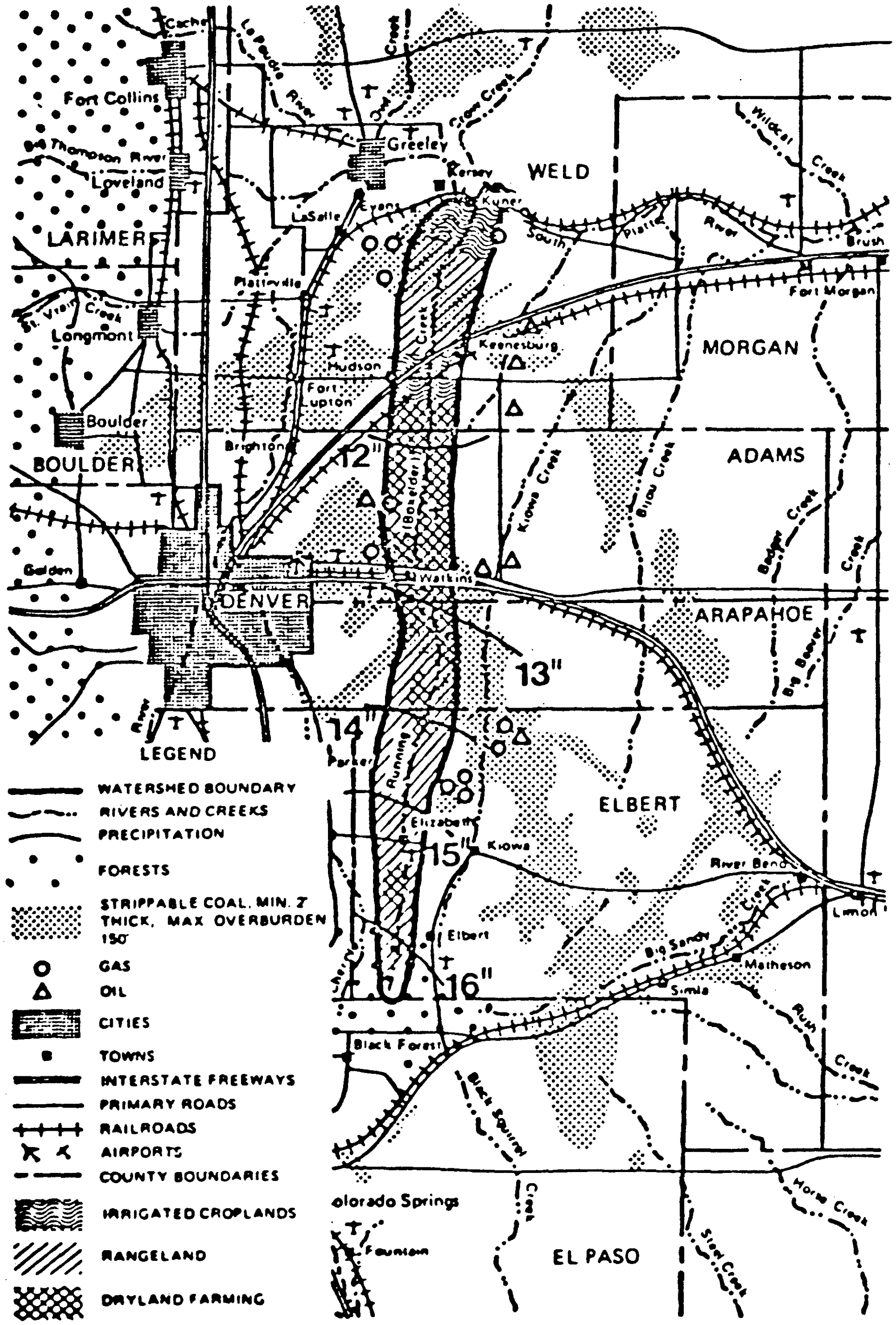


Figure 4. The Box Elder Watershed

Source: Wright-Ingraham, 1976, p. 5.

adjacent to Box Elder Creek, with satellite development planned for the area. This type of development must not be allowed to occur. Floodplains (at least 100-year floodplains) should also be considered before developing detailed plans.

Extensive study of the Box Elder watershed has been carried out by Wright-Ingraham (33). This long narrow watershed contains elements of many problems facing the western United States today: urban pressures on agricultural land, recoverable energy resources, proximity to a major metropolitan area, potential as a corridor for transportation and transmission, serious water constraints, increasing potential for environmental deterioration, jurisdictional conflicts for land use planning, heavy dependence on weather, and climatic limitations. Wright-Ingraham recommends that extremes of either direction (complete preservation vs. extensive development) be avoided, and that a carefully planned middle ground approach to use of the Box Elder watershed area be followed.

Water Availability. Water is the critical limiting factor in this semi-arid region in eastern Colorado. Both legal and physical problems limit the potential options for water procurement. The gasification facility and associated mine planned by Cameron Engineers was to use approximately 8,500 acre-feet of water per year (5,260 gallons per minute), as shown in Table 12. Water will be in short supply during coming years in the Watkins area, and it is essential that an adequate and reliable source of water supply be obtained by developers before operations begin. There will be many competing water users in the Denver metropolitan area, and priorities will have to be decided upon when allocating scarce water supplies. The U.S. Department of Housing and Urban Development (34) estimates an overall water deficit in the Denver metro area of 134,550 acre-feet per year by 2000.

There does appear to be several sources of water which may be available to Adams County coal gasification developers, one or more of which would have to be utilized to provide the water requirements for plant and mine operation. These sources include waste water from Denver and/or Aurora; bedrock aquifers beneath the development area; alluvial aquifers in Box Elder Creek; and water rights on the South Platte River system which are subject to change in use and point of diversion (35).

It is recommended that the waste water source be used as much as possible, that deep bedrock aquifer sources be used to make up any deficit, and that the two other potential sources (alluvial aquifers and surface water rights obtained from others) not be used for gasification development

Table 12

Water Requirements for Strip Mine and Gasification Facility

	GPM	%
Process Consumption		
To supply hydrogen	1,120	
Produced as methanation by-product	-600	
Net consumption	520	9.9
Return to Atmosphere		
Evaporation:		
From raw water ponds	420	
From cooling tower	1,520	
From quenching hot ash	360	
From pelletizing sulfur	250	
From wetting of mine	500	
	3,050	
Via stack gases:		
From steam blowing of boiler tubes	200	
From stack gas scrubbers	40	
	240	
Total return to atmosphere	3,290	62.5
Disposal to Mine Reclamation		
In water treating sludges	100	
In wetted boiler ash	30	
In wetted gasifier ash	720	
Total disposal to mine	850	16.2
Others		
Retained in slurry pond	20	
Miscellaneous mine uses	580	
Total others	600	11.4
GRAND TOTAL	5,260	100.0

Source: Cameron Engineers, 1975, p. 48.

because of priority to other (mainly agricultural) water uses. Under the terms of Denver's decree for water out of the Blue River (Dillon Reservoir and Roberts Tunnel), Denver is required to make an effort to use and re-use that water in order to minimize exportation of water from the Colorado River Basin. In addition, the Blue River decrees require that the return flows be used for municipal and industrial purposes within the area socially and economically integrated with Denver (36). The deep Laramie-Fox Hills aquifer is nearly unused in the study area, and could be used to make up a water deficit (37).

Water Quality. There exists many sources of both surface and ground water in the study area, the quality of which may become degraded from the mining and coal gasification operations. It is initially clear that a lack of adequate hydrological data exists to assess water quality in the Watkins area, and a thorough study should be undertaken before any detailed mining plan is developed. Existing Colorado and Federal water law should also be considered before development occurs to avoid potential future problems.

Of special concern are the ground water aquifers, which are used as a source of drinking water in the area through the use of wells. Currently, these aquifers (Denver and Arapahoe) are of relatively good quality (38). The strip mining operation potentially could degrade the quality of well drinking water from the Denver formation aquifers in the Watkins area (the mine will most likely not disturb the Arapahoe aquifers). High-yield irrigation wells from shallow aquifers along Box Elder Creek may also be affected if mining occurs in this alluvial plain. Solid waste burial is another potential source of pollutants into Adams County aquifers.

Surface water quality will be affected by deposition, erosion and runoff during mining, with the potential release of substances into the stream system from the gasification facility also being of major concern. An estimate of the composition of wastewater from the coal gasification process is given in Table 13. It is uncertain if a complete water recycling system can be successfully developed for a coal gasification facility. Concentration buildups in the water from continuous recycling may pose a major obstacle, and lead to a need to discharge the wastewater. Developers will be required to obtain a National Pollution Discharge Elimination System water quality permit from the State if a completely closed water system cannot be utilized. As with air pollutants, monitoring will be required to keep taps on the types and magnitudes of water pollutants so

Table 13

Coal Gasification Wastewater Composition

Pollutant	Amount (mg/liter)
pH	7.9-8.3
COD	1700-43,000
Ammonia	2500-11,000
Cyanide	0.1-0.6
Thiocyanate	21-200
Phenols	200-6600

Source: Federal Energy Administration, 1974, p. 85.

that permit compliance schedules are met. Downstream impacts must also be anticipated by proper planning. Current surface water quality in the immediate area is thought to be of good quality, although few studies have been undertaken to determine actual water characteristics (39). However, the eventual fate of these surface waters is the South Platte River, which is of much lower quality after pollution discharges occurring in the industrial section of the Denver area.

The South Platte River near the study area has been classified B-2, which means it is to be suitable for domestic water supply, recreation, and warm water fishing.

However, Box Elder (Running) Creek and other (intermittant) streams in the immediate study area have not yet been classified according to the regional water quality planning procedure (208 Plan) discussed previously in this chapter. A revision and expansion of the classification system to include all Colorado water bodies is currently underway, but until these classifications and associated water quality standards are established for streams in the area, the full implications of the 208 plan on strip mining and gasification development in Adams County is uncertain. It is possible that specific local legislation may be necessary to deal with water quality impacts from development.

Solid Waste. The original Cameron Engineers plans called for the use of solid wastes from the Denver metro area as a gasification feedstock to supplement the lignite resource. This would be a positive action, and ease the lack of available solid waste disposal sites in the region. The U.S. Department of Housing and Urban Development (40) estimates that the Denver Area's solid waste disposal sites may be used up as early as 1981 unless large additional sites are designated as suitable. However, cost and efficiency constraints may prohibit this use of solid waste as a feedstock if development does occur at some point in the future.

Developers will be required to prepare detailed solid waste (from both the mine and gasification plant) disposal plans. This is in keeping with the "cradle to grave" thrust of the Resource Conservation and Recovery Act (RCRA). One major problem from solid waste burial may be seepage of pollutants into the extensive aquifer system in the area. It would have to be shown that burial would not injure water users of the area. RCRA will also help determine the fate of the kaolin resource which is found with the lignite. As mentioned in Chapter 2, these kaolin resources could yield a significant source of aluminum. A kaolin facility will most certainly add to the problem of obtaining financing; however, development of the kaolin resource as a by-product may provide the maximum efficient recovery (in both physical and economic measures).

The EPA is very concerned about solid waste disposal and is currently making an effort to determine the best management practices for various types of solid waste disposal problems. Such factors as collection, source separation, storage transportation, transfer, processing, treatment, resource conservation, resource recovery and actual disposal must all be considered in the management plan. Additionally, climate, the available site (space, topography, etc.), and cost must also be considered in the formulation of efficient and environmentally sound solid waste disposal. Again, monitoring (of both water and air impacts caused by the disposal) will be necessary.

Soils. Soils in the Watkins lignite resource area consist mainly of Soil Conservation Service (CSC) classifications III and IV (41). These soil classifications have some severe limitations and require special conservation practices and management techniques. Limitations consist mainly of high erosion potential and climatic extremes (42). However, the soil is considered very productive for dryland farming. Typical winter wheat production in the area today yields 25-30 bushels per acre, compared to an average of 12-17 for these soils.

The soils cannot be classified as prime agricultural lands according to the U.S. Department of Agricultural definition because of the lack of rainfall in the area. However, the study area can probably be classified as "additional farmland of Statewide importance" according to SCS definitions. Additionally, the definition and identification of prime farmlands is not universal and may be modified pending review of local, state, and national levels (43).

The State of Colorado is currently considering recommendations for the designation of lands unsuitable for mining. Agricultural lands being considered for this designation include dry lands where the productivity of the soils and the moisture regime are sufficient to produce cereal grains in marketable quantities (44). Many Adams County farmlands overlying the lignite resource would be included in this classification of lands unsuitable for mining.

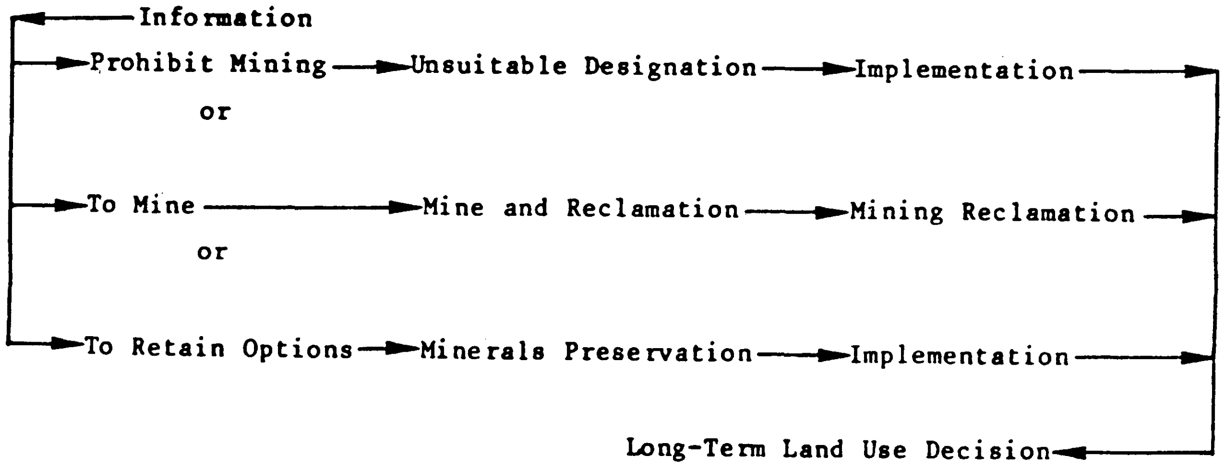
If strip mining development does occur, efforts must be made to separate and protect suitable topsoils for future reclamation. Dole (45) estimates that 54 percent of the Watkins area is covered by soils classified as having fair to good topsoiling suitability. Care must also be taken to minimize the high risk of erosion (both wind and water) and the creation of a surface hardpan in the area during development. The mine plan should address these soil criteria in detail.

Biological. In addition to soil suitability, several climatic factors will have a significant impact upon the success of reclamation efforts. These factors include precipitation, temperature, and winds. Precipitation in the area averages 13-14 inches per year, which is relatively typical of a Great Plains climate. There is great variability in the occurrence of this precipitation, both on a monthly and yearly basis. Because of the high level of radiation cooling which occurs on approximately three-fourths of the nights in the area, the diurnal temperature range is relatively high, with daily maximum and minimum temperature differences of more than 40°F not uncommon. Moderate to high winds also characterize the area, with most windy periods occurring between November and May (46). These and other factors combine to create a short growing period, during which only drought-resistant, hardy and adaptable species can be expected to grow.

Because of the current agricultural land use, the area is frequented by few wildlife species. However, wildlife must be considered in mining plans before a mining permit is issued. Mice, voles, gophers, rabbits, weasels, several bird species, snakes and other adaptable fauna can be found in the area. Although this component of the environment does not appear to be especially critical to mining or gasification development, thought should still be given to secondary impacts from loss of habitat and other ecological disruptions. Major disruptions in the Watkins area might also eventually affect aquatic biota in the South Platte River, Box River Creek, and other streams. As mentioned previously, the South Platte River in the study area is to be suitable for warm water fishing according to the regional 208 Plan, a factor which must be considered in environmental planning and project design. Impacts from water pollutants or air pollutants on aquatic biota may take the form of population decreases and/or the introduction of undesirable substances into the food chain. Additionally, there are two wildlife species (the blackfooted ferret and peregrine falcon) that theoretically could inhabit the area which are listed as endangered species (47). If either specie were documented to utilize or inhabit the area, any thoughts of development would be quashed. However, there is almost no chance of this utilization or habitation within the lignite resources or surrounding areas.

Land Use. The gasification facility and strip mine will require the use of approximately 9,000-10,000 acres of land, only a portion of which will be out of production at any one time. Efforts must be made so that possible conflicting land uses are not encouraged in the study area. Possible conflicts include (in addition to lignite extraction and gasification development) residential housing developments, industrial parks, a regional airport, and a dewatering site for sewage sludge. A land use decision pathway with regards to coal extraction in Adams County is given in Figure 5. The above environmental criteria, socio-economic, and other criteria should be analyzed in detail before long-term land use decisions are made. Also, if strip mining does occur, decisions will have to

Figure 5. Land Use Decision Pathway



Source: Argonne National Laboratory, 1978, p. 5.

be made as to the future land use (return to agriculture, industrial development, etc.) after the mining operation and SNG production stops. The reader is referred to Chapter 7 of this report for further consideration of land use and local policy.

CHAPTER 6. SOCIO-ECONOMIC CONSIDERATIONS

Population Increase and Demand for Services

Adams County is currently undergoing increasing urbanization, and has experienced significant population growth over the past thirty years. From 1940 to 1974 the population increased from 40,234 to 225,600, with further increases expected in coming years. A range of population forecasts through the year 2000 has been developed by the Adams County Planning Department. Those estimates, shown in Table 14, reflect not only local conditions but also regional and state trends. It is anticipated that Adams County will account for between 13 and 19 percent of Denver metropolitan area population in 2000 (48).

Most urbanized areas of the county are concentrated in the western area close to Denver. Incorporated cities in the county east and north of Denver include Brighton, Broomfield, Federal Heights, Northglenn, Thornton, Westminster, Arvada, Commerce City, and Aurora, with Bennett and Strasburg located in the south central section near the border with Arapahoe County. Watkins, with an estimated

Table 14

Adams County Population Estimates

Year	Low	Medium	High
1980	252,245	263,827	281,925
1985	269,604	294,153	322,096
1990	288,363	328,192	368,020
2000	318,705	382,415	446,120

Source: Speas Associates, Inc., 1978, p. 4-4.

population of less than 400 in 1975, is an unincorporated community in close proximity to the probable mining and coal gasification site. Much of the growth in urbanization is expected to be absorbed adjacent to or within these existing incorporated areas of Adams County. The urban areas are generally developed to a relatively low density level with dispersed local service centers. Local service center activities include office buildings, neighborhood commercial, auto repair, service stations, retail stores, restaurants, and other commercial businesses. Industrial activity has developed along major highways (49). Agriculture, however, remains the backbone of Adams County, both physically and economically.

Using a generalized methodology developed for the Environmental Protection Agency (50), estimations for employment needs and population increases from a 12.5 million ton per year strip mine combined with a 250 million cubic feet per day high-Btu coal gasification plant can be made. The peak construction mine and plant worker need would be approximately 1,345, while the peak operation phase need would be roughly 1,425. The total added population from development would be approximately 6,550 and 11,740 for the construction and operation phases, respectively, again using the EPA methodology. These population figures include service personnel, public employees, family members from all worker groups and the plant and mine workers themselves. It must be emphasized that these are only rough estimates based on past experience and previous estimates; the actual situation will vary according to plant and mine engineering design, schedule of production, characteristics of the community, characteristics of the workers and other variables which will not be known until the project is nearer to development. See Appendix I for a general description of the types of impacts which can be caused by this population influx. Tables 15 and 16 give rough estimates, again based on past experience and previous estimates, of the increased demand for services during the construction and operation phases, respectively, to meet the needs of this new population. The reader is urged not to place too much emphasis on the numbers in these tables because of the generalized

Table 15

Needs of New Population During Construction Phase

Need	Land (acres)	Facilities	Employees
Elementary Schools	18	40 classrooms	75
Secondary Schools	21	35 classrooms	115
Water Supply	7	1,312 acre-ft./ year capacity	5
Sewage Treatment	7	656,000 gallons treatment	8
Housing (Permanent)	262	1,181 units	N/A
Housing (Temporary)	82	656 units	N/A
Housing (Other)	9	131 units	N/A
Police Protection	.4	1,312 sq. ft. (station); 3 vehicles	15
Fire Protection	.4	variable	8
Medical	2	26 hospital beds	12
General Government	.2	1,338 sq. ft. (offices); 2,624 sq. ft. (garage)	12
Solid Waste Disposal	N/A	11 acre-ft./year capacity	6
Parks/Recreation	66	variable	4
Libraries	1	3,608 sq. ft. (library); 19,680 books	2
Commercial Land	8	N/A	N/A
Industrial Land	79	N/A	N/A

Source: Author; from Environmental Protection Agency, 1978 methodology.

Table 16

Needs of New Population During Operation Phase

Need	Land (acres)	Facilities	Employees
Elementary Schools	33	72 classrooms	134
Secondary Schools	38	63 classrooms	207
Water Supply	12	2,348 acre-ft./ year capacity	8
Sewage Treatment	12	1,174,000 gallons treatment	14
Housing (Permanent)	657	2,642 units	N/A
Housing (Temporary)	88	704 units	N/A
Housing (Other)	4	59 units	N/A
Police Protection	.7	2,348 sq. ft. (station); 5 vehicles	27
Fire Protection	.8	variable	15
Medical	3	47 hospital beds	22
General Government	.4	2,395 sq. ft. (offices); 4,696 sq. ft. (garage	22
Solid Waste Disposal	N/A	20 acre-ft./year capacity	11
Parks/Recreation	117	variable	8
Libraries	2	6,457 sq. ft. (library); 35,220 books	3
Commercial Land	14	N/A	N/A
Industrial Land	141	N/A	N/A

Source: Author; from Environmental Protection Agency, 1978 methodology.

nature of this model. However, information concerning the relative direction and magnitude of changes predicted by this model may be of significant use to developers, planners, and other interested parties.

Settlement Pattern

Those population and demand for service increases discussed above (using the EPA methodology) are most applicable to a community such as Watkins, which possesses little infrastructure (public and private) and would be significantly impacted by such a rapid influx of population into an unpopulated and unprepared area. However, the close proximity of the probable mine and plant site to the major urban service areas of the Denver metropolitan area will certainly prevent the full brunt of the impact from falling on the immediate Watkins vicinity.

Due to the interrelationships between Adams, Jefferson, Arapahoe, Boulder, and Denver counties, the labor force within the region is very mobile. Adams County has traditionally supplied workers for employment centers located outside the County, with the trend reversing somewhat in recent years because of the increasing urbanization spreading into Adams County (51). Interstate 70 east from Denver to Watkins, along with other highways feeding Interstate 70, would potentially supply a large segment of construction and operation phase workers from the entire Denver metro area. Commuting times from most populated areas within the five-county region to the mine and plant site would rarely be over forty-five to sixty minutes. Realistically, then, it must be expected that many workers may prefer to live in areas other than the development site itself. For example, actual impacts in Clear Creek County, Colorado from the Henderson molybdenum mine site (approximately fifty miles west of Denver) have been less than those expected because of a significant worker preference to live near the Denver metropolitan area and commute to the mine site. Therefore, as long as adequate gasoline supplies or other transportation alternatives are available to Adams County strip mine or gasification plant personnel, some workers and their families may prefer the advantages of shopping, entertainment, recreation, and medical facilities along with other public and private infrastructure already in place in the more urbanized sections throughout the Denver region, although the greatest impacts of development will most likely be in Adams County communities. Aurora, which can provide a wide variety of housing needs, may prove to be a very popular settlement area for new workers.

This dispersed settlement pattern is contrary to most energy development projects in the western United States, and should result in minimal impacts from Adams County development compared to these other western situations. The effects of development, which might otherwise be concentrated into the Watkins area, will be spread out into many other areas. The Denver metro area should be able to assimilate most of the impacts from development much more easily than a smaller, isolated community.

In fact, it may prove to be very difficult to actually separate out those additional services and service personnel resulting directly from mining and gasification development because of the already growing Denver area economy and already occurring population increases. In other words, the Adams County mine and gasification plant alone will show few impacts; it will only be one of a number of sizeable projects or business relocations into the area. However, these are situations that should be analyzed for additive (incremental) or cumulative impacts so that a socio-economic threshhold tolerance level is not violated.

Actual population increases as a direct result of development should be lower than those projected using the EPA methodology because of the probable availability of workers already living in the metropolitan area. These workers, especially construction and some operating personnel, would tend to remain where they are residing and merely commute to the Watkins area. Because of extensive mining safety and training regulations, the majority of miners would most likely be newcomers to the area unless developers preferred to provide the necessary training to local residents or if the availability of experienced miners was in short supply in the western states (which is a likely situation in coming years). This not to say that Watkins itself will not be impacted; however, these impacts should be less than they would normally be because of its close proximity to the Denver area.

Ultimately, many presently unknown variables, such as future housing availability (which may be in short supply by as much as 148,339 and 352,820 dwelling units in the urbanized metro area in 1985 and 2000, respectively, according to the U.S. Department of Housing and Urban Development) (52) will combine to result in actual settlement patterns if development does occur. This settlement pattern will play a major role in determining the types and magnitudes of most of the socio-economic impacts. The most likely result appears to be the decentralized settlement scenario discussed above; however, the smaller-scale impacts from this settlement pattern do not mean that these problems should not be thought through and prepared for by Denver area decision-makers. These problems should be approached on a metropolitan area-wide scale, with special emphasis to Adams County preparation.

Costs vs. Revenues

The coal mine and gasification plant developers will be subject to many types of taxes which will help to pay for the increased services that municipalities must provide for new population. These taxes include ad valorem property taxes, income taxes, sales and use taxes, royalty payments, excise taxes, and a severance tax. A lag time of several years for the collection of some of this tax revenue (such as property tax) must be expected. Claire (53) estimates that development may result in a tax revenue to Adams County of over $2 million annually. However, a controversy can be expected to arise (if development does occur) whether the developers are paying their "fair share" of public revenues. This, as in other western energy developments, is a question that depends largely upon subjective values and opinions, and therefore must remain unanswered in the scope of this report.

Even though the Denver region has a very stable, diversified, and healthy economy with a substantial tax base due to employment increases and the location of many businesses (large and small) into the area in recent years, the net fiscal capacity (the county surplus or deficit of funds) of Denver, Adams, Jefferson, and Arapahoe counties may prohibit the delivery of adequate service to taxpayers in the coming years. As shown in Table 17, Adams County is projected as breaking even in 1985 and 2000, and appears to be in the best financial shape of the four counties. Current fiscal deficiencies in the other counties are made up through intergovernmental subsidies (State and Federal), but there is no guarantee that this practice can continue (54). The issuance of municipal bonds may become increasingly important in coming years for those counties showing a deficit.

There exist several sources of energy impact aid (financial and otherwise) that may be available in certain situations. For a coal mine and gasification facility, these sources include revenues from the Federal Mineral Land Leasing Act of 1920 (Local Government Mineral Impact Fund); interest earned on the Oil Shale Trust Fund; and the State Severance Tax (Local Government Severance Tax Fund). The ability of a community to finance a project from its own resources will be evaluated using the Local Government Fiscal Capacity Evaluation System, developed by the Colorado Division of Local Government. The essence of the evaluation system is to project the local government's growth in revenue

Table 17

Net Fiscal Capacity (Surplus or Deficit)
(thousands of 1974 dollars)

County	1974	1985	2000
Adams	+ 73	even	even
Arapahoe	- 3,107	- 8,646	-13,029
Denver	-21,866	-23,070	-25,989
Jefferson	- 2,234	- 3,214	- 4,540
Four County Total	-30,134	-34,930	-43,558

Source: U.S. Department of Housing and Urban Development, 1978, Volume III, p. 154.

receipts (from all sources), and its growth in operating expenditures based upon population projections for the community (55).

However, according to the criteria and priorities established by the evaluation system, it appears only smaller communities such as Watkins would be granted aid from these sources. Denver area urbanized communities (such as Aurora) would probably not qualify for funds because of their more stable fiscal position and larger population. If Watkins itself were to be impacted, some funds could most likely be obtained to help offset the effects of development.

The criteria and priorities established by the evaluation system are only general in nature, and it is possible that Adams County (as a whole) may qualify for funds during a tax lag period if impacts were especially severe or if its fiscal position deteriorates significantly. Industry itself may wish to (and should be encouraged to) help in easing problems.

Cultural and Social Impacts

The reader is again referred to Appendix I for a brief discussion of the types of socio-economic impacts which may be caused by gasification and strip mine operations. Many impacts of development in Adams County will be impossible to quantify, and are many times difficult to assess and predict. These types of impacts can be considered as cultural and social, or as non-economic quality of life determinants. Quality of life denotes a set of wants, the satisfaction of which makes people happy; it reflects a combination of the subjective feelings and objective status of the "well-being" of people and the environment in which they live (56). People in the Denver area generally have available to them a wide variety of resources which makes for an acceptable quality of life. The probable development site is basically rural in nature today, although urbanization from Denver is rapidly approaching. Growth and development in the study area, whether it is composed of mining and gasification or not, appears to be inevitable unless land use and other policies would prevent activities in this locale.

Those who would be most affected from cultural and social impacts would be those who wish to preserve the existing rural lifestyle of Adams County. These people would most likely be some of the citizens who reside in the area, although others in the Denver region certainly may also wish for rural preservation for a wide variety of reasons. On the other hand, many older citizens currently residing in the Watkins area apparently are willing to sell their farmland, with the major criterion for selling being that they want the land use which would bring them the most profit (57), which would almost certainly be lignite extraction and conversion to SNG compared to other potential land uses including agriculture. Additionally, most Denver area residents could be expected to favor development because of the benefits of having an SNG supply, with no noticeable impacts affecting them directly.

Overall, then, the social and cultural impacts are generally highly subjective in nature. A disruption in lifestyle will certainly occur for some of those living in the Watkins area if development occurs; however, the vast majority of Denver area residents will not even know the plant and mine exists. This does not mean that the social and cultural components of analysis are not important. They must be included in the overall decision-making process, and efforts should be made to ease the transition in land use for affected citizens and to avoid unnecessary social and cultural problems by not planning for their mitigation.

There are several potential socio-economic impacts which should be examined closely after more detailed plans are drawn up by developers, and before operations actually begin. In addition to the ability to provide those services (education, medical, police, fire, sewer, etc.) and housing availability as listed in Tables 15 and 16, noise, aesthetics and archaeology must be considered. Noise, as discussed at the end of Appendix H, can lead to both regional and on-site problems involving both the general public and employees. Land use and other planning tools must be used to avoid problems. Aesthetic concerns take the form of odors and appearance. A buffer zone around the mining and gasification operations will ease aesthetic and noise concerns unless conflicting land uses are allowed to occur. Although there are no known archaeological sites directly on the probable development site, studies indicate north-south routes of 900-year-old Fosom man and old pioneer trails running east-west in the general Watkins vicinity (58). Additionally, several environmental concerns discussed in Chapter 5 (such as regional air pollution and water availability and quality) may affect the socio-economic character of the area. It is clear that environmental and socio-economic concerns are interrelated, and that mitigation should be approached on a holistic and interdisciplinary manner.

CHAPTER 7. POLICY CONSIDERATIONS

Federal Policy

There is no doubt that Federal policy is affecting and will continue to affect the potential for development in Adams County. In addition to environmental policy (as briefly discussed in Appendix G) and SNG pricing policy (as discussed in Chapter 4), Federal energy policy (or lack of energy policy) will also play a major role in development. Appendix J gives a brief overview of the history of United States synthetic fuel energy policy, while Appendix K discusses the major Federal policy-making bodies which may affect Adams County development. It is clear, however, that the major policy implications affecting the potential for development will occur at the State, regional, and Adams County levels of government. In fact, the Federal Surface Mining Control and Reclamation Act (SMCRA) of 1977 specifically recognizes that mineral resources are best dealt with at the State and local levels. Relevant sections of SMCRA pertaining to local and State planning authority are shown in Table 18.

Table 18

Relevant Sections of SMCRA Concerning State and Local Land Use Planning

Reference	Requirement of Guide (Paraphrased)
201 (C)(8)	Technical information on mining and reclamation will be provided to local land use planning agencies.
505(b)	States can enact land use controls more stringent than those required by Federal law.
508(a)(3)	In reviewing and acting on reclamation plans, the regulatory authority will evaluate the selected land use policies and plans, including comments of authorized local planning bodies.
513(a)	Planning agencies shall be notified of application for mine permits and related opportunities for hearings.
515(b)(2)	The proposed postmining land use shall be consistent with applicable land use policies and plans.
522(a)(3)(A)	A specific land area may be designated unsuitable for certain types of coal mining operations if such operations are found to be incompatible with existing public land use plans or programs.
522(a)(5)	Determinations of the unsuitability of land with surface mining shall be integrated with present and future land use planning and regulation processes at the Federal, State, and local levels.

Source: Argonne National Laboratory, 1978, p. 9.

State Policy

In addition to existing Colorado environmental legislation as briefly discussed at the end of Appendix G, and the probability of further legislation including the designation of lands unsuitable for mining and other land use guidelines, there are four State statutes which will play significant roles in the decision-making process concerning mining and gasification development in Adams County. This legislation consists of House Bills 1041, 1529, 1706, and 1034. As will be seen upon examination of these laws, powers to determine and regulate land uses are basically a function of local governments within the State, with those powers derived from the State through its Constitution and statutes.

H.B. 1041 of 1974 provides for State and local participation in the designation and regulation of critical areas and activities of special concern beyond the local level. The State provides the guidance and means to enable local government to designate and to regulate a wide variety of areas and activities including mineral resources. The 1041 program could lead to either the preclusion of mining or the protection of the lignite resource in Adams County. Preclusion could occur, for example, through the designation of an alternative land use (such as agriculture) of Statewide importance. Protection could occur through the identification and designation of "mineral resource areas," as provided in H.B. 1041. If the Colorado Land Use Commission found that a locality failed to make a reasonable designation, it could ask that locality to reconsider or take local officials to court (59).

H.B. 1529 requires counties with populations of 65,000 or more to develop a master plan for the extraction of commercial mineral deposits within their jurisdictions. The plan must consider the maximization of extraction, the ability to reclaim an area, and the impact of mineral extraction on the surrounding areas. The legislation also restricts local governments from zoning, rezoning, or granting any variance or other action for any area known to contain a commercial deposit, in a manner that would interfere with present or future extraction of such deposits (60).

The key position of local government in Colorado in mineral resource planning is further strengthened through House Bills 1706 and 1034. H.B. 1706 authorized local governments to require master plans for mining and reclamation of property overlying commercial mineral deposits (61). H.B. 1034 gives specific powers to local governments to provide for phased development of services and facilities and to regulate the use of land on the basis of the impact on the community or surrounding areas (62).

In addition to the Colorado regulatory and permitting authorities with regards to mineral development (primarily the State Departments of Natural Resources and Health), the State Division of Planning, Departments of Local Affairs and Agriculture, Land Use Commission, and Office of the Governor will be involved in the decision-making process to varying degrees.

Regional Policy

The Denver Regional Council of Governments (DRCOG) is a voluntary association of city and county governments within the eight-county State Planning Region 3. DRCOG defines regional issues, problems, and opportunities; establishes priorities; formulates policies, plans and activities to guide the growth and development of the region; and prepares regional and subarea population and employment estimates and forecasts. The Council is not a unit of government, has no legal authority to bind its members to its policies, and cannot tax or legislate. It is, however, a vehicle for intergovernmental cooperation and strives to resolve problems of an area wide character (63).

A Regional Growth and Development Plan (64) has been formulated by DRCOG which covers Adams, Arapahoe, Boulder, Denver, and Jefferson counties. This Plan provides a single statement of policies designed to guide the location, level, and timing of growth and development in this five-county region. The Plan was formally adopted on June 1, 1978 by DRCOG members, but it is subject to a continuous planning process which will lead to updates and revisions which reflect changing goals and conditions. There are many policies within this Plan which may affect development in Adams County; however, the most important of these policies is Regional Development Policy 31, which states that

> "Development in areas which contain commercially feasible deposits of coal should not interfere with the present or future extraction of the coal deposits, unless it can be shown that extraction would have serious, adverse impacts on existing development. Federal, State, and local governments are encouraged to make a better determination of the locations and extent of commercially feasible coal deposits within the Denver region."

It must again be emphasized that DRCOG policies are only recommendations; Adams County would be under no legal obligation to adopt the course of action concerning the lignite deposits recommended by DRCOG. Realistically, however, there is no reason to assume at this point in time that Adams County, as an active member in DRCOG, would not conform to DRCOG policies.

Adams County Policy

Adams County is governed by a three-member Board of County Commissioners elected for four-year terms. A County Planning Commission monitors planning, zoning, and subdividing in the County, with a Department of Planning and Development supplying the professional manpower for planning and land use decision-making. As discussed previously in this Chapter, most land use power is relegated to local government through the authority of the State Constitution and statutes. The Adams County Commissioners, therefore, will have the power to determine land use within the County, subject to the limits of their legal authority.

A Comprehensive Land Use Plan for Planning Area 5 (which includes the probable gasification and mining sites near Watkins) within Adams County was recently formulated by the Adams County Planning Commission (65). With regards to mineral resources, the Plan states that

> "the area surrounding Watkins will be designated as a mineral resource area. The purpose of this designation is to protect potentially extractable coal reserves, so that if the impacts associated with the development of this resource are within acceptable limits, the resource can be developed. A coal gasification plant, which would process the lignite extracted from the surrounding area, would be encouraged if the lignite is developed."

This policy is basically in accord with the recommended DRCOG policy discussed above. The mineral extraction/preservation plan (as required by H.B. 1529) has been prepared and also is in basic agreement with the DRCOG policy;

however, the 1529 plan has not yet been officially adopted because County officials would like to be certain of applicable State and Federal laws before any ordinance is enacted to protect their mineral resources. It appears that the County Commissioners are trying to keep the strip mining and gasification option open through the adoption of the above land use policy and a "wait and see" attitude until more information on the consequences of development becomes available. Adams County Commissioners do realize the importance of quality and planned development while still preserving the County's agricultural character. Considine (66), in March 1979, relates that it is likely that the Commissioners would favor a specific coal gasification project "if a detailed cost-benefit analysis indicated a positive socio-economic impact, while at the same time included minimal adverse environmental impact options that are acceptable to the general citizenry and decision makers."

The importance of keeping the development option open at this point in time cannot be overlooked, especially in light of a land use decision made in the mid-1970's by the Adams County Commissioners which, to some extent, allows conflicting land uses in the Watkins area. At that time, Adams County asked the Colorado Geological Survey (CGS) to render an opinion on whether residential zoning requests for forty-acre and two-acre lots were located in lignite resource areas. CGS indicated that there were not enough data available to assuredly state whether the site contained economically feasible deposits of lignite or not. Staff members from CGS recommended against rezoning for residential development because of possible future conflicts with lignite development after more information on these resources became available. However, this advice was not taken by the Commissioners who were in office at that time, and the zoning requests were approved. At least three ranchette homes now stand on the forty-acre lot (67). These developments should not directly interfere with mining and gasification on the most likely initial lignite development site (west of Box Elder Creek), but may interfere with secondary lignite extraction on the east side of the Creek in future years.

The Commissioners have, however, turned down a proposed development entitled the Box-Elder Project, which would have directly conflicted with the primary development site. The proposal was originally for a 4,000 acre development to include residential, commercial, and industrial development which was scaled down to approximately 800 acres. The 800 acre proposal was again rejected on the grounds of possible conflicting land use (68).

Adams County itself has no specific environmental legislation with the general exceptions of subdivision regulations, comprehensive plan and zoning among other development controls. State and Federal environmental laws and enforcement powers, where applicable, appear to be quite sufficient, although the County will certainly be concerned with the method and results of development if it does occur.

Public Opinion and Input

As discussed in Chapter 5, landowners in the Watkins area generally wish to do with their land what will bring them the most profit. For those owning lignite rights, this will probably mean the desire for mining and gasification development. Most Denver area residents might be expected to favor development to gain the benefit of a reliable SNG (natural gas equivalent) supply. Others, both in the Watkins area and in the Denver region, may desire preservation of the agricultural land use. A survey sponsored by Cameron Engineers in the mid-1970s of public reaction to the Watkins Project showed that approximately 50 percent of the people questioned favored development, while 25 percent were neutral and approximately 15 percent were opposed. There was little difference in people's reactions to development based on where they live (69). However, the results of this survey could be questioned because of the lack of adequate information given the survey respondents before they answered the questions.

In any case, there will be ample opportunity for public input into the decision-making process. There will be public hearings and meetings held by a variety of public bodies, the most prominent of which will be held by the Adams County Commissioners to consider the change in land use and rezoning, and the U.S. Department of the Interior (which manages the Federal lignite reserves in the area) after a draft Environmental Impact Statement has been prepared.

CHAPTER 8. CONCLUSIONS AND RECOMMENDATIONS

Conclusions

There would be several positive consequences of high-Btu coal gasification development. On the national level, development would help to provide a reliable energy supply from the United States' own resources, thereby reducing our dependence on foreign sources of fuel, and easing some of this country's economic ills; would enable the use of existing gas pieplines, burners, and other equipment; and would allow the continued use of a clean-burning and convenient natural gas equivalent. Those factors which make Adams County development seem appropriate include the probable availability of lignite, water, and other resources in Adams County and the Denver metropolitan region; and a ready SNG market in the Denver area, which is faced with a possible shortfall of natural gas supply between 1985 and 2000.

However, as can be seen from the previous analyses of the physical, technological, economic, environmental, socio-economic and policy considerations of development, there exist a number of currently existing constraints to SNG production in Adams County, with another group of potential contraints to development (uncertain at this point in time) which may blossom into definite constraints in the coming years. The currently existing constraints include:

1) The lack of existing commercial high-Btu SNG industry development in the United States, and corresponding lack of operating experience and knowledge.

2) The capital intensiveness of high-Btu SNG development, and inability to acquire financing from traditional sources.

3) The lack of Federal government participation in and incentives for high-Btu SNG production.

4) The uncertain future environmental costs affecting profitability and SNG production costs.

5) The confusing, time-consuming, and costly governmental permitting and regulatory process.

Potential future constraints to development include:

1) An increased natural gas supply caused by exploration incentives from deregulation, or a decrease in natural gas demand from high prices and other conservation incentives.

2) The inability to form a logical mining unit because of the uncertainty of Federal preference right leases and possible surface right/mineral right ownership conflicts.

3) The enormous scale of operation which would be necessary if the kaolin were to be processed along with SNG production.

4) The possibility of expensive incremental (marginal) SNG pricing policy, as compared to average (rolled-in) pricing.

5) The uncertain availability of water needed for processing.

6) The designation of the Denver region as an air pollution non-attainment region, which will probably require the use of offsets to obtain air pollution permits.

7) The possible disruption of aquifers used for drinking water in the area.

8) The decision to use solid waste as a feedstock along with lignite, and the problems caused by solid waste disposal.

9) The possible designation of the area as being unsuitable for mining because of the productive dry farmlands or other conflicting land uses.

10) The possibility of reaching socio-economic threshhold levels in the Watkins area, or in the Denver region, and the ability to finance socio-economic impact mitigation.

11) The opposition to development from the public or from special interest groups.

The status of the potential for development can best be described as doubtful for at least the next five years, during which time the outcome of most or all of the uncertainties facing SNG industry development (such as pricing policy, governmental participation, commercial demonstration, capital and operating costs, permits and regulations, etc.) should become more clear. During this five-year period, much progress could also be made by potential developers in Adams County concerning the localized constraints to development (such as lack of available environmental and socio-economic data, necessary permits and clearances, mineral right acquisition, study of possible air pollution offsets available in the Denver region, etc.). This potential preliminary planning period must be taken advantage of, and is very essential and necessary to avoid future problems concerning strip mining and SNG production in Adams County. The current position of the Adams County Commissioners and the Denver Regional Council of Governments of keeping the SNG development option open by avoiding conflicting land uses in the area is sound considering all existing data and information. Overall, the author feels there is a very good chance that the previously listed constraints to development, although formidable, will be overcome, and that strip mining and high-Btu coal gasification development will begin in Adams County sometime between 1985 and 1990. This conclusion is based primarily on the probable need for the SNG product in the rapidly growing Denver metropolitan area and the expressed desire for development by the Adams County Commissioners if it can be shown that impacts are manageable and net benefits outweigh net costs.

Recommendations

The recommendations of the author to industry and government decision-makers as development plans progress include:

1) Potential developers should take and open and interdisciplinary approach to development.

2) The community (including special interest groups) should be educated on the subject, kept informed, and involved in decision-making, possibly through the designation of a citizens committee.

3) Data gathering concerning environmental and socioeconomic variables (both site-specific and regional in nature) must be carried out before final decisions are made.

4) Extensive planning should take place once more information has been obtained on a regional level, with special emphasis given to Adams County preparation.

5) Detailed mining and production plans should not be developed until this additional information can be incorporated into such plans.

6) Alternatives to development must be carefully considered before any final decisions are made.

7) Potential developers should begin as soon as possible, after development interest becomes serious, discussions with State and Federal regulatory and permitting agencies and be prepared to keep these agencies informed of all plans.

8) Developers should be prepared to pay extensive environmental costs to mitigate adverse impacts.

9) Regulatory agencies should work with developers, providing them the necessary help so that costly delays do not occur.

APPENDIX A

Strip Mining Technology

The technology of strip (surface) mining is well-known and practiced widely in the United States and other countries today. Advantages of strip mining in comparison to underground mining include higher productivity, lower costs, lower manpower needs, and worker health and safety advantages. There are two major types of surface mining, contour (used in hilly or mountainous terrain) and area (used in flat terrain). Because of the existing flat terrain in Adams County, only the area mining technique need be considered applicable to this discussion.

Area mining involves the removal of overburden to allow recovery of the coal resource directly from the surface. The area mining process begins with the excavation of a box cut which exposes the deposit. After the exposed coal has been removed from this initial cut, the trench is filled with fresh overburden from succeeding cuts as the mine operation advances. The operations included in the area mining process are surface preparation (construction of the necessary infrastructure and removal of surface vegetation), fracturing (blasting to fracture the overburden and coal to make it easier to remove), excavation (use of scrapers, loaders, dozers, shovels, and draglines to remove and load the coal), and transportation (use of truck and/or conveyors to move coal to the site of further processing, i.e., the gasification plant)(70). A fifth operation, reclamation, must be added to this list as it has become a very important part of the overall mining plan. Topsoil is normally separated from other overburden, stockpiled and used in the reclamation process. Reclamation can proceed as trenches are refilled with overburden. Overall area mining efficiency averages about 90 percent.

APPENDIX B

Coal Gasification Technology

As reported by Lindquist (71), the production of SNG from coal consists of five essential phases: coal preparation and pretreatment, gasification, shift conversion, gas purification and methanation. A sixth stage, compression, may be necessary to raise the product gas to pipeline-transmission pressure. The various processes developed for SNG production differ in the design and operation of these phases. A brief description from Lindquist of each of these steps in the gasification processes follows.

Coal preparation and pretreatment. All processes for manufacturing SNG require some degree of coal preparation before gasification can be accomplished. The coal feedstock must meet certain process requirements for particle size and may have to meet criteria for chemical composition. Preparation may involve breaking the raw coal, washing, crushing, screening, and drying. Coal pretreatment involves the destruction of coal-caking properties while retaining as much of the volatile matter as possible. The destruction of coal-caking properties is particularly important when a fixed-bed process is used because agglomeration of coal particles cannot be tolerated; if the particles are stuck together, the heated air and steam in the gasifier cannot have enough surface contact with these coal particles, which will cause a great loss in conversion efficiency.

Gasification. The atomic ratio of hydrogen to carbon is less than 1:1 for coal, while this ratio is 4:1 for methane (natural gas). Therefore, converting coal to SNG necessitates the addition of hydrogen, the removal of carbon, or both. Consequently, gasification by any process must either convert the coal directly into methane or provide a synthesis gas capable of being upgraded to methane-rich gas through further processing. Gas is obtained from coal by the primary methods of pyrolysis, hydrogasification, and synthesis gas methanation. These methods are not mutually exclusive; products or steps of one method can and have been combined with those of another to produce SNG. Pyrolysis involves the heating of coal in the absence of air or oxygen according to the reaction

$$\text{Coal} + \text{heat} \rightarrow C + \underline{CH_4} + \text{other gas.}$$

A portion of the volatile hydrogen combines with carbon to form methane. The desired hydrogen:carbon ratio results in a significant portion of the coal emerging as byproduct char, which can also be gasified. In hydrogasification, hydrogen from an external source is reacted with the carbon in coal or char to form methane according to the reaction

$$C + 2H_2 \rightarrow \underline{CH_4} + heat.$$

The less reactive portion of the coal or char is usually used to produce hydrogen, and the source of hydrogen must be inexpensive for this process to be economical. Synthesis gas production results in an intermediate-Btu gas, which requires further treatment to upgrade it to a methane-rich SNG. In this method, steam and either air or oxygen are reacted with the carbon in the coal. Because essentially all modern processes use oxygen to prevent nitrogen dilution of the product gas, an inexpensive supply of oxygen is necessary. The carbon-steam reaction is highly endothermic; thus heat must be supplied to the gasifier by a heat carrier, by partial combustion of the coal with oxygen, or by an externally applied heat source. The synthesis gas produced contains mainly hydrogen and carbon monoxide. The primary reaction in synthesis gas production is

$$C + H_2O + heat \rightarrow H_2 + CO.$$

Shift conversion. The major components of shift conversion, which requires a large amount of steam, are the waste-heat boiler (where the effluent from the gasifier is cooled), the reactor vessel, and the product-gas cooler. The effluent from the gasifier must be processed to achieve the proper hydrogen:carbon monoxide ratio for attaining methanation. This ratio if adjusted to approximately 3:1 in the shift converter via the water-gas shift reaction of

$$H_2O + CO \rightarrow H_2 + CO_2 + \text{heat.}$$

Gas purification. Purification removes vapor-phase impurities from the gas stream to meet standards of pipeline quality gas and to condition the gas for attaining methanation. Carbon dioxide, a diluent that lowers heating value, is removed by scrubbing. Toxic sulfur compounds must be removed to prevent contamination of the nickel catalysts usually used in the methanator. The primary methods of gas purification are absorption into a liquid, chemical conversion to another compounds, and adsorption onto a solid. These methods are often combined to obtain the desired gas purity.

Methanation. Methanation entails the catalytic conversion of excess hydrogen and carbon monoxide into methane via the reaction

$$CO + 3H_2 \rightarrow \underline{CH_4} + H_2O + \text{heat.}$$

Because this reaction is highly exothermic, heat exchangers are required to control the temperature.

APPENDIX C

Second-Generation Gasification Technologies

In contrast to the fixed-bed gasification process is the use of fluidized-bed gasifiers. Principal reasons for selecting the fluidized-bed technology include an oxygen pretreatment at 750°F which destroys the caking properties of coal and which offers a potential for utilizing a greater variety of coals and the combustion process which produces 50 percent of the total methane in the first step of processing. Its process simplicity results in good operability and reliability because a substantial part of the total methane is formed in the gasifier. Oxygen requirements are lowered and capital requirements of methanization are reduced (72).

The most promising second generation processes (which use fluidized-bed gasifiers) include the HYGAS process (Institute of Gas Technology), the CO_2 Acceptor process (Consolidation Coal Company), the Bi-Gas process (Bituminous Coal Research), and the Synthane process (U.S. Bureau of Mines), all of which are in the pilot plant stage of technological development. Commercial deployment of these second generation processes is not expected until the 1990's, so there would be no real benefit in deferring construction of Lurgi-designed plants in the next five to ten years under current conditions (73). Since the gasification section of the Lurgi plants accounts for only 15-20 percent of the total plant cost, and is the section most susceptible to being obsoleted by second generation technology, most of the knowledge from the Lurgi plants will be common to second generation plants and the experience will speed the ultimate commercialization of the newer technologies (74). The chemistry of second-generation technology is basically the same as that discussed in Appendix B.

APPENDIX D

Coal Gasification Net Energy

In any discussion of energy technology, the consideration of the most efficient use of resources is becoming increasingly important. Decision-makers today must be concerned about how much energy is required to produce and deliver useable energy. As a result of these concerns, efforts to examine the energy requirements of energy production (or net energy analysis) have recently been undertaken. The concept of net energy has been misinterpreted and misused by many, but the Colorado Energy Research Institute (CERI)(75) has compiled a thorough document considering many aspects of net energy. The study consists of data from twenty different energy trajectories, yielding energy of four different qualities: gas, gasoline, coal, and electricity.

Each step in the processing or transportation of energy has energy inputs and outputs. The inputs include principal energy (the fuel to be processed or transported) and external energy (energy which is required from outside to operate the process and to make the materials needed to build and operate the processing system). The outputs include energy product (the processed or transported energy delivered from the process) and energy loss (energy unavailable for further use as a result of the process; this can include physical losses, unrecovered resources in extraction, internally consumed energy, and external energy).

The "resource net yield ratio" accounting method, one of three accounting methods discussed in the CERI study, calculates what resource in the ground and external energy inputs are required for a given energy output. In comparing SNG production from strip-mined coal to other sources of fossil fuel energy, only the natural gas and direct burning of strip-mined coal trajectories have higher net energy ratios than the strip-mined high-Btu gas trajectory as shown in Table D-1.

Table D-1

Fossil Fuels Net Energy Comparisons

Energy Trajectory	Resource Yield Ratio
Natural Gas	4.84
Coal (S) Gas	1.28
Coal (U) Gas	0.32
Petroleum Gasoline	0.40
Oil Shale (S) Gasoline	0.78
Oil Shale (U) Gasoline	0.41
Coal (S) Liquefaction Gasoline	1.13
Coal (U) Liquefaction Gasoline	0.33
Coal (S)	8.18
Coal (U)	0.64
Natural Gas Electricity	0.35
Coal (S) Electricity	0.22
Coal (U) Electricity	0.08
Petroleum Electricity	0.10
Coal (S) Electricity	0.36
Coal (U) Electricity	0.13

Source: Colorado Energy Research Institute, 1976, p. II-23.

APPENDIX E

Capital Costs, Operating Costs, and Price Estimates

The most comprehensive estimates of high-Btu coal gasification capital and operating costs have been compiled by Detman (76) for the U.S. Energy Research and Development Administration and the American Gas Association. The study estimates capital costs and the cost of operation utilizing a western subbituminous coal to estimate the cost of pipeline quality gas for six coal to SNG processes. Table E-1 summarizes these capital and operating costs (1976 dollars).

The estimated SNG prices (1976 dollars) for those same six high-Btu coal gasification processes are shown in Table E-2. The SNG price for the Lurgi process is estimated to be $3.30/MM Btu. Linden (77) similarly estimates the price of SNG/MM Btu for the Lurgi process at $3.30 (1976 dollars). Transmission and distribution costs of $1.15/MM Btu are added to yield a delivered cost to the consumers of $4.45/MM Btu. In late 1978, the American Natural Resources Company estimated their SNG product cost to be approximately $5.50/MM Btu from their proposed North Dakota plant.

Table E-1

Capital and Operating Cost Estimates for SNG Production
(thousands of 1976 dollars)

Process	Capital Cost	Operating Cost
Steam-Oxygen HYGAS	1062	95
Steam-Iron HYGAS (export power)	1560	149
CO_2 Acceptor	1095	146
Bi-Gas	1257	137
Synthane (slurry feed, export char)	1399	135
Lurgi	1308	114

Source: Detman, 1976, p. 1.

Table E-2

SNG Gas Cost
(Dollars/MM Btu)

Process	Gas Cost
Steam-Oxygen HYGAS	2.71
Steam-Iron HYGAS (export power)	4.10
CO_2 Acceptor	3.38
Bi-Gas	3.50
Synthane (slurry feed, export char)	3.70
Lurgi	3.30

Source: Detman, 1976, p. 1.

APPENDIX F

Alternative SNG Price Estimation Methods

Synthetic Gas Coal Task Force Method (78). Two formulas (one for utility financing, the other for private financing) were formulated by the Task Force for use in estimating SNG price when more detailed information concerning capital and operating costs are available. The figures which must be supplied to make an estimation for utility financing include

C (total capital requirement \$MM)
W (working capital, \$MM)
N (total net operating cost in first year, \$MM)
G (annual gas production, trillion Btu/year)
d (fraction debt)
i (interest on debt, % year)
r (return on equity, % year)
and p (return on rate base, % year).

The average gas cost (\$/MM Btu) can then be calculated according to the relationship

$$\frac{1.3435N + 0.05(C-W) + 0.005[p + \frac{48}{52}(1-d)r](C + W)}{G}$$

which assumes escalation of operating costs at 3 percent per year, a 20-year project life, 5 percent/year straight line depreciation, and a 48 percent Federal income tax rate.

The figures which must be supplied for making an estimation according to the private financing method include

I (total plant investment, \$ MM)
S (startup costs, \$ MM)
W (working capital, \$ MM)
N (total net operating cost in first year, \$ MM)
and G (annual gas production, trillion Btu/year).

The constant gas cost (\$/MM Btu) can then be calculated according to the relationship

$$\frac{1.2422N + 0.2353I + 0.1275S + 0.2308W}{G}$$

assuming a 25-year operating life, 16-year sum-of-years-digits depreciation, 100 percent equity capital, 12 percent DCFROR (discounted cash flow rate of return), and 48 percent Federal income tax rate.

Both of these formulas will allow a fairly accurate determination of SNG price. They can be used in circumstances which do not necessitate the highest accuracy in price determine.

<u>Discounted Cash Flow Breakeven Price Method</u> (79). This is the most accurate and most flexible pricing determination method. However, detailed information concerning costs and financial plans must be known in order to make this determination. In this method, the breakeven parameter (in this case, price) is represented by a variable such as X, and

all cash flow calculations are made as a function of this variable. This allows analysis in real-world situations in which cash flow calculations are different in different years, resulting in more accuracy than the other methods. Flexibility is also gained because the analysis can obtain a price at a specified DCFROR, rather than using formulas based on generalized assumptions. Cash flows with the breakeven parameter are calculated and discounted to the present at the desired DCFROR, and the price is obtained by solving for the unknown X (setting the net present value to zero). This method should be used when the highest accuracy in estimation is necessary.

APPENDIX G

Key Federal and State Environmental Legislation

There are six major pieces of Federal environmental legislation which will have a major effect on any coal gasificiation facility and associated strip mine. The major thrust and relevance of theses laws are as follows.

National Environmental Policy Act of 1969 (Public Law 91-190). NEPA has become the most important piece of legislation in the past 25 years through its mandate to make environmental protection a major goal of every Federal agency. Its major thrust has been to require the preparation of an environmental impact statement for major Federal actions significantly affecting the quality of the human environment. Its effect has been widely felt throughout the entire nation. In effect, NEPA provides legislative authority to control development on environmental grounds.

Clean Air Act as Amended in 1977 (Public Law 95-95). The CAA has established standards pertaining to air quality. Included in these regulations are the National Ambient Air Quality Standards (NAAQS), which define maximum allowable concentrations of particulates, sulfur oxides, carbon monoxide, hydrocarbons, nitrous oxides, and photo-chemical oxidants to protect public health (primary standards) and welfare (secondary standards); emission standards for hazardous pollutants, which cover air pollutants for which ambient air quality standards do not apply or those pollutants which are considered toxic or hazardous; New Source Performance Standards (NSPS), which define maximum allowable emissions from particular point sources which may endanger public health and welfare; and Prevention of Significant Deterioration (PSD), which establishes maximum allowable increases (increments) of air pollutants in areas which are cleaner than the NAAQS. The Environmental Protection Agency (EPA) has regulatory authority to enforce this act, but control can be given to individual States with Federally-approved State programs.

Clean Water Act as Amended in 1977. (Public Law 95-217). The FWPCA controls pollutant discharges into all waters of the United States, including the surrounding ocean. It established the National Pollutant Discharge Elimination System (NPDES), under which every discharger must apply for a permit and provide data on the nature of the discharge. Additionally, schedules of compliance and restrictions involving water quality standards, new source performance standards and toxic standards are established under NPDES. The Environmental Protection Agency (EPA) has regulatory authority to enforce this act, but control can be given to individual States with Federally-approved State programs.

Surface Mining Control and Reclamation Act of 1977 (Public Law 95-87). The SMCRA established uniform minimum standards for the regulation of surface mining activity throughout the country on both public and private lands. Of particular importance are the act's provisions regarding environmental protection performance standards and designation of areas unsuitable for coal mining. The Office of Surface Mining has been established to oversee enforcement of SMCRA, and control can be given to individual States with Federally-approved State programs.

Resource Conservation and Recovery Act of 1976 (Public Law 94-580). RCRA provides for the disposal of solid waste in an environmentally sound manner and wise utilization and conservation of valuable resources. Federal assistance (technical and financial) is available to States or regional authorities to accomplish these goals. Comprehensive solid waste management plans must be formulated on both regional and site-specific levels.

Safe Drinking Water Act of 1977 (Public Law 95-190). The SDWA was enacted to protect valuable drinking water supplies throughout the nation. The legislation provides for study of the impacts of pits, ponds, and other physical changes of development on underground water supplies for public water systems.

<u>Other Federal Laws</u>. Other important laws which affect development include the Noise Control Act of 1972 (Public Law 92-574) which establishes noise limitations, the Critical and Endangered Species Act of 1973 (Public Law 93-205) which protects all endangered species, the Fish and Wildlife Coordination Act of 1934 (Public Law 85-624) which requires the consideration of impacts on fish and wildlife, and the Mine Safety and Health Act Amendments of 1977 which protects workers and controls mining practices.

<u>Colorado Legislation</u>. The State of Colorado has enacted legislation, subsequently approved by the EPA, to control and enforce air and water pollution in the State. The Air Quality Control Division and Water Quality Control Division, both within the Colorado Department of Health are the responsible agencies for control and enforcement of these State laws. The Colorado Mined Land Reclamation Act of 1976 established the Colorado Mined Land Reclamation Board to review mining and reclamation concerns and develop standards for the approval of reclamation plans. The Board is now a division of the Colorado Department of Natural Resources. However, the State must enact stricter legislation than the currently existing law to gain control and enforcement powers from the Office of Surface Mining.

APPENDIX H

Generalized Environmental Impacts and Mitigation Techniques

The environmental problems and mitigation techniques to lessen the impact of those problems for a generalized (not site-specific) gasification facility and associated strip mine can be grouped into seven general categories: air, water, solid waste, biological, soils, land use and reclamation, and noise. Brief discussions of these seven categories as summarized from Edwards (80) follow.

Air. There are many sources throughout the coal conversion process, beginning with mining, from which air pollutants can enter the atmosphere. Pollutants take the form of particulates (from the coal preparation plant, storage piles, road and mine dust, airborne ash, conveyors, and some vehicle emissions); gases such as sulfur dioxide, oxides of nitrogen, carbon dioxide, nitrogen, hydrogen sulfide, tar gas, hydrocarbons, carbon monoxide, and ammonia (almost exclusively from the conversion plant); water vapor (from the cooling towers and storage pond evaporation); odors (from the sulfur plant, storage ponds, boiler stacks, hydrogen sulfide, flue gases and scrub sludge); and waste heat (thermal pollution from the coal conversion process).

However, as mentioned in Chapter 1, the conversion of coal to SNG presents a significant air quality advantage over electrification of coal, with nine to twelve times less air emissions from SNG production compared to electricity generation producing an equivalent amount of useable energy. There are many abatement procedures which will take place to improve air quality, including lime slurry stack scrubbers (mainly to remove sulfur dioxide, but also other gases and particulates to some extent from flue gas streams); bag houses and cyclone dust collectors (to remove dust and particulate matter); wetting process (to use recycled water to hold down dust and particulates); electrostatic precipitators (to remove very fine dusts and particulates from stack gases); Claus plant (which is used for high-sulfur coal to remove 97 percent of the sulfur in waste streams and convert it to elemental sulfur); and the Stetford Unit (which is used for low-sulfur coal to remove 94 percent of the sulfur from the tail gases and convert it ot elemental sulfur).

Water. Water concerns take the form of both quality and quantity. Water quality (both surface and ground water) is affected by emissions which take the form of waste heat; acid (not much of a problem in the West); salt; trace metals; phenols (carbonic acid); and particulates (sedimentation and erosion). These pollutants enter the environment from the mine (particulates, salt, and acid) or from the plant (heat, trace metals, and phenols). Conventional abatement techniques such as biological oxidation, gravity separation, and other physical and chemical unit operations should control these emissions to a large extent. With regard to water quantity, a full-scale gasification facility (producing 250 MM CF/day will typically require from 10,000 to 25,000 acre-feet per year of water,with the exact amount depending upon the type of cooling process (which uses the largest amount of water during the coal conversion process) to be used. The impacts of such large water use may be felt in two areas: hydrology and availability. Hydrology will be affected by the strip mining process, which disturbs the surface and subsurface water systems. The large user of water supplies may lower the availability of underground supplies and create increased competition for water supplies (especially relevant in the West).

Solid Waste. Anticipated sources and types of solid waste include the mine and associated coal preparation plant (principally tailings); and the conversion plant (construction debris, quenched ash from the converter, sulfate sludges from scrubbers, elemental sulfur if it cannot be sold, and spent catalysts). Disposal techniques usually consist of burying or burning, both of which may be inadequate and cause other pollutant problems in the form of water and air pollution, respectively. Additionally, burying can cause subsidence and land slides. It is hoped that beneficial uses of some of these products can be found in the near future (such as paving or building material) so that disposal problems are lessened.

Biological. Immediate biological (flora and fauna) concerns include loss of critical habitat because of land disturbance or change of land use; change in population patterns and characteristics such as number of species, competition, or migration; removal of available food and water sources in the area; introduction of toxic elements into the food chain; disruption of interrelationships among flora, fauna, and their surrounding environments; and changing the rate of natural processes such as erosion and weathering which affect vegatative growth. These consequences can be mitigated somewhat through the use of environmental inventories and continued monitoring to determine changes in critical parameters, use of ecological principles in predicting these impacts, and careful environmental planning.

Soils. The conversion complex and associated strip mine can cause the removal of agricultural lands from production; loss of topsoil through erosion and deposition; and contamination of soils by toxic elements. The value of the topsoil may ultimately be greater than the coal resource itself; the soil has been created during a very time consuming process which involves biological, chemical, and physical processes, yet the balance within soils is very delicate and can be easily destroyed. Separation of and stockpiling topsoil is a process which will mitigate these impacts to a great extent. Additionally, assessment, predition and planning processes must be used so as not to introduce harmful substances through air, water, or solid waste pollution into the soil. Protection of good soils is of prime importance considering the increasing trend of converting these lands to other uses, and thereby (at least temporarily) foreclosing the option of using this land for food production.

Land Use and Reclamation. The initial siting study for a coal gasification facility will depend mainly upon the availability of two resources--coal and water. The vast amount of land (15 to 140 square miles depending on a number of factors) needed for infrastructure, mining, and conversion, may require a change in existing land use where these two resources exist together. Therefore, two more elements must be considered before any final siting determination can be made--current and future land use and reclamation potential. It is stipulated by SMCRA that prime farm lands should not be taken out of production for mining uses. Additional unsuitability criteria (the land is considered better suited for other uses) exclude other lands from consideration, and the land must be returned to at least as good a condition than that existing before development began. The potential for successful reclamation in the West is less than that for the East, where climatic factors are more amenable to growth. These factors must be carefully examined before decisions are made.

Noise. Noise pollution is an increasing problem for industrialized societies, and is often the most overlooked of all immediate environmental impacts. Noise can be a source of annoyance; creates stress; interferes with oral communication; causes hearing loss; disturbs plant and animal life; and causes social problems and loss of human productivity. Sources of noise will be most evident in the construction and mining processes, but will also originate from the plant itself and from transportation (of men and materials). Noise impacts on humans can be classified as occupational (involving those workers on the job) and environmental (involving all others who are affected). Mitigation techniques include equipment redesign, barriers and enclosures, use of acoustical absorbing substances, and ear protection devices for occupational noise; and berms, landscaping with trees which serve as noise mufflers, buffer zones, and other types of sound barriers for environmental noise.

APPENDIX I

Generalized Socio-Economic Impacts and Mitigation Techniques

Most socio-economic problems arise from the rapid influx of workers and service personnel into an area unprepared for such growth. Effects from this influx take the form of a wide variety of problems affecting the quality of life of the area, both quantitative and qualitative in nature. Brief descriptions of the impacts follow.

Economic. On the positive side, new development can stimulate economic prosperity within a community or a region. Dollars will begin flowing within the area immediately. However, often times, this economic prosperity causes sharp increases in the cost of living and inflation. Employment opportunities are greatly expanded, and wage scales from energy development are usually higher than other opportunities in the area. Revenues from all types of taxes will increase significantly because of the expanded tax base. However, these increases are usually not collectable when they are most needed to mitigate other disruptions which will soon be occurring and to provide necessary services for the expanded population (such as fire, police, medical, education, etc.). This problem of front-end financing is one of the key problems in any socio-economic analysis.

Social. Disruptions of lifestyle and habits and other changes within the community will begin to cause social problems soon after the influx of population begins. Impacts such as increases in crime, mental illness, domestic disputes, alcoholism, and divorce are typical of many energy boom towns. Loss of community morale may occur, and many times the newcomers and old residents become divided into factions, with little interaction or communication taking place. Lack of adequate housing puts additional strains on the community or region. The aesthetic quality of the area can be expected to deteriorate, and outlets such as entertainment and recreational facilities are often in short supply or non-existent. Cultural problems will occur when a minority group (such as Indians) or other cultural units are disrupted. Value differences between groups are commonplace but are difficult to anticipate and prevent. Archaeological or historical sites may be impacted, also.

Mitigation procedures center around adequate preparation and anticipation by the community and region. Planning, especially the tools of a comprehensive land use plan and zoning, can prevent many problems. The acquisition of an accurate data base (for such wide-ranging variables as demographic profile, housing units, employment, etc.) before development occurs will give an estimation of critical problem areas. Manpower and institutions must be readied. Determinations of sources of help (monetary, technical assistance, and otherwise) to the community must be made. Orientation programs and other efforts to lessen the immediate impacts of changes can be accomplished by government and/or industry. Industry can also provide other types of help. Citizen involvement and public opinion must be important criteria for input into decision-making.

APPENDIX J

Federal Synthetic Fuel Energy Policy

One of the five major initiatives of the 1975 Energy Program announced by President Ford was the goal of producing synthetic fuels from coal and oil shale equivalent to one million barrels per day by 1985. Following this announcement, a Synfuels Interagency Task Force was organized by the Office of Management and Budget in February 1975 to outline a program which would demonstrate the commercial viability of synthetic fuels, taking into consideration the overall costs and benefits from a national viewpoint, including such factors as direct financial cost to the government, opportunity cost, environmental and social impacts, macro-economic and distributional effects, and national security/insurance benefits. The name of this program was recently changed from the Synthetic Fuels Commercialization Program to the Alternative Fuels Demonstration Program (AFDP). No Congressional approval was ever granted for this Energy Program, and although a final Environmental Impact Statement was prepared in late 1977 for the AFDP, the program has essentially been set aside pending further development of United States energy policy.

Although President Carter's 1977 National Energy Plan (NEP-1)(81) recognized the importance of coal for future energy use, no specific plans were made for high-Btu coal gasification. NEP-2, to be released in April or May of 1979, is expected to address high-Btu coal gasification and other synthetic fuels in more detail. Meanwhile, the tentative 1980 U.S. energy budget includes $169 million for synthetic gas research and development, with only $55 million devoted for design and construction of a plant to demonstrate high-Btu gas technology (82).

APPENDIX K

Key Federal Regulatory and Policy-Making Bodies

There are many Federal gencies with regulatory and/or policy-making authority which will affect a gasification facility and associated strip mine. Most notably, the Departments of Energy, Interior and Agriculture will serve key roles in development along with the Environmental Protection Agency. Brief descriptions of important departments or agencies, the organizational units within those departments or agencies, and programs or functions with regulatory, policy-making or research authority follow.

Department of Energy. Within the DOE, the Fossil Energy Division is concerned with coal utilization technology demonstrations, makes supply/demand forecasts, and helps in the leasing of publically-owned coal lands; the Fossil Energy Program Office is concerned with coal utilization research and development; and the Energy Regulatory Administration will help to regulate gas produced from coal.

Department of Interior. Within the DOI, the Bureau of Mines is concerned with mining technology, reclamation demonstration, and safety and health; the Geological Survey is concerned with research on the environment, classifications of Federal coal lands, and regulation of operations on leased coal lands; the Office of Surface Mining is concerned with developing mining technology, reclamation of abandoned areas, and regulation of surface mining and the surface effects of underground mining; the Bureau of Land Management is concerned with leasing and operation of public coal lands and environmental studies relating to coal; the Bureau of Reclamation is concerned with water availability; and the Fish and Wildlife Service conducts surface mining studies relating to wildlife.

Department of Agriculture. Within the DOA, the Forest Service is concerned with mined land reclamation and conducts land management planning and environmental studies; and the Soil Conservation Service provides data on planning, soils, plant materials, and hydrological studies.

Environmental Protection Agency. Within the EPA, the Office of Air Quality Planning and Standards is concerned with air quality regulation; the Office of Water Planning and Standards is concerned with water quality regulation; the Office of Toxic Substances regulates toxic materials; the Office of General Enforcement enforces EPA regulations and standards; the Office of Health and Ecological Effects is concerned with biomedical and environmental effects; and the Office of Energy, Minerals, and Industry conducts studies on environmental control technologies and coal utilization and development.

Within the Department of Labor, the Mine Safety and Health Administration regulates coal mine safety and health; within the Department of Commerce, the Economic Development Administration provides help with socio-economic planning; within the Department of Health, Education, and Welfare, the National Institute for Occupational Safety and Health is concerned with biomedical and environmental effects on workers; within the Corps of Engineers, the Civil Works Division regulates new and existing mine waste piles; the Department of Treasury establishes tax policy; the Department of Housing and Urban Development is concerned with housing and development of new communities; the Community Services Administration helps solve community economic problems; the Federal Trade Commission promotes fair competition and prevents price fixing; the Securities and Exchange Commission reviews disclosures; and the Federal Energy Regulatory Commission has regulatory authority over sales of power by establishing and enforcing rates and charges.

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