DOE/FE/20219-2

Final Report
Feasibility and Economic Study of Medium-BTU Coal Gas Blended with High-BTU By-Product Gas as an Industrial Energy Source at Billings, Montana

May 1981

Prepared for:
U.S. Department of Energy
Assistant Secretary for Fossil Energy
Office of Coal Processing
Coal Processing Resources Development Division
Washington, D.C. 20461

Prepared by:
Northern Resources Inc.
Billings, Montana 59101

Under Grant No. FG01-79RA20219

Preface

This report is one of a series that was sponsored by the Office of Coal Resource Management, Resource Applications, Department of Energy, based on responses to a Program Interest Notice (PIN) (RA-21) issued March 15, 1979. The purpose of the Program Interest Notice was to obtain a realistic assessment of the feasibility (from the owner/user's point of view) of utilizing low or medium-Btu gas from coal in a variety of industrial or commercial applications.

Although processes for producing environmentally acceptable gas from coal are available commercially, the lack of commercial operating experience in the United States requires that the pioneer users of this technology to principally rely on engineering and economic analysis. The uncertainty of costs, operating reliability and retrofit impacts; effect of gas on product quality and plant processes; plant siting and environmental factors; gas distribution costs and safety; regulatory impacts; coal supply and transportation; capital/financing arrangements, etc., are all considerations which a potential owner/user must weigh when seriously considering the use of low/or medium-Btu coal gas as an alternative fuel option. This series of studies, by emphasing site specific applications, was aimed at developing answers to some of these concerns.

Coal Resource Management
Fossil Energy

STUDY PARTICIPANTS

Northern Resources, Inc.
Billings, Montana

Ford, Bacon & Davis Utah
Salt Lake City, Utah

Davy McKee Corporation
Cleveland, Ohio

Environmental Research & Technology, Inc.
Fort Collins, Colorado

SRI International
Energy Center
Menlo Park, California

EXXON Refinery
Billings, Montana

Conoco Refinery
Billings, Montana

Cenex Refinery
Laurel, Montana

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1. EXECUTIVE SUMMARY

1.1 ABSTRACT

This study assesses the technical and economic feasibility of blending a medium-Btu gas (MBG) produced from coal by the Winkler fluidized bed gasification process with excess refinery fuel gas to be used as an industrial fuel in Billings, Montana. This report includes a discussion of the background of the project; the site selection process; the conceptual design of the process and supporting facilities; the retrofit requirements and other costs associated with burning the MBG; the environmental and permitting aspects of the project; the cost estimates and economic considerations; the contract provisions for MBG buy/sell agreements; the government's role in supporting the project; and the market potential for the project in Billings and similar projects in other markets. The study concludes that the project is technically feasible and economically viable today although parity with conventional fuels will not occur until 1985.

1.2 BACKGROUND

In late 1978, Northern Resources Inc., observed a set of circumstances in Billings, Montana that were ideal for a medium-Btu coal gasification project. During a survey of industrial facilities in the Billings area, it was found that the Billings EXXON Refinery produced high-Btu refinery fuel gas in excess of its needs. The gas was not saleable because of fluxuating production and high hydrogen sulfide content. It was also found that the Billings Conoco and the Laurel Cenex Refineries were users of large quantities of natural gas and faced annual declining allotments of domestic natural gas and seasonal curtailments. One refinery purchased imported natural gas to make up the shortfall in fuel. Discussions with the refineries indicated an interest in medium-Btu gas as an alternate fuel.

Based on this set of circumstances a project was conceived that would entail production of a medium-Btu gas from coal and then blending the synthetic gas with the excess refinery off-gas. The product gas would then be sold as an industrial fuel gas. With this basic concept, a project was structured in four phases. Phase I would consist of determining conceptual economics and discussions with potential users regarding their interest in an alternate fuel supply. Phase II would consist of a detailed feasibility and economic study and would be implemented if sufficient market interest was found. Phase III would consist of definitive engineering and obtaining firm commitments to purchase the MBG and would be implemented if the feasibility study continued to indicate economic feasibility, and if letters of intent could be obtained from the prospective buyers of the MBG. Phase IV would consist of procurement, construction, and start-up of the synthetic fuel plant. Phase IV would be implemented during Phase III when firm commitments were obtained for buying the MBG, and project financing was finalized.

Investigations prior to this study consisted of a series of discussions with the three refineries to determine the interest of Conoco and Cenex in purchasing MBG; the availability, quantity, and quality of excess refinery fuel offered by EXXON; and a conceptual economic study to provide an estimate of capital cost, operating cost, and an estimated sales price of the MBG.

The discussions with the using refineries indicated that utilization of a MBG would not pose any technical problems and only minor retrofit would be necessary. The primary decision to purchase the gas would be based on economics and assurance of supply.

An economic analysis was made on a conceptual basis. The purpose was to provide an early estimate of the MBG sales price. This study indicated a total estimated capital cost of $30,280,000 (early 1979 dollars). This estimate included all facilities associated with coal handling gasification, gas treatment, and delivery of the MBG to the customers. Annual operating and feestock costs were estimated to be $6,826,000. A breakeven cost of $3.10 (1979 dollars) per million Btu was calculated. At a rate of return on investment of 20 percent, a sales price of $3.50 per million Btu was indicated. At this time, domestic natural gas was priced at about $2.00 per million Btu and the imported natural gas used by one of the refineries was priced at approximately $3.00 per million Btu. Domestic natural gas was expected to rise at a 12 to 15 percent annual rate, thus it was projected that by 1985 the price of MBG would be cheaper than natural gas. Also, both refineries had experienced short-term curtailments and annual cutbacks in domestic natural gas curtailments. This scenario enhanced the economic feasibility of the project.

Investigation of the availability of excess refinery fuel gas from EXXON indicated that up to 5 million cubic feet per day would be available, depending on seasonal demand for products, unit condition, maintenance, related shutdown, and refinery feedstocks. Early discussions related to potential price of the refinery fuel gas indicated that $2.00 per million Btu was within the anticipated asking price. Since $2.00 per million

Btu was less than the production cost of MBG (approximately $3.10 per million Btu), economic benefits would accrue if utilization of the refinery gas could be worked into the project.

At this point in the project development and based on the interest of the refineries, a decision was made to conduct a detailed feasibility study and conceptual design. As this decision was being made, the Department of Energy announced its Low/Medium-Btu Coal Gasification Utilization Assessment Program for Potential Users through the Office of Resource Applications. Northern Resouces Inc., submitted an unsolicitated proposal to conduct a feasibility study and conceptual design on a cost sharing basis and was awarded DOE Grant No. DE-FGOI-79RA20219.

1.3 STUDY OBJECTIVES AND SCOPE

The objective of this study is to obtain a conceptual design and conduct feasibility and economic studies in sufficient detail to prove the viability of the project and to provide the basis for long-term contracts for the sale of MBG and financing of the project. The project includes:

- Selection of a gasification process.
- Conceptual design.
- Retrofit requirements of users associated with burning MBG.
- Selecting a plant site.

- Determining environment constraints and permitting requirements.
- Capital and operating cost estimates.
- Determining economic viability.
- Developing contract classes unique to a MBG sales contract.
- Assessing the role of government in the project.
- Determining market potential.

1.4 PROCESS SELECTION

Eight companies representing various gasification technologies in various stages of development were sent solicitations inviting proposals to supply the gasification process. Four companies responded representing fixed (moving) bed, fluidized bed, intrained flow, and molten salt gasification technologies. A detailed analysis was conducted of the propsal submitted. The evaluation considered the technical viability of the process, commercialization status, efficiency, and cost.

The Winkler fluidized bed process was judged to be overall superior; the process is considered commercial, and the Winkler produced MBG was estimated to cost less than gas from the other processes.

1.5 SITE SELECTION

The project will occupy 8 acres in the southeastern corner of a 45-acre site. The site selected offers several benefits, among these are; good location for optimum pipeline lengths, rail access, water availability, and price. The site is also located near a power plant which allows sharing of coal unloading and stockpile facilities and the purchase of steam for the process facilities. The site is outside but surrounded by the city of Billings and is adjacent to the Conoco Refinery. The site is compatible with the project from an enviromental and socioeconomic view.

1.6 CONCEPTUAL DESIGN

The plant size was established to meet the estimated demand of 10 billion Btu per day required by the users. Coal gasification is to provide 5.6 to 7.0 billion Btu per day and 3.0 to 4.4 billion Btu per day is to be provided by refinery off-gas. The cold, clean gas is to be compressed and delivered by pipeline to the users. The blended gas is to have less than 10 grains/100 scf H_2S and a higher heating value of 406 Btu/scf. The higher heating value is based on manufacturing coal gas of 285 Btu/scf and blending with refinery off-gas of 900 Btu/scf.

Run-of-mine coal is delivered to the site and placed in storage. The coal is then reclaimed and delivered to the coal preparation facility where it is crushed to 3/8 inches x 0 and dried to a moisture content of 8 percent. The dried coal is stored in a nitrogen blanketed bin. Oxygen and nitrogen is supplied to the process by a vendor owned and operated air separation plant. Process steam is supplied from a waste heat recovery boiler and purchased from a nearby power plant.

The coal is gasified by the Winkler fluidized bed process. An innovation introduced to the Winkler system for this project is in operation at an elevated pressure of four atmospheres. A lock hopper coal feed system is the means used to elevate the pressure. The innovation is well within current technology. The gasification section is composed of two gasification trains, each designed to produce 60 percent of the gas requirement. Each train consists of a coal feeding system, a gasifier vessel, a waste heat recovery unit, a char extraction system and a particulate removal unit. Common to both trains is a char concentration unit which prepares the wet and dry char for disposal, project use, or sales. The medium-Btu gas is delivered to the gas treatment unit at 120°F and 45 pisa. The coal gas is then treated to remove sour gases.

The refinery fuel gas is received at the gas treatment unit and is processed through an Amine Unit. Sulfur is removed from the sour gas streams by a Claus Unit. The total H_2S in the treated gas is 10 grains per 100 cubic feet.

The coal gas and refinery gas are blended in a 50-foot section of 12-inch pipe. The blended gas is dried, compressed, and delivered to the users by pipeline.

All supporting facilities such as wastewater treatment, maintenance shops, admninistrative office, utility systems, and fire protection facilities are included in the project.

Three process alternate studies were investigated during this study. Use of lignite coal as an alternate feedstock was investigated and it was found that feed rates of coal, oxygen, and steam would vary and more ash would be produced. However, lignite was found to be a very suitable feedstock. The use of 95 percent purity oxygen versus 99.5 percent was studied. The major process change would be an increase in gas volume to produce an equal quantity of Btu, for example, the Btu value of the coal gas is reduced. The third alternate study involved overall efficiency of the process considering use versus disposal of the residual char. It was found that the process had an overall thermal efficiency of 88.3 percent if the char is used. If the char is sent to disposal, the overall efficiency was found to be 78.6 percent.

1.7 RETROFIT

This study investigated the retrofit requirements necessary to permit the using refineries to safely and efficiently burn the MBG gas. It was found that the MBG offered lower heat losses to the stack that more than offset the lower heat of combustion of the MBG and the MBG has a higher tolerance against flame lift-off thus permitting higher primary air pressure and better mixing than natural gas. The retrofit requirements generally include installation of larger orifices in burners, increasing diameter of gas pipelines, and various instruments and controls. All modifications were considered minor and within current technology. Cost of modifications at each refinery ranged from $350,000 to $385,000.

1.8 ENVIRONMENTAL CONSIDERATIONS AND PERMITS

Federal, state, and local regulations and permits relevant to the proposed project were identified and reviewed. The applicable categories of regulations and permits include:

- Federal and State Air Quality Standards
- Federal and State Water Quality Standards
- Solids or Hazardous Waste Disposal Requirements

- Groundwater Appropriation

- Right-of-Way and Easements

- Cultural Resources

The Winkler coal gasification process has a long history of operation; however, no Winkler unit is in operation in the United States. The extremely limited existing environmental data causes some uncertainty regarding the environmental analysis of the process. A preliminary assessment of environmentally significant emissions, effluents, and solid wastes produced by gasification process was made based on analogy with other coal gasification processes and is briefly summarized below.

1.8.1 Air Emissions

In addition to fugitive emissions, the major potential air emissions sources from the project include coal drying vent, vent of nitrogen used to pneumatically transport lock hopper ash to storage, the CO_2-rich off-gas, and the Claus tail gas. The former two represent emissions that can be controlled by conventional particulate removal equipment, for example, baghouse filters; the latter two represent hydrocarbon and/or sulfur emission sources controllable by current technology. The temperature characteristics of the Winkler gasifier and the injection of coal into the bottom of the fluidized bed preclude the production of significant heavy hydrocarbons. The existing data base for air quality is excellent for the Billings area and includes both state-owned and industrial air monitoring stations. No additional preoperational air resources data collection is expected to be needed as input to air quality modeling for this project.

1.8.2 Liquid Effluents

The current proposed wastewater disposal method is to discharge to the Billings municipal sewage treatment facility. Although no specific pretreatment regulations exist for coal gasification, pretreatment of these wastewaters prior to discharge to the sewer will be required. It is anticipated that the process liquor will have a very low organic content and contain small amounts of HCN, various trace elements, and potentially significant amounts of H_2S and NH_3. Given the nature of the process wastewaters from coal preparation and waste heat recovery/particulate removal areas, the pretreatment operations will include: (1) settling basin for solids removal; (2) sour water stripper for removal of NH_3, H_2S, and HCN; and (3) trace element removal via precipitation, after which the wastewater can be used as cooling tower make-up or discharged directly to the sewer. The metal sludge will likely be treated as a hazardous waste, while the settled solids must be tested to assess their hazardous classification.

1.8.3 Solid Waste

The major solid effluents from the gasification plant include any coal pile refuse and particulate runoff to the containment basin, the by-product sulfur, the solids from the wastewater settling/treatment basin(s), and the gasifier ash. The major concern with all these materials is their potential for classification as a hazardous substance under the Resource Conservation and Recovery Act (RCRA). A hazardous classification dictates stringent packaging, labeling, transportation, and disposal criteria; a nonhazardous classification would permit disposition of these materials in the mine or any other authorized disposal site.

Solid waste disposal planning will require generation of data on quantities, composition, leachability, and hazardous properties of any solids to be disposed.

At this time it is anticipated that none of these solids will be classified as hazardous (excluding the sludge from trace element precipitation which was discussed as a secondary environmental impact of wastewater treatment operations). Verification of this assumption will require actual testing but preliminary assessments predict a pure, saleable by-product sulfur, and coal refuse and ash with trace elements which are basically immobile.

1.8.4 Socioeconomic, Biological, Cultural Resource and Noise Assessment

Sufficient socioeconomic and biological data exist for the Billings area to assess the impacts of the project on the human and biological environment. A cultural resources site survey will be conducted to verify compliance with the Historic Preservation Act of 1966. A separate data collection program for noise has been proposed because inadequate ambient noise baseline measurements and receptor/source identification exist in the immediate vicinity of the project site.

1.9 COST ESTIMATES

The capital cost information included in this report was obtained from engineering-construct firms participating in the feasibility study. A major objective of the study was to obtain capital cost estimates of the highest degree of certainty. Given the level of engineering accomplished and construction experience in the project subsystems, it was possible to obtain lump sum, fixed price bids for portions of the work. However, two major subsystems, gasification and gas treatment, were estimated. Table 1-1 provides a summary of the capital costs. The operating costs estimate is based on a production rate of 10.0×10^9 Btu per day (5.6×10^9 Btu produced from coal and 4.4×10^9 Btu per day purchased off-gas). On-stream time was determined to be 365 days per year due to multiple trains, on-line spares, and turn-up capability of the systems. Table 1-2 provides a summary of operating and maintenance costs. Costs were based on current 1980 prices and escalated at 10 percent per year to 1984.

1.10 ECONOMIC ANALYSIS

The approach taken to determine economic feasibility was to calculate the MBG selling price that would meet all expenses and recover the investment at an adequate rate of return. A life cycle cash flow model was structured and discounted cash flow analysis was utilized to determine an internal rate of return on investment in the project. Several key financial parameters were tested through sensitivity studies and the competitive position of the MBG was assessed.

Based on a financial structure of 75 percent and 25 percent equity, a general escalation rate of 10 percent, an initial MBG sales price of $6.10 per mm Btu, a MBG price escalation of 8 percent, a 20-year tax life, straight-line depreciation and an effective income tax rate of 50 percent, the project shows an internal rate of return of 24 percent annually, after tax.

TABLE 1-1

CAPITAL COST SUMMARY

ITEM	COST	% OF TOTAL
Land	600,000	1.1
Working Capital	500,000	.9
Construction Cost	46,985,206	85.3
Initial Supplies	250,000	.45
Start-Up	500,000	.9
Owners Cost	6,288,794	11.35
	$55,124,000	100.0

TABLE 1-2

O&M COST ESTIMATE (1984)

ITEM	ANNUAL COST
Feedstocks (Coal, Oxygen, Refinery Gas)	$10,289,406
Catalysts and Chemicals	381,015
Utilities	1,219,882
Operating Labor	523,600
Maintenance (Labor and Materials)	681,560
Administration and Overhead	1,837,304
	$14,932,767

Figure 1-1 shows the effect on MBG price resulting from a 10 percent change in significant cost elements. The sensitivity analyses showed that the MBG price is most sensitive to demand. A 10 percent decrease in demand results in an 11 percent increase in MBG price. Operating and maintenance cost was also found to be an important cost factor. A 10 percent increase in O&M cost resulted in a 5 percent increase in MBG price. The MBG price was found to be less sensitive to other parameters such as capital cost and other feedstock cost. It was also found that the internal rate of return is very sensitive to MBG sales price and interest rate. A 3 percent increase in MBG price resulted in a 29 percent increase in rate of return. A 2 percentage point increase in the long-term financing interest rate caused a 21 percent decrease in rate of return.

Figure 1-2 provides a comparison of the projected refinery fuel costs and the projected price of MBG. Since a large portion of the MBG price is tied to construction and is fixed, the constant dollar MBG price is expected to rise at a rate not to exceed 2 percent. Constant dollar conventional fuel prices are expected to rise at a 9 percent rate. Using these factors, the MBG becomes cost competitive with conventional fuels in 1985. If conventional fuels rise at only 6 percent, the MBG becomes competitive in 1990. The long-term fuel cost savings to the refineries is great and offers an annual rate of return to them in excess of 60 percent.

1.11 MBG SALES CONTRACT

Preliminary contract clauses unique to a MBG sales contract were drafted. It is intended that these clauses be used as the starting point for negotiating the final contracts. The

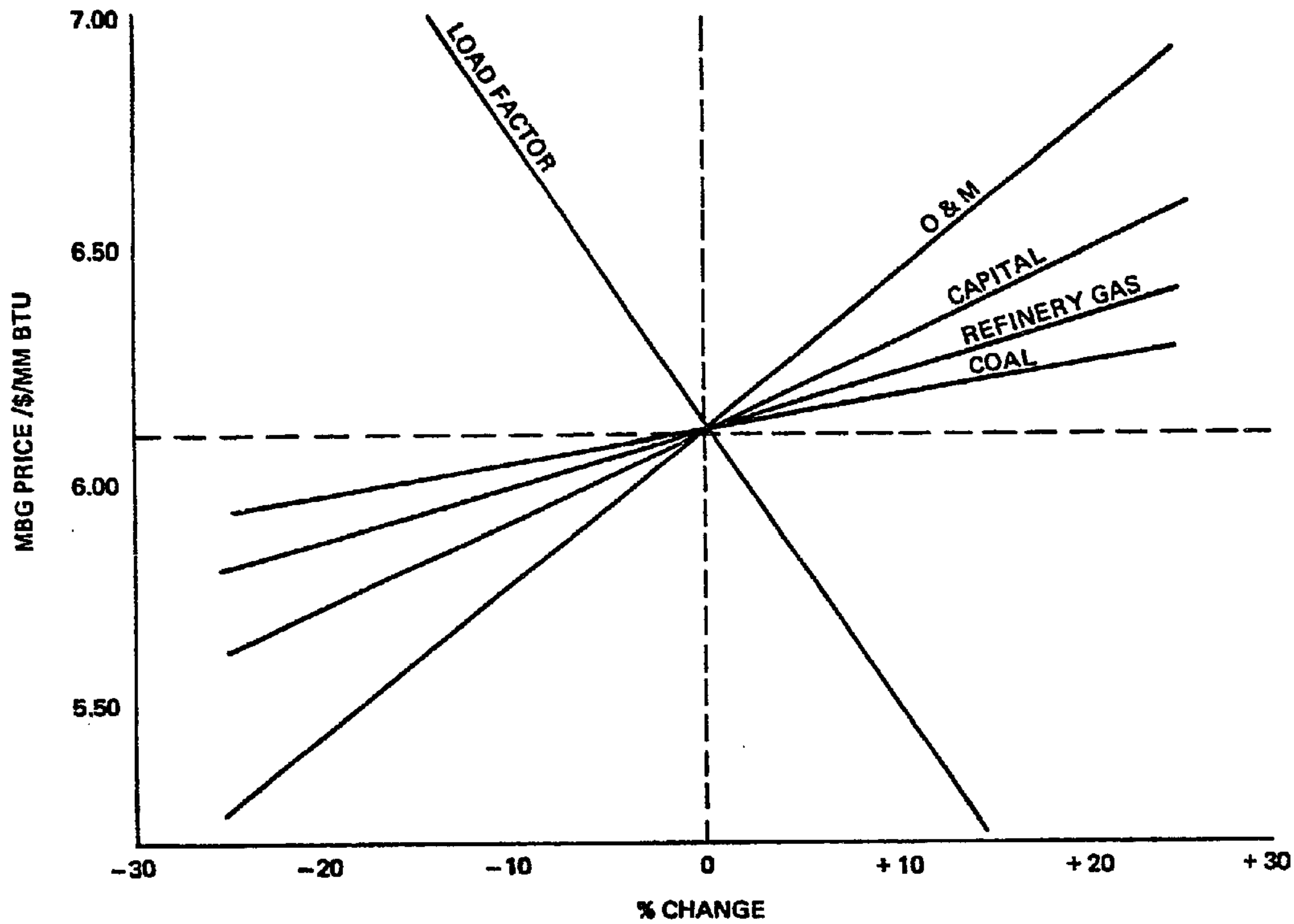

FIGURE 1-1
SENSITIVITY CURVES

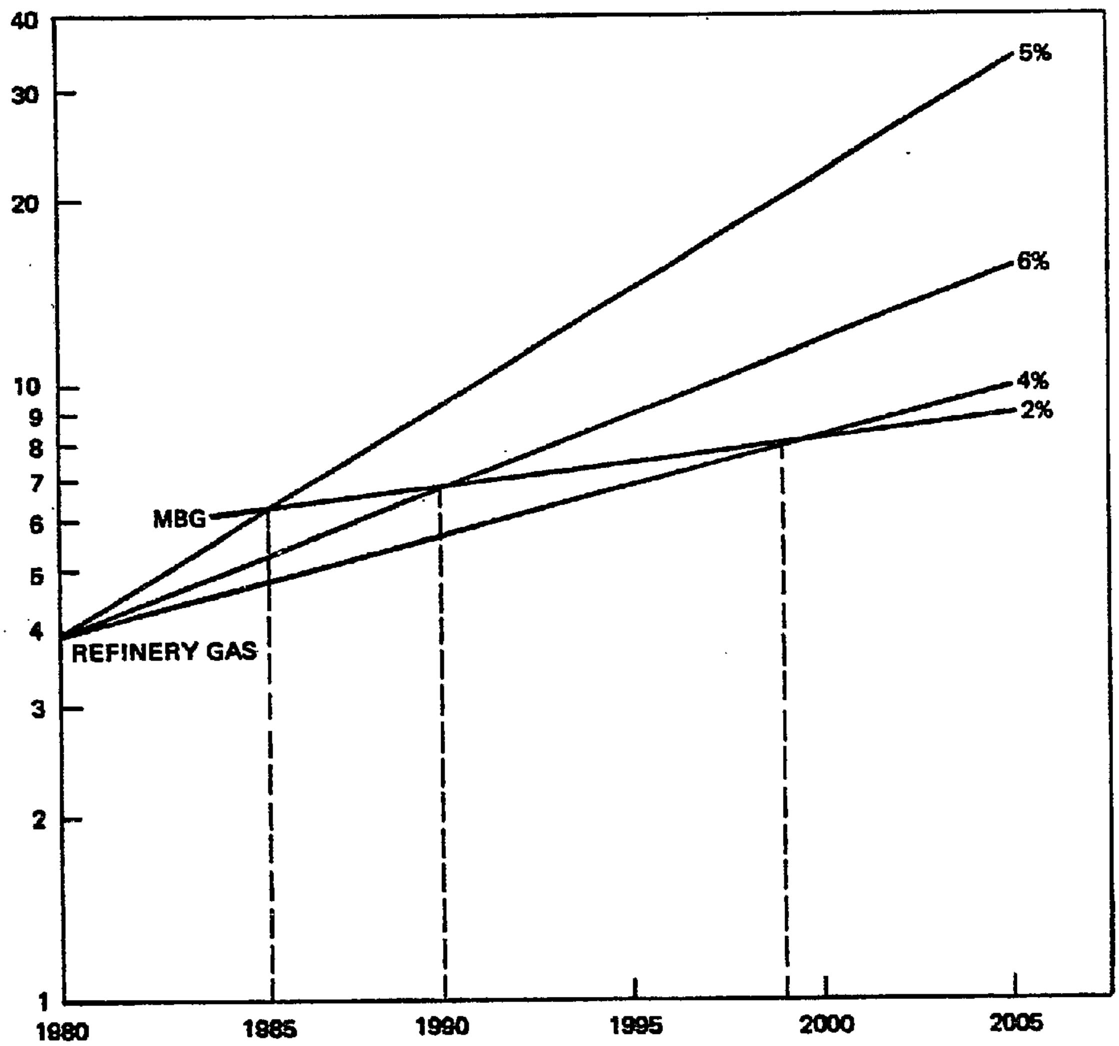

FIGURE 1-2
COMPARISON OF REFINERY GAS AND MBG
CONSTANT DOLLARS

contract clauses primarily deal with term, quantity of gas, delivery point, base price, price adjustments, and quality adjustments.

1.12 GOVERNMENT ROLE

During the study, four specific areas were identified that the government could provide significant assistance in expediting this project.

1.12.1 Environmental

It was found that the definitive regulations were not in existence for gasification projects. Not only did local, state, and federal agencies express different views and interpretations within a single-government agency but disagreement occurred. The government can greatly assist the permitting process by establishing guidelines and combining permit requirements.

1.12.2 Deregulations

Rapid and complete deregulation of crude oil and natural gas would remove the most significant restraint, price competitiveness. The price of synthetic fuels should not be constrained by regulation.

1.12.3 Financial Incentives

Until crude oil and natural gas are deregulated and have risen to world prices, grants for feasibility studies and construction loan guarantees and product price supports should continue.

1.12.4 Pipeline Right-of-Way

A change in agency policy that would permit construction of the distribution pipeline within the Interstate Highway 90 right-of-way would greatly improve the project economics and expedite construction.

1.13 MARKET POTENTIAL

Although the market for this specific project is limited to the two refineries and perhaps a few very small industrial users, the nationwide market for similar projects is quite significant. Natural gas and residual fuel oil back-out in refineries represents a total estimated market of 3.1×10^{12} Btu per day. In terms of gasification units of a 3.5×10^{9} Btu per day nominal production (the size of one of the units considered for this project), this market indicates a potential of over 880 gasifier units producing the equivalent of 534,000 barrels of crude oil per day. Constraints such as availability of cheap delivered coal (location near the coal source) and current prices for natural gas would tend to limit early development to specific areas of the United States. The first targets should be in those areas with high natural gas prices (those dependent on imported natural gas) and/or those areas highly dependent on imported crude oil and with good markets for residual fuel oil.

MBG, as a primary fuel and/or feedstock for other industries, offers a broad market much larger than petroleum refining alone. Based on industrial usage of energy in gross terms, the industrial fuel gas market is perceived to be several times as large as the refining industry. The market is broad and includes all users of natural gas and fuel oil. The limiting factors are perceived to be size (minimum of 7.0 billion Btu per week demand). Studies by others indicate this market could approach 900 plants supplying 3.0 quads of energy per year.

2. SITE SELECTION

The site selected for the Billings MBG Project is an area of 45 plus or minus acres locally known as the Goggins Industrial Park. Northern Resources Inc., purchased an option to buy the site prior to January 1, 1981. As of this date the site has been surveyed, topographic maps prepared, and preliminary soils data gathered.

The project will occupy approximately 8 acres in the southeastern corner of the site and will border the Conoco Refinery on the refinery's north boundary. The site is currently outside but surrounded by the city limits of Billings, Montana.

The site selected for the Billings MBG Project is ideal from several points of view. First, when shown on a map, the refineries lie in a straight line with EXXON at the northern end, Conoco approximately 3 miles SSW, and Cenex 15 miles SSW from the Conoco Refinery. From a pipeline view, a plant located on this line will minimize the pipeline length. Second, it was found that the Burlington Northern Railroad ran along this straight line and served the three refineries. Since Burlington Northern Inc., is the major stockholder of Northern Resources Inc., permission could be obtained to use the railroad right-of-way for the pipeline, thus eliminating a significant time and money requirement necessary to obtain a right-of-way from private landholders. Third, the site selected is already zoned for heavy industry and partially developed as an industrial park. Fourth, from a cost point of view, the site selected could be purchased for 50 percent of comparable industrial property in the Billings area. Fifth, the site is located adjacent to the Conoco Refinery and offers the optimum location along the line between the refineries to minimize gas distribution costs. Sixth, the site is served with electrical power. Water is available from the Yellowstone River, wells can be drilled on the site or from the city of Billings. Industrial wastes (after treatment) can be disposed of by city sewage or discharged to the Yegen Drainage Ditch (an industrial drain). Seventh, the site has undergone some development and is flat and level and will require minimal site preparation. Eighth, the site is adjacent to the city of Billings, thus it has available a large manpower pool to obtain labor for construction and operation. Ninth, preliminary data indicates that the site is acceptable from an environmental point of view.

Of the other three potential sites in the Billings area, one was located in the Yellowstone River flood plain, a second was considerably more expensive, and the third would require greater gas distribution cost.

3. DESIGN FACTORS

3.1 PLANT CAPACITY

The nominal plant size was established to be 10 billion Btu per stream day of blended gas. Coal gasification is to provide 5.6 to 7.0 billion Btu per stream day and 3.0 to 4.4 billion Btu per stream day is to be provided as refinery off-gas.

3.2 CAPACITY FACTOR

The capacity factor was established to be 100 percent of demand. This factor is consistent with operating experience of similar gasifiers outside the United States. Sparing philosophy, parallel trains, maintenance, and equipment reliability are to be designed around this factor. Actual maximum plant capacity would be 11.4 billion Btu per day.

3.3 SITE CONDITIONS

The site selected for the project is a vacant industrial park site of 45 acres. The site is located in Billings, Montana adjacent to the Conoco Refinery. The project will be located on approximately 8 acres along the south side of the site.

3.3.1 General Conditions

- Average annual temperature 47.7°F
- Average monthly temperature
  - January - 22.6°F
  - July 75°F
  - Summer dry bulb temperature - 94°F
  - Summer wet bulb temperature - 67°F
  - Average annual rainfall - 14.51 inches
  - Average annual snowfall - 30.0 inches
  - Prevailing winds - southwest
  - Snow load - 40 psf

- Wind load - 25 psf
- Seismic zone - 1
- Elevation - 3,002 feet

3.3.2 Environmental Zone

The project site is located within one mile of CO and TSP non-attainment areas. The project is located in AQCR 140.

3.3.3 Water Quality

The source of water will be the city of Billings. Table 3-1 provides a typical water analysis for Zone 1 of the city of Billings water system.

3.3.4 Soils

A preliminary soils investigation was conducted to determine the physical properties of the soil so as to determine the feasibility of siting the proposed plant on this site. The subsurface profile consists of ancient alluvial deposits from the Yellowstone River activity. The upper layers of silty sand and clay extended to depths ranging from 2 to 9.5 feet. Also at the surface, clay and gravel fill materials up to 1.5 feet deep were encountered at the south and north ends of the site. These surface materials are underlain by a compact to very dense sandy gravel to depths varying from 19.5 to 22.6 feet. This gravel is underlain by a very hard sandy shale bedrock. These materials are described in greater detail as follows:

- Fill. A dump was located in this area several years ago and has since been covered. Deep fills were not encountered in the borings but may exist within the site boundaries.

TABLE 3-1

WATER QUALITY

Characteristics Tests:

Alkalinity, Total mg/L	140.00
Chlorine Residual, mg Cl_2L	.35
Conductivity, uohns/cm	510.4
Hardness, Total, mg CaCO/L	224.3
Hardness, Magnesium, mg MG/L	21.4
pH	7.48
Solids, Dissolved, Percent	.038
Solids, Total Percent	.038
Temperature, ^oC	5.00
Turbidity, NTU	.48

Inorganics Tests:

Aluminum, mg Al/L	.013
Calcium, mg Ca/L	54.6
Fluoride, mg F/L	.41
Iron, mg Fe/L	.025
Magnesium, mg Mg/L	21.4
Manganese, mg Mn/L	.05
Nitrogen, mg N/L (Kpeldahl)	0.00
Phosphate, Total mg P/L	.023
Silica, mg Li/L	.023
Sulfate, mg SO_4L	95.00
Sulfate, mg SO_3L	2.00
Chloride, mg Cl-/L	3.22

- Clays. The natural clay is generally firm with moderate to medium high plasticity. The clay is compressible and contains some organic pockets.

- Sand. The sands are typical alluvial deposits with clay intermixed. Standard penetration resistance values of 16 to 20 blows per foot and cone penetration values of 5 to 7 blows per foot were made.

- Gravel. The natural gravel is dense and contains some cobbles and bolders. N valves ranged from 31 to over 100 blows per foot and cone values ranged from 36 to over 100.

- Bedkrock. Bedrock consists of sandy shale and becomes very hard with depth. Seams of siltstone and sandstone are interbedded with this material. This material has a plasticity index of about 12 percent.

- Engineering Considerations. Foundations placed in the upper soil profile may experience excessive differential settlements due to the heterogeneous nature of the materials. Settlements in the fill are unpredictable as the extent, depth, and type of fill is expected to vary considerably. The clays are compressible and the sand is loose in some areas. There are some isolated areas of high organic concentrations in the alluvial materials including the gravel.

  In general the gravel is a competent bearing material for moderate foundation loads, provided there is not a high organic content.

Bedrock is a competent bearing material for deep foundations. Pile penetrations into the bedrock may be limited in some areas due to the siltstone and sandstone layers. Timber piles may not penetrate the coarse gravel. Steel or auger cast piling may provide feasible deep foundations.

3.3.5 Other Site Conditions

The site is adjacent to Interstate Highway 90 and is served by a rail spur dividing the property roughly into two equal parts. Power lines of 50kV, 100kV, and 200kV cross the site. The site is outside but surrounded by the limits of the city of Billings.

3.4 PLANT LIFE

For the purpose of project economics, a plant life of 20 years was assumed. Analysis of plant components seem to indicate a longer plant life could reasonably be expected. Technical obsolescence was not considered a life expectancy factor.

3.5 FEEDSTOCKS

3.5.1 Coal

A Montana subbituminous coal was selected as the feedstock for the production of medium-Btu gas by the Winkler coal gasification process. The coal selected for the study is the Western Energy Rosebud coal.

The Rosebud coal lease area falls within the Fort Union geological formation of the Tongue River Basin. This basin is shaped somewhat like a football with its length divided approximately between the states of Montana and Wyoming. The coal in the basin is classified as subbituminous and is generally less than 1 percent in sulfur content.

The Rosebud mine is located approximately 50 miles northeast of Hardin, Montana or 90 miles northeast of Billings.

In the Western Energy lease area there are two prominent seams of coal. The upper seam is the Rosebud seam which is 23 feet thick. An 8-foot seam underlies above the Rosebud. The aggregate thickness of the two coal seams is 31 feet.

The Western Energy leases consist of approximately 790 million tons of coal in place. The Western Energy Rosebud Mine is currently in operation at a production rate in excess of 11 million tons per year. Production capacity is 13 million tons per year. Table 3-2 shows an analysis of the coal.

3.5.2 Refinery Gas

For the Billings MBG Project, NRI intends to purchase refinery gas from the Billings EXXON Refinery. The gas to be purchased is excess to the refineries' requirements. EXXON has expressed an interest in selling the gas and has assisted by providing analysis and production data. Table 3-3 provides the data regarding the gas. The gas will be provided to NRI at the refineries' fuel gas header and will be transported to the gasifier location by pipeline.

TABLE 3-2

REPRESENTATIVE COAL ANALYSIS

	Average	Low	High
Btu/Lb	8657.00	8501.00	9029.00
Equilibrium	23.31	21.49	24.72
Grindability Index (Hardgrove)	49.8	44.4	58.8
Proximite Analysis			
Moisture	23.40	20.25	24.69
Volatile Matter	29.79	26.15	32.59
Fixed Carbon	36.56	34.29	39.20
Ash	10.25	8.65	11.73
	100.00		
Ultimate Analysis			
Carbon, C	50.66	49.18	52.94
Hydrogen, H_2	3.43	3.09	3.62
Sulfur, S	.73	.60	.89
Oxygen, O	10.78	9.98	12.42
Nitrogen, N	.74	.49	1.16
Moisture	23.40	20.25	24.69
Ash	10.25	8.64	11.73
Chlorine	.01	.00	.02
	100.00		
Sulfur Forms A/R			
% Pyritic Sulfur	.35	.25	.50
% Sulfate Sulfur	.01	.00	.02
% Organic Sulfur	.37	.26	.54
	.73		

TABLE 3-2 (Continued)

	Average	Low	High
Mineral Analysis of Ash			
Phosphate Pentoxide, P_2O_5	.41	.18	1.70
Silica, SiO_2	38.64	35.41	42.58
Ferric Oxide, Fe_2O_3	6.25	4.18	8.25
Alumina, Al_2O_3	18.27	16.68	21.27
Titania, TiO_2	.67	.38	1.36
Lime, CaO	14.80	12.64	16.82
Magnesia, MgO	2.82	1.21	4.43
Sulfur Trioxide, SO_3	13.63	10.48	15.77
Potassium Oxide, K_2O	1.06	.57	1.46
Sodium Oxide, Na_2O	2.53	.47	3.67
Undetermined	.92	.00	2.31
	100.00		
Ash Fusion Temperature, $^{\circ}F$			
Oxidizing			
Initial Deformation	2180	2100	2260
Softening (H=W)	2203	2110	2330
Softening (H=1/2W)	2233	2130	2335
Fluid	2295	2130	2460
Reducing			
Initial Deformation	2097	2000	2225
Softening (H=W)	2123	2010	2280
Softening (H=1/2W)	2145	2020	2320
Fluid	2198	2130	2390

TABLE 3-3

REFINERY FUEL GAS DATA

General Data

Btu/cubic feet - 1000

Temperature - 115°F

Pressure - 89 psig

Volume - 1-5 million SCF/D

Analysis	Lbs/Hr
H_2O	196.2
H_2	341.0
CO	154.0
CO_2	523.6
Light Hydrocarbons	6550.6
H_2S	1264.8
N_2	949.2

3.6 PRODUCT SPECIFICATIONS

The proposed blend gas consists of a blend of approximately 80 percent medium-Btu (285 Btu/scf) manufactured gas from NRI's subbituminous coal gasification plant and 20 percent of EXXON's excess refinery gas (900 to 1000 Btu/scf). The resultant blend gas is treated and estimated to have less than 10 grains H_2S/100 scf, a higher heating value of 406 Btu/scf, a specific gravity of 0.684, and a molecular weight of 19.84. The above properties have been calculated based on actual analysis of the refinery gas and anticipated composition of the MBG based on the analysis of the coal proposed for the project. Table 3-4 provides the composition and properties of the two gases. Table 3-5 shows the anticipated composition and properties of the blended gas calculated from the data of Table 3-4.

3.7 PLANT EXPANSION

The plant design is based on the current and projected need of a specific group of customers. Expansion plans are limited due to siting constraints.

3.8 PLANT TURNDOWN

The capacity and turndown ratio of the Winkler gasifier are limited at the lower end by minimum flow required for fluidization and at the upper end by minimum resident time for combustion of the residues. A range of 25 to 130 percent of nominal capacity is anticipated without appreciable loss of efficiency.

TABLE 3-4

COMPOSITION AND PROPERTIES OF NRI BLENDED GAS

	Mol %	Mscf/Hr	Mol/Hr	Mol Wt	Lb/Hr	Btu/Scf	HHV	Flammability Limits Lower	Flammability Limits Higher	Specific Flame Intensity Btu/sec/Sq ft
H_2	36.8	373.4	985.1	2.0	1,970	325	120	4.0	75.0	703
N_2	1.7	17.0	44.8	28.0	1,254			-	-	
CO	32.3	327.4	863.8	28.0	24,186	321	104	12.5	74.0	124
CO_2	15.1	152.6	402.6	44.0	17,714			-	-	
Methane	9.3	93.8	247.8	16.0	3,965	1,010	94	5.0	15.0	
Ethane	2.6	26.5	69.8	28.0	1,954	1,769	46	2.9	13.0	
Ethylene	1.4	14.6	38.4	27.0	1,037	1,600	22	2.7	24.0	108 to 145
Propane	0.2	2.3	6.1	44.0	268	2,518	5	2.1	9.5	
Propylene	0.6	5.6	14.8	43.0	636	2,334	14	2.0	10.0	
iC_4	-	.4	1.1	58.0	64	3,253	1			
Total	100.0	1,013.6	2,674.3	19.84	53,046		406			

HHV = 406 Btu/scf

Specific Gravity = .684

TABLE 3-5

COMPOSITION AND PROPERTIES OF BLEND COMPONENTS

	WINKLER MBG					EXXON OFF-GAS			
	Mol %	Mscf/Hr	Mol/Hr	Mol Wt	Lb/Hr	Mol %	Mscf/Hr	Mol/Hr	Lb/Hr
H_2	37.9	310.7	819.3	2.	1,639	31.9	62.7	165.4	331
N_2	.6	4.9	12.9	28.	361	6.2	12.1	31.9	893
CO	39.7	325.3	858.0	28.	24,024	1.1	2.1	5.5	154
CO_2	18.1	148.4	392.3	44.	17,265	2.1	4.2	11.0	484
Methane	3.4	27.9	73.5	16.	1,176	33.5	65.9	174.3	2,789
Ethane				28.		13.5	26.5	69.8	1,954
Ethylene				27.		7.4	14.6	38.4	1,037
Propane				44.		1.2	2.3	6.1	268
Propylene				43.		2.9	5.6	14.8	636
iC_4				58.		0.2	.4	1.1	64
Total	100.0	817.2	2,156.0	20.65	44,465	100.0	196.4	518.3	8,610

HHV = 287 Btu/scf

Specific Gravity = .712

HHV = 900 Btu/scf

Specific Gravity = 0.067

Mol Wt = 16.6

3.9 OPERATION ON ALTERNATE FEEDSTOCKS

The Winkler fluidized bed gasification process operates extremely well and has been extensively demonstrated commercially on subbituminous and lignite type coals. It can handle a wide variation in the coal characteristics such as ash and moisture contents. Some decrease in efficiency is experienced as ash and moisture contents increases. Drying of coal is required only to ensure flowability of the coal and to satisfy operating economics (oxygen consumption when producing MBG).

The Winkler plant designed for this project can handle any Montana or western United States coal with only minor process adjustments required.

4. CONCEPTUAL DESIGN

4.1 PROCESS DESCRIPTION

The project process systems are shown on the System Flow Block Diagram, Figure 4-1. The systems are grouped into two units. The inside battery limits (ISBL) group consists of coal gasification, waste heat recovery, particulate removal, and ash handling. The outside battery limits (OSBL) group consists of all others.

4.1.1 Coal Handling System

The coal handling system is designed to serve the following functions.

- Raw Coal Receiving and Storage

  The 1-1/2 inch x 0 run of mine coal will be delivered to the plant site by a series of conveyor belts from Montana Power Company, Billings station, across Interstate 90.

  The raw coal will be transferred from the power company's live storage pile to NRI's coal conveyor system by variable rate vibrating feeders (provided by Montana Power Company) designed to deliver 0 to 30 tons of coal per hour. The raw coal conveyor system will consist of three separate conveyor belts. The first belt, approximately 1700 feet in length, conveys the raw coal from the live storage loading point to a point just each of Interstate 90. This conveyor belt runs at grade level. The second conveyor, approximately 600 feet in length, is the

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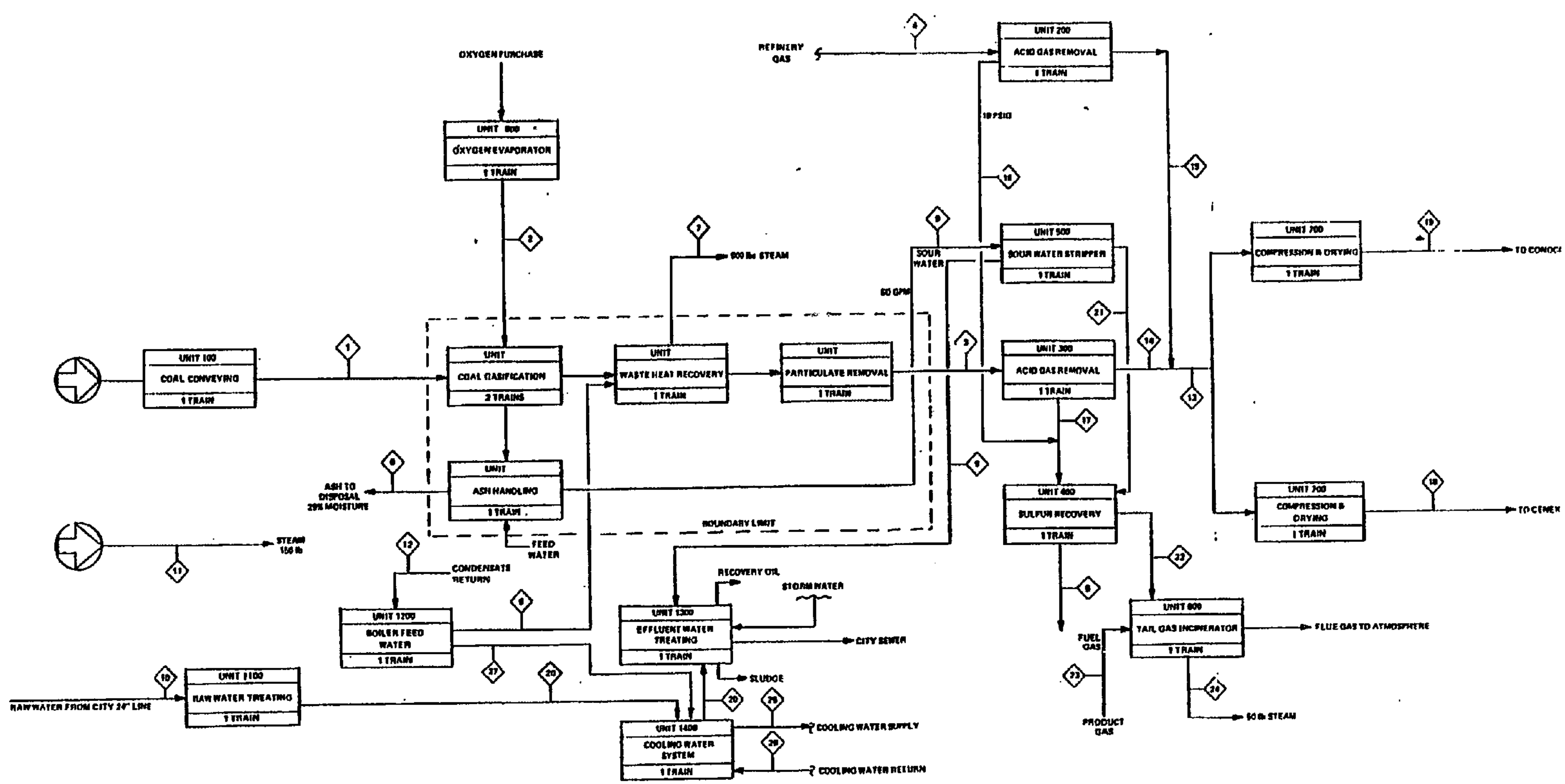

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
FLUID OR COMMODITY	COAL	OXYGEN	COAL	REFINERY GAS	SULFUR	WET CHAR	STEAM	BOILER FEED WATER	WASTE WATER	RAW WATER	STEAM	CONDENSATE	COMBINED GAS STREAMS	SWEET COAL GAS	SWEET REFINERY GAS
FLOW lbs/HR.	29,682	16,575	44,114	11,710	1,856	9,254	22,281	42,404	9,515	72,078	34,095	54,726	53,922	43,825	10,087
PRESSURE PSIG	ATM	60	30	27	—	ATM	600	700	30		150		29	29	29
TEMPERATURE °F	AMBIENT	260	120	60	—	100	489	228	120	60	366		80	80	80

STREAM NO.	16	17	18	19	20	21	22	23	24	25	26	27	28	29
FLUID OR COMMODITY	ACID GAS	ACID GAS	PRODUCT GAS TO CENEX	PRODUCT GAS TO CONOCO	COOLING TOWER & BLOWDOWN MAKEUP	ACID GAS	TAIL GAS	FUEL GAS PROD. GAS	STEAM	COOLING WATER SUPPLY	COOLING WATER RETURN	CONDENSATE TO COOLING TOWER MAKEUP		
FLOW lbs/HR.	1,700	3,224	30,831	20,020	79,000	UNDER 50	2,195	879	5,000	3.5×10^6	3.5×10^6	18,927		
PRESSURE PSIG	19	10	116	71	—	10	—	71	50	—				
TEMPERATURE °F	70	70	100	100	80	70	—	100	281	80	60	—		

REVISIONS					
DESCRIPTION	DATE	BY	CHK D	APP D	NO

REVISIONS				
DESCRIPTION	DATE	BY	CHK D	APP D

REFERENCE DRAWINGS	
DRAWING NO	TITLE

ISSUE RECORD				
DATE	ISSUE	REV	TO	FOR

ENGR. RECORD | INITIAL | DATE

CURRENT DRAWING STATUS. | INITIAL | DATE

Ford, Bacon & Davis Utah
ENGINEERS CONSTRUCTORS
SALT LAKE CITY, UTAH

TITLE
NORTHERN RESOURCES INC.
BILLINGS GASIFICATION PLANT
OVERALL SYSTEM FLOW DIAGRAM

FOR

SCALE | JOB NO UC-353 | FB&DU DWG NO | OWNERS D

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transfer belt which transfers the coal through an 8-foot diameter tunnel to NRI site just west of Interstate 90. This belt runs approximately 15 feet below grade. The third conveyor transfers the raw coal from the transfer belt to a 24-hour storage bin. This belt will be approximately 200 feet in length with a slope of about 16 degrees. Transfer houses will be provided for each angle change. All conveyor belts will be 24 inches and equipped with electronic belt scales to monitor and record the coal feed rates. Dust collection systems will be provided at both conveyor loading points and the bin entrance point. The dust system at loading point (if required) will be provided by the Montana Power Company.

All conveyor belts described above will be designed for adequate fire and weather protection.

- Coal Preparation

The coal preparation facility is designed to prepare the raw coal for the gasification process.

As the raw coal is delivered to the preparation plant, an in-line, self-cleaning tramp iron magnet will remove all magnetic materials such as bolts, small tools, etc. The 1-1/2 inches x 0 coal is then fed into a double roll type crusher to crush the coal to 100 percent, 3/8 inches x 0 product.

The crush product is discharged into a chute and then is passed through a thermal dryer. The dryer is designed to utilize saturated steam at 150 psig, and to dry 24 tons per hour of coal with a maximum moisture content of 25 percent to 20 tons per hour of coal at 8 percent moisture.

Both the crusher and the dryer are served by a 4000 cfm dust collector system.

- Prepared Coal Storage and Delivery to the Gasification Plant

  The prepared coal product is discharged via a chute onto a 24-inch nitrogen blanketed conveyor belt. The conveyor then discharges the coal into one 430-ton storage bin. The bin will have a seal type arrangement which will permit retention of nitrogen on top of the coal. This inert environment will prevent oxidation of the coal while in storage. Due to the use of nitrogen blanketing system, no dust collection system is included for this bin at this time.

  Reclaim from the storage bin is via a vibrating feeder conveyor arrangement. The bin is serviced with two feeders and two conveyors each capable of 100 percent capacity. The 24-inch, 250-ton-per-hour reclaim conveyors will transfer the prepared coal from storage to the gasification plant. The dual feeder conveyor arrangement will allow a complete backup for the coal feeding system.

4.1.2 Oxygen Plant

A supply of oxygen and nitrogen to the systems will be by a vendor owned and operated air separation plant. Several vendors have expressed an interest in constructing a facility adjacent to the site. Oxygen of 99.5 percent purity and at a rate of 200 tons per day will be supplied to the Winkler gasifier. Oxygen of 99.5 percent purity is selected based on two factors. The first, 99.5 percent purity permits the production of a higher heating value MBG. The second is that vendors recommended 99.5 percent purity so as to allow the possibility of other oxygen sales, thus enabling the construction of a larger plant. Through economics of scale, the larger plant would then sell the oxygen at a lower unit price. Vendor plans to sell by-product nitrogen also offers the possibility of lower oxygen costs. Nitrogen will also be provided for blanketing dried coal and instrument air.

4.1.3 Steam

Steam is required in the process for the following services:

- Feedstock in the coal gasification system.
- Reboiling towers in the gas cleanup system.
- Heating steam in the sulfur plant.
- Steam tracing of the molten sulfur systems.
- Coal drying in the coal preparation system.
- Space heating.
- Glycol regeneration.

The steam requirements are met by steam generated in waste heat boilers in the gasification system and the sulfur plant, with the balance of the steam purchased from Montana Power.

The condensate from all major steam users will be collected and returned to the boiler feed system. Steam condensate from isolated steam traps used for keeping sulfur molten and other tracing services will spill to the process sewer system (1 to 2 gpm).

The recovered condensate will be returned to the boiler feed surge tank or the deaerator. The amount of condensate to be recovered will exceed the requirements for boiler feedwater makeup. Therefore, a boiler feedwater treating system will not be required. The additionl condensate comes from the steam purchased from Montana Power which the power company does not want returned.

The excess condensate beyond boiler feedwater requirements will be used as cooling tower makeup.

The boiler feedwater is pumped to the deaerator where oxygen and other gases are stripped from the water with low pressure steam (5 psig). The water is subsequently pumped to the individual boilers by separate boiler feed pumps.

4.1.4 Coal Gasification

The Winkler gasification section is composed of two gasification trains, each designed for 60 percent of the total requirement. Each train consists of a coal feeding system, a gasifier, a waste heat recovery unit, a char extraction system, and a particulate removal system. Common to both trains is a char concentration section which prepares the wet and dry char for disposal. Figures 4-2 and 4-3 provide a flow diagram of this section of the plant.

Subbituminous coal (or lignite as an alternate feed material) is received in an elevated storage bin from the coal preparation area where it has been crushed to 3/8" x 0 and dried to 8 percent moisture.

The coal is discharged into either of two surge bins via a weigh feeder. Each surge bin holds a minimum of eight hours supply of gasifier feed coal. The feed conveyors and bins are blanketed with nitrogen to prevent spontaneous ignitition of the coal. A vent scrubbing system is provided to handle the vent gases from both surge bins and the coal conveyors.

The coal flows by gravity from the bottom of the surge bin down into a lock hopper gasifier feed system. This lock hopper feed system serves to elevate the pressure above the coal to the operating pressure of the gasifier (about 58 psia). This pressurizing operation is accomplished by filling an atmospheric upper cyclic pressure lock hopper with coal. The pressure of this upper lock hopper is then increased to the operating pressure of the gasifier. When the upper lock hopper pressure reaches gasifier pressure, the coal drops down to the lower lock hopper which is maintained at the gasifier pressure. When the upper lock hopper is empty, it is depressurized to accept more coal from the surge bin and repeat its cycle. The coal which had been dropped into the lower lock hopper is then metered into the Winkler gasifier by two variable speed, feed screw conveyors. The rate of coal feed is set to maintain the proper product gas composition.

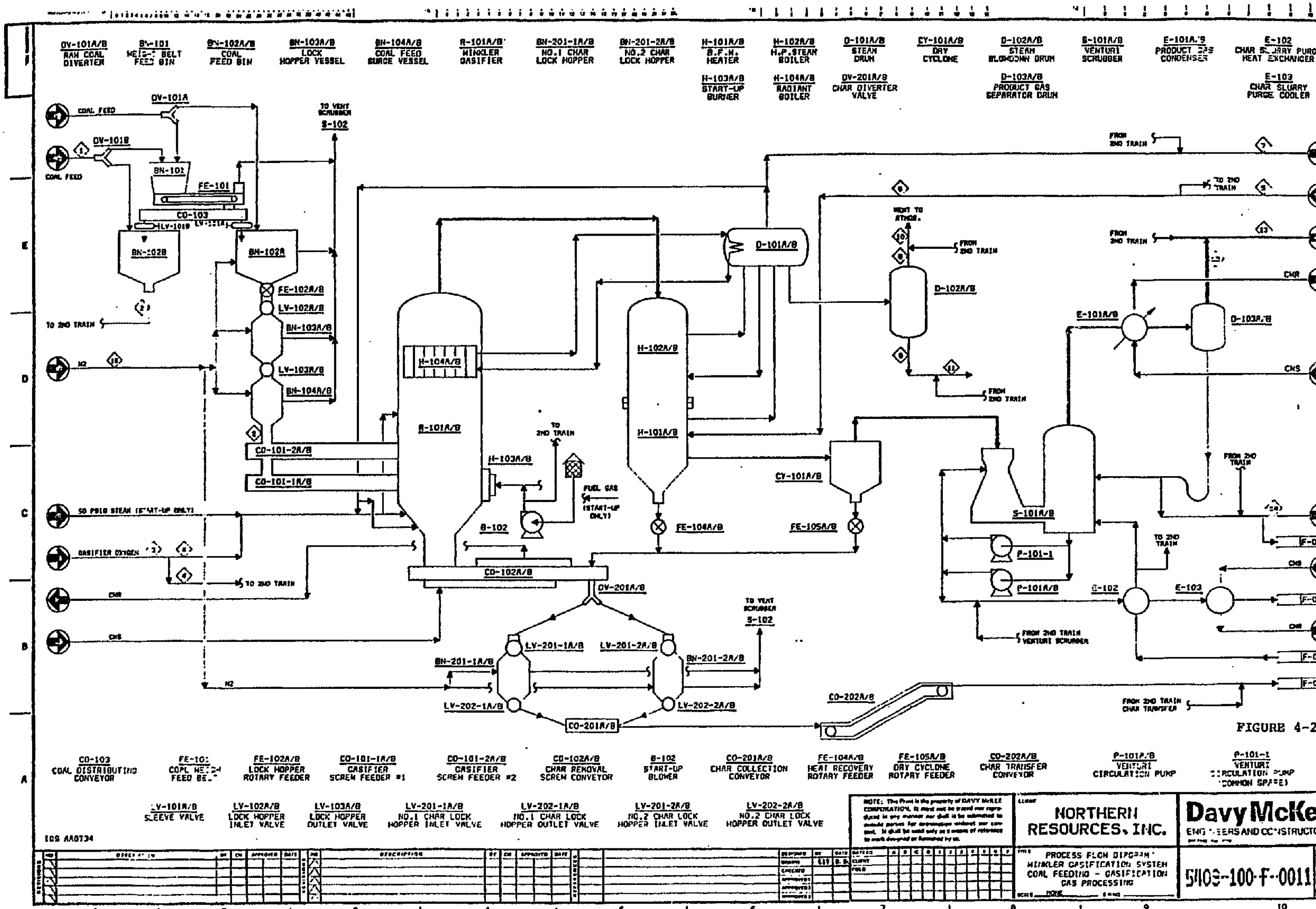
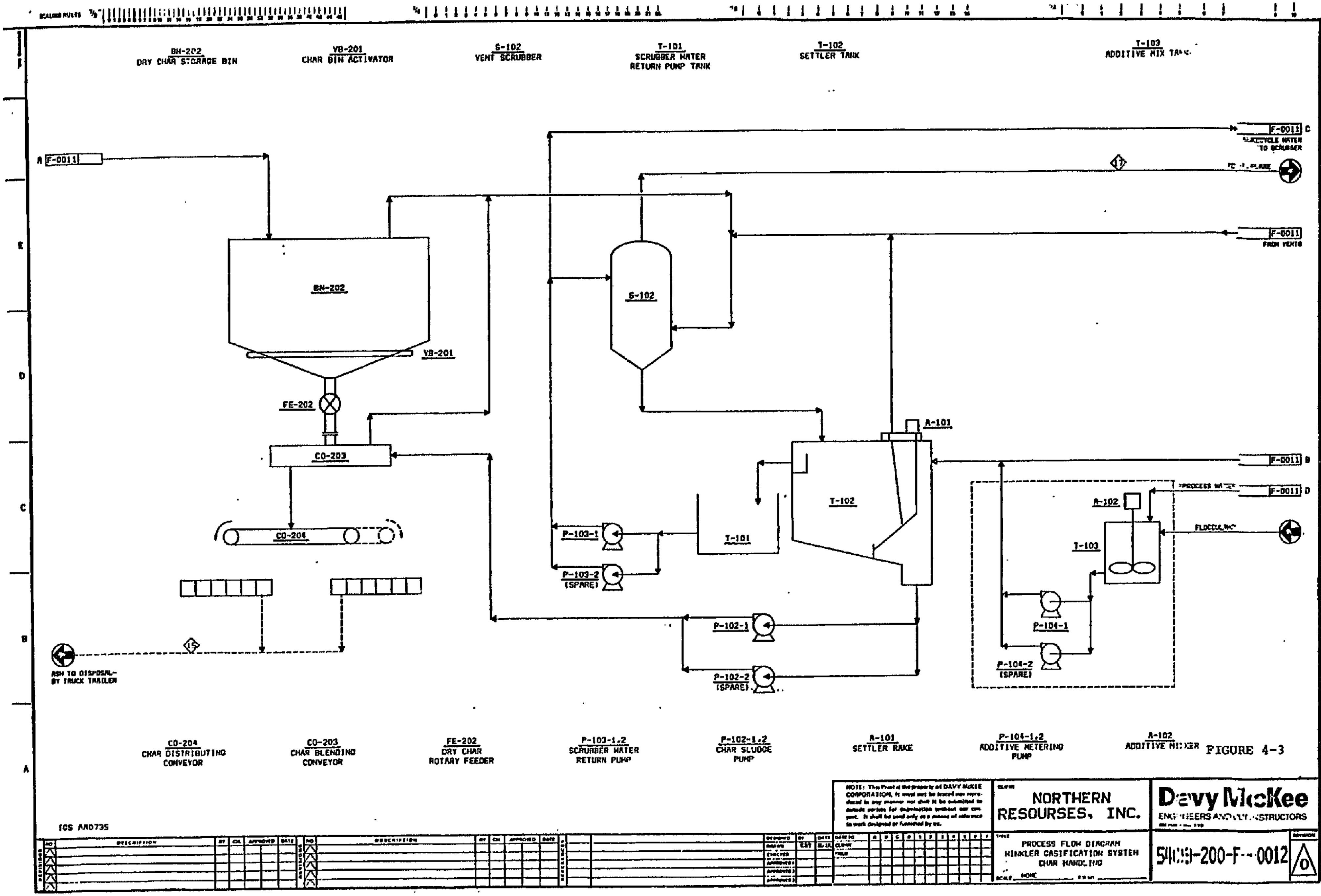

DV-101A/B RAW COAL DIVERTER
BN-102A/B COAL FEED BIN
BN-103A/B LOCK HOPPER VESSEL
BN-104A/B COAL FEED SURGE VESSEL
R-101A/B WINKLER GASIFIER
BN-201-1A/B NO.1 CHAR LOCK HOPPER
BN-201-2A/B NO.2 CHAR LOCK HOPPER
H-101A/B B.F.W. HEATER
H-103A/B START-UP BURNER
H-102A/B H.P. STEAM BOILER
H-104A/B RADIANT BOILER
D-101A/B STEAM DRUM
DV-201A/B CHAR DIVERTER VALVE
CY-101A/B DRY CYCLONE
D-102A/B STEAM BLOWDOWN DRUM
D-103A/B PRODUCT GAS SEPARATOR DRUM
S-101A/B VENTURI SCRUBBER
E-102 CHAR SLURRY PURGE HEAT EXCHANGER
E-103 CHAR SLURRY PURGE COOLER
CO-103 COAL DISTRIBUTING CONVEYOR
FE-102A/B LOCK HOPPER ROTARY FEEDER
CO-101-1A/B GASIFIER SCREW FEEDER #1
CO-101-2A/B GASIFIER SCREW FEEDER #2
CO-102A/B CHAR REMOVAL SCREW CONVEYOR
B-102 START-UP BLOWER
CO-201A/B CHAR COLLECTION CONVEYOR
FE-104A/B HEAT RECOVERY ROTARY FEEDER
FE-105A/B DRY CYCLONE ROTARY FEEDER
CO-202A/B CHAR TRANSFER CONVEYOR
P-101A/B VENTURI CIRCULATION PUMP
LV-101A/B SLEEVE VALVE
LV-102A/B LOCK HOPPER INLET VALVE
LV-103A/B LOCK HOPPER OUTLET VALVE
LV-201-1A/B NO.1 CHAR LOCK HOPPER INLET VALVE
LV-202-1A/B NO.1 CHAR LOCK HOPPER OUTLET VALVE
LV-201-2A/B NO.2 CHAR LOCK HOPPER INLET VALVE
LV-202-2A/B NO.2 CHAR LOCK HOPPER OUTLET VALVE
COAL FEED
TO VENT SCRUBBER S-102
TO 2ND TRAIN
N2
50 PSIG STEAM (START-UP ONLY)
GASIFIER OXYGEN
CHR
CHS
FUEL GAS (START-UP ONLY)
FROM 2ND TRAIN
VENT TO ATMOS.
FROM 2ND TRAIN VENTURI SCRUBBER
FROM 2ND TRAIN CHAR TRANSFER
IDS AA0734
NORTHERN RESOURCES, INC.
Davy McKee
PROCESS FLOW DIAGRAM
WINKLER GASIFICATION SYSTEM
COAL FEEDING - GASIFICATION
GAS PROCESSING
5103-100-F-0011

FIGURE 4-2


BN-202
DRY CHAR STORAGE BIN
VB-201
CHAR BIN ACTIVATOR
S-102
VENT SCRUBBER
T-101
SCRUBBER WATER
RETURN PUMP TANK
T-102
SETTLER TANK
T-103
F-0011
BN-202
VB-201
FE-202
CO-203
CO-204
S-102
T-101
T-102
A-101
A-102
T-103
P-103-1
P-103-2
(SPARE)
P-102-1
P-102-2
(SPARE)
P-104-1
P-104-2
(SPARE)
F-0011 C
F-0011 E
FROM VENTS
F-0011 B
F-0011 D
ASH TO DISPOSAL-
BY TRUCK TRAILER
CO-204
CHAR DISTRIBUTING
CONVEYOR
CO-203
CHAR BLENDING
CONVEYOR
FE-202
DRY CHAR
ROTARY FEEDER
P-103-1,2
SCRUBBER WATER
RETURN PUMP
P-102-1,2
CHAR SLUDGE
PUMP
A-101
SETTLER RAKE
P-104-1,2
ADDITIVE METERING
PUMP
A-102
ICS AR0735
NORTHERN
RESOURSES, INC.
Davy McKee
PROCESS FLOW DIAGRAM
WINKLER GASIFICATION SYSTEM
CHAR HANDLING
5409-200-F--0012
FIGURE 4-3

The feed coal is meterd into the lower section of the gasifier directly into the fluid bed. Once inside the gasifier, the coal immediately comes in contact with the hot fluid bed and instantaneously reacts with oxygen and stream to produce a mixture of mainly carbon monoxide, hydrogen, carbon dioxide and methane. Minor components in the gas are nitrogen, hydrogen sulfide, and carbonyl sulfide. Due to the rapid gasification of the coal at temperatures between 1700°F and 2000°F, there are no tars, oils or higher hydrocarbons than methane in the raw gas leaving the gasifier.

Since the Winkler gasifier operates on a high throughput per cross sectional area basis, much of the by-product char (ash containing ungasified carbon) passes out the top of the gasifier with the hot, raw gas. The remaining char forms the stable, fluidized bed and provides the inherent safe operating conditions for the Winkler process. As the fluid bed char accumulates, it is withdrawn from the bottom of the gasifier to maintain the bed level.

The gaseous oxygen required for the gasification reactions is supplied from an air separation plant at the required pressure. This oxygen, at 99.5 percent purity, is mixed with superheated steam which is provided by the waste heat recovery unit, and flow-controlled to the gasifier. The flow rate of oxygen/steam mixture is controlled to maintain the total product gas flow rate.

A radiant boiler section has been included in the upper portion of the gasifier vessel. This device allows greater operating flexibility of the gasifier. Variations in composition and operating characteristics of the coal can be tolerated by the control of existing char temperatures which is accomplished by the cooling capacity of the radiant boiler.

Addition of oxygen and steam above the fluid bed, thus raising the reaction temperature in this zone, can be effective in handling variations in the ash content and adjusting the optimum gasification temperatures.

The hot, dust-laden product gas leaving the top of the gasifier passes down through the waste heat recovery unit where this product gas is cooled by producing 625 psia saturated steam and preheating boiler feedwater. A portion of this steam is letdown for the process steam while the remaining major portion is exported to the other parts of the plant.

The cooled raw product gas next enters a two-stage particulate removal system designed to reduce the dust content of the product gas to less than 0.01 grains/scf. The first stage of particulate removal is a high efficiency dry cyclone. The expected efficiency across this cyclone is 80 to 85 percent removal of particulates. The partially cleaned gas then enters a wet, venturi scrubber. This unit serves to remove most of the remaining particulates by direct contacting the gas with a circulating stream of water. The gas is further cooled and saturated with water and leaves the venturi scrubber separator at approximately 214^{o}F and 52.5 psia.

At this point, the gas enters a cooler/condenser which cools the gas down to 120^{o}F and removes most of its moisture. The product gas from each train is then combined and the total gas delivered to the battery limits at approximately 120^{o}F and 44.7 psia.

The char in the gasifier fluid bed is withdrawn through the bottom of the gasifier by a variable speed, cooling screw conveyor. At the end of this conveyor, the gasifier char is combined with the dry char from the waste heat recovery unit and the char from the dry cyclone. The char is then depressurized in the parallel set of char lock hoppers. In this set of lock hoppers, each vessel operates alternately to depressurize the char for disposal. This is down to reduce the overall height of the gasification section and to provide continuous removal. This cooled, dry, depressurized char then travels in a nitrogen blanketed inclined conveyor to a dry char surge bin. There is one dry char surge bin which serves both gasification trains.

The dry char has excellent combustion characteristics and Btu content which make it suitable for coal drying fuel. An alternate materials balance with char utilization is included in Section 9.

The char which is removed in the wet venturi scrubber is purged from the circulating solution to a char settler. This slurry purge is first cooled to 110°F and then depressurized before entering the settler. There is one char settler serving both gasification trains. The clear overflow from the settler is returned to the venturi scrubbers by pump through one of the char slurry purge coolers. A char sludge stream, about 25 Wt percent solids, is withdrawn from the settler bottom and blended in a screw conveyor with a stream of dry char from the char surge bins. This resulting damp by-product char can be dumped into trailers for transport to an off-plant site.

If the dry char is utilized for fuel, the char sludge stream can be settled in a pond. The clarified water can be returned to the settler and the concentrated char can be removed monthly by mechanical means.

4.1.5 Gas Blending and Delivery

The flow of gas from the EXXON Refinery and the Winkler Gasifier eventually combine to form the product gas to be delivered to the Conoco and Cenex Refineries. Figure 4-4 provides a flow sheet of the gas handling system. A description of the gas handling follows:

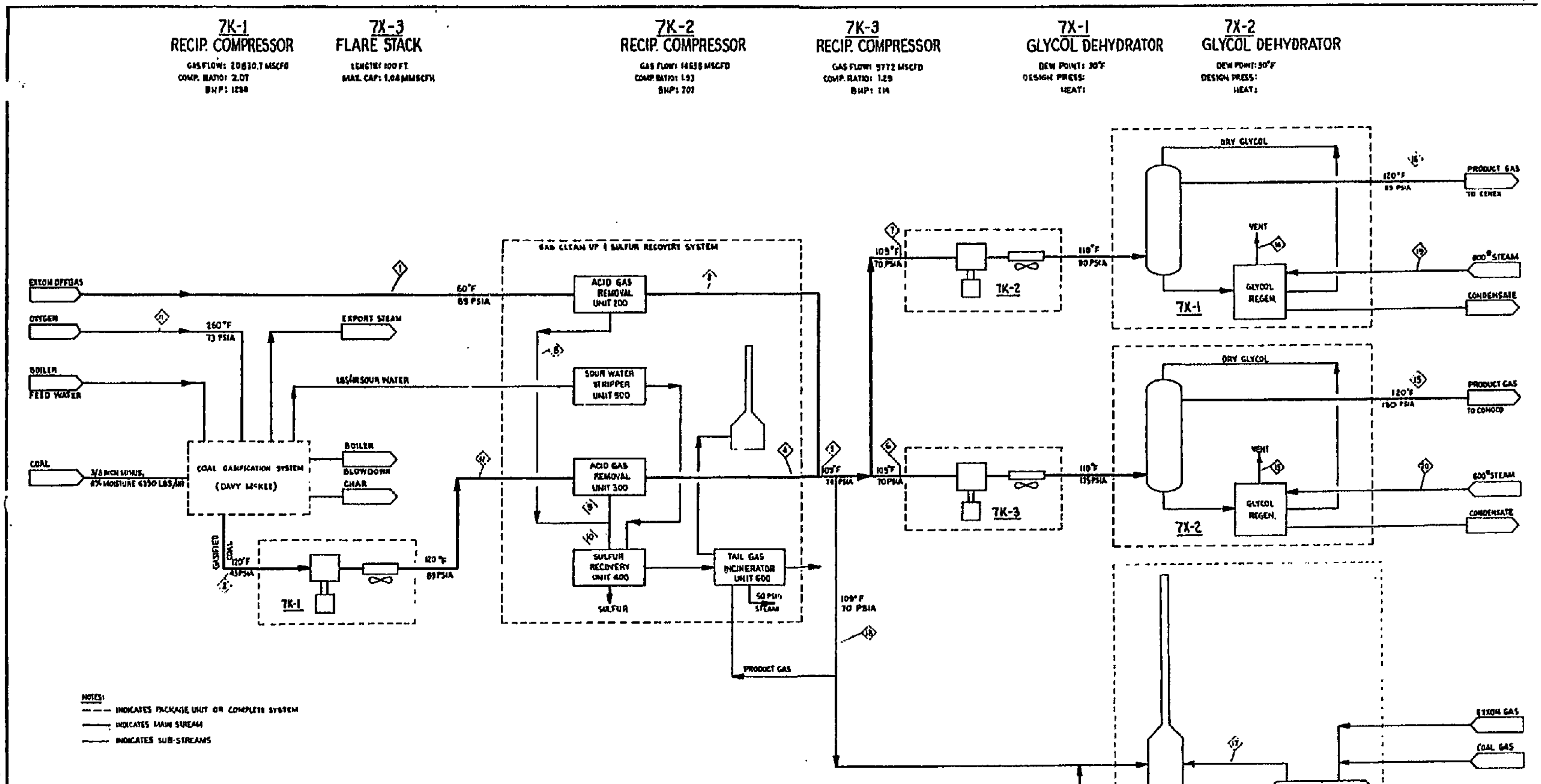
- Gas Delivery from the EXXON Refinery

  Dry refinery off-gas from the EXXON plant will be delivered by an 8-inch buried pipeline to the battery limits of the Gasification Unit on-site facilities. The distance is approximately 3 miles. It will be received at 80 psia and at varying temperatures due to seasonal changes in ground temperature, but normally 60^{o}F. The gas will be metered and analyzed and sent to the gas treating portion of the plant for sulfur removal.

  The gas produced by the gasifier is delivered to the boundary limit at 43 psia and 120^{o}F. Compression of this gas is required to increase the pressure to 89 psia before being sent to the treatment plant for sulfur removal.

- Gas Blending and Compression

  Treated refinery gas and treated gasifier gas are received at 74 psia and blended together in a 50-foot section of 12-inch pipe. Turbulence in the pipe adequately mixes the two-gas streams. The heating



NO	STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		EXXON OFFGAS	COAL GAS	CLEANED EXXON GAS	CLEANED DAVY McKEE GAS	PRODUCT GAS(ES)	PRODUCT GAS TO CONOCO (40%)	PRODUCT GAS TO CENEX (60%)	SOUR GAS FROM EXXON	SOUR GAS FROM COAL GAS	TOTAL SOUR GAS	OXYGEN	COAL GAS	WATER VAPOR	WATER VAP.	[illegible]	PRODUCT GAS TO CONO.	FLARE HEADER	PRODUCT FUEL GAS	STEAM TO DEHY. 7X-1	STEAM TO DEHY 7X-2
		LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR
1	PRESSURE-PSIA	89	43	79	79	76	70	70				73	89	ATM	ATM	85	130	–	70	615	618
2	TEMPERATURE-°F	60	120	70	110	109	109	109				260	120	210	210	120	120	–	109	488.6	486.5
3	WATER	–	–	–	–	–	–	–	–	–	–	–	–	662.0	1027.8	–	–	–	–	–	–
4	STEAM	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2053	1373
5	GAS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
6	[illegible]	136.2	1630.8	136.2	1610.6	1627.0	723.6	1085.5	–	–	–	–	1630.8	–	–	60.8	58.2	–	11.9		
7	[illegible]	341.0	1661.8	341.0	1661.8	2002.8	793.3	1189.9	–	–	–	–	1661.8	–	–	793.3	1189.9	–	19.6		
8	[illegible]	156.0	24438.4	154.0	24438.4	24592.4	9740.4	14,610.7	–	–	–	–	24438.4	–	–	9740.4	14610.7	–	241.5		
9	[illegible]	513.6	17437.2	429.7	16238.7	14726.4	5832.8	8149.1	93.9	3140.5	3234.4	–	17437.2	–	–	5832.8	8749.1	–	144.5		
10	LIGHT HYDROCARBONS	6550.6	1152.4	6550.6	1152.4	7803.0	3090.6	4655.8	–	–	–	–	1252.4	–	–	3090.6	4655.8	–	76.6		
11	[illegible]	1264.8	244.8	3.2	19.8	23.0	9.1	13.7	1261.6	215.0	1456.6	–	244.6	–	–	9.1	13.7	–	0.2		
12	[illegible]	9431	344.4	9432	344.4	1233.6	512.4	768.5	–	–	–		344.4	–	–	512.4	768.5	–	12.7		
13	[illegible]	–	–	–	–	–	–	–	–	–	–	16,667	–	–	–	–	–	–	–	–	–
14	TOTAL	9979.4	42,009.8	8423.5	43,644.5	52,268.1	20,102.2	31,055.2	1355.5	3365.6	4721.0	16,667	42009.8	662.8	1027.3	20039.4	30025.9	–	512.8	2053	1313
15	AVERAGE MOL. WT.	17.94	20.56	16.49	19.93	19.3	19.3	19.3	34.59	43.14	40.27	32	20.56	18	18	19.3	19.3	2056 MAX	19.3	18	18

PRELIMINARY

FIGURE 4-

ISSUE RECORD					ENGR RECORD	DATE
DATE	ISSUE	REV	TO	FOR	DRAWN MLCK	4/23/8
					CHECKED	
					ENGINEERED	
					PROJECT ENG	

REFERENCE DRAWINGS

Ford, Bacon & Davis Utah Inc.
ENGINEERS-CONSTRUCTORS
SALT LAKE CITY, UTAH

FOR NORTHERN RESOURCES INC. BILLINGS, MONTANA

TITLE
PROCESS FLOW SHEET
GAS COMPRESSION AND DRYING
UNIT 700

DRAWING NO. D353-D-001 REV. A

value of the mixed stream is determined with a gas analyzing system. The stream is split with approximately 40 percent going to the Conoco Refinery and the remaining 60 percent delivered to the Cenex Refinery.

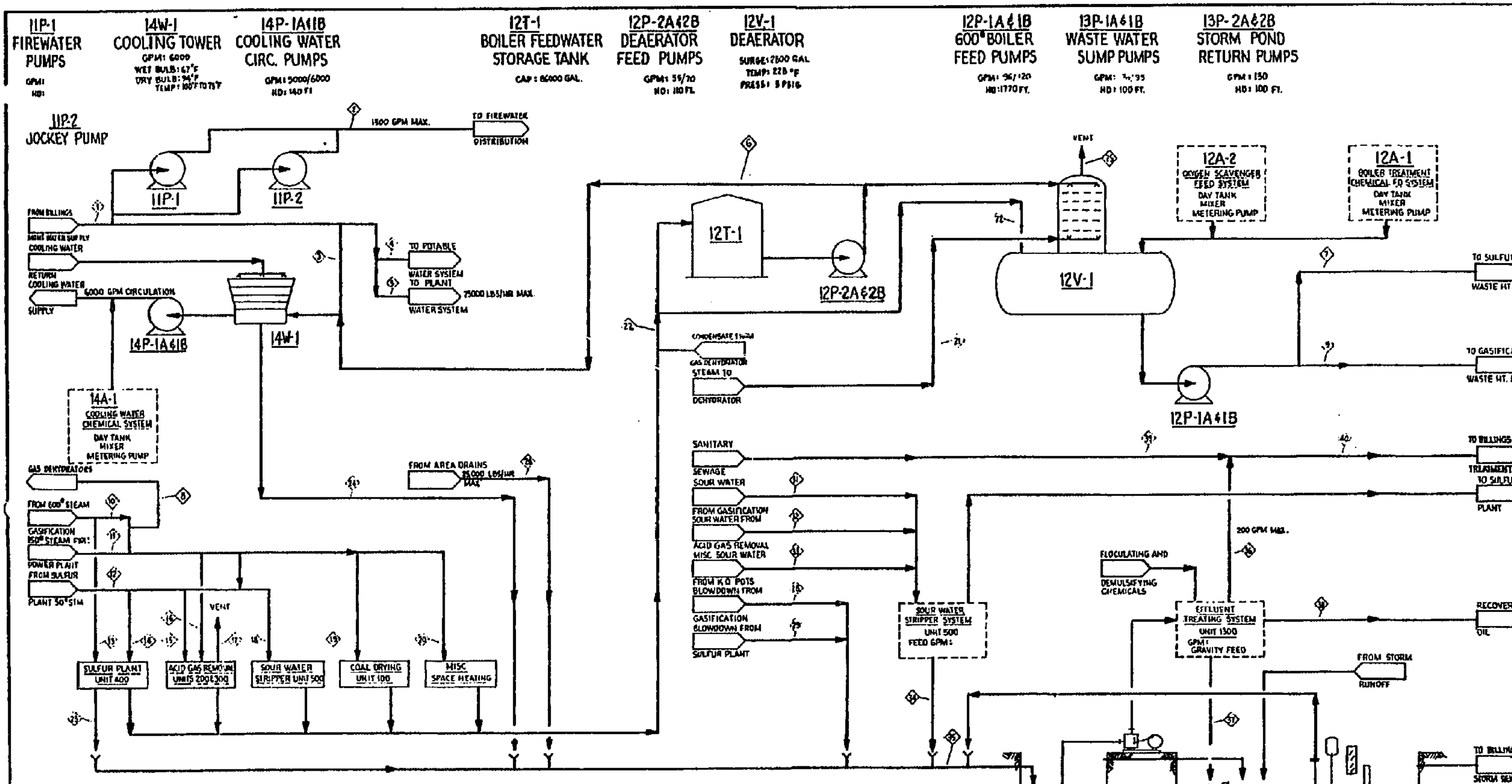
Separate compressors are used for each consumer due to the different discharge pressure requirements. After compression each steam is dried by a simple Glycol Contact Dehydrator to a dewpoint of 30^{o}F before the gas is sent to the refineries.

The 17 miles of pipelines to the Cenex Refinery require a compressor discharge pressure of 135 psia to deliver gas to the refinery fuel system at 100 psig. The Conoco Refinery is near the gasifier plant at a distance of 0.38 miles and requires less pressure at the compressor discharge. An outlet pressure of 90 psia is sufficient to deliver gas to Conoco's fuel system at 70 psig.

At the outlet of each dryer, an accurate product meter is supplied for purposes of accounting and billing to the customers.

4.1.6 Water Treatment, Porocess Effluent Cleanup, and Fire Protection System

Figure 4-5 provides a flow sheet for water treatment system. The water and fire water for the plant will be purchased from the city of Billings. The design of the boiler feedwater system is based on a surplus of condensate recovered from steam purchased from Montana Power and that the condensate from the power plant will meet the requirement of 150 ppm



NO	STREAM	⟨1⟩ TOTAL WATER SUPPLY	⟨2⟩ FIRE WATER	⟨3⟩ COOLING WATER MAKE UP	⟨4⟩ POTABLE WATER	⟨5⟩ PLANT WATER	⟨6⟩ CNDS. TO 0/150# WHB MAKEUP	⟨7⟩ BFW TO SULFUR PLT WHB	⟨8⟩ STEAM TO GAS DEHYDRATORS	⟨9⟩ BFW TO GASIFICATION WHB	⟨10⟩ 600# STM FROM GASIF. WHB
		LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR
1	WATER/STEAM	72078	0	69,076	500	2500	10,922	5,500	3426	47604	22,261
2	DISSOLVED SOLIDS	350 PPM									
3	SUSPENDED SOLIDS										
4	SUSPD OIL & GRS	0									
5	TOTAL FLOW	72078									
	GPM	145		139	1	5	22	11	53	85	

NO	STREAM	⟨11⟩ 150# STM FM POWER PLANT	⟨12⟩ 50# STM. FM SULFUR PLT. WHB	⟨13⟩ 600# STM TO SULFUR PLANT	⟨14⟩ 50# STM TO SULFUR PLANT	⟨15⟩ 50# STM TO ACID GAS REMOV	⟨16⟩ 150# STM TO SOLV. RECLAIM	⟨17⟩ SOLVENT RECLAIM VENT	⟨18⟩ 50# STM. TO SWS	⟨19⟩ STM. TO COAL DRYING	⟨20⟩ STM. TO SPACE HEATING
		LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR	LBS/HR
1	WATER/STEAM	34,065	5,000	700	500	26,500	1500	1500	6,000	17,100	1,000
2	DISSOLVED SOLIDS										
3	SUSPENDED SOLIDS										
4	SUSPD OIL & GRS										
5	TOTAL FLOW			700	500	26,500	1500	1500	6,000	17,100	1,000
	GPM										

NO	STREAM	⟨21⟩ STEAM TO DEAERATOR	⟨22⟩ RECOVERED CONDENSATE	⟨23⟩ STEAM TRACING TRAP DROP	⟨24⟩ COOLING TOWER BLOWDOWN	⟨25⟩ DEAERATOR VENT STEAM	⟨26⟩ FROM AREA DRAINS	⟨27⟩	⟨28⟩ BOILER BLOWDOWN GASIFIC. PLT	⟨29⟩ BOILER BLOWDOWN FM SULFUR PLT.	⟨30⟩
1	WATER/STEAM	4600	54,726	500	20,000	500	2500		1846	500	
2	DISSOLVED SOLIDS		NIL	NIL	1090 PPM						
3	SUSPENDED SOLIDS										
4	SUSPD OILS & GRS										
5	TOTAL FLOW	4600	54,726	500		500					
6	GPM		110	1	40		5		4*	1	

NO	STREAM	⟨31⟩ SOUR WATER FM. GASIFICATION	⟨32⟩ SOUR WATER FROM ACID GAS SYSTEM	⟨33⟩ SOUR WATER FM MISC. K.O. POTS	⟨34⟩ STRIPPED SOUR WATER	⟨35⟩ AVG. WASTE WATER TO TRTG.	⟨36⟩ TREATED WASTE WATER	⟨37⟩ SLUDGE FROM WST. TREATING	⟨38⟩ RECOVERED OIL	⟨39⟩ SANITARY SEWAGE	⟨40⟩ TOTAL WASTE WATER
1	WATER/STEAM	9515	3000	0	12,515	37,861	37,861			500	38,361
2	DISSOLVED SOLIDS	[illegible]									
3	SUSPENDED SOLIDS	NIL									
4	SUSPD OILS & GRS	1-10 PPM					10 PPM				10 PPM
5	TOTAL FLOW										
6	GPM	19	6	NIL	25	76	76			1	77

REVISIONS

NO.	DESCRIPTION	BY	CHKD	APPD	DATE
B	CHANGES SHOWN CHGS REQUIRE (EXPLAINABLE)				

ISSUE RECORD

DATE	ISSUE	REV	TO	FOR
	1	A	NORTHERN RESOURCES	FOR QUOTE
	2	B	NORTHERN RESOURCES	FOR QUOTE

REFERENCE DRAWINGS

D-353-D-001

ENGR. RECORD — DRAWN: MICKEY — DATE: 5/7/80

PRELIMINARY

FIGURE 4

Ford, Bacon & Davis Utah Inc.
ENGINEERS - CONSTRUCTORS
SALT LAKE CITY, UTAH

FOR NORTHERN RESOURCES INC. — BILLINGS, MONTANA

TITLE: PROCESS FLOW SHEET
WATER TREATMENT FACILITY
COAL GASIFICATION PROJECT

DRAWING NO. D-353-D-002

(maximum) total dissolved solids imposed by Davy McKee's design. With proper control of flowdown and scale inhibiting chemicals, the cooling water makeup will not need to be treated. Wastewater will be collected and treated in an enhanced gravity type separator for the removal of suspended oil and grease and the readily settleable solids. After treating, the water will be released to the Billings sewer system.

The design of all water systems is based on a minimum supply pressure of 60 psig at the tie-in to the city water system.

4.1.6.1 Water Supply. The project plans on purchasing the required water from the city of Billings. Cost estimates include extension of the 24-inch line located at the corner of 21st Street and Montana Avenue about 4,000 feet to the industrial park area, with a 21-inch extension to the actual plant site.

4.1.6.2 Water Treatment System. Water required for boiler feedwater will be recovered condensate from the varied steam users. Makeup to the boiler feedwater system will be the condensate received from the steam purchased from Montana Power. The condensate from the purchased steam will exceed the plant's boiler feedwater makeup requirements. For start-up, treated boiler feedwater will normally be available in the boiler feedwater storage tank. If the storage tank did not have enough boiler feedwater for plant start-up, the sulfur plant could be started and run for a while to provide the necessary boiler feedwater for the plant start-up.

4.1.6.3 Wastewater Treatment Systems. Wastewater will come from the sources listed below:

- Sour water from coal gasification, gas treatment facilities, and compressor drip pots.
- Boiler blowdown from coal gasification and sulfur plant.
- Cooling tower blowdown.
- Plant area surface drains (normal flow, wash down, storm).
- Sanitary sewage.

Since the wastewater stream volumes are quite low, both oil and non-oily bearing stream will be combined. However, the domestic sewage will be segregated.

The following discussion outlines the internal treatment included in our proposal.

4.1.6.4 Sour Water. Process wastewater that may contain H_2S or NH_3 are wastewaters from Davy McKee's gasification unit and water from drip pots within the gas cleanup facilities and the compressor area. The sour waters will be routed to the sour water stripper where H_2S and NH_3 will be stripped to 10 ppm, respectively, or lower. The H_2S/NH_3 mixture will be treated in the Claus sulfur plant. The residual water will be discharged to the process waste system. This individual stream will be low in phenols (0.1 to 1.0 mg liter), low in cyanide (0.005 to 0.15 mg/liter) and moderate in dissolved solids (1160 to 3540 mg/liter). The COD is expected to be 50 to 200 mg/liter and the BOD_5 is expected to be 20 to 80 mg/liter. These data are based on information supplied by Davy McKee.

4.1.6.5 Boiler Blowdown. Boiler blowdown, containing approximately 3500 ppm of total dissolved solids (no oil or suspended solids), will be discharged from the waste heat boiler in the gasification unit, the water heat boiler in the sulfur plant, and the auxiliary boiler. Each blowdown stream will be flashed to atmospheric pressure and then discharged to the process sewer system.

4.1.6.6 Cooling Tower Blowdown. The cooling tower blowdown will also be discharged to the process sewer system for on site oil and solids separation. FB&DU's design is based upon using acrylate and phosphonate scale inhibiting cooling water chemicals. Cooling tower treatment has not been included since blowdown from cooling towers using chemicals of this type does not require treatment prior to discharge to sanitary sewage systems. These treatment chemicals are presently in use in the Billings area.

The use of acrylates and phosphonates avoids the environmental problems and treatment costs associated with chrome and zinc cooling water treatment systems.

4.1.6.7 Plant Area Surface Drains. Major traffic areas and potential drain areas in each process system will be paved. Drains will also be placed by adjoining pumps and compressors, etc.

The normal streams entering the surface drain would be condensate from steam traps on steam traced systems (flow too small to collect), water pump seal leaks, etc.

Periodic wash down from housekeeping activities will also be routed to the process sewer.

Storm runoff from areas that do not have process facilities will be routed to the storm sewer system.

Limited storm runoff from within the process areas that drain into the process sewer will be collected and treated. However, runoff from the storm sewer may overload the process sewer.

The process sewer will be equipped with a storm overflow diverter to route mixed storm and process water to the storm pond system. Collected process and storm water will be pumped back to the treatment system.

4.1.6.8 Storm Water. A storm water containment pond, designed to contain a 10-year, 24-hour maximum storm is included. As mentioned above, collected storm water and overflow process wastewater will be returned to the wastewater treatment system. During the infrequent periods when the storm pond capacity is inadequate, the excess water will flow into the local city storm drain line and then into the Yellowstone River. The storm pond overflow system will be equipped with an underflow/overflow baffle arrangement to retain floating materials within the storm pond.

4.1.6.9 Sanitary Sewage. The sewage from the office/shop/ warehouse complex and the latrines within the operating units will be isolated and sent directly to the Billings Sanitary Sewage System.

4.1.6.10 Process Wastewater Treatment. After collection of the wastewater, as discussed above, the wastewater will be treated in an enhanced gravity separator (parallel plate type or equivalent). The separator will be designed to reduce the free oil to about 10 ppm with all readily settlable solids removed.

The floating oil will be collected for disposal off site. The sludge will be sent to the sludge settling section of the storm pond. The sludge can be removed from the pond once every three or four years and disposed of off site.

After separation of the oil and settled solids, the wastewater will be routed to the Billings Wastewater Treatment Plant. The expected water quality is inside the limits established by the city of Billings.

The treatment system has been designed to handle twice the normal flow to allow containment and treatment from normal housekeeping, minor storms, and the first part of major storms.

4.1.6.11 Fire Protection System. A fire protection system has been provided for the facility. The fire protection system takes suction from the city water main header at the plant battery limit. The system includes a 10-inch steel fire line with several yard hydrants. The warehouse also has four hose stations located around the walls. Fire water has been provided for the coal preparation building with a stand pipe and valve. The fire system has one jockey pump to maintain pressure in the fire loop and two 2000 gpm fire pumps.

Each fire pump will supply 2000 gpm at 160 feet of head. One fire pump is a standby or spare unit. The fire pumps are electric motor driven. There is an emergency generator supplied for the plant with sufficient capacity to run a fire pump in case of an electrical power failure.

4.1.7 Electric Facilities

Approximately 5 mVa will be required for the outside battery limits facilities as well as the gasification facility. The Montana Power Company will provide the substation. The power from this point will be distributed through project-supplied switchgear to various load centers throughout the facility. The power will be provided at 4160 volts by the utility and will be generally distributed at this same level. At the load centers, it will be transformed to the utilization voltage, which in most cases is 480 volts.

There are six load centers: Main Substation, Gas Treatment Plant, Gasification Facility, Coal Prep Plant, Office/Shop Building, and Water Treatment.

At most load center locations, a transformer and a motor control center (MCC), switch rack, or switchgear will be provided. These locations will be located in nonhazardous areas when possible to maintain low capital costs.

Distribution from the main substation to the load centers will be by underground duct banks and by pole lines to the more remote locations.

Secondary distribution from the load centers to the point of use will be run in rigid galvanized steel conduit mounted to facility structures.

Motor controls will be located near the equipment. Major equipment status will be annunciated in the control room located in the gasification plant.

Industrial intercoms with two-way communications between the control room and several sites about the facility will be provided.

General area lighting will be provided about the plant with high-pressure sodium fixtures.

A ground grid will be established, and all major structures will be mechanically and electrically connected to it.

An emergency diesel generator will be provided to allow a safe shutdown of the facilities and also to allow operation of the main fire pump in the event of normal power failure.

4.1.8 Gas Treating and Sulfur Removal

A conceptual design (Figure 4-6) and cost estimate were prepared on the gas treating and sulfur removal portion of the plant. It is proposed to treat the EXXON sour gas in a standard amine unit separately from the coal gas. The EXXON gas has a relatively low CO_2 content (CO_2 to H_2S ratio of 0.32 to 1) and thus is best kept separate from the diluted H_2S stream from the gasifier. In addition, the separate treating facilities will allow the Claus Unit to operate if either of the two raw gas streams are shut down for any operating reason. If the EXXON gas is excluded, the Claus Unit can operate at reduced rates on the acid gas from the coal gasifier. If the coal gasifier is shut down, the Claus

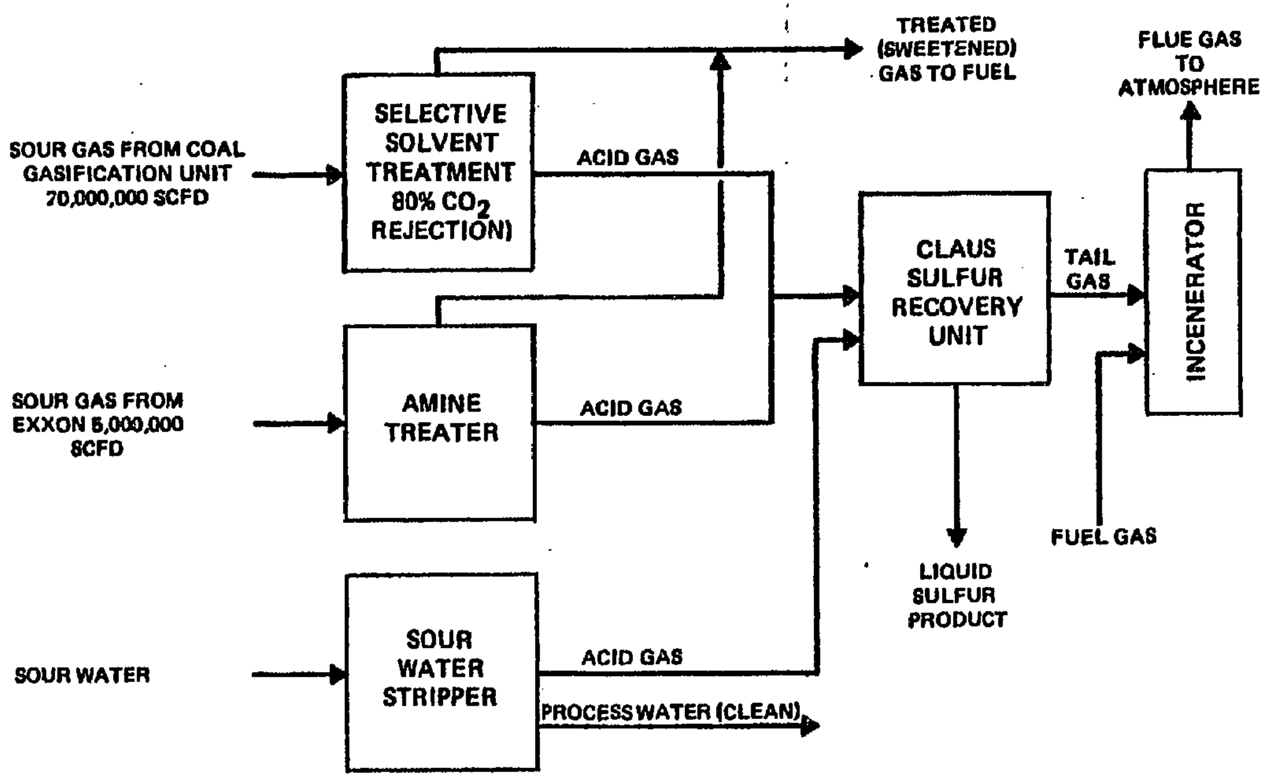


FIGURE 4-6
SULFUR RECOVERY COMPLEX
NRI COAL GASIFICATION PROJECT
BLOCK FLOW DIAGRAM

Unit can operate on the acid gas from the EXXON fuel gas. This operating flexibility justifies the installation of a pretreater on the raw sour gas from the coal gasifier.

4.1.8.1 Sour Gas from Gasifier. The conceptual design of the treating of the sour gas from the coal gasification unit is based on a feed rate of 200MM SCFD. Because of the relatively high CO_2 to H_2S ratio in the coal gas (about 50 to 1), the H_2S must be concentrated in a feed pretreater. This feed pretreater will operate to reject about 80 percent of the CO_2, which will reduce the cost and size of the Claus Unit. Also, improved sulfur recovery will be possible with the elimination of the major portions of the CO_2 from the Claus Unit feed. The treated gas leaving the unit will contain between 10 to 15 grains H_2S per 100 ft^3.

Davy McKee indicated that contaminants in the coal gas will be less than 200 ppm total. There were no contaminants listed in the gas composition such as cyanides, ammonia, ring organic compounds (e.g., benzene, toluene, napthalene). As a result, facilities for treating such compounds have not been included.

4.1.8.2 Sour Gas from EXXON. By keeping the refinery and gasifier gas separate during treating, a standard amine unit can be used to remove the H_2S from the refinery stream. The conceptual design for this unit was based on 5MM SCFD from the EXXON Refinery. The treated gas will contain 10 to 15 grains of H_2S per 100 ft^3.

4.1.8.3 Claus Unit. The sulfur recovery of the Claus Unit includes three catalytic reactors, a combination incinerator/stack, two plant stream analyzers (one for the Claus Unit tail gas and one for the stack gas), a spare air blower, molten sulfur storage, and loading facilities (truck only). The Amaco royalty is included in the cost. The two amine units each include one absorber and one regenerator; spare, lean, and rich amine pumps; spare reflux pumps; a combined amine sump complete with one sump pump; and an amine storage tank. All equipment is motor driven. The incinerator operates at 1500°F with 50 percent excess air.

4.1.8.4 Sour Water Stripper. The sour water stripper (SWS) is based on a maximum sour water rate of 50 gpm. This is an estimated value, and if the actual rate increases the equipment size and cost would increase accordingly. Included in the SWS are a reboiler, overhead condenser, spare reflux pumps, etc. It also includes feed tank (sour water) storage. Cooling is accomplished by water coolers. No air coolers were required.

4.1.9 Civil/Structural Facilities

A 26-foot-wide access road will be provided at the site. The roadway will be placed on 9 inches of granular fill and will comply with HS-20 loading requirements. Road drainage will be provided and will begin and terminate at the start and the end of the new road construction. A 6-foot-high chainlink fence will be provided all around the plant site. A gravel parking lot will be provided next to the office, shop, and warehouse building.

Adequate surface drainage will be provided to direct all runoff to the containment pond which is then discharged to the city storm line.

A 20- by 40- by 50-foot eave height structural steel building (approximate size) will be provided to adequately house all mechanical equipment necessary for the operation of the plant. All structural elements will be adequately designed to sustain all imposed dead and live loads.

A 50- by 75- by 18-foot eave height shop and warehouse and a 50- by 25- by 12-foot eave height office building (approximate size) will be provided to support the normal staff of the total complex (oxygen plant is excluded).

A 100- by 30- by 20-foot high building (approximate size) will be provided for deaerator and wastewater treatment equipment.

Structural steel supports are provided for pipe racks and are adequate to sustain all loads.

All structural steel is included for conveyor trusses and bents which will be adequate to sustain all the dead load and live loads.

Concrete foundation and structural steel designs are based on the preliminary vendor information and drawings.

4.2 OUTSIDE BATTERY LIMIT (OSBL) PRELIMINARY ENGINEERING AND DESIGN

The preliminary engineering and design was accomplished in two packages by two firms. The first package is designated as the outside battery limits facilities, and the second is designated inside battery limits facilities. Figure 4-1 displays the boundary limit. The OSBL facilities include all systems except coal gasifications, ash handling, waste heat recovery and particulate removal.

It should be noted that a change was made in project scope subsequent to completion of the preliminary engineering packages. This change was the deletion of coal receiving, 13,000-ton coal storage silo, associated conveyors, auxiliary boiler, and associated piping and water treatment. These facilities were deleted when it was found feasible to purchase coal and steam from the local Corette Power Plant, located 3,000 feet from the project site. Coal will be transported to the project by a covered 24-inch conveyor. Steam will be supplied by an 8-inch steam main. Due to cost constraints, all drawings were not revised to reflect these changes. Conceptual design drawings are included as Appendix B.

4.2.1 Civil Design Criteria

4.2.1.1 Codes and Standards. Engineering, design, materials, and construction shall be in accordance with the applicable portions of the latest revision of the following codes and standards.

- American Society for Testing and Materials (ASTM)
- American Association of State Highway and Traffic Officials (AASHTO)
- Montana State Highway Department - Specifications and Standards

4.2.1.2 Earth Work

- General - Rough grades shall utilize the most economical arrangement of excavation while also providing a balanced longitudinal profile. Fills will be constructed from the excavated materials.

- Cuts and Fills - Cuts in rock to be 1h:1v or steeper. Cuts in earth to be 1-1/2h:1v to 2h:1v. Fills to be 2h:1v.

NOTE

Cut and fill slopes to be modified as required by soils investigation

- Finished Grades - Earth finished grades at buildings will be a minimum of 12 inches below finished floor slabs and will slope away from the building on a continuous grade of 2 percent.

4.2.1.3 Storm Drainage

- Plant Runoff - Diversions, culverts, interceptor ditches: 10-year, 24-hour.

- Sedimentation Ponds - Volume and principal spillway: 10-year, 24-hour. Emergency spillway: 25-year, 24-hour.

- Precipitation Data - NOAA Atlas, Volume II Montana.

- Design Methods - Drainage area less than 2000 acres: SCS TP-149 Method of Estimating Runoff from Small Watersheds.

- Channel Section - Trapezoidal or triangular section with 2h:1v side slopes, minimum freeboard, 0.5 ft.

- Culverts - Minimum diameter 18 inches. Use asphalt coated corrugated steel pipe or reinforced concrete pipe.

4.2.2 Structural and Architectural Design Criteria

4.2.2.1 Codes and Standards. Engineering design, materials and construction shall be in accordance with the applicable portions of the latest revision of the following codes and standards:

- Uniform Building Code (UBC)

- Building Code Requirements for Reinforced Concrete (ACI 318)

- Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings (AISC)

- Building Code Requirements for Minimum Design Loads in Buildings and Other Structures (ANSI A58.1)

- American Society for Testing and Materials (ASTM)

- American Welding Society (AWS D1.1)

- The National Fire Code

- Occupational Safety and Health Standards (OSHA)

- FB & DU Standard Procedure - Structural Engineering 6-SP-03

4.2.2.2 Design Loads.

- Roof snow load - Roofs will be designed to withstand a basic snow load of 30 psf.
- Floor live loads
- Operating floor - Weight of equipment plus 100 psf on accessible floor areas
- Miscellaneous platforms and floors - 100 psf
- Offices - 50 psf
- Conveyor walkways - 50 pounds per linear foot
- Warehouse - 500 psf slabs on grade only
- Stairs and landings - 100 psf
- Maintenance shop area - 100 psf or vehicle wheel load, whichever is heavier
- Wind pressure - 25 psf wind pressure map area of the Uniform Building Code.
- Seismic loads - Per Uniform Building Code Requirements for Zone 1.

4.2.2.3 Materials of Construction

- Structural Steel - ASTM A36 cast-in-place concrete
- Concrete: f'c = 3000 psi @ 28 days

- Reinforcing steel: ASTM A615 Grade 60

- Flooring

- Operating floors - 1/4-inch checkered floor plate or 1-by 3/16-inch (minimum) bar grating

- Conveyor Walkways - Morton open grip Strut Walkway, galvanized

- Handrail - 1-1/4-inch diameter pipe with 1/4-foot by 4-inch toe plate

4.2.2.4 Stairs and Ladders

- Width of stairs: 3 feet

- Maximum stair rise without break: (per OSHA)

- Maximum ladder rise without break: (per OSHA)

- Maximum ladder height without cage: (per OSHA)

- Type of treads: Bar grating with nonstop nosing.

4.2.2.5 Foundations

- Footing depths for frost protection: (unless deposited on solid rock or granular fill)

  - Exterior footings: 5'-0" below outside finished grade

- Exterior grade beams: 5'-0" below outside finished grade

- Minimum size: Minimum size of footings shall be 2 feet 6 inches square.

- Allowable Soil Bearing Pressures: See preliminary soil and foundation investigation report from HKM Associated, dated April 9, 1980

- 13,000-ton silo foundation: 254 to 100-ton capacity pile 20 feet long

- 430-ton storage bin foundations: 12 to 50-ton capacity pile 20 feet long

- Preparation plant foundations: 18 to 50-ton capacity pile 20 feet long

- Conveyor belt foundations: 30 to 50-ton capacity pile 20 feet long

- Spread footings will be used for the rest of facilities

4.2.2.6 Other Design Criteria. All excavation costs included in the firm price bid are based on the use of normal excavation methods. If rock, groundwater or any other unpredictable conditions exist which require special excavating techniques (for example jack hammering, blasting, dewatering, etc.) such procedures shall be considered as extra work and subject to negotiation for additional compensation.

The firm price offering includes no costs for repair of streets, sidewalks, utilities encountered or necessarily disturbed in the prosecution of this work. If any such repairs or relocations are required, such costs shall be considered extra work.

4.2.3 Electrical Design Criteria

4.2.3.1 Scope. All electrical equipment and materials for power distribution, controls, interlocking, grounding, and wiring for the facilities and equipment for the outside battery limits portion of the coal gasification plant shall be provided and installed as follows:

4.2.3.2 Installation. All electrical equipment and controls will be furnished and installed in accordance with the latest edition of the National Electrical Code (NEC), National Electrical Safety Code and all local codes and regulations.

4.2.3.3 Electrical Power System. Power to this project will be supplied by Montana Power Company, including the main transformer. 4.16kV power will be stepped down to 480V at six load centers around the plant. 4.16kV distribution will in general be a radial type system. All switching at primary distribution voltages (4.16kV) will be done by means of switch- gear with drawout air circuit breaker units. Breakers with identical ratings will be interchangeable.

The load center philosophy of power distribution (use of load centers located at or near center or the load area) will be used.

4.2.3.4 Enclosures of Electrical Equipment. Enclosures will be suitable for the area classification involved.

- Motor enclosures, in general, will be totally enclosed, fan cooled, except in hazardous areas requiring special enclosures.
- In nonhazardous wet areas NEMA 4 enclosures will be used. In dirty or dusty areas NEMA 12 will be used.
- Equipment in pressurized electrical rooms will have NEMA 1 (gasketed) enclosures.
- Enclosures in hazardous areas will be NEMA 7 or 9 as required.

4.2.3.5 Motors. Motors rated less than 1/2 horsepower will in general be supplied at 120 volts, single phase. Motors rated 1/2 horsepower to 100 horsepower will be supplied at 480 volts, 3 phase. Motors 250 horsepower and larger will be supplied at 4160 volts, 3 phase.

4.2.3.6 Load Centers. Indoor power load centers will consist of silicone oil filled transformers to reduce voltage to 480 volts and air circuit breakers for feeder circuits. Ground fault protection will be provided where required as will the necessary metering.

4.2.3.7 Motor Controllers. 480-volt motors will be controlled from motor control centers with circuit breaker type combination starters.

Motor control centers will be standard plug-in type not more than six units high. Control centers will be provided with 120-V AC control power for controls. Compartment wiring will be NEMA Class I Type B.

4000-volt motors will be controlled from 4160-volt Class E2 fused motor controllers, as indicated.

4.2.3.8 Wiring Methods. Rigid metal conduit will, in general, be used for power control, lighting and instrumentation circuits. Nonmetallic PVC conduit in concrete encasement will, in general, be used underground. Electrical metallic tubing may be used in administration building and office areas, but shall not be used underground. Cable trays may be used in areas where applicable and economy dictates this method is most suitable.

4.2.3.9 Materials

Wire and Cable - Cable used for low voltage (600V and below) power and lighting circuits will be type XHHN-XHHW. Minimum size will be No. 12 AWG. Wire for all cables will be stranded copper, including grounding conductors.

Ground cable will be bare stranded copper or insulated, with a green color jacket.

Control cables will be 600-volt single or multi-conductor type, XHHN-XHHW. Minimum size shall be #14 AWG.

All instrument wires for low level signals will be multi-conductor shielded twisted cables having at least the number and size of conductors required for the particular service. Minimum conductor size will be No. 18 AWG.

All cable used on 4.16 kV circuits will be shielded single copper conductors with ethylene-propylene insulation and a PVC jacket. Cable will be rated 5 kV and will conform to IPCEA and NEMA standards.

4.2.4 Instrumentation and Control Design Criteria

Because of the flexibility required in the system for compensation of flow metering, system interlock capabilities, etc., we have elected to go with an electronic control system. All control signals terminating in the control room will be 4-20 MaDC.

Local control loops will be pneumatic with a 3-15 psi signal. All control valves will have pneumatic activators and required local 20 psi supply.

Coal handling, feed systems, and all systems requiring interlock capabilities will be interlock through a programmable controller or controllers depending on total system requirements.

Flow metering for all purchased or product supplies will be both temperature and pressure compensated for maximum accuracy in monitoring and billing.

No winterization of instruments is included in estimate.

Cost of main control instruments are included in estimate. Cost of main panel board and installation of these instruments is also included.

It is assumed that the main control panel will be located within battery limits.

4.2.4.1 Inplant Piping Design Criteria. Specification for the inplant piping is included as Appendix A.

4.2.4.2 Gas Transmission Pipeline Design Criteria. The client (NRI) will furnish all necessary rights of way, extra work space and permits for the construction of the pipelines, including payments for damages to crops, trees, buildings, etc., within the right of way and work space.

Continuous casing will not be required where the pipelines parallel railroad tracks no matter how close the pipelines are laid to the edge of the tracks. Casing will be installed where the pipelines cross under tracks.

No metering or regulating stations are included in the estimate.

The 14-inch line will have scraper traps on each end and three intermediate mainline valves. The 8-inch line will have scraper traps on each end and no intermediate mainline valves. The 12-inch line will have mainline valves on each end and no scraper traps.

The pipelines will terminate at the property line fence of the refineries.

No environmental assessment study is included at this time for the pipeline.

The pipeline will be designed and constructed in accordance with the D.O.T., Title 49, Part 192, "TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS" and the ANSI B31.8.

Both field engineering and construction will be performed during reasonable weather conditions.

The pipelines generally follow the route selected by Ford, Bacon & Davis representatives during the site visit on June 10 and 11, 1980, and it is outlined in the gas transmission pipeline specification.

Utility crossings are assumed to be made by conventional pipeline construction methods.

A general pipeline specification for the gas transmission pipeline is included in Section 4.3 of this report. See Specification No. 353-302-028.

4.2.5 OSBL Preliminary Design Drawings

The preliminary design drawings prepared for the Billings MBG Project are provided in Appendix B. A list of these drawings follows:

Process Flow Sheets

Title	Drawing No.	Dated
Gas Compression & Drying Unit 700	D-353-D-001	4/29/80
Water Treatment Facility	D-353-D-002	5/7/80
Coal Prep. & Handling	D-353-M-003	5/8/80
Coal Prep. & Handling	D-353-M-004	4/22/80

Piping & Instrumentation Drawings

Product Gas System	D-353-D-003	6/19/80
Product Gas System	D-353-D-004	6/19/80
Utility Piping	D-353-D-005	6/19/80

Title	Drawing No.	Dated
Water Treating Systems	D-353-D-006	6/19/80
Water Treating Systems	D-353-D-007	6/19/80
Water Treating Systems	D-353-D-008	6/19/80

Mechanical and General Arrangement Diagrams

Title	Drawing No.	Dated
Conveyor Profiles	D-353-M-002	5/13/80
Coal Preparation Plant	D-353-M-005	5/8/80

Civil and Structural Drawings

Title	Drawing No.	Dated
Site Plan	D-353-M-001	4/9/80
Pipe Rack Location	D-353-SK-001	5/23/80
Office Shop and Warehouse	D-353-A-SK-01	4/28/80

Electrical Drawings

Title	Drawing No.	Dated
One Line Diagram	D-353-E-SK-001	6/3/80

4.3 ISBL PRELIMINARY ENGINEERING AND DESIGN BASIS

4.3.1 Base Case

4.3.1.1 Inputs. The base case design for the ISBL section of this study is as follows:

- Plant Output: Medium-Btu fuel gas with a higher heating value of 275.9 Btu/scf with a total 5.6 billion Btu per day.

- Coal Type: Subbituminous coal as provided by Northern Resources.

Raw materials, utilities and chemicals as received at the battery limits:

- Prepared coal: Size - 3/8" x 0

	WT%
Carbon	60.85
Hydrogen	4.12
Sulfur	0.87
Oxygen	12.95
Nitrogen	0.89
Water	8.00
Ash	12.31
Chlorine	0.01
	100.00

- Boiler Feed Water
  Temperature - 228°
  Pressure - 715 psia

- Oxygen
  Purity - 99.5 percent (Vol.)
  Temperature - 257°F
  Pressure - 75 psia

- Nitrogen
  Purity - 100 percent
  Temperature - Ambient
  Pressure - 75 psia

- Start-Up Fuel Gas: Refinery Off-Gas
  As required
  Duty 10 million Btu per hour

- Start-Up Steam: Temperature - 320°F
  Pressure - 100 psia

- Power: 480 Volts
  3 Phase
  60 Hertz

- Instrument Air: Temperature - Ambient
  Pressure - 100 psia

- Cooling Water: Temperature - 85°F
  Pressure - 60 psia

4.3.1.2 Products and Effluents

Product Gas:

	Volume %
CO	39.27
CO_2	18.68
H_2	38.07
CH_4	2.51
N_2	1.14
H_2S	0.30
COS	0.03
	100.00

H_2O/D.G. (Volume) - 0.0394
Temperature - 120
Pressure - 44.7 psia

- Wet Char: **Weight %**

  Moisture = 26

- Export Steam: Temperature - 491°F
  Pressure - 625 psia

- Blowdowns: (Basis 2 percent of Steam Generation)

  Vent Steam - Temperature - 227°F
  Pressure - 20 psia

  Liquid Blowdown - Temperature - 227°F
  Pressure - 20 psia

- Process Condensate: Temperature - 120°F
  Pressure - 44.7 psia

- Nitrogen Vent: Temperature - Ambient
  Pressure - 16 psia

- Cooling Water Return: Temperature - 105°F
  Pressure - 50 psia

4.3.2 Alternate Considerations

Evaluation of process alternates was completed during this study. The major alternates considered were:

- Lignite coal for gasification.

- Use of 95 percent purity O_2 versus 99.5 percent purity in the base case.

- Char utilization for use in coal drying or additional steam production.

Section 9 contains the results of these alternate evaluations. All other sections of the report refer only to the base case unless noted.

4.3.4 Design Practices

All engineering design for this study incorporates the appropriate engineering codes, standards and safety regulations for plants constructed in the United States.

4.3.5 Process Flows

The following are the flows of the raw materials, utilities, and chemicals required at the battery limits of this plant:

- Raw Material

- Prepared Coal (8 WT % moisture)	lb/hr	31530
- Boiler Feedwater (at 715 psia, 228°F)	lb/hr	47320
- Oxygen (99.5 percent at 75 psia, 257°F)	lb/hr	18166

- Utilities

- Nitrogen (at 75 psia, ambient)	Scfh	11200
- Instrument air (at 100 psia, ambient, -40°F D.P.)	Scfh	2000
- Cooling water (ΔT = 20°F)	GPM	1870

- Power (480 V/3Ø/60 Hz) — KW Oper. 79; Conn 112

- Chemicals
  - Flocculent chemicals (polyelectrolyte) — lb/day 20
- Products

Product Fuel Gas

Flow, Dry Scfh		845,124
H_2O/DG (Vol/Vol)		0.0394
Pressure, psia		44.7
Temperature, °F		120
Gas composition,	Volume %	
CO	39.27	
CO_2	18.68	
H_2	38.07	
CH_4	2.51	
N_2	1.14	
H_2S	0.30	
COS	0.03	
TOTAL	100.00	

High Pressure Steam

Flow, lb/hr	25,512
Pressure, psia	625
Temperature, °F	491

- **Effluents**

  - Wet Sludge

Flow, lb/hr		9362
Composition,	WT.%	
C	32.15	
Ash	41.44	
Chlorides	0.2	
Sulfur	0.43	
Water	25.96	
TOTAL	100.00	
Temperature, ^{o}F		110

  - Process Condensate

Flow, lb/hr	11662
Pressure, psia	44.7
Temperature, ^{o}F	120

  - Nitrogen Vent

Flow, lb /hr	473

  - Blowdowns

Vent Steam

Flow lb/hr	830
Pressure, psia	20
Temperature, ^{o}F	227

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Liquid Stream	
Flow lb/hr	2058
Pressure, psia	20
Temperature, ^{o}F	227

4.3.6 Overall Material Balance with Total Char Disposal

IN	LB/HR
Process Coal (8 WT. % moisture)	31530
Oxygen (99.5 vol percent purity)	18166
Boiler Feedwater (228^{o}F)	47320
Nitrogen to Feed Systems (11,200 ScfH)	827
Total In	97843

OUT	
Fuel Gas	47946
Process Condensate	11662
Char Sludge (74 WT. % Solids)	9362
Export Steam (625 psia Satd.)	25512
Blowdown	
Vent Steam (5 psig)	830
Liquid (5 psig)	2058
Nitrogen Vent from Feed System	473
Total Out	97843

4.3.7 Process Flow Diagrams and Material Balances

Included as Appendix C are the material balances for the gasification section. Appendix D contains the ISBL process flow diagrams, plot plan, and single-line equipment list.

4.3.8 Energy Balance with Total Char Disposal

IN	10 Btu/hr	Percent
Coal (HHV 10398 Btu/lb, 8 percent moisture)	327.85	97.40
Oxygen Sensible Heat (at 257°F) (99.5 volume percent purity)	0.77	0.23
BFW (at 228°F)	7.97	2.37
Nitrogen to Feed System, Sensible Heat (at 100°F)	0.01	----
Total In	336.60	100.00
OUT		
Product Fuel Gas		
Sensible Heat (at 120°F)	2.70	0.80
Heating Value	233.93	69.50
Export Steam (at 625 psia Satd.)	29.99	8.91
Heat to Cooling Water	18.67	5.55
Plant Char Disposal, Heat Content	42.63	12.66
Process Condensate (at 120°F)	0.70	0.21
Blowdown Stream	1.28	0.38
Nitrogen Vent from Feed System (at 100°F)	0.01	---
Radiation Losses	6.69	1.99
Total Out	336.60	100.00

Overall Gasification Thermal Efficiency =

$$\frac{\text{HHV of Gas + Steam Export}}{\text{HHV of Coal + BFW}} = \frac{233.93 + 29.99}{327.85 + 7.97} = 78.6\%$$

4.3.9 Alternate Studies

Three major process alternates were investigated during this study. A description of each is presented with a summary of the results.

4.3.9.1 Lignite Coal. Use of lignite coal, as specified by Northern Resources, was investigated. Heat and material balances around the gasifier were completed. This coal is also in the range of Winkler operating experience. Coal, steam, and oxygen rates vary slightly and more ash per hour is produced than with the subbituminous. The lignite is very suitable for the plant designed in this study.

4.3.9.2 Oxygen. With the possible savings of oxygen costs in mind, a study of the use of 95 percent purity O_2 vs. 99.5 percent was completed. Material balance for the 95 percent purity O_2 case is included in Appendix C. The major process change is the increase in the gas volume required for the same fuel gas heating valve. No major equipment modifications would be required for use of 95 percent O_2.

4.3.9.3 Char Utilization. The use of residual char from the gasification section was investigated. Use of Winkler char as boiler fuel has been demonstrated in a number of commercial plants. The char has excellent burning characteristics and can be blended with coal for use as fuel in this plant.

A revised energy balance is presented using char as fuel which indicates a considerable increase in the overall gasification efficiency. Char utilization would also reduce the raw coal requirements OSBL.

4.3.10 Dry Char Utilization Energy Balance

IN	10 Btu/hr	Percent
Coal (HHV 10398 Btu/lb, 8 percent moisture	327.85	97.40
Oxygen Sensible Heat (at 257°F) (99.5 volume percent purity)	0.77	0.23
BFW (at 228°F)	7.97	2.37
Nitrogen to Feed System, Sensible Heat (at 100°F)	0.01	---
Total In	336.60	100.00

OUT	(at 120°F	
Product Fuel Gas		
Sensible Heat (at 120°F)	2.70	0.80
Heating Value	233.93	69.50
Export Steam (at 625 psia Satd.)	29.99	8.91
Heat to Cooling Water	18.67	5.55
Usable Dry Char (HHV 6995 Btu/lb)	32.60	9.68
Gasifier Bottom Ash (HHV 2818 Btu/lb)	4.32	1.28
Wet Ash	5.71	1.70
Process Condensate (at 120°F)	0.70	0.21
Blowdown Stream	1.28	0.38
Nitrogen Vent from Feed System	0.01	---
Radiation Losses (at 100°F)	6.69	1.99
Total Out	336.60	100.00

USABLE CHAR

This is mainly derived from the recovery of char from waste heat recovery and cyclone. This char has a higher heating value of 6995 Btu/lb with the following composition:

	WT%
C	49.6
Ash	49.6
Sulfur	0.8
Total	100.0

5. RETROFIT

This section evaluates the retrofit requirements and includes a cost estimate required to permit the Conoco and Cenex refineries to burn, safely and efficiently, the blend gas that will be pipelined to the refinery by NRI. This gas will be a blend of medium-Btu gas from NRI's proposed coal gasifiers and excess refinery gas from EXXON's Billings Refinery that NRI will purchase from EXXON.

5.1 ADVANTAGES OF THE NEW BLEND GAS

- The gas will be priced at a level to attract Conoco and Cenex to use it instead of natural gas and discretionary "own consumption" fuel such as propane and saleable residual.

- The supply will not be interruptible in the winter weather as is most of the natural gas supply.

- The heat losses to the stack are lower for the new blend gas because the volume ration of air required for burning H_2 and CO is only about 28 percent of that for natural gas. This more than offsets the lower heat of combustion for the H_2 and CO manufactured gas.

- The blend gas will have higher tolerance against flame lift-off, and as a result, will permit higher primary air and thus realize better mixing than natural gas.

5.2 DISADVANTAGES OF THE NEW BLEND GAS

- The explosive limits of this gas are several times as high as natural gas, but the refineries are experienced in dealing with this problem when burning the hydrogen rich mix stream from the catalytic reformer and hydrotreating units.

- The flashback tendency of hydrogen is higher because of its high flame speed, which means that burners should be taken out of service in reduced load rather than reducing the gas to all burners.

- The new gas, having a lower Btu content than the natural gas replaced, will require increasing the orifice areas on those burners that are presently near capacity.

5.3 COMPOSITION AND PROPERTIES OF BLENDED MBG

The proposed blend gas consists of a blend of approximately 80 percent medium-Btu (285 Btu/scf) manufactured gas from NRI's subbituminous coal gasification plant and 20 percent of EXXON's excess refinery gas (900 Btu/scf). The resultant blend gas is treated and estimated to have less than 10 grains/100 scfH_2S, a higher heating value of 406 Btu/scf, a specific gravity of 0.684, and a molecular weight of 19.84. The above properties have been calculated in Table 5-1 from data presented over the phone to SRI from NRI in March 1980 and tabulated in Table 5-2.

TABLE 5-1

COMPOSITION AND PROPERTIES OF BLEND COMPONENTS

	NORTHERN RESOURCES PRODUCER GAS					EXXON OFF-GAS			
	Mol %	Mscf/Hr	Mol/Hr	Mol Wt	Lb/Hr	Mol %	Mscf/Hr	Mol/Hr	Lb/Hr
H_2	37.9	310.7	819.3	2.	1,639	31.9	62.7	165.4	331
N_2	.6	4.9	12.9	28.	361	6.2	12.1	31.9	893
CO	39.7	325.3	858.0	28.	24,024	1.1	2.1	5.5	154
CO_2	18.1	148.4	392.3	44.	17,265	2.1	4.2	11.0	484
Methane	3.4	27.9	73.5	16.	1,176	33.5	65.9	174.3	2,789
Ethane				28.		13.5	26.5	69.8	1,954
Ethylene				27.		7.4	14.6	38.4	1,037
Propane				44.		1.2	2.3	6.1	268
Propylene				43.		2.9	5.6	14.8	636
iC_4				58.		0.2	.4	1.1	64
Total	100.0	817.2	2,156.0	20.65	44,465	100.0	196.4	518.3	8,610

HHV = 287 Btu/scf

Specific Gravity = .712

HHV = 900 Btu/scf

Specific Gravity = 0.067

Mol Wt = 16.6

TABLE 5-2

COMPOSITION AND PROPERTIES OF NRI BLENDED GAS

	Mol %	Mscf/Hr	Mol/Hr	Mol Wt	Lb/Hr	Btu/Scf	HHV	Flammability Limits Lower	Flammability Limits Higher	Specific Flame Intensity Btu/sec/Sq ft
H_2	36.8	373.4	985.1	2.0	1,970	325	120	4.0	75.0	703
N_2	1.7	17.0	44.8	28.0	1,254			-	-	
CO	32.3	327.4	863.8	28.0	24,186	321	104	12.5	74.0	124
CO_2	15.1	152.6	402.6	44.0	17,714			-	-	
Methane	9.3	93.8	247.8	16.0	3,965	1,010	94	5.0	15.0	
Ethane	2.6	26.5	69.8	28.0	1,954	1,769	46	2.9	13.0	
Ethylene	1.4	14.6	38.4	27.0	1,037	1,600	22	2.7	24.0	108 to 145
Propane	0.2	2.3	6.1	44.0	268	2,518	5	2.1	9.5	
Propylene	0.6	5.6	14.8	43.0	636	2,334	14	2.0	10.0	
iC_4	-	.4	1.1	58.0	64	3,253	1			
Total	100.0	1,013.6	2,674.3	19.84	53,046		406			

HHV = 406 Btu/scf

Specific Gravity = .684

5.4 CENEX STUDY

A retrofit examination was made on April 1, 1980, through the courtesy of and in conjunction with members of the staff of the Cenex Refinery. The physical layout of the refinery fuel system was examined and review was made of the burners' capacity problems from records available at the refinery.

SRI made recommendations and received concurrence from Cenex on the most logical point of entry for the blend gas, the need for and the location of the blend/drip tank and the details of the piping distribution along with the controls, other instruments, and alarms that should be installed. Cost allowances for retrofit of the burners needing modification were determined jointly by Cenex and SRI as well as the estimated capital cost for the various facilities required.

5.4.1 Summary

The estimated capital cost for the entire project within the Cenex Site is $350,000. This is a scope type estimate including 20 percent contingencies and is probably accurate within the range of plus or minus 30 percent. It is SRI's opinion that this capital for facilities installed within the Cenex Refinery should be for the account of Cenex. The negotiated price of the blend gas would have to be attractive to Cenex considering both the above capital cost and the alternate cost for natural gas and own production propane gas and residual fuel. The reason for this is that if this capital was included in the NRI venture, it would be viewed by IRS as a grant-in-aid by NRI to Cenex and taxable to Cenex the year of installation, but only amortizable at an even rate over the life of the project. In this manner, both entities would have to treat the installation costs as an after tax capital cost which would be double indemnity on income taxes.

Cenex should obtain a commitment from natural gas suppliers under the new conditions where they would supply only the solar turbine compressor and other critical uses, but would cover the refinery on an interruptible basis for full current demand on very few occasions per year.

Further, to protect both parties, it would be advisable for the gas sales contract to contain provisions for escalation of costs of natural gas, propane, residual fuel, coal feedstock, and labor at the gasification plant.

5.4.2 Description of Existing Fuel System

The refinery sweet gas fuel system consists of a 6-inch header running generally north* and south through the refinery and fed principally by a product line from the D.E.A. sour gas treater. Natural gas is fed in at various places along the header and propane is injected from a vaporizer** which is located near the refinery wall adjacent to the railroad right-of-way and under the entry way of the pipeline trestle to Route 310, the Laurel to Cody Highway. SRI requested that

*When north is used in this report, as well as associated compass directions, it refers to "refinery north" which is about 315° bearing from true north.

**It is proposed to install the new drip tank north of and adjacent to this vaporizer.

Cenex furnished NRI the plot plan of the refinery indicating the connection point to the proposed Billings to Laurel blend gas pipeline under this trestle.

There are 30 furnaces in the refinery that use sweet gas. This includes the sulfur plant afterburner. The refinery header is held at 70 psig. The individual furnace gas off-takes flow through back pressure controllers that hold various pressures on the individual burner orifices. In addition, in some cases there is further hand control throttling of the gas to the individual burner. Some of the furnaces are capable of burning residual fuel as well as gas and some of them are set at a rather high oil usage in order to consume some 800 barrels per day of viscous heavy fuel that Cenex has determined is more economical to burn than purchased gas.

5.4.3 Description of Proposed Blend Gas System

5.4.3.1 Gas Volume. Cenex's letter of March 21, 1980, to NRI indicated a demand of 4,950 mm Btu per day, plus or minus 50 percent. Based on this letter Cenex's demand, for the purpose of this study, was established to be 4,950 mm Btu per day. The 4,950 mm Btu per day demand results in 513,000 scf per hour (26,863 pounds per hour) flow of blend gas from the pipeline. When mixed with 8,650 mm Btu per day of 1,000 Btu Cenex Refinery gas, it totals a load to the new blend tank of 13,610 mm Btu per day of 873,000 scf per hour (42,538 pounds per hour) of a mixed gas of 0.636 specific gravity, 646 higher heating value, and 18.45 molecular weight.

5.4.3.2 Proposed Facilities. It is estimated that the total gas flow results in a pressure drop through a 10-inch line at 70 psig of about 0.2 psi per 100 feet of line using Fanning equation nomographs. For this reason SRI feels that an 8-inch header system is of adequate size, paralleling the existing 6-inch in the heart of the system.

5.4.3.3 New Facilities Required

- One 8-foot 6 inch by 12-foot blend/drip tank. 150 psi S.W.P. equipped with a 2-foot packed coalescer section near the top and 8-inch inlet nozzle on top with an 8-inch outlet nozzle on lower side under a diversion baffle.

- A 4-inch drain nozzle on the bottom header to a separate oil and water vessel 2 by 4 feet or an equivalent boot on the large vessel will be insulated and steam traced and finished with a gauge glass. (Above installed on foundation in the vicinity of the propane vaporizer.)

- One 6-inch line about 400 feet long from new drip outlet to existing platforming drum which will serve the south of the existing 6-inch sweet gas header. One 8-inch line about 1,000 feet long from new drip outlet to vicinity of the boiler house. (This line will loop the existing northward bound sweet gas header and be hot tapped to this header in the vicinity of the boiler house and another location approximately halfway from the new drip to the boiler house.)

- One 6-inch line about 800 feet long, an extension of the above from boiler house to existing north drip.

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- One 6-inch connection to the new drip inlet from the DEA treated gas knockout drum.

- One 4-inch connection, each for natural gas and vaporized propane to connect to the 6-inch inlet line to the new drip.

- A 4-inch correction blinded off should be made on the new header at strategic spots so service connections to large loads may be looped if found necessary.

- Various required instruments and controls, including but not necessarily limited to the following: One remote operated shut-off in NRI gas line outside the refinery wall and operated from an emergency station near the new drip tanks. This valve may be adapted as a flow controller if it is found necessary to flow control the new gas supply for variable flow characteristics; one high-level alarm on drip tank; one differential level control on boot controlling a valve on water outlet. This outlet valve will also shut off a high flow action in the water line.

- One back flow preventer on NRI gas entering the new drip tank.

- One back pressure regulator (probably existing) in natural gas line to the new drip tank.

- 28 burners retrofitted with large spuds or supplement with additional torches.

ESTIMATED COSTS FOR FACILITIES

		Dollars
Provision for increasing the capacity of 28 burners		$60,000
Drip tank, installed		30,000
8" and 6" headers, and 4" laterals		150,000
Instruments, controls, alarms, gauges, etc.		45,000
	Subtotal	285,000
Contingencies		65,000
	Total	$350,000

This is a scope type estimate. Before any final decision is made, the changes should be engineered thoroughly and a final estimate should be prepared by Cenex.

5.5 CONOCO STUDY

Personnel visited the Conoco Refinery on July 1, 1980, for purposes of studying the fuel gas system and discussing changes necessary to accommodate a leaner fuel gas. Conoco staff engineers were most cooperative in describing not only the fuel system, but also refinery operations generally, and anticipated changes in future fuel requirements. Copies of plot plans, fuel system, Piping and Instrument Diagrams (P&ID), and a fired heater summary with duties and numbers and types of burners were supplied along with data on current fuel types and quantities. A tour of the process area was made to identify the principal fuel gas supply and distribution lines.

After learning from NRI where the new blend-gas line would pass nearest to the Conoco Refinery, SRI in conjunction with refinery staff, selected a logical point of entry for the necessary spur line. Location and adequacy of existing pipe racks were also discussed, along with questions of controls and instruments. Location of a new knockout drum, if required, was agreed on. Since all burners in the refinery are set to operate at 15 psi pressure drop and with gas of 900 Btu/scf or higher, it was recommended by the refinery staff that all two hundred and fifty-five (255) burners be retrofitted. Ten of these are dual-fired (gas/oil) burners located on the boilers. They currently operate on oil part or all of the time.

After the refinery visit, SRI analyzed the above data and estimated sizes and capacities of new equipment required. Finally a cost estimate was made for both the new facilities and retrofit of the burners. The latter cost element was determined jointly with Conoco.

5.5.1 Summary

The estimated capital cost for the entire project within the Conoco site is $380,000. This is a scope type estimate including 20 percent contingencies and is probably accurate within the range of plus or minus 30 percent. It is SRI's opinion that this capital for facilities installed within the Conoco Refinery should be for the account of Conoco. The negotiated price of the blend gas would have to be attractive to Conoco considering both the above capital cost and the alternate cost for natural gas and refinery-produced propane gas and residual fuel. Moreover, if this capital was included in the NRI venture, it would be viewed by IRS as a grant-in-aid by NRI to Conoco, taxable in the year of installation, but only amortizable at an even rate over the life of the project.

In this manner both entities would have to treat the installation costs as an after tax capital cost which wold be double indemnity on income taxes.

Conoco should obtain a commitment from natural gas suppliers under the new conditions wherein they would supply the refinery on an interruptible basis for full current demand on a very few occasions per year.

Further, to protect both parties, it would be advisable for the gas sales contract to contain provisions for escalation of cost of natural gas, propane, residual fuel, coal feedstock and labor at the gasification plant.

5.5.2 Description of Existing Fuel System

The refinery sweet gas fuel supply is made up of three principal components. The major component is refinery off-gas from two DEA contractors; one serving the catalytic cracking light ends unit, and the other taking gases from distillate and naphtha hydrotreaters. Refinery gas is supplemented with natural gas from Montana Dakota Utilities (MDU) and with propane, generated as required in Vaporizer, X-109. It was stated that on the rare occasions when supply by MDU is interrupted, there is always sufficient warning (3 to 4 hours) to allow for replacement by additional propane vaporization. These sweet gas components are mixed in Fuel Mix Drum D-47 and then pass through fuel gas knockout drum D-212 before entering the fuel as distribution system.

The distribution system consists of two 8-inch headers, each of which serves a group of furnaces through a manifold. Pres- sure at the knockout drum is held at approximately 45 psig by a pressure controller on the MDU supply line. Fuel gas to individual furnaces, via 2-, 3-, 4-, or 6-inch stub headers, passes through flow recorders and back pressure controllers set to hold 15 psi on burner orifices. Twenty-four fired heaters are supplied by this system, including four boilers which are equipped to burn oil also. Current consumption of fuel oil is about 740 barrels per day.

5.5.3 Description of Proposed Blend Gas System

5.5.3.1 Gas Volume. In our discussion of July 1, 1980, Conoco presented a tabulation that resulted in a potential demand for the blend gas of 6,406 mm Btu per day. However, as a result of the refinery's ongoing program to conserve energy the above demand for blend gas is expected to be reduced to 4,520 mm Btu per day by early 1981.

Although the economics should be calculated on a real future demand or whatever rate that Conoco agrees to take from NRI, SRI recommends that the facilities be installed on the basis of receiving 4,520 mm Btu per day. The 4,520 mm Btu per day rate results in 464,000 scf per hour (24,195 pounds per hour) flow of blend gas from the pipeline. When mixed with 14,320 mm Btu per day of 1,100 Btu per scf refinery gas, it results in a total load to the knockout drum of 18,840 mm Btu per day, or 1,006,000 scf per hour (52,925 pounds per hour) of a mixed gas of 0.689 specific gravity, 780 Btu per scf HHV, and 19.96 molecular weight.

5.5.3.2. Proposed Facilities. It is estimated that the total gas flow results in a pressure drop tnrough a 10-inch line at 45 psig of about 0.8 psi per 100 feet of line and a velocity of about 110 fps. On this basis, SRI feels that a 6-inch header system would be of adequate size, paralleling the existing 8 inches in the heart of the distribution system, but recommends parallel 8-inch headers to reduce velocity and pressure drop.

Knockout drum D-212 appears to have been considerably oversized and is adequate for the new combined flow of fuel gas. In SRI's opinion, a new drum is not required.

Blend gas at approximately 60 psig will be delivered to D-212 from a point on the refinery fence line, next to Interstate Highway 90 where the service road north of the main flare swings northeast. SRI recommends a 10-inch line which gives a pressure drop at design flow rate of about 0.14 psi.

5.5.3.3. <u>New Facilities Required</u>. New facilities required to accommodate the new, lower Btu fuel gas are as follows:

- Retrofit of 255 burners with larger orifices or additional torches.
- About 1,500 feet of 8-inch line to loop the existing fuel gas headers.
- Approximately 100 feet of 6-inch line for looping lateral connections between headers and burners.
- About 500 feet of 4-inch line as above.
- About 500 feet of 2-inch and 3-inch lines as above.
- Necessary manual block valves and flow recorders on all new laterals to heaters, as well as valving and connections between the new 8-inch headers and other refinery units as shown on the Fuel Gas System P&ID.

- Possible looping of the 10-inch lines connecting D-212 and the headers out of D-47. Since these drums are next to one another, the lines are quite short; it seems likely that the extra pressure drop due to increased gas flow can be tolerated without looping.

- Approximately 2,000 feet of 10-inch line to bring blend gas from NRI's main line to knockout drum D-212.

- Various instruments and controls including, but not necessarily limited to, the following: One remotely operated shut-off in the blend gas header outside the refinery fence and operated from an emergency station near D-212. This valve may be adapted as a flow controller if necessary, or alternatively a pressure controller may be installed on this header close to D-212.

ESTIMATED COST FOR FACILITIES

	Dollars
Retrtofit of 255 burners	$150,000
10" inlet header	50,000
8" distribution headers and 6", 4", 3", and 2" laterals	80,000
Valves, instruments and controls	40,000
Subtotal	$320,000
Contengies	65,000
Total	$385,000

As mentioned earlier, this is a scope type estimate. Before a final decision is made the changes required in the fuel gas system should be engineered thoroughly and a final estimate should be prepared by Conoco.

6. ENVIRONMENTAL

6.1 INTRODUCTION

Three tasks are identified and discussed in the following sections:

- Regulations and Permits Relevant to the Proposed Coal Gasification Project - An identification and review of applicable federal, state, and local regulations and permits, as well as the requirements necessary to satisfy these regulations and secure the permits.

- Process Design Environmental Evaluation - A summary of the Winkler coal gasification process and a preliminary assessment of emissions, effluents, and solid wastes associated with the process.

- Preoperational Environmental Monitoring Needs - A determination of environmental parameters not satisfied by the existing data base and which will therefore require monitoring to meet applicable environmental regulations and to secure the necessary permits.

6.2 REGULATIONS AND PERMITS RELEVANT TO THE PROPOSED COAL GASIFICATION PROJECT

6.2.1 Introduction

Federal, state, and local permit and program review requirements which have been identified are summarized in Table 6-1. The following discussion evaluates the current status of the

TABLE 6-1

PRELIMINARY LISTING OF MAJOR REGULATORY CONSTRAINTS AND PERMIT REQUIREMENTS

Permit and/or Requirement	Granting Authority (Agency)	Estimated Time Required
Air Quality Review and Permit to Construct	Department of Health and Environmental Sciences (DHES)	6 months from submittal
Air Quality Operating Permit (including PSD permit)	DHES	2 months prior to full-scale commercial operation
Montana Pollution Discharge Elimination System (MPDES) Review and Approval (includes NPDES requirements), Permit to Discharge to State Waters	DHES	6 months prior to intended discharge
Solid or Hazardous Waste Disposal Permit (incorporates federal, RCRA requirements)	DHES	Solid - 30 days Hazardous - 60 to 120 days
Ground Water Appropriation (water right)	Department of Natural Resources and Conservation (DNRC)	140 to 260 days
Right-of-Way - Stream Crossing Easement	Department of State Lands	60 days
Right-of-Way - Stream Crossing Permit - Highway Crossing Permit - Highway Utility Easement	Department of Highways	60 days (concurrent)
Right-of-Way - Railroad Utility Easement	Public Service Commission	60 days

TABLE 6-1 (Continued)

Permit and/or Requirement	Granting Authority (Agency)	Estimated Time Required
Floodway/Floodplain Excavation Permit	DNRC	60 days
Natural Streambed and Land Preservation Act Compliance Review	Department of Fish, Wildlife and Parks and County Soil and Water Conservation District	60 days
Historic Preservation Clearance	Montana Histcrical Society	60 days
County Road Crossing Permit	County Commission	30 days

major pertinent regulatory requirements and briefly explains the less critical regulatory and review constraints.

6.2.2 Federal and State Air Quality Standards

The proposed NRI Coal Gasification Project will require air quality analyses and review for three main regulatory purposes which are related to three primary regulatory agencies.

6.2.3 EPA Region VIII

The proposed facility will be required to undergo a new source review. This entails submitting a completed questionnaire on the facility relating to the following air regulations for which EPA Region VIII has jurisdictional responsibility:

6.2.3.1. New Source Performance Standards (NSPS). These are emission regulations. Currently there are no NSPS for coal gasification plants. However, EPA is in the early phases of developing technical support for the future promulgation of NSPS for coal gasification facilities. This process may take 2 to 6 years.

EPA is examining available coal gasification emission data and data on biologic responses to a variety of air contaminants to determine what contaminants (from a list of over 600 compounds) are of concern for coal gasification. This, coupled with information on control techniques, is being used to generate a guidance document on coal gasification emission control. This document is expected to be available for use by state and federal agencies and private industry by late 1980. Some of the contaminants of concern are sulfur dioxide (SO_2), oxides of nitrogen (NO_x), carbon monoxide (CO), carcinogenic polycyclic organic matter, anthracenes, amines, oxygenated compounds, cyclic sulfur compounds, and benzopyrenes.

6.2.3.2 National Emissions Standards for Hazardous Air Pollutants (NESHAP). This is a very comprehensive permitting process covering the following areas:

- Demonstration that Best Available Control Technology (BACT) will be implemented.

- Demonstration that allowable emission increases will not cause or contribute to a violation of any federal or state ambient air quality standard or PSD increment (for SO_2 and particulates).

  The Clean Air Act as amended in 1970 requires the EPA to adopt National Ambient Air Quality Standards that are to be the minimum acceptable standards. Since the states clearly retained the authority to adopt more stringent standards, the status of Montana air standards must be considered concurrently. The Montana air standards must be considered concurrently. The current federal standards are listed in Table 6-2. The Act requires each state to develop a State Implementation Plan to reduce pollution in the state to meet the standards; the Montana Department of Health and Environmental Sciences (DHES) is charged with this responsibility for Montana. The plan has been developed but not yet approved by Region VIII of the EPA.

TABLE 6-2

NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Primary Standard	Secondary Standard	Averaging Time
Sulfur oxides	80 μg/m³		Annual (arithmetic mean)
	365 μg/		24-hour[a]
		1300 μg/m³	3-hour[a]
Suspended particulates	75 μg/m³	60 μg/m³[c]	Annual (geometric mean)
	260 μg/m³	150 μg/m³	24-hour[a]
Carbon monoxide	9 ppm	9 ppm	8-hour[a]
	35 ppm	35 ppm	1-hour[a]
Nitrogen dioxide	100 μg/m³		Annual (arithmetic mean)
Nonmethane hydrocarbons[c]	160 μg/m³		3-hour (6-9 a.m.) [a]
Photochemical oxidants	0.08 ppm	0.08 ppm	1-hour [a]
Lead[b]	1.5 μg/m³	1.5 μg/m³	Quarterly (arithemtic mean)

[a] Not to be exceeded more than once a year.

[b] Proposed calendar quarter arithmetic mean.

[c] Guidelines to achieving related standards.

In 1977, amendments to the Clean Air Act established two new rules which have almost the same effect as National Ambient Air Quality Standards. The Prevention of Significant Deterioration (PSD) regulations address the allowable level of sulfur dioxide and particulates by defining increments of change which are acceptable within certain classes of air quality. Table 6-3 shows the present federal standards for allowable SO_2 and particulate increments by air class. EPA Region VIII has PSD authority in Montana, although DHES has incorporated PSD rules into the Montana Clean Air Act and will eventually assume authority from Region VIII. The schedule for assuming this authority has not been established. Fuel conversion plants are subject to the PSD rules if potential emissions equal or exceed 100 tons per year for any air pollutant.

At this time, the Montana and federal maximum allowable increases over baseline concentrations are specified only for SO_2 and Total Suspended Particulates. EPA is also mandated to establish PSD increments for the other criteria pollutants as well.

For administrative reasons, EPA proposed to ignore certain minuscule rates of emission or net increases in emissions or ambient impacts. These minuscule rates and ambient impacts are termed *de minimis*, a legal concept meaning that they are so negligible that they fall outside the strict requirements of the law. The *de minimis* exemptions apply either to

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TABLE 6-3

PREVENTION OF SIGNIFICANT DETERIORATION INCREMENTS

Pollutant	Class I	Class II	Class III	Averaging Time
Sulfur dioxide	2 μg/m³	20 μg/m³	40 μg/m³	Annual
	5 μg/m³	91 μg/m³	182 μg/m³	24-hour[a]
	25 μg/m³	512 μg/m³	700 μg/m³	3-hour[a]
Suspended particulates	5 μg/m³	19 μg/m³	37 μg/m³	Annual
	10 μg/m³	37 μg/m³	75 μg/m³	24-hour[a]

[a]Not to be exceeded more than once per year.

emissions of pollutants from a new source or to "net increases" of emissions from modifications to existing sources.

As stated previously, a new fuel conversion plant must undergo PSD review if emissions of any pollutant equal or exceed 100 tons per year. However for existing facilities, any major modification must undergo PSD review if emissions of any pollutant equal or exceed the set de minimus emission levels (Table 6-4). Since the de minimus emission levels for every pollutant are less than 100 tons per year, PSD review is generally triggered more easily for major modifications than for new sources (except for carbon monoxide which has a de minimus rate equivalent to 100 tons per year). The de minimus emission rates are also used to determine whether the new or modified source must show BACT. For those pollutants below the de minimus emission rates, BACT need not be demonstrated.

There is also a de minimus impacts test. If ambient impacts, as determined from simplified screening modeling, are less than the de minimus impact levels (Table 6-5), the emissions for the pollutant do not require a year of background ambient air monitoring and detailed dispersion modeling evaluations.

- Air quality and meteorological monitoring for one year prior to the submission of a PSD application unless the applicant can demonstrate that existing data are adequate and excepting those pollutants below de minimus impact levels.

TABLE 6-4

EPA GUIDELINES FOR SIGNIFICANT EMISSION RATES

Pollutant	De Minimus Emission Rate
Carbon monoxide	100 tons per year
Nitrogen oxides	40 tons per year
Total suspended particulates	25 tons yer year
Sulfur dioxide	40 tons per year
Ozone	40 tons yer year of volatile organic compounds
Lead	0.6 ton per year
Mercury[1]	0.1 ton yer year
Beryllium[1]	0.0004 ton per year
Asbestos[1]	0.007 ton per year
Fluorides[1]	3 tons per year
Sulfuric acid mist[1]	7 tons per year
Vinyl chloride[1]	1 ton per year
Total reduced sulfur (including H_2S)	10 tons per year
Reduced sulfur compounds	10 tons per year
Hydrogen sulfide	10 tons per year

[1]Noncriteria pollutants

TABLE 6-5

EPA GUIDELINES FOR SIGNIFICANT AMBIENT AIR QUALITY IMPACTS

Pollutant	Air Quality Impact
Carbon monoxide	75 $\mu g/m^3$, 8-hour average
Nitrogen oxides	14 $\mu g/m^3$, 14-hour
Total suspended particulates	10 $\mu g/m^3$, 24-hour
Sulfur dioxide	13 $\mu g/m^3$, 24-hour[1]
Ozone	
Lead	0.1 $\mu g/m^3$, 24-hour
Mercury	0.25 $\mu g/m^3$, 24-hour
Beryllium	0.0005 $\mu g/m^3$, 24-hour[2]
Asbestos	[2]
Fluorides	0.25 $\mu g/m^3$, 24-hour[2]
Sulfuric acid mist	[2]
Vinyl chloride	15 $\mu g/m^3$, 24-hour
Total reduced sulfur (including H_2S)	10 $\mu g/m^3$, 1-hour
Reduced sulfur (including H_2S)	10 $\mu g/m^3$, 1-hour
Hydrogen sulfide	0.023 $\mu g/m^3$, 1-hour

[1] No *de minimis* air quality impact is proposed for ozone. Any increase, however, of 100 tons per year of volatile organic compounds subject to PSD would be required to perform ambient impact analysis, including the gathering of ambient air quality data.

[2] No satisfactory monitoring technique is available at this time.

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- Air quality and moteorological monitoring during operation of the proposed facility to establish the effect the proposed source emissions will have on air quality (if EPA Region VIII determines it necessary).

- Analysis of the impairment of visibility, soils, and vegetation (especially in nearby PSD Class I areas) that would occur as a result of the proposed source, including the effects of secondary sources due to population growth associated with the proposed source.

6.2.3.4 Nonattainment (NA) Regulations. These regulations complement the PSD regulations. Specifically, PSD rules cover those areas of the United States that are in attainment of the National Ambient Air Quality Standards (NAAQS). Those areas that are nonattainment are covered by the NA regulations. Sources in NA areas have to demonstrate two things for those pollutants:

- Potential emissions would be more than offset by a reduction in emissions from other existing sources.

- The facility would construct and operate pollution control equipment that is equivalent to the Lowest Achievable Emission Rate (LAER). LAER is essentially the most technically efficient removal rate without regard for energy impacts and economic justification.

The proposed facility would be located in an area which is NA for carbon monoxide and total suspended particulates. The Montana DHES has NA authority.

On the basis of the information submitted in the New Source Review application, EPA Region VIII in conjunction with the Montana DHES will determine which regulations apply and which permits must be obtained.

6.2.4 Montana Department of Health and Environmental Science (DHES)

The proposed facility will be required to obtain an air quality permit from the state. Information that must be delineated in the permit application primarily relates to project description, scheduling, and pollution control devices. The majority of this information will already have been developed in the PSD application.

The Montana DHES originally developed Ambient Air Quality Standards which are listed in Table 6-6. Due to ambiguities in the law, however, the use of ambient standards for enforcement purposes was challenged. In response, DHES drafted new standards which they maintained would be directly enforceable against a source. The proposed standards, which were promulgated on August 15, 1980, are listed in Table 6-7.

6.2.5 Department of Energy

The proposed facility will probably be required to submit an Environmental Assessment Report (EAR) to the lead federal agency on the project, in this case the DOE. Baseline air quality and meteorological conditions will have to be defined in addition to impacts expected from the proposed facility. Identifying and describing impacts due to alternatives to the proposed action will be an important activity in preparing the EAR. Most of the information required for the EAR (except for impacts due to alternatives) will already have been developed in the PSD application for issuing permits for the discharge

TABLE 6-6

ORIGINAL MONTANA AMBIENT AIR QUALITY STANDARDS

Pollutant	Standard	Averaging Time
Suspended particulates	$75\ \mu g/m^3$ $200\ \mu g/m^3$ [3]	Annual 24-hour
Sulfur dioxide	0.02 ppm 0.10 ppm[4] 0.25 ppm[1]	Annual 24-hour 1-hour
Settled particulates (dustfall)	$15\ tons/mi^2$ (residential area)	3-month
Suspended sulfates	$4\ \mu g/m^3$ $12\ \mu g/m^3$	Annual
Sulfuric acid mist	$4\ \mu g/m^3$ $12\ \mu g/m^3$ [2] $30\ \mu g/m^3$ [2]	Annual --- 1-hour
Hydrogen sulfide	0.03 ppm[5] 0.05 ppm[6]	1/2-hour 1/2-hour
Reactive sulfur (sulfation)	$0.25\ mg\ SO_3/100\ cm^2$ day $0.50\ mg\ SO_3/100\ cm^2$ day	Annual 1-month
Lead	$5.0\ \mu g/m^3$	30-day
Beryllium	$0.01\ \mu g/m^3$	30-day
Fluorides, total in air (as HF)	1 ppb	24-hour
Fluorides (as F) in forage for animals' consumption	35 ppm	
Fluorides (gaseous)	$0.3\ \mu g/cm^2$	28-day

[1]Not to be exceeded for more than 1 hour in any 4 consecutive days.
[2]Not to be exceeded more than one percent of the time.
[3]Not to be exceeded more than one percent of the days in a year.
[4]Not to be exceeded more than one percent of the days in a 3-month period.
[5]Not to be exceeded more than twice in any 5 consecutive days.
[5]Not to be exceeded more than twice a year.

TABLE 6-7

CURRENT MONTANA AMBIENT AIR QUALITY STANDARDS

Pollutant	Standard	Averaging Time
Sulfur dioxide	0.02 ppm 0.10 ppm 0.50 ppm	Annual 24-hour[1] 1-hour[1]
Total suspended particulates	75 $\mu g/m^3$ 200 $\mu g/m^3$	Annual 24-hour[1]
Settled particulates	10 gm/m^3	30-day
Visibility	Particle scattering coefficient of $3 \times 10^{-5}/m^3$	----
Foliar fluoride	20 $\mu g/g$ in forage	3-day
Photochemical oxidants (Ozone)	0.10 ppm	1-hour[1]
Nitrogen dioxide	0.05 ppm 0.30	Annual 1-hour[1]
Carbon monoxide	9 ppm 23 ppm	8-hour[1] 1-hour[1]
Lead	1.5 $\mu g/m^3$	Quarterly
Hydrogen sulfide	50 ppb	1-hour[1]
Arsenic	Deferred for further study	
Cadmium	Deferred for further study	

[1]Not to be exceeded more than once a year.
[2]Not to be exceeded more than 18 times a year.
[3]As measured by an integrating nephelometer. Applicable to mandatory Class I areas. Nonmandatory Class I areas are evaluated on a case-by-case basis.

of pollutants from point sources into state waters. MPDES regulations require submittal of detailed information on a project including process and waste streams, construction plans, treatment plans, and any other information deemed necessary by the state. Based upon this information and allowable standards, the DHES will either issue or deny a discharge permit.

Montana has adopted a nondegradation policy. The state surface water quality standards thus establish maximum allowable changes in water quality and established limits for pollutants. In other words, the standards identify those values which an effluent must meet before being discharged into receiving waters. Industrial wastes must receive treatment equal to the best practicable control technology currently available (BPCTCA 50 CFR 434.22). For the design of disposal systems, stream flow dilution requirements must be based on the minimum consecutive seven-day average flow which may occur on the average of once every ten years. When dilution flows are less than the effluent flow at the point of discharge, the discharge is governed by permit conditions of the MPDES permit. If the flow records are insufficient to calculate a ten-year, seven-day low flow, the DHES shall determine an acceptable stream flow.

It is important to note that there are procedures within MPDES for requesting a waiver of nondegradation from the Board of Health. This procedure could potentially enable a point source discharge to have values greater than the standards allow. This, however, only applies to cases where receiving water quality is significantly lower than the classification standards.

The project site is located near the Yegen Drain, a small drainage canal that empties into the Yellowstone River. Because of the site's proximity to the drain, it will most likely become the point of discharge for the project, if discharge to the municipal sewage treatment facility (the preferred option) proves infeasible. The existing classification for the Yellowstone River, including the Yegen Drain, is $B\text{-}D_3$. A $B\text{-}D_3$ classification requires that the quality be "maintained suitable for drinking, culinary and food processing purposes after adequate treatment equal to coagulation, sedimentation, filtration, disinfection and any additional treatment necessary to remove naturally present impurities; bathing, swimming and recreation; growth and propagation of nonsalmonid fishes and associated aquatic life, waterfowl, and furbearers; and agricultural and industrial water supply." The specific water quality standards for a $B\text{-}D_3$ classification are identified in Table 6-8.

The proposed classification for the Yellowstone River and tributaries is C-3. A C-3 classification is similar to a $B\text{-}D_3$ in that water quality must be maintained suitable for "bathing, swimming and recreation; growth and propagation of nonsalmonid fishes and associated aquatic life, waterfowl, and furbearers; and agricultural and industrial water supplies." Table 6-9 identifies the standards for a C-3 classification.

In developing the design for the project's sewage treatment, the standards in Table 6-9 will probably apply. Certain complexities in this table should be recognized. The criteria listed in the <u>Quality Criteria for Water</u>, published by the EPA in 1976 and incorporated to the standards by reference, are in the process of revision. Proposed criteria for many substances have been developed; however, final acceptance of many

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TABLE 6-8

EXISTING STATE OF MONTANA WATER QUALITY STANDARDS FOR B-D_3 CLASSIFICATION

Pollutant	Standard
Fecal coliform group	Fecal coliforms must not exceed 200/100 ml nor may 10% of total samples from 30-day period exceed 400/100 ml. Coliforms must not exceed 1,000/100 ml nor may 20% of total samples from a 30-day period exceed 1,000/100 ml.
Dissolved oxygen	Must not be reduced below 5.0 mg/l.
pH	Within range of 6.5 to 8.0 induced variation must be less than 0.5 pH. Outside of this range pH must be maintained. Natural pH above 7.0 must be maintained above 7.0.
Turbidity	Maximum allowable increase is 10 Jackson Candle Units.
Temperature	For receiving waters between 35° to 82°F a 3°F maximum increase is allowed. For waters between 82° to 84°F no thermal discharge is allowed that will cause water to increase to 85°F. For water 84.5°F or greater the maximum allowable increase is 0.5°F.
True color	Must not be increased more than 5 units above naturally occurring color.
Sediment, settleable solids, oils or floating solids	Must not be increased above naturally occurring concentrations.
Toxic or deleterious substances	Concentrations, after treatment for domestic use, are not to exceed the recommended limits contained in the 1962 U.S. Public Health Service Drinking Water Standards or subsequent editions; also, maximum allowable concentrations are to be less than acute or chronic problem levels as revealed by bioassay or other methods.

TABLE 6-9

PROPOSED STATE OF MONTANA SURFACE WATER QUALITY STANDARDS FOR C-3 CLASSIFICATION

Pollutant	Standard
Fecal coliform group	Must not exceed 200/100 ml (geometric mean) nor should 10% of the total samples for a 30-day period exceed 400/100 ml.
Dissolved oxygen	Must not be reduced below 5.0 mg/l.
pH	Within range of 6.5 to 9.0 induced variation must be less than 0.5 pH. Outside of this range pH must be maintained without change. Natural pH above 7.0 must be maintained above 7.0.
Turbidity	Maximum allowable increase is 20 nephelometric turbidity units.
Temperature	For receiving waters between 32° to 82°F a 3°F maximum increase is allowed. For waters between 82° to 84°F no thermal discharge is allowed that will cause water to increase to 85°F. For water 84.5°F or greater the maximum allowable increase is 0.5°F.
True color	Must not be increased more than 10 units above naturally occurring color.
Sediment, settleable solids, oils or floating solids	Must not be increased above naturally occurring concentrations.
Toxic or deleterious substances	Maximum allowable concentrations must not exceed following levels:[1/]
Alkalinity	20 mg/l or more as $CaCO_3$ except where natural concentrations are less
Ammonia	0.02 mg/l (as unionized)
Arsenic	100 μg/l
Beryllium	11 μg/l soft water (0-75 mg/l $CaCO_3$); 1,100 μg/l hard water (150-300 mg/l $CaCO_3$)
Boron	750 μg/l

TABLE 6-9 (Continued)

Pollutant	Standard
Cadmium	4.0 μg/l - soft water. 12.0 μg/l - hard water
Chromium	100 μg/l
Chlorine	10.0 μg/l
Copper	0.1 times a 96-hour LC_{50} as determined by a non-areated bioassay using a sensitive aquatic resident species
Cyanide	5.0μg/l
Iron	1.0 mg/l
Lead	0.01 times a 96-hour LC_{50} value using the receiving or comparable water as the diluent and soluble lead measurement (using 0.45 micron filter)
Manganese	50 μg/l[2/]
Mercury	0.05 μg/l
Mixing zone	Standards do not apply within zone; water quality should be 96-hour LC_{50} of significant biota to aquatic community is not exceeded
Nickel	0.01 times the 96-hour LC_{50} for resident sensitive species
Nitrates and nitrites	10 mg/nitrate nitrogen (N)[2/]
Oil and grease	0.01 times the lowest continuous flow 96-hour LC_{50} for resident species
Phenols	1 μg/l[2/]
Phosphorus	0.10 μg/l (elemental phosphorus)[3/]
Selenium	0.01 times the 96-hour LC_{50} for resident sensitive species
Chlorides and sulfates	250 mg/l[2/]
Sulfides-hydrogen sulfide	2 μg/l undissociated H_2S
Zinc	0.01 times the 96-hour LC_{50} for a resident sensitive species

TABLE 6-9 (Continued)

Pollutant	Standard
Aluminum4/	No Standard (NS)
Calcium4/	NS
Magnesium4/	NS
Potassium4/	NS
Silicon4/	NS
Sodium4/	NS
Titanium4/	NS
Antimony4/	NS
Lithium4/	NS
Molybdenum4/	NS
Thallium4/	NS
Tin4/	NS
Vanadium4/	NS
Flourides4/	NS
Iodine4/	NS

1/ U.S. Environmental Protection Agency. Office of Waters and Hazardous Materials. 1976. Quality Criteria for Water ("Red Book"). EPA, Washington, D.C. 256 pp.

2/ Standard is included for information purposes only since a standard for protecting aquatic resource is not given and standards for water supplies do not apply to a C-3 classification. Determination of standard will be made in cooperation with Department of Health and Environmental Sciences.

3/ Standard is included for information purposes only since a standard for protecting freshwater aquatic resource is not given. Determination of standard will be made in coordination with Department of Health and Environmental Sciences.

4/ Other possible pollutants of gasification process waters in which state standards (as identified in the "Red Book") have not been defined.

of these will most likely not occur within the next six months. Thus, the revised criteria should also be considered. Another consideration is the requirement of some parameters for 1/100 or 1/20 of 96-hour LC_{50} (lethal concentration where 50 percent of the test organisms die) as the criterion. This would require that bioassays of resident sensitive species be run before determination of the standard can be made.

As mentioned above, the preferred effluent disposal method is discharge to the Billings sewage treatment plant. There are currently no specific federal pretreatment standards for discharge to a municipal sewage system from a coal gasification plant. EPA has suggested they do not anticipate any regulation will be promulgated for the industry (J. Dunn, EPA Region VIII pretreatment specialist, personal communication, February 1, 1980). Thus, the burden of regulating discharges to a local sewage system depends entirely upon municipal authorities. In accepting effluent from an industrial source, in lieu of specific standards, municipal authorities will be required to apply the following federal criteria:

- The discharge must not cause fires or explosions.
- The pH of the effluent must not be less than 5.
- No solid or viscous discharge that could interfere with the system flow may be accepted.
- The temperature of the discharge must not be greater than 150°F.
- The discharge must not interfere with the treatment plant processes.

The city of Billings has also adopted parallel codes which prohibit the discharge of certain matters into public sewers (Code 18.08.090). These include:

- Any liquid or vapor having a temperature higher than $150^{o}F$.
- Any water or waste which may contain more than 300 parts per million (ppm) of fat, oil, or grease.
- Any gasoline, benzene, naphtha, fuel oil, or other flammable or explosive liquid, solid or gas.
- Any garbage that has not been properly shredded.
- Any ashes, cinders, sand, mud, straw, shavings, metal, glass, rags, feathers, tar, plastics, wood, paunch manure, or any other solid or viscous substance capable of causing obstruction to the flow in sewers, or other interference with the proper operation of the sewerage works.
- Any waters or wastes having a pH lower than 5.5 or higher than 9.0, or having any other corrosive property capable of causing damage or hazard to structures, equipment, and personnel of the sewerage works.
- Any waters or wastes containing a toxic or poisonous substance in sufficient quantity to injure or interfere with any sewage treatment process, constitute a hazard to humans or animals, or create any hazard in the receiving waters of the sewage treatment plant.

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- Any waters or wastes containing suspended solids of such character and quantity that unusual attention or expense is required to handle such materials at the sewage treatment plant.

- Any noxious or malodorous gas or substance capable of creating a public nuisance.

For admission to the public sewer system, the city requires the approval of the city engineer for water or wastes with (Code 18.08.140):

- A five-day biological oxygen depletion (BOD) greater than 300 ppm of suspended solids.

- More than 350 ppm of suspended solids.

- Any quantity of substances identified in Code 18.08.090 (described above).

- An average daily flow greater than 3 percent of the average daily sewage flow of the city.

When necessary, the city can request pretreatment of sewage, at the owner's expense, to (Code 18.08.150):

- Reduce BOD to 300 ppm and suspended solids to 350 ppm.

- Reduce objectionable characteristics or constituents to within maximum limits (as identified above).

Communications with the Public Utilities Department (PUD) of Billings indicate that before accepting application for sewage admission from a gasification plant, the PUD will want to review carefully the quantity and quality of the effluent. The PUD is particularly concerned about heavy metals and other trade elements in the effluent (K. Lustig and A. Towlerton, Billings Public Utilities Department, personal communication, January 21, 1980).

6.2.6 Solid or Hazardous Waste Disposal Requirements

The Montana Department of Health and Environmental Sciences is the administrative agency for provisions of Montana's Solid Waste Management Act and Consumer Product Safety Act. This legislation and pursuant regulations incorporate provisions of the Federal Hazardous Substances Act and the Resource Conservation and Recovery ACT (RCRA). A disposal license is required for any solid wastes. If any solid wastes are determined to be hazardous ("...may cause or contribute to an increase in mortality or an increase in serious illness, taking into account the toxicity, persistence and natural degradability of the waste and its potential for assimilation or concentration in tissue"), a separate hazardous waste disposal permit will be required. Alternatively, pretreatment of the waste to remove hazardous components, such as undesirable trace or heavy metals, toxic compounds, etc., may be a feasible way of removing the waste from the hazardous classification.

6.2.7 Groundwater Appropriation

Under Montana's Water Resources Act and Water Use Act, the DNRC has jurisdiction over water rights, allocations, and withdrawal permitting. The DNRC regulates construction and maintenance of wells to prevent waste and contamination of groundwater. If the gasification facility requires water in excess of 100 gallons per minute (gpm) from a new on-site well, a DNRC review/water use permit will be required. In reviewing such withdrawal applications, DNRC considers criteria such as aquifer capacity, existing and conflicting water rights, and contamination potential.

6.2.8 Rights-of-Way and Easements

The main right-of-way requirement for the facility will be for incoming and outgoing gas pipelines. Several agencies will have regulatory involvement in the routing and construction phases of these pipelines:

- Department of State Lands (DSL) - Crossing of variable streams requires purchase of an easement from DSL.

- Department of Highways - Highway and stream crossing permits and an easement for common use of an existing highway right-of-way will be required.

- Public Service Commission - As regulator of the public carriers, including the railroads, the PSC will review and approve any alterations of, or additions to, existing rights-of-way; the PSC will also be involved in any relocation of public utilities.

- Department of Fish, Wildlife and Parks - With the County Soil and Water Conservation District, reviews routing and construction plans for compliance with the Natural Streambed and Land Preservation Act.

- DNRC - Floodplan/floodway excavation permit and a separate permit under the Open Cut Mining Act for any construction borrow or fill extracted outside of the right-of-way would be required.

- County Commission - County road and highway crossings must be approved by the Board of Commissioners.

6.2.9 Cultural Resources

Site clearance, under the National Historic Preservation Act of 1966 and 36 CFR 800, must be obtained from the State Historic Preservation Officer of the Montana Historical Society. Since the site and proposed rights-of-way have been substantially disturbed, there is little likelihood of encountering historically significant structures. An archaeological reconnaissance can be used to verify the presence or absence of archaeologically significant sites.

6.3 PROCESS DESIGN ENVIRONMENTAL EVALUATION

6.3.1 Summary of thw Winkler Gasification Process

Development of the Winkler coal gasification process was initiated in 1922 and, along with the Koppers-Totzek and Lurgi processes, it represents the "first generation" coal gasification technologies. The first commercial Winkler gas producer was put into operation in Germany in 1936. Since then, 36 pro- ducers in a total of 16 installations have been designed, engineered, and commissioned. To date, no Winkler unit is in operation in the United States.

A schematic of NRI gasification project is presented in Figure 6-1. The flow sheet is based on the gasification of

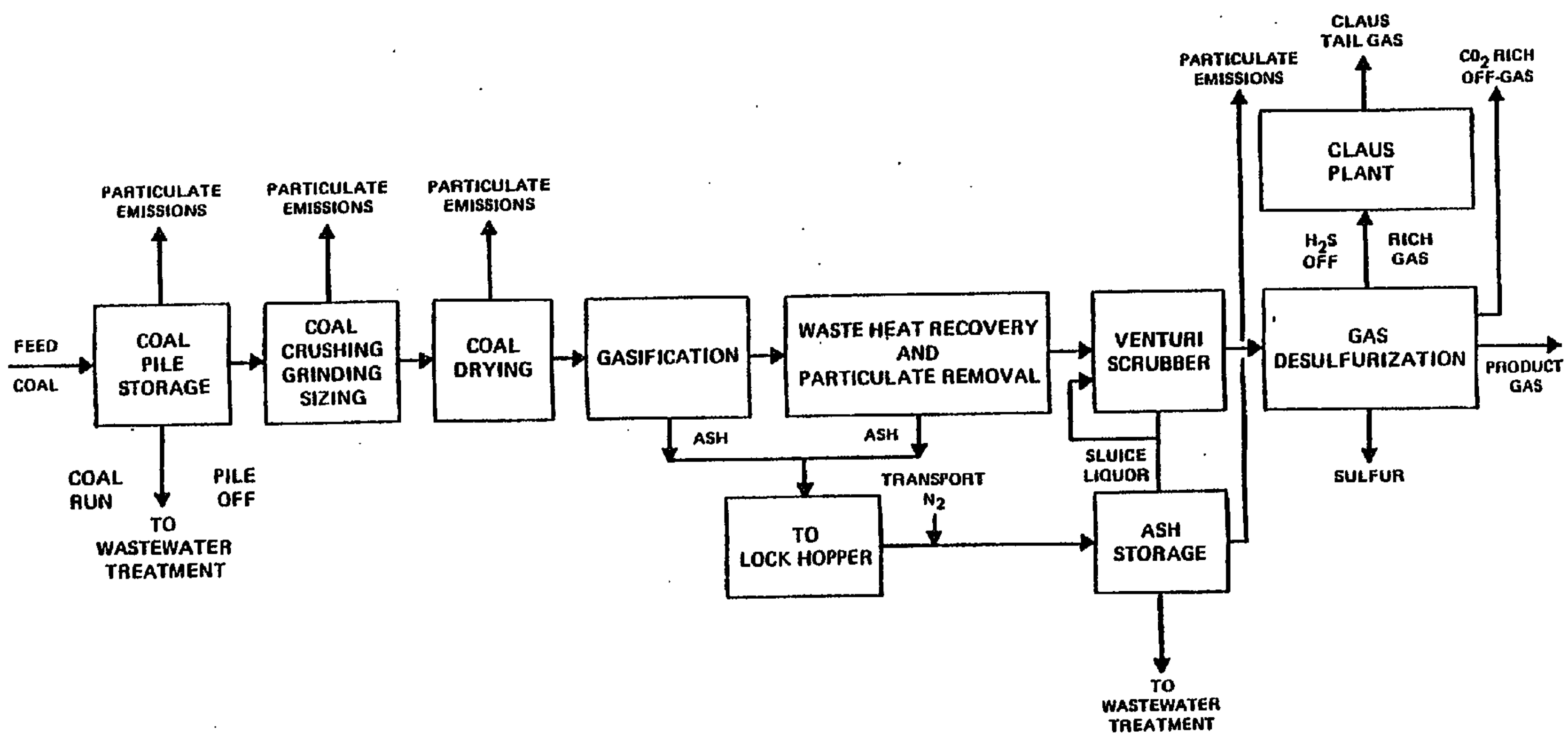

FIGURE 6-1
SCHEMATIC OF NRI GASIFICATION PROCESS FLOWSHEET

coal from Westmoreland Resources, Inc., with characteristics shown on Table 6-10. Gas production will be equivalent to 5.6 billion Btu per day or approximately 22 (10^6) standard cubic feet (SCF) per day (assumes high heating value (HHV) of 250 Btu/scf).

6.3.1.1 Coal Preparation. Coal will be mined off-site and transported (truck or railroad) to an on-site storage pile with a 30- to 90-day coal capacity. The run-of-mine coal, approximately minus 3 inches, will then be crushed, ground, and sized to minus 3/8 inch. Due to the moisture content of the coal, the feed coal must be dried. Experience with the Winkler process has indicated that the maximum permissible moisture content is 18 percent provided the surface of the coal is not wet (Banchik 1975). In the extreme, depending upon the coal characteristics, the moisture content of the coal may have to be reduced to as low as 8 percent. Drying of the coal will be accomplished in either tray driers or fluidized bed driers.

6.3.1.2 Coal Gasification. The sized and dried coal will be fed to the bottom of the fluidized bed gasifier using variable speed screws. The coal reacts with steam and oxygen to yield product gas and residual ash. As a result of fluidization, ash particles segregate according to size and specific gravity. Heavier particles pass into the ash discharge unit at the bottom of the generator, while lighter particles are transported out of the bed by the product gas. Approximately 30 percent of the ash leaves at the bottom, while 70 percent is caried overhead.

One unique feature of the Winkler gasifier is the injection of steam and oxygen into the zone above the bed. The injection of this gasifying medium controls the gasification efficiency by assuring that minimal unreacted carbon escapes from

TABLE 6-10

CHARACTERISTICS OF COAL PROPOSED FOR NRI GASIFICATION PROJECT

Proximate Analysis

	Percent by Weight Average	Low	High
Moisture	23.40	20.25	24.69
Volatile Matter	29.79	26.15	32.59
Fixed Carbon	36.56	34.29	39.20
Ash	10.25	8.65	11.73
	100.00		

Ultimate Analysis

	Percent by Weight Average	Low	High
Carbon	50.66	49.18	52.94
Hydrogen	3.43	3.09	3.62
Sulfur	.73	.60	.89
Oxygen	10.78	9.98	12.42
Nitrogen	.74	.49	1.16
Moisture	23.40	20.25	24.69
Ash	10.25	8.65	11.73
Chlorine	.01	.00	.02
	100.00		

the gasifier in the form of overhead ash carryover. As a result of this injection, the maximum temperature in the generator occurs in this zone and induces ash melting. To prevent buildup of deposits from the molten material, waste heat is recovered immediately above the gasification zone. The gas is cooled to 350 to 400°F which prevents sintering of the ash on the refractory walls of the exit duct.

6.3.1.3 Waste Heat Recovery/Particulate Removal. The greater part of the sensible heat of the gas and fly ash is recovered/removed in a waste heat train that generates and superheats steam and preheats boiler feedwater. It is anticipated that 30 to 40 percent of the fly ash will be removed in the waste heat train. Cyclones or multiclones downstream of the waste heat recovery will remove an additional 45 to 50 percent of the fly ash. The fly ash from the waste heat train and cyclones will be combined with the gasifier bottom ash and gravity fed to a lock hopper for depressurization. Following depressurization, the combined ashes are pneumatically transported to char/ash storage using nitrogen as a carrier gas.

Final particulate cleanup of the product gas downstream of the cyclones occurs in a venturi scrubber. A recycle liquor contacts the gas and removes fine particulates and cools the gas below its dew point. The scrubber liquor reports to a settling vessel where the supernatant is recycled to the venturi. The bottoms of the settler are purged (~30 to 40 percent solids) and used as sluice liquor for the transport of the dry ash from storage to treatment and/or disposal.

6.3.1.4 Product Gas Desulfurization. The processing scheme for the product gas desulfurization has not been finalized.

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The selection depends upon a number of process and environmental factors including the sulfur content (organic and inorganic) of both the gasifer product gas and the refinery off-gas, the quantities of carbon dioxide (CO_2) in these streams, and the final sulfur requirements of the user refineries. However, based upon the projected characteristics of both product gases, it has been suggested that each gas be desulfurized prior to blending. The refinery off-gas will be treated in either an amine or carbonate scrubber while the quenched and particulate-free gasification product gas will be handled in a Rectisol unit. Since this analysis is concerned largely with the gasification complex and selection of the refinery gas cleanup has not been finalized, only the gasification product gas desulfurization process will be discussed at this time.

The Rectisol process operates at elevated pressure, typically 300 pounds per square inch gauge (psig), and uses methanol as its absorbent. In the first stage of the countercurrent scrubber, the bulk of the CO_2, practically all of the hydrogen sulfide (H_2S) and an appreciable amount of organic sulfur (COS, CS_2) are removed. The methanol is regenerated by two successive pressure reductions and flashing of dissolved gases. The flash gases are rich in H_2S and contain CO_2 as well. The regenerated methanol is recirculated to the first stage scrubber. In the second stage of the scrubber, the remaining CO_2 and practically all the residual organic sulfur compounds are removed from the gas by a fresh methanol wash. This methanol is sent to a conventional stripping column where the acid gas, mostly CO_2, is stripped from the solvent. The fresh solvent is recirculated to the second stage scrubber. Typically, the H_2S-rich off-gas is treated in a Claus plant where the gas phase sulfur is recovered as elemental sulfur, while the CO_2-rich gas is vented to the atmosphere.

6.3.2 Preliminary Assessment of Emissions, Effluents and Solid Wastes

In spite of a long history of operation, extremely limited environmental data exist on the Winkler gasification process; this lack of data is a major source of uncertainty regarding the environmental analysis of the process (Oak Ridge National Laboratory 1976; Banchik 1975).

A two-step approach is used to evaluate the environmental impact sources from the gasification facility. First, identify the production of environmentally significant species within the gasifier and follow the distribution of these species through the downstream processing. Specifically for the NRI project, the assessment of effluent production in the gasifier was based on analogy from other coal gasification processes. Second, consideration was given to the likely nature of the specific effluents, their control, and their ultimate disposition. With this philosophy in mind, priority sampling can be focused on the major process outlets and each of the major effluent/emission sources.

6.3.2.1 Identification of Air Emissions. Particulate emissions may be significant in the coal preparation area. The major sources include:

- Entrainment from the coal pile
- Loss during transport between unit operations
- Emissions during crushing, grinding and sizing
- Emissions during coal drying.

The first three sources are typical for coal-handling industries, and emissions can be readily estimated and controlled. Coal-drying emissions, on the other hand, will depend upon the extent to which drying is required and the process equipment utilized for this operation. The selection of tray versus fluidized bed driers will influence the particulate emissions from this operation. For either type of drying unit, the coal-drying temperature must be carefully controlled to less than 650 to 700°F to prevent the initiation of coal devolatilization. The evolution of coal-derived heavy hydrocarbons would preclude the use of conventional particulate control equipment and necessitate additional considerations regarding hydrocarbon control.

There are no air emissions or liquid effluents from the gasifier, although it is the effluent characteristics of the overhead product gas that dictate the nature of downstream air emissions and water effluents. The parameters of particular importance are the production of heavy hydrocarbons and the distribution of coal-bound nitrogen, sulfur, and trace elements in the gasifier.

The temperature characteristics of the Winkler gasifier and the injection of coal into the bottom of the fluidized bed preclude the production of significant heavy hydrocarbons. It is anticipated that any heavy hydrocarbons that escape the fluidized bed would be rapidly consumed by the above-bed injection of steam and oxygen. Thus, no significant heavy hydrocarbons are anticipated downstream of the gasifier.

Feed-coal nitrogen is primarily distributed among the char/ash, hydrocarbons, ammonia, hydrogen cyanide, and molecular nitrogen. Since heavy hydrocarbon production is negligible, the species of greatest environmental significance produced by the gasifier are ammonia and hydrogen cyanide.

Ammonia production has been documented for several gasification processes involving high-pressure, steam-oxygen systems (Table 6-11). Ammonia production in these systems ranges from 14 to 26 pounds per ton of moisture-ash-free (MAF) coal and represents approximately 40 to 95 percent of feed-coal nitrogen in low pressure, steam-air gasifiers. Explanations for the trends in ammonia production have been formulated, although several process variables such as carbon conversion and the percentage of steam in the gasifier are believed to be important. For example, there is a linear relationship between the fraction of feed-coal nitrogen converted to ammonia and carbon conversion in the Hygas gasifier (Massey and Fillo 1978). The conversion of feed-coal nitrogen to ammonia is a function of steam in the product gas of the Mond gas producer, which was designed to produce gas from coal by alternately injecting air and then steam into a fixed bed of coal; as the fraction of steam in the gasifier increases (due to either increased steam input or decreased steam decomposition), conversion of feed-coal nitrogen to ammonia increases

TABLE 6-11
SUMMARY OF AMMONIA PRODUCTION DURING COAL GASIFICATION

Process	Coal Type	Reactants	Pressure, atm.	Temp. °F	Ammonia Production lb/ton coal, MAF	Conversion of Feed Nitrogen %
Synthane[1]	Ill. No. 6	steam/oxygen	40	1300-1500	~20	73
	N.D. Lignite	steam/oxygen	40	1300-1500	~20	63
CO_2 Acceptor[2]	Lignite	steam	10	1500	17-26	95-98
Hygas[3]	Montana Lignite	steam/oxygen	70	900-1400	13	--
	Ill. No. 6	steam/oxygen	70	900-1400	15	--
Lurgi (dry ash)[4]	Ill. No. 6	steam/oxygen	20-30	1800-2500	16-18	42-46
Slagging Fixed Bed Reactor[5]		steam/oxygen	10-30	1800-2500	14-16	--

[1] Source: Reference (5).

[2] Source: Reference (8).

[3] Source: Reference (9).

[4] Source: Reference (10).

[5] Source: Reference (11).

for a constant carbon conversion of 92 to 94 percent (Bone and Wheeler 1907). Based on these observations, ammonia production in the Winkler gasifier is anticipated to be approximately 10 to 30 percent of the feed-coal nitrogen.

Hydrogen cyanide production generally represents less than 1 percent of the feed-coal nitrogen. Due to its environmental significance, however, detailed characterization of its presence has been a recent focal point in coal gasification. As shown in Table 6-12 hydrogen cyanide production ranges from 0.008 to 1.3 pounds per ton of MAF coal. These production figures are similar to those for coking of coal which yields approximately 0.02 to 0.05 pound per ton of MAF coal. In contrast to ammonia production, there is an apparent inverse trend in production of hydrogen cyanide with steam content in the gasifier which indicates that as steam content increases, hydrogen cyanide production decreases. Based on these observations, a hydrogen cyanide production in the range of 0.1 to 1.0 pound per ton of coal MAF is anticipated.

The distribution of feed-coal sulfur between the reduced (H_2S, CS_2) and oxidized (COS, SO_2) sulfur species is critical for the specification of appropriate control technology to assure regulatory compliance. Present estimations by Davy-McKee project H_2S and COS levels in the raw product gas of 3,000 to 6,000 and 500 to 1,000 parts per million volume (ppmv), respectively. This represents a proportion of conversion of feed-coal sulfur to H_2S and COS of 65 to 100 percent and 10 to 20 percent, as 92 percent of the feed sulfur may be present as H_2S and 6 percent as COS; the remainder reports to char and/or tar (Booz-Allen Applied Research, 1974). Prediction of this sulfur distribution is difficult since the attainment of chemical equilibrium between the

TABLE 6-12
SUMMARY OF HYDROGEN CYANIDE PRODUCTION DURING THE GASIFICATION OF COAL

Process	Coal Type	Characterization Basis	No. of Data Points	Cyanide Production, lb/ton, MAF
Synthane[1]	Illinois No. 6	o Raw gas quench liquor and quenched gas	5	0.04 ± 0.01
CO^2 Acceptor[2]	Lignite	o Raw product gas	4	0.01 ± 0.007
		o Gasifier samples[6]	1	0.30
			6	0.19 ± 0.07
			5	0.03 ± 0.02
		o Raw gas quench liquor and quenched gas	19	0.13 ± 0.07
Hygas[3]	Lignite	o Raw product gas	5	0.05 ± 0.04
			2	0.01 ± 0.01
			7	0.05 ± 0.05
			1	0.006
			3	0.09 ± 0.01
Lurgi (dry ash)[4]	Illinois No. 6	o Raw gas quench liquor	2	0.04 ± 0.02
	Illinois No. 5	o Raw gas quench liquor	2	0.03 ± 0.03
	Sub-bituminous	o Raw gas quench liquor	2	0.023 ± 0.024
	Pittsburgh	o Raw gas quench liquor	2	0.007 ± 0.001
Slagging Fixed Bed[5]	Lignite	o Raw gas quench liquor and quenched gas	1	1.3

[1] Pilot Development Unit - 20-40 lb/hr coal feed.

[2] Pilot Plant - 1-3 ton/hr coal feed.

[3] Pilot Plant - 3 ton/hr coal feed.

[4] Lurgi Westfield Semiplant.

[5] Pilot Plant - 1 ton/hr coal feed.

[6] Samples withdrawn from the gasifier at three different locations near the point of coal injection.

various sulfur species has not been documented. It is believed that the H_2S to COS ratio of the Lurgi gasifier (~15:1) is on the high end of the spectrum and that a 3:1 ratio may represent a lower limit. Consequently, the ranges of estimated conversion rates presented above seem reasonable; however, variation of the actual values could be significant with respect to environmental compliance of the proposed process.

The trace elements present in coal undergo a complex and poorly understood variety of physicochemical transformations in the temperature, pressure, and chemical environment of a coal gasifier. The end result is a partitioning of the elements between the bottom ash and the overhead raw product gas by volatilization, reaction, and condensation. The final partitioning, which is crucial in assessing the downstream processing fate of trace elements, varies widely for each element from less than 0.1 percent to over 90 percent volatilization. Environmentally significant elements which are expected to be highly volatile in a gasifier (about 50 percent or more of the coal element partitioning to the product gas) include antimony, arsenic, boron, chlorine, mercury, and selenium. Moderately volatile (roughly 10 to 30 percent volatilization) elements include cadmium, chromiun, fluorine, zinc, and possible beryllium and thallium. Environmentally significant elements with slight or negligible volatility (less than 1 percent reporting to the gas) include copper, lead, and nickel (Aul et al. 1979; Jonardi et al. 1979; Anderson et al. 1979; Carun and Massey 1978).

The volatilized elements are present in the raw gas as a variety of chemical species with physical and chemical properties and concentrations which will determine their fate in downstream processing units. Although measured speciation data are not available for raw Winkler product gas, thermodynamic equilibrium calculations have been made for Lurgi and other gasifiers which predict speciation for various elements (Anderson et al. 1979; Attari et al. 1976; Wilde and Halbrook 1977). For example, volatilized selenium is expected to occur primarily as H_2Se, arsenic as AsH_3, mercury as Hg(g), and boron as $B(OH)_3$ (Anderson et al. 1979). Speciation has both occupational health and processing significance; AsH_3, for example, is more volatile than halo-arsenic species (Perry et al. 1963) and has acute toxicity effects (American Conference of Governmental Industrial Hygienists 1971).

Air emissions represent the most significant environmental concern of the desulfurization operations. Both the CO_2-rich Rectisol off-gas and the Claus plant tail gas have the potential to emit hydrocarbon and/or sulfur emissions to the atmosphere. The CO_2-rich off-gas may contain significant quantities of COS (approximately 1/2 of the total COS produced in the gasifier), as well as hydrocarbons such as the methanol solvent. The Claus tail gas may contain excessive sulfur due to the formation of COS or CS_2 from trace hydrocarbons in the Claus reactor or as a result of catalyst fouling from heavy hydrocarbons and reduced sulfur removal. In either case, the use of a tail gas scrubber may be required to reduce exit sulfur levels to acceptable limits. The need for such a unit will be dictated largely by the level of H_2S and heavy hydrocarbons present in the CO_2-rich off-gas.

6.3.2.2 Treatment and Control of Air Emissions. In addition to fugitive emissions, the major potential air emissions sources from the gasification complex include (1) coal drying vent, (2) vent of nitrogen used to pneumatically transport lock-hopper ash to storage, (3) the CO_2-rich Rectisol off-gas, and (4) the Claus tail gas. The former two represent particulate emissions that can be handled by conventional particulate removal equipment, for example, baghouse filters. The latter two represent hydrocarbon and/or sulfur emission sources. Control of the heavy hydrocarbons by incineration has the potential to produce significant SO_2 emissions. Control of the SO_2 emission is generally treated using any one of a number of absorption/reaction processes. The nature of the control requirements will depend largely on the characteristics of the raw gasifier product gas and, specifically, on the distribution of feed-coal sulfur and nitrogen between H_2S and COS/CS_2 and NH_3 and HCN, respectively.

6.3.2.3 Identification of Liquid Effluents. Aqueous runoff from coal piles represents the most likely significant environmental liquid effluent from the coal preparation area. These effluents are not unique to coal gasification and have been dealt with previously by the mining and utility industries; however, with the recent concern regarding trace element contamination of wastewaters, the trace element content of these runoffs has become a major issue. A preliminary examination of the trace element content of raw coal provides an initial worst-case assessment of the potential for coal pile runoff to contribute trace metal contaminants to the plant wastewater discharge. Table 6-13 presents the distribution of several environmentally significant trace metals for some broad categories of American coals and a summary of coal leachates for these same constituents from selected eastern interior coals. It should be noted that the wide variation in leachate quality was attributed to coal type, particle size, and storage conditions.

As mentioned under Air Emissions, there are no liquid effluents directly from the gasifier, although the effluent

TABLE 6-13

SUMMARY OF SELECTED TRACE METAL CONCENTRATIONS IN RAW COAL AND RAW COAL LEACHATES[1]

	Concentration in Raw Coal PPMW[2]				Concentration in Raw Coal Leachates PPMW[3]		
Constituent	Min.	Max.	Mean[4]	StD. Deviation	Ill. No. 6	Ky No. 9	Pitts. No. 8
Iron	3400	43200	19200	790	7710	9850	296
Arsenic	0.5	93	14	18	0.15	9.1	0.016
Barium	ND[5]				<0.2	<0.2	<0.2
Cadium	0.10	65	2.5	8	0.27	0.17	0.010
Chromium	4	54	14	7	0.44	0.72	0.011
Lead	4	218	35	44	0.014	0.012	0.008
Selenium	0.45	8	2	1.1	0.44	0.83	<0.020
Silver	ND[5]				0.004	0.0001	<0.0001
Mercury	0.02	1.6	0.2	0.2	0.001	0.0002	0.0001

[1]Leachates and coal analyses were not performed on the same coal samples.

[2]Source: Reference (3).

[3]Source: Reference (4).

[4]Mean of 101 coal samples.

[5]ND = No Data.

characteristics of the overhead gas determine the nature of both downstream water effluents and air emissions. The major process liquid effluent originates from the venturi scrubber of this portion of the plant. It is here that the gas is contacted with a recycle liquor and cooled below its dew point. The scrubbing and cooling action of the liquor removes condensibles, particulates, and water-soluble gas-phase noncondensibles. The nature of this liquor depends upon the characteristics of the feed gas and the design of the scrubber. Based on the previous discussion regarding the character of the raw product gas, it is anticipated that the process liquor will have a very low organic content (including only minor amounts of phenol), and contain small amounts of hydrogen cyanide, various trace elements, and potentially significant amounts of H_2S and ammonia. The quantity of condensate and recycle liquor, as well as its pH, will dictate the actual levels of ammonia, hydrogen cyanide, H_2S and trace metals in the process liquor. Due to aqueous interactions of the various constituents, a variety of other species such as thiocyanate, thiosulfate, nitrates, and sulfates will likely also be present in the process liquor.

As presently proposed, there are no significant liquid effluents from the product gas desulfurization portion of the gasification facility. Should a tail gas scrubber be required for the Claus tail gas, it is likely that a liquid scrubber blowdown or scrubber sludge will be produced and required disposal (and possible pretreatment).

6.3.2.4 Treatment and Disposal of Liquid Efflents. The present plan for the disposition of the gasification plant wastewaters is discharge to the municipal sewage treatment plant. Although no specific pretreatment regulations exist for coal gasification, pretreatment of these wastewaters prior to discharge to the sewer will be required. Given the nature of the process wastewaters from coal preparation and waste heat recovery/particulate removal areas, the pretreatment operations will include (1) settling basin for solids removal; (2) sour water stripper for removal of ammonia, hydrogen sulfide, and hydrogen cyanide; and (3) trace element removal via precipitation, after which the wastewater can be used as cooling tower make-up or discharged directly to the sewer.

The need for hydrocarbon separation or a flotation unit is not anticipated due to the lack of heavy hydrocarbon production in the gasifier. If residual hydrocarbon is present, it will be diluted substantially upon discharge into the sewer and ultimately will be destroyed in the municipal treatment plant. Other constituents such as thiocyanate, thiosulfate, and free cyanide will also be removed in the geological system. Denitrification and fixed-cyanide removal, however, will not consistently occur and may cause discharges in excess of limitations for both ammonia and cyanide.

The need for the various wastewater treatment unit operations will be dictated by the quality of the wastewaters, which has not yet been adequately documented. The specific wastewater treatment technologies selected will dictate the secondary environmental impacts of the residual solids from the settling basin, the sour water stripper off-gas, and the sludge from trace element precipitation. The stripper off-gas can be incinerated, although it represents a potential source of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). The metal sludge will likely be treated as a hazardous waste, while the settled solids must be tested to assess their hazardous classification.

Should disposal of these wastewater streams to the Billings Sewage Treatment Plant prove infeasible, additional treatment will be required to allow discharge to the Yegen Drain. Federal and Montana water quality regulations relevant to wastewater discharge permitting were discussed previously.

6.3.2.5 Identification of Solid Effluents

It would be reasonable to expect the solid refuse from coal preparation to react similarly to the raw coal; this would imply a potential for trace element contamination of coal refuse leachates. The trace element concentration of the refuse and the ability to leach these elements from the refuse must be identified. Table 6-13 shows results of trace element analysis of the raw Westmoreland coal.

The gasifier ash is the only major discharge from the gasifier. It is removed and transported dry to a storage facility; however, ultimately it is contacted with the slurry from the particulate removal portion of the plant and sluiced to disposal. The trace element content of this ash and its leaching characteristics are important environmental parameters. Extensive trace element leaching of this ash could dictate its classification as a hazardous waste under the Resource Conservation Recovery Act (RCRA).

Extensive studies on other gasification ashes reveal that few of the ashes qualify as a hazardous material per the leach test proposed by RCRA (Luthy and Carter 1979; U.S. Environmental Protection Agency 1978). The response of each gasifier ash, however, may vary based on the nature of the feedstock and the gasifier process conditions. Consequently, only actual testing of each material can assure the appropriate classification of the ash. It should be noted that the overhead ash of the Winkler gasifier may have significantly different leaching characteristics than the bottom ash due to the extreme temperatures in the upper zone.

The high above-bed temperatures may enhance trace element volatilization and, should these elements pass through a molten state and resolidify, the remaining trace elements may be significantly less mobile and represent significantly less of a leaching problem. These considerations are particularly important since approximately 70 percent of the gasifier ash is expected to leave the gasifier via this route.

The elemental sulfur by-product and spent catalyst from the catalytic converters of the Claus plant are the major solid effluents from product gas desulfurization. Given the basic lack of heavy hydrocarbons in the gasification product gas, it should be possible to attain high-purity elemental sulfur which could be sold, thereby eliminating the disposal issue. The spent catalyst, however, will require disposal. This material will probably be addressed by RCRA; however, the relatively small quantities of material generated could escape the full requirements of the Act.

6.3.2.6 Treatment and Disposal of Solid Effluents

The major solid effluents from the gasification plant include any coal pile refuse and particulate runoff to the containment basin, the by-product sulfur, the solids from the wastewater settling/treatment basin(s), and the overhead and bottom gasifier ash. The major concern with all these materials is their potential for classification as a hazardous substance under RCRA. This classification is based on the leaching of specific heavy metals from these materials using an acetic acid solution. A hazardous classification dictates stringent packaging, labeling, transportation criteria, and disposal at a hazardous waste site; there is only one such site currently approved in Montana. On the other hand, a nonhazardous classification would permit disposition of these materials in the mine or any other authorized disposal site.

At this time, it is anticipated that none of these solids will be classified as hazardous (excluding the sludge from trace element precipitation which was discussed as a secondary environmental impact of wastewater treatment operations). Verification of this assumption will require actual testing, but preliminary assessments predict a pure, saleable by-product sulfur, and coal refuse and ash with trace elements which are basically immobile. The overhead ash and bottom ash may be tested separately due to the differences in their temperature histories. In the event that they are classified differently, it may be feasible to handle them separately to minimize total treatment/disposal quantities and costs.

6.4 PREOPERATIONAL ENVIRONMENTAL MONITORING NEEDS

A preliminary environmental information assessment was used to determine which environmental parameters will not be satisfied by the existing data base and will require preoperational monitoring. Following is a list of environmental monitoring activities needed to meet applicable environmental regulations and to secure the necessary permits.

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6.4.1 Air Quality

The data base for air quality is excellent in the Billings area including both state-operated and industrial air monitoring stations; no additional preoperational air resources data collection is expected to be needed as input to air quality modeling for this project. Components of the proposed air quality program include a Surface Fugitive Dust Source Inventory, Sequential VALLEY modeling, Multiple Point Source Diffusion Modeling, ERT Air Quality Modeling, regional scale modeling, visibility modeling for Class I areas (VIRAD), and an evaluation of secondary impacts.

6.4.2 Water Quality

The currently proposed wastewater disposal method is to discharge to the Billings Municipal Sewage Treatment Facility. However, the Yegen Drain, adjacent to the gasification facility, is being investigated as a possible surface discharge location should sewer system discharge prove infeasible. Water quality data for the Yegen Drain is limited, so the water quality assessment and permitting program will be based on flow and quality data on the Yellowstone River which is considered to be an adequate data base to comply with Montana Pollution Discharge Elimination System (MPDES) requirements.

6.4.3 Solid Waste Disposal

Solid waste disposal planning will require generation of data on quantities, composition, leachability, and hazardous properties of any solids to be disposed. If no hazardous properties are detected, there are no special restrictions on disposal. If preliminary worst-case evaluation of feed-coal trace constituents suggests the ash may be classifiable as hazardous under the guidelines of the Resource Conservation and Recovery Act (RCRA), an assessment of feed-coal and gasifier ash for trace element leaching characteristics will be made. An acetic acid leach test (or other approved procedure) will be used to make this determination. Gross trace element laboratory analyses have been conducted on the Westmoreland coal; however, since there is no Winkler gasifier in operation in the United States, an alternative ash evaluation must be employed. Coal and ash samples will be collected from an operating Winkler gasifier in Turkey and analyzed to establish estimators for distribution of trace element constituents and differences in trace element leachability (due to physico-chemical reactions in the gasifier) between top and bottom ash.

6.4.4 Socioeconomic, Biological, and Cultural Resource Assessment

Sufficient socioeconomic and biological data exist for the Billings area to assess the impacts of the project on the human and biological environment. A cultural resources site survey will be conducted to verify compliance with the Historic Preservation Act of 1966.

6.4.5 Noise

Inadequate ambient noise baseline measurements and receptor source identification exist in the immedate vicinity of the project site. A separate data collection program for noise is proposed.

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