5.2.8.7 Existing Utilities

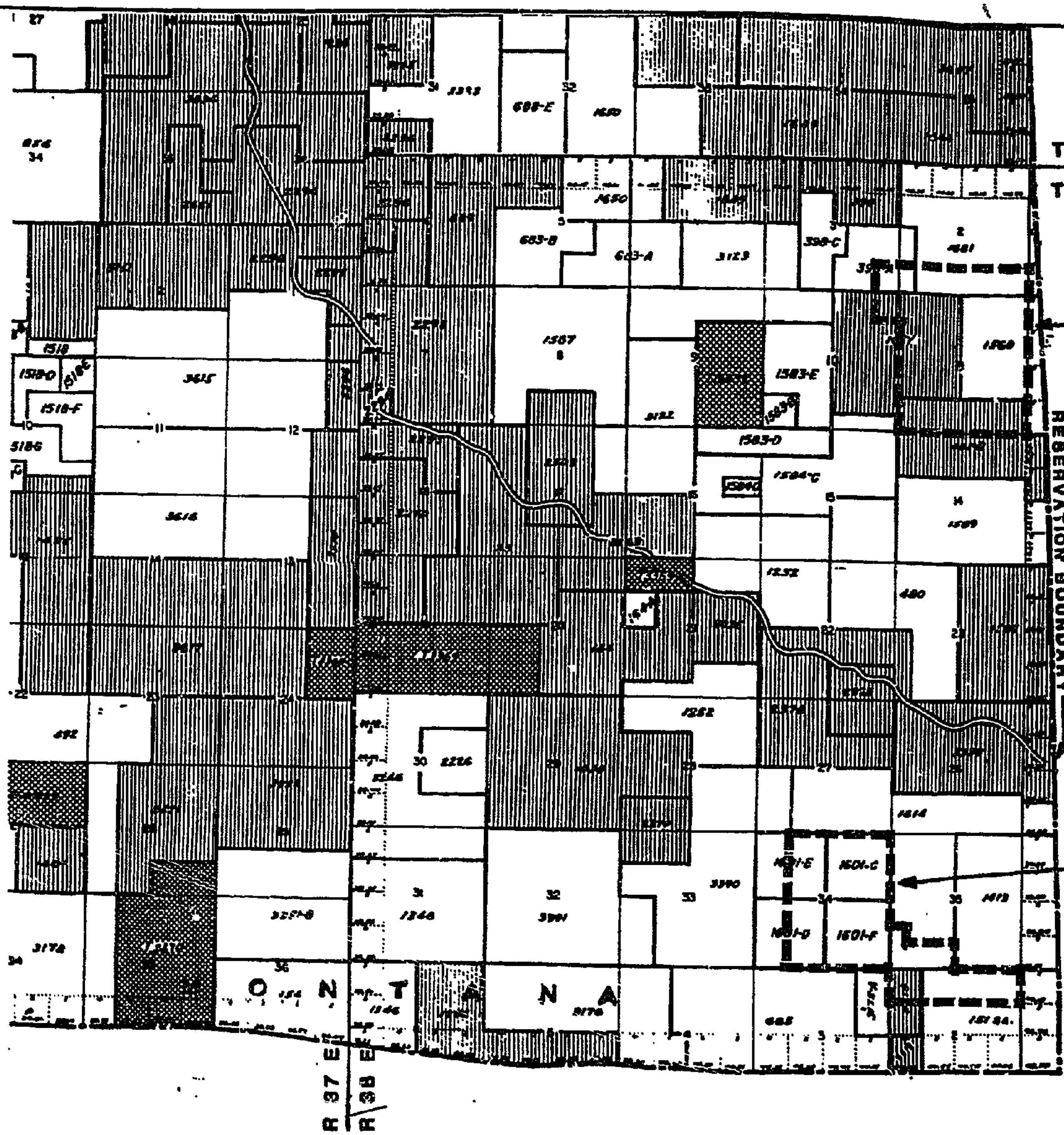
An existing powerline is located approximately 11 miles southwesterly of the site. The powerline runs in a southeasterly direction from Yellowtail Dam toward Sheridan, Wyoming as shown on Drawing 835704-00-4-081. This could supply temporary power to the site during plant construction and startup operations.

5.2.8.8 Land Ownership Status

The land ownership status of Site 23 is shown on Drawing 835704-00-2-110 and Drawing 835704-00-2-111.

The westerly half and southerly quarter of the plant site are Fee Lands. This land is owned by the Shell Oil Company. The northerly and easterly portions of the site are Trust Lands - individually owned Indian allotment or tract.

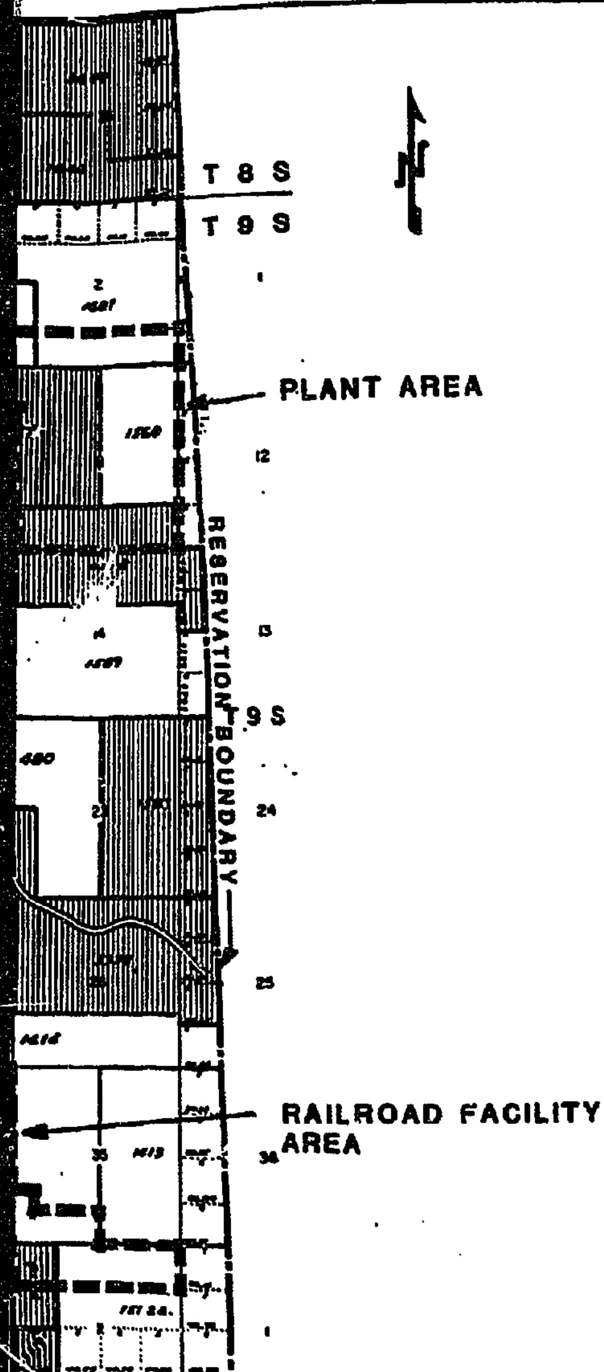
The railroad facility and the required right-of-way are located primarily on Trust Land - individually owned Indian allotment or tract. A small portion is Fee Land; this land is not owned by either the tribe or individual Indians.



**SOURCE: U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF INDIAN AFFAIRS**

REV. NO.	DATE	REVISION DESCRIPTION	DRAWN CHECK	DATE
1	6-2-82	ISSUED FOR STUDY	m.D.	6/2/82

FLUOR



LEGEND

- OO — TRUST—Individually Owned Indian Allotment or Tract
- TRUST—Tribally Owned by The (NO. DENOTES AN ACCQUIRED ALLOTMENT/TRACT)
- TR — TRUST—Tribally Owned in Reserve Status
- G — GOVERNMENT OWNED—B I A Submarginal Lands
- G — GOVERNMENT OWNED—B I A
- GOVERNMENT OWNED—OTHER FEDERAL AGENCY
- FEE LANDS
- Paved Road
- Graveled Road
- Improved Dirt Road
- Unimproved Dirt Road or Trails
- Dashed township or section lines indicate unsurveyed area.

UOR

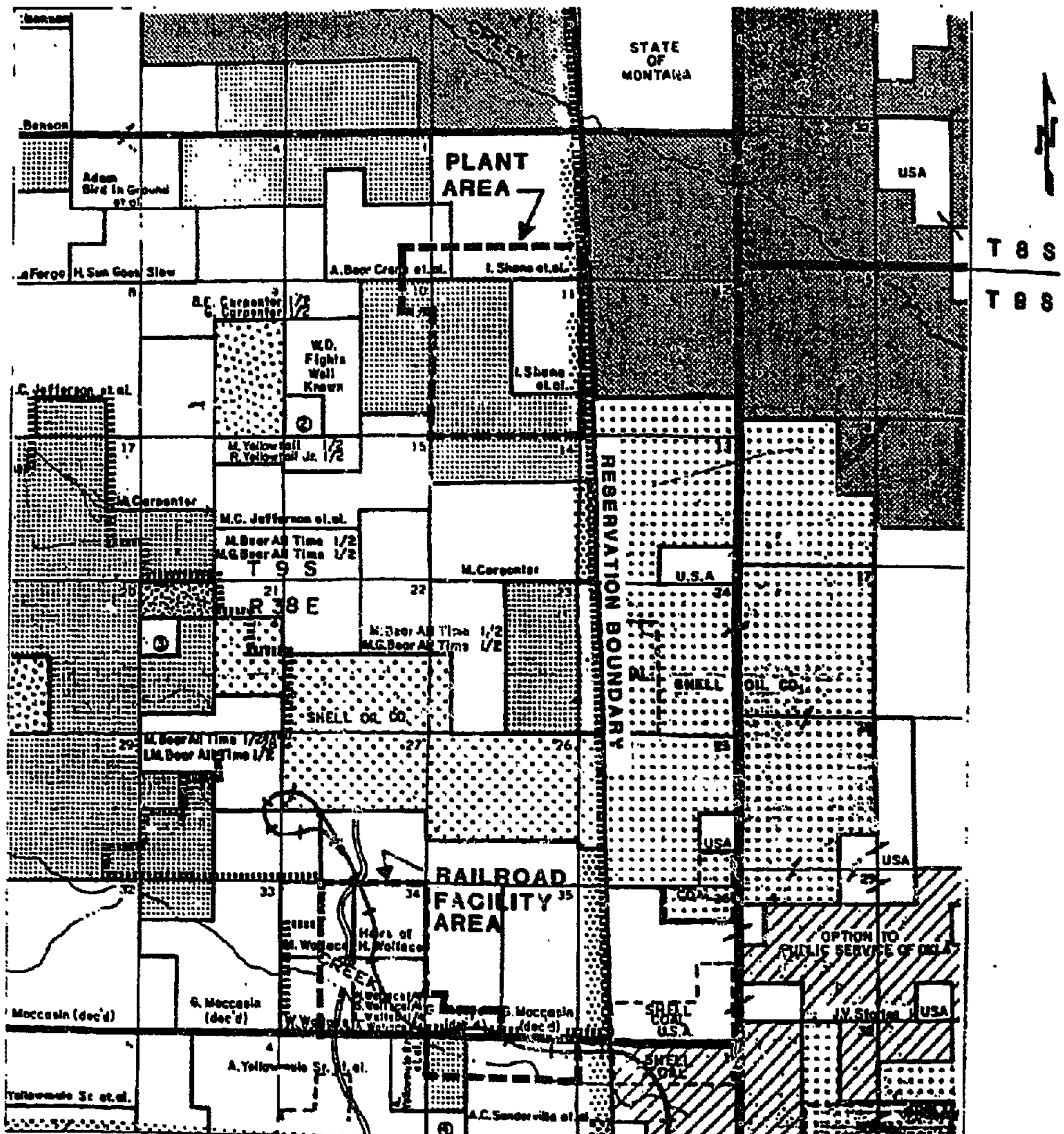
DRAWN BY	J. GRAU
CHECKED BY	M. DORIN
SUPERVISOR	A. QUINONES
RELEASE DATE	6/2/82
SUPERVISING ENGR.	M. DORIN
INITIALS	M Dorin
PROJECT ENGR.	R. LANG
APP. DATE	RL 6/2/82
CLIENT	
APP. DATE	

SITE #23 LAND OWNERSHIP STATUS

SYNFUELS FEASIBILITY STUDY

CROW TRIBE OF INDIANS — MONTANA

SCALE	DRAWING NUMBER	REVISION
1"=1 Mile	835704-00-2-110	1



SOURCE: SHELL OIL COMPANY

REV. NO.	DATE	REVISION DESCRIPTION	DRAWN / CHECK	DATE
1	6-2-82	ISSUED FOR STUDY	M.D.	6/2/82

FLUO

8 S

9 S

LEGEND

- SHELL OIL CO
- CONSOLIDATION COAL CO
- H.A. SCOTT
- K.A. KANE
- J. WALLOP
- J. SCHAAK
- BAR 69 CATTLE CO
- OPT TO OKLA PUB SERV J.V. STATES
- TRIBAL LAND

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DRAWN BY: J. GRAU		
CHECKED BY: M. DORIN		
SUPERVISOR: A. QUINONES	RELEASE DATE: 6/2/82	
SUPERVISING ENGR.: M. DORIN	INITIALS: M. Dorin	
PROJECT ENGR.: R. LANG	APP. DATE: RAL 6/2/82	
CLIENT	APP. DATE	

UOR

SITE #23 LAND OWNERSHIP STATUS

SYNFUELS FEASIBILITY STUDY

CROW TRIBE OF INDIANS — MONTANA

SCALE	DRAWING NUMBER	REVISION
1"=1 Mile	835704-00-2-111	1

FORM E-306 REV. 8/78 PRINTED IN U.S.A.

5.3 RAW WATER ANALYSIS

The raw water analysis shown in Table 5.3-1 gives the chemical and physical characteristics of the raw water used for the design of the process and utility units. The analysis is based on data gathered at two sites on the Bighorn River - one near St. Xavier, Montana, the other at Bighorn, Montana.

TABLE 5.3-1

RAW WATER ANALYSIS

Constituent	Concentration (ppm as $CaCO_3$)
Calcium (Ca)	185
Magnesium (Mg)	124
Sodium (Na)	190
Potassium (K)	14
Bicarbonate (HCO_3)	164
Carbonate (CO_3)	0
Sulfate (SO_4)	317
Chlorine (Cl)	27
Nitrate (NO_3)	3
Fluorine (F)	2
Total Anions	513
Iron (mg/l)	0.2
Manganese (mg/l)	0.1
Boron (mg/l)	0.2
Silica (mg/l)	13
Carbon Dioxide (mg/l)	9
pH	7.6
Turbidity (JTU)	118
Suspended Solids (mg/l)	20 (assumed)
Total Dissolved Solids (mg/l)	744
Temperature (°F)	60

5.4 UTILITY DESIGN INFORMATION

Design criteria for the plant utility systems are shown in Table 5.4-1. These criteria are used to maintain compatibility of the process units with the utility producing systems.

TABLE 5.4-1

UTILITY DESIGN INFORMATION

Utility	Normal Conditions: Producer Battery limits psig	Producer Battery limits °F	User Battery Limits psig	User Battery Limits °F
Steam:				
1500 psig	1500	930	1450	925
600 psig	600	760	550	756
100 psig	100	SAT	90	330
60 psig	60	SAT	50	303
Boiler Feed Water:				
HHP	1930	230	1925	230
HP	815	230	775	230
MP/LP	175	230	140	230
Cooling Water:				
Supply	75	80	70	80
Return	40	110	45	110
Plant Air:	125	100	100	100
Instrument Air:	125	100	100	100
LP Nitrogen:	50	95	35	95
Fuel Gas: (1)	60	75	50	75
Raw Water:	100	70	80	70
Fire Water:	150	70	125	70

NOTE: (1) Typical fuel gas properties are:

Molecular Weight	12.5
Net Heating Value	430 Btu/SCF

5.5 PRODUCT AND BYPRODUCTS SPECIFICATIONS

5.5.1 PRODUCT SPECIFICATIONS

The principal product of the synfuels facility is pipeline quality substitute natural gas (SNG). Also, excess power is generated on site and delivered to the utility grid for export sales. The following data outline the significant specifications used for this project.

SNG

Heat of Combustion (HHV), Btu/SCF (min.)	960
Methane purity, % vol. (min.)	95
Carbon Monoxide, % vol. (max.)	0.1
Hydrogen, % vol. (max.)	1.5
Carbon Dioxide, % vol. (max.)	2.0
H_2O	nil

5.5.2 BYPRODUCTS AND ASH SPECIFICATIONS

Byproducts from this coal conversion facility fall into two categories. Saleable byproducts: ammonia, hydrotreated naphtha and sulfur. Waste byproducts of ash and gypsum sludge: these solids have no commercial value and must be suitable for landfill disposal.

Ammonia (Agricultural Grade)

Ammonia Purity, % wt. (min.)	99.5
Water Content, % wt. (max.)	0.5
Organic Material, ppm wt. (max.)	5.0

Hydrotreated Naphtha

Stabilized for storage and transportation	
Specific Gravity	0.82

5.5.2 (Continued)

ASTM Distillation (Estimated)

Vol. %	°F
IBP	172
10	192
30	207
50	223
70	252
80	270
90	300
FBP	374

Sulfur (Molten)

Sulfur Purity, % wt. (min.)	99.8
Carbon Content, % wt. (max.)	0.06
Ash Content, % wt. (max.)	0.02
Free Acidity, % wt. (max.)	0.003
Color	Bright Yellow
Free of As, Se, Te	

Ash and Gypsum

Solid effluents have been tested according to the U.S. EPA Hazardous Waste Identification Extraction Procedure Toxicity Test. The gasifier ash leachate was found to contain trace metals at a concentration below the limits specified in the RCRA regulation 40 CFR 261.24.

Gypsum produced in the Flue Gas Desulfurization Unit is considered to be nonhazardous according to the RCRA standard.

5.6 ECONOMIC CRITERIA - CAPITAL COSTS

Capital cost estimates have been developed using capacity factored, Machinery and Equipment (M & E) factored, and detailed estimating techniques. Capacity factored estimating is based on multiplying the cost of a like unit for which the Direct Field Costs (DFC) are known by the ratio of the new unit's capacity to that of the like unit. Capacity ratios are adjusted by an exponent chosen on the basis of the unit type. Machinery and equipment factored estimating is based on equipment capacities/costs from which all other costs are factored to determine the total Direct Field Cost. Some detailed estimates are prepared based on Material Take-offs (MTO's) from preliminary overlays or sketches where available.

Capacity factored estimates have been developed for those units for which Fluor has cost data on a comparable unit. The majority of units in this category are factored from data compiled from previous experience. Other units in this category are either factored from costs of units constructed by Fluor or from other in-house sources.

Machinery and equipment factored estimating is used for units for which Fluor has no comparable cost data from actual projects constructed by Fluor. Process design and equipment specifications are developed for these units by process engineering and then priced on an individual basis by Fluor's mechanical and vessel engineering groups. All bulk materials and labor man-hours are factored from equipment capacities/costs. The factors for bulk materials and labor man-hours are based on Fluor's historical experience.

Detailed estimates have been prepared for several offsites and utility units and most site sensitive portions of the estimate. Included in this category are site preparation, site improvements, buildings, railroads, and other civil/structural site specific items.

5.6 (Continued)

Capital cost estimates for all cases reflect instantaneous January, 1982 dollars and worldwide procurement of direct field materials. Each estimate reflects the appropriate site location. The capital cost estimates are not escalated to an "end of job" cost basis.

Cost scaling exponents and capacity factors, Tables 5.6-1 and 5.6-2, provide a list of recommended exponents and applicable commodity bases that were used for capacity factored estimating for each unit. A capacity ratio based on the recommended commodity and adjusted by its respective exponent is applied to the Direct Field Cost of the unit. A recommended exponent and ratio basis is provided for adjusting Indirect Field Costs (IFC) and Office Costs with respect to a capacity factored estimate for a total plant.

The exponents provided in the tables are meant to cover a range of varied combinations of scaling options and can be used for any commercial size unit. These exponents could be higher when adding/deleting trains or lower when increasing/decreasing capacity per train. Thus the exponents are considered "average" for the types of units covered and may benefit from adjustment based on the particular situation to which they are applied.

Minimal exponent, for any change = (confidential)

For process units and most offsite/utility units, (confidential) is recommended.

A (confidential) exponent is used for changes in capacity where the number of trains remains constant.

Note: Certain data required for the cost estimate development is considered confidential. It is an "examinable", but not included as part of the final report.

TABLE 5.6-1

COST SCALING EXPONENTS

UNIT	UNIT TITLE	EXPONENT
01	Coal Screening	Data is confidential
02	Coal Distribution	
03	Ash Handling	
10	Gasification	
11	CO Shift	
12	Gas Cooling	
13	Rectisol	
14	Gas Liquor Separation	
15	Tar Distillation	
16	Naphtha Hydrotreating	
17	Phenosolvan	
18	Ammonia Recovery	
19	Sulfur Recovery	
	Stretford	
	ADIP	
	Claus	
	SCOT	
20	Process Steam Superheater	
21	Methanol Synthesis	
22	Methanation	
23	SNG Purification and Compression	
24	Partial Oxidation	
25	Hydrogen Production	
40	Oxygen Production	
41	Steam Generation	

TABLE 5.6-1 (Continued)

COST SCALING EXPONENTS

UNIT	UNIT TITLE	EXPONENT
42	Power Generation	Data is confidential
43	Flue Gas Desulfurization	
44	Raw Water Treating	
45	BFW & Condensate Treating	
46	Air & Nitrogen Systems	
47	Process Cooling Water	
48	Utility Cooling	
49	Potable Water	
50	Utility Water	
51	Fire Water	
52	Fuel Gas	
53	Flare	
54	Wastewater Treating	
55	Tankage & Dispatch	
56	Sanitary Sewer	
57	Interconnecting Pipelines	
61	Buildings	
65	Electrical	
67	Control Systems	
68	Ash Disposal	
71	Site Preparation	
75	Site Improvement	

TABLE 5.6-2

CAPACITY FACTORS

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

UNIT	UNIT NAME	BASIS FOR CAPACITY FACTOR	SELF-SUFF. CASE @ SITE 1	COPROD. CASE @ SITE 1	SHELL COAL CASE @ SITE 23
01	Coal Screening	Coal, TPD		Confidential Data	
02	Coal Distribution	Coal, TPD			
03	Ash Handling	Gasifier Ash, TPD			
10	Gasification	No. of Gasifiers			
11	CO Shift	Catalyst Volume, ft^3			
12	Gas Cooling	Cooling Duty, MM Btu/hr			
13	Rectisol	Acid Gas Removed, lb mol/hr			
14	Gas Liquor	Net Gas Liquor Feed, lb/hr			
15	Tar Distillation	Tar/Oil Feed, lb/hr			
16	Naphtha Hydrotreating	Naphtha Feed lb/hr			

TABLE 5.6-2 (Continued)

CAPACITY FACTORS

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

UNIT	UNIT NAME	BASIS FOR CAPACITY FACTOR	SELF-SUFF. CASE @ SITE 1	COPROD. CASE @ SITE 1	SHELL COAL CASE @ SITE 23
17	Phenosolvan	Net Gas Liquor Feed, lb/hr		Confidential Data	
18	Ammonia Recovery	Ammonia Product Rate, lb/hr			
19	Sulfur Recovery				
	ADIP	Gas Feed, lb mol/hr			
		H_2S Absorbed, lb mol/hr			
	Claus	Sulfur Product Rate, TPD			
	SCOT	Gas Feed, lb mol/hr			
	Stretford	Gas Feed, lb mol/hr			
20	Process Steam Superheater	Vent Gas Feed, lb mol/hr			

TABLE 5.6-2 (Continued)

CAPACITY FACTORS

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

UNIT	UNIT NAME	BASIS FOR CAPACITY FACTOR	SELF-SUFF. CASE @ SITE 1	COPROD. CASE @ SITE 1	SHELL COAL CASE @ SITE 23
21	Methanol Synthesis	Methanol Production Rate, TPD		Confidential Data	
22	Methanation	Feed Rate, lb mol/hr			
23	SNG Purification & Compression	-Ditto-			
24	Partial Oxidation	Liquids Feed Rate, lb/hr			
25	Hydrogen Production	H_2 Production Rate, lb mol/hr			
40	Oxygen Production	O_2 Production Rate, TPD			
41	Steam Generation	Steam Production Rate, M lb/hr No. of Boilers			

TABLE 5.6-2 (Continued)

CAPACITY FACTORS

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

UNIT	UNIT NAME	BASIS FOR CAPACITY FACTOR	SELF-SUFF. CASE @ SITE 1	COPROD. CASE @ SITE 1	SHELL COAL CASE @ SITE 23
42	Power Generation	Generation Capacity, MW No. of Trains	Confidential Data		
43	Flue Gas Desulfurization	Flue Gas Feed Rate, MM SCFM or SO_2 Removed, lb mol/hr			
44	Raw Water Treating	Raw H_2O Flow Rate, gpm			
45	BFW & Condensate Treating	Total BFW Flow Rate, gpm			
46	Air & Nitrogen System	Air + N_2 Quantity, SCFM			
47	Process Cooling Water	Cooling H_2O Flow, gpm			
48	Utility Cooling Water	-Ditto-			

TABLE 5.6-2 (Continued)

CAPACITY FACTORS

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

UNIT	UNIT NAME	BASIS FOR CAPACITY FACTOR	SELF-SUFF. CASE @ SITE 1	COPROD. CASE @ SITE 1	SHELL COAL CASE @ SITE 23
49	Potable Water	Water Flow, gpm		Confidential Data	
50	Utility Water	Design Capacity, gpm			
51	Firewater	-Ditto-			
52	Fuel Gas	Fuel Gas Quantity, MM Btu/hr			
53	Flare	Design Capacity, MM lb/hr			
54	Wastewater Treating	Wastewater Flow Rate, gpm			
	API Separation				
	Biotreatment				
	Evaporation				
55	Tank Farm	Working Capacity, bbl			

TABLE 5.6-2 (Continued)

CAPACITY FACTORS

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

UNIT	UNIT NAME	BASIS FOR CAPACITY FACTOR	SELF-SUFF. CASE @ SITE 1	COPROD. CASE @ SITE 1	SHELL COAL CASE @ SITE 23
55 (Continued)			Confidential Data		
	Intermediate Tankage				
	Byproduct Tankage				
	IPE/Methanol Tankage				
	Sulfur Storage				
	Ammonia Storage				
	Sulfuric Acid and Caustic Ammonia				
56	Sanitary Sewer				
57	Interconnecting Pipeway				
61	Buildings				
65	Elect. Distribution				
67	Control Info. System				
68	Ash Disposal				
71	Site Preparation				
75	Site Improvements				

5.6 (Continued)

Where a single train is involved, but the type and mix of equipment are very similar and capacity changes are partly achieved by adding pieces of equipment like extra bays (fin fans coolers), shells (shell and tube exchangers), pumps or compressors, the exponent may range up to (confidential).

Generally, an exponent in the range of (confidential) is chosen based on inspection of equipment list and method of capacity increase.

Exponents in the range of (confidential) are used for changes in numbers of trains, where a great degree of equipment duplication is involved within a given unit.

All capital cost estimates are comprised of the following components:

Direct Field Costs (labor man-hours, labor dollars, and material dollars)

Material Transportation Costs

Indirect Field Costs

Office Costs

The sum of these four items comprise the Total Field and Office Costs. Other Capital Costs are associated with the project to obtain the Total Capital Required.

Other Capital Costs include the following:

Construction Camp
Initial Catalysts and Chemicals

5.6 (Continued)

Land
Spare Parts
Paidup Royalties
Shop, Machinery, and Lab Equipment
Owners Costs
Startup Costs
Management Reserve
Working Capital
Financing Costs
Interest During Construction (IDC)

The Direct Field Cost for each unit is estimated on an individual basis according to a unit estimate scope developed by process engineering, and is summarized to the total level. Material Transportation, Indirect Field, and Home Office Cost estimates are developed at the total level only. Contingency is evaluated on a unit basis and summed to a total contingency recommendation for each case and is included as a part of the management reserve. Fees are included in the capital cost estimates at the total level only. There is no sales tax in Montana.

A complete list of units with area description, showing the estimate bases and techniques used to prepare the Direct Field Cost estimates for the Base Case, is summarized in Table 5.6-3. Refer to Table 5.6-2 for the other process cases.

TABLE 5.6-3

ESTIMATING TECHNIQUE FOR CROW FEASIBILITY STUDY

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

Area No.	Area Description	Unit No.	Unit Description	Estimate Basis	Estimate Technique
01	Coal Handling	01	Coal Screening	Fluor	Capacity Factor
01	Coal Handling	02	Coal Distribution	Fluor	Capacity Factor
01	Coal Handling	03	Ash Handling	Fluor	Capacity Factor
02	Gas Production	10	Gasification	Fluor	Capacity Factor
02	Gas Production	11	CO Shift	Fluor	M & E Factor
02	Gas Production	12	Gas Cooling	Fluor	M & E Factor
02	Gas Production	13	Rectisol	Fluor	Capacity Factor
02	Gas Production	24	Partial Oxidation	Fluor	Capacity Factor
03	Byproducts Processing	14	Gas Liquor Separation	Fluor	Capacity Factor
03	Byproducts Processing	15	Tar Distillation	Fluor	Capacity Factor
03	Byproducts Processing	16	Naphtha Hydrotreating	Fluor	Capacity Factor
03	Byproducts Processing	17	Phenosolvan	Fluor	Capacity Factor
03	Byproducts Processing	18	Ammonia Recovery	Fluor	Capacity Factor
03	Byproducts Processing	19	Sulfur Recovery	Fluor	Capacity Factor
03	Byproducts Processing	20	Vent gas Incineration	Fluor	M & E Factor
03	Byproducts Processing	21	Methanol Synthesis	Fluor	Capacity Factor
03	Byproducts Processing	25	Hydrogen Production	Fluor	Capacity Factor
04	Methanation & SNG	22	Methanation	Fluor	Capacity Factor

TABLE 5.6-3 (Cont'd)

ESTIMATING TECHNIQUE FOR CROW FEASIBILITY STUDY

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

Area No.	Area Description	Unit No.	Unit Description	Estimate Basis	Estimate Technique
04	Methanation & SNG	23	SNG Purification & Compression	Fluor	Capacity Factor
05	Oxygen Production	40	Oxygen Production	Fluor/Vendor	Capacity Factor
06	Utilities	41	Steam Generation	Fluor/Vendor	
06	Utilities	42	Power Generation	Fluor/Vendor	
06	Utilities	43	Flue Gas Desul-furization	Vendor	Vendor Cost
06	Utilities	44	Raw Water Treating	Fluor	Capacity Factor
06	Utilities	45	BFW & Condensate Treating	Fluor	Capacity Factor
06	Utilities	46	Air & Nitrogen Systems	Fluor	Capacity Factor
06	Utilities	47	Process Cooling Water	Fluor	
06	Utilities	48	Utility Cooling	Fluor	
06	Utilities	49	Potable Water	Fluor	Capacity Factor
06	Utilities	50	Utility Water	Fluor	Capacity Factor
06	Utilities	51	Fire Water	Fluor	Capacity Factor
06	Utilities	52	Fuel Gas	Fluor	Capacity Factor
06	Utilities	53	Flare	Fluor	Capacity Factor

TABLE 5.6-3 (Cont'd)

ESTIMATING TECHNIQUE FOR CROW FEASIBILITY STUDY

BASE CASE: WESTMORELAND COAL, 40% FINES @ SITE 1

Area No.	Area Description	Unit No.	Unit Description	Estimate Basis	Estimate Technique
07	Offsites	54	Wastewater Treating	Fluor	Capacity Factor
07	Offsites	55	Tankage & Dispatch	Fluor	Capacity Factor
07	Offsites	56	Sanitary Sewer	Fluor	Capacity Factor
07	Offsites	57	Interconnecting Pipelines	Fluor	Detailed
07	Offsites	61	Buildings (w/electrical)	Fluor	Capacity Factor
07	Offsites	63	Communications	Fluor	
07	Offsites	65	Electrical Distribution	Fluor	Detailed
07	Offsites	67	Control System	Fluor	Capacity Factor
08	General	71	Site Preparation	Fluor	Detailed
08	General	75	Site Improvements	Fluor	Detailed

5.6.1 DIRECT FIELD COST ESTIMATE

The Direct Field Cost (DFC) estimate for each unit consists of field labor man hours, labor dollars, and material dollars, on a direct hire basis only.

The Direct Field Labor (DFL) man-hours are estimated according to Fluor's standard base. These base man-hours are adjusted for each site location using a 67 percent labor efficiency in relation to that base. The 67 percent labor efficiency reflects a 50-hour work week at the jobsite location.

The direct field labor wage rate is established as shown on Table 5.6-4 and includes premium pay for a 50-hour work week. The composite wage rate is based on a craft mix considered applicable to the type of project covered in this study. The direct field wage rate does not include craft benefits and burdens. (All craft benefits and burdens are included in the Indirect Field Costs.)

The direct field material costs are instantaneous January, 1982 dollars and reflect worldwide procurement of both major equipment and bulk materials. The ratio of U.S. to foreign purchase is shown in Table 5.6-5.

Each of the process unit estimates is based on Fluor's experience with previous projects and reflect in-house generated costs adjusted for worldwide procurement, using the general multipliers shown in Table 5.6-5.

The direct field material costs include freight to the jobsite for domestic purchased material and freight to the port of export for foreign procured material.

TABLE 5.6-4

CRAFT WAGE RATES

DIRECT FIELD LABOR

Craft	Craft Mix, %	Montana Journeyman Rate (40 hr/5 days), $/hr
Boilermaker	2.6	15.00
Bricklayer	0.5	16.00
Carpenter	10.9	12.10
Cement Mason	2.0	12.00
Electrician	11.3	16.30
Insulators	1.1	18.80
Ironworkers	5.8	14.40
Laborers	16.8	10.70
Sheet Metal Workers	0.1	15.20
Millwrights	2.3	13.10
Oilers	0.8	12.50
Operating Eng.	4.0	13.20
Painters	2.1	12.50
Pipefitter/Welders/Rigger	38.3	17.60
Teamster	1.4	12.60
Journeyman Composite	100.0	14.85
Foreman Adjustment		.25
Composite Wage Rate - 40-hour week		15.10
Overtime Adjustment to 50 hr., 5 day week		2.50
Composite Direct Field Labor Rate: 50-hour week		17.60
Average Rate - Use		17.60

NOTES:

(1) Basis is Montana area
(2) Effective 1st Qtr. 1982

TABLE 5.6-5

GENERAL ESTIMATING GUIDELINES FOR WORLDWIDE PROCUREMENT ADJUSTMENT

A/C	Description	Country	% Purchase	Multiplier	Composite Multiplier
00	Excavation	U.S.A	100	Confidential	Data
10	Concrete	U.S.A	100		
20	Structural Steel	U.S.A	100		
30	Buildings	U.S.A	100		
40					
41	Field Fabricated Vessels	U.S.A	100		
42	Shop Fabricated Vessels	U.S.A	35		
		Other	65		
43	Compressors	U.S.A	100		
44	Exchangers	U.S.A	50		
		Other	50		
45	Fired Heaters/Boilers	U.S.A	80		
		Other	20		
46	Pumps	U.S.A.	60		
		Other	40		
47/	Material Handling	U.S.A	65		
48		Other	35		
49	Miscellaneous	U.S.A.	85		
		Other	15		
50	Piping	U.S.A	30		
		Other	70		
60	Electrical	U.S.A	50		
		Other	50		
70	Instruments	U.S.A	90		
		Other	10		
80	Painting/Insulation	U.S.A	100		

5.6.1 (Continued)

Other general estimate qualifications and assumptions are as follows:

All direct field cost estimates include labor and material costs for excavation, concrete, structural steel, buildings, machinery and equipment, piping (valves, pipe, fittings, etc.), electrical (including major equipment) instrumentation, scaffolding, painting, and insulation. (All construction equipment and small tools are included in the indirect field costs.)

Each unit direct field cost estimate is developed on a direct hire basis only. However, it is recognized that for the actual project a number of items would be subcontracted.

Each site direct field cost estimate assumes that no piling will be required.

Direct field costs for each unit include common facilities such as substation buildings (excluding major equipment), pipe racks from the unit to the main interconnecting pipeway, cable trays, etc.

The pricing basis for the detailed portions of the estimate are as follows:

SITE PREPARATION & SITE IMPROVEMENTS

Nearly all of the estimate was priced as subcontract, based on in-house prices and telephone inquiries in the Billings, Montana area.

BUILDINGS

The majority of pricing was obtained from in-house prices and telephone inquiries.

5.6.1 (Continued)

MACHINERY AND EQUIPMENT

Most of equipment pricing (about 70 percent) was in-house. The large dollar items, like compressors, were priced by vendor by telephone. Written quotes from vendor were obtained on the boilers, stack, cooling towers, and turbine generators.

5.6.2 INDIRECT FIELD COST ESTIMATE

Indirect field cost estimates are developed based on Fluor's construction experience with other related projects of similar magnitude.

The Indirect Field Cost category covers the following areas:

The labor and material costs for temporary construction facilities, such as temporary buildings, roads, utilities, and railroads. A variety of offices, shops, warehouses, and other facilities are required to support the construction effort. These facilities are used for approximately 42 to 48 months and are removed at the completion of the project.

The labor and material costs for construction services such as medical and first aid, janitorial work, final job cleanup, handling and servicing of construction equipment, consumables (i.e., welding supplies, paper cups, etc.), and the cost (rental or purchase) of construction equipment.

Field staff salaries, expenses, and overheads.

Field staff and craft burdens, benefits and insurance. This account includes burdens and benefits for all field labor, which is expressed as a percent of total labor cost.

5.6.2 (Continued)

Burdens: Defined as legislated costs, such as FICA, worker's compensation, liability insurance, state and federal unemployment insurance.

Benefits: Defined as nonlegislative costs, such as health and welfare, vacation, sick leave, holiday, travel expense and mileage, pension fund, apprentice fund.

Temporary Construction Facilities: A variety of offices, shops, warehouses, and other facilities are required to support the zoned construction effort. These facilities are used for approximately 48 months and are removed at the completion of the project. Approximately 300 acres of equipment, materials lay down, and storage areas are required for temporary facilities. The project is divided into construction zones of equal magnitude and includes:

Administration offices
Site security building and firehouse
Site security guard buildings
Craft orientation and training building
Equipment maintenance shop and services area
Communication and computer building
Client administration building
Material warehouses
Pipe shop
Quality control building
Electrical and instrument shop
Craft shops
First aid buildings
Generator building
Toilet trailers
Office trailers

5.6.2 (Continued)

Craft change houses and weather shelters
Brass alleys

5.6.3 OFFICE COST ESTIMATE

Office cost estimates are developed based on previous experience and adjusted for each site. The office cost estimates cover the following areas:

Engineering, design and procurement man-hours, and labor costs for each case.

Office expenses such as computer costs, reproduction costs, travel, etc.

Licensor costs for basic processing engineering (e.g., Type A process package).

Office burdens, benefits, and overhead costs.

5.6.4 MATERIAL TRANSPORTATION COST ESTIMATE

Material transportation cost estimates are developed based on Fluor's experience and instantaneous January 1982 freight rates. This estimate category includes the cost of transporting worldwide purchased material from the port of export to the project site location. Specifically, the material transportation cost estimate includes:

1. Port Terminal Charges

2. Ocean Freight

5.6.4 (Continued)

3. Air Freight

4. Brokerage and Freight Forwarding Fees

5. Inland Freight from Dock to Jobsite (Separate Estimate/Each Site Location)

6. Import Duties

7. Mariner Insurance

5.6.5 OTHER CAPITAL COSTS

The following describes the basis for the Other Capital Cost items:

Construction Camps

Separate, but adjacent, camps are included for single status craft employees and married supervisory staff employees. The camps should be located near the construction site to minimize travel distances. Each subcontractor erected camp includes paved roads, parking areas, utilities, and recreation facilities in addition to the housing. All buildings are modular and are "pre-engineered." The camps are totally enclosed by fencing and area lighted for security purposes. Approximately 40 to 50 acres are required for the total camp.

Temporary diesel generators are included to provide power for camp operation and for temporary construction power. A package sewage treatment plant is included to serve the camp. Water is obtained from a preconstructed pipeline. The water is treated in a package unit treatment plant.

5.6.5 (Continued)

The single status camp provides accommodations for all direct hire employees, male and female. The camp will accommodate approximately 1800 personnel. Included in the camp are:

Dormitories - Approximately three hundred 5-to-7-man modules assembled into building complexes of varying configurations.

Kitchen/Diner - Dining area allows for serving 1800 persons in shifts; includes kitchen, bakery, food preparation area, food storage, and refrigerated storage.

Recreation Building - Houses post office, cashier, game room, television room, library, lounge, and similar activities. Facilities for baseball, soccer, volleyball, etc., are located adjacent to and administered from the recreation building.

Administration Office - Provides office space for the necessary camp registration, administration, and security. Offices are fully heated and air conditioned.

Other camp buildings included are warehouses, maintenance shops, garages, and guard houses.

No separate staff camp is included in the total camp cost estimate.

Camp operation is contracted to a firm with experience in operating a camp of this size. Camp operator's duties will include:

Food preparation in single status camp
Housekeeping in single status camp

5.6.5 (Continued)

The construction of the project is accomplished using direct hire labor working a 50-hour work week during warm weather months, with an overall construction duration of 42 months.

The manpower estimates correspond to the construction schedule, material deliveries, and climatic conditions.

To complete the project, approximately 22 million manhours will be expended requiring a peak work force of approximately 3,400 craftsmen and 200 to 300 supervising staff persons. The peak manpower arrives during the 4th Quarter, 1987 and includes total field labor, both direct and indirect.

Although the capital cost estimate has been prepared on a total direct hire field labor basis, during actual execution of the project, subcontracts will be issued for at least the following major work items:

Site Preparation

Installation of temporary facilities, including fencing buildings, water and sewer treatment, and power

Electrical

Insulation/Painting

Trash and garbage disposal

Camp construction, operation, and maintenance

Security (Jobsite and Camp)

5.6.5 (Continued)

Initial Catalysts and Chemicals

Initial catalysts and chemicals quantities are developed as part of the process design. Unit prices are based on published supplier data.

Land

Land acreage is based on facility and right-of-way requirements. Estimates of land prices on the reservation were determined, and an allowance was made to accommodate the anticipated total requirements. Cost differences between cases was not determined because of the small impact on the total capital costs.

Spare Parts

Spare parts are based on two percent of direct field materials used on the project. They represent the warehouse stored spare parts such as spare turbine rotors, pumps, heat exchanger tube bundles, instruments, and other replacement materials required to maintain the synfuels facility.

Paid-up Royalties

Paid-up royalties are based on royalties licensors will charge for processes used in plant design.

Shop, Machinery, and Laboratory Equipment

Equipment included in this category are cranes, maintenance vehicles, fire trucks, ambulances, cars, building furniture, maintenance shop equipment, and laboratory equipment.

5.6.5 (Continued)

Owners Costs

Owners costs included owners engineering costs, consultants costs, owners construction management costs, environmental costs, legal costs, permitting costs, and coal testing costs.

Startup Costs

Startup costs for the one year startup period include the following:

One year cost for operating and maintenance manpower and materials
One year cost for plant supervision
Six months cost for catalysts and chemicals
Six months costs for raw materials
An allowance of one percent of total plant cost for field modifications

No credit is taken for saleable byproducts produced during startup.

Management Reserve

Contingency requirements have been evaluated on a section by section basis for the direct field cost portion of the capital cost estimate. The contingency evaluation for indirect field costs, home office costs, and items other than direct field costs, has been made on an overall cost estimate basis.

Contingency is evaluated as follows:

Direct Field Costs (section by section):
Process Definition
Pricing Basis
Estimating Method

5.6.5 (Continued)

Indirect Field Costs and Other Costs (total job only):

Pricing Basis

Estimating Methods

Other capital costs (total job only):

Contingency included in allowance

Note that items analyzed on a total job basis have been assigned a contingency based on the Base Case analysis only.

Working Capital

Working capital represents the accounts payables, accounts receivables, and cash on hand required to conduct the operations of the plant. Two months of operating costs are the basis for working capital.

Financing Costs

Financing costs are the costs associated with obtaining the necessary financial arrangements for the project. These are described in Volume III, Financial and Legal Analysis.

Interest During Construction

Interest during construction is the cost of capital for the engineering, procurement, and construction period of project. It is based on the cash flow projections and the appropriate interest rate. Details of its development are in Volume III, Financial and Legal Analysis.

5.6.5 MANPOWER PLANS

Manpower data is provided for field manpower (Direct Field Labor and Indirect Field Labor) and office manpower (engineering, design, and procurement).

All manpower requirements shown are based on summations of manpower data for each estimate as a whole, and not on individual units. All manpower data is tabulated on a quarterly basis, in conformance with the project schedule.

All field manpower plans are based on a 50-hour work week (650 hours per quarter) and reflect an equivalent number of men.

Office manpower plans were generated for the total estimate only. The total project manpower plans for all cases are tabulated on a quarterly basis. Office manpower plans are based on a 40-hour work week (520 hours per quarter).

The Construction and Engineering/Design progress curves used to develop manpower plans are based on Fluor's historical data and experience with similar projects. These curves have been modified for each case to reflect the project duration and activity relationships specific to the respective case as determined by the project master schedule and the scope of work.

5.7 ECONOMIC CRITERIA - OPERATING AND MAINTENANCE COSTS

Operating and maintenance costs are the annual costs associated with operating the synfuels facility. The components comprising the operating and maintenance costs and the basis for their estimation are presented as follows:

5.7.1 COAL COST

Coal cost is based on the coal quantity developed in the process design and the coal price at the plant gate as determined in the Coal Supply Study presented in Volume V, Special Studies. These are as follows:

Westmoreland Resources, Inc. Coal	-	\$14.75/ton
Shell Oil Company Coal	-	\$15.85/ton

5.7.2 CATALYSTS AND CHEMICALS

Annual catalysts and chemicals consumptions are developed in the process design and the unit prices are determined from suppliers published chemicals and catalysts data. These costs are detailed in Table 6.1.10-1.

5.7.3 PLANT MANAGEMENT STAFF

Supervision costs for the plant staff is based on plant operating labor costs. Preliminary manning charts were developed for the facility, and the supervision costs were estimated to be 10 percent of operating labor and materials costs. Staff estimates are presented in Table 6.1.11-1.

5.7.4 PLANT OPERATING LABOR AND MATERIALS

Operating labor and materials cost are based on projected operating labor requirements assuming a yearly cost of $35,000 per man with an allowance of 10 percent of manpower costs for materials. Manpower estimates are presented in Table 6.1.11-1.

5.7.5 MAINTENANCE LABOR AND MATERIALS

Annual maintenance costs have been established by applying a factor to the installed cost of each unit. This factor varies from four percent for units with high maintenance requirements (Gasification and Tar Distillation) to one percent for several utility/offsite units. The majority of the process units are set at three percent, and the majority of the utility units are set at two percent.

For the Base Case: Westmoreland Coal, 40% Fines @ Site 1, the annual maintenance cost is estimated to be $36,100,000. This total cost is assumed to be 60 percent materials and 40 percent labor.

Using an average labor rate (including overheads) of $35,000 per annum for each maintenance staff position, the total maintenance manpower equals 413.

The maintenance staff includes maintenance personnel, laborers, craft foremen, plant engineering, purchasing, and warehouse personnel.

5.7.6 WATER PUMPING COST

Water pumping requirements are developed in the Water Supply Study included in Volume V, Special Studies. Electricity is based on 4¢/kWh.

5.7.7 SOLID WASTE DISPOSAL

Solid waste disposal requirements are determined in the process design for each case. Two options are considered in developing the disposal cost, depending on the case. For the Westmoreland coal based cases, disposal costs are based on disposal at a site adjacent to Site 1. These costs were developed in the Solid Waste Disposal Study included in Volume V, Special Studies. The costs reflect the civil work associated with preparing the site and reclaiming the disposal site to its previous state. At Site 23, solid wastes are disposed in the Shell mine for a cost of $5.50 per ton.

5.7.8 TAXES AND INSURANCE

Ad Valorem taxes and insurance for the plant are estimated to be two and one-half percent of Total Field and Office Costs.

5.7.9 BYPRODUCTS CREDIT

Offsetting the operating and maintenance costs are credits from byproduct sales. Byproducts which generate revenue for the project include naphtha, ammonia, sulfur, and electric power. SNG and methanol are products and are not included in the byproducts credit. The unit prices for the byproducts are as follows:

Naphtha	-	$268/ST
Ammonia	-	$235/ST
Sulfur	-	$60/ST
Power	-	4¢/kWh

The quantities produced are developed in the process design.

SECTION 6.0
CONTENTS AND RESULTS

6.1 BASE CASE OVERALL PLANT DESCRIPTION

6.1.1 INTRODUCTION

The synfuels plant is a complete "grass roots" facility for the conversion of coal into consumer energy products, primarily pipeline quality methane substitute natural gas (SNG); also, power is generated for sales. Coal from the Westmoreland mine and raw water from the Bighorn River are the only natural resource materials used in the plant, which is a totally self-sufficient operating facility. Section 6.1.2 contains a summary of the major raw materials and products/wastes for this plant.

The coal gasification and byproducts treating processes are licensed by Lurgi Mineraloetechnik of West Germany and have been successfully demonstrated at commercial scale in South Africa. The methanation process is also based on Lurgi technology. The offsite and utility systems for this plant are all based on commercially proven technology.

The plant uses the best available control technology to protect the local environment. Particulate matter and sulfur oxides are removed from flue gases; coal dust is contained within closed conveying and storage systems. The plant water management system is designed to achieve zero effluent discharge. Solid wastes from the plant are made suitable for safe disposal as landfill. Mechanical equipment is designed for low noise operation to maintain the relatively quiet local environment.

The following sections address the Base Case, however, most text pertaining to the processes is applicable to the alternate cases. Unique differences between the Base Case and alternatives are addressed in Section 6.4, 6.5, and 6.6 of this Volume.

6.1.1.1 PROCESS DESCRIPTION

A list of plant units is given in Section 6.1.5. Coal enters the plant at the coal screening unit which screens and distributes the as-received coal to provide sized coal (2 x 1/4 inch) for feed to Lurgi gasifiers and coal fines for boiler fuel.

Coal is gasified by reaction with steam and oxygen. The resultant gas is cooled and combined with gas produced in the Texaco Partial Oxidation Unit (described later). The combined stream is reacted in a Lurgi Sour Gas Shift Unit to generate additional hydrogen by the reaction $CO + H_2O = CO_2 + H_2$. The shift conversion unit produces the proper H_2-to-CO ratio for the methane synthesis reaction.

The shifted gas is cooled, condensing water vapor and hydrocarbons. Products of the Gas Cooling Unit are a liquid stream called "gas liquor" containing water, phenols, tar, and oil, and a "raw gas" containing hydrogen, carbon monoxide, carbon dioxide, sulfur compounds, methane, light hydrocarbons, and naphtha.

In the gas purification area, the Lurgi Selective Rectisol Unit condenses naphtha and removes carbon dioxide and sulfur compounds from the raw gas. Products of the Rectisol Unit are a pure gas for methanation, naphtha which is hydrotreated for sales as a gasoline blending component and three acid gas streams: an H_2S-rich gas stream containing most of the H_2S removed from the raw gas, CO_2 and light hydrocarbons; an H_2S-lean gas stream containing CO_2 and some H_2S and light hydrocarbons; and a CO_2-rich gas stream containing CO_2, traces of sulfur and light hydrocarbon compounds.

A Lurgi Methanation Unit reacts carbon monoxide, carbon dioxide and hydrogen in the pure gas to produce methane. The pure gas feed contains an excess of carbon dioxide which is removed in the SNG Purification and Compression Unit. The resultant product "SNG" is compressed to pipeline delivery pressure.

6.1.1.1 (Continued)

The gas liquor produced in the Gas Cooling Unit flows to the Lurgi Gas Liquor Separation Unit where gas liquor is separated into aqueous and hydrocarbon streams.

The hydrocarbon stream flows to Tar Distillation for further processing. The aqueous stream flows to the Phenosolvan Unit. The phenols are extracted and sent to the Texaco Partial Oxidation Unit. The aqueous stream, after phenol removal, flows to the "Phosam-w" (licensed by U.S. Steel) Ammonia Recovery Unit where ammonia is recovered and purified to produce a saleable byproduct. The aqueous "stripped gas liquor" is biotreated in the Wastewater Treating Unit and used as cooling tower makeup water.

The Tar Distillation Unit separates the hydrocarbon stream containing tars, oils, and naphtha into a naphtha stream sent to Naphtha Hydrotreating, and a tar/oil stream sent to the Texaco Partial Oxidation Unit. The Lurgi Naphtha Hydrotreating Unit hydrotreats the naphtha recovered in the Rectisol and Tar Distillation units to reduce the sulfur, oxygen, nitrogen and reactive unsaturated hydrocarbon content of the naphtha. The naphtha product is suitable for use as a gasoline blending component.

In the Partial Oxidation Unit phenols, tar and oil are reacted with oxygen and steam to produce additional "raw" synthesis gas. This gas is sent to the Shift Unit along with the Lurgi "raw" gas.

The H_2S-rich acid gas stream from the Rectisol Unit is enriched in H_2S content in a Shell ADIP unit and processed in a Claus plant for sulfur recovery. The Claus unit offgas is processed in a (Shell) SCOT unit and flows to a Peabody-Holmes designed Stretford unit for byproduct sulfur recovery. The H_2S lean acid gas stream from Rectisol is also processed in the Stretford unit. The Stretford offgas containing some hydrocarbons and unreacted sulfur compounds and CO_2-rich acid gas stream from

6.1.1.1 (Continued)

Rectisol are combusted in the Process Steam Superheater to convert these compounds to carbon dioxide and sulfur dioxide. Superheated steam for use in the gasifiers is generated in the combustion. The flue gas is discharged to the atmosphere.

6.1.1.2 UTILITIES AND OFFSITES DESCRIPTION

Coal fines are sent to the coal-fired steam boilers where 1500 psig superheated steam is generated. The steam flows to the power generation unit where steam turbine driven generators produce the total power requirement for the plant plus power for sale.

The boiler flue gas is treated for sulfur removal using lime in a Davy McKee Saarberg-Hoelter desulfurization unit. A low SO_2 flue gas is produced, and a nonhazardous gypsum sludge suitable for landfill is recovered.

The plant water management is based on a zero liquid discharge philosophy. The aqueous stream generated in the Lurgi units is processed in an activated sludge biotreatment system. The Process Cooling Towers are designed to evaporate the treated Lurgi water.

The balance of the utility and offsite units are similar to the conventional refinery systems and are not described.

6.1.2 FEED AND PRODUCT SUMMARY

Table 6.1.2-1 contains a summary of the raw materials used and the products and solid wastes generated in this plant.

TABLE 6.1.2-1

FEED AND PRODUCT SUMMARY[1]

BASE CASE: WESTMORELAND COAL - 40% FINES - SNG

	UNITS	QUANTITY
Raw Materials		
Coal from Mine	ST/D	18,000
Lurgi Gasification Feed	ST/D	10,800
Boiler Feed	ST/D	7,200
Bulk Chemicals		
Liquids	ST/D	72
Solids	ST/D	158
Water	Acre-Ft/D	30.1
Products[3]		
SNG	MM SCF/D	137.5[2]
Aromatic Naphtha	BPSD	1,351
Anhydrous Ammonia	ST/D	76.8
Sulfur	ST/D	87.2
Methanol	ST/D	-0-
Solid Wastes		
Gasifier Ash (Dry)	ST/D	827
Boiler Ash (Dry)	ST/D	531
Gypsum	ST/D	387
Plant Refuse	ST/D	50

TABLE 6.1.2-1 (Continued)

Solid Wastes (Continued)

Raw Water Treatment Sludge	ST/D	20
Spent Catalyst	ST/D	0.02
Biotreating Incinerator Ash and Cooling Tower Sludge	ST/D	30

NOTES:

(1) All quantities per stream day

(2) SNG production equals 125 MM SCF/D calendar day basis

(3) Plant also produces 283.2 MW power for sales

6.1.3 THERMAL EFFICIENCY CALCULATION

Table 6.1.3-1 summarizes the overall thermal efficiency calculation for the plant. Only the net saleable products are considered in the plant efficiency. The remainder of the plant energy balance consists of energy losses in the air coolers, cooling towers, and warm stack gases vented to the atmosphere.

TABLE 6.1.3-1

THERMAL EFFICIENCY CALCULATION

BASE CASE: WESTMORELAND COAL - 40% FINES-SNG

	Design Flow[1]	Mass Flow lb/hr	Energy Content	MM Btu/hr
Feed Streams				
Coal to Gasifiers	10,800 ST/D	900,000	8,612 Btu/lb	7,751
Coal to Boilers	7,200 ST/D	600,000	8,612 Btu/lb	5,167
			TOTAL	12,918
Product Streams				
SNG	137.5 MM SCFD	245,948	980 Btu/SCF	5,615
Methanol	-	-	-	-
Aromatic Naphtha	1,351 BPSD	16,348	20,500 Btu/lb	335
Ammonia (99.5% liquid)	76.8 ST/D	6,398	9,030 Btu/lb	58
Sulfur (liquid)	87.2 ST/D	7,265	4,000 Btu/lb	29
Export Power	283.2 MW	283,200 kw	3,414 Btu/kWh	967
			TOTAL	7,004

$$\text{Thermal Efficiency} = \frac{\text{Products}}{\text{Feed}} \times 100 = \frac{7,004}{12,918} \times 100 = \underline{54.2\%}$$

(1) Stream-day rates

6.1.4 DESIGN BASIS

6.1.4.1 PURPOSE OF PLANT

The Crow Synfuels Plant converts subbituminous coal from the Westmoreland Absolaka Mine to pipeline quality substitute natural gas (SNG). Power, and byproducts including ammonia, naphtha and sulfur are also produced for sales.

6.1.4.2 SCOPE OF PLANT

The plant encompasses a series of processing steps including coal receiving from the mine, coal gasification, gas purification, methanation and delivery of SNG to pipeline. Several byproduct processing units, ammonia recovery, naphtha hydrotreating, sulfur recovery, steam and power generation, water treating facilities and the other utility and offsite units are included to make the plant a complete, self-sufficient grass-roots facility.

6.1.4.3 GENERAL DESIGN CRITERIA

The plant is designed to use the available natural resource materials with a minimum impact on the local environment. Coal crushed to two inch size and smaller at the Absolaka Mine is transported by railcars and received at the plant site. The plant design is based on 60 percent sized coal at two inch by one-fourth inch and 40 percent coal fines at less than one-fourth inch size. The sized coal is gasified in Lurgi gasifiers and the fines are fed to the boilers to generate steam.

The plant is designed to produce 125 MM SCF per day of SNG on a calendar day basis. The various process and utility units are designed with multiple trains and sufficient standby capacity to obtain an overall plant

6.1.4.3 (Continued)

on-stream factor of 332 days per year. Surge storage of critical plant liquid streams is provided between units to maintain operating flexibility. Section 6.1.6 discusses the train philosophy of the plant units.

The plant is designed to meet all applicable federal, state, and local regulations for the protection of the environment. Best Available Control Technology (BACT) is used throughout the plant for environmental protection design. Process equipment vent streams and waste materials are strictly controlled and monitored to ensure compliance with regulations covering noise, air quality, water quality and solid waste disposal.

In particular, the plant is compatible with the nearby Class I area for ambient air concentration of SO_2 based on using Site 1 for the proposed plant. Particulate and SO_2 emissions from the coal fired boilers are reduced to environmentally acceptable levels by electrostatic precipitation and flue gas desulfurization, respectively. Hydrocarbon compounds and carbon monoxide contained in process vent streams are destroyed by combustion in the Process Steam Superheating Unit. Particulate emissions are controlled in the coal and ash handling areas. The plant waste water treatment facilities are designed with recycle so that no liquid effluent is discharged from the plant. Solid wastes from the plant are disposed in a neighboring disposal site.

6.1.4.4 PLANT FEED

The only resources fed to the plant are coal and raw water. Crushed coal from the mine is fed to the plant at a design rate of 18,000 ST/SD. Section 5.1 contains the coal analyses. The plant uses raw water from the Bighorn River at a nominal rate of 10,000 acre feet per year. The water analysis is shown in Section 5.3.

6.1.4.5 Products

The principal product of this facility is pipeline quality substitute natural gas (SNG). The specifications of the SNG and the byproducts listed below are included in Section 5.6. The SNG is compressed to sufficient pressure to enter the gas pipeline system.

Power produced within the plant in excess of the internal requirements is exported. Other saleable byproducts from the plant include anhydrous liquid ammonia, molten sulfur and hydrotreated aromatic naphtha.

Solid wastes from the plant are mainly coal ash and flue gas desulfurization sludge. These are combined and conveyed to a neighboring disposal site.

No liquid effluent is discharged from the plant.

6.1.4.6 DESIGN BASIS - MECHANICAL ENGINEERING

Mechanical equipment and vessels are configured and cost estimated based upon equipment specifications defined by process requirements. Equipment specification data sheets, complete with process requirements data, were reviewed by mechanical equipment and vessels engineers, and, in turn, matched with existing equipment models, or standard designs, wherever possible. Each existing equipment model or standard design considered conforms to Fluor equipment specifications. These specifications are developed in accordance with accepted industry standards and applicable government codes and standards shown in Table 6.1.4-1.

With mechanical equipment and vessel configurations determined by the forgoing, prices were obtained from in-house data or computer programs, and direct contact with suppliers. The computer programs and in-house data bases are updated continuously from actual cost data obtained from equipment procurement activity. These costs, and other specific data about the equipment, are documented on each data sheet.

TABLE 6.1.4-1

MAJOR CODES AND STANDARDS

Pressure Vessels

ASME SECTION II	Material Specifications, Parts A and B
ASME SECTION VIII, DIVISION 1	Pressure Vessels
ASME SECTION VIII, DIVISION 2	Alternate Rules

Tanks

API 620	Recommended Rules for Design and Construction of Large, Welded, Low Pressure Storage Tanks
API 650	Specification for Welded Steel Tanks for Oil Shortage
API 2000	Venting Atmospheric and Low Pressure Storage Tanks

Heat Exchangers

API 660	Heat Exchangers for General Refinery Services
API 661	Air Cooled Heat Exchangers for General Refinery Services

TABLE 6.1.4-1 (Continued)

ASME SECTION I	Power Boilers (Steam Systems)
ASME SECTION II	Material Specifications, Parts A and B
ASME SECTION VIII, DIVISION 1	Pressure Vessels
TEMA	Standards of Tubular Exchanger Manufacturers Association, and Addenda

Fired Heat Transfer Equipment

API RP 530	Recommended Practice for Calculation of Heater Tube Thickness in Petroleum Refineries
API 630	Tube and Heater Dimensions for Fired Heaters for Refinery Service
ASME SECTION I	Power Boilers
ASME SECTION II	Material Specifications, Parts A and B
ASME SECTION VIII, DIVISION 1	Pressure Vessels

Rotating and Mechanical Equipment

API 610	Centrifugal Pumps for General Refinery Services
API 611	General Purpose Steam Turbines for Refinery Services

TABLE 6.1.4-1 (Continued)

API 612	Special Purpose Steam Turbines for Refinery Services
API 613	Special Purpose Gear Units for Refinery Services
API 614	Lubrication, Shaftsealing and Control Oil Systems for Special Purpose Applications
API 615	Combustion Gas Turbines for General Refinery Services
API 617	Centrifugal Compressors for General Refinery Services
API 618	Reciprocating Compressors for General Refinery Services
API 619	Rotary Type Positive Displacement Compressors for General Refinery Services
API 672	Packaged, Integrally Geared Centrifugal Plant and Instrument Air Compressors for General Refinery Services
API 674	Positive Displacement Pumps Reciprocating

TABLE 6.1.4-1 (Continued)

API 675	Positive Displacement Pumps Controlled Volume
API 676	Positive Displacement Pumps Rotary
ANSI B73.1	Specification for Horizontal End Suction Centrifugal Pumps
ASME SECTION VIII, DIVISION	Pressure Vessels
NEMA MG-1	Motors and Generators
NEMA SM21	Multistage Steam Turbines for Mechanical Drive Service

6.1.5 PLANT UNITS

The plant units required for the Crow Synfuels Plant are listed in Table 6.1.5-1. This table also indicates whether the unit is a proprietary process designed by a licensor or a nonproprietary unit designed by Fluor.

TABLE 6.1.5-1

PLANT UNITS

BASE CASE: WESTMORELAND COAL - 40% FINES-SNG

Unit Number	Unit Name	Licensor/Designer
01	Coal Screening	Fluor
02	Coal Distribution	Fluor
03	Ash Handling	Fluor
10	Gasification	Lurgi
11	CO Shift	Lurgi
12	Gas Cooling	Lurgi
13	Rectisol	Lurgi
14	Gas Liquor Separation	Lurgi
15	Tar Distillation	Lurgi
16	Naphtha Hydrotreating	Lurgi
17	Phenosolvan	Lurgi
18	Ammonia Recovery	U.S. Steel
19	Sulfur Recovery	Shell/Peabody-Holmes/Fluor
20	Process Steam Superheating	Fluor
21	Methanol Synthesis	Lurgi
22	Methanation	Lurgi
23	SNG Compression & Purification	Fluor/Lurgi
24	Partial Oxidation	Texaco
25	PSA Hydrogen Production	Union Carbide
40	Oxygen Production	Lotepro
41	Steam Generation	Fluor
42	Power Generation	Fluor
43	Flue Gas Desulfurization	Davy-McKee
44	Raw Water Treating	Fluor
45	BFW and Condensate Treating	Fluor
46	Air & Nitrogen Systems	Fluor

TABLE 6.1.5-1 (Continued)

Unit Number	Unit Name	Licensor/Designer
47	Process Cooling Water	Fluor
48	Utility Cooling Water	Fluor
49	Potable Water	Fluor
50	Utility Water	Fluor
51	Firewater	Fluor
52	Fuel Gas	Fluor
53	Flare	Flucr
54	Wastewater Treating	Fluor
55	Tank Farm and Dispatch	Fluor
56	Sanitary Sewage Treatment	Fluor
57	Interconnecting Pipeway	Fluor

6.1.6 PLANT TRAIN PHILOSOPHY

General

The general philosophy for the Crow Synfuels Facility is to divide the major process units into two 50 percent capacity parallel trains.

The two train philosophy permits scheduling a general shutdown of one-half the facility for maintenance and inspection while continuing plant operation at 50 percent capacity and phased construction for manpower leveling. Additionally, the multiple train approach avoids total loss of production due to a single process unit shutdown. Parallel trains are cross-connected for operating flexibility.

The design philosophy of each process unit reflects an overall plant onstream time of 332 days per year. Factors which influence the onstream performance of a plant are the use of parallel trains, intermediate product surge tankage and sparing of critical equipment. For single train units with liquid hydrocarbon feed stocks, feed surge is provided; also sufficient unit capacity is provided to process feed accumulated during a unit shutdown. Spare equipment is provided in critical services in accordance with accepted refinery practice for the targeted onstream factor.

The philosophy adhered to in the design of the utility and offsite units is to ensure that support systems have 100 percent availability. For critical systems, such as steam generation, the "N + 1" approach is used, where N is the number of units required to meet design production. For example, one additional boiler is provided for the Steam Plant.

Process Units

Table 6.1.6-1 summarizes the number of trains and the criteria (equipment size limitation, and/or operating and maintenance flexibility) which determine the number of trains for each unit. The train philosophy is shown schematically on Drawing No. 835704-00-4-001.

Coal Screening consists of two 66 percent trains. Two 100 percent capacity conveyors are provided to ensure delivery of coal to the gasifiers; similarly, two 100 percent conveyors provide coal to the boilers.

The Gasification Unit consists of two parallel gasifier trains, each train consisting of seven gasifiers. To support normal operation 12 gasifiers are required. Fourteen gasifiers are provided to ensure continuous production at design rates. Gasifiers are taken offline for scheduled maintenance and are also subject to unscheduled interruptions due to mechanical problems or variations in coal properties.

The Ash Handling Unit consists of two 50 percent trains. Four sluiceways deliver ash slurry from Gasification to Ash Handling. Two spare sluiceways are provided between units to allow for maintenance shutdown of a sluiceway normally in operation.

The Partial Oxidation Unit consists of one train. Feed storage is provided to allow for maintenance shutdown of up to two weeks. The CO Shift Unit consists of two 66 percent trains, and the Gas Cooling Unit has two 50 percent trains. The Selective Rectisol Unit is provided with two 55 percent trains. Methanation and SNG Purification/Compression consist of two trains of 50 and 55 percent capacity respectively.

Methanol Synthesis Unit has one train with sufficient spare capacity to allow shutdowns without interrupting methanol makeup to Rectisol. PSA Hydrogen Production Unit consists of one 100 percent train.

TABLE 6.1.6-1

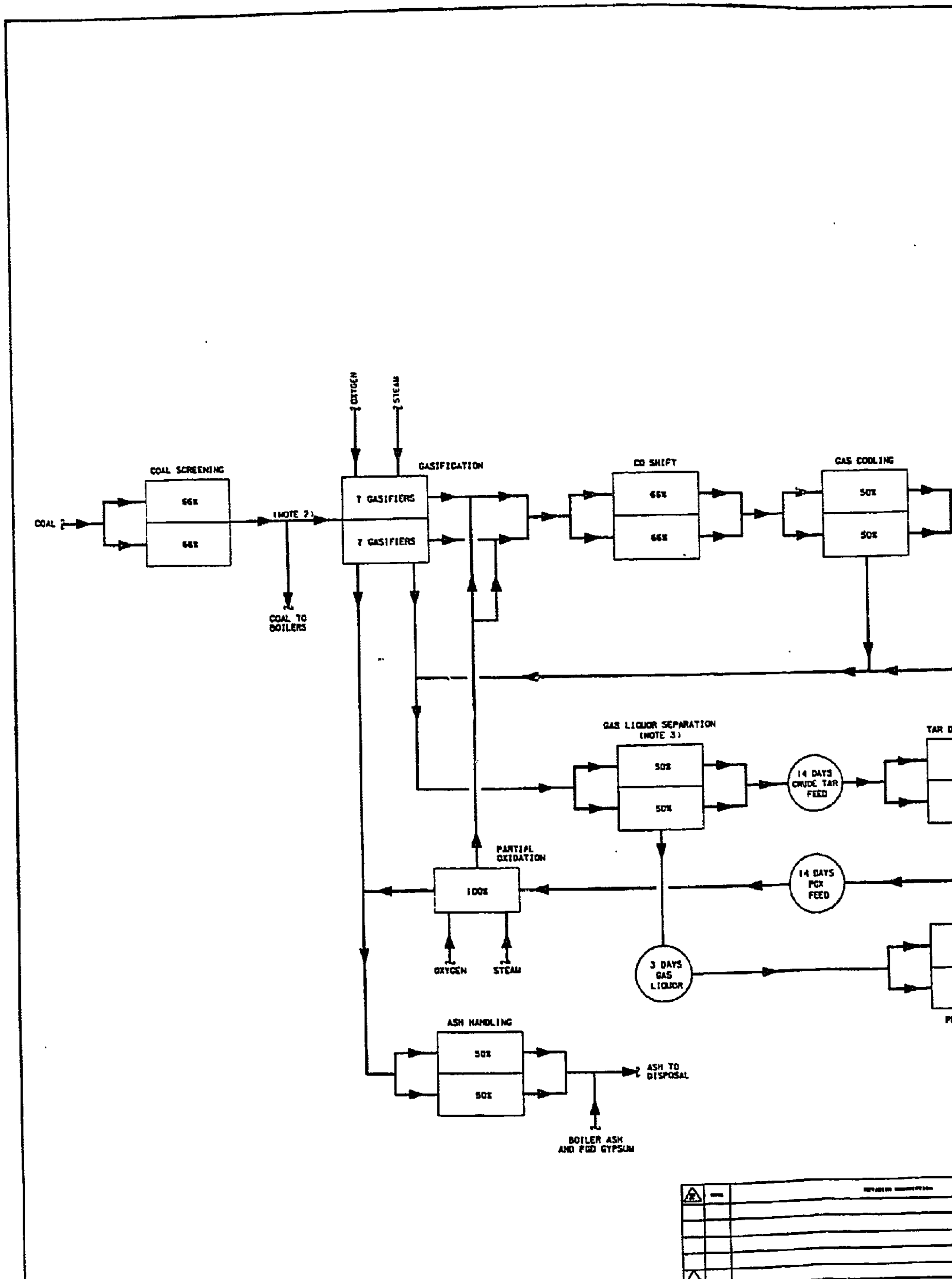
TRAIN PHILOSOPHY - PROCESS UNITS

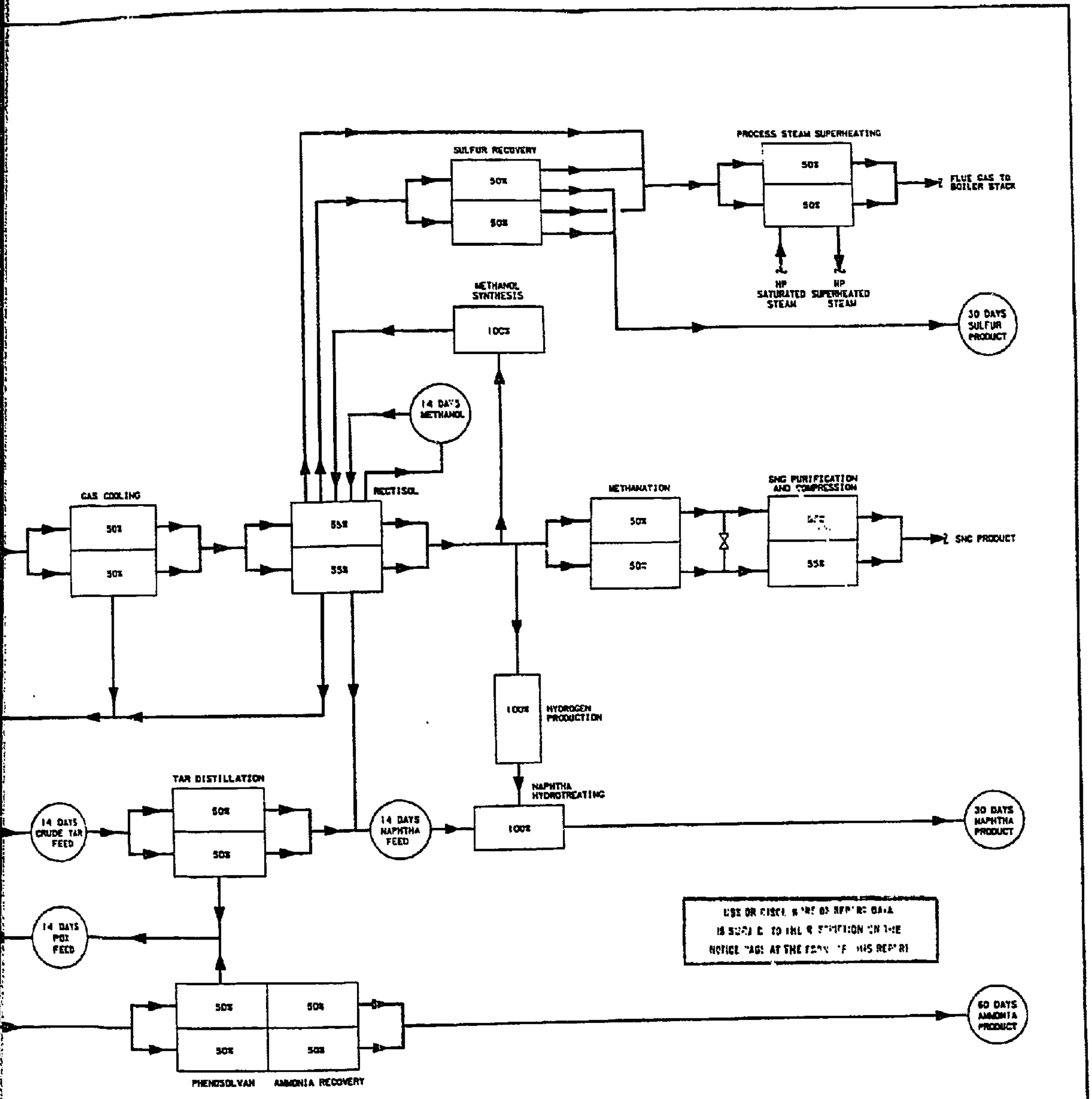
Unit	No. of Trains	Criteria[1]
01 Coal Screening	2 x 66%	a-Screening Modules, b
02 Coal Distribution	2 x 100%	b
03 Ash Handling	2 x 50%	b
10 Gasification	14 (12 operating)	a-Mk IV Gasifiers, b
11 CO Shift	2 x 66%	a-Reactor, b
12 Raw Gas Cooling	2 x 50%	a-Air Coolers, b
13 Rectisol	2 x 55%	a-Methanol Wash Towers, b
14 Gas Liquor Separation	2 x 50% (2)	b
15 Tar Distillation	2 x 50%	b
16 Naphtha Hydrotreating	1 x 100%	
17 Phenosolvan	2 x 50%	b
18 Ammonia Recovery	2 x 50%	b
19 Sulfur Recovery	2 x 50%	b
20 Process Steam Superheating	2 x 50%	b
21 Methanol Synthesis	1 x 100%	
22 Methanation	2 x 50%	a-Reactors, b
23 SNG Purification & Compression	2 x 55%	a-Compressors, b
24 Partial Oxidation	1 x 100%	
25 Hydrogen Production	1 x 100%	

NOTES:

(1) Criteria for number of trains are as follows:
  (a)-Equipment size limitation
  (b)-Operating and maintenance flexibility

(2) Primary separation of dusty tar is 100% spared


OXYGEN
STEAM
COAL SCREENING
66%
66%
COAL
(NOTE 2)
COAL TO BOILERS
GASIFICATION
7 GASIFIERS
7 GASIFIERS
CO SHIFT
66%
66%
GAS COOLING
50%
50%
GAS LIQUOR SEPARATION (NOTE 3)
50%
50%
14 DAYS CRUDE TAR FEED
PARTIAL OXIDATION
100%
OXYGEN
STEAM
14 DAYS POX FEED
3 DAYS GAS LIQUOR
ASH HANDLING
50%
50%
ASH TO DISPOSAL
BOILER ASH AND FGD GYPSUM



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NOTES:

1. CIRCLES INDICATE STORAGE.
2. COAL DISTRIBUTION CONSISTS OF 2 - 100% CONVEYORS TO GASIFICATION AND 2 - 100% CONVEYORS TO STEAM GENERATION.
3. DUSTY TAR SEPARATION IS 100% SPARED.

FLUOR

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W. O'BELMITO
R. McCARTHY
R. LANG

BLOCK FLOW DIAGRAM
TRAIN PHILOSOPHY - PROCESS UNITS
CASE: WESTMORELAND COAL - 40% FINES - SNG

CROW TRIBE OF INDIANS — SYNFUELS FEASIBILITY STUDY

NONE | 835704-00-4-001 | 1

Gas Liquor Separation consists of two 50 percent trains with the exception of the dusty tar separation area which consists of two 100 percent trains.

Three days storage capacity is provided for the feed to Phenosolvan. Phenosolvan and Ammonia Recovery consist of two 50 percent trains.

Fourteen day storage is provided for the feed to Tar Distillation, which consists of two 50 percent trains. Naphtha Hydrotreating consists of a single train and is provided with fourteen days of feed storage to permit continued operation of Gasification when this unit is down.

Sulfur Recovery and Process Steam Superheating each consist of two trains.

UTILITY AND OFFSITE UNITS

Table 6.1.6-2 summarizes the number of trains and applicable criteria for each system. The train philosophy is shown schematically on Drawing Number 835704-00-4-002.

The Oxygen Plant consists of two 50 percent capacity trains. No provision is made for liquid oxygen storage in view of the high reliability of oxygen plants and the provision of multiple trains. A spare oxygen compressor, however, is provided for each train.

The Air and Nitrogen System, which supplies instrument air, plant air and LP nitrogen, consists of one train with critical equipment spared.

Two emergency flare stacks are provided, each handling 50 percent of the maximum relief load.

TABLE 6.1.6-2

TRAIN PHILOSOPHY - UTILITY & OFFSITE UNITS

Unit	No. of Trains	Criteria[1]
40 Oxygen Production	2 x 50%	a-Compressors
41/42 Steam and Power Generation	3 x 50%	a-Boilers, b
43 Flue Gas Desulfurization	3 x 50%	b
44 Raw Water Treating	1 x 100%	
45 BFW & Condensate Trtg.	1 x 100%	
46 Air & Nitrogen	1 x 100%	
47 Process Cooling Water (2)	2	b
48 Utility Cooling Water	1 x 100%	
49 Potable Water	1 x 100%	
50 Utility Water	1 x 100%	
51 Firewater	1 x 100%	
52 Fuel Gas	1 x 100%	
53 Flare	2 x 50%	b
54 Wastewater Treating	2 x 50%	b
55 Tank Farm & Dispatch	1 x 100%	
56 Sanitary Sewage Treatment	1 x 100%	

NOTE:

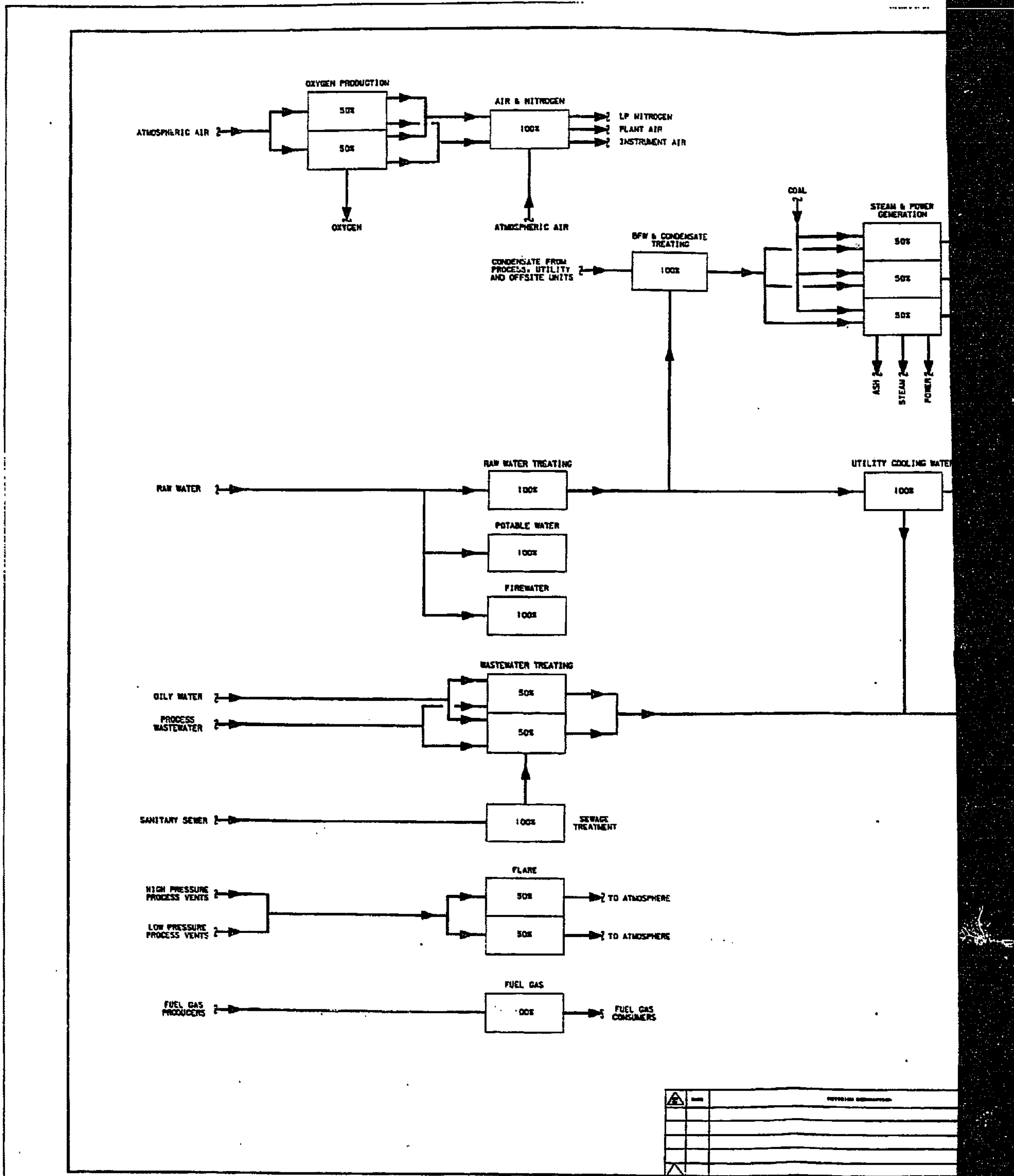
(1) Criteria for number of trains are as follows:
(a)-Equipment size limitation
(b)-Operating and maintenance flexibility

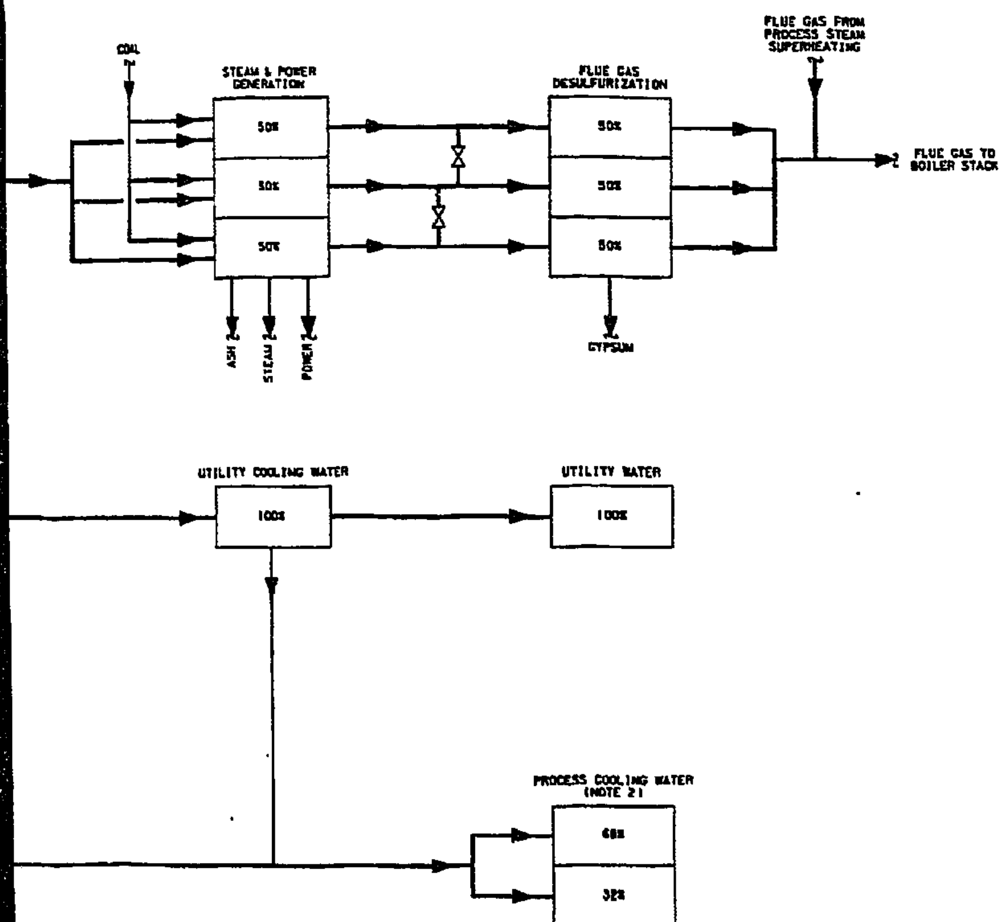
(2) A 32% capacity train serves the process units, and a 68% capacity train serves the Power Generation and Tank Farm Units.

The intermediate tankage area is provided with one 14-day storage tank for each hydrocarbon processing unit feed stock. The final product tankage area is designed for 60-day storage of ammonia and 30-day storage for naphtha and sulfur.

The water treating units - Raw Water Treating, BFW & Condensate Treating, Potable Water, Utility Water and Firewater - consist of one train each. Because the Wastewater Treating Unit is susceptible to upset, it consists of two 50 percent trains so that 50 percent capacity operation can be maintained. The "N + 1" philosophy is applied to the equipment that requires regeneration and/or backwashing, including filters, softeners, and ion exchange beds. Critical pumps are spared.

The Steam and Power Generation facilities consist of three 50 percent trains in accordance with the "N + 1" philosophy. All trains are normally in operation at reduced load. However, if one train should fail, the trains remaining in operation can handle the full plant load. Three 50 percent trains of flue gas desulfurization are provided to be compatible with boiler operation.


OXYGEN PRODUCTION
50%
50%
ATMOSPHERIC AIR
OXYGEN
AIR & NITROGEN
100%
LP NITROGEN
PLANT AIR
INSTRUMENT AIR
ATMOSPHERIC AIR
COAL
STEAM & POWER GENERATION
50%
50%
50%
ASH
STEAM
POWER
BFW & CONDENSATE TREATING
100%
CONDENSATE FROM PROCESS, UTILITY AND OFFSITE UNITS
RAW WATER TREATING
100%
RAW WATER
UTILITY COOLING WATER
100%
POTABLE WATER
100%
FIREWATER
100%
WASTEWATER TREATING
50%
50%
OILY WATER
PROCESS WASTEWATER
SANITARY SEWER
100%
SEWAGE TREATMENT
FLARE
50%
50%
HIGH PRESSURE PROCESS VENTS
LOW PRESSURE PROCESS VENTS
TO ATMOSPHERE
TO ATMOSPHERE
FUEL GAS
100%
FUEL GAS PRODUCERS
FUEL GAS CONSUMERS



NOTES:

1. PRODUCT STORAGE OF 60 DAYS FOR AMMONIA AND 30 DAYS FOR NAPHTHA AND SULFUR AND INTERMEDIATE TANKAGE OF 14 DAYS ARE SHOWN ON DRAWING 835704-00-4-001. TRAIN PHILOSOPHY - PROCESS UNITS.
2. THE 32% CAPACITY TRAIN SERVES THE PROCESS UNITS. THE 68% CAPACITY TRAIN SERVES THE POWER GENERATION AND TANK FARM UNITS.

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IS SUBJECT TO THE RESTRICTION ON THE
NOTICE PAGE AT THE FRONT OF THIS REPORT

FLUOR

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C.C. ABATAY
W.O'BELMITO
R. McCARTHY
R. LANG

BLOCK FLOW DIAGRAM
TRAIN PHILOSOPHY - UTILITY AND OFFSITE UNITS
CASE: WESTMORELAND COAL - 40% FINES - SNG
CROW TRIBE OF INDIANS — SYNFUELS FEASIBILITY STUDY

Scale	Drawing number	Rev.
NONE	835704-00-4-002	1

001 35700002

6.1.7 PLOT PLAN

The development of plot plans involves conforming to industry standard practices, in addition to economics, constructability and operability. The units are spaced to comply with risk insurers recommendations.

For the overall plot plan, the units are arranged, as much as possible, in the same sequence as the process flow of the plant. Some units, however, are located out of sequence and adjacent to or near other units for economic reasons, such as minimizing long runs of large diameter exotic piping.

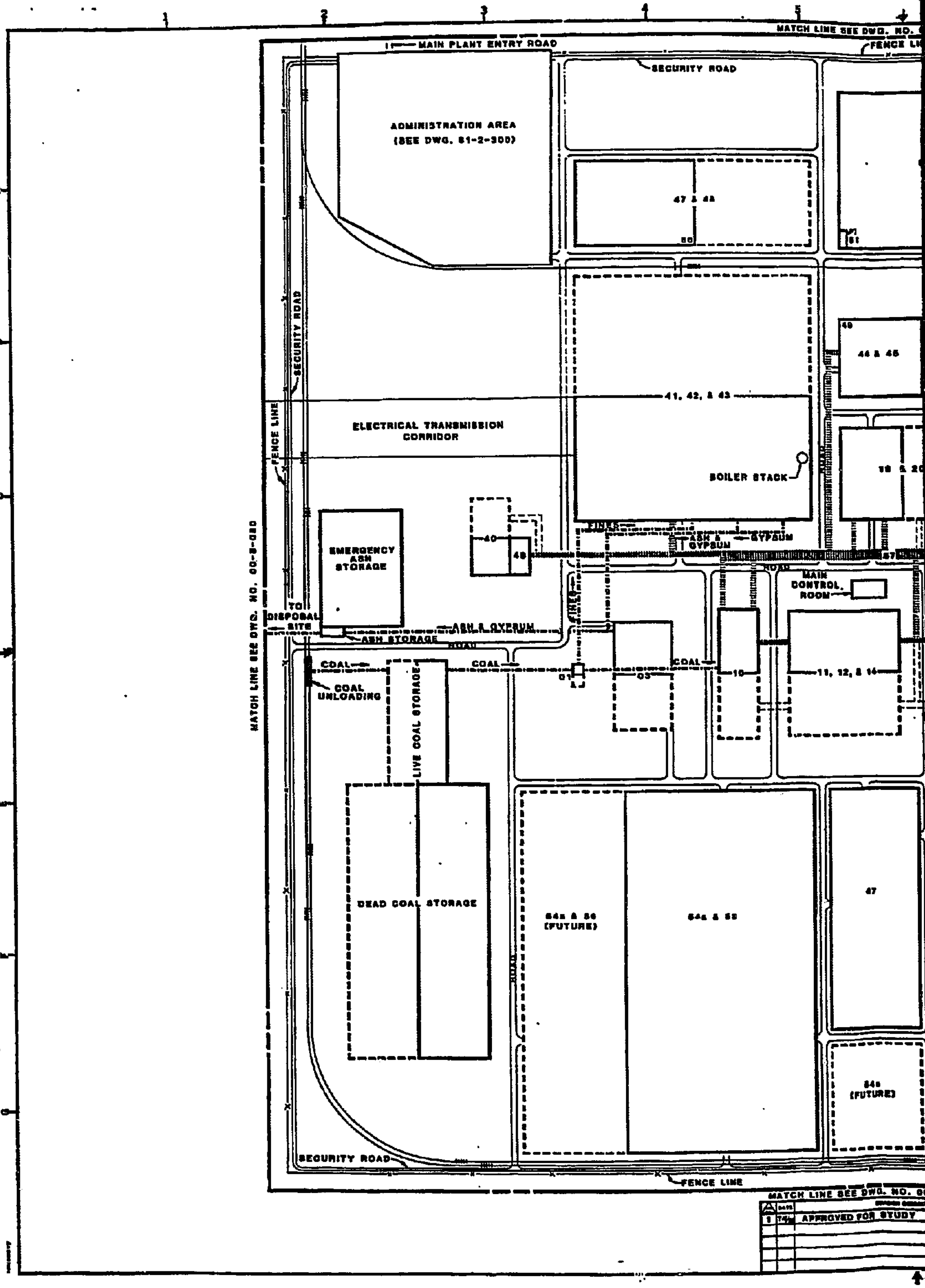
For example:

> The Steam Generation (Unit 41) area is located adjacent to Oxygen Production (Unit 40) which requires large quantities of high pressure steam.
>
> Sulfur Recovery (Unit 19) is located adjacent to Flue Gas Desulfuration (Unit 43) in order to utilize a common stack.
>
> Oxygen Production (Unit 40) is located such that it is upwind of the rest of the plant (based upon the prevailing wind, TBD).
>
> The cooling towers are located such that the water vapor plume does not interfere with the plant operation.
>
> Ponds are, in general, grouped together and located in the low area of the plant.
>
> The Flares (Unit 53) are located in the Solar Evaporation Pond (Unit 54B) to minimize plant acreage.

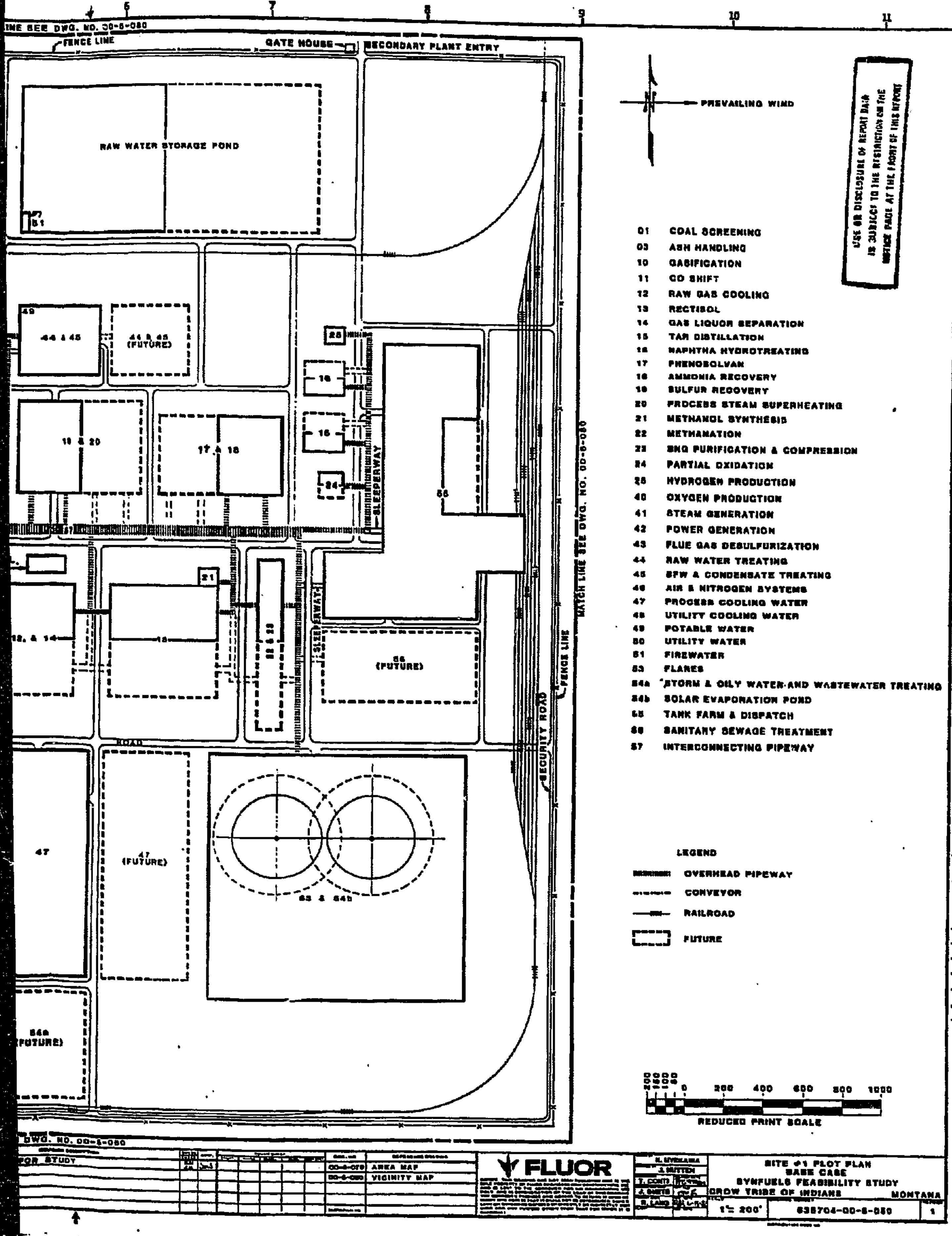
The main control building is centrally located.

Sufficient railroad switchyard is provided to allow for makeup of trains, switching, and sorting of incoming cars and storage of cars. A spur is also provided to the maintenance and warehouse area, and Flue Gas Desulfurization (Unit 43) for unloading of supplies.

The Plot Plan for the Base Case is shown on Drawing Number 835704-00-5-050.



MAIN PLANT ENTRY ROAD
SECURITY ROAD
ADMINISTRATION AREA
(SEE DWG. 81-2-300)
47 & 48
44 & 45
41, 42, & 43
ELECTRICAL TRANSMISSION CORRIDOR
BOILER STACK
SECURITY ROAD
FENCE LINE
EMERGENCY ASH STORAGE
FINES
ASH & GYPSUM
GYPSUM
MAIN CONTROL ROOM
TO DISPOSAL SITE
ASH & GYPSUM
ASH STORAGE
ROAD
COAL
COAL UNLOADING
LIVE COAL STORAGE
11, 12, & 14
DEAD COAL STORAGE
ROAD
(FUTURE)
SECURITY ROAD
FENCE LINE
APPROVED FOR STUDY



GATE HOUSE
SECONDARY PLANT ENTRY
FENCE LINE
RAW WATER STORAGE POND
PREVAILING WIND
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01 COAL SCREENING
03 ASH HANDLING
10 GASIFICATION
11 CO SHIFT
12 RAW GAS COOLING
13 RECTISOL
14 GAS LIQUOR SEPARATION
15 TAR DISTILLATION
16 NAPHTHA HYDROTREATING
17 PHENOSOLVAN
18 AMMONIA RECOVERY
19 SULFUR RECOVERY
20 PROCESS STEAM SUPERHEATING
21 METHANOL SYNTHESIS
22 METHANATION
23 SNG PURIFICATION & COMPRESSION
24 PARTIAL OXIDATION
25 HYDROGEN PRODUCTION
40 OXYGEN PRODUCTION
41 STEAM GENERATION
42 POWER GENERATION
43 FLUE GAS DESULFURIZATION
44 RAW WATER TREATING
45 BFW & CONDENSATE TREATING
46 AIR & NITROGEN SYSTEMS
47 PROCESS COOLING WATER
48 UTILITY COOLING WATER
49 POTABLE WATER
50 UTILITY WATER
51 FIREWATER
53 FLARES
54a STORM & OILY WATER AND WASTEWATER TREATING
54b SOLAR EVAPORATION POND
55 TANK FARM & DISPATCH
56 SANITARY SEWAGE TREATMENT
57 INTERCONNECTING PIPEWAY
44 & 45
44 & 45 (FUTURE)
19 & 20
17 & 18
SLEEPERWAY
MATCH LINE SEE DWG. NO. 00-6-080
FENCE LINE
SECURITY ROAD
ROAD
55 (FUTURE)
47
47 (FUTURE)
53 & 54b
54a (FUTURE)
LEGEND
OVERHEAD PIPEWAY
CONVEYOR
RAILROAD
FUTURE
0 200 400 600 800 1000
REDUCED PRINT SCALE
FOR STUDY
00-6-070 AREA MAP
00-6-080 VICINITY MAP
FLUOR
SITE #1 PLOT PLAN
BASE CASE
SYNFUELS FEASIBILITY STUDY
CROW TRIBE OF INDIANS
MONTANA
1" = 200'
838704-00-6-050
1