7. COST ESTIMATES

7.1 CAPITAL COST ESTIMATE

The capital cost information included in this report was
obtained from engineering-construction 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. Two major subsystems, gasification and gas treat-
ment, were estimated due to lack of actual construction
experience in the United States and application of processes.
In the information that follows, capital investment costs are
treated in two major parts; OSBL and ISBL, since two contrac-
tors were used and each used different scope of estimates.

7.1.1 Capital Cost Breakdown

Table 7-1 provides a capital cost summary. Appendix E
provides a breakdown of cost of the OSBL major equipment.
Cost estimate details for the ISBL major equipment are given
in Appendix F.

7.1.1.1 Land. The land purchase price of $600,000 is based
upon a negotiated price and option to purchase in the amount
of $40,000 per acre for the 15-acre project site.

7.1.1.2 Total Installed Cost. Total installed cost of the
process plant and offsites is $46,985,206. Detail estimate
is given below.

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TABLE 7-1

CAPITAL COST SUMMARY (1983)

CAPITAL COST ITEM	ESTIMATE	DOLLAR TOTAL	PERCENT TOTAL
Land	600,000		1.1
Working Capital	500,000		0.90
		1,100,000	2.0
Total Installed Cost			
ISBL	8,850,000		16.1
OSBL	33,695,206		16.1
Project Contingency	4,440,000		8.1
		46,985,206	85.3
Initial Catalyst,			
Chemicals and			
Operating Supplies	250,000		0.45
		250,000	
Start-Up			
ISBL	250,000		0.45
OSBL	250,000		0.45
		500,000	0.9
Owner's Cost			
Finance and Legal	300,000		0.55
Market Analysis	116,000		0.2
Environmental and			
Permits	225,794		0.4
Interest During			
Construction	5,647,000		10.2
		6,288,794	11.35
TOTAL CAPITAL COST		$55,124,000	100.0

7.1.1.3 <u>Paid-up Royalties</u>. Royalties for the gas processing is included in the gas treatment capital cost estimate and not identified separately. Agreement with the gasification process grantor is that there will be no royalties for the gasification process.

7.1.1.4 <u>Initial Catalysts, Chemicals, and Operating Supplies</u>. Materials consumed in the processing operation is estimated to be $250,000. When this category is not identified separately, it is included in operating or working capital.

7.1.1.5 <u>Working Capital</u>. Funds required for cash on hand, materials purchased, inventories, stocks of chemicals, catalysts, tools, spare parts, etc., is estimated to be $500,000.

7.1.1.6 <u>Start-up Cost</u>. Operating costs necessary to bring the plant on-stream is estimated to be $500,000. This figure includes operator training, equipment testing, and additional capital required to correct problems.

7.1.1.7 <u>Contractor's Home Office Cost and Fee</u>. When not identified separately, this item is included in the capital cost for the subsystem. It was not possible to fully identify all of these costs because firm price bids were provided by one contractor.

7.1.1.8 <u>Owner's Cost</u>. Owner's cost for market analysis, finance and legal, environmental studies, interest during construction, and obtaining construction permits is estimated to be $6,288,794.

Other costs incurred for process selection, site selection, and feasibility studies were cost shared by this government

grant or treated as sunk costs by the company, and not considered for recapture in the project economic analysis.

7.1.1.9 Project Contingency. Based on accuracy analysis of the cost estimates, a contingency of $4,440,000 is added to cover uncertainties during project execution and price escalation.

7.1.1.10 Process Contingency. Due to process operating experience of the contractors and process guarantees, a process contingency is not considered appropriate.

7.1.2 ISBL Capital Cost Estimate

The ISBL capital cost estimate is of a preliminary or budget classification with a gross accuracy range of plus or minus 20 percent. The estimate is based upon:

- Equipment list
- Equipment motor list
- Preliminary plot plan and elevation
- Process flow diagrams
- P&ID's
- Vendor quotes
- Material take-offs

Table 7-2 gives a summary of the ISBL capital costs.

7.1.2.1 ISBL Project Schedule. The following project schedule was assumed, using historical information of projects of the same approximate magnitude.

TABLE 7-2

ISBL COST SUMMARY

COST ITEM	DOLLAR VALUE	PERCENT TO ISBL T.I.C.
Equipment	$ 1,950 M	17.0
Bulk Materials	1,490	12.9
S/C Materials	280	2.4
S/C Labor (26M-man-hours)	690	6.0
D/H Labor (74M-man-hours)	860	7.5
SUBTOTAL DIRECT COSTS	5,270 M	45.8
Field Indirects	1,460 M	12.7
Professional Services	2,010	17.5
Insurance	110	0.9
Start-up	250	2.2
SUBTOTAL	9,100 M	.79.1
Escalation	1,390 M	12.1
Contingency	1,010	8.8
TOTAL INSTALLED COSTS	$11,500 M	100.0

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Engineering Start	1/01/81	
Engineering Completion	7/01/82	18 Months
Procurement Start	8/01/81	
Procurement Completion	11/01/82	15 Months
Construction Start	11/01/81	
Construction Completion	11/01/83	24 Months
TOTAL PROJECT		34 Months

7.1.2.2 ISBL Estimate and Procedure

Equipment

Equipment pricing for this project is based on single-source
vendor quotations specifically obtained for this project and
in-house pricing and factoring.

The major equipment pricing for this project is summarized as
follows:

	Percent
● Single Vendor Quotes	92
● In-House Pricing	6
● Factored from In-House Data	2
TOTAL EQUIPMENT	100

Bulk Materials

Bulk material quantities were developed through semirigorous
take-offs from the reference drawings and documents by the

take-off groups. The following techniques were employed by the individual disciplines.

- Piping ($351M Direct Material)

  Linear footage of pipe was tabulated by size and metallurgy. Valves were counted and listed by size and metallurgy. Fittings, flanges, and shop fabrication costs were factored using relationships established from the plot plan and Davy McKee's historical experience. Specialty items (for example, orifice flanges, temporary strainers, monitors, etc.) were taken off sketches in detail based on the P&ID's. Preliminary estimating isometric sketches were made for stainless steel lines only. Pricing was based on in-house information.

- Civil Structural ($539M Direct and S/C Material)

  Structural steel quantities for the pipe racks and structures were scaled from the plot plan and elevation drawing, based on a pounds per linear foot per member.

  Concrete filled pipe piles (30 feet long, 10-inch diameter) were used for the reactor and truck loading structures, along with the pipe rack and conveyor bents.

  Equipment, structures, pipe rack, and conveyor bents foundations were assigned required cubic yards of concrete based on size and weight.

  Electrical control room was priced on a square foot basis.

Reactor structure siding was scaled off of the elevation drawings and priced on a square foot basis.

All civil/structural pricing was based on in-house information.

● Electrical ($102M Direct and S/C Material)

Major electrical equipment requirements were tabulated from motor horsepower and equipment list. Power and control devices, lighting fixtures, receptacles, and switches were tabulated from preliminary equipment layout plot plans and estimate sketches.

● Instruments ($563M Direct Material)

Instrument device quantities were tabulated from P&ID's and equipment list. Instrument bulk material quantities for instrument piping, tubing, mounting, and supports were determined from typical installation details and preliminary plot plan. Pricing was based on in-house information.

● Insulation/Fireproofing/Painting ($25M Direct and S/C Material)

Piping insulation was derived on a lineal footage technique. The coal-feed bins (BN-102 A, B) were the only equipment items insulated and this price is included with equipment.

The first 16 feet of the reactor structure was fireproofed. This quantity was based on a square footage of fireproofing per linear foot of structural steel member.

Piping painting was factored based on the linear footage of pipe. Equipment and structural steel painting were factored based on their weight. The settler tank (T-102), Coal-Feed Bins (BN-102 A, B) and the gasifiers (R-101 A, B) are the only equipment items painted.

All insulation, fireproofing, and painting prices were in-house.

Labor Direct Hire (74M-Man-hours, $860M)
Subcontract (25M-Man-hours, $692M)

Generally all direct labor man-hours, both direct hire and subcontract, were developed in the same manner. The quantities determined from the adjusted/conditioned material take-offs were man-houred using Davy McKee Base 1.0 units. The base 1.0 labor man-hours generated were then adjusted to "at-site" man-hours using a productivity factor of 1.40. This productivity factor was taken from an independently published survey for the Billings, Montana, area.

Direct hire labor was priced using a composite project wage rate that was developed using a historical craft mix from a similar type project. Subcontract labor was priced using a built-up S/C wage rate.

Miscellaneous direct hire labor man-hours were included in the estimates at seven percent of the total direct hire labor man-hours for each phase. These man-hours were included for the following:

- Clean-up
- Show-up

- S/C assistance
- Scaffolding
- Equipment protection

Field Indirects ($1460M)

The field indirects estimate includes construction super-
vision, field office labor, auxiliary labor, temporary con-
struction, construction equipment, small tools, consumables,
field office cost and related payroll burden.

The field indirects costs for this project was developed on a
percent-to-direct-labor basis using historical data from com-
pleted projects.

Payroll burdens for direct hire labor, auxiliary labor and
field office labor were included at 52 percent of direct labor
which includes 14.8 percent for craft fringes and 37.2 percent
to cover taxes and insurance for direct and indirect labor.

Professional Services

Professional services for this project were developed as a
percentage of current direct cost by using historical infor-
mation from completed projects.

Fringes and overhead were developed using current DCAA audited
rates. Home office fee was established using government fee
guidelines.

Insurance ($110M)

Insurance coverages included in the estimate cover general
liability, automobile liability, installation all risk, and
bare rental coverage. The cost of insurance was included as
a percentage of the "Total Installed Cost."

Taxes (0)

There are no applicable sales or use taxes in Montana.

Royalties

As per agreement with Northern Resources Incorporated, no
technology license fee is required on the Winkler gasifier.

Start-up

An allowance of $250M was included based on providing 76 man-
weeks of start-up services and includes salaries, fringe
benefits, overhead, fee, out-of-pockets, and escalation.

7.1.3 OBSL Capital Cost Estimate

The OBSL capital cost estimate is a combination of firm fixed
price and budget-type estimate. The gas treatment system is
of the budget estimate category. The remainder is firm fixed
priced. The cost estimate is based upon:

- Preliminary designs
- Equipment lists
- Process flow diagrams
- Vendor quotes
- Material take-offs

Table 7-3 gives a summary of OSBL capital costs.

7.1.3.1 OBSL Project Schedule. The following project
schedule was assumed, using historical data from projects of
approximate scope and magnitude.

Engineering Start	1/01/81	
Engineering Completion	1/01/82	12 Months
Procurement Start	5/01/81	
Procurement Completion	7/01/82	14 Months
Construction Start	5/01/82	
Construction Completion	12/31/83	20 Months
TOTAL PROJECT		36 Months

7.1.3.2 OSBL Estimate and Procedure

Equipment

Equipment pricing for the project is based upon vendor quota-
tion specifically written and obtained for this project. All
of the major equipment pricing was obtained by written quotes.

Bulk Materials

Bulk material quantities were developed by rigorous take-offs
from the project preliminary drawings. The following tech-
niques and procedures were used by the various disciple take-
off groups.

●   Earthwork and Concrete

     Surface area of earthwork and roads were scaled from
     the plot plan drawings. Pricing was based on
     in-house data for similar work.

TABLE 7-3

OSBL COST SUMMARY

ITEM		ESTIMATE	PERCENT To OSBL T.I.C.
Earthwork and Concrete		3,683,511	10.2
Electrical System		1,891,024	5.3
Structural Steel and Buildings		2,361,826	6.4
Instruments and Controls		1,096,749	3.0
Major Equipment		6,882,073	19.1
Insulation		530,575	1.5
Piping System		2,927,769	8.1
Painting		175,400	.5
Gas Transmission		6,624,100	18.4
Gas Treatment:		7,707,000	21.4
Refinery Gas	2,424,000		
Coal Gas	5,283,000		
		33,835,273	93.9
Construction Fee		992,973	2.8
		34,828,000	96.7
Engineering and Procurement		3,621,206	10.1
		38,449,206	106.8
Contingency		2,040,000	5.7
		40,489,206	112.5
Coal Handling Deduction		(2,435,000)	(6.8)
Steam Generation Deduction		(2,319,000)	(6.4)
		35,735,206	99.3
Start-up		250,000	.7
		$35,985,206	100.0

Concrete volumes were calculated from the floor
dimension, typical footings and foundations, and
size and weight of equipment. Pricing was based
upon in-house data.

- Structural Steel and Buildings

Quantities of structural steel for pipe racks and
structures were scaled from the preliminary drawings.
Pricing was based on pounds per linear foot and
in-house and vendor data. Square footage of build-
ings were scaled from the preliminary drawings.
Pricing was based upon the square footage of similar
type buildings.

- Piping System

Linear footage of pipe was scaled from drawings and
tabulated by size and specification. Valves were
counted and listed by specifications. Fittings,
flanges, and fabrication costs were factored, based
on company experience. Pricing was based on in-house
and vendor data.

- Electrical Systems

Electrical material quantities were tabulated from
motor horsepower, equipment list, and scaling from
preliminary drawings. Power and control devices,
lighting, receptacles, and switches were taken off
the preliminary drawings and factored. Pricing was
based upon vendor and in-house data.

Instrumentation and Controls

Quantities of instrument devices were tabulated from the
preliminary drawings. Instrument piping, tubing, mounting and
supports were obtained from typical installation details and
scaling from the preliminary drawings. Pricing was based on
vendor information.

Insulation

Linear footage of piping insulation was obtained by scaling
the preliminary drawings. Pricing was based on vendor and
in-house data.

Painting

Quantities for painting were based on linear footage of piping
and square footage of flat surface areas. Pricing was based
on vendor data.

Transmission Pipeline

Quantities of pipe was determined by scaling maps. Road
crossings were determined by counting. Pricing was based on
in-house and vendor data.

Gas Treatment

A budget type estimate for gas treatment facilities was based
upon gas characteristics and flow quantities. Pricing was
based on in-house and vendor data. To permit definition of
the refinery off-gas treatment cost, the estimate is divided
into two parts: coal gas and refinery gas.

Labor

Labor quantities were developed from the material take-offs
and adjusted for the project area.

Engineering, Procurement and Management

Engineering and procurement costs were developed based on a
count of drawings required and percentage of direct costs by
using in-house data from completed projects. Burdens and
overhead were applied at current audited rates.

Construction Management and Supervision

Construction management costs were developed as a percentage
of direct costs based on historical in-house data.

Construction Fee

The construction fee was developed as a percentage of force
account direct costs.

7.1.3.3 Capital Savings Adjustments. Subsequent to the com-
pletion of the preliminary engineering and cost estimates a
decision was made to reduce capital costs and improve project
economics. Due to study cost constraints, the changes were
reflected only on the most important drawings and documents.
The cost estimate was revised to show a net deduction for each
change.

Coal Handling

To reduce coal storage and handling facilities cost, a change
was made to share the Montana Power Company, Corette Plant

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coal receiving and storage facilities. By sharing these
facilities the coal hopper, storage silo (13,000T), some con-
veyors and other auxiliaries could be eliminated. To complete
the coal handling link, a conveyor would be required between
the plants. This change resulted in a new deduction of
$2,435,000.

Steam Generation

To reduce steam generation and feedwater treatment costs, a
change was made to purchase steam and condensate from the
Corette Plant. The auxiliary boilers and associated equipment
were eliminated. A pipeline was added to transport steam to
the project site. This change resulted in a net deduction of
$2,319,000.

7.2 OPERATING COST ESTIMATE

The operating cost estimate is based upon 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 7-4 provides a summary of operating and
maintenance costs. Costs were based on current 1980 prices
and escalated at 10 percent per year to 1984.

7.2.1 Feed Materials

Feed materials consist of coal, oxygen, and refinery gas. The
quantity of coal was detemined from a supplier's quote. The
quantity of oxygen was determined from the material balance.
The oxygen price was obtained from a vendor based on over-the-
fence sale to the project. The quantity of refinery gas was

TABLE 7-4

OPERATING COST ESTIMATE (1984)

ESTIMATE BASE

COST ITEM	UNIT	QUANTITY	PRICE	ANNUAL COST
Feed Materials				
Coal	Ton	155,125	17.57	2,725,422
Refinery gas	10^6 Btu	1,606,000	2.66	4,278,544
Oxygen	Ton	66,000	49.78	3,285,440
				10,289,406
Catalysts and Chemicals	l.s.	l.s.	l.s.	381,015
Utilities				
Water and Sewage	M gal	52,560	0.56	29,242
Nitrogen	Ton	25,000	6.60	165,000
Electricity	KwH	8,000,000	.06	440,000
Steam	M lbs	350,400	1.67	585,640
				1,219,882
Operating Labor				
Operators Man Shift per year		21.25	19,800	420,750
Shift Supervisor per year		4.25	24,200	102,850
				523,600
Maintenance				
Labor Man Shift per year		3.00	19,800	59,400
Materials	l.s.	l.s.	l.s.	622,160
				681,560
Administration and Overhead				
Plant Manager person		1.00	44,400	44,400
Process Engineer person		1.00	33,300	33,300
Clerk-Typist person		1.00	13,200	13,200
Overhead	l.s.	l.s.	l.s.	110,000
				200,900
Fringe Benefits Salaries	673,900	26%		172,304
Local Taxes and Insurance	l.s.	l.s.		1,464,100
				14,932,767

obtained by subtracting produced gas from estimated demand.
Refinery gas price was estimated based on discussions with the
potential supplier.

7.2.2 Catalysts and Chemicals

Catalysts and chemicals were determined by factored estimates
based on size of using equipment and current prices.

7.2.3 Utilities

Quantities for water and sewage, nitrogen, electricity, and
steam was derived from the material balance. Prices were
obtained from suppliers in current 1980 prices and escalated
to 1984 at 10 percent per year escalation.

7.2.4 Operating Labor

Operating labor was based upon an analysis of each shifts
requirements. One operator is required for coal conveying,
drying, dry coal storage, and feeding coal to the gasifier
hoppers. One operator is required for gasifier operation,
waste heat recovery, and char removal. One operator is
required for gas treatment and compression. One helper is
required for each shift. One operator is required for the
control room. One supervisor is required for each shift.
Annual shift requirements is 4.25 per position.

7.2.5 Maintenance

Analysis of maintenance requirements showed the need for one
pipefitter, one electrical/instrument man and one helper.
Maintenance materials was factored from plant cost.

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7.2.6 Administration and Overhead

Analysis of overhead and administration functions indicated a requirement for a plant manager, process engineer, and clerk-typist. Miscellaneous administrative supplies, materials, and corporate burden was estimated.

7.2.7 Fringe Benefits

Fringe benefits and payroll taxes was estimated to be 26 percent. Sick leave and vacation is not included since salaries include these costs.

7.2.8 Local Taxes and Insurance

Local taxes and insurance were factored from plant cost.

7.2.9 Royalties

All royalties are paid-up and not applied to operations.

7.2.10 Waste Disposal

Sewage disposal is included with water cost. Solid waste disposal was not considered since ash, the major solid waste, is planned to be sold. No credit is taken for ash or sulfur, also to be sold.

8.   ECONOMIC ANALYSIS

8.1   INTRODUCTION

This section of the report presents an analysis of the economic feasibility of the Billings MBG Project. The approach to determining economic feasibility was to determine the MBG selling price that would meet all expenses and recover all investments 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.

8.2   ECONOMIC ANALYSIS PARAMETERS

Table 8-1 summarizes the data used in the economic analysis of the Billings MBG Project.

8.2.1   Sponsor

The sponsor of the project is a group consisting of private commercial companies with government support in the form of an alternate fuels production program grant and loan guarantees.

8.2.2   Dollar Method

Then-current dollars are used in all financial analysis. Prices are escalated to the current year to account for inflation.

TABLE 8-1

ECONOMIC ANALYSIS DATA SUMMARY

SPONSOR   Private

DOLLAR METHOD   Then-current

BASE YEAR ESTIMATES

Dollar Year for all Base Data	1984
Estimated Construction Costs	$55,124,000
Depreciable Plant Costs	$53,658,000
Annual Operating Costs	$14,932,767
Annual By-Product Revenue	None Taken
Annual MBG Output	$3,650,000 \times 10^6$ Btu

ANALYSIS PARAMETERS

Schedules		Dates	Years
Construction		11/81 - 12/83	2.17
Operation		1/84 - 12/03	20
Retirement:	Equity	1/84 - 12/03	20
	Debt	12/84 - 12/03	20

Capital Expenditure Rates

- 1981 - 10%
- 1982 - 38%
- 1983 - 52%

Plant Start-Up Rate   100% - 1984

Discount Rates

Low Interest Equity Advance	5%
Construction Loans	17%
Debt Financing	14%
Equity Financing	20%
Overall Project Rate	11.4%

TABLE 8-1 (Continued)

ECONOMIC ANALYSIS DATA SUMMARY

Financial Structure

    Debt   75%
    Equity 25%

Escalation Rate

    General Rate   10%
    Refinery Gas   5%

Depreciation Method

    Tax Life   20 years
    Method   Straight Line

Tax Rate and Schedules

    Effective Income Tax   50%
    Federal Income Tax   43%
    State Tax   7%
    Investment Tax Credit   20%
    ITC Claim Schedule   1984 with 7 years carry forward
    Other Tax Credits   None

8.2.3 Base Year Estimates

All base year figures are expressed in January, 1980 dollars. Estimated construction costs and depreciable plant costs were taken from Table 7-1. Depreciable plant costs were calculated by subtracting nondepreciable costs from total capital cost. Annual operating cost was taken from Table 7-5. By-product revenue was not considered although it is anticipated that elemental sulfur, ash, and char will be sold. Annual MBG output is 100 percent of design output.

8.2.4 Analysis Parameters

8.2.4.1 Schedules. The construction schedule was taken from Section 7 by combining the ISBL and OSBL construction schedules proposed by the contractors. The operations schedule was determined by assuming a twenty-year project life. Retirement of equity is treated as occurring at the end of the project life. Debt is amortized over the twenty-year project life.

8.2.4.2 Capital Expenditure Rate. Based on the project schedule, the following capital expenditures are anticipated: 1981 - 10 percent, 1982 - 38 percent, 1983 - 52 percent.

8.2.4.3 Plant Start-Up Rate. Plant start-up is scheduled for late 1983 with 100 percent production reached on January 1, 1984.

8.2.4.4 Discount Rates. The interest rate for the low interest equity advance will be 5 percent. The interest rate for the construction loan was assumed to be 17 percent based on conversations with bankers. Debt financing was assumed to be 14 percent based on a current rate of 16 percent with a 2 percent point discount for government or joint venture

partners guarantee of the loan. A 20 percent interest rate was used for equity financing. The overall project rate was calculated to be 11.4 percent, a weighted average based on the debt equity ratio and after tax (.75 x .17 x .5 + .25 x .20 = .06375 + .050 = .11375 = .114).

8.2.4.5 Financial Structure. Based on discussion with bankers and company management, the financial structure of 75 percent debt and 25 percent equity was chosen.

8.2.4.6 Escalation Rate. A general inflation rate of 10 percent was used through the cash flow analysis except for escalation of refinery gas. A rate of 5 percent was assumed for this item.

8.2.4.7 Depreciation Method. A tax life of 20 years was assumed. Since the expected salvage value is less than 10 percent, salvage value was assumed to be 0. The straight line depreciation method was chosen to provide maximum tax benefits in the later years of the project. This is optimum because of leverage (interest deductions), investment tax credits, and lack of other income.

8.2.4.8 Tax Rates and Schedules. An effective income tax rate of 50 percent was calculated based on a federal rate of 43 percent and a state rate of 7 percent. Investment tax credit was taken at 20 percent, 10 percent general credit plus 10 percent for energy investment. Although the general investment tax credit expires in 1981, historically Congress renews it. It was assumed that a new tax credit would be passed equal to the present one. For investment tax credit purposes, it was assumed that the plant will go on line in January, 1984, thus 1984 will be the first year for the credit. A seven-year carry forward period was assumed based

on current laws. No other tax credits were assumed or taken. Current prices for uncontrolled domestic crude exceed the cut-off point for the alternate fuels tax credit contained in the Windfall Profits Tax Bill.

8.3 INVESTMENT PATTERN

The methodology used to develop the project investment pattern was to treat investment in two phases. The first phase is preproduction and the second, production. The preproduction phase includes engineering, procurement, and construction and start-up. The production phase starts at the full attainment of 100 percent production capability and extends for the twenty-year project production life. The rationale for this methodology is that the sponsoring company has no other income to take advantage of the construction interest deductions. If carried forward as an operating loss against future income, significant investment tax credits would be lost. The most advantageous method of financing construction would then be for the joint venture shareholders to borrow the construction funds and take the annual interest expense as a deduction against their income. The joint venture shareholders would pass the tax savings to the project through a lower effective interest rate for the construction period. When the plant reaches production, the joint venture company will then assume the long-term debt repayment and the joint venture shareholders will retain the equity portion of the capital structure.

Table 8-2 shows the capital expenditures and investment pattern. The low interest equity advance will be used for detailed engineering and will be expended during 1981. Expenditures of other funds occur during 1981 through 1983. The expenditures are prorated on a 75 percent debt, 25 percent

TABLE 8-2

CAPITAL EXPENDITURE PATTERN

$(\$ \times 10^6)$

CONSTRUCTION FINANCING	1981	1982	1983	TOTAL
Government Grant	3.8	—	—	3.8
Private				
Debt (75%)	.825	14.10	19.35	34.275
Equity (25%)	.275	4.70	6.45	11.425
	4.90	18.80	25.80	49.500
Interest				
Government Grant (5%)	.095	.195	.205	.495
Private (11.4%)	.063	1.205	3.884	5.152
	.158	1.400	4.089	5.647
Total Investment	5.058	20.200	29.889	55.147

LONG-TERM FINANCING	AMOUNT
Government Grant	$ 4,295,000
Debt	38,139,000
Equity	12,713,000
	$55,147,000

equity contribution basis. During 1981, expenditure will be
made to acquire land and engineering work. Expenditures for
1982 and 1983 will be made for procurement and construction.
Interest costs were calculated based on level monthly expendi-
tures thus the interest charge for the year would be the
stated interest rate times one-half of the annual expenditure.
Interest rates were taken from the economic analysis param-
eters, Section 8.2. Interest was accumulated, compounded and
rolled into the construction cost to give a total capital cost
of $55,147,000 (rounding off of numbers for this calculation
causes slightly different total capital cost than shown in
Table 7-1). When production is reached, the interim financ-
ing is converted to long-term debt and assumed by the joint
venture company. The joint venture shareholders retain an
equity position of $12,713,000.

8.4 MBG PRICING

The methodology used in pricing the MBG was to consider only
project requirements and not allow the price to be influenced
by market condition. The price must meet all expenses
incurred by the project, including debt principle repayment.
The pricing approach was to project the first operating
year's costs and divide by units produced to find the
required selling price. This initial selling price would
then be escalated annually, based on cost escalation.

Table 8-3 provides the calculation of the initial MBG sales
price to cover all incurred cash outlays for the year.
Operations costs were taken from Section 7 of this report.
Interest was determined from the long-term debt shown earlier
in this section, Table 8-2. These cost items were supposed
to obtain total expected 1984 costs. Depreciation was not
considered since it does not represent a real cash outflow.

TABLE 8-3

MBG INITIAL SALES PRICE 1984

OPERATIONS COST	1984 EXPENSE (Millions
Feedstocks	
Coal	$ 2.73
Refinery Gas	4.27
Oxygen	3.29
Other Operating Costs	
Interest	
Government Grant for Engineering	.22
Private Debt	5.34
Total Costs	20.49
Plus Debt Principle	1.20
Required Revenue	$21.69
÷ Sales 3.65 million mm Btu	$ 5.9425
Round-up	$ 5.95 per mm Btu

Principal reduction was added since it is a real cash outlay. Taxes were considered and determined that they would be zero since the first year price would be essentially a breakeven case. A total required revenue of $21.69 million was calculated. This figure was divided by expected sales to determine the unit price. The unit price was rounded up to $5.95 per million Btu since conventional rounding would cause a selling price that would not cover costs ($5.94 less than $5.9425).

Cost escalation was examined to determine a percentage escalation for the MBG price. In the first years it was found that total costs escalated at about 6 percent per year. In the final project years costs escalated at 8 percent. The cost escalation increased because decreasing interest costs shifted more weight to the costs influenced by the assumed 10 percent inflation rate. To prevent steady declining profits in the final years, the 8 percent escalation rate was selected. Thus, profits are expected to steadily rise, then flatten out in the final years.

The initial selling price of $5.95 per mm Btu was escalated at 8 percent resulting in a set of prices that were used to determine annual revenues. When the internal rate of return was calculated, a 16.79 rate of return on investment was found. Since this is below the required rate, the initial price was increased to $6.10. A discounted rate of return of 20.72 percent was calculated which meets the minimum 20 percent rate required.

8.5 CASH FLOW SCHEDULE

The cash flow schedule presents a schedule of annual disbursements and receipts for the various project accounts. Table 8-4 provides the cash flow schedule for the operating

period. The schedule for the capital investment period is provided in Table 8-2. The data needed to develop the operating cash flow schedules is shown in Table 7-5. In preparing the cash flow schedules, the following general assumptions were made:

- No cash contributions are made by investors other than specified in the capital investment pattern.

- Each annual account is treated as a discrete end-of-year transaction.

- Escalation of costs estimates and prices is applied at the beginning of the year for the entire year.

- The plant is assumed to operate at 100 percent capacity for the entire year.

- Equity is recovered through depreciation and salvage value.

- Depreciation is treated as a cash flow item.

- MBG price is a single price for the year, expressed in then-current dollars.

8.5.1 Revenue

Determined by multiplying the annual MBG price per unit times the units sold. One hundred percent, 3,650,000 mm Btu, is assumed to be sold each year.

TABLE 8-4
BILLINGS MBG PROJECT
CASH FLOW SCHEDULE
($ x 10^6)
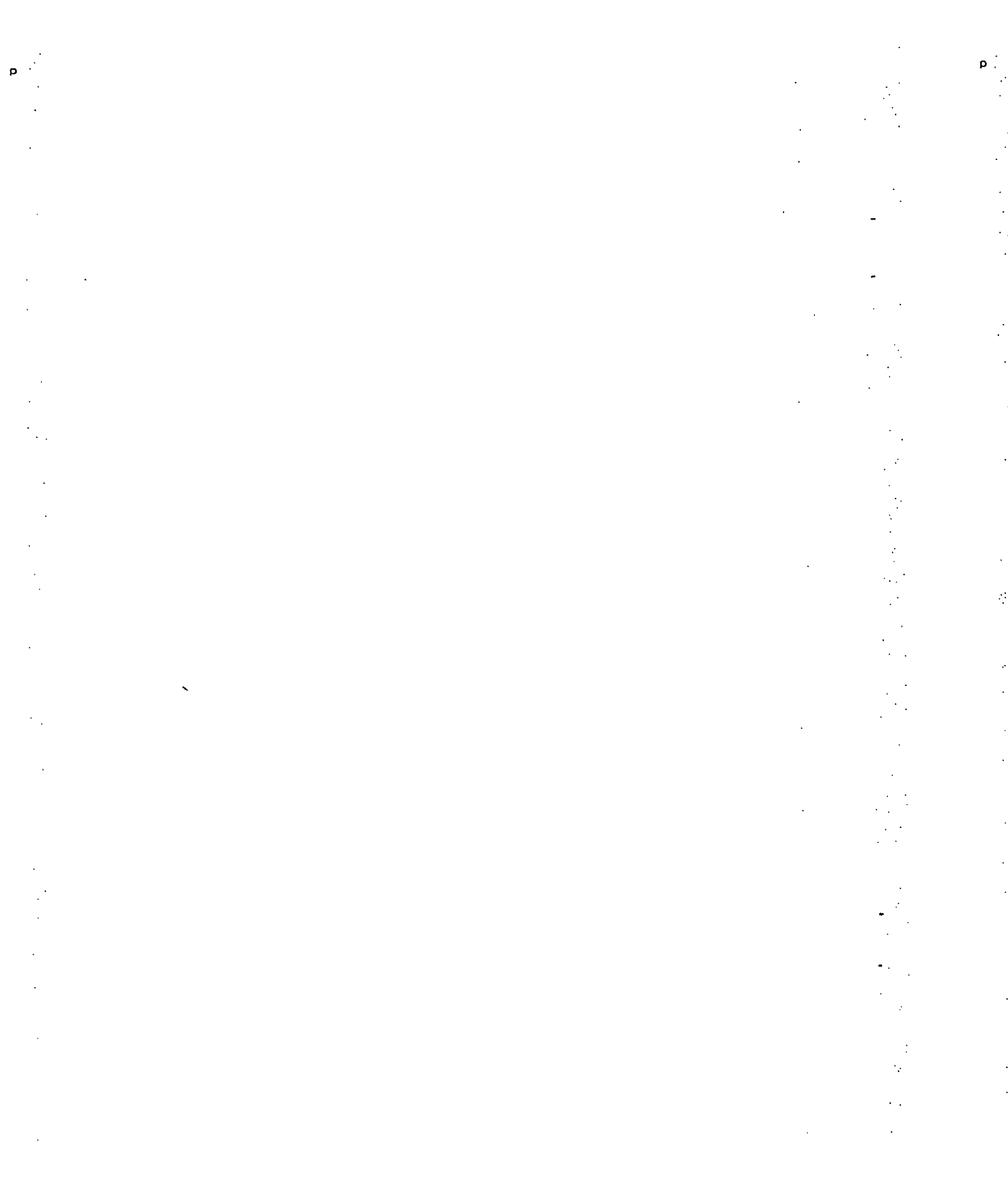
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
CALENDAR YEAR	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
PROJECT YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
MBG PRICE ($/mm BTU)	6.10	6.59	7.12	7.68	8.30	8.96	9.60	10.65	11.29	12.19	13.17	14.22	15.36	16.60	17.92	19.35	20.90	22.57	24.38	26.33
REVENUE	2,227	2,405	2,599	2,803	3,030	3,270	3,533	3,814	4,121	4,449	4,807	5,190	5,606	6,059	6,541	7,063	7,629	8,238	8,899	9,610
COSTS																				
Feedstocks																				
Coal	273	300	330	363	399	439	483	531	584	642	706	777	854	939	1,031	1,137	1,250	1,375	1,513	1,664
Refinery Gas	427	448	470	484	519	545	572	601	631	663	696	731	768	806	847	889	934	980	1,029	1,081
Oxygen	359	382	398	439	483	531	584	642	706	777	854	939	1,033	1,136	1,250	1,375	1,512	1,664	1,830	2,031
Other Operating Costs	414	511	562	618	680	747	822	904	995	1,094	1,204	1,324	1,456	1,602	1,762	1,938	2,132	2,345	2,579	2,837
Interest																				
Low Interest Equity Advance	22	18	14	09	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Private Debt	534	518	521	516	505	495	484	471	456	440	420	399	371	346	311	277	235	187	133	71
Depreciation	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
TOTAL COSTS	2,317	2,415	2,563	2,705	2,859	3,025	3,213	3,417	3,640	3,884	4,138	4,430	4,753	5,097	5,473	5,886	6,331	6,819	7,352	7,934
NET INCOME BEFORE TAX	(90)	(30)	36	98	171	245	320	397	481	565	669	752	853	962	1,068	1,179	1,298	1,419	1,547	1,676
Operating Loss Carry Forward	(90)	(120)	(84)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
INCOME TAX																				
Income Tax	—	—	—	07	86	123	160	199	241	283	330	376	427	481	534	590	649	710	774	838
Less ITC	(940)	(940)	(940)	(940)	(933)	(847)	(724)	(564)	(365)	—	—	—	—	—	—	—	—	—	—	—
INCOME AFTER TAX																				
ITC Carry Forward	(940)	(940)	(940)	(940)	(933)	(847)	(724)	(564)	(365)	—	—	—	—	—	—	—	—	—	—	—
Net Tax	—	—	—	—	—	—	—	—	241	283	330	376	427	481	534	590	649	710	774	838
INCOME AFTER TAX	(90)	(30)	36	98	171	245	320	397	240	282	339	376	426	481	534	589	649	709	773	838
Depreciation	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Cash Flow	178	238	304	366	439	513	588	665	508	550	607	644	694	749	802	857	917	977	1,041	1,106
Less Principal Payments																				
Low Interest Equity Advance	78	82	86	90	95	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Private Debt	42	48	54	62	71	81	92	105	120	136	155	177	202	230	262	299	341	389	443	505
TOTAL PRINCIPAL	120	130	140	152	166	81	92	105	120	136	155	177	202	230	262	299	341	389	443	505
NET CASH FLOW	58	108	164	214	273	432	496	560	388	414	452	467	492	519	540	558	576	588	598	601

IRR = 20.728

8.5.2 Costs

8.5.2.1 Feedstocks. Coal is escalated at the rate of
10 percent per year. The amount shown is for coal delivered
to the plant gate. Refinery gas is escalated at 5 percent
per year. The amount shown is the price at the refinery
gate. Oxygen is escalated at 10 percent per year. The
amount shown is based on over-the-fence sale, delivered to
the plant gate.

8.5.2.2 Other Operating Costs. Other operating costs
include chemicals, utilities, operating and maintenance
labor, maintenance materials, administration and overhead.
Other operating costs are escalated at 10 percent per year.

8.5.2.3 Interest. Interest for the low interest equity
advance is based on repayment over a five-year period with a
level end of year payment which includes interest and
principal. Only interest is shown here. Interest for debt
is based upon repayment over a twenty-year period with a
level end of year payment which includes principal and
interest. Only interest is shown here.

8.5.2.4 Depreciation. The straight line depreciation method
was used. The base for depreciation was taken from Table 8-1.
For tax purposes, salvage value was considered less than
10 percent and not deducted from depreciable costs.

8.5.2.5 Total Costs. Summation of costs.

8.5.3 Net Income Before Tax

Revenues minus total costs. Operating losses are carried
forward for a maximum of seven years.

8.5.4 Income Tax

Income tax was calculated using an assumed 50 percent
effective tax rate. Investment tax credit was taken as
20 percent of qualified items, 10 percent normal investment
for credit, plus 10 percent energy investment tax credit. It
was assumed that the credit would be taken when the plant is
put in service, 1984. .Tax credit not used carried forward
for seven years.

8.5.5 Income After Tax

Net income before tax minus net tax.

8.5.6 Cash Flow

Income after tax plus depreciation.

8.5.7 Principal Payments

Reduction of long-term debt and equity advance.

8.5.8 Net Cash Flow

Cash flow minus principal payments. This figure was used to
calculate the internal rate of return.

8.5.9 IRR

The internal rate of return as the discounted cash flow rate
of return of the Net Cash Flow stream, based on an equity
investment of $12.71 million.

8.6 SENSITIVITY ANALYSES

This section of the study looked at the sensitivity of the initial sales price of the MBG to several operating parameters. The sensitivity of the discounted cash flow internal rate of return to initial sales price and financing options was studied.

8.6.1 MBG Price to Total Capital Cost

Variations in total capital cost yield the MBG prices shown in Figure 8-1. A 12 percent change in total capital cost causes a 3 percent change in MBG price.
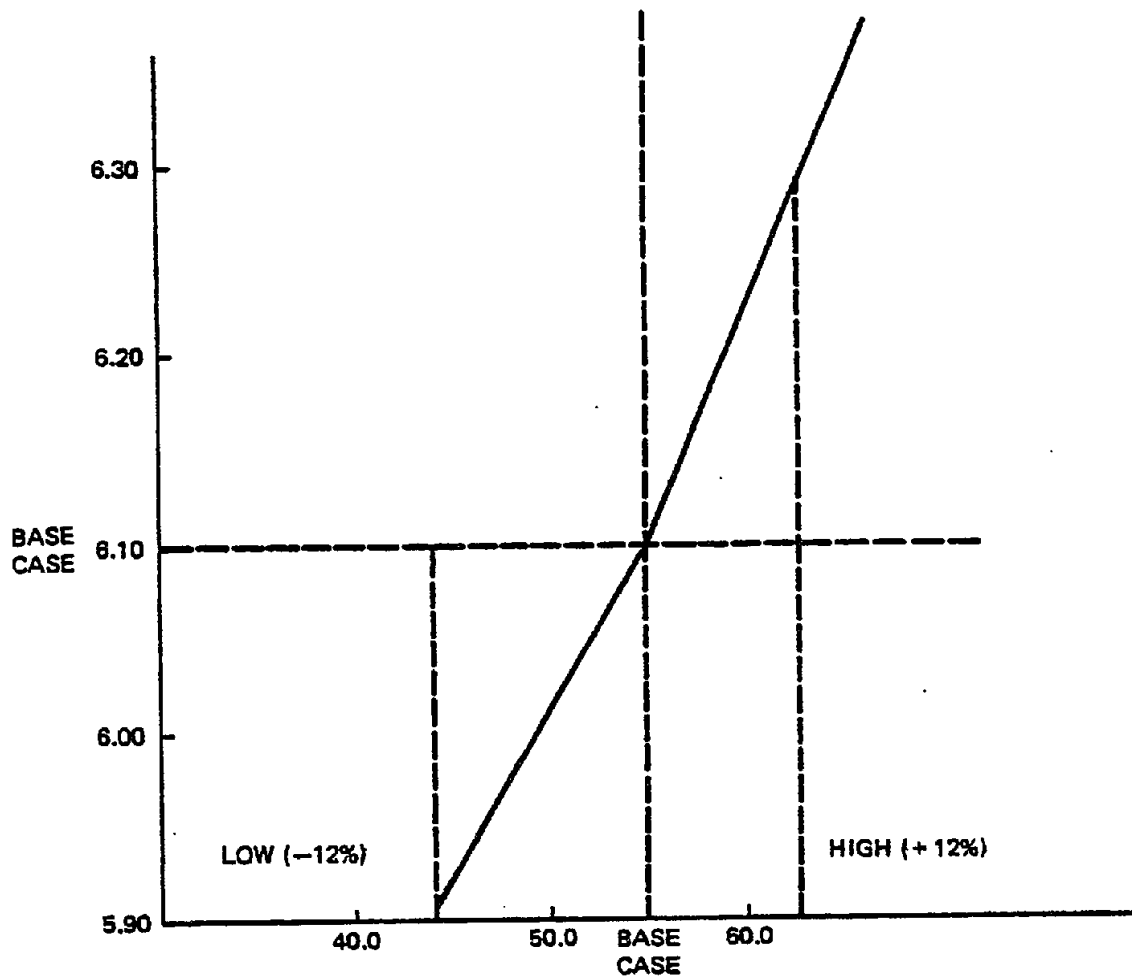
8.6.2 MBG Price to Delivered Coal Price

Figure 8-2 shows the effect on MBG price caused by variations in delivered coal price. A 10 percent change in the delivered coal price causes about 1 percent change in MBG price.

8.6.3 MBG Price to O&M Cost

The sensitivity of the 1984 MBG price to operating and maintenance cost, minus coal cost, is shown in Figure 8-3. A 10 percent change in O&M cost causes a 5 percent change in MBG price.

8.6.4 MBG Price to Load Factor

As shown in Figure 8-4, the MBG price is very sensitive to load factor. A 10 percent change in load factor causes an 11 percent change in MBG price.
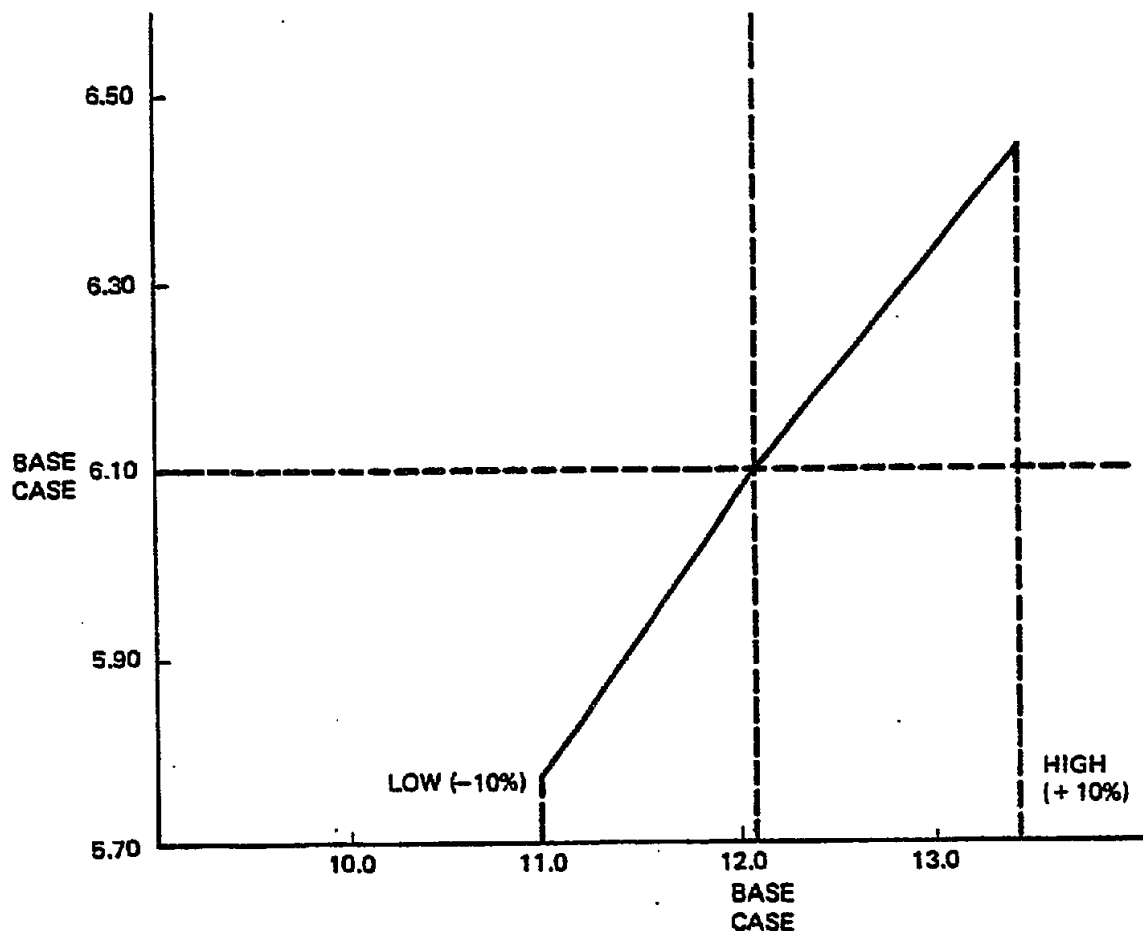
BASE CASE	6.30		

LOW (−12%)   HIGH (+ 12%)

5.90   40.0   50.0   BASE   60.0
                                CASE

	CAPITAL COST	1984 MBG PRICE $/MM BTU
BASE CASE	$65,124,000	6.10
LOW CASE (−12%)	48,509,120	5.91
HIGH CASE (+ 12%)	61,738,880	6.29

FIGURE 8-1

**SENSITIVITY OF 1984 MBG PRICE
TO CAPITAL COST**

8−16

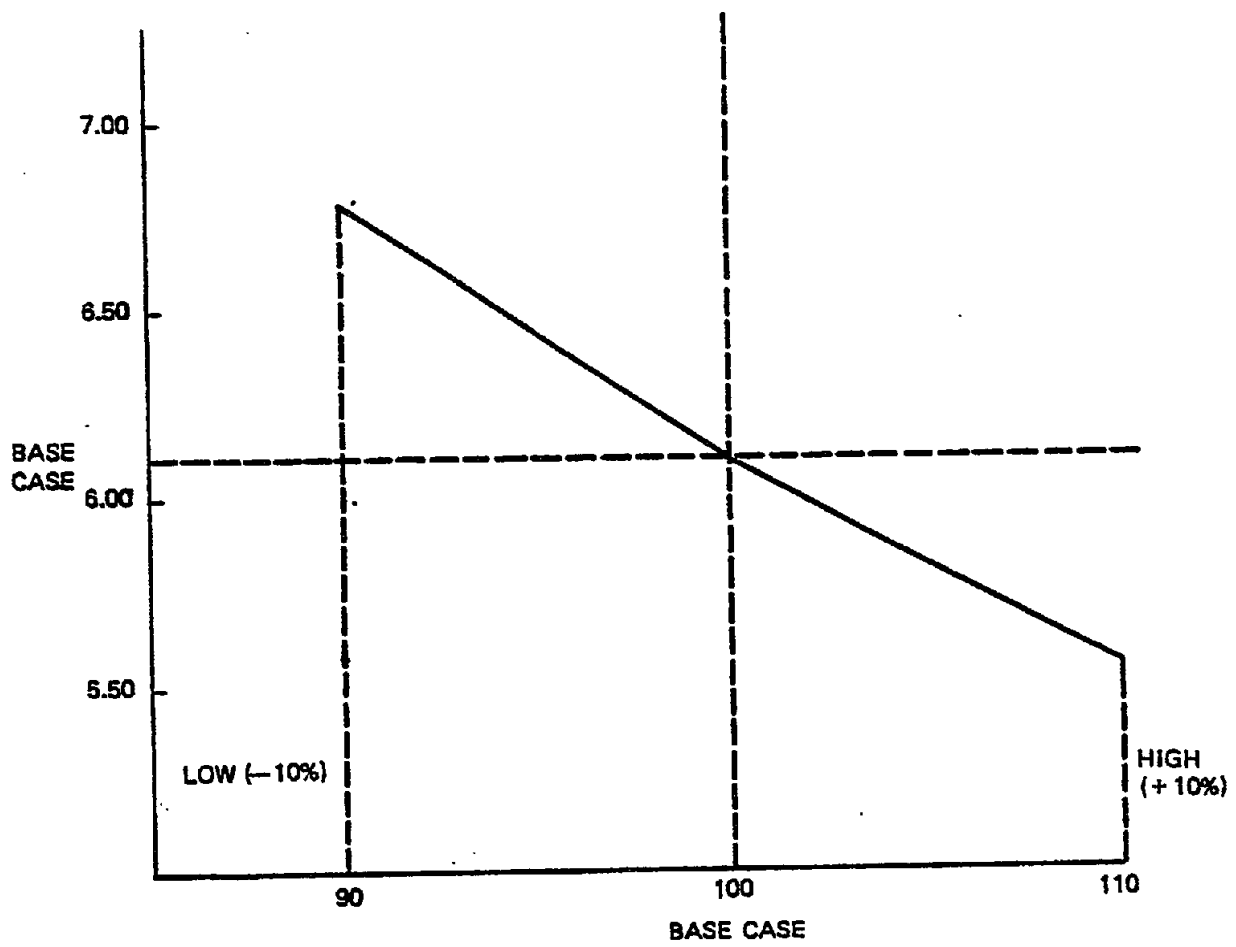p   p
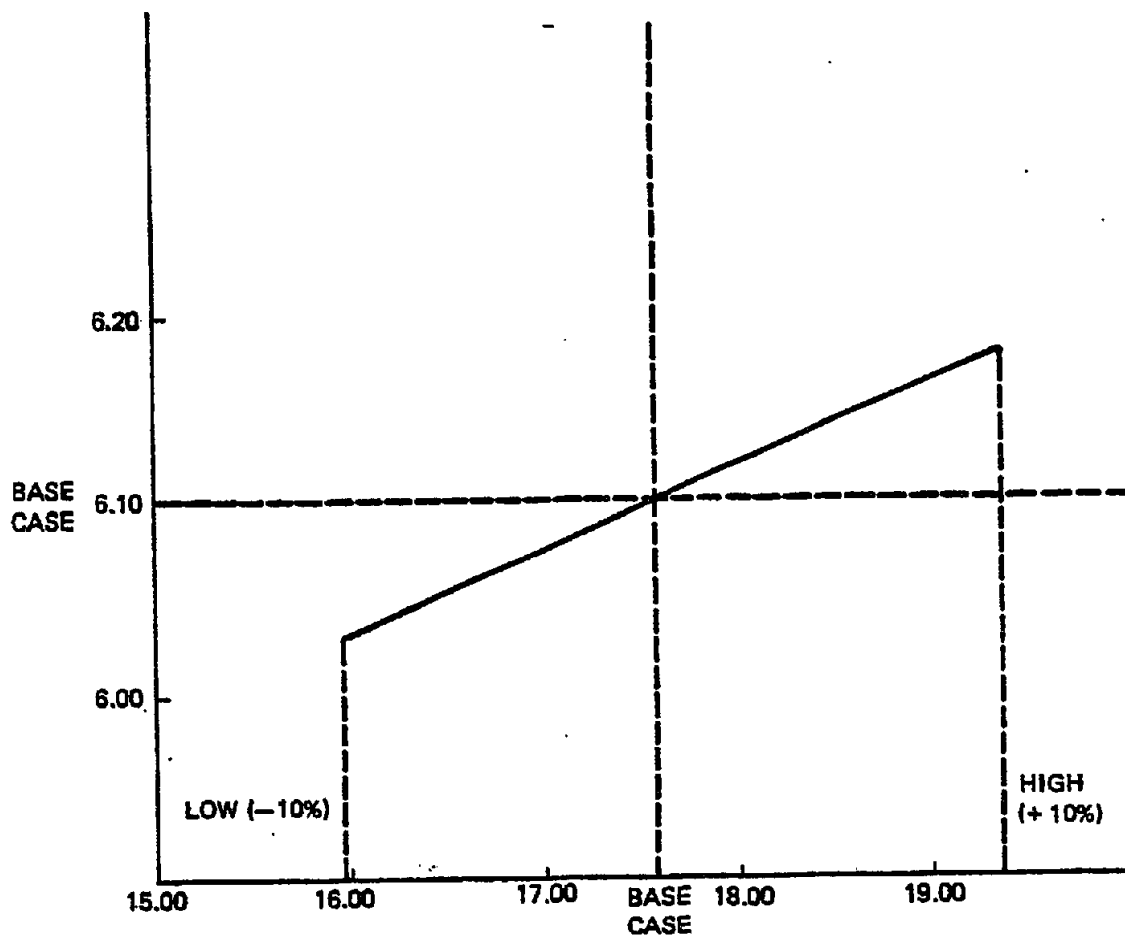
	1984 DELIVERED COAL PRICE (S/TON)	1984 MBG PRICE S/MM BTU
BASE CASE	17.57	6.10
LOW CASE (– 10%)	15.97	6.03
HIGH CASE (+ 10%)	19.33	6.17

FIGURE 8-2

**SENSITIVITY OF 1984 MBG PRICE
TO DELIVERED COAL PRICE**

8-17

	1984 O&M COST (EXCLUDING COAL)	1984 MBG PRICE $/MM BTU
BASE CASE	12,207,345	6.10
LOW CASE (–10%)	10,986,611	5.77
HIGH CASE (+ 10%)	13,428,079	6.44

FIGURE 8-3

SENSITIVITY OF 1984 MBG PRICE
TO O&M COST

	LOAD FACTOR	1984 MBG PRICE $/MM BTU
BASE CASE	100%	6.10
LOW CASE (-10%)	90%	6.78
HIGH CASE (+10%)	110%	5.54

FIGURE 8-4
SENSITIVITY OF MBG PRICE
TO LOAD FACTOR

8.6.5 MBG Price to Refinery Gas Price

Figure 8-5 shows the sensitivity of the MBG price to the cost of the refinery gas. A 10 percent change in refinery gas produces a 2 percent change in the initial MBG price.

8.6.6 IRR to Initial MBG Price

Figure 8-6 shows the effect that the 1984 MBG price has on the discounted cash flow internal rate of return. The analysis assumed the same escalation rate as in the base case, 8 percent. A 3 percent increase in MBG price causes a 29 percent increase in the IRR. A 2.5 percent decrease in MBG price causes a 20 percent decrease in IRR. It is seen that a small variation in MBG price has a great effect on the rate of return.

8.6.7 IRR to Financing Option

Sensitivity of the discounted cash flow rate of return to financing option is shown in Table 8-5. Three alternative financing methods were examined. Case II, 75 percent debt/ 25 percent equity and a 14 percent interest rate is the most likely case. Using the 75/25 debt equity ratio it was found that a 2 percentage point increase in the interest rate causes a 21 percent decrease in IRR.

8.7 INTERFUEL COMPETITION

The technical capability of the refineries to use MBG has been established. Assuming that the needed system modifications are made, the principal issues in the use of MBG are economic. Informal conversations with the refinery managers

8-20
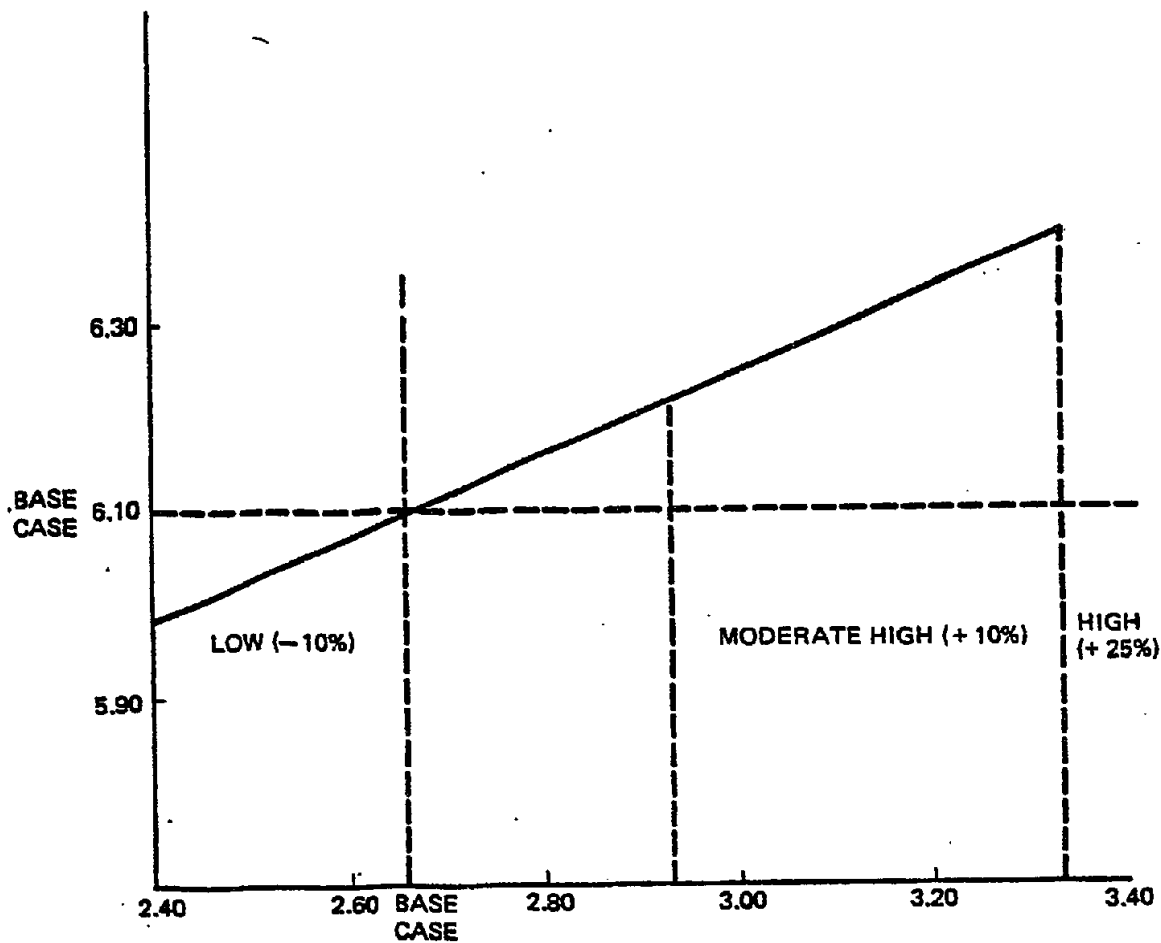
	1984 REFINERY GAS $/MM BTU	1984 MBG PRICE $/MM BTU
BASE CASE	2.66	6.10
LOW CASE (— 10%)	2.40	5.98
MODERATE HIGH (+ 10%)	2.93	6.22
HIGH (+ 25%)	3.33	6.39

FIGURE 8-5

SENSITIVITY OF MBG PRICE
TO REFINERY GAS COST
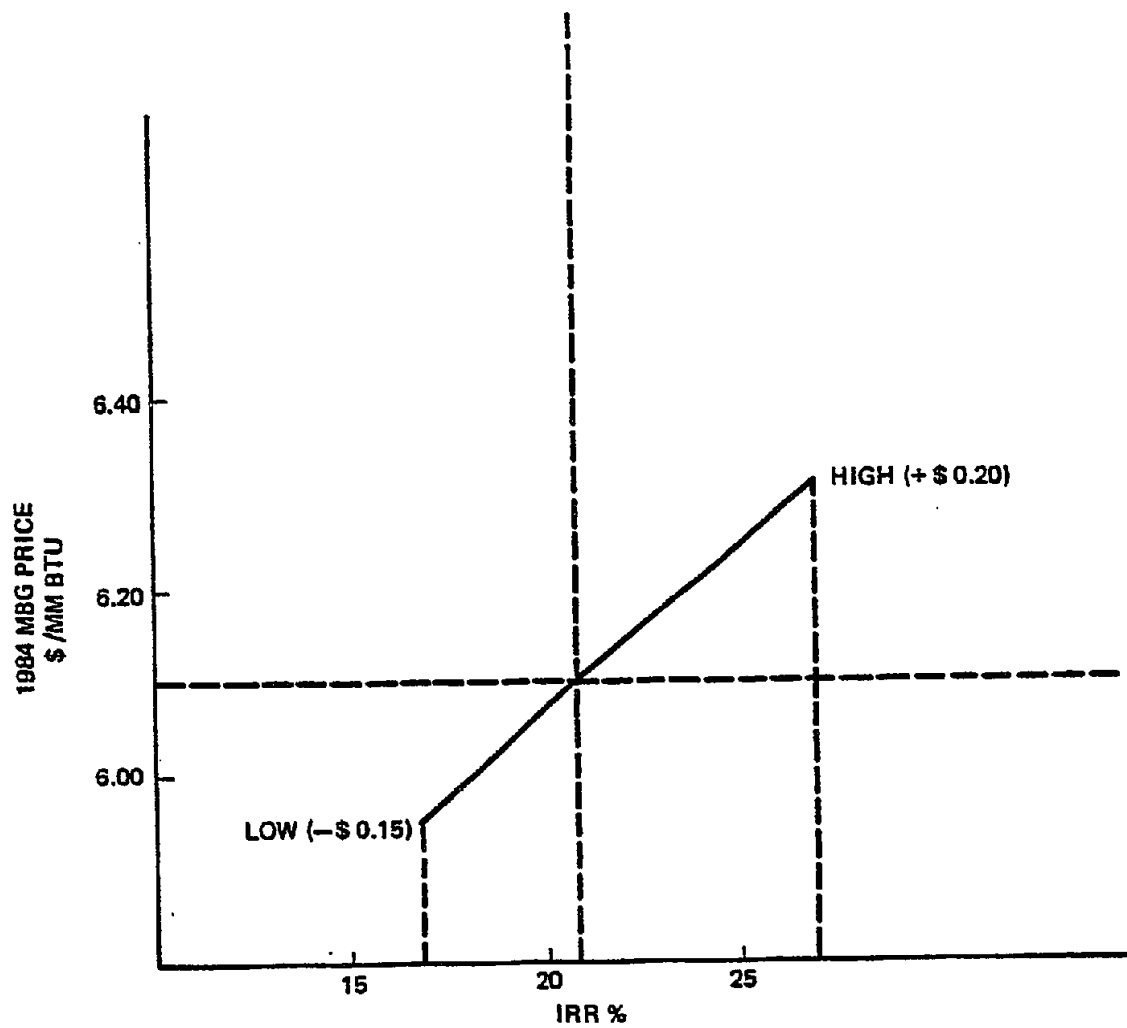
	1984 MBG PRICE $/MM BTU	IRR, %
BASE CASE	6.10	20.76
LOW CASE	5.95	16.67
HIGH CASE	6.30	26.88

FIGURE 8-6

SENSITIVITY OF IRR TO 1984 MBG PRICE

TABLE 8-5

SENSITIVITY OF IRR TO FINANCING

	SOURCE	AMOUNT	TERMS	IRR, %
BASE CASE	Equity Advance	$ 4,300,000	5%/5 yr	20.79
	Private Debt	38,135,000	14%/20 yr	
	Equity	12,711,000		
CASE I	Private Debt	41,360,000	12%/20 yr	24.08
	Equity	13,787,000		
CASE II	Private Debt	41,360,000	14%/20 yr	21.03
	Equity	13,787,000		
CASE III	Private Debt	41,360,000	16%/20 yr	16.62
	Equity	13,787,000		

indicate a willingness to use MBG if it is less costly than conventional alternatives. This subsection of the report compares projected costs of MBG with those of a mix of conventional refinery fuels.

8.7.1 Current and Future Refinery Conventional Fuel Price

The Conoco and Cenex refineries provided estimates of current refinery fuel costs. The figures provided by Conoco are based on 1980 year-end crude price of $34.00 per barrel, or $5.86 per million Btu. Conoco planning personnel advised that crude and fuel costs are expected to escalate at a 9 percent annual rate in constant dollar terms. The cost of natural gas is soon expected to reach 2/3 of the crude oil price on a con-tained energy basis. This expectation suggests a 1980 value of $3.90 per million Btu. According to Conoco's planners, this same value can be applied to residual fuel oil which is frequently burned in place of or in addition to natural gas. Current fuel costs figures provided by Cenex yield a weighted average fuel price of $3.91 per million Btu. The Cenex cost differed negligibly from that provided by Conoco. Cenex cur-rently relies upon imported natural gas for about 40 percent of its requirements at a price of about $5.00 per million Btu. Thirty percent of its requirements are met by domestic natural gas at $2.47 per million Btu. The final 30 percent share is residual fuel oil. Personnel at the Cenex and Conoco refin- eries agreed to evaluating residual fuel at $3.90 per million Btu and a 9 percent annual escalation rate in real terms.

8.7.2 Refinery Gas and MBG Price Comparison

Figure 8-7 provides a graphical representation of constant dollar refinery fuel costs escalated from 1980 at 4, 6, and 9 percent rates. The constant dollar MBG costs are also
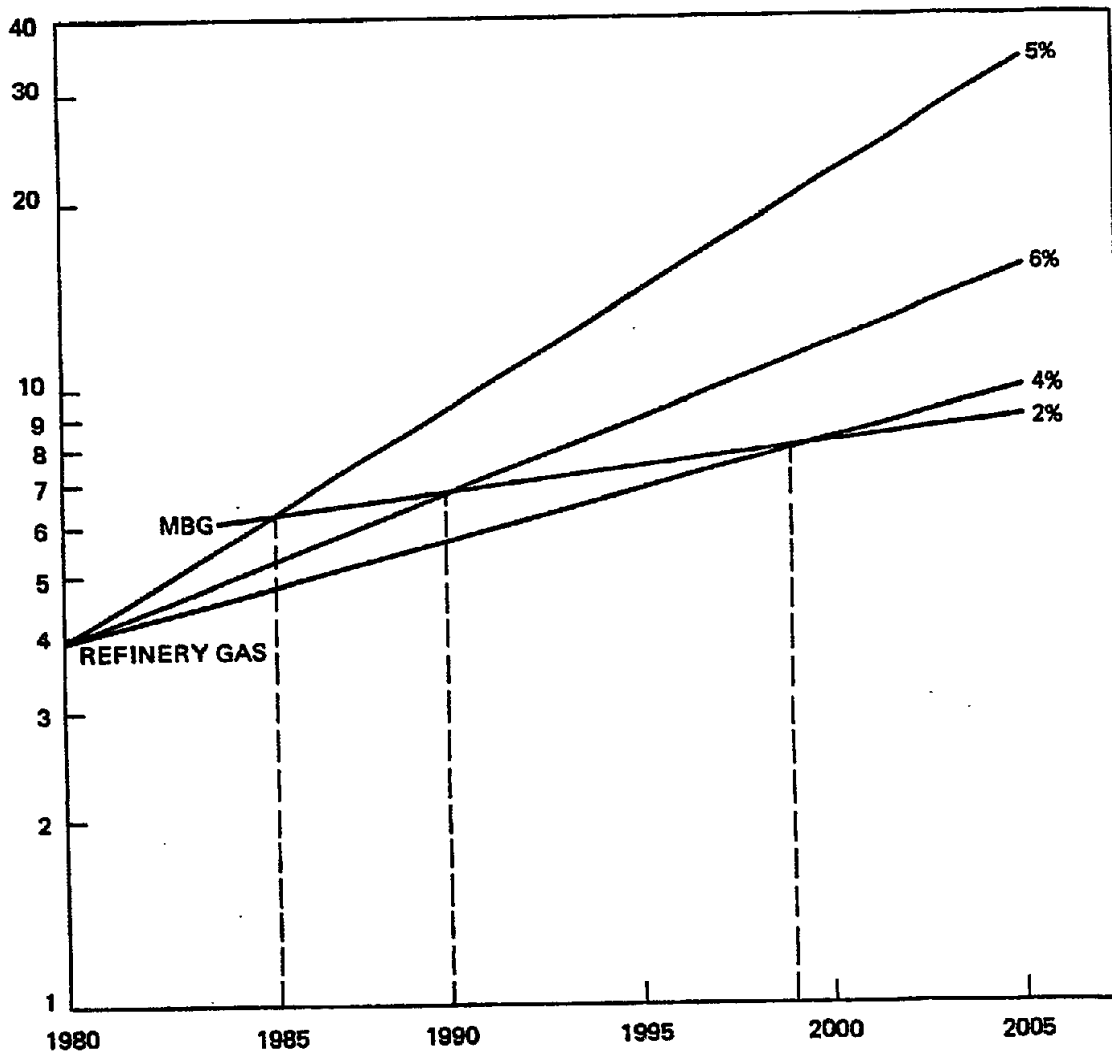
FIGURE 8-7

COMPARISON OF REFINERY GAS AND MBG

CONSTANT DOLLARS

plotted for comparative purposes. Since the MBG is manufac-
tured and its costs are to a large degree tied to inflationary
increases through long-term contracts for feedstocks and
utilities, the constant dollar MBG price curve is flatter and
expected to increase at a 2 percent real rate. As seen in
Figure 8-7, MBG becomes competitive with conventional alter-
natives between 1985 and 1986 when conventional fuels rise at
the expected 9 percent real rate. The MBG becomes competitive
in 1990 at a 6 percent real increase rate in conventional
fuels. The semilog plot somewhat obscures the magnitude of
MBG's advantage in later years. Figure 8-8, a linear plot,
graphically displays the MBG price advantage over conventional
fuels. As the plot indicates the MBG price disadvantage is
only one or two years and the long-term potential advantage
is tremendous.

One of the assumptions that have been made in this analysis
is that patterns of refinery fuel consumption will remain
constant. However, there is some likelihood that both quan-
tity and the mix of refinery fuel requirements will vary with
time. In particular, energy conservation programs may be
expected to reduce overall plant energy requirements. As
fuel requirements are reduced, purchases of the most costly
fuel may be disproportionately reduced, which may cause a
corresponding alteration in the weighted average cost of the
refinery fuel mix.

Finally, there is another consideration that can influence
the marketability of MBG. The use of MBG to replace residual
fuel oil will increase the refiner's yield of residual fuels.
This incremental supply of residual fuel may be difficult to
market locally. In the Rocky Mountain area such fuel markets
are often weak. Since residual fuels are generally not
transported by pipeline and water transportation options are
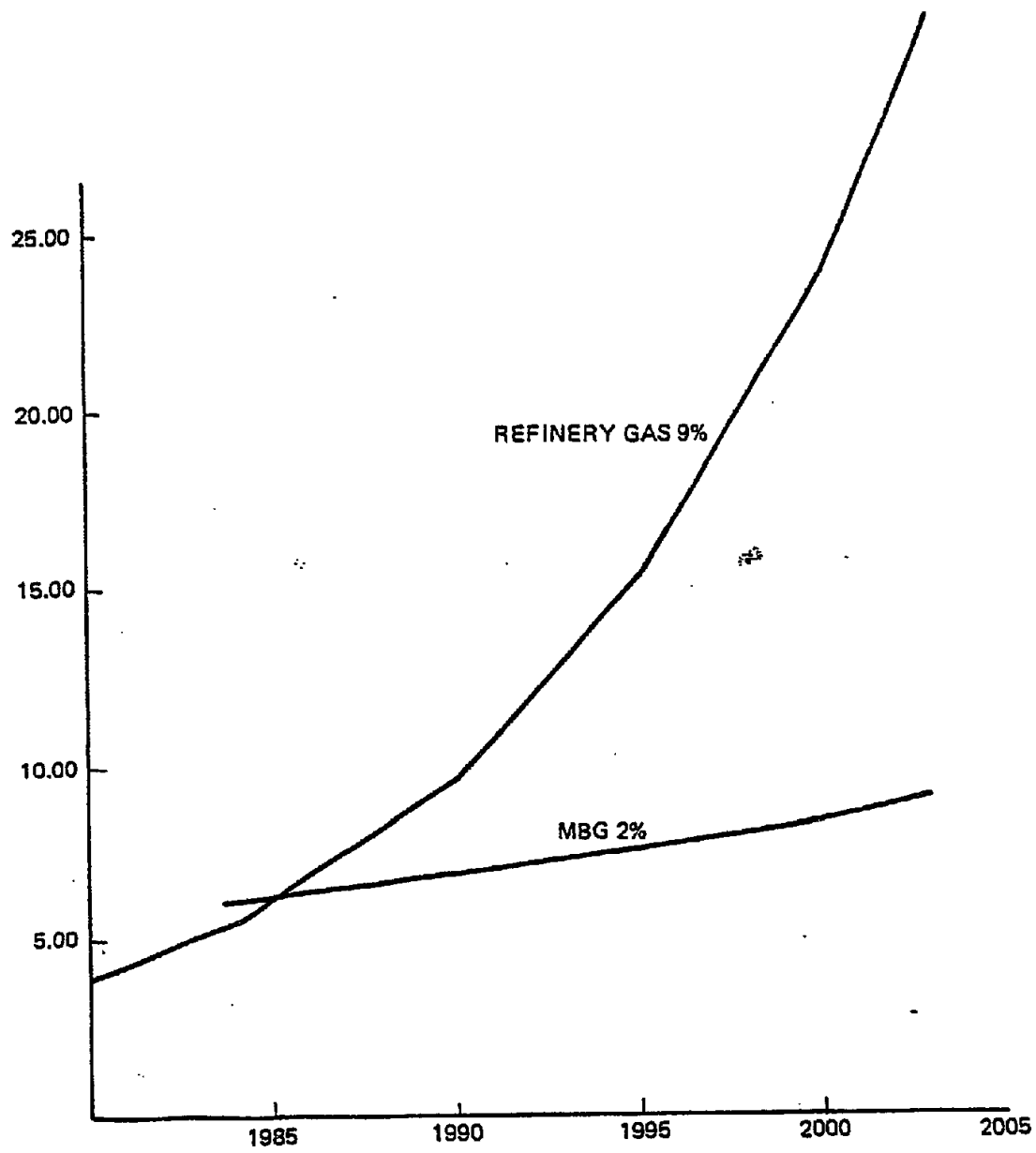
FIGURE 8-8

**COMPARISON OF REFINERY GAS AND MBG
CONSTANT DOLLARS**

not available, it is necessary to transport residual oils by
relatively expansive rail transportation. High transportation
costs can seriously impair refinery netbacks on residual fuel
sales. However, since the residual fuel replace by MBG can
be sold, the refinery netback will increase refinery revenues.
Although the increased cost of MBG will tend to reduce the
cost differential. It is expected that since residual oil
will rise at a higher real rate than the MBG the price curves
will cross in the near future, about 1988, thus making the
use of MBG less expensive than the use of residual oils.

9. MBG SALES CONTRACT

9.1 GENERAL

It is the purpose of this task of the feasibility study to draft preliminary contract clauses unique to the sale of Btu gas. It is intended that these clauses would be added to the companies general clauses and then be used as a basis for negotiating the final contract.

9.2 CONTRACT CLAUSES

9.2.1 Term

The term of this contract shall be for a period of twenty (20) fiscal years beginning with January 1, 1984, each of such years to consist of twelve (12) months ending December 31.

9.2.2 Quantity

During each of the years provided for, Buyer shall purchase and accept delivery, and Seller shall sell and deliver, quantities of medium-Btu gas as set forth below:

Year	Minimum Quantity (Millions of Btu)	Maximum Quantity (Millions of Btu)
1984	0,000,000	0,000,000
1985	0,000,000	0,000,000
1986	0,000,000	0,000,000
1987	0,000,000	0,000,000
1988	0,000,000	0,000,000
1989	0,000,000	0,000,000
1990	0,000,000	0,000,000
1991	0,000,000	0,000,000

Year	Minimum Quantity (Millions of Btu)	Maximum Quantity (Millions of Btu)
1992	0,000,000	0,000,000
1993	0,000,000	0,000,000
1994	0,000,000	0,000,000
1995	0,000,000	0,000,000
1996	0,000,000	0,000,000
1997	0,000,000	0,000,000
1998	0,000,000	0,000,000
1999	0,000,000	0,000,000
2000	0,000,000	0,000,000
2001	0,000,000	0,000,000
2002	0,000,000	0,000,000
2003	0,000,000	0,000,000

At least six (6) months prior to the beginning of each fiscal year, Buyer shall advise Seller of the millions of Btu's of gas to be purchased in the immediately succeeding fiscal year within the minimums and maximums above specified. In the event that Buyer fails to notify Seller within this time frame, Buyer shall be deemed to have elected to receive the minimum quantity.

Notwithstanding the above provisions regarding minimum and maximum quantities, the parties agree that Buyer may not purchase more than 00,000,000 millions of Btu's over the life of this contract.

9.2.3 Quality

During the term of this contract, Seller agrees to supply the medium-Btu gas by pipeline of the following approximate average quality and substantially free of sulfur, water and particulates.

Approximate Analysis

Constituent	Mole %
H_2	36.8
N_2	1.7
CO	32.3
CO_2	15.1
Methane	9.3
Ethane	2.6
Ethylene	1.4
Propane	0.2
Propylene	0.6
	100.00

HHV=406 Btu/scf
Specific Gravity = 0.684

Seller warrants that the gas shall have an "as received" heat content of not less than 286 Btu per cubic foot; however, that the approximate average quality of the gas shall be as specified above.

In the event Seller fails to meet the warranted specifications provided hereunder for any gas shipped to Buyer, and where such gas is burned by Buyer, Seller shall reduce the then current price by _____ percent (___%) per million Btu. Seller agrees to provide Buyer with notice of shipment of any gas not meeting the minimum specifications as soon as Seller becomes aware of this fact. In the event the gas shipped by Seller to Buyer is unsuitable for burning, and is not burned by Buyer, Buyer shall not pay Seller for such shipments.

Seller agrees to acquire and install at the gasification plant the most modern and efficient machinery, equipment and other facilities (as determined by Seller) required to produce, prepare and deliver the quality and quantity of gas provided for in this agreement. Seller further agrees to operate and maintain said machinery, equipment, and facilities in accordance with good engineering practices so as to efficiently and economically produce, prepare and deliver said gas.

9-3

9.2.4 Delivery

All gas purchased hereunder shall be delivered by Seller FOB Buyer's plant gate, and title thereto to shall pass to Buyer downstream of the meter. Buyer shall notify Seller at least twenty (20) days prior to the beginning of each month during the term of this contract of the quantities of gas Buyer will purchase during such month, and the average daily requirement. In addition, Buyer will furnish Seller an estimate of the quantities to be ordered in each of the two months following such month. Monthly quantities ordered by Buyer during each fiscal year shall relate to the annual quantities of gas to be purchased during the particular fiscal year, such relationship to be based on a ten percent (10%) variance of the figure derived by dividing the annual shipments specified by Buyer under Section _____ by three hundred sixty-five (365), said result to be multiplied by the number of days during the month. The daily quantities to be delivered by Seller shall not exceed _____ million Btu's during any twenty-four (24) hour period.

9.2.5 Measurement of Gas Quantity and Quality

Seller shall measure the volume of all gas shipped under this agreement. Seller shall monitor the gas constituents on a continuous basis. The Btu's of gas delivered shall be based upon quantities delivered times the higher heating value of the gas constituents. The quantity of Btu's delivered shall be based on eight-hour averages. The formula to calculate Btu's delivered shall be agreed to prior to signing this agreement and included at Buyer's plant gate. Meters shall be regularly calibrated using such methods as are then prescribed by standard accepted practices. During any period when the Seller's plant gate measuring facilities are not in operation,

measurements by Buyer shall be used for all purposes under
this contract. Seller shall notify Buyer immediately of any
failure in Seller's measurement facilities. Buyer shall have
the right to have its personnel present during any measurement
or during any calibration of the respective scales. Buyer
shall also have the right to review the results of any
calibration test.

In the event that Seller's measurement devices are shown to be
faulty thereby causing erroneous measurements, an appropriate
adjustment shall be made in the price to reflect the correc-
tion for these errors provided that no such adjustment shall
be retroactive for a period in excess of one month prior to
the date of discovery of fault in the equipment, provided
that if the devices have not been tested as above provided,
any such adjustment for excess measurement shall be retro-
active to the last time such devices were so tested.

9.2.6 Sampling and Analysis

Sampling and analysis of gas delivered hereunder shall be
performed expeditiously by qualified employees or agents of a
mutually acceptable independent commercial testing organiza-
tion (the "Organization") using suitable testing equipment
provided by Seller, said sampling and testing to be in accor-
dance with the then current methods approved by the American
Society for Testing Materials (ASTM). The results of the
sampling and analysis so performed shall be mailed to Buyer
as the tests are completed. Buyer may have a representative
present at any time to observe the sampling. One part shall
be forwarded to Buyer for analysis, one part shall be retained
for analysis by the Organization, and the third part shall be
retained in one of the aforementioned containers, properly

sealed and labeled to be saved for future analysis in the event of a dispute between the parties regarding the analyses. Should analysis of the third part be found necessary, such analysis shall be made in quadruplicate by an independent commercial testing laboratory (the "Lab"), selected by the parties, with the average of the results of such an analysis to be binding on the parties. The cost of the analysis made by the Lab shall be shared equally by the parties.

9.2.7 Price

The base price of gas per million Btu FOB Buyer's plant gate which complies with the standard set forth above shall be $_____. The base price shall be subject to the adjustments provided for in Articles _____ hereof.

9.2.8 Price Adjustments

The per million Btu price of gas may be increased or decreased from the base price. The increase or decrease, when added to the base price, shall be called the current price. For the purpose of this contract, the base price date is deemed to be January 1, 1984, unless another date is specified hereunder. Price adjustments shall be computed quarterly or at such other time as may be specified in this article, with Seller sending Buyer a copy of each such calculation within thirty (30) days after the effective date of the adjustment.

The individual price adjustments specified in this article will be rounded to the nearest 1/100 of 1¢ per million Btu.

Seller shall furnish to Buyer a computation showing the effect of any price changes due to the below-enumerated paragraphs. In the event that Buyer is not satisfied with the computation

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of the adjustments, Buyer shall promptly notify Seller in writing of those portions of the computations with which it is not in agreement. The parties to this agreement shall meet within ten (10) days of such notification in an effort to arrive at a mutually satisfactory computation.

If the meeting of the parties does not resolve the matter, they shall immediately refer same to a national independent accounting firm, selected by mutual agreement of the parties, for the purpose of arriving at the correct computation. Seller agrees to provide the independent accounting firm to arrive at its computation. The findings made by the independent accounting firm shall be final. During the period of verification of the computations, Seller shall continue to deliver hereunder and neither party shall be required to pay any part of the adjustment in question, provided, however, that when the matter is finally determined by the parties or the independent accounting firm, the paying party shall also pay interest at the rate of one percent above the Bank of America of Los Angeles prime rate during the period commencing fifteen (15) days after the date of first billing by Seller, to which such adjustment was applicable, and ending on the date of actual payment. The fees and other charges of the independent accounting firm shall be paid by the party whose contention as to the proper amount of the adjustment is farthest from the amount determined to be proper by such firm; in the event there is no such party, the fees shall be shared equally by both parties.

Seller will receive from or pay to Buyer within a period of thirteen (13) months following the termination date of this contract, any price adjustments resulting from the application of this Article where such adjustments were not known or subject to calculation as of the date this contract termiates

or otherwise expires, provided, however, that such price adjustment may only relate to a period of eighteen (18) months immediately preceding the date the contract termiates or otherwise expires.

9.2.8.1 Materials and Supplies. A Composite Index shall be computed for each calendar quarter from the monthly Bureau of Labor Statistic Wholesale Price Index for:

- Chemicals and allied products

- Fabricated metal products

- Machinery and equipment

- Industrial fittings

Each of said indexes is reported in the U.S. Department of Labor, Bureau of Labor Statistics publication "Wholesale Prices and Price Indexes."

The three monthly values of each index shall be ar hmetically averaged to determine a quarterly average value. The quarterly average value for each index shall then be arithmetically averaged to obtain the quarterly average value of the Composite Index.

At the beginning of each calendar quarter, the price of gas delivered in that quarter shall be increased or decreased from the then base price. The quarterly average value for each index shall then be arithmetically averaged to obtain the quarterly average value of the Composite Index.

At the beginning of each calendar quarter, the price of gas delivered in that quarter shall be increased or decreased from the then base price. The quarterly average value as determined above for that quarter will be compared with the average for the quarter ending _____, to determine the percentage increase or decrease. The percentage increase or decrease so derived times $_____ will be the increase or decrease in the price per million Btu in determining the new current price.

In the event the United States Department of Labor, Bureau of Labor Statistics shall change the basis of either or both of the indexes referred to herein, the parties shall agree upon the new basis to be followed in determining the adjustment of the price of coal as a result of increases or decreases in the cost of materials and supplies. If the parties are unable to agree to a new basis to be followed or to a means of utilizing the revised indexes within a period of fifteen (15) days after the start of any calendar quarter, the unresolved matter shall be resolved by arbitration, in accordance with the rules of the American Arbitration Association. Within thirty (30) days after the start of any calendar quarter the parties shall apply to such Association to appoint an arbitrator. Each part shall designate an established governmental index as a new basis to be followed in determining the increases or decreases in the cost of materials and supplies, whichever is applicable, and the arbitrator shall pick one of the two. The arbitrator shall have no power to reach any other decision. The decision of the arbitrator shall be binding upon both Buyer and Seller, and such decision shall constitute the method for adjusting the price of coal as a result of increases or decreases in the cost of materials and supplies. The new indexes or bases determined pursuant to this paragraph shall be used in lieu of the indexes or bases replaced by same for all applicable purposes of this agreement.

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9.2.9 Labor, Salaries, and Related Costs

A weighted average hourly wage rate for labor at the plant shall be computed whenever labor costs contained in the salary and wage list and fringe benefit list applicable to the plant are more or less than the costs shown on the initial salary list and fringe benefit list, attached hereto and made a part hereof. The cost of labor shall be computed in the manner prescribed by the Manning Table for labor cost adjustments, which is attached hereto and made a part hereof. As used herein, "labor costs" shall be deemed to include only those costs of labor as specified above provided, however, that any new or additional expenditures on behalf of past, present, or future employees not reflected on the initial salary and fringe benefit lists which are required by a new labor agreement, governmental, judicial or legislative action, shall be considered as increased cost of labor.

The number of persons employed in each classification listed on the position list shall not be changed and no new categories shall be added unless required by new labor agreements, governmental, judicial, or legislative acton, effective after _____. In this event, Seller shall advise Buyer of such changes and the persons will be added at the appropriate rate to arrive at a new weighted average hourly wage rate. To the extent that persons are added to the numbers the position list resulting from new labor agreements, governmental, judicial or legislative action, and where such requirement is later reduced or eliminated, then the number of persons shown on the position list may be reduced to the extent of the increases. Seller shall not be required to show Buyer a payroll or other information relative to the number of persons actually employed. Seller agrees to provide Buyer with a

letter from an independent certified public accounting firm
acceptable to both of the parties certifying the propriety of
the labor costs included in the calculation.

The price per million Btu of gas shall be increased or
decreased by the amount derived by multiplying the percentage
of increase or decrease in the weighted average hourly wage
rate times $_____. The price adjustment shall be
effective with respect to gas shipped on or after the
effective date of the change in labor rates.

9.2.10   Costs Based on Values

Seller shall compute the total amounts paid governmental
bodies and ad valorem property taxes, or similar governmental
exactions, based upon the value of (a) personal property
(including intangibles where such intangibles arise solely out
of Seller's ownership or operation of the plant), (b) produc-
tion taxes, or (c) real estate (to include only real estate
needed by Seller to produce and distribute the gas where such
properties (real or personal) were owned by Seller and consti-
tute part of or were used solely in connection with the plant,
excluding any such amounts which are includable in the calcu-
lation of any other adjustment under any other provisions of
this Article. Buyer shall pay Seller, or Seller shall pay
Buyer, within a reasonable period of time after such taxes and
exactions payable for the year in question have been paid, as
the case may be, a lump sum amount equal to the total million
Btu purchased by Buyer during such year multiplied by the
greater or less than $_____. In the event that such
payments by Seller are not based on millions of Btu produced,
the total amounts paid by Seller for such year shall be
divided by the greater of 0,000,000, or the number of millions
of Btu of gas from the plant delivered by Seller to all

customers during such year. Buyer is hereby given the right
to contest the validity of, or increase in, any such tax or
exaction (in the name of Seller, if necessary); provided,
however, that such contest is handled and paid for by Buyer.
Seller shall give Buyer such assistance in prosecuting such
contest as Buyer reasonably requests, provided Buyer pays the
costs incurred by Seller in so doing.

9.2.11 Other New or Increased Taxes

The price of gas delivered hereunder shall be increased or
decreased from the basic price to reflect the amount that the
cost per million Btu of producing gas at the plant is
increased or decreased by new, additional or reduced taxes
(or changes in the rates of said taxes) of any kind whatso-
ever, enacted or effective after _____. Neither this
provision nor any other shall apply to costs relating to state
or federal taxes on net income, profits or excess profits
(except that a reduction in federal incentives shall be
deemed to be an increase in cost within this provision). In
the event that such payments by Seller are not based on Btu's
produced, the per million Btu cost of such taxes shall be
determined by dividing the amount of such taxes paid in the
fiscal year involved by the greater of the actual number of
million Btu's shipped in the previous fiscal year or
0,000,000. The calculation and payment of the amount due
hereunder shall be accomplished promptly. This section shall
not apply to taxes specified in other sections.

9.1.12 Additional Costs Imposed by Legislation, Regulation, Judicial Action, or Changes in the Method of Operation due to Material Shortages.

The price of gas shall be increased from the base price to
reflect increases in the cost per million Btu of producing gas

at the plant due to any investment (other than costs or
increases therein covered by any other Section hereof)
required in order to comply with any new legislation, regula-
tion, judicial action (other than the codification of the
common law), enacted, promulgated, or taken or made effective
after _____, which pertain to production practices,
health and safety (other than compensation to employees for
injuries or death), and all aspects of reclamation, such as
waste disposal, air and water quality standards, and the like.
In the event that a capital investment is so required, said
cost will be recovered by Seller as follows. The price per
million Btu of the first 0,000,000 million Btu multiplied by
millions of Btu to be delivered subsequent to the date of
payment of such investment cost by Seller, shall be increased
from the base price by an amount equal to $\frac{Ia}{X}$, where:

I =   The dollar cost of the investment item.

a =   The level annual payment which will amortize a one
       dollar investment over T years at Z interest rate.

Z =   The cost of money to Buyer expressed as an
       interest rate on debt securities having a maturity
       date of five (5) years obtainable by Buyer.

T =   The useful life allowed by the Internal Revenue
       Service for depreciation purposes of the investment
       item, if any, or if none, seventeen (17) years.

X =   The greater of (i) the total number of million Btu
       of gas to be delivered to all customers by Seller
       from the plant during the fiscal year the invest-
       ment is made, or (ii) _____ million (0,000,000).

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The per million Btu price of gas may be increased in the event that Seller incurs greater expense resulting from the purchase and consumption of a different item of significant materials and supplies due to the shortage or unavailability of a previously used item of significant materials and supplies, if the unit price of such different item is equal to or greater than 120 percent of the unit price of such item previously purchased and consumed in the preceding calendar quarter (the "Base Quarter"), or whenever the actual unit price of a significant item of materials and supplies purchased and consumed during any calendar quarter is equal to or greater than 120 percent of the unit price of such item purchased and consumed in such Base Quarter. A significant item of materials and supplies is herein defined as any item which represents at least 1 percent of Seller's total annual operating costs at the plant, said costs to be certified to by a national firm of independent certified public accounts. In the event the above occurs, the price of coal delivered in that fiscal quarter and each subsequent fiscal quarter during which the unit price of the items in question is equal to or greater than 120 percent of the unit price of such items in the applicable Base Quarter shall be increased by an amount equal to:

$$\frac{T(C-P) - [(I-Ib) \ (TP)]}{X}$$

C = Current fiscal quarter unit price of materials and supplies to which this paragraph applies, including "different materials and supplies" and/or "material items," where applicable.

P = Base unit price of each "previously purchased and consumed materials and supplies and/or "material items."

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T = The quantity of each item of "previously purchased and consumed materials and supplies" and/or "significant materials" purchased and consumed during the Base Quarter.

X = Total million Btu of gas produced during the applicable Base Quarter.

I = The percentage increase in the Composite Index as defined above for the quarter in question.

I_b = The value of I in the applicable Base Quarter.

9.2.13 Transfer Taxes

Buyer shall be liable for any and all applicable transfer taxes, such as sales and use taxes imposed by any governmental authority, upon the purchase or use of gas by Buyer. Buyer agrees to reimburse to Seller within twenty (20) days from the date of receipt of billing, any such transfer tax imposed upon Seller. Seller represents that as of _____, 198__, the State of Montana does not impose a sales or use tax upon a transaction such as is contemplated herein. (Needs to be verified.)

For the purpose of this section, a transfer tax is deemed to include only a tax imposed by a governmental authority upon the transfer of property from Seller to Buyer, or the consumption of property received from Seller or Buyer.

9.2.14 Other Price Adjustments

The price of gas shall be increased or decreased from the base price to compensate either party for increases or decreases

in the cost of coal, oxygen, refinery gas and utilities. The
increase or decrease shall be determined as follows. The
annualized increase or decrease in cost shall be divided by
the annual quantity of gas to be produced (expressed in
millions of Btu) to derive a dollar per million Btu cost
increase or decrease. The base gas price shall be adjusted
to reflect this change in price. The adjustment in the price
of gas under this section shall be made when the cost changes
occur and will apply to gas shipped after the effective date
of the change.

9.2.15 Composite Adjustment

The price of gas shall be increased or decreased from the
base price to compensate either party for the increases or
decreases in the various items making up the total base price
and which are not otherwise provided for herein. The
increase or decrease shall be determined as follows:

(a) _____ percent of $0.00 shall be multiplied by the
percentage increase or decrease in the weighted average
hourly wage rate (as determined above) from that in effect at
the base date.

(b) _____ percent of $0.00 shall be multiplied by the
percentage increase or decrease in the wholesale price index
for construction machinery and equipment for each calendar
quarter.

(c) _____ percent of $0.00 shall be multiplied by the
percentage increase or decrease in other price adjustments.
The base date in making both of these calculations shall
be _____, 198__. The adjustment in the price of gas under

this section shall be made (i) under subsection (a) at such time that the weighted average hourly wage rate is increased or decreased, (ii) under subsection (b) as soon after the end of each calendar quarter that the index is available for such period, and (iii) under subsection (c) when the price adjustment is made, all adjustments to apply to gas shipped after the effective date of the applicable change.

9.2.16 Quality Adjustment

Adjustments to compensate for deviations in as-received Btu from _____ shall be calculated within fifteen (15) days from the close of each calendar month with the calorific content of gas delivered during such month being the basis of adjustment. The determination of Btu content shall be made as provided by above, and shall be the basis for this price adjustment. The adjustment shall be the amount derived by the following formula:

(To be determined during negotiations)

10. GOVERNMENT ROLE

10.1 ENVIRONMENTAL

During the investigation of permit requirements for the
project, it was found that definitive regulations were not in
existence for coal gasification projects. Different views
were often expressed by personnel within a single government
agency. Such uncertainty causes an adverse impact on the
financing of the project.

It was also found that the same type of permits, air quality
for example, must be obtained from state agencies as well as
from the Federal Environmental Protection Agency. Neither
the state nor federal agency expressed a willingness to issue
a permit based on the other's recommendations or findings.
This lack of cooperation will require a duplication of per-
mitting effort and expense. The government could greatly
assist the permitting process by establishing definitive
environmental guidelines and combining federal and state
permit requirements.

10.2 DEREGULATIONS

Rapid and complete deregulation of domestic crude oil and
natural gas will allow these fuels to rise to world prices,
thus eliminating the government imposed constraint on the
competiveness of synfuels. The price of synfuel should not
be constrained by regulation.

10.3 FINANCIAL INCENTIVES

Financial incentives should be given in two categories,
owner/operator and user.

10.3.1 Owner/Operator Incentives

From the view of the Billings MBG Project, the following financial incentives/assistance would expedite the project and ensure its commercial success.

- Grants - Until medium-Btu gas is proven commercially viable, grants should be available for feasibility studies and engineering for projects of this type. The feasibility study grant Northern Resources received for this project expedited the project a minimum of one year. A follow-on grant for engineering and permitting would help ease the uncertainty arising from inconsistent of nonexistent environmental regulations and construction cost uncertainties.

- Loan Guarantees - Financial institutions are not willing to make the large sums of capital available for construction of synfuel plants without strong guarantees of repayment. In the case of the Billings MBG Project, government loan guarantees will eliminate the financial barriers and make available capital at comparatively reasonable rates resulting in lower MBG cost.

- Price Supports - Since synfuel parity with conventional energy is some years ahead, price supports are needed to expedite synfuel production if national goals are to be achieved. For this project price supports would ensure the competiveness of the MBG with the natural gas and residual fuel oil that it would replace. The price support should make up the difference between the refineries' current cost of fuel and the sales price of the MBG. The support

should be contained until parity is reached. The length of time price supports would be needed would be dependent upon world energy prices, assuming complete decontrol of natural gas and crude oil. For this project, this period is expected to be 5 to 7 years.

- Rapid Depreciation - Rapid depreciation would not be a good incentive for the Billings MBG Project. For projects with a large equity position, rapid depreciation would provide some incentive.

10.3.2 Customer Incentives

Specific financial incentives for users of synfuel would also expedite acceptance and commercial viability.

- Rapid Depreciation - In the case of MBG, retrofit costs of the refinery are small in relation to total plant cost but are a significant cost during the year incurred. Competition with other capital improvements of greater payback indicates the need for rapid depreciation for this type of investment. A one year write-off for investment of retrofit costs would increase the attractiveness of investment in fuel change.

- Tax Credits - Tax credits for the user of synfuel would provide more rapid acceptance of the higher price fuel. They should be used with price supports to achieve parity of the synfuel with fuel being replaced.

10.4 OTHER GOVERNMENT ACTIONS

During the investigation of pipeline routes it was found that the most direct route between the plant site and the Cenex Refinery would be along Interstate Highway 90. When the local, state, and federal highway right-of-way authorities were contacted regarding application for a permit to lay the pipeline inside the right-of-way, they said it could not be done. The authorities could not provide documentation that such permits were prohibited. The government could greatly improve the project economics by allowing the pipeline inside the highway right-of-way. A savings of two to three million dollars in pipeline construction costs could be achieved.

11. MARKET POTENTIAL

11.1 GENERAL REFINERY MARKET

The technical feasibility of refineries to use medium-Btu gas
has been established and documented in other studies.

Generally, refineries use energy in the form of process heat,
steam, and electricity. Process heat is developed by furnaces
and heaters to process crude oil. Steam is produced by
boilers and is used to power turbines and pumps, in heat
exchangers, and is used as a stripping agent. Electricity is
purchased or cogenerated and is used for lighting and to
power pumps. The refining industry obtains about two-thirds
of its energy from its raw materials or by-products. The
remaining one-third is purchased. Table 11-1 provides a
breakdown of energy sources and its utilization.

The largest single source of energy is off-gases from the
refining processes. This refinery gas accounts for over
40 percent of the industries energy. Other signicant sources
include natural gas, petroleum coke, residual fuel oil and
electricity. Overall, the refinery industry accounts for
4 percent of the total United States energy consumption. In
1978 the industry consumed the equivalent of 1.4 million
barrels of crude oil per day in the processing of
14.7 million barrels of crude oil per day. The potential
market for medium-Btu gas from coal is the nearly 80 percent
or 1.1 barrels of crude oil equivalent per day currently
consumed in the form of refinery gas, natural gas, and
residual fuel oil.

TABLE 11-1

1978 REFINING INDUSTRY FUEL USE

Energy Source	10^{12} Btu's	Percent
Refinery Gas	1291.7	42.2
Natural Gas	820.6	26.8
Petroleum Coke	394.8	12.9
Residual Fuel Oil	314.6	10.3
Purchased Electricity	94.8	3.1
Liquid Petroleum Gas	57.1	1.9
Distillate Fuel Oil	51.7	1.7
Purchased Steam	32.9	1.0
Coal	3.2	.1
Crude Oil	2.6	0
	3064.0	100.0

Source: "Crude Petroleum, Petroleum, and Natural Gas Liquids: 1978," U.S. Department of Energy, DOE/EIA-0108/78.

It is recognized that replacing the refinery gas could require large capital expenditures to construct additional facilties to make marketable products from the refinery gas. Accordingly, the initial market potential would be limited to replacement of natural gas and residual fuel oil which require small expenditures for retrofitting.

Natural gas and residual fuel oil represents a total 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 considered for this project), this market size 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 coal, locations 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.

11.2 BILLINGS MBG PROJECT MARKET POTENTIAL

The basic market approach utilized by Northern Resources is to size the gasification plant to the demand of a specific group of customers committed to the purchase of the industrial fuel gas. The potential for plant expansion is limited to the expansion plans of these committed customers. Since it is possible that a new MBG customer could locate near the Billings MBG Project, additional land was purchased and no cost or very inexpensive considerations for possible expansion is to be incorporated in the final design. The approach of

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establishing plant size to committed customers ensures a very
high load factor, enables selling of the MBG at the most
advantageous price, and eases financing of the project.

11.3 OTHER MARKETS

MBG as primary fuel and feedstock for other industries,
offers a broad market much larger than petroleum refining
alone. Based on industrial usage of energy in gross terms,
Northern Resources perceives the industrial fuel gas market
in total being 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 day), and load
factor (24-hour per day, 7-day per week demand). Studies by
others indicate this market could approach 900 plants
supplying 3.0 quads of energy per year.

APPENDIX A
PIPING SPECIFICATIONS

SERVICE: Instrument Air, Plant Air, inert gases

CONSTRUCTION MATERIAL: 1/2" and smaller tubing 1/2" thru 3" screwed, 3" thru 12" buttweld and Flange.

CORROSION ALLOWANCE: .1 inches

GENERAL MATERIAL: Copper tubing and carbon steel pipe.

ANSI Rating: 150 lb

TEMPERATURE RANGE: -20°F to 300°F.

MAXIMUM DESIGN PRESSURE: 275 psig at 100°F or 230 psig at 300°F.

PNEUMATIC TEST AT: 303 psig.

VALVES

Check	1/2" and smaller	VC 10A 150# scrd bronze lift type
	1/2" thru 3"	VC-10A 150# scrd, bronze lift type
	3" thru 12"	VC-18A 150# flanged, C.S., swing type
Globe	1/2" and smaller	Use VG 10A
	1/2" thru 3"	VG-10A 150# scrd, bronze
	3" thru 12"	VG-18A 150# flanged carbon steel
Gate	1/2" and smaller	VG-10A 150# scrd bronze
	1/2" thru 3"	VG-10A 150# scrd bronze
	3" thru 12"	VG-18A 150# flanged carbon steel
Ball	1/2" and smaller	VG 10A 150# scrd bronze
	1/2" thru 3"	VB-45A 600# scrd Carbon Steel
	3" thru 12"	VB-18B flanged carbon steel

TUBING   1/2" and smaller   Copper   0.032 Wall Astm B68 or Astm B75

PIPING
1/2" thru 3"   Astm A53 GrB Type E or Astm A106 GrB Sch 80
3" thru 12"   Astm A53 GrB Type E or Astm A106 GrB std wall thickness

FITTINGS

Tubings   1/2" and smaller   Swagelock tubing brass tubing fitting or approved equal

Pipe
1/2" thru 3"   3000# Forged steel scrd Astm A105
3" thru 12"   Std wall, buttweld fitting Astm A 234 WPB

FLANGES
1/2" thru 3"   150# RF threaded, Astm A105
3" thru 12"   150" RF Weldneck with the same bore as the adjoining pipe Astm A105

ORIFICE FLG
1/2" thru 3"   300# RF threaded, Astm A105
3" thru 12"   300# RF weldneck, Same bore as the adjoining pipe Astm A105

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UNIONS

Tubing	1/2" and smaller	Swagelock brass union or approved equal
Pipe	1/2" thru 3"	3000# Forged Steel Steel to Steel seats Astm A105

PLUGS

1/2" thru 3" — 3000# Forged Steel bull plug, Astm A105

NIPPLES

1/2" thru 3" — Threaded both ends, Sch 80, Astm A106

REDUCERS

Tubing	1/2" and smaller	Swagelock Brass reducer or approved equal
Piping	1/2" thru 3"	Swage Sch80 Astm A234 TBE Astm A234 WPB
	3" thru 12"	Buttwelded reducer Std wall thickness Astm A234 WPB

GASKETS

150# 1/16" compressed asbestos – flat ring.

BOLTING

Studs Astm A-193 Gr B-7 with A194 Gr 2H hvy Hex Nuts

BRANCH CONNECTION

	HEADER SIZE																	
BRANCH SIZE	24"	20"	18"	16"	14"	12"	10"	8"	6"	4"	3"	2½"	2"	1½"	1¼"	1"	3/4"	1/2"
1/2"						L	L	L	L	L	F/L		F	F		F	L	T
3/4"						L	L	L	L	L	F/L		F	F		F	T	
1"						L	L	L	L	L	F/L		F	F		T		
1¼"																		
1½"						L	L	L	L	L	F/L		F	T				
2"						L	L	L	L	L	F/L		T					
2½"																		
3"						L/W	L/W	L/W	L/W	L/W	T							
4"						W	H	H	H	T								
6"						H	H	H	T									
8"						H	H	T										
10"						H	T											
12"						T												
14"																		
16"																		
18"																		
20"																		
24"																		

CODE

C = COUPLING
E = EXTRUSION
F = TEE w/SWAGE OR REDUCER
H = TEE; REDUCING OUTLET
L = THREDOLET, SOCKOLET
R = STUB-IN, REINFORCED
S = STUB-IN, PLAIN
T = TEE, STRAIGHT
W = WELDOLET

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NOTES:

1. Vents shall be 3/4" coupling with plug.

2. Drains shall be 3/4" coupling with plug.

3. The temporary valves used to accomplish the hydrostatic test snall be removed upon the request of the customer.

4. ASTM A53 GR B smls pipe may be substituted for ASTM A106 GR B pipe when A53 GR B smls is available.

5. When Engineering judgement dictates, buttweld valves may be used in place of flanged valves. See Specification Sheets VG-20A, VU-20A, VB-20A and 20b, and VC-20A.

6. For instrument connections use 3000# FS Scr'd. ASTM A-105 half couplings or threadolets.

7. When Engineering judgement dicates the 1/2" to 3" size screwed requirement may be changed to a buttweld or socketweld design.

8. All underground piping shall be welded.

SERVICE: Fire water, Potable Water, Process water

CONSTRUCTION MATERIAL: 1/2" thru 1-1/2" screwed, 2" thru 24" butweld and flange.

CORROSION ALLOWANCE .1 Inch

GENERAL MATERIAL: Carbon Steel

ANSI RAING 150 lb RF

TEMPERATURE RANGE -20° to 400°

MAXIMUM DESIGN PRESSURE 275 psig at 100°F or 200 psig at 400°F

HYDROSTATIC TEST at 425 psig

VALVES   (See Note 5)

Check	1-1/2" and smaller	VC-10A 150# scrd, bronze, lift type
	2" and larger	VC-18A 150# flanged, swing type
Globe	1-1/2" and smaller	VO-10A 150# scrd, bronze ISRS
	2" and larger	VO-18A 150# flanged, OS&Y
Gate	1-1/2" and smaller	VG-10A 150# scrd, bronze ISRS
	2" and larger	VG-20A 150# buttweld, OS&Y
Butterfly	2" thru 12"	VF-22C 150# wafer, CS body
	2" thru 6"	VF-16A 150# wafer, CI body, (Firewater)
PIPE	1/2" thru 1-1/2"	ASTM A120 Galvanized Sch. 80
	1/2" thru 1-1/2"	ASTM A53 Gr.B Type E or A106 Gr.B Sch. 80
	2" thru 24"	ASTM A53 Gr.B Type E or ASTM A106 Gr.B. Std Wall Thickness
FITTINGS	1/2" thru 1-1/2"	300# Mallable iron, scrd, Galv. ASTM A47 Gr.32510
	1/2" thru 1-1/2"	3000# ASTM A105 Sch. 80
	2" thru 24"	Std Wall, buttweld fittings ASTM A234 WPB
FLANGES	1/2" thru 1-1/2"	150# RF (FF if companion flange is FF), threaded, ASTM A105
	2" thru 24"	150#RF (FF if companion flange is FF), weldneck, same bore as the adjoining pipe, ASTM A105
ORIF. FLGS.	1/2" thru 1-1/2"	300# RF, threaded, ASTM A105
	2" thru 24"	300# RF weldneck, same bore as the adjoining pipe, ASTM A105
UNIONS	1/2" thru 1-1/2"	300# Mallable iron, Galv. metal to metal seats - ASTM A47 Gr 32510
	1/2" thru 1-1/2"	3000# F.S. ASTM A105 metal to metal seats

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Ford, Bacon & Davis Utah Inc.

SALT LAKE CITY, UTAH

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PLUGS	1/2" thru 1-1/2"	3000# FS, bull plug.- ASTM A105
NIPPLES	1/2" thru 1-1/2" 1/2" thru 1-1/2"	Sch 80, TBE – ASTM A120 Galv. Sch 80, TBE – ASTM A106
REDUCERS	1/2" thru 1-1/2" 1/2" thru 1-1/2" 2" thru 24"	Reducer Coupling, Galvanized ASTM 47 Gr 32510 Swage Sch 80, TBE – ASTM A106 Buttweld reducer with std wall thickness, ASTM A234 WPB
GASKETS		150# 1/16"compressed asbestos – flat ring (full face for FF flanges)
BOLTING		Studs – ASTM A-193 GR B-7 W/A-194 GR 2H Hvy Hex Nuts

BRANCH CONNECTION

BRANCH SIZE \ HEADER SIZE	24"	20"	18"	16"	14"	12"	10"	8"	6"	4"	3"	2½"	2"	1½"	1¼"	1"	3/4"	1/2"
1/2"	L	L	L	L	L	L	L	L	L	L	L		L	L		L	L	T
3/4"	L	L	L	L	L	L	L	L	L	L	L		L	L		L	T	
1"	L	L	L	L	L	L	L	L	L	L	L		L	L		T		
1¼"																		
1½"	L	L	L	L	L	L	L	L	L	L	L		L	T				
2"	S	S	S	S	S	S	S	S	S	H	H		T					
2½"																		
3"	W	W	W	W	W	W	W	H	H	H	T							
4"	W	W	W	W	W	W	H	H	H	T								
6"	W	W	W	W	W	H	H	H	T									
8"	W	W	W	W	W	H	H	T										
10"	W	W	W	H	H	H	T											
12"	W	W	W	H	H	T												
14"	W	W	W	H	T													
16"	W	W	H	T														
18"	W	W	T															
20"	W	T																
24"	T																	

CODE
C=COUPLING
E=EXTRUSION
F=TEE W/SWAGE OR REDUCER
H=TEE: REDUCING OUTLET
L=THREDOLET, SOCKOLET
R=STUB-IN, REINFORCED
S=STUB-IN, PLAIN
T=TEE, STRAIGHT
W=WELDOLET

A-6

NOTES:

1. Vents shall be 3/4" coupling with plug.

2. Drains shall be 3/4" coupling with plug.

3. The temporary valves used to accomplish the hydrostatic test shall be removed upon the request of the customer.

4. ASTM A53 GR B smls pipe may be substituted for ASTM A106 GR B pipe when A53 GR B smls is not available.

5. When Engineering judgement dictates, buttweld valves may be used in place of flanged valves. See Specification Sheets VG-20A, VO-20A, and VC-20A.

6. For instrument connections use 3000# FS ASTM A105 Scr'd half couplings, threaolets, or 300# Mallable Iron scr'd Tec ASTM A-47 Gr 32510

7. When Engineering judgement dictates the 1/2" to 1 1/2" size screwed requirement may be changed to a buttweld or socketweld design.

8. All underground piping shall be welded.

SERVICE: Flammable Gases, Steam, Condensates, Hydrocarbon liquids

CONSTRUCTION MATERIAL 1/2 thru 1-1/2 socketweld 2" thru 14" buttweld and flange

CORROSION ALLOWANCE 1 inch

GENERAL MATERIAL Carbon Steel

ANSI RATING 150 lb

TEMPERATURE RANGE -20°F to 400°F

MAXIMUM DESIGN PRESSURE 275 psig at 100°F or 200 psig at 400°F

HYDROSTATIC TEST at 425 psig

VALVES   (See Notes 5 and 9)

Check	1/2" thru 1-1/2"	VC-49A 600# swing check, socketweld
	2" thru 14"	VC-18A 150# swing check, flanged
Plug	1/2" thru 1-1/2	VP-27A 300# screwed (seal welded)
	2" thru 4"	VP-18A 150# flanged
	6" thru 14"	VP-18B 150# Flanged
Ball	1/2" thru 1-1/2"	VB-12D 150# socketweld
	2" thru 4"	VB-18B 150# flanged
Globe	1/2" thru 1-1/2"	VO-49A 600# socketweld
	2" thru 14"	VO-18A 150# flanged
Gates	1/2" thru 1-1/2"	VG-30A 300# socketweld
	2" thru 14"	VG 18A 150# flanged
Butterfly	2" thru 12"	VF-22C 150# wafer, CS body
PIPE	1/2" thru 1-1/2"	ASTM A53 GrB Type E or A106 GrB Sch. 80
	2" thru 14"	ASTM A53 GrB Type E or A106 GrB Std Wall thickness
FITTINGS	1/2" thru 1-1/2"	3000#FS, socketweld ASTM A105
	2" thru 14"	Std Wall thickness, buttweld fittings ASTM A234 WPB
FLANGES	1/2" thru 1-1/2"	150# RF, socketweld, ASTM A105 (see Note 9)
	2" thru 14"	150# RF, weldneck, same bore as the adjoining pipe, ASTM A105 (see Note 9)
ORIF. FLGS.	1/2" thru 1-1/2"	300# RF, socketweld, ASTM A105
	2" thru 14"	300# RF weldneck, same thickness as bore as the adjoining pipe, ASTM A105
UNIONS	1/2" thru 1-1/2"	3000# FS, Steel to steel seats - ASTM A105

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	Spec No. 1CB

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PLUGS	1/2" thru 1-1/2"	3000# FS, bull plug, ASTM A105
NIPPLES	1/2" thru 1-1/2"	Sch 80 plain both ends, ASTM A106.
REDUCERS	1/2" thru 1-1/2" 2" thru 14"	Swage Sch.80 plain both ends ASTM A234 WPB Buttwelded reducer with the std wall thickness, ASTM A234 WPB
GASKETS		150# 1/8" Spiral Wound 304 SS w/asbestos filler Flexitallic Style CG
BOLTING		Studs — ASTM A-193 GR B-7 w/A-194 GR 2H Hvy hex Nuts

BRANCH CONNECTION

BRANCH SIZE \ HEADER SIZE	24"	20"	18"	16"	14"	12"	10"	8"	6"	4"	3"	2½"	2"	1½"	1¼"	1"	3/4"	1/2"
1/2"					L	L	L	L	L	L	L		L	H		H	H	T
3/4"					L	L	L	L	L	L	L		H	H		H	T	
1"					L	L	L	L	L	L	H		H	H		T		
1¼"																		
1½"					L	L	L	L	L	H	H		H	T				
2"					S	S	S	S	S	H	H		T					
2½"																		
3"					W	W	W	H	H	H	T							
4"					W	W	H	H	H	T								
6"					W	H	H	H	T									
8"					H	H	H	T										
10"					H	H	T											
12"					H	T												
14"					T													
16"																		
18"																		
20"																		
24"																		

CODE
C=COUPLING
E=EXTRUSION
F=TEE w/SWAGE OR REDUCER
H-TEE: REDUCING OUTLET
L=THREDOLET, SOCKOLET
R=STUB-IN, REINFORCED
S=STUB-IN, PLAIN
T=TEE, STRAIGHT
W=WELDOLET

NOTES:

1. Vents shall be 3/4" coupling or threadolets with plug.

2. Drains shall be 3/4" coupling or threadolets with plug.

3. The temporary valves used to accomplish the hydrostatic test shall be removed upon the customer's request.

4. ASTM A53 GR B smls pipe may be substituted for ASTM A106 GR B pipe when A53 GR B smls is available.

5. When engineering judgement dictates, buttweld valves may be used in place of flanged valves. See Specification Sheets VC-20A, VB-20A & 20B, VO-20A, and VG-20A.

6. For instrument connections use 3000# FS Scr'd. ASTM A-105 half couplings or threadolets.

7. When engineering judgement dictages the 1/2" to 1-1/2" size socketweld design may be changed to a buttweld or screwed design.

8. All underground piping shall be socketwelded or buttwelded.

9. All gas service containing free hydrogen gas shall be a minimum of 300# ANSI class rating, all screwed connection shall be seal welded, and all screwed instrumentation connections shall be seal welded up to the first block valve. For Flanged Valve use specification sheets VC-33A, VP-33A & B, VB-33A and VG-33A.

A-10

SERVICE: Flammable gases,
          hydrocarbon liquids,
          steam, condensates,
          refrigerants

CONSTRUCTION MATERIAL 1/2 thru 1-1/2 socket welded 2" thru 12" buttweld and flange

CORROSION ALLOWANCE .1 inch

GENERAL MATERIAL Carbon Steel

ANSI RATING 300 lb RF

TEMPERATURE RANGE -20°F to 400°F

MAXIMUM DESIGN PRESSURE 740 psig at 100°F or 635 psig at 400°F

HYDROSTATIC TEST at 1110 psig

VALVES (See Note 5)

Check	1/2" thru 1-1/2"	VC-61A, 600# lift check, socket weld
	2" thru 12"	VC-33A, 300# swing check, flanged
Plug	1/2" thru 1-1/2	Use VG-30A
	2" thru 4"	VP-33A & B, 300# plug, flanged
Ball	1/2" thru 1-1/2"	VG-30A, 600# ball, socket weld
	2" thru 12"	VB-33A, 300# ball, flanged
Globe	1/2" thru 1-1/2"	VO-73A, 800# gobe, socket weld, FS
	2" thru 12"	VO-33A, 300# globe, flanged
Gate	1/2" thru 1-1/2"	VG-30A, 800# gate, socket weld
	2" thru 12"	VG-33A, 300# gate, flanged
Butterfly	3" thru 12"	VF-30A, 300# wafer,
PIPE	1/2" thru 1-1/2"	ASTM A53 GrB Smls or A106 GrB Sch 80
	2" thru 12"	ASTM A53 GrB Smls or A106 GrB Std Wall thickness
FITTINGS	1/2" thru 1-1/2"	3000# FS, socket welded ASTM A105
	2" thru 12"	buttweld fittings, Std wall thickness - ASTM A234 WPB
FLANGES	1/2" thru 1-1/2"	300# RF, socketwelded, same bore as the adjoining pipe, ASTM A105
	2" thru 12"	300# RF, weldneck, same bore as the adjoining pipe, ASTM A105
ORIF. FLGS.	1/2" thru 1-1/2"	300# RF, Socketweld, same bore as the adjoining ASTM A105
	2" thru 12"	300# RF, weldneck, same bore as the adjoining ASTM A105

A-11

UNIONS	1/2" thru 1-1/2"	3000#FS, Socketweld, steel to steel seats ASTM A105
PLUGS	1/2" thru 1-1/2"	3000# FS, bull plug – ASTM A105
REDUCERS	1/2" thru 1-1/2" 2" thru 12"	Swage Sch 80, plain end – ASTM A234 buttwelded reducer, Std wall thickness, ASTM A234 WPB.
GASKETS		300# spiral wound, 1/8", type 304 SS coils w/asbestos filler-flexitallic Style CG
BOLTING		Studs – A193 GR B-7 w/A-194 GR 2H Hvy hex Nuts

BRANCH CONNECTION

BRANCH SIZE	HEADER SIZE																	
	24"	20"	18"	16"	14"	12"	10"	8'	6'	4"	3'	2½"	2"	1½"	1¼"	1"	3/4"	1/2"
1/2'						L	L	L	L	L	L		L	H		H	H	T
3/4'						L	L	L	L	L	L		H	H		H	T	
1'						L	L	L	L	L	H		H	H		T		
1¼'																		
1½'						L	L	L	L	H	H		H	T				
2"						S	S	S	S	H	H		T					
2½'																		
3'						W	W	H	H	H	T							
4'						W	H	H	H	T								
6'						W	H	H	T									
8'						H	H	T										
10'						H	T											
12'						T												
14'																		
16'																		
18"																		
20'																		
24"																		

CODE
C=COUPLING
E=EXTRUSION
F=TEE w/SWAGE OR REDUCER
H=TEE; REDUCING OUTLET
L=THREDOLET, SOCKOLET
R=STUB-IN, REINFORCED
S=STUB-IN, PLAIN
T=TEE, STRAIGHT
W=WELDOLET

A-12

NOTES:

1. Vents shall be 3/4" thredolet with plug.

2. Drains shall be 3/4" thredolet with plug.

3. The temporary valves used to accomplish the hydrostatic test shall be removed upon customer request.

4. When engineering judgement dictates, buttweld valves may be used in place of flanged valves. See Valve Specification Sheets VC-36A, VP-36A, VB-34A & B, VO-36A, and VG-36A.

5. For instrument connections use 3000# FS. ASTM A-105 threadolets or screwed half couplings.

6. When engineering judgement dictates, the 1/2" to 1-1/2" size socketweld requirement may be changed to a buttwelded or screwed design.

7. All underground piping shall be welded.

A-13

SERVICE: Flammable gases,
           steam, condensates,
           refrigerant hydro-
           carbon liquids

CONSTRUCTION MATERIAL: 1/2" thru 1-1/2"
socketweld 2" thru 12" buttweld and flange

CORROSION ALLOWANCE .1 inches

GENERAL MATERIAL: Carbon Steel

ANSI Rating   600 lb

TEMPERATURE RANGE -20°F to 750°F

MAXIMUM DESIGN PRESSURE 1480 psig at 100°F or 885 psig at 750°F

HYDROSTATIC TEST at 2220 psig

VALVES

Check	1/2" thru 1-1/2"	VC-61A, 800# swing check, socketweld
	2" thru 12"	VC-54A, 600# swing check, buttweld
Plug	1" thru 1-1/2"	Use ball valve
	2" thru 6"	VP-54A, 600# plug, buttweld
	6" thru 12"	Use Butterfly valve
Ball	1/2" thru 1-1/2"	VB-46A, 600# ball, socketweld
	2" thru 4"	VB-50A, 600# ball, buttweld
	6" thru 12"	VB-50B, 600# ball, buttweld
Globe	1/2" thru 1"1/2"	VO-61A, 800# globe, FS socketweld
	2" thru 12"	VO-54A, 600# globe, buttweld
Gate	1/2" thru 1-1/2"	VG-60A, 800# gate, socketweld
	2" thru 12"	VG-54B, 600# gate, buttweld
butterfly	3" thru 12"	VG-50A 600# wafer
PIPE	1/2 thru 10	Astm A53 GrB smls or Astm A106 GrB x Strong wall thickness
	12	Astm A53 GrB Smls or Astm A106 GrB Sch 80
FITTING	1/2" thru 1-1/2"	Socketweld fitting xstrg wall thickness ASTM A105
	1/2" thru 12"	Buttwelded fitting with the same wall thickness as the adjoining pipe ASTM A234 WPB
FLANGES	1/2" thru 12"	600# RF, weldneck with the same bore as the adjoining pipe, ASTM A105
PLUGS	1/2" thru 1-1/2	3000# FS, bull plug ASTM A105

A-14

REDUCERS	1/2" thru 1-1/2"	Swage plain end xstrg ASTM A234 WPB
	2" thru 10"	Buttwelded reducer, xstrg wall thickness ASTM A234 WPB
	12"	Buttwelded reducer, Sch 80, ASTM A234 WPB
GASKETS		600# 1/8" spiral wound, 304 SS winding, asbestos filled, flexitallic type CG
BOLTING		Studs – ASTM A193 GR B-7 w/A-194 GR 2H Hvy Hex Nuts

BRANCH CONNECTION

		HEADER SIZE																	
		24"	20"	18"	16"	14"	12"	10"	8"	6"	4"	3"	2½"	2"	1½"	1¼"	1"	3/4"	1·2"
BRANCH SIZE	1/2"						L	L	L	L	L	L		L	L		L	L	T
	3/4"						L	L	L	L	L	L		L	L		L	T	
	1"						L	L	L	L	L	L		L	L		T		
	1¼"																		
	1½"						L	L	L	L	L	L		L	T				
	2"						W	W	W	W	H	H		T					
	2½"																		
	3"						W	W	H	H	H	T							
	4"						W	H	H	H	T								
	6"						H	H	H	T									
	8"						H	H	T										
	10"						H	T											
	12"						T												
	14"																		
	16"																		
	18"																		
	20"																		
	24"																		

CODE
C=COUPLING
E=EXTRUSION
F=TEE W/SWAGE OR REDUCER
H=TEE, REDUCING OUTLET
L=THREDOLET, SOCKOLET
R=STUB-IN, REINFORCED
S=STUB-IN, PLAIN
T=TEE, STRAIGHT
W=WELDOLET

NOTES:

1. Vents shall be 3/4" thredolet with plugs.

2. Drains shall be 3/4" thredolet with plugs.

3. The temporary valve used to accomplish the hydrostatic test shall be removed upon customer request.

4. When engineering judgement dictates, RF flanged valves may replace buttweld valves. See Valve Specification Sheets VC-51A, VPA & B, VB-51A & B, VO-51A, and VG-52A.

5. For instrument, connections use 3000# FS Scr'd. ASTM A-105 half couplings or Thredolet and use Valve VG-50A.

6. For high pressure grease and oil piping when no corrosion allowance is needed, see the engineer for maximum pressure and temperature limits.

APPENDIX B

OSBL PRELIMINARY DESIGN DRAWINGS

7K-1
RECIP COMPRESSOR

7K-3
FLARE STACK

7K-2
RECIP COMPRESSOR

7K-3
RECIP COMPRESSOR

7K-1
GLYCOL DEHYDRATOR

7K-2
GLYCOL DEHYDRATOR

COAL GASIFICATION SYSTEM (DRY FEED)

ACID GAS REMOVAL UNIT 300

ACID GAS REMOVAL UNIT 700

SOUR WATER STRIPPER UNIT 500

SULFUR RECOVERY UNIT 400

TAIL GAS INCINERATOR UNIT 600

GAS CLEAN UP / SULFUR RECOVERY SYSTEM

COAL

OXYGEN

BOILER FEED WATER

EXPORT STEAM

CHAR

BLOWDOWN

BOILER

GASIFIED COAL

SULFUR

PRODUCT GAS

STARTUP PROPANE

GLYCOL REGEN.

GLYCOL REGEN.

DRY GLYCOL

DRY GLYCOL

VENT

VENT

CONDENSATE

PRODUCT GAS TO OUTPUT
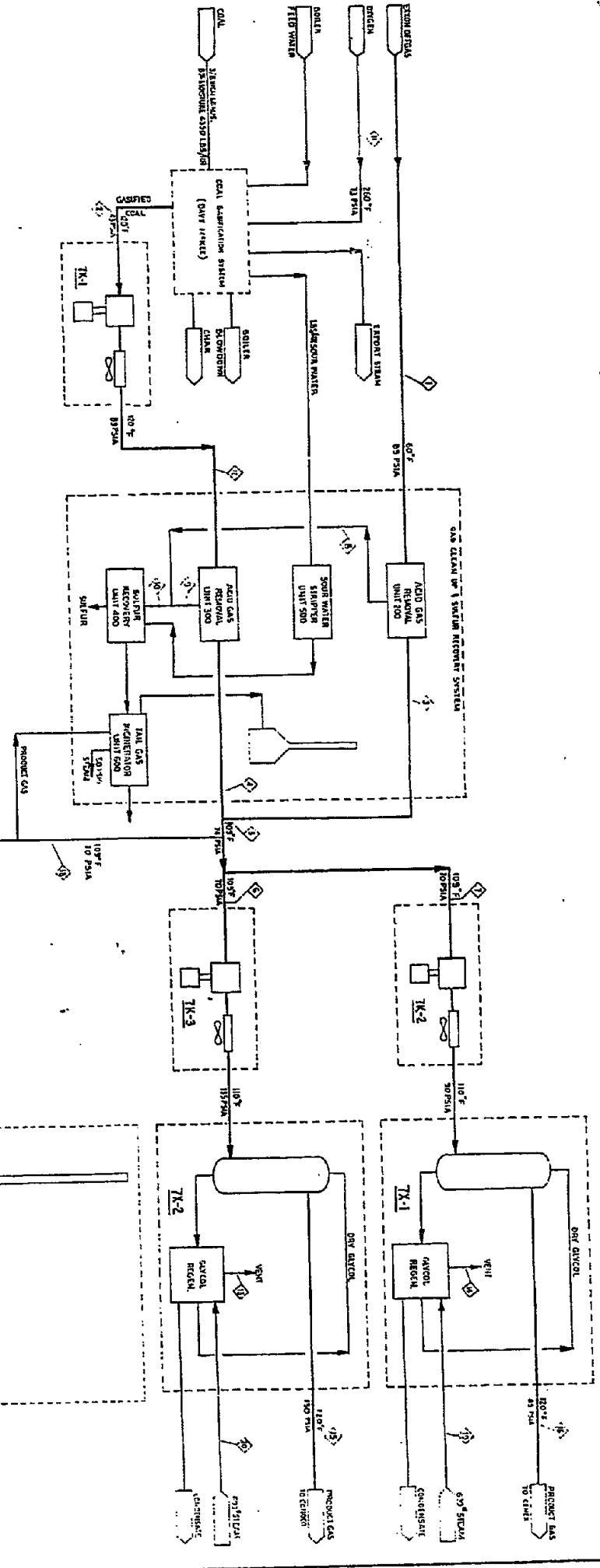
NOTES:
_____ INDICATES PACKAGE UNIT OR COMPLETE SYSTEM
_____ INDICATES MAIN STREAM
_____ INDICATES SUB-STREAMS

B-2

Process Flow Sheet — Water Treatment Facility, Coal Gasification Project

MASS FLOW BASIS:
1. BOILER SIZE 30,000 LBS/HR AT ... GAL
2. 80% CONVERSION OF CARBON
3. 30% EXCESS AIR
4. 60% BOTTOM ASH, 40% FLY ASH
5. 99% DUST COLLECTOR EFFICIENCY
6. 23.4% TOTAL MOISTURE, ... IN COAL

1HP-1
TRUCK DUMP HOPPER
130 TDN

1HP-1

1F-1

1C-1
BELT CONVEYOR
24" WIDE, 240 TPH
75 HP

1P-1
SUMP PUMP
100 GPM, 100' TDH

1P2-1
BELT SCALE
REMOTE TOTALIZER
TPH METER

1F-3
DUST COLLECTION
4000 GPM, PULSE JET
20HP FAN, ROTARY VALVE

IVF-1 & IVF-2
IVF-1 (REAR SIDE)
IVF-2 (FAR SIDE)
VIBRATING FEEDERS
96" WIDE x 54' LONG
0 TO 550 TPH
2HP EX-PROOF

1F-1
DUST COLLECTION
1000 GPM
ROTARY VALVE

1F-2
VENT FILTER
1000 GPM

IVF-3, IVF-4, IVF-5
VIBRATING FEEDERS
18" WIDE x 30' LONG
3 @ 30 TPH
½ HP EX-PROOF

1SL-1
RAW COAL SILO
13,000 TONS
70 TON x 100' HIGH
ROOF EXPLOSION DOORS

1C-2
BELT CONVEYOR
24" WIDE, 20 TPH
5 HP

1MS-1
MAGNETIC SEPARATOR
23 TPH STEAM FIRED
13,000,000 BTU/HR
100 HP DRIVE
EX-PROOF

1E-1
HEATING COIL

1D-1
THERMAL DRYER
23 TPH STEAM FIRED
13,000,000 BTU/HR
100 HP DRIVE
EX-PROOF

1C2-1
CRUSHER-RAW COAL
PRODUCT ¼" x 0
20 TPH
15 HP EX-PROOF

1SF-1
SCREW FEEDER

1F-6
DUST COLLECTION
4000 CFM
20 HP FAN
ROTARY VALVE
SCREW CONVEYOR

1C-3
BELT CONVEYOR
24" WIDE, 20 TPH
5 HP

1B-1
PREPARED COAL
BIN
250 TON

IVF-6 & IVF-7
VIBRATING FEEDERS
50" WIDE x 54' LONG
0 TO 350 TPH
2 HP

1B-1

IC-4 & IC-5
24" WIDE, 250 TPH
50 HP

GASIFICATION PLANT

SEE SHEET "2"

IG-1, IG-2, IG-3
SURGE GATES

B-5

COMPRESSOR UNIT
7K-1

FIREWATER PUMP
11P-1

JOCKEY PUMP
11P.

SOUR GAS CLEAN-UP
UNIT 300

7K-1

UNIT 300
INCLUDES: INCINERATOR
AMINE REGENERATION
SULFUR RECOVERY

LEAN AMINE

RICH AMINE

GAS FROM COAL
GASIFIER

GAS FROM COAL
GASIFIER CNDS. TO
DRY SCRBR

GAS FAN EXSTN

REFINERY
INSTRUMENT
D-355-D

NITROGEN
BOILER

FEEDWATER
D-555-D

SOUR WATER
MAKEUP

FIREWATER

NOTE:
* TO FLARE HEADER

11P-1A

11P-1B

11P-2

GAS
SAMPLING
SYSTEM

FUEL GAS

TO INCINERATOR
FUEL GAS

FROM GAS TO 2-265
COMPRESSOR UNITS

TO OFFICE
SPRINKLING SYSTEM
TO FIREHYDRANTS

TO FIRE CABINET
HI COAL PREP PLUS-

TO CHAMBER

UNIT
TO AUXILIARY

BOILER BUILDING,
COOLING WATER

TO COM.

REVISIONS

REFERENCE DRAWINGS

ISSUE RECORD

ENGR. RECORD

CURRENT DRAWING STATUS

INSTRUMENTS

PIPING & INSTRUMENTATION DIAGRAM
PRODUCT GAS SYSTEM
NRI COAL GASIFICATION

Ford, Bacon & Davis Utah, Inc.

B-7

FLARE
7X-3

PROPANE
TANK

PLANT AIR
COMPRESSOR
10K-1

PLANT AIR
RECEIVER
10V-1

INSTRUMENT NITROGEN
RECEIVER
10V-2

FUEL GAS
FUEL GAS
TO INCINERATOR
OILY SEWER

OXYGEN
NITROGEN
AIR

TRUCK UNLOADING
PROPANE RECEIVING

PSV & ESD AT COAL GAS I
PSV & ESD AT GAS BLEND..
PSV & ESD AT GAS TO COMP...
PSV & ESD AT GAS TO OXYGEN
PROPANE PSV

COOLING WATER
RETURN
COOLING WATER
SUPPLY

10K-1
10V-1
10V-2

REVISIONS
DESCRIPTION | DATE | BY | CHK'D | APP'D | NO

REFERENCE DRAWINGS
TITLE | DRAWING NO

ISSUE RECORD

ENGR RECORD
CURRENT DRAWING STATUS

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

PIPING & INSTRUMENTATION DIAGRAM
UTILITY PIPING
N.R.1. COAL GASIFICATION

SCALE | DWG NO | D-353-D-005 | REV A

TO WAREHOUSE
TO GASIFIER
TO GAS COMPRESSION
AREA
TO OXIDIZER
UNIT
TO GAS
TO AUXILIARY
BOILER HOUSE
TO COAL PREP
DESULFUR AREA
TO GAS COMP &
BOILER
TO AUXILIARY
SILOS
TO GAS
TO CO...
OXYGEN
AREA

WASTE WATER COLLECTION SUMP
13T-1

WASTE WATER SUMP PUMPS
13P-1A & 1B
FLOW: 130 GPM
HD: 100 FT.
HP: 15

13P-1A
13P-1B
13T-1

WASTE WATER TREATMENT
UNIT 1300
GRAVITY SEPARATION AND FLOCCULATION
CHEMICAL FEED

WASTE WATER TREATMENT
ENHANCED GRAVITY TYPE

OIL SETTLING TANK

STORM POND RETURN PUMPS
13P-2A & 2B
FLOW: 130 GPM
HD: 100 FT
HP: 15

STORM POND
13X-2

13P-2A
13P-2B
13X-2

WASTE WATER IN
STORM POND

SPENT WATER

RECOVERED OIL TO OFFSITE DISPOSAL VIA VACUUM TRUCK

SLUDGE SETTLING
TRASH SCREENS

TO BILLINGS
TO TREATMENT
SANITARY SEWAGE
WASTE WATER FROM PLANT STORM RETURN

NOTE
ALL ABOVE PIPING IS OF 304 MATERIAL TYPE

REVISIONS
NO | DESCRIPTION | DATE | BY | CHK'D | APP'D
REFERENCE DRAWINGS
DRAWING NO | TITLE
ISSUE RECORD
DATE | ISSUE | REV
ENGR RECORD
ISSUE DATE
CURRENT DRAWING STATUS
ISSUE DATE

Ford, Bacon & Davis Utah, Inc.

PIPING & INSTRUMENTATION DIAGRAM
WATER TREATING SYSTEMS
NRI COAL GASIFICATION
BILLINGS MONTANA

DWG NO
D-353-D-006

COOLING WATER
CHEMICAL SYSTEM
14A-1

BOILER WATER
TREATING SYSTEM
11X-1

BOILER FEEDWATER
CHEMICAL SYSTEM
12A-1
(CORR. INHIBITOR)

BOILER FEEDWATER
CHEMICAL SYSTEM
12A-2
(OXYGEN SCAVENGER)

ACID STORAGE
TANK
12T-1

CAUSTIC STORAGE
TANK
12T-3

COOLING
TOWER
14X-1

COOLING WATER
CIRC. PUMPS
14P-1A & 1B

150° STEAM

SCALE INHIBITORS
ACRYLATE
PHOSPHONATE

BOILER WATER
TREATMENT SYSTEM
UNIT 1230

GRAVITY FEED

GRAVITY FEED

ACID
12T-1

CAUSTIC
12T-3

14P-1A

14P-1B

14X-1

NOTES:
ALL MAJOR PIPE ARE OF A
ICA MATERIAL SPECIFICATION

Ford, Bacon & Davis Utah, Inc.

PIPING & INSTRUMENTATION DIAGRAM
WATER TREATING SYSTEMS
HRI COAL GASIFICATION
RESOURCES INC

D-355-0-001

BOILER FEEDWATER STORAGE TANK 12T-1

DEAERATOR FEED PUMPS 12P-3A&3B

150° BOILER FEED PUMPS 12P-2A&2B

DEAERATOR 12V-1

600° BOILER FEED PUMPS 12P-1A&1B

OXYGEN SCAVENGER FEED SYSTEM 12A-2

CORROSION INHIBITOR FEED SYSTEM 12A-1

12T-1

12V-1

12P-3A
12P-3B
12P-2A
12P-2B
12P-1A
12P-1B

12A-2
12A-1

VENT

NOTE:
ALL MAJOR PIPE IS 6"
A 1CA NAIL CO.

REVISIONS
DESCRIPTION | DATE | BY | CHK'D | APP'D
REFERENCE DRAWINGS
ISSUE RECORD
ENGR. RECORD
DRAWING NO

BOILER LAYOUT

MECH TUBE COLLECTOR

BAGHOUSE

BOILER

BOILER

TRUCK DUMP HOPPER

CONVEYOR /C-1
24 BELT 150TPH

GENERAL PLANT

CONVEYOR N°3 IC-4 T/C-S
30 BELT 250 TPH

CONVEYOR IC-2
24 BELT

CONVEYOR IC-3
24 BELT 150 TPH

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

COAL GASIFICATION FACILITY
COAL PREP PLANT

ENERGY MANAGEMENT RESOURCES, INC.
BILLINGS, MONTANA

D 553-M-005

Ford, Bacon & Davis Utah, Inc.

COAL GASIFICATION FACILITY
SITE PLAN

PLAN

PERSPECTIVE VIEW

REVISIONS

NO	DESCRIPTION	DATE	BY	CHK'D	APP'D

REFERENCE DRAWINGS

DRAWING NO	TITLE	DATE	ISSUE	REV

ISSUE RECORD

ENGR. RECORD

CURRENT DRAWING STATUS

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

COAL GASIFICATION FACILITY
OFFICE SPACE & WAREHOUSE
ARCHITECTURE PLAN & PERSPECTIVE

PRELIMINARY

Ford, Bacon & Davis Utah Inc.

TITLE: COAL GASIFICATION FACILITY
ONE LINE DIAGRAM

REVISIONS

REFERENCE DRAWINGS

ISSUE RECORD

ENGR RECORD

CURRENT DRAWING STATUS

APPENDIX C
ISBL MATERIAL BALANCES

DavyMcKee   MATERIAL BALANCE SHEET

PROJECT NUMBER: RC-5409   PROJECT NAME: WINKLER GASIFICATION 5.6 BILLION BTU/DAY   CLIENT: NORTHERN RESOURCES   Sheet 1 of 1

STREAM NUMBER			1 TOTAL PLANT DRIED COAL		2 COAL FEED PER TRAIN		3 TOTAL PLANT OXYGEN		4 OXYGEN PER TRAIN		5 PLANT RAW REQUIRED		6 RAW PER TRAIN	
PHASE			S		S		G		G		L		L	
DESCRIPTION / COMPONENT	MOL WT		LB/HR	WT %	LB/HR	WT %	MOL/HR	VOL %	MOL/HR	VOL %	LB/HR	WT %	LB/HR	WT %
CARBON	12.011		19186	60.85	9593	60.85								
HYDROGEN	2.016		1300	4.12	650	4.12								
OXYGEN	32.000		4084	12.95	2042	12.95	565.20	99.50	282.60	99.50				
NITROGEN	28.014		280	0.89	140	0.89	2.84	0.50	1.42	0.50				
SULFUR	32.060		274	0.87	137	0.87								
CHLORIDE	--		2	0.01	1	0.01								
ASH	--		3882	12.31	1941	12.31								
WATER	18.016		2522	8.00	1261	8.00					47320	100.00	23660	100.00
CARBON MONOXIDE	28.011										(TDS-150PPM)		(TDS-150PPM)	
CARBON DIOXIDE	44.011													
METHANE	16.043													
HYDROGEN SULFIDE	34.076													
CARBONYL SULFIDE	60.071													
TOTAL			31530	100.00	15765	100.00	568.04	100.00	284.02	100.00	47320	100.00	23660	100.00
TOTAL GAS FLOW - MOL/HR.	(DRY)						568.04		284.02					
WATER (V)/DRY GAS	(VOL/VOL)													
TOTAL (WET) FLOW, LB/HR			31530		15765		18166		9083		47320		23660	
PRESSURE - PSIA							75		75		715		715	
TEMPERATURE - °F			AMB		AMB		257		257		229		228	
VOL. FLOW RATE - SCFH (DRY)														
HHV BTU/LB			10397		10397									
HHV BTU/SCF DRY GAS														

5070   1-6152-VHD

Davy McKee   MATERIAL BALANCE SHEET   PROJECT NUMBER PC-5409   PROJECT NAME _____   CLIENT _____

STREAM NUMBER		7		8		9		10		11		12		13	
DESCRIPTION		NET 610 PSIG STEAM EXPORT		LP STEAM VENT PER TRAIN		BLOWDOWN PURGE PER TRAIN		TOTAL VENT STEAM		TOTAL PLANT BLOWDOWN		PRODUCT GAS PER TRAIN		TOTAL PRODUCT GAS	
PHASE		G		G		L		L		L		G		G	
COMPONENT	MOL WT	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	MOL/HR	VOL %	MOL/HR	VOL %
CARBON	12.011														
HYDROGEN	2.018											423.90	36.63	847.80	36.63
OXYGEN	32.000														
NITROGEN	28.014											12.74	1.10	25.48	1.10
SULFUR	32.060														
CHLORIDE	--														
ASH	--														
WATER	18.018	25512		415		1029		830		2058		43.90	3.79	87.80	3.79
CARBON MONOXIDE	28.011											437.31	37.78	874.62	37.78
CARBON DIOXIDE	44.011											207.98	17.97	415.96	17.97
METHANE	16.043											27.93	2.41	55.86	2.41
HYDROGEN SULFIDE	34.078											3.35	0.29	6.70	0.29
CARBONYL SULFIDE	60.071											0.29	0.03	0.58	0.03
TOTAL		25512	100.00	415	100.00	1029	100.00	830	100.00	2058	100.00	1157.40	100.00	2314.80	100.00
TOTAL GAS FLOW, MOL/HR. (DRY)												1113.50		2227.00	
WATER IN/DRY GAS (VOL/VOL)												0.0394		0.0394	
TOTAL (WET) FLOW, LB/HR		25512		415		1029		830		2058		23973		47946	
PRESSURE - PSIA		625		20		20		20		20		44.7		44.7	
TEMPERATURE -- °F		491		227		227		227		227		120		120	
VOL FLOW RATE - SCFH (DRY)												422562		845124	
HHV BTU/LB															
HHV BTU/SCF DRY GAS												275.9		275.9	

INCLUDES SOME SLIP HYDROGEN FROM COAL FEED SYSTEM

Davy McKee   MATERIAL BALANCE SHEET   PROJECT NUMBER PC-5409   PROJECT NAME _____   CLIENT _____

STREAM NUMBER		14		15		16		17	
DESCRIPTION		TOTAL PROCESS CONDENSATE		TOTAL PLANT ASH FOR DISPOSAL		TOTAL PLANT N_2 TO FEED SYSTEM		TOTAL PLANT N_2 VENT GAS	
PHASE		L		L/S		G		G	
COMPONENT	MOL WT	LB/HR	WT. %	LB/HR	WT. %	MOL/HR	VOL. %	MOL/HR	VOL. %
CARBON	12.011			3010	32.15				
HYDROGEN	2.016								
OXYGEN	32.000								
NITROGEN	28.014					29.51	100.00	16.87	100.00
SULFUR	32.060			40	0.43				
CHLORIDE	--			2	0.02				
ASH	--			3880	41.44				
WATER	18.016	11662	100.00	2430	25.96				
CARBON MONOXIDE	28.011								
CARBON DIOXIDE	44.011								
METHANE	16.043								
HYDROGEN SULFIDE	34.076								
CARBONYL SULFIDE	60.071								
TOTAL		11662	100.00	9362	100.00	29.51	100.00	16.87	100.00
TOTAL GAS FLOW: MOL/HR.	(DRY)					29.51		16.87	
WATER (V)/DRY GAS	(VOL/VOL)								
TOTAL (WET) FLOW. LB/HR		11662		9362		827		473	
PRESSURE - PSIA		44.7		50		75		16	
TEMPERATURE - °F		120		110		AMB		AMB	
VOL FLOW RATE - SCFH (DRY)				4550		11,200		6,402	
HHV BTU/LB									
HHV BTU/SCF DRY GAS									

C-4

STREAM NUMBER		1		2		3		4		5		6		7	
DESCRIPTION		TOTAL PLANT DRIED COAL		COAL FEED PER TRAIN		TOTAL PLANT OXYGEN		OXYGEN PER TRAIN		PLANT BFW REQUIRED		BFW PER TRAIN		NET 610 PSIG STEAM EXPORT	
PHASE		S		S		G		G		L		L		G	
COMPONENT	MOL.WT	LB/HR	WT%	LB/HR	WT%	MOL/HR	VOL%	MOL/HR	VOL%	LB/HR	WT%	LB/HR	WT%	LB/HR	WT%
CARBON	12.011	19186	60.85	9593	60.85										
HYDROGEN	2.016	1300	4.12	650	4.12										
OXYGEN	32.000	4084	12.95	2042	12.95	565.20	95.00	282.60	95.00						
NITROGEN	28.014	280	0.89	140	0.89	29.74	5.00	14.87	5.00						
SULFUR	32.060	274	0.87	137	0.87										
CHLORIDE	--	2	0.01	1	0.01										
ASH	--	3882	12.31	1941	12.31										
WATER	18.016	2522	8.00	1261	8.00					47320	100.00	23660	100.00	25512	100.00
CARBON MONOXIDE	28.011									(TDS = 150 PPM)		(TDS = 150 PPM)			
CARBON DIOXIDE	44.011														
METHANE	18.043														
HYDROGEN SULFIDE	34.078														
CARBONYL SULFIDE	60.071														
TOTAL		31530	100.00	15765	100.00	594.94	100.00	297.47	100.00	47320	100.00	23660	100.00	25512	100.00
TOTAL GAS FLOW, MOL/HR. (DRY)						594.94		297.47							
WATER (V)/DRY GAS (VOL/VOL)															
TOTAL (WET) FLOW, LB/HR		31530		15765		18920		9460		47320		23660		25512	
PRESSURE -PSIA						75		75		715		715		625	
TEMPERATURE – °F						257		257		228		228		491	
VOL. FLOW RATE - SCFH (DRY)		AVB		AVB											
HHV BTU/LB		10,397		10,397											
HHV BTU/SCF DRY GAS															

STREAM NUMBER		8 LP STEAM VENT PER TRAIN		9 BLOWDOWN PURGE PER TRAIN		10 TOTAL VENT STEAM		11 TOTAL PLANT BLOWDOWN		12 PRODUCT GAS PER TRAIN		13 TOTAL PRODUCT GAS		14 TOTAL PROCESS CONDENSATE	
DESCRIPTION															
PHASE		G		L		L		L		G		G		L	
COMPONENT	MOL WT	LB/HR	WT%	LB/HR	WT%	LB/HR	WT%	LB/HR	WT%	MOL/HR	VOL%	MOL/HR	VOL%	LB/HR	WT%
CARBON	12.011														
HYDROGEN	2.016									423.90	36.20	847.80	36.20		
OXYGEN	32.000														
NITROGEN	28.014									26.19	2.24	52.38	2.24		
SULFUR	32.060														
CHLORIDE	--														
ASH	--														
WATER	18.016	415	100.00	1029	100.00	830	100.00	2058	100.00	43.90	3.75	87.80	3.75	11632	100.00
CARBON MONOXIDE	28.011									437.31	37.35	874.62	37.35		
CARBON DIOXIDE	44.011									207.98	17.76	415.96	17.76		
METHANE	18.043									27.93	2.39	55.86	2.39		
HYDROGEN SULFIDE	34.076									3.35	0.29	6.70	0.29		
CARBONYL SULFIDE	60.071									0.29	0.02	0.58	0.02		
TOTAL		415	100.00	1029	100.00	830	100.00	2058	100.00	1170.85	100.00	2341.70	100.00	11632	100.00
TOTAL GAS FLOW, MOL/HR (DRY)										1126.95		2253.90			
WATER (V)/DRY GAS (VOL/VOL)										0.0389		0.0389			
TOTAL (WET) FLOW, LB/HR										24166		48230		11632	
PRESSURE – PSIA		20		20		20		20		44.7		44.7		44.7	
TEMPERATURE – °F		227		227		227		227		120		120		120	
VOL FLOW RATE – SCFH (DRY)										427666		855332			
HHV BTU/LB															
HHV BTU/SCF DRY GAS										273.63		273.63			

Includes some silica
Nitrogen from Coal Feed System

STREAM NUMBER		15		16		17	
DESCRIPTION		TOTAL PLANT ASH FOR DISPOSAL		TOTAL PLANT N₂ TO FEED SYSTEM		TOTAL PLANT N₂ VENT GAS	
PHASE				G		G	
COMPONENT	MOL WT	LB/HR	WT%	MOL/HR	VOL%	MN/HR	VOL%
CARBON	12.011	3010	32.15				
HYDROGEN	2.016						
OXYGEN	32.000						
NITROGEN	28.014			29.51	100.00	16.87	100.00
SULFUR	37.060	40	0.43				
CHLORIDE	--	2	0.02				
ASH	--	3880	41.44				
WATER	18.016	2430	26.96				
CARBON MONOXIDE	28.011						
CARBON DIOXIDE	44.011						
METHANE	16.043						
HYDROGEN SULFIDE	34.076						
CARBONYL SULFIDE	60.071						
TOTAL		9362	100.00	29.51	100.00	16.87	100.00
TOTAL GAS FLOW, MOL/HR.	(DRY)			29.51		16.87	
WATER (V)/DRY GAS	(VOL/VOL)						
TOTAL (WET) FLOW, LB/HR		9362		822		473	
PRESSURE - PSIA		50		75		16	
TEMPERATURE - °F		110		AMB		AMB	
VOL. FLOW RATE - SCFH (DRY)				11,200		6402	
HHV BTU/LB		4550					
HHV BTU/SCF DRY GAS							

APPENDIX D
ISBL PRELIMINARY DESIGN DRAWINGS

D-3

Legend:
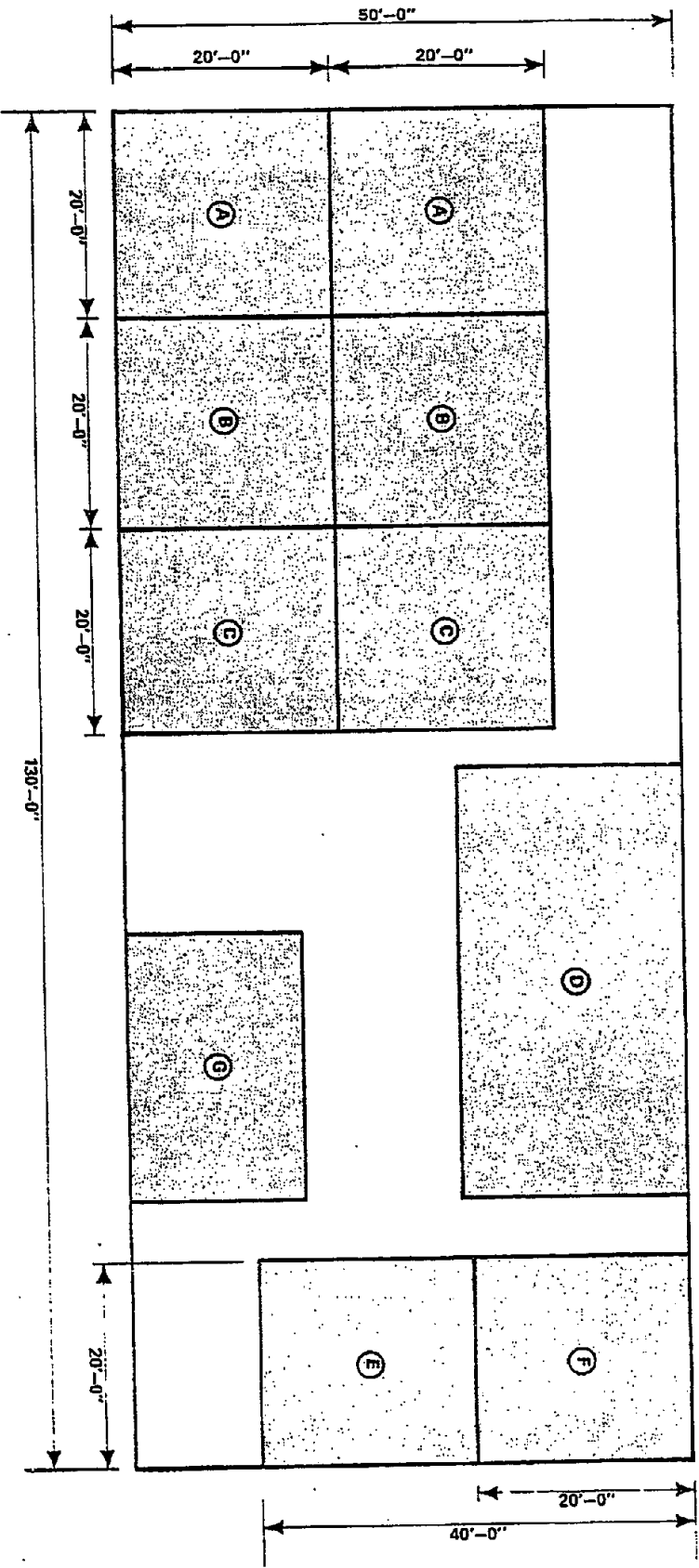
- Ⓐ COAL SURGE AND FEEDING
- Ⓑ GASIFICATION
- Ⓒ WASTE HEAT RECOVERY AND PARTICULATE REMOVAL
- Ⓓ CHAR SETTLER
- Ⓔ CHAR STORAGE
- Ⓕ CHAR DISPOSAL
- Ⓖ CONTROL ROOM

Dimensions: 50'-0", 20'-0", 20'-0", 70'-0", 20'-0", 20'-0", 130'-0", 20'-0", 40'-0", 20'-0"

CLIENT: NORTHERN RESOURCES, INC.
BILLINGS, MONTANA

TITLE: OVERALL PLOT PLAN
WINKLER COAL GASIFICATION

DWG NO.: 5409-00-A-0100

D-4

4.3.9 SINGLE-LINE EQUIP. LIST.

AREA 100

ITEM	NO. REQUIRED	DESCRIPTION
A-101	1	Settler Rake
A-102	1	Additive Mixer
B-102	1	Start-up Blower
BN-101	1	Weigh Belt Feed Bin
BN-102 A,B	2	Coal Feed Bin
BN-103 A,B	2	Lock Hopper Vessel
BN-104 A,B	2	Coal Feed Surge Vessel
CO-101-1 A,B	2	Gasifier Screw Feeder #1
CO-101-2 A,B	2	Gasifier Screw Feeder #2
CO-102 A,B	2	Char Removal Screw Conveyor
CO-103	1	Coal Distributing Conveyor
CY-101- A,B	2	Dry Cyclone
D-101 A,B	2	Steam Drum
D-102 A,B	2	Steam Blowdown Drum
D-103 A,B	2	Product Gas Separator Drum
DV-101 A,B	2	Raw Coal Diverter
E-101 A,B	2	Product Gas Condenser
E-102	1	Char Slurry Purge Heat Exchanger
E-103	1	Char Slurry Purge Cooler
FE-101	1	Coal Weigh Feed Belt
FE-102 A,B	2	Lock Hopper Rotary Feeder
FE-104 A,B	2	Heat Recovery Rotary Feeder
FE-105 A,B	2	Dry Cyclone Rotary Feeder
H-101 A,B	2	Boiler Feed Water Heater

ITEM	NO. REQUIRED	DESCRIPTION
H-102 A,B	2	High Pressure Steam Boiler
H-103 A,B	2	Start-up Burner
H-104 A,B	2	Radiant Boiler
LV-101 A,B	2	Sleeve Valve
LV-102 A,B	2	Lock Hopper Inlet Valve
LV-103 A,B	2	Lock Hopper Outlet Valve
P-101 A,B	2	Venturi Circulation Pump
P-101-1	1	Venturi Circulation Pump (common spare)
P-102 1,2	1 + 1 (spare)	Char Sludge Pump
P-103 1,2	1 + 1 (spare)	Scrubber Water Return Pump
P-104 1,2	1 + 1 (spare)	Additive Metering Pump
R-101 A,B	2	Winkler Gasifier
S-101 A,B	2	Venturi Scrubber
S-102	1	Vent Scrubber
T-101	1	Scrubber Water Return Pump Tank
T-102	1	Settler Tank
T-103	1	Additive Mix Tank

AREA 200

ITEM	NO. REQUIRED	DESCRIPTION
BN-201-1 A,B	2	No. 1 Char Lock Hopper
BN-201-2 A,B	2	No. 2 Char Lock Hopper
BN-202	1	Dry Char Storage Bin
CO-201 A,B	2	Char Collection Conveyor
CO-202 A,B	2	Char Transfer Conveyor
CO-203	1	Char Blending Conveyor

ITEM	NO. REQUIRED	DESCRIPTION
CO-204	1	Char Distributing Conveyor
DV-201 A,B	2	Char Diverter Valve
FE-202	1	Dry Char Rotary Feeder
LV-201-1 A,B	2	No. 1 Char Lock Hopper Inlet Valve
LV-201-2 A,B	2	No. 2 Char Lock Hopper Inlet Valve
LV-202-1 A,B	2	No. 1 Char Lock Hopper Outlet Valve
LV-202-2 A,B	2	No. 2 Char Lock Hopper Outlet Valve
VB-201	1	Char Bin Activator

APPENDIX E
MAJOR EQUIPMENT COST ESTIMATES

OSBL Major Equipment Quotes

Detail specifications were developed for major pieces of equipment within the OSBL facility. These specifications were then sent out for bids and quotations from vendors were received. After a preliminary bid evaluation successful vendors were identified for all items of equipment.

This Appendix shows the list of all equipment specifications, Inquiry numbers and bid dates.

An equipment list was also developed to identify each piece of equipment and its supplier along with the adjusted equipment price. The adjusted prices are the bid prices from the vendors, adjusted to suit the requirement of the OSBL plant.

Ford, Bacon & Davis Utah Inc.
ENGINEERS-CONSTRUCTORS
EQUIPMENT LIST
(PUMPS)

CLIENT ___NORTHERN RESOURCES, Inc.___

JOB NAME ___NRI Coal Gasification___

JOB NO. ___UC 353-302___

PAGE ___1___ OF ___1___

EQUIP. NO.	Inquiry Number	DESCRIPTION	VENDOR PRICE *	DELIVERY**	VENDOR
1P - 1	353-Q-010	SUMP PUMP, 100 gpm 100 TDH	3,494		
11P-1A	353-Q-004	FIRE PUMP, 2000 gpm	12,891		
11P-1B	353-Q-004	FIRE PUMP, 2000 gpm	12,891		
11P-2	353-Q-004	JOCKEY PUMP gpm	782		
12P-1A	353-Q-010	H.PRESS. BOILER FEED 130gpm 1765 TDH	41,869		
12P-1B	353-Q-010	H.PRESS. BOILER FEED 130 gpm 1765 TDH	41,869		
12P-2A	353-Q-010	L.PRESS. BOILER FEED 100 gpm 546TDH	6,071		
12P-2B	353-Q-010	L.PRESS. BOILER FEED 100 gpm 546 TDH	6,071		
12P-3A	353-Q-010	DEAERATOR FEED 75gpm 110TDH	1,750		
12P-3B	353-Q-010	DEAERATOR FEED 75gpm 110TDH	1,750		
13P-1A	353-Q-010	SUMP PUMP,130gpm 100TDH	11,052		
13P-1B	353-Q-010	SUMP PUMP,130gpm 100TDH	11,052		
13P-2A	353-Q-010	SUMP PUMP,130gpm 100TDH	11,052		
13P-2B	353-Q-010	SUMP PUMP,130gpm 100TDH	11,052		
14P-1A	353-Q-010	COOLING WATER Recirc.6300gpm 140 TDH	28,303		
14P-1B	353-Q-010	COOLING WATER Recirc.6300gpm 140TDH	28,303		

E-3

*Adjusted vendor price (no tax included).
**Vendor's estimate of delivery at bid time.

Ford, Bacon & Davis Utah Inc.

ENGINEERS-CONSTRUCTORS

EQUIPMENT LIST

CLIENT ___NORTHERN RESOURCES, Inc.___

JOB NAME ___NRI Coal Gasification___

JOB NO. ___UC 353-302___

PAGE ___ OF ___

EQUIP. NO.	INQUIRY NUMBER	DESCRIPTION	VENDOR* PRICE	DELIVERY**	VENDOR
1L – 1	353-Q-012	HOIST & TROLLEY 2 TON Cap	4,710		
7L – 1	353-Q-012	BRIDGE CRANE,HOIST & TROLLEY 10 Ton	48,600		
12A – 1	353-Q-024	CHEMICAL FEED	17,665		
12A – 2	"	CHEMICAL FEED	Included		
14A – 1	"	CHEMICAL FEED	Included		
11X – 1	353-Q-005	FIRE SPRINKLER SYSTEM	11,919		
10V – 1	353-Q-008	PLANT AIR TANK	16,381		
10V – 2	"	INST. NITROGEN TANK	incl.		
10H – 1	353-Q-002	AUX. BOILER Two 20,000lb/hr.Unit	2,432,693		
12T – 1	353-Q-014	BOILER FEED WATER TANK 88,127 g.	61,110		
	353-Q-003	BOILER FEED WATER TREATING SYS.	155,460		
12A – 1	353-Q-011	DEAERATOR 100,000 lb/hr.cap.	25,038		
7X – 1	353-Q-009	GLYCOL CONTACT DEHYDRATOR	176,337		
7X – 2	353-Q-009	GLYCOL CONTACT	151,606		
7X – 3	353-Q-007	GAS FLARE	35,298		
13A – 1	353-Q-015	WASTE WATER TREATING SYS.	90,500		

*Adjusted vendor price (no tax included).
**Vendor's estimate of delivery at bid time.

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ENGINEERS-CONS UCTORS

EQUIPMENT LIST
COMPRESSORS

CLIENT ___NORTHERN RESOURCES, Inc.___

JOB NAME ___NRI Coal Gasification___

JOB NO. ___UC 353-302___

PAGE _____ OF _____

EQUIP. NO.	INQUIRY NUMBER	DESCRIPTION	VENDOR PRICE*	DELIVERY**	VENDOR
7K - 1	353-Q-001	COAL GAS COMP. 1238 hp	561,171		
7K - 2	353-Q-001	GAS COMP. TO CENEX	358,138		
7K - 3	353-Q-001	GAS COMP. TO CONOCO	164,436		
10K - 1	353-Q-001	PLANT AIR COMP.	30,733		

*Adjusted vendor price (no tax included).
**Vendor's estimate of delivery at bid time.

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CLIENT __NORTHERN RESOURCES, Inc.__

JOB NAME __NRI Coal Gasification__

JOB NO. __UC 353-302__

PAGE ____ OF ____

EQUIP. NO.	Inquiry Number	DESCRIPTION	VENDOR* PRICE	DELIVERY **	VENDOR
1CR – 1	353-Q-023	CRUSHER, S-A 18" x 18"	15,116		
1SF – 1	353-Q-020	SCREW FEEDER, 9" x 11'-4	8,244		
1F – 1	353-Q-019	DUST COLLECTOR, 1000 cfm	55,319	14-16 wks	
1F – 2	"	DUST COLLECTOR, 1000 cfm	INCL.	14-16 wks	
1F – 3	"	DUST COLLECTOR, 4000 cfm	"	14-16 wks	
1F – 4	"	DUST COLLECTOR, 4000 cfm	"	14-16 wks	
1VF – 1	353-Q-021	VIBRATING FEEDER	33,826	12-14 wks	
1VF – 2	"	VIBRATING FEEDER	INCL.	12-14 wks	
1VF – 3	"	VIBRATING FEEDER	"	12-14 wks	
1VF – 4	"	VIBRATING FEEDER	"	12-14 wks	
1VF – 5	"	VIBRATING FEEDER	"	12-14 wks	
1VF – 6	"	VIBRATING FEEDER	"	12-14 wks	
1VF – 7	"	VIBRATING FEEDER	"	12-14 wks	
1D – 1	353-Q-022	STEAM COAL DRYER	377,500		

*Adjusted vendor price (no tax included).
**Vendor's estimate of delivery at bid time.

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Foly, Bacon & Varts Man Inc.

ENGINEERS-CONSTRUCTORS
EQUIPMENT LIST

CLIENT ___NORTHERN RESOURCES, Inc.___

JOB NO. ___UC 353-302___

JOB NAME ___NRI Coal Gasification___

PAGE ___ OF ___

EQUIP. NO.	Inquiry Number	DESCRIPTION	VENDOR* PRICE	DELIVERY**	VENDOR
IC – 1	353-Q-018	CONVEYOR,	882,935	23-30 wks	
IC – 2	"	CONVEYOR,	Incl.	23-30 wks	
IC – 3	"	CONVEYOR,	"	23-30 wks	
IC – 4	"	CONVEYOR,	"	23-30 wks	
IC – 5	"	CONVEYOR,	"	23-30 wks	
IC – 7	"	CONVEYOR,	"	23-30 wks	
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*Adjusted vendor price (no tax included).
**Vendor's estimate of delivery at bid time.

APPENDIX F
ISBL COST ESTIMATE DETAILS

ISBL EQUIPMENT COST DETAILS

NORTHERN RESOURCES

SYSTEM *	MATERIAL COST (Including Freight)	DIRECT LABOR COST	SUB-CONTRACT COST	TOTAL INSTALLED COST
100-2501 Coal Feed System	193,300	14,000	100,100	307,400
100-2502 Gasifiers w/re-fractory	260,000	38,200	202,600	500,800
100-2503 Waste Heat Re-covery	726,400	40,600		767,000
100-2504 Particulate Removal	438,900	12,500		451,400
100-2505 Char Thicken-ing System	68,200	11,800	43,900	123,900
200-2501 Char Handling System	261,700	23,300		285,000

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* Attached pages describes systems.

SYSTEM	EQUIPMENT ITEMS INCLUDED	
	ITEM NO.	NO. REQUIRED
100-2501 Coal Feed System	BN-101	1
	BN-102 A,B	2
	BN-103 A,B	2
	BN-104 A,B	2
	CO-101-1 A,B	2
	CO-101-2,A,B	2
	CO-103	1
	DY-101 A,B	2
	FE-101	1
	FE-102 A,B	2
	LV-101 A,B	2
	LV-102 A,B	2
	LV-103 A,B	2
100-2502 Gasifier w/Refractory	B-102	1
	H-103 A,B	2
	R-101,A,B	2
100-2503 Waste Heat Recovery	D-101 A,B	2
	D-102 A,B	2
	FE-104 A,B	2
	H-101 A,B	2
	H-102 A,B	2
	H-104 A,B	2
100-2504 Particulate Removal	CD-102 A,B	2
	CY-101 A,B	2
	D-103 A,B	2
	E-101 A,B	2
	FE-105 A,B	2
	P-103 1,2	1 + 1 (spare)
	S-101 A,B	2
	S-102	1
100-2505 Char Thickening System	A-101	1
	A-102	1
	E-102	1
	E-103	1
	P-101 A,B	2
	P-101-1	1
	P-102 1,2	1 + 1 (spare)
	P-104 1,2	1 + 1 (spare)
	T-101	1
	T-102	1
	T-103	1

SYSTEM

	ITEM NO.	NO. REQUIRED
200-2501 Char Handling System	BN-201-2	2
	BN-201-2 A,B	2
	BN-202	1
	CD-201 A,B	2
	CD-202 A,B	2
	CO-203	1
	CO-204	1
	DY-201 A,B	2
	FE-202	1
	LV-201-1 A,B	2
	LV-201-2 A,B	2
	LV-202-1 A,B	2
	LV-202-2 A,B	2
	VB-201	1