TECHNOLOGY ASSESSMENT GUIDE
NO. 5
LURGI-ANG HIGH-BTU GASIFICATION

DRAFT

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

The Lurgi-ANG project is a planned commercial facility currently in the final stages of design, prior to the initiation of its construction in North Dakota. The process is based on well-known Lurgi gasification technology, and uses conventional systems for coal handling and preparation, air separation, gas cooling, shift conversion, acid gas removal and methanation. Because of the extensive experience base with all major subsystems in the process, technical risk is seen as being quite low. The project will be located very close to the coal supply, a situation which appears to guarantee adequate supplies at manageable prices for the projected life of the plant.

Recent uncertainties in funding sources among the project's five sponsors have cast doubt on the future of the project. The economic success of the project will depend upon the Great Plains Coal Gasification Associates' ability to control capital equipment costs and construction schedule (to minimize interest during construction), and the future market for pipeline quality gas. Because of the expectation that the plant will be successful technically, the proliferation of this plant design concept throughout the United States will most likely depend on the future strength of the natural gas market.

1.2 ENGINEERING ASPECTS

North Dakota lignite is the planned feedstock for the ANG facility. Because of its non-caking nature, no pretreatment or mechanical agitators will be necessary for its use in the dry-ash Lurgi gasifiers which will be used. Extensive experience with European low-rank coals in the Lurgi gasifier is somewhat applicable to the North Dakota lignite feedstock, and suggests that few problems will be encountered. Due to high moisture contents in the lignite, the feed will have to be at least partially dried prior to gasification. Extensive drying reduces the quantity of waste liquor produced, but may also decrease the reactivity of the coal, suggesting that some optimal moisture content may be found depending on coal properties and process conditions.

The dry-ash Lurgi gasifiers represent first generation coal gasification technology. The fact that this gasifier is designed to produce ash in a dry, non-slagged form is responsible for its rather poor thermal efficiency (cold gas gasifier efficiency $\sim$68%) in comparison to other gasification systems. The reason for the low efficiency lies in the use of large quantities of live steam to control bed temperatures below the ash softening point of the coal being used. Most of the enthalpy in the steam which is used for this purpose is never recovered in useful form. The requirement to maintain bed temperatures below the ash softening point is critical to proper operation of the gasifier, and must be adequately monitored to prevent temperature excursions. Production of ash wastes in a non-slagged form also increases the chance of leaching harmful materials into groundwaters.

Operation of the gasifier at low temperatures (to prevent slagging), favors methane production, especially at elevated pressures used in the ANG design. However, since reaction rate is highly dependent on temperature, gasifier throughput is considerably lower than comparably sized gasifiers operating at higher temperatures.

Because of its countercurrent flow arrangement, with coal coming in at the top of the gasifier and reactant and product gases rising upward, there is a minimum size for feed coal. Below this minimum size (approximately 1/4") coal particles are entrained out of the gasifier before reacting. Therefore, fines cannot be fed together with the sized coal feed in the top of the gasifier. As much as 10 percent of total coal feed rate can be in the form of fines if they are fed with steam through tuyeres in the bottom of the reactor. This poses a problem when feeding many coals, since fines are generated in the crushing process, often in excess of 10 percent. In addition lignitic coals have a tendency to decrepitate, or produce fines, during drying. Some sources also feel that lignite has an increased propensity to generate fines when crushing, although this has not been established by a laboratory evaluation. Coal fines which cannot be handled by the Lurgi gasifiers will be sold for use in a pulverized coal power plant. Alternatively, had the process design called for the use of an entrained flow gasifier in addition to the Lurgi units, all of the coal fed to the gasification plant could have been used without the need for export sales.

The countercurrent flow arrangement is also responsible for the considerable production of tars, oils, phenols, naphthas, and other unreacted hydrocarbons. As coal enters the top of the reactor, hot gases begin to warm it to reaction temperature. The coal passes through several temperature stages, most notably devolatilization, prior to gasification and combustion further down in the bed.

In the devolatilization zone, the coal loses its volatile components to the vapor phase, most of which are carried out of the gasifier with the raw gas before having a chance to react. Once cooled downstream, these volatile components condense, thereby coating the surfaces of heat exchangers and other process equipment. A water treatment problem is also created since considerable quantities of water also condense with these volatile materials. The ANG facility plans a biological wastewater treating facility to handle these contaminated water streams. It is possible that variations in feedstock and process conditions may produce a range of wastewater concentrations which will be too great for the chosen organism to deal with. Blending may be used to achieve some degree of consistency, but it is possible that different organisms may have to be used from time to time. Although this is not a major concern, it is one of the few uncertainties associated with the process.

Downstream of the reactor, the raw gas is cooled, then split approximately in half prior to shift conversion. This is done because the gas is under pressure, and experiences a pressure loss in the shift conversion unit. The shift unit can be operated to produce enough hydrogen in the slipstream to meet the requirements for the entire raw gas flowrate. Both shifted and unshifted raw gas streams are cooled further, followed by recompression of the shifted stream. Thus, shifting only a fraction of the total gas flow reduces recompression requirements.

Following acid gas removal, the synthesis gas is methanated and compressed. This gas is dehydrated in a glycol unit, then sent back for final gas compression before pipeline distribution. Dehydration is carried out at an intermediate pressure for more complete water removal. Dehydration at pipeline pressures (~1000 psi) would require extremely thick vessel walls, the cost of which could not be justified by the added degree of moisture removal achieved (which would be very small).

1.3 CURRENT COSTS

The total capital required for this 91.25 x 10^{12} Btu/year plant is \$3.86 billion, which is dominated by a capital investment of \$2.35 billion. Interest during construction is the next largest item at \$1.21 billion. Working Capital and Start-up costs are each approximately \$142 million, with Catalysts and Chemicals making up the remainder of \$15 million. Annual operating and maintenance costs (at a 90% plant capacity factor), exclusive of coal costs, total \$80.1 million. Sulfur and ammonia are given by-product credits of \$40/ton and \$140/ton respectively, giving a net operating and maintenance cost of \$68.5 million.

Taken together with a 20 percent capital charge, these operating costs result in a product cost of \$10.23/10^6 Btu, which is exclusive of coal costs.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

The Lurgi gasification technology and other process subsystems used in the ANG plant are well characterized through years of practical industrial experience. With the exception of the choice of biological culture used in the wastewater treatment facility, little or no research is envisioned for the facility.

As process improvements are made within the coal gasification field in the coming years, those applicable to the ANG facility will undoubtedly be reviewed. For example, the current work in the development of the BGC-slagging Lurgi gasifier may have application to the ANG facility if the new slagging gasifiers are judged to be sufficiently reliable, efficient and economical.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

This technology assessment guide is based upon an actual project now in the final design stage to produce pipeline quality gas in North Dakota. The dry-ash Lurgi gasification system was selected to produce a crude medium-Btu gas which will be upgraded to pipeline quality by purification and methanation. The gasifier is blown with oxygen and steam at approximately 450 psig. Despite it's inherent low efficiency and other drawbacks, the Lurgi system was chosen for several important reasons:

- It has been demonstrated for approximately 40 years in commercial operation.

- It operates well on non-caking low-rank coals indigenous to North Dakota.

- Oxygen requirements are fairly low due to the low temperatures in the gasifier, and the non-reaction of tars in the off gas stream.

- The low temperature high pressure conditions in the gasifier produce a significant portion of the final methane in the product gas.

- At these same conditions, the water-gas shift equilibrium is about 2:1, H_2:CO. This reduces downstream shift reaction requirements.

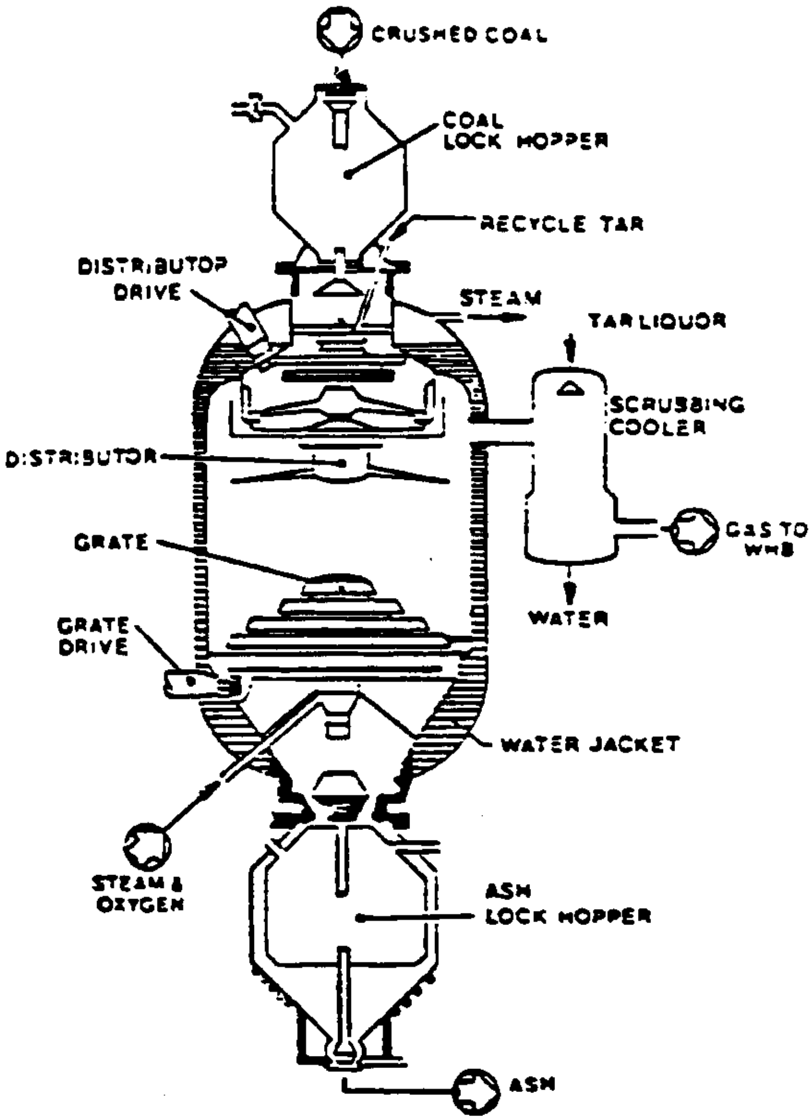
Figure 2-1 depicts the dry-ash Lurgi system, the heart of the gasification plant. Screened coal in the 1/3 to 1-1/2 inch size range is introduced into the system via a lockhopper mounted above the reactor. A motor driven distributor insures even allocation of the coal over the coal bed. The bed depth varies from seven to ten feet. Coal moves slowly downward under the influence of gravity and against a countercurrent flow of gas.

Steam and either air or oxygen are injected at the bottom of the bed through the slowly rotating grate. The extent of steam injection is determined by the ash softening point. Since it is desired to remove the ash from the reactor in a dry (non-slagged) form, sufficient steam must be injected to maintain the reaction temperature below the ash softening point. The enthalpy contained in the steam is never recovered by the process in useful form, and is eventually rejected as waste heat. Because of the large steam consumption in the gasifier, this energy loss has a significant impact on the process efficiency. Slagging operation has been tried in an experimental unit, but requires a different mechanical configuration which is as yet commercially unproven.

Several reaction zones are established within the gasifier because of the countercurrent flow of coal and gaseous reactants. From the top they are the preheating or drying zone, the carbonization zone, and the ash zone. Heat is transferred from the rising gases to the down-flowing solids, and, with adequate bed depth, the crude gas which is discharged at the top is at a moderate temperature. The oxygen is utilized to burn out the residual carbon entering the ash layer and to provide the heat required by the gasification reactions. The volatile carbonization products (tars, oils, and so on) enter the gas stream with minimal exposure to the high gasification temperatures and are cracked or reformed to a minimum extent.

Figure 2-1

The Dry Bottom Lurgi Gasifier



Source: Reference 2-3

Raw gas is removed from the side of the unit at a temperature between 700 and 1100°F and flows into a scrubber-cooler where it is washed by a circulating liquor stream.

As compared to fluidized and entrained flow reactors, fixed bed gasifiers are characterized by a relatively long overall contact time between reactants, excellent heat transfer between solid and gaseous constituents resulting in moderate offtake gas temperatures, minimal reaction between volatile carbonization products (tar, oil, and hydrocarbons), and moderate oxygen usage, since the coal volatiles have a minimal chance of reacting with oxygen. The dry ash discharge Lurgi has the advantage of a proven method of ash discharge and the disadvantage of lower rates of gas production, although the hydrogen to carbon monoxide ratio is better than in a slagging operation. The production of tars in the raw gas complicates wastewater treatment systems, lowers the conversion efficiency of coal to gas, and can be difficult to sell in outside markets if there is not inplant use of the material. The lower thermal efficiency of the gasifier is also an important consideration.

2.2 PROCESS FLOW, ENERGY AND MATERIAL BALANCES

A generalized process flow diagram is shown in Figure 2-2, and plant area numbers are summarized in Table 2-1. The material balance for the process flow diagram is given in Table 2-2.

The offtake of the Lurgi gasifier discharges directly into a scrubber and partial cooling unit, part of plant area 1220. There the temperature of the crude gas stream is reduced to the point where the partial pressure of the water remains high enough to supply sufficient steam to the shift conversion unit. At the same time a large fraction of the condensable portion of the stream is removed as condensate.

The crude gas stream is then divided and about half, or somewhat more, goes to the gas cooling unit. The other portion goes to shift conversion unit where steam is added and the following reaction takes place:

$$CO + H_2O \xrightarrow[\text{catalyst}]{} H_2 + CO_2$$

The catalyst in this unit is sulfur resistant. Minimal catalyst deterioration occurs, although some carbon deposition will require periodic catalyst reactivation. The shifted crude gas then goes to gas cooling, where, after cooling it is repressurized and mixed with the first unshifted cooled portion. The combined stream is the crude synthesis gas and has the hydrogen to carbon monoxide ratio adjusted to about 3.5, which is suitable for subsequent methanation.

Figure 2-2
Lurgi-ANG Gasification Process

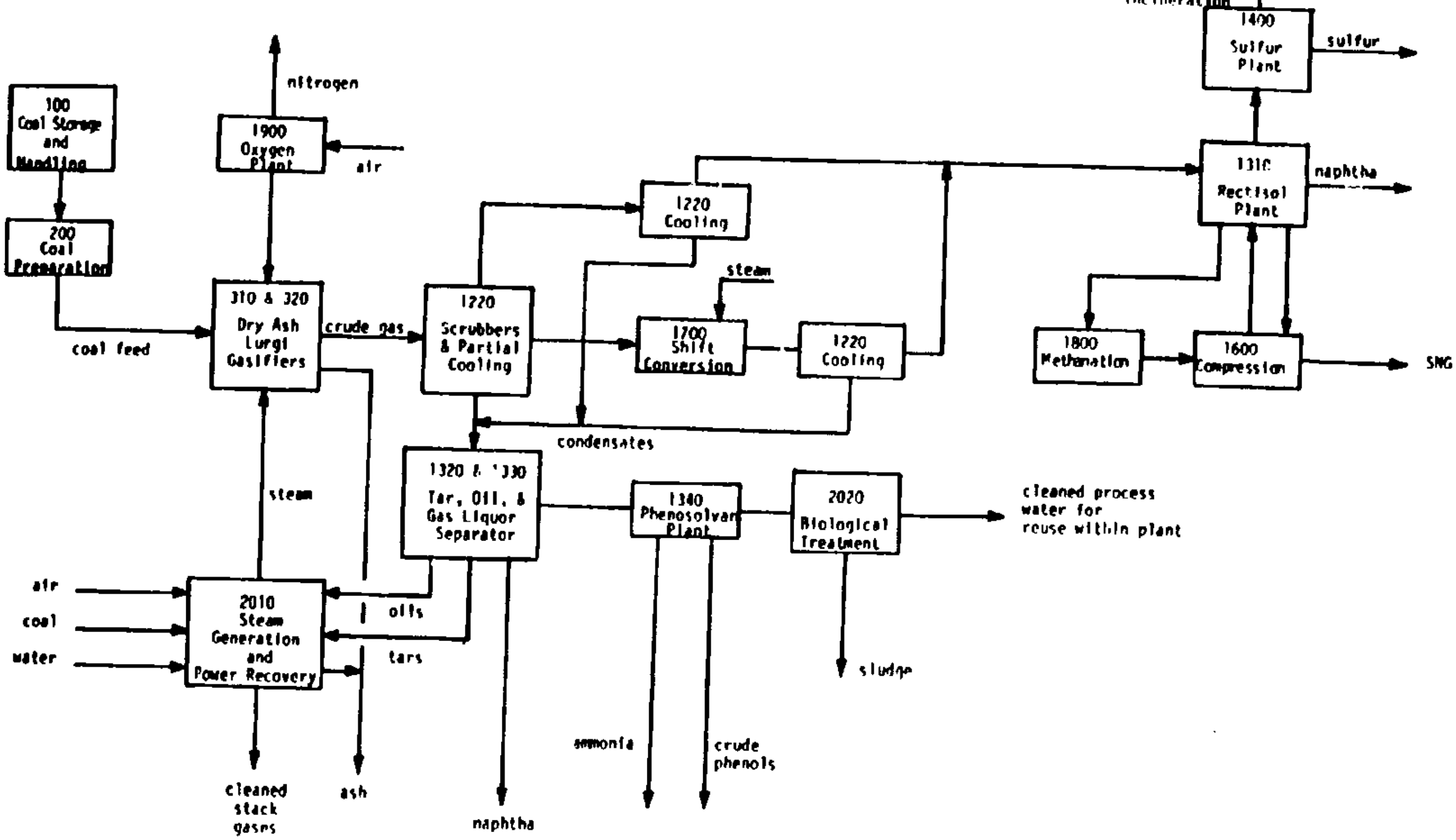


Table 2-1

Relevant Plant Area Numbers for Lurgi-ANG Coal Gasification

100	COAL STORAGE AND HANDLING	
		110 Coal Storage
		120 Coal Handling and Transportation
200	COAL PREPARATION	
		210 Crushing and Grinding
		250 Size Classification
300	GASIFICATION	
		310 Gasification
		320 Ash Quench and Handling
1200	RAW GAS COOLING	
		1220 Gas Quenching and Cooling
1300	ACID GAS REMOVAL	
		1310 Rectisol Plant
		1320 Ammonia Recovery
		1330 Tar Separation
		1340 Phenosolvan Unit
1400	STRETFORD SULFUR RECOVERY	
		1410 Sulfur Recovery
		1420 Tail Gas Treating
1600	PRODUCT GAS EXPANSION	
1800	METHANATION	
1900	AIR SEPARATION	
2000	UTILITIES AND SUPPORT SYSTEMS	
		2010 Steam Generation and Power Recovery
		2020 Biological Wastewater Treatment
2100	OFFSITES AND MISCELLANEOUS	

Table 2-2

Lurgi-ANG Gasification Net Plant Material Balance

Plant Inputs	From	To	Flow, lb/hr
Coal	Coal Handling	Lurgi Gasifiers	2,033,436
Steam and Boiler Feed Water	Steam Generation	Lurgi Gasifiers	2,148,886
Oxygen	Air Separation	Lurgi Gasifiers	411,532
Water	Water Treating	Rectisol	56,518
		Total	4,650,372
Plant Outputs			
Ash	Lurgi Gasifiers	Ash Handling	133,582
Tar	Gas Liquor Sep'n	Plant Fuel	63,745
Tar Oil	Gas Liquor Sep'n	Plant Fuel	10,741
Crude Phenols	Phenosolvan	Plant Fuel	12,318
Naphtha	Rectisol	Plant Fuel	10,309
Ammonia	Ammonia Recovery	Sales	16,182
Dephonolized Water	Phenosolvan	Cooling Tower	1,999,950
Off-Gas	Rectisol	Stretford Sulfur Rec.	1,654,282
Tail Gas	Ammonia Recovery	Stretford Sulfur Rec.	43,231
Condensate	Methanation	Steam Generation	270,432
Expansion Gas	Gas Liquor Sep'n	L.P. Flare	5,182
Product SNG	Product Gas Compression	Sales	430,418
		Total	4,650,372

NOTE: The above material flows represent plant operation at 100% capacity

Source: Reference 2-2

At this point in the processing scheme, the coal has been changed to crude synthesis gas which is contaminated with sulfur compounds, such as H_2S, COS, and CS_2. In addition, the gas contains uncondensed naphtha vapor, NH_3, and some HCN. The coal ash has been discharged directly from the gasifier and is ready for ash handling and disposal. The condensed vapor, tar, tar oil, and gas liquor, together with gasifier blow-over dust (coal particles), have been collected and are ready for separation and further processing. There have been no waste gas streams generated other than the vent gas from the coal locks.

The Rectisol plant is the next unit in the processing train and is of major importance in the control of gaseous effluents from the process. It is here that the crude synthesis gas is purified and made ready for the methanation step. The nickel catalyst used in methanation requires that the synthesis gas be virtually sulfur free and imposes the requirement that the Rectisol plant remove all sulfur compounds and provide a clean synthesis gas.

The crude synthesis gas is chilled before entering the prewash tower of the Rectisol unit. In this tower the residual water and naphtha are removed by a cold methanol wash. The naphtha-free gas enters the absorber where H_2S and COS are removed. The heat of absorption is removed by refrigeration, as the temperature of the cold methanol washes are generally maintained at $-20^{\circ}F$ to $-50^{\circ}F$. Some of the absorbed gases are removed from methanol by multi-stage flashes in the flash regenerator, and the remainder is stripped in the hot regenerator. These off-gas streams are collected and sent to the sulfur recovery plant.

The naphtha is recovered from the methanol and water by means of a naphtha extractor and by the use of an azeotrope column. The methanol is recovered by distillation in a methanol-water distillation column.

From the Rectisol unit the clean synthesis gas feed goes to methanation, plant area 1800. This unit converts the relatively low Btu synthesis gas (about 375 to 430 Btu/cu ft) to methane-rich, high-Btu gas (about 980 Btu/cu ft) by the following exothermic reactions:

$$CO + 3H_2 \xrightarrow[\text{catalyst}]{} CH_4 + 4H_2O$$

$$CO_2 + 4H_2 \xrightarrow[\text{catalyst}]{} CH_4 + 2H_2O$$

Other minor reactions which take place are the hydrogenation of ethylene to ethane and the hydrocracking of ethane to methane.

The feed gas entering the methanation reactors is preheated by exchange with product gas and passes through a fixed bed containing a pelleted, reduced-type, nickel catalyst. The temperature rise within a reactor is controlled by the recycling of methanated effluent gas which is mixed with the feed gas. The reaction heat is removed by waste heat exchangers at the outlet of each reactor. The gas leaving the synthesis loop is passed through a cleanup reactor to completely convert any remaining carbon monoxide. The gas is cooled, the condensed water is separated, and the gas is sent to the gas compression units. The only effluent stream produced is liquid water which is used as boiler feed water.

The product gas leaving methanation goes through first-stage compression. The final moisture removal is accomplished with a glycol dehydration unit following compression. The gas is then ready for pipeline distribution.

Plant area 2010, Steam Generation and Power Recovery, is designed to operate on a variety of plant derived fuels as well as supplementary coal feed. The steam boilers are fired with tar and tar oil that are recovered from the gasification train (tar, oil and gas liquor separator). Each boiler is fitted with an electrostatic precipitator to minimize particulate discharge. The products of combustion from the boilers are piped to the main plant stack for discharge to the atmosphere.

The steam superheaters are fired with gasification train by-products as well as several of the waste gas streams. The superheater fuels include tar oil, not required in the operation of the boiler plant; naphtha, recovered in the Rectisol plant; crude phenols, recovered in the Phenosolvan plant; vent gases from the Stretford sulfur recovery plant; and coal lock gas, discharged from the gasifier coal locks. The steam superheaters are not fitted with electrostatic precipitators, and the products of combustion are discharged to the atmosphere through the main plant stack.

One other small gaseous effluent stream is discharged to the atmosphere through the main stack. This stream is composed of the exhaust from the oil-fired rotary dryer used in recovering sodium sulfate from the bleed stream of the Stretford solution in the Stretford plant. The products of combustion pass through a cyclone for removal of particulate and then enter the main stack.

The products of combustion of the various fuels used in the steam boilers and superheaters are not treated for further sulfur removal and are discharged directly from the main plant stack to the atmosphere.

The process condensates from the gasifiers, shift conversion, gas cooling, and Rectisol (primarily methanol still bottoms) are sent to gas liquor, tar, and tar oil separation. After separation the gas liquor is sent to the Phenosolvan plant (area 1340) where phenols, acid gases, and ammonia are separated, and the aqueous effluent, without biological treatment, is used as make-up to the process water cooling tower. Storm water falling on contaminated paved areas is collected in a retention pond, passed through an oil separator, and clarified by flocculation. This cleaned water is also used as make-up to the process water cooling tower. Waste sanitary water after biological treatment would also be used as make-up to the process cooling system. The blowdown stream from the process water cooling water tower is sent to a multi-effect evaporator, and the reclaimed water is recycled to the low-pressure steam system or ammonia recovery.

The design described above differs from the actual ANG plant in that all electric power is obtained from the utility for the ANG system. For consistency with other technology assessment guides, the current design assumes all plant power is generated on site.

Table 2-3 shows the overall plant energy balance.

Table 2-3

Overall Plant Energy Balance
Lurgi-ANG Gasification Facility

Plant Inputs	MM Btu/Day
Coal to Gasifier	358,500
Coal for Power Generation	29,600
Coal for Gasification Steam	61,900
Coal for Process Steam Generation	24,600
	474,600
Plant Outputs	
SNG	244,300
Ammonia	4,690
Sulfur	1,100
	250,090

Overall Plant Efficiency: $\frac{250{,}090}{474{,}600} = 52.7\%$

Notes:

- Electric Power valued at 9,000 Btu/KWH
- Process steam to coal converted at 80% efficiency
- Energy flows based on Higher Heating Values
- The sulfur production rate is not available but is small and has a negligible impact on the plant efficiency estimate
- Coal for process steam generation is required in addition to the entire plant production of tars, oil, phenols and naphthas which are consumed for this purpose.

Source: Reference 2-2

2.3 PLANT SITING AND SIZING ISSUES AND CONSTRAINTS

The general location of the ANG gasification facility, near Beulah, North Dakota, has already been selected. Assuming that a candidate plant site has reasonable access to coal and water supplies, and that ready markets for SNG exist, the next major determinant of plant site will be environmental regulations.

Setting new source performance standards is a difficult task for a major gasification facility, and is complicated by several facts:

1. The physical separation distance of the plant units can be significant (1000 meters or more (1/2 mile)).

2. Process design differences, even with Lurgi technology, can change the emission control equipment requirements and the effluent characteristics (e.g., a Claus/Stretford sulfur recovery unit instead of just a Stretford Unit).

3. An obvious design choice is to combine power plant emissions with those from the gasification plant, for treatment. This makes the task of monitoring and control more difficult.

4. The setting of standards for only one of the gasification technologies may establish a precedent that is not appropriate for other and new gasification technologies.

5. No commercial gasification plants currently exist in this country. As a result, an operational data base is absent.

6. The sulfur effluent control system units (Stretford, Stretford/Claus, and Claus) are well established technologies. However, there has been little experience with these technologies in a gasification plant environment. Consequently, there is little question as to whether these systems will work; only as to how well they will work.

Because of the above reasons and several others, the Environmental Protection Agency has decided to issue guidelines (EPA, March 1978) for the emissions from gasification facilities rather than promulgate standards.

North Dakota has no existing state standards for gasification plant emissions. The state is using the PSD and air quality regulations as its principal guidelines. ANG, the only gasification plant with permits, was granted its construction permit on the basis of the PSD and air quality regulations and the use of mathematical models.

The exact siting of any other such plant is therefore very dependent upon coal and water supplies, SNG markets, and the existing attainment or nonattainment status of each candidate plant location.

The ANG coal gasification facility represented in this report is sized to produce 250 million SCFD (standard cubic feet per day) of substitute natural gas. This design employs multiple process trains to achieve this capacity. As such, the incremental capital cost of added capacity is very nearly a linear function (i.e., the scaling factor is essentially 1.0). The size of the facility will therefore be determined primarily by the availability of coal and water, the extent of demand for SNG accessible by the plant, and the availability of funds for construction.

2.4 RAW MATERIAL AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

North Dakota lignite is planned for use in the ANG gasification system. Lignite from the Beulah region will have the following approximate properties and composition:[2-3]

Heat content, Btu/lb	6,900
Ash content, wt.% as received	6.4
Moisture content, wt.% as received	36.4
Ash fusion temperature, °F	2300

Ultimate Analysis (dry basis)

	Wt.%
C	41.2
H	6.8
O	44.2
N	0.7
S	0.7
Ash	6.4
	100.0

The plant is designed to consume a total of approximately 29,900 tons per day of this coal at 100 percent plant capacity.

2.4.2 Catalyst and Other Required Materials

The Rectisol acid gas removal and Stretford sulfur recovery system are the primary consumers of catalysts and chemicals. Catalysts are also used in the shift conversion and methanation plant areas.

Table 2-4 shows the make-up requirements fcr the Rectisol and Stretford systems.

Table 2-4

Make-up Rates for Catalysts and Chemicals

Plant Facility	Chemical	Rate
		lb/hr
Rectisol	Methanol	1000
	Aqueous (20%) NaOH	700
Stretford	Anthraquinone Disulfuric Acid	100
	Sodium Metaranadate	67
	Sodium Carbonate	55
	Sodium Bicarbonate	250
	Enthylenediamine Tetraacetic Acid	30
	Iron	0.6

Replaceable catalysts are used in the shift conversion, methanation and sulfur recovery sections. Shift conversion catalysts will require replacement once every three years. Methanation catalysts are replaced annually, and sulfur recovery catalysts are replaced every two years.

2.4.3 Water Requirements

The ANG plant will require approximately 11,275,000 gallons of raw water per day, for both gasification and plant power production activities. Use is made of water produced in the process by chemical reaction, and that which is released from the coal.

2.5 EFFECT OF COAL TYPE

In choosing a coal feedstock for either the slagging or non-slagging Lurgi gasifier, several considerations apply:

- Coal should range in size from 1/8 to 1-1/2 inch
- Moisture level should be below 35%
- Non-caking coals should be used unless a mechanical stirrer can be provided
- Up to 10% coal fines (<1/8") may be used if they are injected with the steam at the bottom of the bed.

The North Dakota lignite chosen for use in the ANG facility will have the following process impacts:

- The absence of any caking tendencies for lignite allows its use without any mechanical stirring devices in the gasifier

- Operating temperatures within the gasifier must be kept well below the initial deformation point of the lignite ash, to avoid clinker formation

- The high initial moisture content of the coal requires some drying before gasification. The tendency of lignite to produce considerable quantities of fines during drying (or crushing in some cases) necessitates some other nearby use for the fines (such as a power plant).

2.6 AIR POLLUTION CONTROL TECHNOLOGY

2.6.1 Ability of Existing Technology to Meet Regulations

The Environmental Protection Agency has decided to issue guidelines (EPA, March 1978) for the emissions from gasification facilities rather than promulgate standards.

Standards exist for the control of particulates from the coal handling and pre-treatment unit and limit particulate emissions to 20 percent capacity (Federal Register, January 18, 1976). This is important because drying will be required for the lignitic feedstocks.

The sulfur emissions from the plant are very adequately controlled by the Stretford units. Carbon monoxide and non-methane hydrocarbons are controlled by combustion.

Figure 2-3 summarizes the sources and types of major gasification effluents and the quantities which are given in Table 2-5.

It is highly probable that the existing federal guidelines can be met with existing best available control technology (BACT). This technology consists of proper operating procedures, the use of covered containers to limit particulate emissions, and the use of the Rectisol and Stretford acid gas systems. Combustion is an effective, reliable tool for control of Stretford tail gases. Control of NO_x and particulates for power plants is established and will meet existing standards.

There are many substances which are presently uncontrolled. Which elements or compounds are likely to receive

Figure 2-3

Gaseous Emission and Emission Sources For
The Lurgi-ANG Gasification Facility

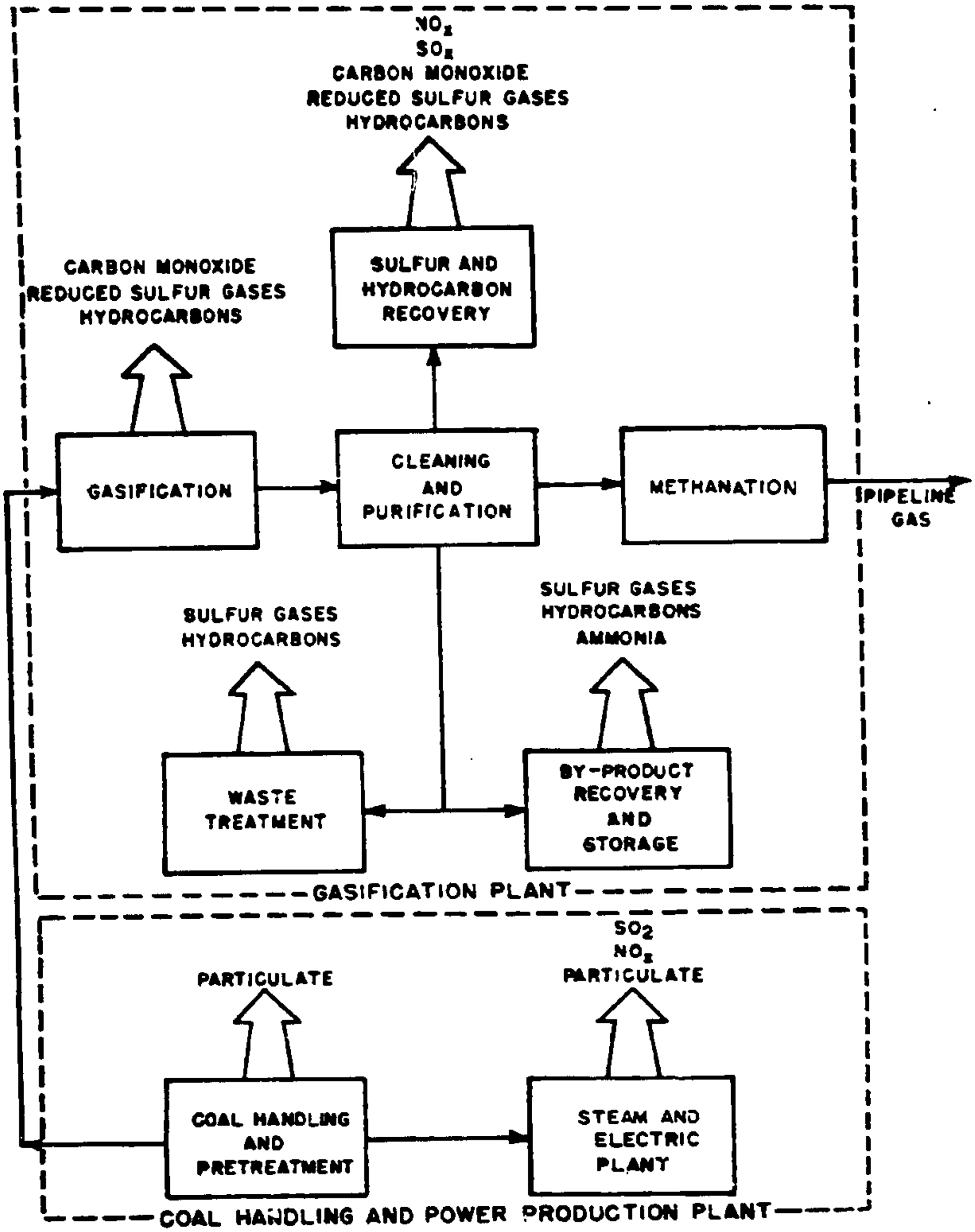


Table 2-5

Major Gaseous Effluents For The Lurgi-ANG Gasification Complex
250 MMSCFD[a] Of Synthetic Pipeline Gas

Components, tons per stream day[b,c]

Plant Source	N_2	O_2	H_2O	CO_2	CO	H_2	CH_4	C_2H_6	C_3H_8	C_2H_4	C_3H_6	H_2S	SO_2	COS	CS_2	NO_x	Parti-culate	Total
	ANG Coal Gasification Co.[d]																	
Main Stack (sum of a,b,c)	15,870	620	1,830	24,080	P	O	P	P	P	P	P	O	30.34	O	O	13.3	2	42,440
a. Stream Boiler Vent[e]	10,240	400	730	2,900	P	O	O	O	O	O	O	O	12.43	O	O	12.2	2	14,300
b. Superheater Vent[e]	5,570	220	1,090	21,170	P	O	P	P	P	P	P	O	17.89	O	O	1.1	P	28,070
c. Stretford Bleed Stream, Dryer Vent	55	2	5	14	P	O	P	P	P	P	P	O	.02	O	O	O	P	76
Stretford Oxidizer	1,680	580	110	290	P	P	P	P	P	P	P	O	O	P	P	O	P	2,660
Gas Liquor, Low Pressure Flare	6	D	2	7	P	P	P	P	P	P	P	P	.21	P	P	P	O	15
Oxygen Plant Vent	18,080	100	P	P	O	O	O	O	O	O	O	O	O	O	O	O	O	18,180
Cooling Towers	A	A	37,410	P	O	O	O	O	O	O	O	P	O	O	O	O	P	37,410
Total Gaseous Effluent	35,640	1,300	39,350	24,380	P	P	P	P	P	P	P	P	30.55	P	P	13.3	2	100,710

NOTES:
[a]Plant production of synthetic pipeline gas per calendar day at 100% capacity.

[b]Atmospheric discharge in tons per day where numbers are shown. Where letters are used, they have the following significance:
- P = may be present in very small quantities, possibly detectable
- O = probably absent
- A = air used but not estimated; e.g. cooling towers
- B = no estimate

[c]Conversion Table
- N_2 (tons per day) x 18.763 = acfm (60°F, 30"Hg)
- O_2 (tons per day) x 16.424 = scfm (60°F, 30"Hg)
- CO_2 (tons per day) x 11.942 = scfm (60°F, 30"Hg)
- Air (tons per day) x 18.217 = scfm (60°F, 30"Hg)
- H_2O (tons per day) x 0.1664 = gpm
- H_2O (tons per day) x 0.2442 = acre ft. per operating year
  Operating year = 332 stream days at nominal 275 mmcfd

[d]Primary References: - (a) ANG Coal Gasification Company, North Dakota Project, Draft Environmental Impact Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. DES 77-11, March 17, 1977, and: - (b) ANG Coal Gasification Company, Member of the American National Resources System. Supplemental Application to the North Dakota State Department of Health for a Permit to Construct a Coal Gasification Plant in Mercer County, North Dakota, September 1976.

[e]Tar, tar oil, naphtha, phenols, Stretford tail gas, and coal lock gas are all being burned in the steam boilers and superheaters. All of these are by-products of the coal being gasified. The yields of these by-products were calculated from the composition of raw gas leaving the gasifiers. The products of combustion (POC) were estimated by the authors and an allowance was made for the possible use of additional supplemental fuel such as fuel oil

attention first is, at this time, an open question. Part of EPA's rationale in establishing the multimedia environmental goals (MEG) program was to establish a data base that will assist them in establishing controls on key substances, compounds, and elements. Control methods and the accompanying technology have not been established on an industrial scale for the vast majority of the 650 compounds contained on the original MEG list. The minor (by weight) constituents are, by in large, uncontrollable. At this time it is difficult, if not impossible, to project what these effluents will be. In most cases, it is likely that the monitoring and control technology will be absent for most of these compounds.

2.6.2 Impacts on Process Efficiency

Sulfur removal is required to protect sensitive process catalysts and to meet environmental regulations. The low sulfur content of the lignite feedstock is not helpful in the Rectisol plant, since the entire volume of gas flow is treated. However, lower H_2S levels translate to a somewhat smaller Stretford plant than would be required with a higher sulfur content coal. The effect is not in proportion to the sulfur content of the gas due to the overriding effect of large amounts of CO_2 in determining Stretford unit size.

Since sulfur removal is mandated by process requirements, and the degree of removal is far in excess of that which would be required by environmental regulations alone, the cost in energy efficiency of this environmental control technology is irrelevant.

In a similar way, although to a lesser extent, the same is true of particulate removal. Energy requirements for particulate control are low, on the order of 0.05% of plant output.[2-1]

2.7 WATER POLLUTION CONTROL TECHNOLOGY

2.7.1 Ability of Existing Technology to Meet Regulations

The Lurgi-ANG plant has incorporated the concept of zero liquid effluent discharge into the plant design to meet the stipulations in P.L. 92-500. Consequently, no liquid effluent discharge in to surface water is planned. Deep well disposal is planned for the water treatment effluent and boiler blowdown stream from the plant. Waters leaving the plant site will include water contained in the ashes and sludges, which possibly will be disposed of at the mine site, and water evaporated from the cooling towers. The major in-plant water reuse is for the cooling make-up water.

The use of the cooling tower as a means of disposal of the impaired quality water in the gasification plant might help to meet the "zero effluent discharge" goal, but the impact on the environment resulting from the air pollutants in the evaporated water needs to be studied.

There is some question concerning the need for biological treatment of Phenosolvan effluent waters. Future designs will probably use Phenosolvan effluent as cooling tower make-up if this practice does not result in unacceptable environmental impact and equipment deterioration. The use of hypothetical activated sludge systems for Phenosolvan water treatment has been investigated as the natural alternative to the direct use of these waters.

Operating data for the water treatment system in the plants is lacking at this time. In all likelihood, the operation of such a treatment system will be quite reliable and will meet the plant water-reuse objective.

2.7.2 Water Recycling Systems

The recycling of process water can be an effective method for the control of aqueous phase contaminants as well as being an efficient use of natural resources. In order to meet the design objective of zero liquid discharge to adjacent surface water, the water required for the operation of the plant complexes will be treated and recycled within the plant boundaries to the maximum extent possible. The major portion of the aqueous effluent discharged from each plant complex will be evaporated. Cooling tower evaporation will account for about 8.4 percent of this value. In addition to evaporative water discharge, liquid will accompany the solids and sludges as well as sediment from evaporation ponds, all of which are returned to the mine for burial. The bulk of the solids (primarily ash) returned to the mine for burial will contain about 18 percent water by weight, but the water content of the sludges returned for burial cannot be estimated with reasonable accuracy from the data available.

Besides the aqueous liquid discharges there will be other fluid by-products recovered during synthesis gas production. None of these materials will be disposed of by direct discharge to the environment.

2.7.3 Impacts on Plant Efficiency

Water recycling and treatment systems are necessary for the conservation of natural resources and protection of the environment from emission of hazardous materials. Primary energy users in these process operations are pumps and reaction vessels (requiring low levels of process heat). Due to the extensive reliance on recycling in the ANG facility, the total impact on process efficiency may be upwards of 2 percent.

2.8 SOLID WASTE HANDLING

2.8.1 Disposal Requirements

Most of the solid wastes generated by a gasification complex are derived from the coal feedstock that is used. The waste quantity is directly related to the ash content of the coal. In addition, there are solids derived from raw water treatment and solids derived from the use of chemicals used in various processing steps. Ash is discharged from the Lurgi gasifiers and from boilers used for the production of steam and power. Also, fly ash is recovered from electrostatic precipitators used on the stack gases from combustion equipment. Where stack gas scrubbing is employed on flue gases, calcium salts of sulfur compounds are produced. These solid wastes, particularly gasifier ash and boiler ash, are often handled in hydraulic sluiceways and delivered to a loading point where they are dewatered and hauled to the mine for burial. They are handled wet to minimize dust evolution; even after dewatering, the material generally contains 20 to 30 percent water. The sludges obtained from raw water treatment and the calcium salts from stack gas scrubbing are handled in much the same manner and are mixed with the ash.

The primary method of solid waste disposal is by mine burial, usually at depths of 50 to 100 feet or more below the surface of the reclaimed mine land area. As mine burial takes place, the wastes will be hydrologically isolated as much as possible from the adjacent groundwater system. In this way the possible leaching of compounds from the buried wastes by percolating surface water will have a minimal effect on the quality of the adjacent groundwater systems.

The preceding discussion of solid waste control and disposal has not included dust evolution from coal preparation, handling, and storage facilities. These problems are generally handled by one or more of the following:

1. The use of water sprays which may include a wetting agent.

2. The compaction of large long-term storage piles in approximately one-foot lifts possibly including a spray which induces crust formation.

3. The use of covered conveyors with adequate ventilation and the passing of discharged air through bag filters and similar arrangement where the coal is charged to the operating bunkers.

4. Adequate ventilation and baghouse collection of particulate where dry coal crushing and screening operations are being conducted.

The collected particulate is disposed of by mine burial.

The major solids and sludges handling requirements for the ANG facility are summarized in Table 2-6.

2.8.2 Leaching Problems

The leaching of metal ions and other hazardous materials from unslagged gasifier ash and gasification plant sludges has been demonstrated in laboratory simulations. The extent of leaching in an actual burial situation will depend on many factors; among the most important are water pH, and the physical structure and chemical nature of the ash.

Table 2-6

Lurgi-ANG Gasification Plant Major Solids and Sludges Handling
250 MMSCFD[a] Of Synthetic Pipeline Gas

rce	Disposition	Estimated Quantity of Effluent Per Day: Total, Solids Plus Water (tons)	Estimated Quantity of Effluent Per Day: Dry Solids (tons)
1 Preparation			
Cnal (2" x 1/4")	Synthesis Gas Production	24,400	24,400
Coal (-1/4" fines)	Fine Coal to Sales and Power Production	14,290	14,290
er Treatment	Lime Sludge to Ash Handling	0[b]	
Cooling Tower Water Blowdown	To Concentrator (Evaporator)	0[b]	
Concentrator	Sludges to Mine Burial	no estimate	
Steam System Blowdown and Softener & Demineralizer Regenerator Wastes	Brine or Sludge to Deep Well Injection	1,216	15
etford Bleedstream	Na_2SO_4 to Sales		21
Handling			
Boiler Fly Ash	To Mine for Burial	1,800	6
Gasifier Ash	To Mine for Burial		1,505
al Solid Waste Effluent			1,525[c]

ES:

[a]Plant production of synthetic pipeline gas per day at 100% capacity.

[b]There are no effluent solids discharged at this point as the sludges go to the ash handling system.

[c]Does not include concentrator sludges.

rce: Reference 2-1

Solid wastes and sludges are, at this time, unregulated by government agencies. There is, however, significant research being conducted to establish the probable impact of solid waste disposal and to establish techniques to minimize the potential impact. Present permitting requirements force examination of and approval of the mining, solid waste disposal, and reclamation plans for each facility. The potential for disposing of some of the plant's waste water in the sludges in the mined area is high. This practice, if implemented, will probably precipitate controls on sludge disposal. Existing waste water treatment technology could probably treat sludge additive liquids to environmentally acceptable limits prior to disposal. Hydrologic isolation techniques either exist or can probably be developed should an impact be found due to leaching or sludge liquid drainage, but technology for post-disposal treatment does not exist.

2.9 OSHA ISSUES

Several potential worker health and safety hazards may exist in the Lurgi-ANG plant. In the coal handling and preparation area, workers may be exposed to noise from milling operations, to fire from spontaneous combustion of coal and to coal dust. Leaks from the gasifier could expose the worker to hot, high pressure toxic gas, steam and oxygen. The gas is high in toxic carbon monoxide and hydrogen sulfide. In addition, the gasifier area will present the danger of noise, exposure to carcinogenic tar, and fire.[2-4]

The coal tar produced in the Lurgi system is probably highly carcinogenic, as it resembles coke-oven tars and primitive gas-works tars, which are proven carcinogens.[2-5] Worker exposure to this tar would be highest during maintenance operations, such as cleaning the gasifier and clearing lines of accumulated tar. Precautions such as protective clothing, shower rooms and frequent medical examinations will be necessary.[2-5]

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketability

The composition of the product gas from the ANG gasification plant is given below:

Compound	Mol % (% by Volume)
H_2	3.00
CH_4	95.95
CO	0.05
CO_2	0.40
N_2 + Ar	0.60
	100.00

The higher heating value of this gas is approximately 1027 Btu/SCF. Gas of this quality is suitable for pipeline transmission and sale to commercial users. Sales to residential users may require the addition of mercaptans or other malodorous compounds to facilitate the detection of leaks. The gas is an excellent replacement for natural gas in virtually every application.

2.10.2 Capacity Factors, Flexibility and Reliability

The Lurgi-ANG facility is designed to operate at approximately a 90 percent capacity factor, producing substitute natural gas at an efficiency of approximately 59 percent. The design is based upon extensive operating experience with this gasifier where a coal derived synthesis gas was required. Combining the gasifier turndown ratio of 4:1 with the considerable number of gasifiers (36) gives an extremely high degree of operational flexibility in the gasification sector (few numbers of downstream equipment trains limit the overall plant flexibility). Although the plant is capable of operating at considerably below design capacity to meet daily and seasonal fluctuations in feed, product and internal flowrates, it should be noted that plant operation at or near design specifications is essential for the economic success of the project.

Because of the Lurgi gasifier's considerable operating history, and the wide experience base for all other unit operations, (which have functioned in various industries), virtually all of the operating problems associated with a developing technology have been resolved. Reliability is therefore expected to be excellent.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

2.11.1 Current Status

The first commercial demonstration of the Lurgi gasifier took place in Germany in 1936. Although there are no commercial scale installations in the United States, the 18 plants world-wide are summarized in Table 2-7.

2.11.2 Key Technical Uncertainties

Because of the mature state of the Lurgi dry ash gasification technology, gasifier operation is completely characterized. Although a great deal of experience with North Dakota lignite does not exist, Lurgi gasifiers have been used extensively in the past on other lignites and low-rank coals, which are especially well suited because of their non-caking properties. Virtually the same level of experience applies to the other plant operations, although some of these systems have been most extensively used in other industries such as petroleum refining.

Because of the importance of tar in the process, the performance of the water treating facility will be critical. Adjustments to operating conditions or bacterial species may be necessary to accommodate the particular type and concentration ranges encountered from the use of the planned coal feedstock. Future attempts to improve process efficiency by placing (for example) heat exchange surfaces rather than gas scrubbers to contact the raw gas stream may result in poor availability or performance, especially in light of the high tar concentrations in the raw gas.

Table 2-7

Lurgi Gasifier Installations

Location	Year	Fuel	Gasifier I.D.	Capacity (MM SCFD)	No. of Gasifiers
Hirschfelde, Central Germany	1936	Lignite	3'9"	1.1	2
Bohlen, Central Germany	1940	Lignite	8'6"	9.0	5
Bohlen, Central Germany	1943	Lignite	8'6"	10.0	5
Most., CSSR	1944	Lignite	8'6"	7.5	3
Zaluzi-Most., CSSR	1949	Lignite	8'6"	9.0	3
Sasolburg, South Africa	1954	Subbituminous	12'1"	150.0	9
Dorsten, West Germany	1955	Caking Subbituminous	8'9"	22.0	6
Morwell, Australia	1956	Lignite	8'9"	22.0	2
Daud Khel, Pakistan	1957	High Volatile Coal	8'9"	5.0	2
Sasolburg, South Africa	1958	Subbituminous	12'1"	19.0	1
Westfield, Great Britain	1960	Weakly Caking	8'9"	28.0	3
Jealgora, India	1961	Different Grades	N/A	0.9	1
Westfield, Great Britain	1962	Weakly Caking Subbituminous	8'9"	49.0	1
Coleshill, Great Britain	1963	Caking Subbituminous	8'9"	46.0	5
Sasolburg, South Africa	1966	Subbituminous	12'1"	75.0	3
Luenen, GFR	1970	Subbituminous	11'4"	1400 MM Btu/hr.	5
Sasolburg, South Africa	1973	Subbituminous	12'4"	190.0	3

Source: Reference 2-3

2.11.3 Availability for Commercial Production

The Lurgi-ANG plant is in the final design stages. All technologies planned for the facility are technologically mature and fully available for commercial production.

2.11.4 Unit Design and Construction Schedule

The plant design for this system is well understood, and should not experience any unusual delays in construction. Plant operation is expected to begin approximately seven years following project inception (engineering phase).

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

The Lurgi-ANG facility is ideally situated for access to a large coal supply. The vast extent of the coal reserves in this general area will provide for a short transportation distance to the plant during its lifetime, and should guarantee an uninterrupted coal supply at reasonable prices.

The use of extensive water recycling within the plant, for conservation and environmental reasons, fits well with the water supply constraints imposed by this semi-arid region. The reduced dependence on raw water will help alleviate any future impact of availability problems or price increases.

2.12.2 Environmental Control Constraints

There are no existing state standards for gasification plant emissions. The state is using the PSD and air quality regulations as its principal guideline. ANG, the only gasification plant with permits, was granted its construction permit on the basis of the PSD and air quality regulations and the use of mathematical models. North Dakota had not established plans to incorporate federal guidelines at the time of the writing of this report.

2.12.3 Siting Constraints

As mentioned above, the location chosen for the Lurgi-ANG facility (Beulah, N.D.) is outstanding with respect to coal availability. Water availability is limited but this difficulty is somewhat mitigated due to the extensive internal recycling systems designed into the facility. The lack of large high industrialized centers near the plant means that a significant portion of the SNG produced by the plant will have to be distributed long distance by pipeline to consumers. This poses no difficulty, however, due to the vast service area of existing natural gas pipelines in the United States.

References

2-1. Somerville, M.H., et al. "A Comparative Study of Effluents and Their Control From Four Dry Ash Lurgi Gasification Plants," 100-4035-2 (Section A), U.S. DOE (Fossil Energy), Executive Summary, A Comparative Study of Effluents and Their Control, Supplementary Data, July 1978.

2-2. ANG Coal Gasification Company North Dakota Project. Prepared by Bureau of Reclamation, Upper Missouri Region, Department of the Interior, January 20, 1978.

2-3. "Low-Rank Coal Study," Volume 2- Resource Characterization, Energy Resources Co., November 1980.

2-4. National Institute for Occupational Safety and Health, "Occupational Exposures in Coal Gasification Plants," September 1978, Department of Health, Education and Welfare, Publication No. 78-191.

2-5. Braunstein, H.M. et. al., eds. Environmental Health and Control Aspects of Coal Conversion: An Information Overview, Oak Ridge National Laboratory, April 1977, No. ORNL/EIS UC-11, -41, -48, -90.

CHAPTER THREE: ECONOMIC ANALYSIS - LURGI-ANG

This section discusses the economics of the Lurgi High-Btu gasification system, American Natural Gas design.

3.1 METHODOLOGY AND INTRODUCTION

3.1.1 Methodology

The design of the Lurgi-ANG plant is nearly complete and construction of the plant is underway. This economic analysis relied on economic data filed by Great Plains Gasification Associates in 1978 with the Federal Energy Regulatory Commission (FERC) (3-1). By-Product production was derived from an earlier report (3-2). The cost of a coal-fired electric power plant to supply 121.5 MW at a 90 percent capacity factor was added to the cost estimates to make the plant completely self-sufficient in energy. The cost estimate for the coal-fired power plant was derived from an Electric Power Research Institute report (3-5). Economic data from the references was then scaled to the standard plant size of 250 million Btu per day and adjusted to third quarter 1980 dollars.

3.1.2 Scaling Exponents

The reference plant size was for Phase I of the Great Plains Lurgi-ANG project, with a capacity of 137 MMBtu per day. These costs were scaled up to the standard plant size of 250 MMBtu per day with a scaling exponent of 1.0. The figure of 1.0 was used because the reference plant embodied all economies of scale.

3.1.3 Price Indices

Reference plant costs were given in 1978 dollars. These were adjusted to 1980 dollars using the methodology explained in the Background section.

3.1.4 Economic Criteria

The standard economic criteria discussed in the Background section were used to estimate the total capital requirement of the project and the product costs. The construction period is five years. The investment schedule was derived from the manpower needs of construction (3-3) according to the assumption that a year requiring a certain proportion of the total construction staff-years would require the same proportion of the Total Plant Investment. This method resulted in an expenditure schedule of 7.3 percent, 22.2 percent, 30.8 percent, 31.1 percent and 8.6 percent in years one through five of construction.

3.1.5 Contingencies

A project contingency of 15 percent was added to the subtotal of the installed cost of all equipment and miscellaneous investments (contractor's fees, taxes, equipment, engineering, general and administrative, and miscellaneous). The contingency is meant to cover increases in costs which arise as the plant design is completed.

A process contingency of 10 percent of the cost of Areas 1200 and 1800 was added to cover technical uncertainties in these areas.

3.2 CAPITAL COSTS

3.2.1 Itemized Capital Costs

The Total Plant Investment is $2352.4 million in third quarter 1980 dollars. Wastewater Treating and Water Supply, at $220.5 million, is the most expensive process unit. Gasification (Area 300) would cost $216.4 million. The largest single component of the Plant Investment is Unit 2130, Other Support facilities, at $501.8 million. A breakdown of the Total Plant Investment by area and unit is shown in Table 3-1.

The total capital requirement amounts to $3859.9 million as is shown on Table 3-2. Interest During Construction over the long construction period amounts to $1208.2 million. Working Capital and Start-Up add $143.5 million and $141.1 million respectively.

3.2.2 Variability of Capital Costs

The Lurgi-ANG project is well advanced in its design. As a result, the cost estimate is very reliable. According to ANG testimony before FERC (3-3), the probability that their estimate of the total plant investment is within ±10% is over 90 percent. Because of the passage of time since the estimate was made, and the adjustments to the costs made by ERCO, the confidence interval should be widened to ±20 percent.

3.3 ITEMIZED OPERATING AND MAINTENANCE COSTS

Annual operating and maintenance (O&M) costs total \$80.1 million, as is shown in Table 3-3. Contract maintenance, at \$22 million, would be the largest cost. O&M costs would be slightly offset by sales of by-product ammonia and sulfur. Sulfur sales would net \$1.8 million and ammonia \$9.8 million. Subtracting the by-product credit of \$11.6 million from the gross O&M costs of \$80.1 million results in a net O&M cost of \$68.5 million.

3.3.1 Variability of Operating and Maintenance Costs

Operating and maintenance costs were predicted based on actual manpower requirements, taxes and other costs. Therefore, the estimate should be well within the ±20% range of the capital cost estimate.

3.4 EFFECT OF TECHNOLOGY DEVELOPMENT ON COSTS

Although Lurgi technology has been commercially available for many years, experience with American coals is limited. The shift conversion and methanation steps have been demonstrated only a limited basis. As a result, the areas of Coal Preparation, Gasification, Raw Gas Cooling, Shift Conversion and Methanation can be considered novel technologies (3-4). These areas account for approximately 30% of the total plant investment.

Based on a maximum experience factor of 10% for novel energy technologies (see Background section) the experience factor for Lurgi technology is 30% times 10%, or 3%. One

TABLE 3-1

TOTAL PLANT INVESTMENT[a]

AREA	UNIT	ITEM	COST (10^6 $)	PERCENT OF SUBTOTAL[c]
100		Coal Storage and Handling	(see 200)	7.3
200		Coal Preparation	135.2	11.7
300		Gasification	216.4	2.0
1200		Raw Gas Cooling	36.6	2.2
1300		Acid Gas Removal and Gas Cleaning		
1300	1310	H_2S and CO_2 Removal	126.6	6.8
	1320	Ammonia Recovery	32.0	1.7
	1330	Tar and Oil Separation	52.2	2.8
	1340	Phenol Recovery	26.0	1.4
1400		Sulfur Recovery and Tail Gas Treating	34.5	1.9
1600		Product Gas Compression	24.9	1.3
1700		Shift Conversion	26.4	1.4
1800		Methanation & Other Catalytic Reforming	73.5	4.0
1900		Air Separation	134.3	7.3
2000		Utilities and Support Systems		
	2010	Steam Generation and Power Recovery	34.7	1.9
	2020	Wastewater Treating and Water Supply	220.5	11.9
	2030	Solids Disposal	27.8	1.5
	2040	Plant & Instrument Air	117.0	6.3
2100		Offsites and Miscellaneous		
	2110	Flare and Incineration	9.3	.5
	2120	Tankage - Shipping - Receiving	20.8	1.1
	2130	Other Support Facilities	501.8	27.1
		Subtotal	1850.5	100.0
		Process Contingency[b]	11.0	-
		Project Contingency @ 15%	305.4	-
		Miscellaneous	185.5	-
		Total Plant Investment	2352.4	-

[a]Source: 3-1, updated and scaled by ERCO. Third Quarter 1980 dollars.

[b]10% of areas 1200 and 1800.

[c]Does not add to exactly 100 because of rounding.

TABLE 3-2

TOTAL CAPITAL REQUIREMENT[a]

ITEM	YEARLY COST (10^6\$)	PERCENT OF TOTAL
Total Plant Investment	2352.4	60.9
Interest During Construction	1208.2	31.3
Working Capital	143.5	3.7
Start-Up	141.1	3.7
Catalysts and Chemicals	14.7	.4
Total	3859.9	100.0

[a]Source: (3-1), scaled and updated to third quarter 1980 dollars. Interest during construction, start-up and working capital computed using standard ERCO methodology.

TABLE 3-3

NET ANNUAL OPERATING AND MAINTENANCE COSTS
(AT 90% CAPACITY FACTOR)[a]

ITEM	YEARLY COST (10^6\$)	PERCENT OF TOTAL[b]
Gross Operating and Maintenence		
Catalysts & Chemicals	10.4	13.0
Labor & Benefits	12.3	15.4
Contract Maintenance	22.0	27.5
General & Administrative	14.9	18.6
Insurance & Other Taxes	7.2	9.0
Privilege Tax	13.3	16.6
Total Gross O&M Costs	80.1	100.0

By-Product Credits	(10^6 \$)	Percent of Total
Sulfur	(1.8)	15.6
Ammonia	(9.8)	84.4
Total	(11.6)	100

Net Operating and Maintenance	(10^6 \$)
Gross O&M Costs	80.1
By-Product Credits	(11.6)
Net O&M Costs	68.5

[a]Source: (3-1) and (3-2), scaled and corrected to third quarter 1980 dollars by ERCO.

might expect a 3% reduction in unit capital costs (in constant dollars) for each doubling of Lurgi high-Btu production capacity.

This 3 percent however, may be considered a lower limit on the experience factor. Although most components of the plant are made of mature technologies and so no reductions in costs would result by building more Lurgi-ANG plants, savings may accrue because fewer support units would be needed. For example, if the steam requirements of the gasifiers were reduced, future plants could build smaller steam generation units, which would yield significant cost savings. Cost reductions in the less developed technologies could reduce the size of necessary equipment throughout the entire plant design, reducing costs even further.

3.5 PRODUCT COSTS

The synthetic natural gas (SNG) produced by the plant has three cost components: capital charges, net O&M costs, and fuel costs. A non-fuel product cost can be computed from the capital charges and the net O&M costs using the formula described in the Background section. The non-fuel cost is the cost of converting the coal to high-Btu gas. From Table 3-2, and 3-3, the total capital requirement is \$3859.9 million and the net O&M cost is \$68.5 million. With a capacity factor of 90 percent and a capacity of 91.25 x 10^{12} Btu/yr, the non-fuel product cost is:

$$P = \frac{(\$3859.9 \times 10^6 \times 20\%) \quad + \quad \$68.5 \times 10^6}{91.25 \times 10^{12} \text{ Btu} \times 90\%}$$

$$= \underset{\text{(capital costs)}}{\$9.40/10^6 \text{ Btu}} \quad + \quad \underset{\text{(O\&M costs)}}{\$.83/10^6 \text{ Btu}}$$

$$= \underset{\text{(Total non-fuel product cost)}}{\$10.23/10^6 \text{ Btu}}$$

The total non-fuel product cost is \$10.23/10^6 Btu, with capital costs of \$9.40/10^6 Btu, and O&M costs of \$.83/ 10^6 Btu.

The non-fuel cost can be combined with a cost of coal to yield a total product price using the formula given in the Background. The overall coal to gas efficiency of the process is 59 percent. With a coal cost of \$1.50/10^6 Btu, the product cost can be computed as follows:

$$E = \underset{\text{(capital and O\&M costs)}}{\$10.23/10^6 \text{ Btu}} \quad + \quad \underset{\text{(coal costs)}}{\frac{\$1.50/10^6 \text{ Btu}}{52.7\% \text{ efficiency}}}$$

$$= \underset{\text{(capital and O\&M costs)}}{\$10.23/10^6 \text{ Btu}} \quad + \quad \underset{\text{(coal costs)}}{\$2.85/10^6 \text{ Btu}}$$

$$= \underset{\text{(total product costs)}}{\$13.08/10^6 \text{ Btu}}$$

The total product cost would be \$13.08/10^6 Btu.

References

3-1. Federal Energy Regulatory Commission, Docket CP78-391, Hearing Exhibits No. 18D, No. 19D and No. ETZ-7, 1978.

3-2. Somerville, Mason H., et al., (Engineering Experiment Station, University of North Dakota), "A Comparative Study of Effluents and Their Control From Four Dry Ash Lurgi Gasification Plants", U.S. Department of Energy, July 1978, No. COO-4035-2.

3-3. Federal Energy Regulatory Commission, Docket CP78-391, Hearing Exhibit No. 131, 1978.

3-4. Hederman, W.F. (Rand Corporation) "Prospects for the Commercialization of High-Btu Coal Gasification", U.S. Department of Energy, April 1978, R-2294-DOE.

3-5 Electric Power Research Institute, "Technical Assessment Guide" EPRI Number PS 1201-SR, July 1979, p. 8-11.