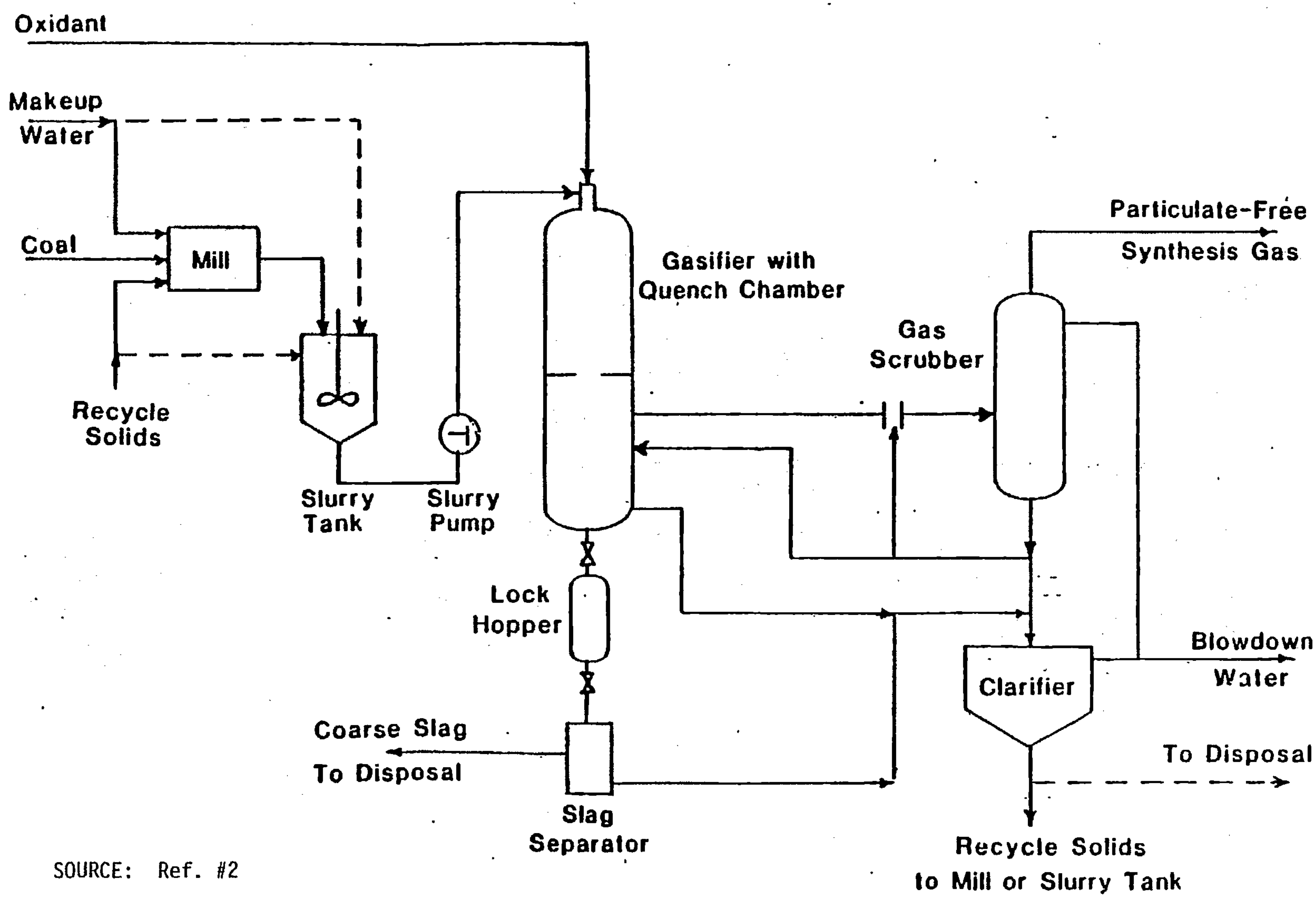
FIGURE 4.1

TEXACO COAL GASIFICATION PROCESS

Direct Quench Mode



SOURCE: Ref. #2

FIGURE 4.1

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4.0 PROCESS DESCRIPTION (CONTD.)

- In the direct quench mode, the hot gas and molten slag flow downward to a water spray chamber, thus producing a large quantity of steam. The gas temperature in this zone is low enough to allow unlined steel equipment to be used.

- The solidified slag is removed through a series of lockhoppers and is taken away for disposal while the steam-saturated raw synthesis gas is water quenched and scrubbed to remove particulate matter before further processing.

- The water streams containing ash and soot are sent to a settler where clarified water is received for recycle. To prevent the buildup of dissolved solids, a blow-down stream is taken and sent to a wastewater treatment facility.

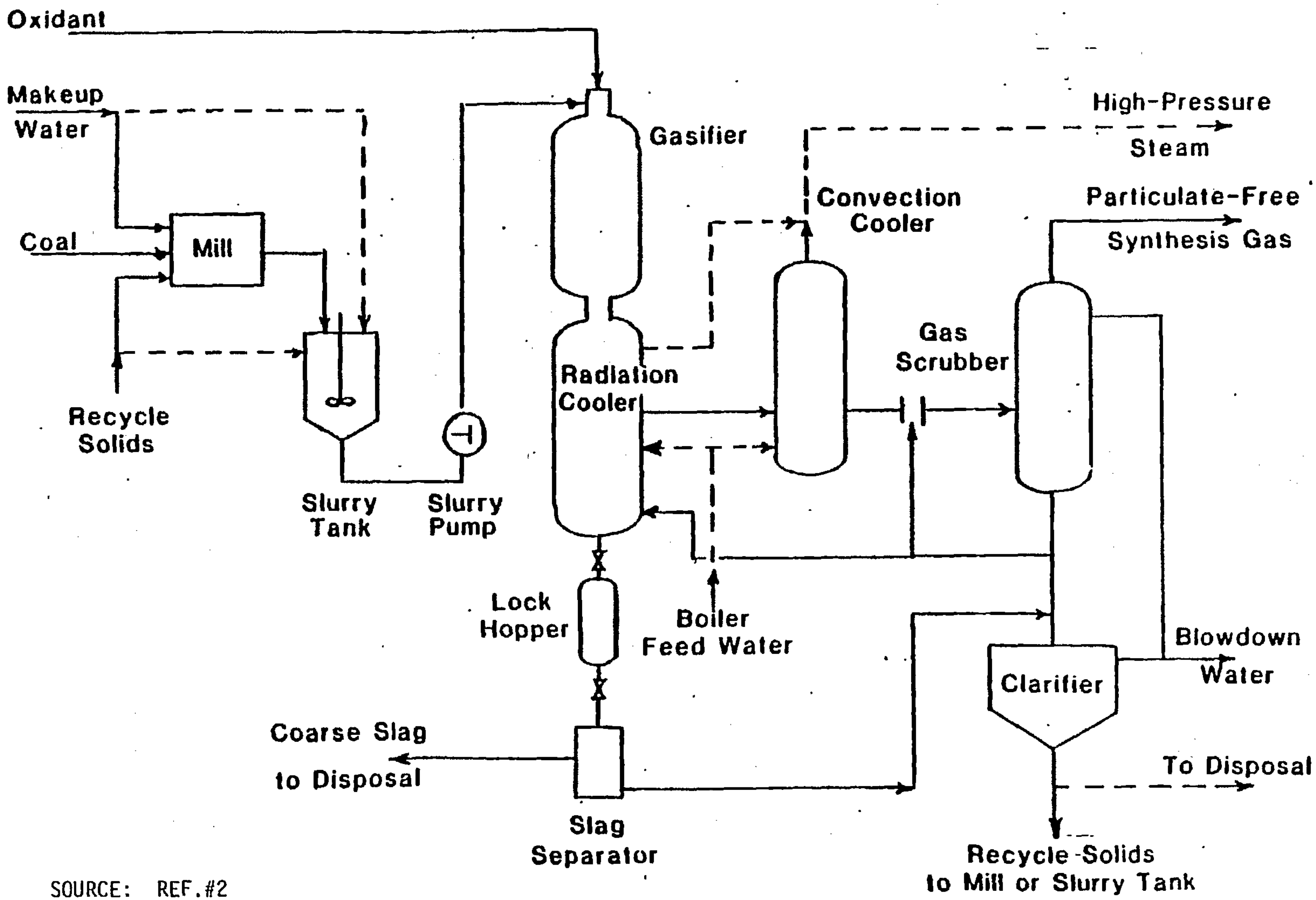
- In the gas cooler mode (Figure 4.2), the raw synthesis gas, after separation from the molten slag, is sent to a gas cooler where high pressure steam is produced.

- The raw synthesis gas in this operating mode requires a more thorough water scrubbing since it usually contains a higher level of particulates.

- The remainder of the gasification system of the gas cooler operation mode is similar to that of the direct quench mode.

FIGURE 4.2

TEXACO COAL GASIFICATION PROCESS
Gas Cooler Mode



SOURCE: REF.#2

TABLE 5.1

TEXACO COAL GASIFICATION PROCESS
BITUMINOUS COAL GASIFICATION

Coal Type	Kentucky No. 9	Illinois No. 6	Pittsburgh No. 8	South African	Polish
Feed Rate, Dry Short Tons/Day	1000	1000	1000	1000	1000
Dry Analysis, Wt Pct					
C	67.00	68.70	74.79	65.60	72.15
H	4.80	4.80	4.96	3.51	4.37
N	1.20	1.10	1.29	1.53	1.27
S	3.90	3.80	3.49	0.87	1.15
O	6.50	9.60	6.10	7.79	5.95
Ash	16.50	12.00	9.37	20.70	15.11
High Heating Value, Btu/Lb	12400	12400	13600	11200	12800
Pure Oxygen, Short Tons/Day	920	940	1010	870	980
Water, Lb/Hour	52500	55600	68200	44900	48900
Product Composition Mol Pct					
CO	34.33	32.92	31.08	36.534	38.28
H_2	28.34	27.03	27.69	26.01	27.95
CO_2	14.02	15.16	14.97	15.67	13.91
H_2O	21.59	23.23	24.88	20.82	18.94
CH_4	0.16	0.19	0.08	0.02	0.08
N_2+A	0.50	0.46	0.47	0.68	0.53
H_2S+COS	1.06	1.01	0.83	0.27	0.31
H_2+CO, MMSCF Per Operating Day	54.6	53.7	58.4	47.7	57.6

SOURCE: Ref.#3

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TABLE 5.1 (Cont.)

TEXACO GASIFICATION PROCESS
COAL LIQUID RESIDUE AND HEAVY PETROLEUM GASIFICATION

Source Feed Type	Coal Lurgi Tar and Oils	Coal SRC II Vacuum Residue	Coal EDS Vacuum Residue	Petroleum Middle East Vacuum Residue
Feed Rate, Dry Short Tons/Day	1000	1000	1000	1000
Dry Analysis, Wt Pct				
C	84.16	62.59	71.7	83.8
H	8.28	3.59	4.9	10.5
N	0.70	1.12	1.2	0.5
S	0.33	2.86	2.3	5.1
O	6.38	1.23	3.9	-
Ash	0.13	28.16	16.0	0.1
High Heating Value, Btu/Lb	16400	11300	13200	17500
Pure Oxygen, Short Tons/Day	1010	700	800	1100
Water, Lb/Hour	16700	41200	37500	29200
Product Composition, Mol Pct				
CO	54.34	43.26	46.87	44.82
H_2	37.94	32.67	35.67	40.82
CO_2	2.68	9.28	7.40	4.44
H_2O	4.43	13.08	8.97	8.60
CH_4	0.19	0.26	-	0.05
N_2+A	0.33	0.52	0.42	0.13
H_2S+COS	0.09	0.93	0.67	1.14
H_2+CO, MMSCF Per Operating Day	85.3	55.7	75.2	98.0

SOURCE: Ref.#3

TABLE 5.1 (Cont.)

TEXACO COAL GASIFICATION PROCESS
PETROLEUM COKE GASIFICATION

Feed Type	Delayed Petroleum Coke	Fluid Petroleum Coke	Fluid Petroleum Coke from Tar Sands Bitumen
Feed Rate, Dry Short Tons/Day	1000	1000	1000
Dry Analysis, Wt Pct			
C	88.50	85.98	78.89
H	3.90	2.00	1.65
N	1.50	0.98	1.35
S	5.50	8.31	7.88
O	0.10	2.27	2.08
Ash	0.50	0.46	8.15
High Heating Value, Btu/Lb	15400	13800	12600
Pure Oxygen, Short Tons/Day	1080	1030	920
Water, Lb/Hour	53500	54400	48900
Product Composition Mol Pct			
CO	46.20	47.14	48.12
H_2	28.69	24.33	24.13
CO_2	10.68	13.16	12.79
H_2O	12.37	12.67	11.97
CH_4	0.17	0.09	0.09
N_2+A	0.55	0.42	0.59
H_2S+COS	1.34	2.19	2.31
H_2+CO, MMSCF Per Operating Day	73.3	64.2	58.3

SOURCE: Ref.#3

5.0 PERFORMANCE DATA

- o Typical operating data from process development facilities are as shown in Table 5.1.

- o Test results from the Ruhrchemie demonstration plant are:

  - Run Length Data (as of June 1982)
    Total time on stream, Hrs: $>$11,000
    Total Coal gasified, Tons: $>$66,000
    Total Gas Produced, MMSCF: 3,700

  - Gasifier Throughput
    Coal, Ton/hr: up to 9.0
    Gas, SCF/hr : up to 567,000

  - Gasifier Performance

Pressure psig	:	up to 600
Temperature, ^{o}F	:	2200 to 2900
Carbon Conversion	:	up to 99
Cold Gas Efficiency	:	77%
Gas Thermal Efficiency	:	94%
Gas Composition	:	vol %
CO	:	55.0
H_2	:	33.0
CO_2	:	11.0
CH_4	:	0.1
H_2/COS	:	0.3
N_2	:	0.6

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACTS

- o No phenols, tars or other heavy materials produced.

- o Most water streams are recycled to slurry the feedstock such that those impurities get cracked to extinction.

- o Slag from the gasifier exhibits low levels of leachability and can be disposed of by landfill.

7.0 COMMERCIAL DESIGN PLANS

A number of demonstration and commercial projects are complete, under construction or at design phase. A listing of the most promising projects worldwide are shown in Table 7.1. No detailed techno/economic evaluations have been found in literature for SNG. A block flow diagram for coal-to-SNG using Texaco coal gasification process is presented in Figure 7.1.

TABLE 7.1

TEXACO COAL GASIFICATION PROCESS LICENSED PROJECTS

Project	Location	Design Feed	Design Capacity, Short Tons Dry Feed/Day	Startup Date	End Product
Olin-Mathieson	Morgantown, W. VA	Hi-sulfur Bituminous Coal	100	1956	Ammonia
Ruhrchemie/ Ruhrkohle	Oberhausen, Germany	German (Ruhr) Semi-Anthracite Coal	165 (220 after "Debottlenecking")	1978	Oxo-chemicals
Dow Chemical	Plaquemine, LA	Ill. No.6 Coal	400	1979	Electricity
TVA	Muscle Shoals, AL	Ill. No.6 Coal	200	1982	Ammonia
Tennessee Eastman	Kingsport, TN	Hi-Sulfur Bituminous Coal	900	1983	Methanol plus CO (for acetic acid)
Cool Water	Daggett, CA	Utah (low-sulfur) Bituminous Coal	1000	1984	Electricity
SRC II	Morgantown, W. VA	SRC II Vacuum Bottoms from Pitt. No.8 coal	-	***	Hydrogen
WyCoalGas	Wyoming, USA	Lurgi Liquid By-Products	-	***	SNG
Alsands	Alberta, Canada	Tar-Sand-Derived Fluid Petroleum Coke	4200	***	Refinery Hydrogen
Ube Ammonia	Ube City, Japan	Imported Coal	1650	1984	Ammonia

*** Project suspended

SOURCE: Ref.#3

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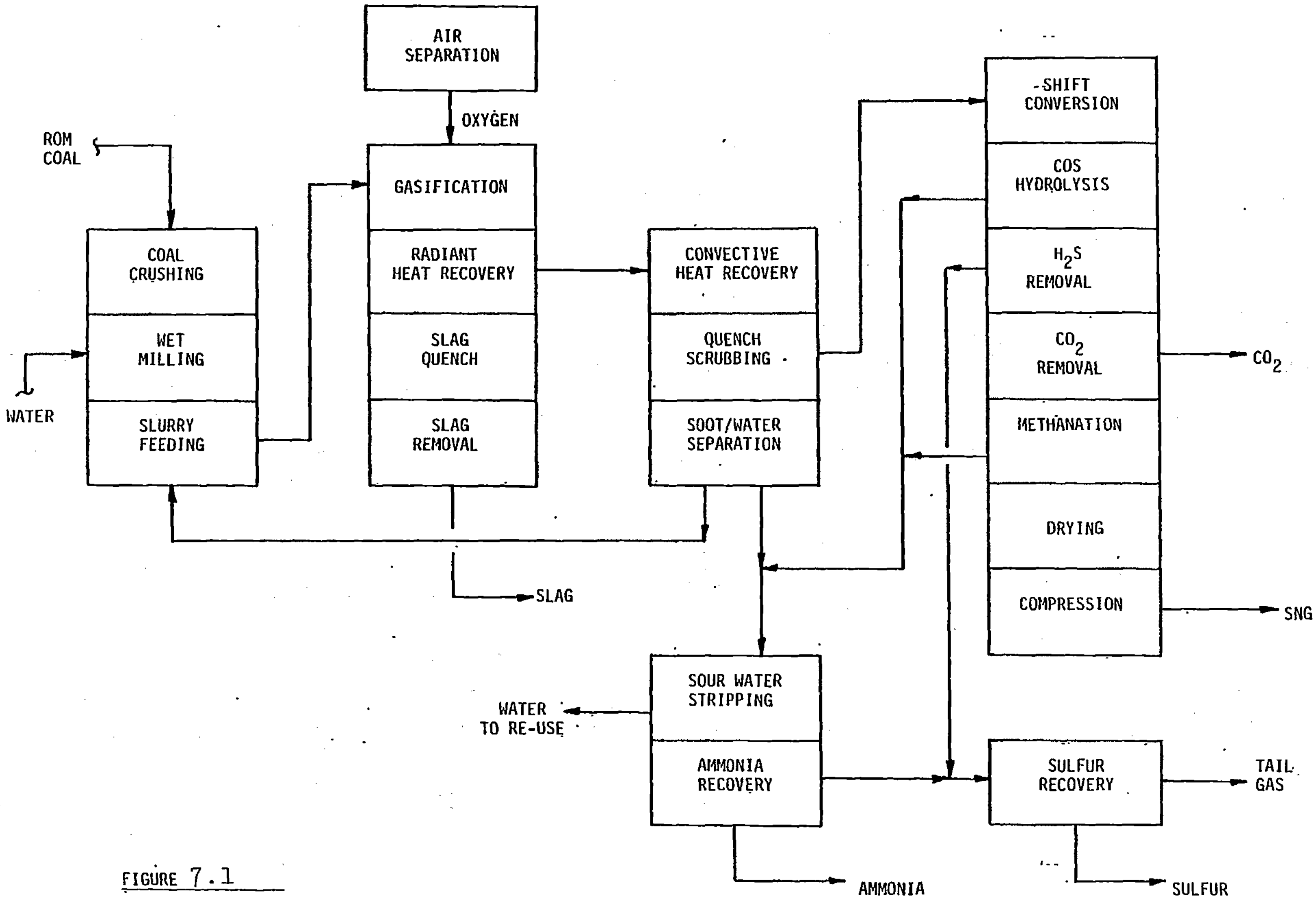


FIGURE 7.1

COAL-TO-SNG WITH TEXACO GASIFICATION

8.0 ADVANTAGES/DISADVANTAGES

- Advantages

  - Wide range of feedstocks
  - Pressure flexibility
  - Rapid process response
  - No liquid byproducts
  - Low impurities in product gas.
  - Alternate process configurations
  - Direct use of coal from slurry pipeline

- Disadvantages

  - Water slurry feed results in high oxygen and feedstock consumption
  - Relatively short life (≤ 1 year) of refractories in gasifier due to slagging conditions
  - High-moisture coals (e.g., lignite) cannot be processed without pre-drying since vaporization of inherent moisture would otherwise lower temperature below that required for slagging.

9.0 REFERENCES

1. "Handbook of Gasifiers and Gas Treatment Systems," prepared for DOE by UOP/SDC, Report # WD-TR-82/008-010, September 1982.

2. Schlinger, W. G., et al., "Commercialization Status of Texaco Coal Gasification Process," Executive Coal Gasification Conference/Europe 82, October 20, 1982.

3. Crouch, W. B., "The Texaco Coal Gasification Process -- Synthesis Gas for Chemical Feedstocks," International Coal Conversion Conference, South Africa, August 1982.

STATUS SUMMARY:
BGC/LURGI (SLAGGING) GASIFICATION

BGC/LURGI SLAGGING GASIFIER

1.0 GENERAL INFORMATION

Developer: British Gas Corporation
326 High Holborn
London, WC1V 7PT

Type: Pressurized, fixed-bed, gas up-flow, counter-current, slagging ash gasifier. Reactor is water cooled and refractory lined.

PDU: Operated at Westfield, Scotland. Gasifiers of 3 and 6 feet I.D. have been tested. An 8-foot I.D. gasifier is planned for 1984.

Conditions Operates at 450 psig and exit gas temperature is 800-950°F. Bottom temperature is high to produce a slag. Carbon conversion not cited, but higher than dry ash Lurgi (approx. 99%). Residence time is relatively high due to low gas velocity.

Coal Type: Gasifier will accept caking, low reactive and high ash content coals. For high melting-point-ash coal, addition of limestone flux is necessary. Feed coal is sized to + 1/8" - 2". Coals containing up to 25 to 35 wt% fines (-1/4") have been gasified. Additional fines and byproducts, such as tars, oil and phenolic liquor have been introduced through the tuyeres. English, Scottish, Ohio #9, and Pittsburgh #8 coals, among several others, have been tested. The gasifier is, however, particularly suitable for high volatile, low-reactive bituminous coals.

1.0 GENERAL INFORMATION (CONTD.)

Products: In addition to CO, H_2 and CO_2, the gasifier produces relatively high CH_4 (6-7% in dry gas), plus tars, tar oils and phenols.

Applications: Competitive for town gas and SNG production. Perhaps less competitive for H_2, methanol or ammonia because of methane production.

Status: Early in 1982, BGC announced that they would guarantee 8-foot I.D. gasifier to process 600 TPD of coal. This gasifier is currently being installed at Westfield for operation in 1984. Within the United States, BGC supported Florida Power and Light Company in a feasibility study to use BGC/Lurgi gasifier for a combined cycle power plant application.

2.0 PROCESS DEVELOPMENT

- In the 1950's British Gas started developmental work to improve the Lurgi dry-ash process so it could gasify coals with low ash melting points efficiently. Gasification of such coal in dry-ash process requires use of high steam/oxygen ratios to keep the bed operating temperatures below that at which ash fuses and forms clinkers. The process efficiency can be improved by operating the gasifier at high temperature and lowering the steam consumption. This, however, required that the ash be allowed to melt and be removed as liquid slag.

- In 1955, an experimental gasifier (3 feet diameter, 100 ton/day) was purchased from the Lurgi Company and erected at British Gas' Midlands research station. It was used for some exploratory research into slagging gasification using coke. As a result of this work, the gasifier was modified to operate up to 375 psig and outputs of 5 MMSCFD of crude gas. Work on this gasifier between 1962-1964 demonstrated slagging gasification of coal at pressures of 20 bars and provided justification for its development to a commercial scale. However, with discovery of North Sea natural gas reserves, further development was delayed for almost a decade.

2.0 PROCESS DEVELOPMENT (CONTD.)

- In 1974, the slagging gasifier at Westfield was constructed by modifying one of the four existing commercial Lurgi gasifiers. The modified gasifier operates at a maximum pressure of 350 psig and can process 350 tons of coal per day. The principal modifications were:

  - Reduction in the interal diameter of the gasifier from 9 feet to 6 feet because of limitation imposed by the output of the oxygen plant.

  - A completely new bottom section, consisting of new tuyeres, hearth and slag tap together with associated control equipment.

  - A second gas off-take at the top to accommodate the increased output.

- During 1974-1977, the development was carried out with American financial support. During this program, modification to the stirrer allowed gasification of highly swelling and caking, high sulfur Ohio No. 8 and Pittsburgh No. 8 coals.

- During 1978, under the sponsorship of DOE, work continued to perfect the operating procedures, develop systems for fines handling and disposal of effluents. At the same time, performance data were obtained on a wide range of British coals.

- During 1979, a 3-month program was carried out for EPRI to demonstrate the viability of slagging gasifier for combined cycle power generation.

- In 1981, a 90-day test run was conducted to demonstrate the reliability, life and performance of the gasifier and its major components such as the refractory.

- The summary of the Westfield development program between 1974 - 1981 is presented in Table 2.1.

- Presently, a gasifier with an eight foot ID is being installed at Westfield for operation in 1984. This gasifier will be used to demonstrate the larger (commercial) size and new British Gas's new Combined-Shift-Methanation (HICOM) process.

2.0 PROCESS DEVELOPMENT (CONTD.)

- A pilot scale gasifier is also likely to be constructed in the near future to explore process improvements and operation at higher pressure.

3.0 FEEDSTOCKS TESTED

Table 3.1 lists the coals tested in the British Gas/Lurgi Gasifier at Westfield (1975-1981).

4.0 PROCESS DESCRIPTION

The slagging gasifier (Figure 4.1) consists of a vertical cylindrical reactor in which coal is injected through a lockhopper and a rotating coal distributor. The coal moves slowly down the reactor in contact with gases passing through the bed countercurrently. A mixture of steam and oxygen is injected through nozzles, called tuyeres. The base of the coal bed is called the raceway, where high temperatures cause the ash to melt, yielding a fluid slag which drains from the hearth through a centrally-placed slag tap. The slag is quenched in a chamber filled with water to form a glassy frit, and subsequently removed via a slag lock hopper.

The predominant reaction in the raceway is combustion of carbon yielding hot gases containing steam and carbon oxides. As this gas moves up the fixed bed, carbon is rapidly gasified by steam and carbon dioxide. Since these reactions are highly endothermic, the temperature drops rapidly, effectively limiting the very high temperature slag

TABLE 2.1

SUMMARY OF WESTFIELD SLAGGING GASIFIER PROJECTS

PROJECT	No. of Runs	Hours on Line	Fuel Gasified (US Tons)
Sponsor's Program* 1974-1977	27	1,500	21,800
DOE Program, 1978	15	980	12,200
EPRI Trials, 1979	3	420	4,400
British Gas Program, 1978-1981	25	4,260	58,900
TOTALS	70	7,160	97,300

*This project was sponsored and financed by the following companies:

Continental Oil Company
El Paso Natural Gas Company
Gulf Energy & Minerals Company (a division of Gulf Oil Corporation)
Michigan Wisconsin Pipe Line Company
Natural Gas Pipeline Company of America
Panhandle Eastern Pipe Line Company
Southern Natural Gas Company
Standard Oil Company (Indiana)
Tennessee Gas Pipeline Company (a division of Tenneco Inc.)
Texas Eastern Transmission Corporation
Transcontinental Gas Pipe Line Corporation
Sun Oil Company
Cities Service Gas Company
Northern Natural Gas Company
TransCanada Pipelines

TABLE 3.1

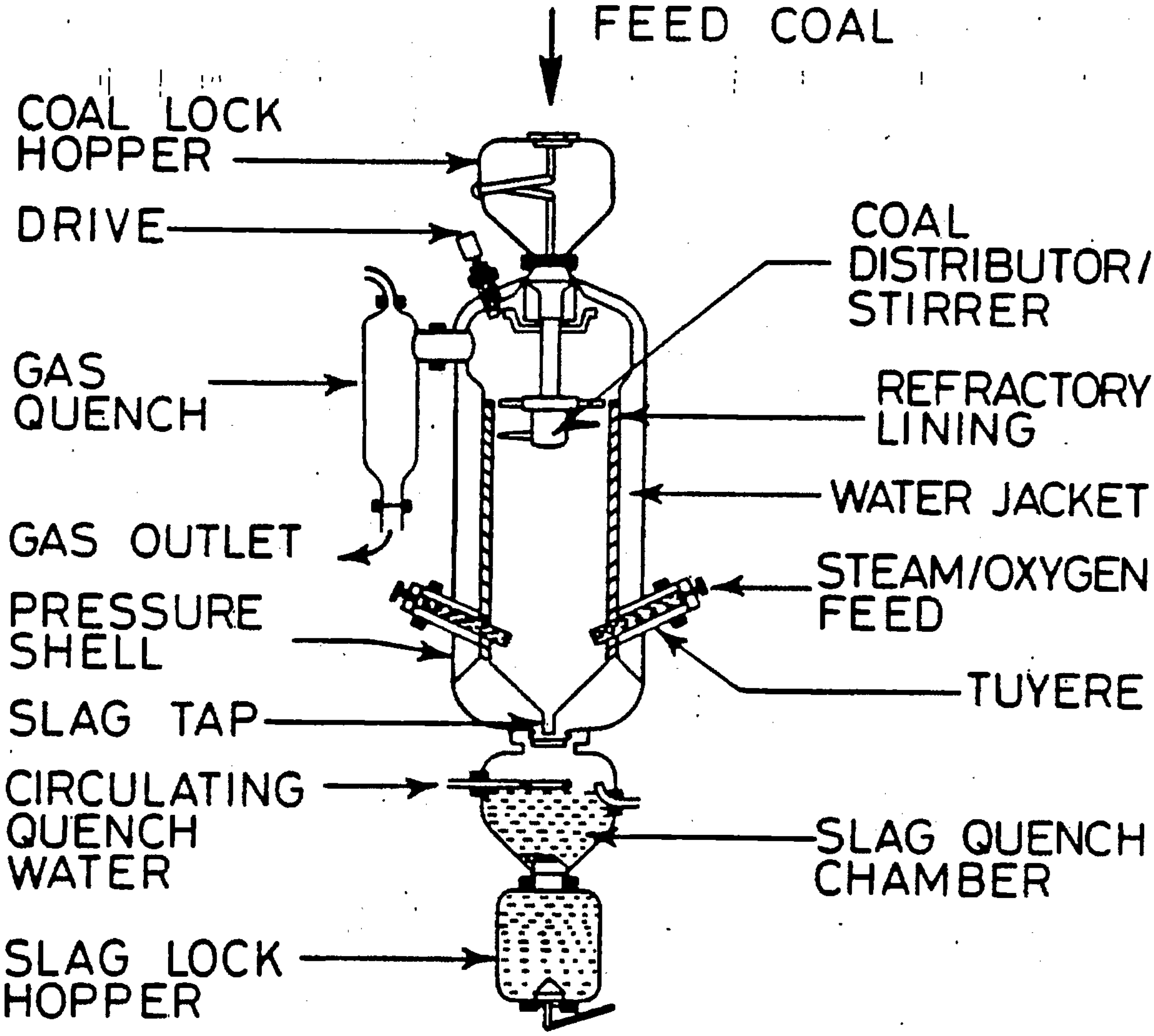
Coals Used in the British Gas/Lurgi Slagging Gasifier at Westfield (1975-1981)

Coal	Comrie	Cotgrave	Frances	Gedling	Hucknall	Killoch	Lynemouth	Manton
Origin	Scotland	England	Scotland	England	England	Scotland	England	England
Proximate Analysis wt %								
Fixed Carbon	57.0	38.9	54.0	50.7	55.6	53.7	51.4	57.1
Volatile Matter	33.2	35.1	32.9	31.3	34.1	33.7	32.0	31.5
Moisture	4.7	10.5	8.7	13.3	6.4	8.1	11.3	4.1
Ash	5.1	15.5	4.4	4.7	3.9	4.5	5.3	7.3
Caking Index (Gray King)	F	B	B	C	G	E	E	G6
B.S. Swelling No.	2½	½	1½	1½	3½	3½	3½	6½

Coal	Manvers	Markham Main	Rossington	Seafield	Belle Ayr	Illinois No.5	Ohio No.9	Pittsburgh No.8
Origin	England	England	England	Scotland	U.S.A.	U.S.A.	U.S.A.	U.S.A.
Proximate Analysis wt %								
Fixed Carbon	55.5	54.3	54.7	41.8	31.3	42.3	41.4	50.2
Volatile Matter	32.6	31.4	31.2	26.5	33.0	31.1	33.6	34.1
Moisture	6.3	10.1	9.5	12.0	30.2	11.8	6.1	5.0
Ash	5.6	4.2	4.6	19.7	5.5	14.8	18.9	10.7
Caking Index (Gray King)	F	D	E	A	A	A	G	G6
B.S. Swelling No.	3½	1½	1½	1	0	0	4½	7

Source: Ref.#4

FIGURE 4.1



THE BRITISH GAS/LURGI SLAGGING GASIFIER.

4.0 PROCESS DESCRIPTION (CONTD.)

liberation zone to a small volume. This is beneficial in reducing the heat losses and potential refractory problems. As the gases move upward in the bed, a progressively lower temperature results, lowering reaction rates, until a point where gasification reactions effectively stop. Above this point, rapid heating of the fresh coal results in drying and devolatilization reactions. These reactions yield tars and oils, significant amounts of methane, sulfur compounds, steam and other minor products, which are carried out of the gasifier in the product gas.

The Westfield process development facility is illustrated in Figure 4.2.

5.0 PERFORMANCE DATA

- Table 5.1 gives typical performance data of the slagging gasifier and a comparison with the dry-ash Lurgi.
- Tables 5.2 and 5.3 give data pertaining to the operation of the tuyeres with tar and fines injection.
- The following observations can be made regarding the data presented in these tables.
  - Coals exhibiting a wide range of properties such as reactivity, caking (A through G8), swelling (free swelling index of 1/2 through 7-1/2) and ash contents (4-20%) have been gasified.
  - Gasifier performance is similar irrespective of type of coal used. Oxygen consumption is 0.6 lb/lb MAF coal and steam consumption is 0.4 lb/lb MAF coal, both fairly constant. The liquor production is fairly low at 0.2 lb/lb MAF coal.
  - The thermal efficiency of the gasifier is approximately 80%.
  - Operation of the tuyeres has been demonstrated for use in tar and fines injection.

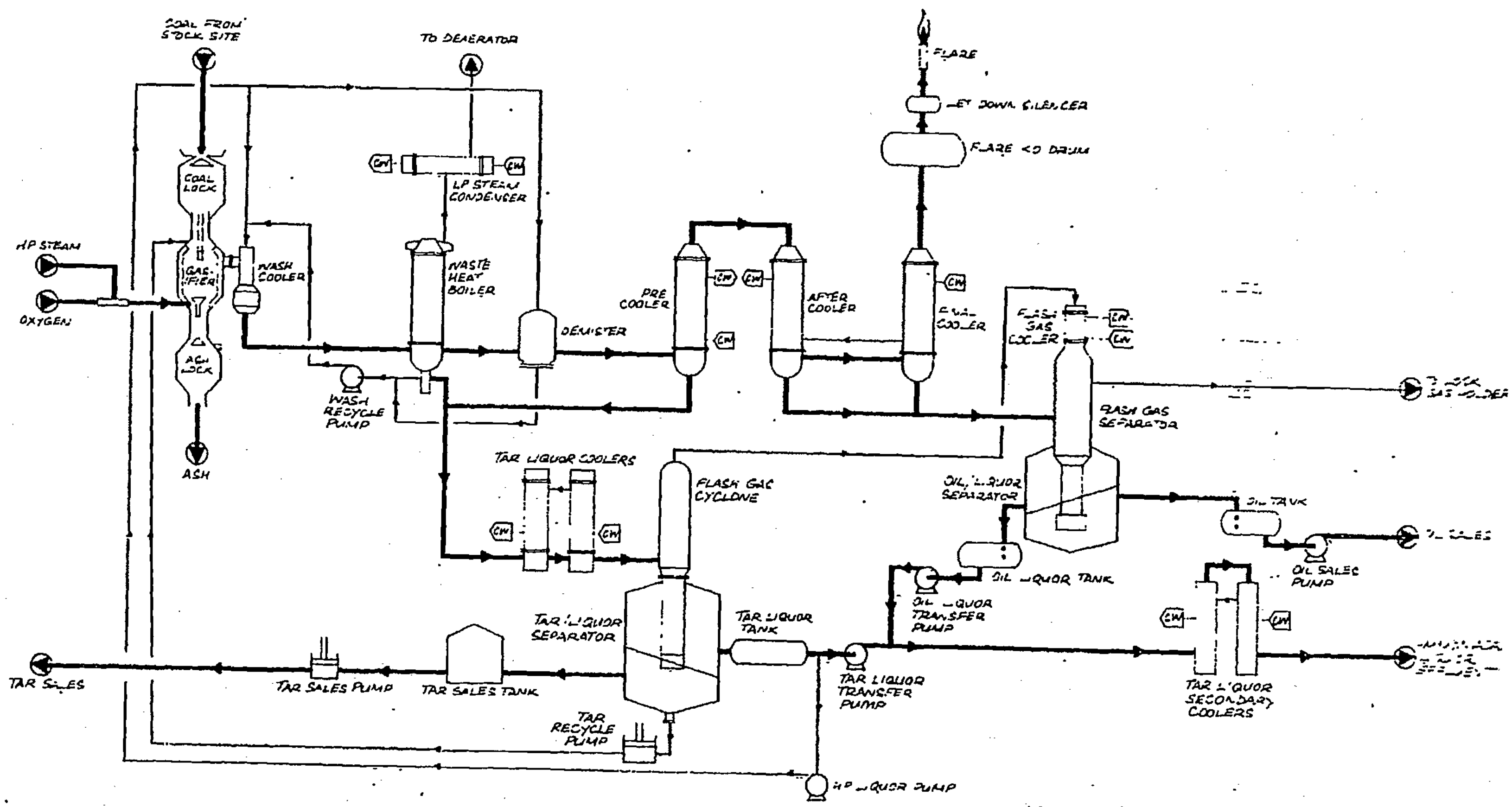


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FIGURE 4.2 . Simplified Flow Diagram-Westfield Trials

TABLE 5.1

Performance Data for British Gas/Lurgi Slagging and Lurgi Dry-Ash Gasifiers at Westfield

Gasifier Type	Slagging				Dry Ash
COAL Origin	Frances Scotland	Rossington England	Ohio 9 USA	Pittsburgh 8 USA	Pittsburgh 8 USA
Size (ins)	¼-1	¼-1	¼-1	⅛-1¼	⅛-1¼
PROXIMATE ANALYSIS, (%w/w)					
Moisture	8.7	9.5	6.1	4.2	4.8
Ash	4.4	4.6	18.9	7.2	7.9
Volatile Matter	32.9	31.2	33.6	35.4	37.4
Fixed Carbon	54.0	54.7	41.4	53.2	50.3
ULTIMATE ANALYSIS (%w/w)					
Carbon	83.0	83.5	79.6	82.4	84.9
Hydrogen	5.5	4.9	6.1	5.3	5.8
Oxygen	9.2	7.7	7.4	9 1	5.0
Nitrogen	1.4	1.7	1.2	1.5	1.6
Sulphur	0.5	1.7	5.6	1.6	2.6
Chlorine	0.4	0.5	0.2	0.1	0.0
B.S. Swelling No.	1½	1½	4½	7½	7½
Caking Index (Gray King)	B	E	G	G8	G8
OPERATING CONDITIONS					
Gasifier Pressure, (atm)	24	24	24	24	24
Steam/Oxygen ratio (v/v)	1.3	1.3	1.3	1.3	9 0
Outlet Gas Temperature (°F)	896	896	770	950	1220
CRUDE GAS COMPOSITION, (%v/v)					
H_2	28.6	27.2	28.7	28.9	38.8
CO	57.5	58.1	53.2	54.9	17.9
CH_4	6.7	6.8	6.9	7.1	8.4
C_2H_6	0.4	0.5	0.3	0.6	0.7
C_2H_4	0.2	0.2	0.2	0.2	0.3
N_2	4.2	3.9	4.0	4 4	2.4
CO_2	2.3	2.9	5.5	3.4	30.8
H_2S	0.1	0.4	1.2	0.5	0.7
HHV, (Btu/scf)	375	375	362	375	298
DERIVED DATA					
Coal Gasification Rate (lb/ft²h)	852	848	664	666	140
Steam Consumption, (lb/lb coal)	0.405	0.398	0.390	0.407	3.540
Oxygen Consumption, (lb/lb coal)	0.539	0.549	0.555	0.547	0 700
Liquor Production, (lb/lb coal)	0.20	0.21	0.16	0:21	2.24
Gasifier Thermal Output, (therms/ft²/h)	106	106	78	83	17

Coal expressed 'moisture and ash free'

SOURCE: Ref. #2

TABLE 5.2

Performance with Tar Injection Through Tuyeres with Pittsburgh No. 8 Coal

	Without Tar Injection	With Tar Injection
Coal	Pittsburgh 8	Pittsburgh 8
Size (mm)	6 - 25	6 - 25
Volatile Matter (%)	34.1	36.1
Moisture (%)	5.0	4.7
Ash (%)	10.7	10.9
Calorific Value (btu/lb)	10616	10598
Operating Conditions pressure (psig)	335	335
Steam to oxygen ratio (vol/vol)	1.22	1.13
Outlet gas temperature (°C)	516	521
Coal gasification rate (lb/ft^{2}h)	816	592
Tar injection rate (lb/ton coal)	0	931
Thermal output (10^6 btu/ft^{2}h)	10.0	8.0
Steam consumption (lb/lb coal)	0.39	0.42
Oxygen consumption (lb/lb coal)	0.57	0.64
Liquor production (lb/lb coal)	0.17	0.17
Gasifier Thermal Efficiency	85.1	83.7

TABLE 5.3

Performance Data with 15% Fines Injection Through Tuyeres.

Coal	Markham Main
Origin	England
Size, mm.	6-25 or pulverised
Proximate Analysis (%)	
Moisture	7.2
Ash	4.4
Volatile Matter	33.4
Fixed Carbon	55.0
BS Swelling No.	1
Caking Index (Gray King)	D
Operating Conditions	
Steam to oxygen ratio (vol/vol)	1.18
Outlet Gas temperature, (°C)	546
% Coal Feed Gasified as Fines	15
Crude Gas Composition, % vol.	
H_2	27.5
CO	55.6
CH_4	5.7
C_2H_6	0.4
C_2H_4	0.1
N_2	7.2
CO_2	3.1
H_2S	0.4
Derived Data	
Steam consumption, (lb/lb coal)	0.40
Oxygen consumption, (lb/lb coal)	0.63
Liquor production, (lb/lb coal)	0.22

Note: Coal expressed as dry, ash free.

SOURCE: Ref.#3

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACT

- Typical by-product and residue production rates from the slagging gasifier are as follows:

	Tons/100 Tons Coal
Naphtha	0.6 - 0.7
Phenols	0.5 - 0.6
Sulfur	3.9 - 4.0
Ammonia	0.4 - 0.5
Slag	11
Sludge	0.04 - 0.06
Waste Water	22
Nitrogen	180
Flue Gas	80-100

- The naphtha and phenols can either be sold as by-products or gasified by re-injection.

- As compared to dry-ash Lurgi, liquors containing phenol and ammonia are more concentrated. Use of dephenolation, microbiological treatment, liming and activated carbon clean-up provide acceptable effluents.

- The slag frit is a clean, black, glassy, low-surface-area material which is readily separated from the quench water and easily handled. Because of its glassy character, the amounts of impurities arising from long-term leaching are negligible. The slag has several potential uses including use as a road fill.

- The slag quench water contains low levels of trace materials. The sludge from the treatment of various effluents will concentrate the trace elements, together with substantial quantities of lime and will have to be disposed as waste.

- The sulfur and ammonia can be recovered in high purity and are saleable.

- The slagging gasifier also offers the possibility of reinjecting liquid effluents via the tuyeres at a small economic penalty.

- In general, less effluents are produced by the slagging gasifier than by the dry-ash Lurgi. There are no serious problems in making the effluents environmentally

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACT (CONTD.)

acceptable; rather, the major issue is the most economic method of treatment.

7.0 ADVANTAGES AND DISADVANTAGES

- The high efficiency of the gasifier is achieved by a process steam requirement that is not much above stoichiometry. In the combustion zone, the process steam is almost completely decomposed so that the steam content of the product gas originates mainly from the moisture in the coal. The volume of the phenolic effluent liquors is therefore small.

- The high temperature zone in the reactor is confined to a small volume and is an important factor in reducing heat loss and preventing refractory problems. Further advantage of the high temperature is complete gasification of the input carbon with essentially no loss of feed carbon in the slag.

- The amount of tars produced in the gasifier requires additional capital investment for cleanup. However, according to BGC the tars protect the reactor offtake and downstream equipment from corrosion, enabling them to be manufactured from inexpensive carbon steels. The carryover of the fines in the offtake gas can also be controlled by adding by-product tar to the top of the bed, thereby increasing the throughput of the reactor which is limited by the entrainment of fines.

- The presence of a large inventory of carbon contributes to gasifier stability and a system that is flexible.

- The low offtake temperature removes the need for high grade heat recovery but could reduce the overall process efficiency.

- The gasifier can handle coal with minimum pre-treatment. No expensive crushing, pulverization for heat pretreatment of coal is necessary. However, fines are typically screened out to produce graded coal in the

7.0 ADVANTAGES AND DISADVANTAGES (CONTD.)

range of +1/8" to -2" to be fed to the top of the gasifier. Normally 10% of fine material can also be added in this manner, but with caking coals higher fines content (up to 35%) can be accepted. This is possible since fines carry-over is restricted by the caking properties of the coals and aided by use of tar injection. It must be noted, however, that the modern mechanical mining techniques produce coal that contains up to 50% fines. The slagging gasifier has been demonstrated to accept additional coal fines (25 to 35 wt% of total feed) by injected through the tuyeres into the raceway with some reduction in the throughput. However, this requires that the coal be pulverized, entrained in a carrier gas and injected into the raceway where, because of the high temperature, they are instantly gasified.

8.0 SUMMARY OF TECHNO/ECONOMIC EVALUATIONS

- Results from technical and economic evaluation of BGC/Lurgi Slagging Gasification Process by CF Braun for Production 232 Billion Btu/day of 942 BTU/SCF SNG.

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TABLE 8.1

DESCRIPTION OF CASE

Coal Type/Case	Illinois #6
Location Basis	Eastern
Evaluating Contractor*	C F Braun
Evaluation for	GRI
Project/Report #	PB-83-242628
Date Published	March 1983

Coal Properties

Proximate Analysis, as Received, wt %

Moisture	12.08
Volatile Matter	30.80
Fixed Carbon	43.85
Ash	13.27
	100.00

Ultimate Analysis, Dry Basis, wt %

Carbon	64.99
Hydrogen	4.47
Nitrogen	0.94
Sulfur	5.05
Oxygen	9.28
Ash	15.09
Chloride	0.18
	100.00
HHV, Btu/lb dry	11,590

*C F Braun's modification of Conoco work FE-2542-10

TABLE 8.2
PLANT OVERALL MATERIAL BALANCE
(M Lb/Hr)

INPUT	Illinios #6
Coal to gasification, dry	1,236.6
Coal to boilers, dry	144.3
Excess coal fines, dry	680.2
Water in coal	283.2
Flux	69.2
Oxygen to Gasifier	648.3
Combustion Air	2,891.8
Purchased Water	6,036.6
TOTAL	11,990.2
PRODUCTS	
Product Gas	430.3
Ammonia	4.0
Sulfur	63.0
Excess Coal fines	680.2
Water in Excess Coal Fines	93.5
Subtotal	1,271.0
VENTS AND LOSSES	
CO_2 Vent	2,244.2
Flue Gas	3,076.7
Slag to Landfill	251.4
Misc. Waste Solids	95.2
Steam and Water Losses	5,051.7
TOTAL	11,990.2

TABLE 8.3
PLANT OVERALL ENERGY BALANCE

Energy Input (MM BTU/HR)	
Coal to Process, HHV	14,332.5
Coal to Boiler, HHV	1,672.3
Fines to Export, HHV	7,883.5
Total Input	23,888.3
Energy Distribution (MM BTU/HR)	
Product Gas, HHV	9,666.8
By-Products, HHV	
Sulfur	283.4
Ammonia	38.8
Fines to Export, HHV	7,883.5
Subtotal Product and By-Product	17,872.5
Consumption and Losses	6,015.8
Total Distribution	23,888.3
Plant Efficiency (without fines), %	
Cold Gas	60.4
Thermal	62.4
Plant Efficiency (with fines export), %	
Cold Gas	40.5
Thermal	74.8

TABLE 8.4
GASIFIER MATERIAL BALANCE AND OPERATING CONDITIONS
(Illinois #6 Case)

INPUT	TEMP, °F	LB/HR
Sized Coal and Flux	77	1,475,720
Superheated H.P. Steam	750	461,673
Oxygen	275	648,288
Fuel Gas	102	1,090
Carbon Dioxide	158	216,761
Dusty Recycle Tar	160	58,320
Clear Tar	160	43,680
H.P. Boiler Feed Water	250	250,463
Boiler Feed Water (Quench Makeup)	250	5,000
Filling Water	158	375,000
Cooling Water Blowdown (Quench Makeup)	87	30,000
Injection Water	160	737,503
Total Input		4,303,498
OUTPUT		
Total Raw Gas	331	2,600,041
Dusty Gas Liquor	356	947,862
H.P. Carbon Dioxide Lock Hopper Off-gas	32	104,582
L.P. Carbon Dioxide Lock Hopper Off-gas	68	3,965
Slag and Water	158	497,592
Slag Quench Drains	226	141,000
Vent Gas	250	1,161
Jacket Blowdown	457	7,295
Total Output		4,303,498
Pressure, Psig	500	
Number of Gasifiers (Operating)	9	

Notes: 1. Data given are for 9 gasifiers.

TABLE 8.5
GASIFIER RAW GAS COMPOSITION
(Illinois #6 Case)

Component	Raw Gas Mol %	Raw Gas Lb/Hr	Dusty Gas Liquor Mol %	Dusty Gas Liquor Lb/Hr
Hydrogen	25.69	47,784	5.80	12
Carbon Monoxide	58.52	1,512,532	11.32	327
Carbon Dioxide	6.44	261,606	40.52	1,844
Methane	6.09	90,174	1.35	22
C_nH_m	0.50	16,687		
Nitrogen	0.71	18,378		
Hydrogen Sulfide	1.93	60,640	41.01	1,445
Organic Sulfur	0.12	6,643		
Total Dry Gas	100.00	2,014,444	100.00	3,650
Water		545,543		828,218
Total Wet Gas		2,559,987		831,868
Other Components		40,054		115,994
Total Stream		2,600,041		947,862

TABLE 8.6
TOTAL FACILITIES CONSTRUCTION INVESTMENT
$MM, mid-1982)

ONSITE FACILITIES ($ MM)	Illinois #6
Coal & Flux Handling	44.2
Air Separation	156.2
Gasification	81.0
Gas Cooling	9.4
Rectisol Unit	75.7
Methanation	44.6
Benfield Unit	89.6
Compression & Drying	17.1
Sulfur Recovery - Claus Plant	14.3
Slag Handling	2.2
Gas-Liquor Separation	17.3
Phenol Extraction	5.3
Ammonia Recovery	7.2
General Facilities & Computer	83.4
Project Contingency	97.1
Total On-Site Facilities	744.6
OFF-SITE FACILITIES ($ MM)	
Water Treatment & Boiler System	260.2
Cooling Water System	23.4
Plant & Inst Air	3.1
Waste Water Treatment	43.5
Flare	4.7
Tankage	5.2
Shipping & Receiving	0.8
Support Facilities	35.5
Project Contingency	56.5
Total Off-Site Facilities	432.9
Subtotal (On-Site and Off-Site)	1177.5
Engineering & Design Cost	70.6
Contractors Overhead & Profit	70.6
Total Facilities Construction Investment	1318.7

TABLE 8.7
SUMMARY OF CAPITAL AND OPERATING COSTS
(90% Stream Factor, Without PDA, mid 1982 Dollars)

Capital Costs, Millions of Dollars	
Total Facilities Construction Investment	1318.7
Initial Charge of Catalyst & Chemicals	40.6
Paid-Up Royalties	44.0
Start-Up Costs	87.9
TOTAL PLANT INVESTMENT	1491.2
Operating Costs, Millions of Dollars/yr	
Fuel	286.5
Ash & Solids Handling	4.1
Catalysts and Chemicals	16.8
Purchased Water	4.3
Direct Labor	
Process Labor	5.6
Maintenance Labor	32.2
Overhead Costs	
Supervision	9.4
General Plant	17.0
Corporate	11.3
Benefits	9.4
Supplies	1.9
Maintenance Materials	21.5
Local Taxes and Insurance	19.8
TOTAL VARIABLE OPERATING AND MAINTENANCE COST	153.3
TOTAL GROSS OPERATING COST	439.8
Sulfur and Ammonia Byproducts	27.2
Coal Fines	70.9
TOTAL BY-PRODUCT CREDITS	98.1
TOTAL NET OPERATING COSTS	341.7
WORKING CAPITAL - CONSUMABLES, $MM	
Coal Storage (44 days)	38.4
Materials and Supplies	11.9
Spare Parts (Rotors)	7.5
TOTAL	57.8
LEVELIZED (PDA=0), DOLLARS/MM BTU	7.39

TABLE 8.8

CALCULATION OF CONTRIBUTION TO GAS COST
BGC/LURGI GASIFICATION

Coal Type	Illinois # 6
Evaluator	C F Braun
Project Report No.	PB-183-242628
Date Published	March 1983
Plant Capacity	250 Billion Btu/day SNG

CAPITAL COSTS :	$ MM (Mid-1982)
Installed Equipment	113.0
Contingency @ 15%	17.0
Direct Facility Constr Investment	130.0
Home-Office costs @ 12%	15.6
Total Facility Constr Investment	145.5
Royalties	20.0
Total Plant Investment	165.5

OPERATING COSTS :			$/hr
Steam(600 psig)	461,700 #/hr	@ $ 5.50/ 1000 lb.	2539.4
Oxygen	648,300 #/hr	@ $36.00/ 2000 lb.	11669.4
Electricity	2,119 Kw	@ $ 0.05/ Kwh	106.0
Cooling water	5,927 Gpm	@ $ 0.10/ 1000 Gal	35.6
Steam Credit(100 psig)	250,500 #/hr	@ $ 3.95/ 1000 lb.	-989.5
TOTAL			13360.8

Total Operating Cost, $ MM/yr at 100 % Stream factor = 4.9 MM $/Yr

CONTRIBUTION TO GAS COSTS :	Specific Cost, $/MM Btu-Yr	Charge Rate, Year	Contribution, $/MM Btu
Capital Related	2.02	0.089	0.18
Operating	0.06	1.000	0.06
Total			0.24

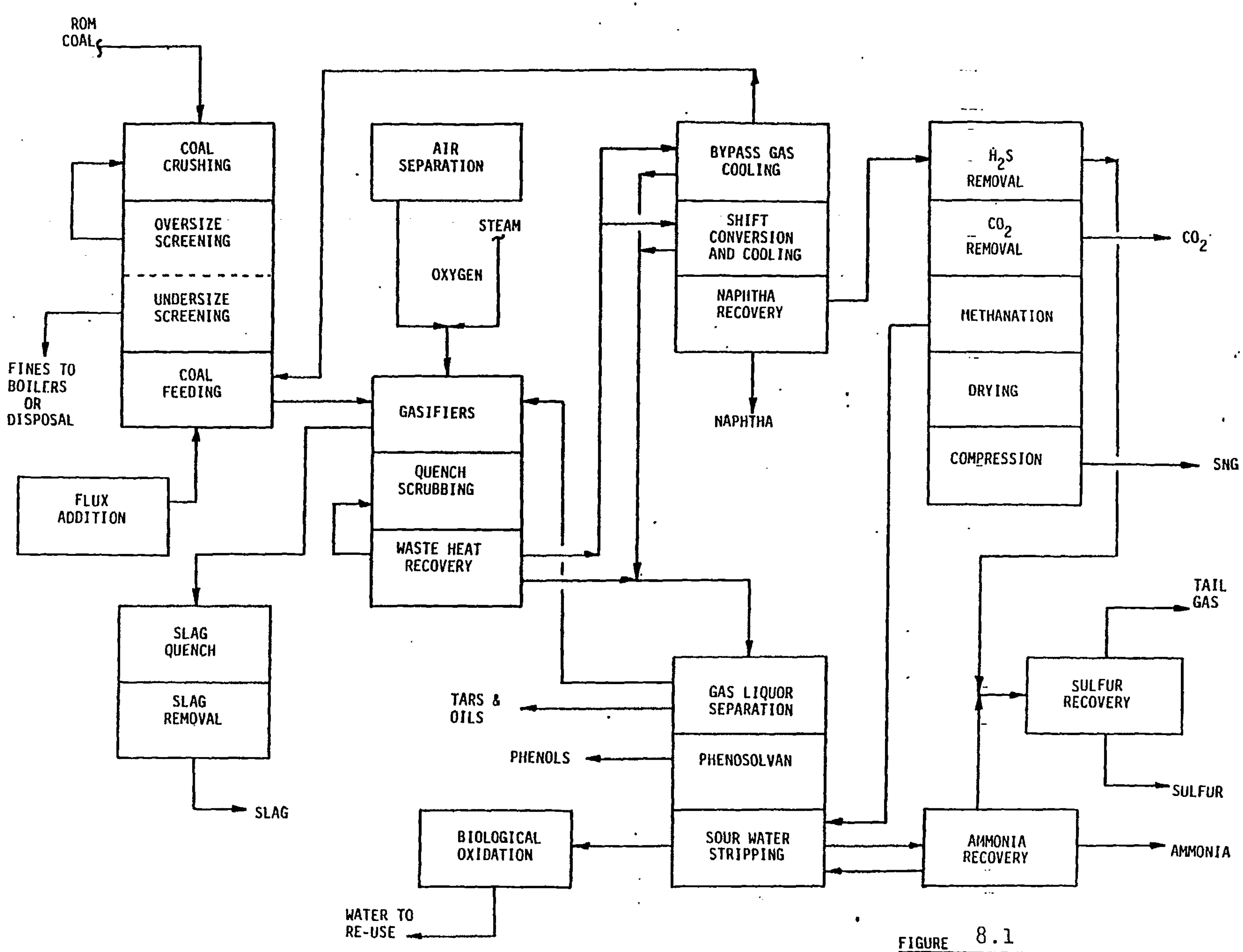

FIGURE 8.1

COAL-TO-SNG WITH BGC/LURGI GASIFICATION

9.0 COMMERCIAL DESIGN PLANS AND DATA

- In 1981, Florida Power Corporation (FPC) completed a study which assessed the feasibility of using coal gasification with combined cycle technology to repower their existing 130 MW, oil-fired Higgins Power Plant. FPC was assisted in the study by Stone & Webster, BGC and Lurgi. The study addresses the technical, environmental and economic aspects of using BGC/Lurgi slagging gasifier to produce medium Btu gas from coal to fuel 320 MW of combustion turbine. The installed capacity of the repowered facility would be 414 MW.

- In late 1975, a proposal by Conoco for a high Btu gasification demonstration plant, based on BGC/Lurgi slagging gasifier, was funded by ERDA (now DOE). A detailed design of a 3500 TPD coal gasification demonstration plant and a conceptual design to produce 250 MM SCFD of SNG from Illinois #6 coal was concluded in mid-1981. This design formed the basis for the Braun study. Conoco then withdrew from the program after DOE funding for the program was rescinded. The Conoco-sponsored work is based on the test runs conducted by BGC on high sulfur Ohio #9 Coal.

10.0 REFERENCES

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2. Sharman, R. B. Lacey J.A., Soctt J. E., "The British Gas Slagging Gasifier - A Springboard into Synfuels," Eighth Annual International Conference on Coal Gasification, Liquefaction and Conversion to Electricity," University of Pittsburgh, Department of Chemical and Petroleum Engineering, August 4-6, 1981.

3. Hebden D., "High Pressure Gasification Under Slagging Conditions," 7th Synthetic Pipeline Gas Symposium, Chicago, Illinois, October 27-29, 1975.

4. Lacey, J.A., "The British Gas/Lurgi Slagging Gasifier," Executive Coal Gasification Conference/Europe 82, Amsterdam, October 20, 1982.

STATUS SUMMARY

WESTINGHOUSE GASIFICATION

WESTINGHOUSE

1.0 GENERAL INFORMATION

- Developer: Westinghouse Electric Corporation
  Synthetic Fuels Division
  Waltz Mill Site, Box 334
  Madison, Pennsylvania 15663

- Type: Single-stage, air or oxygen blown, pressurized, fluidized bed, agglomerating ash gasifier.

- PDU: 15 TPD unit operated at Waltz Mill, PA.

- Conditions: PDU operated in 1,500-1,850°F (gas outlet temperature) at pressures in the range of 130 to 230 psig. Projected commercial conditions: 450 psig pressure and 1700-1850°F temperature.

- Coal Type: Variety of coals have been tested. See Section 3 for listing.

- Products: In addition to CO, H_2 and CO_2, gasifier produces relatively high CH_4 (6-7% on dry gas basis). No tars, phenols and hydrocarbons heavier than C_1 are produced.

- Applications: Suitable for low, medium and high Btu gas, combined cycle electric power generation. Less competitive for H_2, methanol or ammonia because of the necessity to reform methane.

- Status: In July 1983, Westinghouse Electric Corporation announced plans to divest itself of the Synthetic Fuels Division. Principal reason was cited as the anticipated turndown in synfuels activities within USA and abroad. In the same month Westinghouse announced the termination of its joint venture with SASOL (South Africa) to construct and operate the first demonstration scale gasifier, to process Lurgi fines (see Section 7.0). Westing-

1.0 GENERAL INFORMATION (CONTD.)

house, however, remains a participant in the Keystone project, which in May 1983 passed the U.S. Synthetic Fuels Corporation's strength test under the third solicitation. Proprietorship of all Westinghouse gasification technology was assumed by Kellogg Rust, Inc., in early 1984 with the formation of its subsidiary, KRW Energy Systems, Inc.

2.0 PROCESS DEVELOPMENT

- Sponsors:

1972 - 1975	OCR/Industry
1975 - 1978	OCR/ERDA/DOE
1978 - 1983	DOE/GRI/Westinghouse

The industry team in 1972 - 1975 was comprised of Amax Coal Company, Bechtel Inc., Peabody Coal Company, Public Service Company of Indiana, and Westinghouse Electric Corporation.

In 1972, Westinghouse started developing a two-stage air-blown gasification process, consisting of a devolatilizer and a gasifier-agglomerator for direct integration with combined-cycle power plants. The testing began in 1975 on a 15 TPD PDU (air-blown) at Waltz Mill, Pennsylvania, and continued through late 1976. From 1976 to 1978, the proposed applications for the gasification process were expanded to include medium-BTU fuel or synthesis gas, and oxygen-blown gasifier experiments were initiated.

In 1979, greater emphasis was placed on the development of an oxygen-blown process for medium-BTU fuel. Based on the experimental breakthroughs in the process design, it was demonstrated that caking coals, highly reactive coals, and coals with low or high ash content could be processed successfully in a single-stage gasification process. The single-stage configuration then became the prime design for the process instead of the two-stage system.

Major milestones in PDU testing:

- The PDU was operated in the range of 1,500-1,850°F gas outlet temperature at pressures in the range of 130 to 230 psig.

2.0 PROCESS DEVELOPMENT (CONTD.)

- o Coal feed rates of up to 2,500 lb/hr were achieved in the oxygen-blown mode; a total of more than 8,000 hours of hot operation was logged.

- o Gasification of a variety of washed and unwashed bituminous, sub-bituminous, and lignite coal feedstocks has been demonstrated in the PDU with steady state test data that are suitable for scaling up to demonstration designs.

- o Carbon conversion efficiencies were improved with the installation and successful demonstration of a secondary cyclone for increased recovery of entrained fines from the gasifier exit gas. Recycling of fines with no degradation of gasifier operability was successfully demonstrated.

In addition to the PDU testing, a 10 ft. diameter, 35 ft. high semi-circular, Cold Flow Scale-up Facility (CFSF) was constructed at Waltz Mill site to study the effects of solids flow behavior and gas-solid contacting in the gasifier. The CFSF was commissioned in mid-1981, and data were obtained to assess jet penetration length, bubble diameter, bubble frequency and bubble velocity. Crushed acrylic particles were used to simulate coal particles in the gasifier bed.

3.0 FEEDSTOCKS TESTED

- Coals:
  - Pittsburgh #8
  - Indiana #7
  - Western Kentucky #9
  - Wyoming Sub-C
  - Ohio #9
  - Texas Lignite
  - Montana Rosebud
  - RSA (South Africa)
  - Indiana/Ohio (Blend)
  - North Dakota Lignite

- Coke Breeze

- Petroleum Coke

- Renton Fines

3.0 FEEDSTOCKS TESTED (CONTD.)

- FMC Char
- Utah Char
- Minnehaha Coal and Fines

4.0 PROCESS DESCRIPTION

The primary component of the Westinghouse process is the gasifier (Figure 4.1) in which coal and recycled fines are reacted with steam and oxygen to form a synthesis gas consisting mainly of CO, CO_2, H_2, CH_4, and water. The PDU gasifier is a verticial, refractory-lined vessel operable up to 230 psig and 1,850°F and consisting of four sections: freeboard, gasifier bed, combustion zone, and char-ash separator.

Raw coal is ground to 3/16" x 0" (and dried to 5% surface moisture when necessary) and fed pneumatically to the gasifier through a lockhopper system along with the char fines from cyclones downstream of the gasifier. This is accomplished by means of star wheel feeders and recycle gas. The coal and char are fed to the gasifier along its center line, combusted in a stream of oxidant (oxygen or air) fed through the central feed tube; steam is fed together with oxidant as the gasifying medium.

There are several other key flows into the gasifier as shown in Figure 4.2. A flow of steam is provided by annular flow around the nozzle tip to prevent carbon deposition at the base of the jet. Additional recycle gas or steam is injected radially at a location near the middle section of the injection nozzle. This flow mildly fluidizes and cools the ash for withdrawal; the sharp temperature gradient at the char/ash interface is utilized to control withdrawal rate. Recycle gas is also injected through a sparger ring at the base of the ash bed to aid in ash withdrawal.

The coal, char and steam reaction in the gasifier forms hydrogen and carbon oxides. The carbon in the char is consumed by combustion and gasification as the bed of char circulates through the jet. The ash-rich particles resulting from reactions soften, agglomerate and defluidize. The agglomerates migrate to the annulus around the feed tube and are continuously removed by a rotary feeder to lockhoppers. The major portion of the gasifier operates in an essentially

4.0 PROCESS DESCRIPTION (CONTD.)

isothermal condition up to 1,850°F. The lower portion of the annulus operates at about 500°F. Carbon conversion is 95% on an overall basis, while the ash is concentrated to 85% in the agglomerates.

The raw product gas containing no tars or oils exits the gasifier to two refractory-lined cyclones in series where the char particles are removed. The fines collected in the cyclones are cooled, inserted into the recycle gas stream, and fed into the gasifier either with the coal feed or injected into the gasifier annulus or the grid. The product gas is then quenched, cooled and scrubbed of any remaining fines (usually 1 percent) before further processing and recycling.

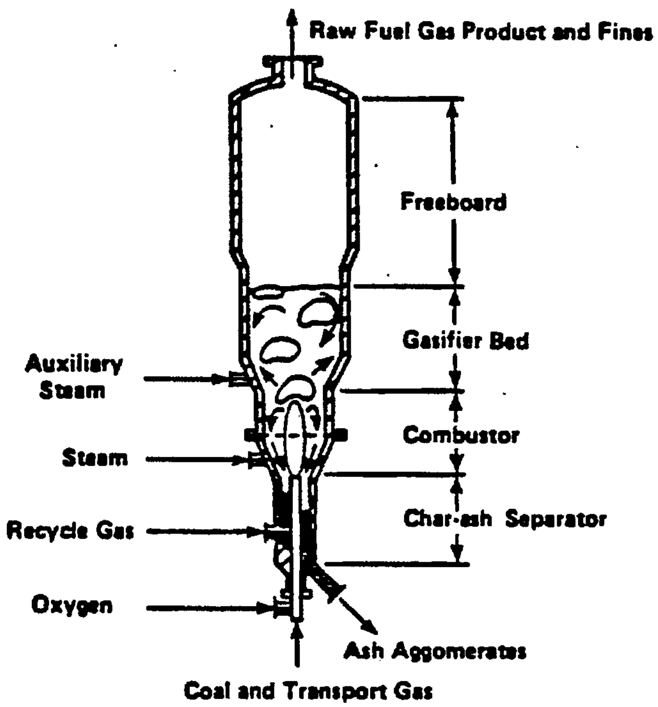

FIGURE 4.1 Functional Schematic of the Westinghouse Gasifier

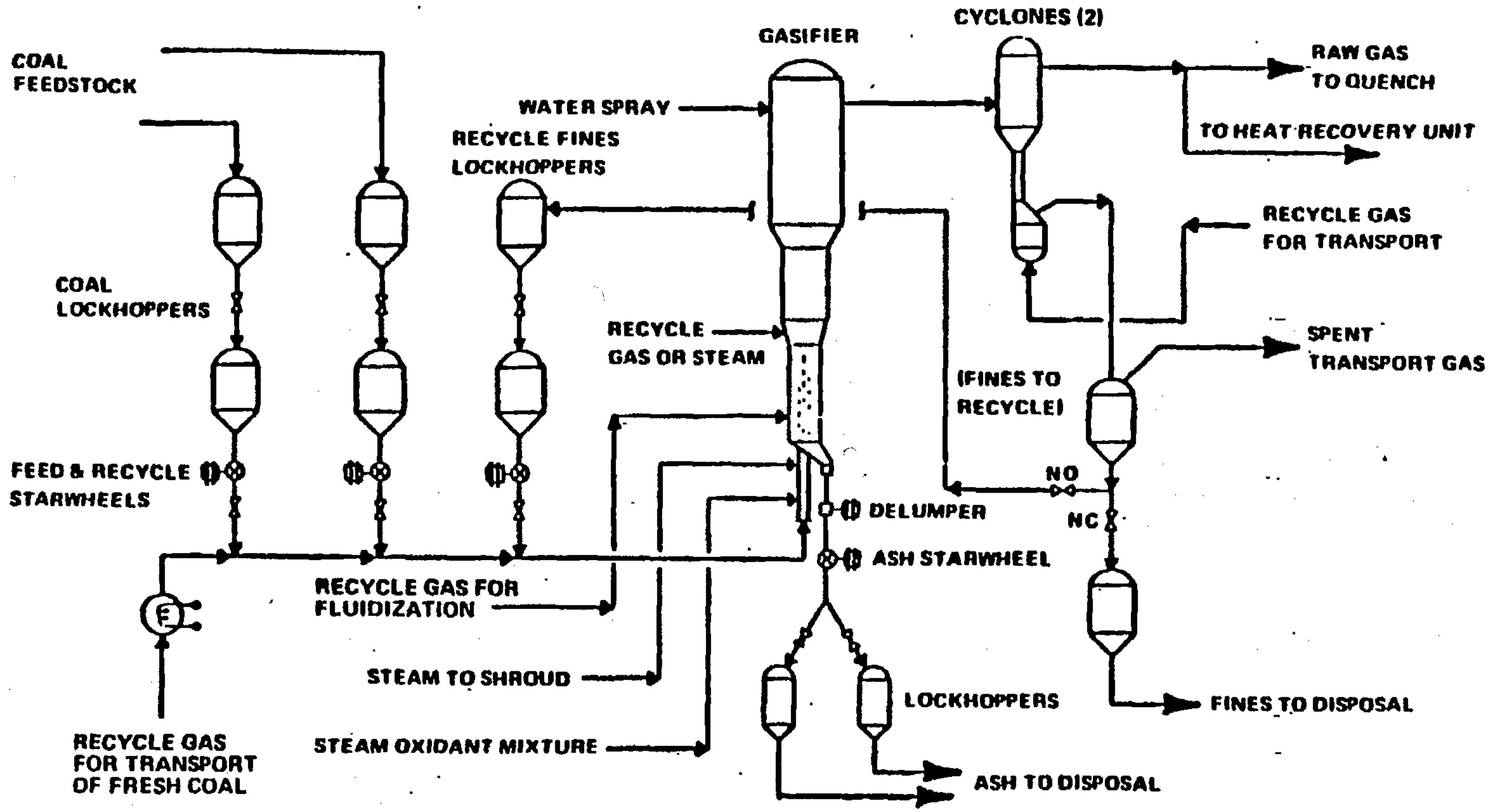

FIGURE 4.2 WESTINGHOUSE SINGLE-STAGE PDU CONFIGURATION

5.0 SAMPLE PDU OPERATING DATA

Operation Mode	Air Blown	O_2-Blown
Coal Type	Pittsburgh #8	Pittsburgh #8
Coal Feed Rate, Lbs/Hr.	731	695
Oxidant/Coal (MAF)	5.53	1.04
Steam/Coal (MAF)	0.21	1.04
Recycle Gas/Coal (MAF)	3.8	1.82
System Pressure, psig	230	130
Free Board Temperature, °F	1,847	1,771
Superficial Bed Velocity, FPS	2.44	2.3
HHV (dry), Btu/SCF	85.2	285
Gas Composition (dry), Vol %		
CO	20.06	49.05
H_2	5.05	29.81
CH_4	0.46	3.16
CO_2	11.87	17.17
N_2	62.55	0.30
H_2S	Neg.	0.50
Net Gas Rate, Lbs/Hr.	5,224	1,009
Ash Rate, Lbs/Hr.	43	29

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACTS

- The process does not produce any liquid hydrocarbon, thus reducing the process condensate treatment requirements.
- The ash, with low leachability comes out of the gasifier, as spherical agglomerates. It does not contain significant amounts of carbon and can probably be disposed of by landfill.

7.0 COMMERCIAL DESIGN PLANS

- SASOL planned to install a 1,200 TPD gasifier at SASOL II, Secunda, South Africa. The principal objective was process fines which are unacceptable as feed to Lurgi gasifiers. Westinghouse was to participate in funding; operation of unit was scheduled for late 1984. These plans were postponed indefinitely.
- Operating the gasifier at high pressure (450-600 psig) has not been demonstrated in PDU and remains as a technical risk in scale-up considerations, due to pressure limitations (230 psig maximum) of PDU.

8.0 SUMMARY OF TECHNO/ECONOMIC EVALUATIONS

- Results of technical and economic evaluations of Westinghouse Coal Gasification Process for production of 250 billion Btu/day of 965 BTU/SCF SNG.

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8.0 SUMMARY OF TECHNO/ECONOMIC EVALUATIONS (CONTD.)

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TABLE 8.1

DESCRIPTION OF CASES

Coal Type/Case	Eastern	Western	Lignite
Location Basis	Eastern	Western	Western
Evaluating Contractor	C F Braun	C F Braun	KRSI
Date Published	April 1983	April 1983	
Coal Properties			
Proximate Analysis, As Received, wt%			
Moisture	6.0	22.0	34.3
Volatile Matter	31.9	29.4	29.0
Fixed Carbon	51.5	42.6	30.5
Ash	10.6	6.0	6.2
	100.0	100.0	100.0
HHV, Btu/lb	12,400	8,800	7,140
Ultimate Analysis, Dry Basis, wt%			
Carbon	71.50	67.70	65.98
Hydrogen	5.02	4.61	4.20
Nitrogen	1.23	0.85	1.30
Oxygen	6.53	18.46	17.90
Sulfur	4.42	0.66	1.20
Ash	11.30	7.72	9.40
Chlorides	*	*	0.02
	100.0	100.0	100.0
HHV, Btu/lb	13,190	11,290	10,870

* Not Reported

TABLE 8.2

PLANT OVERALL MATERIAL BALANCE
(Mlb/Hr)

Case	Eastern	Western	Lignite
INPUTS:			
Coal (MF) to Gasifiers	1,147.0	1,369.0	1,475.9
to Boilers	96.2	140.1	77.2
Moisture in Coal	79.3	425.7	810.8
Oxygen to Gasifiers	695.3	884.8	919.9
Air to Boiler	1,275.3	1,294.2	1,404.3
to Sulfur Plant	*	*	76.0
Nitrogen to AGR	624.5	-	272.1
Raw Water Supply	4,839.3	982.0	809.1
TOTAL	8,756.9	5,095.8	5,845.3
OUTPUTS:			
SNG Product	479.6	476.0	464.4
Sulfur from Acid Gas	49.6	9.2	11.0
from Flue Gas	*	*	7.2
Ammonia Byproduct	13.7	8.5	6.0
Vent/Stack Gases:			
AGR Vent	2,491.7	1,990.0	2,366.3
Gas Drying	*	*	1.4
Sulfur Recovery	*	*	*
Flue Gas Treatment	1,249.2	1,489.6	1,846.6
Evaporation Losses:			
Raw Water Pond	*		8.7
Cooling Tower	4,001.0	676.9	876.5
Steam & Water System	240.5	226.2	55.9
Solids to Landfill	165.9	150.8	166.3
Miscellaneous Losses	9.0	68.9	35.0
TOTAL	8,756.9	5,095.8	5,845.3

* Included in other items of same category or under miscellaneous.

TABLE 8.3

PLANT OVERALL ENERGY BALANCE

Case	Eastern	Western	Lignite
Energy Inputs (MM BTU/HR):			
Coal to Gasifiers	15,131	15,449	16,039
Coal to Boilers	1,268	1,580	839
TOTAL	16,399	17,029	16,878
Energy Outputs (MM BTU/HR):			
SNG Product	10,417	10,417	10,417
Sulfur Byproduct	196	36	72
Ammonia Byproduct	133	83	58
Subtotal	10,746	10,536	10,547
Consumption & Losses	5,653	6,493	6,331
TOTAL	16,399	17,029	16,878
Plant Efficiency, %			
Cold Gas	63.5	61.2	61.7
Thermal	65.5	61.9	62.5

TABLE 8.4

GASIFIER MATERIAL BALANCE AND OPERATING CONDITIONS
(Mlb/Hr)

Input	Eastern	Western	Lignite
Coal, Dry	1,147.0	1,369.0	1,475.9
Moisture	73.2	386.1	456.0
Steam	402.7	403.7	579.8
Oxygen	695.3	884.6	919.9
Recycle Gas	633.3	1,228.6	1,620.4
Recycle Fines	230.7	544.1	2,548.1
TOTAL IN	3,182.2	4,816.1	7,600.1
Output:			
Raw Gas	2,788.0	4,134.7	4,861.2
Fines	244.1	561.5	2,627.4
Ash	150.1	119.9	111.5
TOTAL OUT	3,182.2	4,816.1	7,600.1
Gasifier Freeboard			
Conditions			
Pressure, PSIG	600	600	450
Temperature, °F	1,850	1,750	1,550

NOTES:
1. Eastern coal data for 3 gasifiers
2. Western coal data for 4 gasifiers
3. Lignite coal data for 16 gasifiers

TABLE 8.5

GASIFIER RAW GAS COMPOSITION
(Mol %)

Gases:	Eastern	Western	Lignite
Hydrogen	24.202	20.470	26.08
Carbon Monoxide	38.873	35.815	29.22
Carbon Dioxide	11.887	18.114	21.20
Methane	9.350	8.754	6.51
Hydrogen Sulfide	1.361	0.215	0.36
Carbonyl Sulfide	0.068	0.011	0.03
Ammonia	0.750	0.450	0.19
Nitrogen & Argon	0.457	0.350	0.48
Water	13.052	15.821	15.93
TOTAL	100.00	100.00	100.00
Total MPH	131,383.4	180,354.7	218,267.0
Total M Lb/Hr (Gas)	2,788.0	4,134.7	4,861.2
Solids, M Lb/Hr	244.1	561.5	2,627.4
Total Flow, M Lb/Hr	3,032.1	4,696.2	7,488.6

TABLE 8.6

SUMMARY OF TOTAL PLANT INVESTMENT
($MM Mid-'82)

	WESTINGHOUSE PROCESS		
Onsite Units:	Eastern	Western	Lignite
Coal Storage & Reclaiming	15.9	19.6	22.0
Coal Preparation	24.2	43.3	56.0
Coal Feeding	51.1	62.5	**
Gasification	122.2	132.7	252.0
Raw Gas Quench	14.8	29.5	46.0
Shift Conversion	39.0	*	32.0
Acid Gas Removal	117.0	191.2	115.0
Methanation and Gas Compression	58.7	80.5*	53.0
Sulfur Recovery	54.1	45.8	11.0
Sour Water Stripping	9.6		5.0
Product Gas Drying	2.8	2.8	14.0
Ammonia Recovery	16.0	13.0	5.0
Oxygen Plant	182.5	231.0	202.0
General Facilities	103.4	123.6	86.0
Onsite Subtotal	811.3	975.5	899.0
Offsite Units:			
Flue Gas Desulfurization	33.6	15.5	82.0
Solids Disposal	20.6	42.2	13.0
Steam and Power	155.9	213.3	197.0
Plant Water System	66.4	55.6	32.0
General Facilities	38.7	45.7	69.0
Offsite Subtotal	315.2	372.3	393.0
Total Installed Cost	1126.5	1347.8	
Project Contingency	169.0	202.1	194.0
Engineering & Design Cost	77.7	93.0	89.0
Contractor's Overhead & Profit	77.7	93.0	89.0
Total Facilities Investment	1450.9	1735.9	1664.0

* Western coal case based on combined shift/methanation

** Combined with gasification

TABLE 8.7

SUMMARY OF CAPITAL AND OPERATING COSTS WITHOUT APPLICATION OF PDA (90% STREAM FACTOR, MID-1982 DOLLARS)

	WESTINGHOUSE PROCESS		
Capital Costs, $Million	**Eastern**	**Western**	**Lignite**
Total Facilities Construction Investment	1450.9	1735.9	1664.0
Initial Charge of Catalysts and Chemicals	37.2	26.0	36.0
Paid-Up Royalties	4.0	4.8	17.0
Startup Costs	69.0	51.1	73.0
Total Plant Investment	1561.1	1817.8	1790.0
Operating Costs, $Millions/Year			
Fuel (Coal)	182.48	80.10	93.2
Ash & Solid Waste Disposal	2.66	1.60	1.3
Catalysts and Chemicals	20.63	10.54	9.1
Purchased Water (Raw Water)	3.43	1.16	1.1
Direct Labor			
Process Operating Labor	4.87	4.51	9.0
Maintenance Labor	34.72	42.36	41.3
Overhead Costs			
Benefits	9.90	11.72	12.6
Supervision	9.90	11.72	12.6
General Plant	17.82	21.10	22.6
Corporate	11.88	14.06	15.1
Supplies	1.97	2.34	2.5
Maintenance Supplies	23.14	28.24	27.5
Local Taxes and Insurance	21.76	26.04	25.0
Total Variable Operating Costs/Year	162.67	175.39	179.7
Total Gross Operating Costs/Year	345.15	255.49	272.9
Total ByProduct Credits	25.54	8.27	11.0
Total Net Operating Costs/Year	319.61	247.22	261.9
Working Capital - Consumables, $Millions			
Coal Storage - 44 Days	24.44	10.73	11.2
Material and Supplies	13.06	15.62	15.0
Spare Parts	7.00	7.10	14.0
TOTAL	44.50	33.45	40.2
Levelized Gas Cost, $/MM Btu (PDA = 0)	6.35	5.34	5.43

TABLE 8.8

CALCULATION OF CONTRIBUTION TO GAS COST
WESTINGHOUSE GASIFICATION

Coal Type	N.Dakota lignite
Evaluator	Kellogg Rust Synfuels, Inc.
Project Report No.	None
Date Published	None
Plant Capacity	250 Billion Btu/day SNG

CAPITAL COSTS :

	$ MM (Mid-1982)
Installed Equipment	298.0
Contingency @ 15%	44.7
Direct Facility Constr Investment	342.7
Home-Office costs @ 12%	41.1
Total Facility Constr Investment	383.8
Royalties	15.0
Total Plant Investment	398.8

OPERATING COSTS :

			$/hr
Steam(500 psig)	579,800 #/hr	@ $ 5.50/ 1000 lb.	3188.9
Oxygen	919,900 #/hr	@ $36.00/ 2000 lb.	16558.2
Electricity	22,545 Kw	@ $ 0.05/ Kwh	1127.3
Cooling water	10,410 Gpm	@ $ 0.10/ 1000 Gal	62.5
Steam Credit(1500 psig)	1,142,400 #/hr	@ $ 5.50/ 1000 lb.	-6283.2
TOTAL			14653.6

Total Operating Cost, $ MM/yr at 100 % Stream factor = 5.3 MM $/Yr

CONTRIBUTION TO GAS COSTS :

	Specific Cost, $/MM Btu-Yr	Charge Rate, Year	Contribution, $/MM Btu
Capital Related	4.86	0.089	0.43
Operating	0.06	1.000	0.06
Total			0.50

9.0 ADVANTAGES AND DISADVANTAGES

- Advantages
  - Applicable to wide variety of coals
  - High cold gas efficiency
  - High carbon conversion
  - No tar, phenols or oil produced
  - Lower product gas temperature than entrained flow system
  - Agglomerated ash
- Disadvantages
  - Technology not proven on large scale unit
  - High steam requirements to keep ash below fluid temperature
  - Elaborate gas cleanup system for removal of unreacted fines and entrained ash.

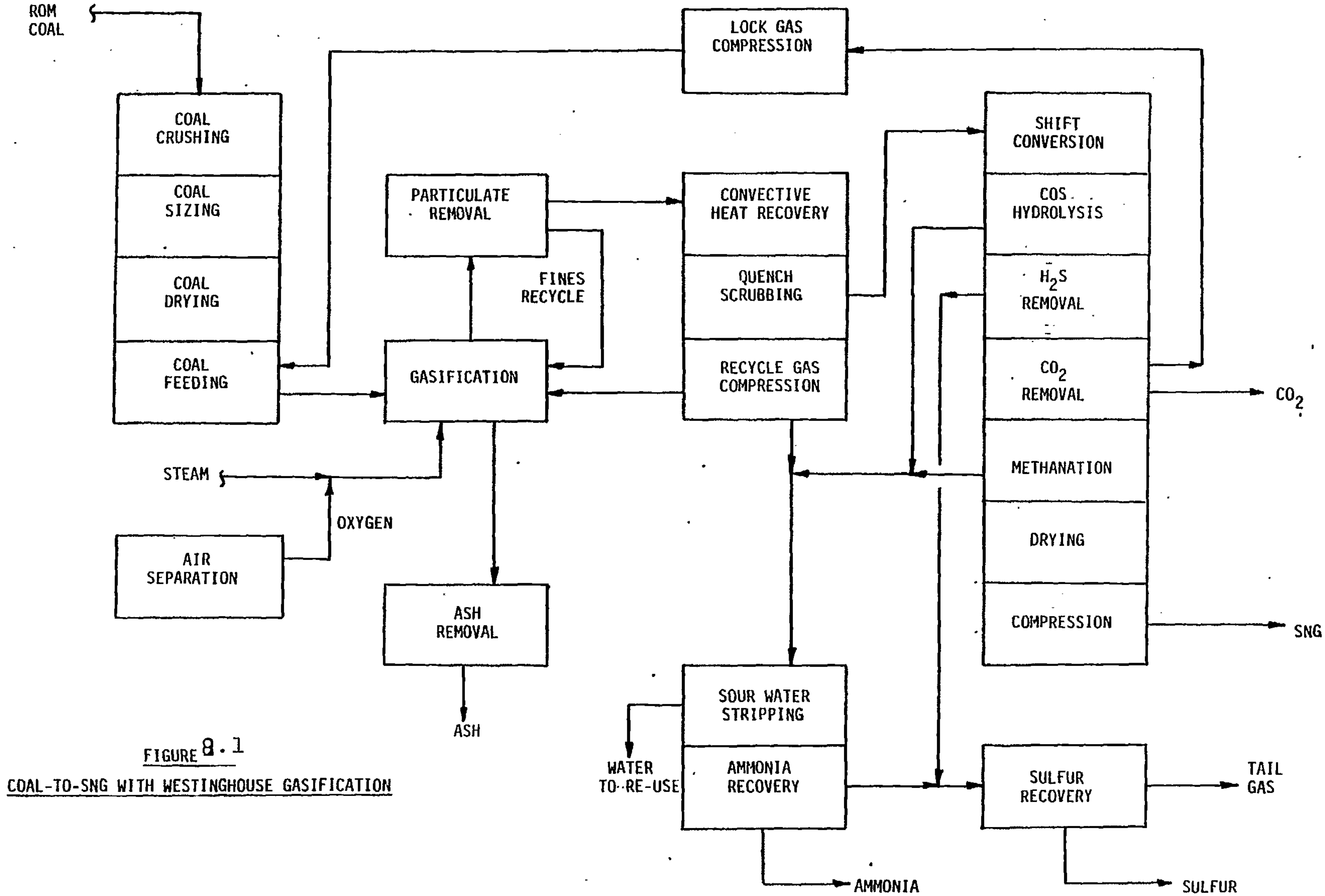

FIGURE 8.1
COAL-TO-SNG WITH WESTINGHOUSE GASIFICATION

10.0 REFERENCES

1. "Joint Coal Gasification Research Program," Program History 1972-1982, by M. W. Kellogg Co., for DOE/GRI, 1982.

2. "Advanced Coal Gasification System for Electric Power Generation - Pressurized Fluidized Bed Coal Gasification Program," March 1980 to January 1982, Final Report Prepared by Westinghouse Electric Corporation, FE-1475-28.

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STATUS SUMMARY:
EXXON CATALYTIC GASIFICATION

EXXON CATALYTIC COAL GASIFICATION (ECCG) (CONTD.)

1.0 GENERAL INFORMATION

- Developer: Exxon Research and Engineering Co., Florham Park, New Jersey
- Type: Pressurized, fluid bed, catalytic, dry ash gasifier. Coal is reacted directly with steam; no oxygen is added.
- PDU facility: PDU operated at Baytown, Texas. PDU gasifier is 10" ID x 80' long, and processes approximately 1 TPD coal.
- Conditions: Pressure: 250-500 psia. Temperature: 1300°F.
- Coal Type: Pulverized coal (-16+100 mesh) catalyzed with KOH or K_2CO_3 solution. Caking coals require pretreatment.
- Products: Methane, carbon dioxide. Carbon conversion 85-95%.
- Application: For SNG or medium BTU gas production.
- Status: Plans to construct a 100 TPD pilot plant in Rotterdam, Netherlands were announced in mid 1982. In February 1983 these plans were delayed in order to get a better grasp of cost through additional technological research on the 1 TPD PDU at Baytown, Texas.

2.0 PROCESS DEVELOPMENT

- The four phases of the Exxon Catalytic Coal Gasification (ECCG) process include: exploratory research, pre-development, process development and precommercialization.
- Exploratory research was conducted from 1971 to 1975. The discovery that a mixture of potassium carbonate and coal char catalyzes the methanation reaction led to the definition of the ECCG process.
- The predevelopment phase, 1975-1977, included operation of 0.75 TPD fluidized bed gasifier, at 115 psig, engineering support studies and a conceptual design of a commercial scale plant.

2.0 PROCESS DEVELOPMENT (CONTD.)

- The process development phase of work covered the period 1978 through 1981. Major portion of the funding for this phase was provided by U.S. Department of Energy and Gas Research Institute. The major task in this phase was the operation of 1 TPD PDU at 500 psig in order to obtain data suitable for scale-up. Bench-scale research and engineering studies were also carried out. The PDU achieved its most significant milestone in April 1981, with a 23-day demonstration run. This run showed the operability, sustainability and control of the ECCG process at the target commercial conditions. It also provided data necessary for the next phase of the program: the design, construction, and operation of a 100 TPD pilot plant.

- The ECCG process has now entered the precommercialization phase involving design and operation of a 100 TPD pilot plant. At present several process improvement studies are continuing at the PDU site. Since completion of the 23 day demonstration run using Illinois #6, four other coals have been run in the PDU. A Continuous Gasification Unit (CGU) is also being employed to study process variables. The CGU, oeprational since 1981, has a 3.4-inch diameter, 15-foot high reactor, and a 100 lb/day coal feeding capacity. A 2 TPD Fluid Bed Sluury Dryer (FBSD) unit was constructed in 1982 and is presently being operated to deposit the catalyst on coal and then recover the heat employed in drying for use as gasification steam. Further test runs are underway in the PDU to confirm suitability of materials used in the catalyst recovery system. This precommercialization phase is expected to be completed in 1989 and a commercial gasifier of 3,000 - 5,000 TPD capacity is projected to be operational in late 1990's.

3.0 FEEDSTOCKS TESTED

- Illinois #6 was used until and during the 23-day PDU demonstration test run conducted in April 1981.

- Since then, four other coals have been reportedly run in the PDU. Three of these were U.S. bituminous coals. The fourth was Wyodak, a Western U.S. sub-bituminous coal. During a 27-day run on the Wyodak coal, higher bed densities and lower char overhead entrainment rates were demonstrated in comparison to the Illinois #6 run.

3.0 FEEDSTOCKS TESTED (CONTD.)

Only one of the three bituminous coals performed to expectations while the other two exhibited lower bed densities and carbon conversions similar to PDU operation on Illinois #6.

4.0 PROCESS DESCRIPTION

The Exxon Catalytic Coal Gasification process development unit (PDU) comprises continuous coal feeding and pretreatment, char withdrawal, product gas cleanup, cryogenic fractionation of methane, synthesis gas recycle and catalyst recovery and recycle. The unit was sized for a nominal coal feed rate of one ton per day, and was designed for fully integrated operation. A simplified flow diagram of the PDU is shown in Figure 4.1.

Fresh coal which has been dried, washed, and screened to 16 x 100 mesh size is transported under nitrogen to a storage hopper. A rotary vane feeder on the bottom of the hopper meters the coal to a ribbon mixer in which catalyst (potassium salts) solution is added to the coal. The catalyzed coal is then dried in a series of steam-heated screw conveyor dryers. Following a pretreatment step in which the coal is subjected to mild oxidation and heat soak to improve bed density, the dry coal is transported to a surge bin before feeding to the gasifier.

The reactor coal feed system consists of two parallel pressurized lock hoppers holding about one ton of catalyzed coal each, with a small lockpot under each hopper. One hopper is feeding while the other is being depressurized, filled from the surge bin, and repressurized for use when the on-line hopper is emptied. The lockpot feeder cycles approximately 25 times per hour to feed 100 lb/hour to the gasifier. The lockpot drops the coal into a vertical two-inch line, reducing to a 3/4-inch line from which the coal is blown into the side of the gasifier by driver gas at a 45° downward angle. The feed coal can be injected 5 feet, 25 feet, or 45 feet from the bottom of the gasifier.

The gasification reactor is shown in Figure 4.2. It is a vertical vessel constructed of HK-40 steel and is heated electrically by radiant ceramic heaters arranged in 16 separate control sections.

4.0 PROCESS DESCRIPTION (CONTD.)

Steam and synthesis gas are injected into the bottom center of the reactor. Steam is generated at 600 psig in an electrically heated vaporizer, then mixed with the synthesis gas and passed through a superheater. The superheater is an electrically heated, fluidized sandbath which heats the gases to 1200°F. A small amount of H_2S is added to the synthesis gas before preheating to prevent carbon deposition on hot metal surfaces.

Product gas leaving the top of the gasifier passes through filters to remove the entrained char. It then passes through a scrubber to condense the unreacted steam which is removed as water and weighed.

The product gas then enters the gas cleanup section to remove CO_2, H_2S, and small amounts of ammonia and water. Monoethanolamine (MEA) is used to absorb the acid gases in a packed tower at 250 psi and ambient temperature. The MEA is regenerated in another packed tower where it is heated and depressurized to atmospheric pressure. The regenerated MEA is then returned to the absorber to form a closed loop. After the MEA tower, the gas passes through a molecular sieve absorber and an activated carbon absorber for removal of final trace impurities before entering the cryogenic system.

The cryogenic fractionator system operates at 250 psig and approximately 250°F, using liquid N_2 as the coolant. Extensive feed-effluent heat exchange is used to reduce the amount of liquid N_2 required. All of the low temperature equipment is inside an insulated, evacuated containment vessel to minimize heat transfer from the atmosphere. Methane is removed as a bottom product from the fractionator and CO and H_2 are the overhead product. The CO and H_2 are sent to the compressors for recycle to the gasifier. However, most of the tests conducted on the PDU were with simulated gas recycle due to frequent problems with the cryogenic unit.

Synthesis gas is recycled from the cryogenic fractionator. Trailer supplies of H_2 and CO are also available for makeup gas and start-up purposes. Two recycle gas compressors are used to raise the synthesis gas supply to 60 psig.

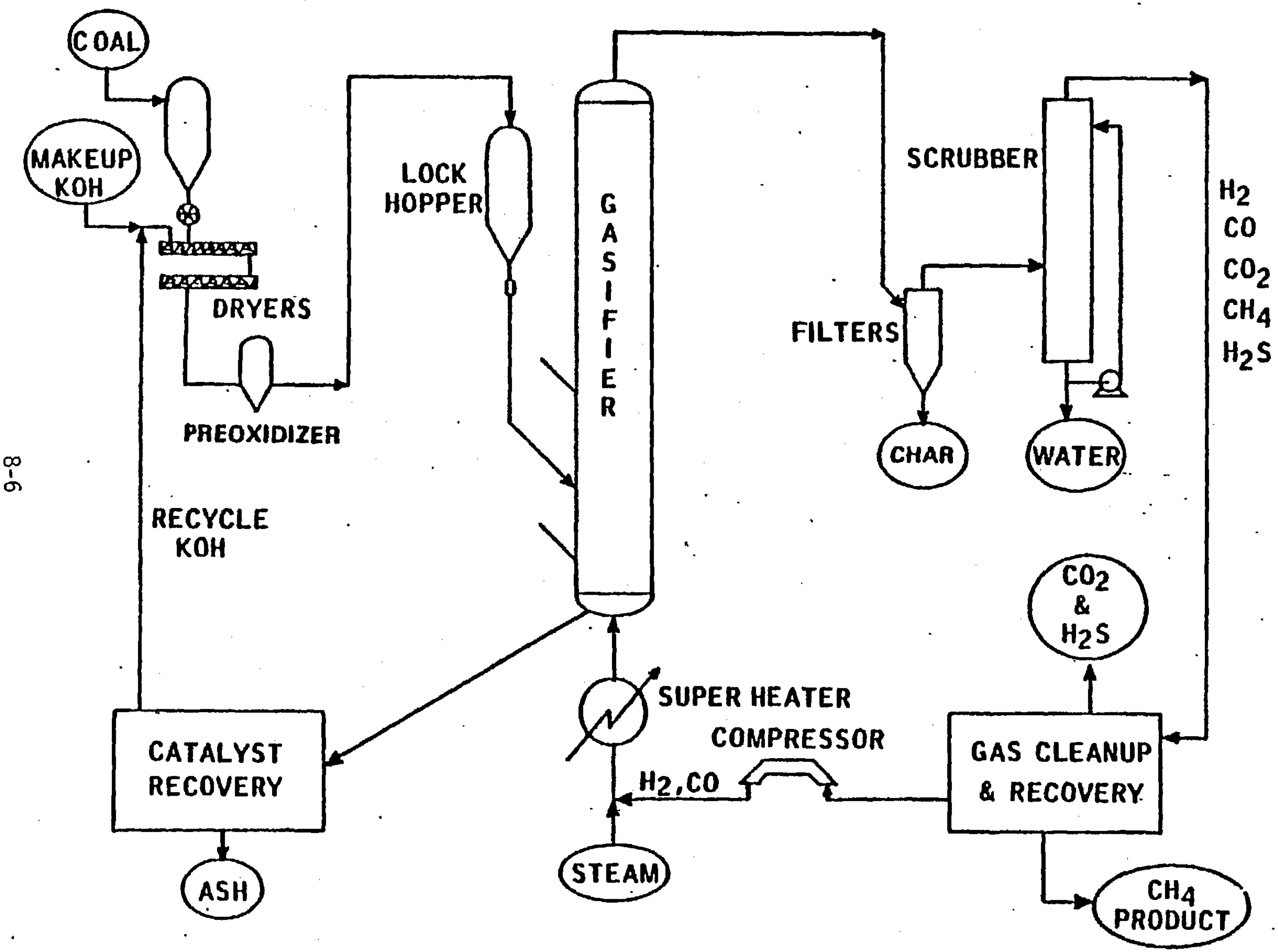

FIGURE 4.1 EXXON PDU FLOW DIAGRAM

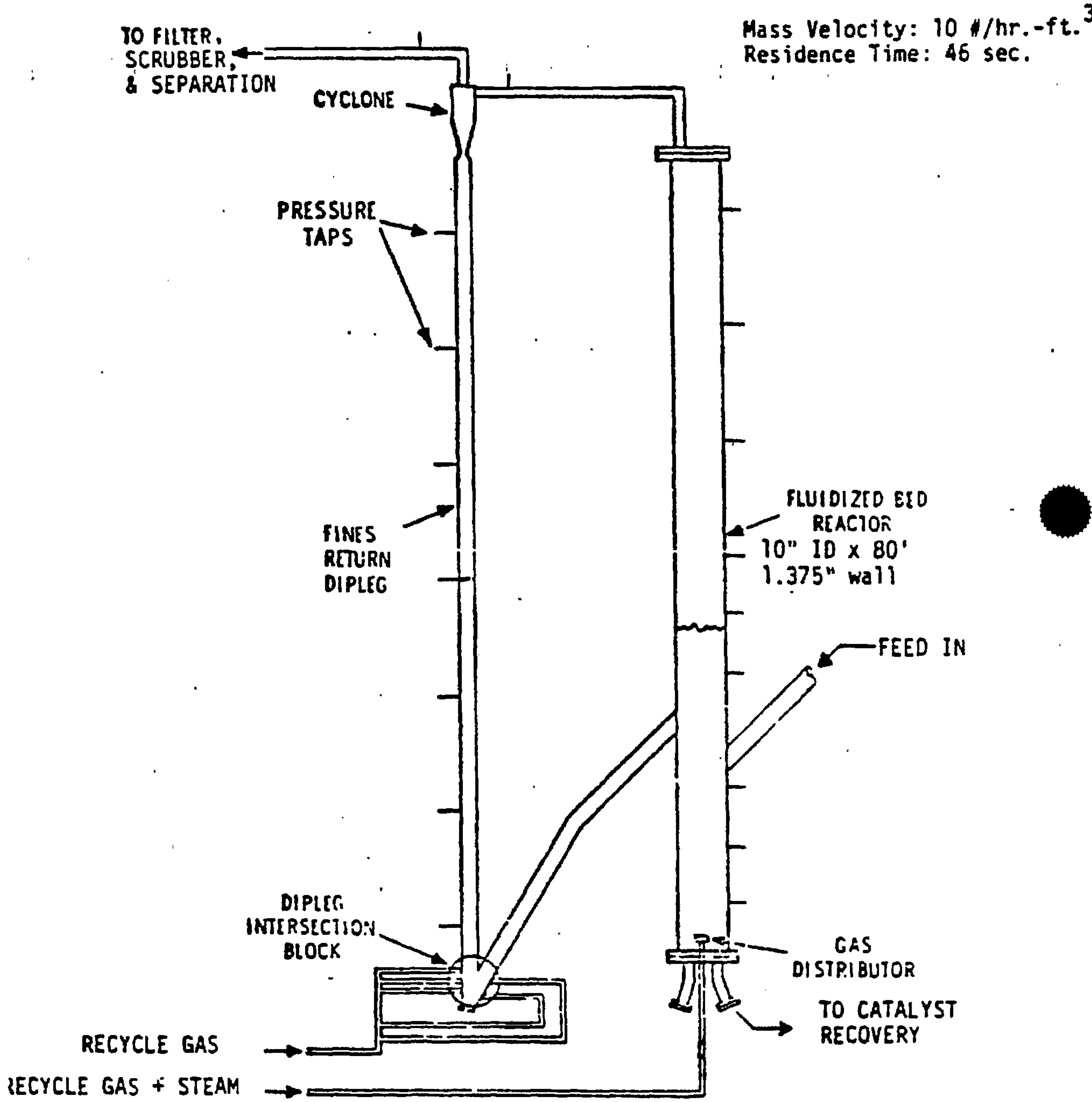

FIGURE 4.2 EXXON GASIFICATION REACTOR

4.0 PROCESS DESCRIPTION (CONTD.)

Char is removed from the bottom of the gasifier through two parallel char withdrawal lines. The lines contain two valves which are cycled in a lock pot manner to lock out a volume of char approximately three feet long in a three-inch diameter pipe. The char drops into a slurry pot on each line which contains water to quench the hot char. An agitator mixes the char into the water and the char is then drawn off as a slurry. The pots operate on 500 psi to minimize the pressure drop and wear on the ball valves which would result from the hot abrasive char.

The char slurry is sent to the catalyst recovery system before the char is finally dumped. The slurry is washed with water and filtered in two countercurrent stages to recover the potassium. The rich solution is concentrated by evaporation to approximately 20% potassium salts and then recycled to the catalyst addition section where it is applied to fresh coal entering the gasifier.

5.0 PERFORMANCE DATA

Between December 1979 and April 1981, approximately 65 material balances were developed from the test runs. The PDU was operated over a wide range of conditions as shown below:

Gasifier Coal Feed Rate	52-132 lbs/hr
Gasifier Pressure	116-500 psia
Gasifier Temperature	1213-1297 ^{o}F
Fluid Density	5-32 lbs/ft^3
Carbon Conversion	30-95%
Steam Conversion	17-44%

Performance data pertaining to Run No. 45 are shown below. Other typical balances are shown in Table 5.1.

- Coal Type: Illinois #6
- Conditions:

  Pressure, 505 psia
  Temperature, 1297^{o}F
  Bed Density, 20 lbs/ft^3

TABLE 5.1

EXXON CATALYTIC COAL GASIFICATION

MATERIAL BALANCES WITH TARGETS ACHIEVED

MATERIAL BALANCE #	TARGET	16	21	22	42	43	45	46
TEMPERATURE, °F		1276	1291	1268	1284	1247	1297	1296
PRESSURE, PSIG		253	265	301	505	504	505	505
COAL + CATALYST, #/HR		73.9	62.1	58.4	86.0	88.9	100.4	88.8
STEAM, #/HR		122.7	115.7	115.5	146.1	150.8	132.9	132.0
BED DENSITY, #/CF	10+	9.9	16.3	12.4	12.6	15.6	20.0	14.4
SYNGAS BALANCE, %	70+	73.8	79.6	91.2	79.1	78.5	74.2	75.1
CARBON CONVERSION, %	80+	78.3	88.3	80.3	89.7	81.6	85.7	83.0
STEAM CONVERSION, %	30+	39.4	36.6	29.9	36.2	33.7	40.8	38.2
CH_4 IN DRY GAS, % VOL	20+	21.4	20.1	22.7	25.0	21.6	24.0	22.2
GASIFICATION RATE*, %/HR		43.6	34.0	24.7	67.0	32.3	36.7	40.0
K/C ATOMIC RATIO		0.20	0.27	0.15	0.40	0.17	0.28	0.24

* $\dfrac{\text{CARBON CONVERTED}}{\text{CARBON IN BED}} \times 100$

5.0 PERFORMANCE DATA (CONTD.)

- Conversions, %: Carbon 85.7%
  Steam 40.8%

- Gasifier Balance, lbs/hr:

	In		Out
Coal + Catalyst	100.4	Product Gas	187.8
Steam	132.9	Water	78.7
Syn Gas	61.8	Char	15.2
	295.1		281.7

- Compositions, mol.%:

	Process Gas*	Recycle Syn Gas
H_2	51.78	85.53
CO	8.22	14.47
CH_4	24.00	
CO_2	15.58	
H_2S	0.42	
Total	100.00	100.00

* dry and N_2 free basis.

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACTS

- Process does not produce any liquids. Sulfur and ammonia are the by-products of the process.

- A comprehensive environmental assessment program to characterize waste waters, spent solids and solids slurries produced in the PDU was carried out in early 1981. The program consisted of analyses of grab samples and time series samples. It was found that the hazardous metal content in the leachate of solid waste was below the 100 times primary drinking water standards. The wastewater pollutant levels were indicated to be about an order of magnitude lower than corresponding levels found in literature sources for other gasification processes.

- All commercialization plans postponed indefinitely. See Item 1.0, Status.

8.0 ADVANTAGES AND DISADVANTAGES

- Advantages:
  - Accelerated steam gasification rate due to presence of catalyst.
  - Catalyst promotes methanation.
  - No oxygen required.
  - Gas conversion units such as shift and methanation not required.
  - Tars, heavy oils or other hydrocarbon heavier than C_1 are not produced.
  - Catalyst reduces swelling and caking of bituminous coals.
  - The gasifier operates thermally neutral at about 1300°F, a temperature at which kinetics of the methanation also allow conversion to reach its thermodynamic equilibrium value.

- Disadvantages:
  - Requires recycle of syngas following separation from methane.
  - Requires catalyst recovery and make-up.
  - Requires special alloys materials of construction to prevent caustic stress corrosion.
  - Produces residual solids containing coal ash, unconverted carbon and insoluble potassium salts.

9.0 SUMMARY OF TECHNO/ECONOMIC EVALUATIONS

- Results from Technical and Economic Evaluations of Exxon Catalytic Coal Gasification Process for Production of 250 Billion Btu/day SNG.

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TABLE 9.1
DESCRIPTION OF CASES

Coal Type/Case	Eastern
Location Basis	Eastern
Evaluating Contractor	C F Braun[1]
Evaluation for	GRI
Project/Report #	GRI -80/0168
Date Published	August 1979
Coal Properties	
Proximate Analysis, As Received, wt%	
Moisture	6.0
Volatile Matter	31.9
Fixed Carbon	51.5
Ash	10.6
	100.00
HHV, Btu/lb	12,400
Ultimate Analysis, Dry Basis, wt.%	
Carbon	71.50
Hydrogen	5.02
Nitrogen	1.23
Oxygen	6.53
Sulfur	4.42
Ash	11.30
Chlorides	*
	100.00
HHV, Btu/lb	13,190

*not required.

[1] Cost updated to mid-1982 basis by KRSI.

TABLE 9.2
PLANT OVERALL MATERIAL BALANCE
(M lbs/Hr)

Input Streams	Eastern
Coal, Dry	
To Gasifiers	979.0
To Steam Plant	286.7
To Coal Dryers	25.1
Water in Coal	82.4
Oxygen to Gasifier	-
Combustion air	3905.8
Raw Water	3912.6
Potassium Hydroxide	54.2
Lime	109.8
Soda Ash	1.8
Total	9357.4
Output Streams	
Product Gas	449.1
By-Products	
Sulfur	32.6
Ammonia	96.5
Waste Streams	
Flue Gas	4583.3
Tail Gas	206.7
Waste Solids, Dry	397.0
Water in Waste Solids	160.9
Bi Ox Sludge	0.1
Losses	
CO_2 Vent	792.2
Cooling Tower	2400.0
Steam and Water	207.8
Miscellaneous	31.2
Total	9357.4

TABLE 9.3
PLANT OVERALL ENERGY BALANCE
(MMBtu/Hr)

Energy Input	Eastern
Coal to Process, HHV	12,914
Coal to Steam Plant, HHV	3,782
Coal to Dryers, HHV	331
Total Input	17,027
Energy Distribution	
Product Gas, HHV	10,747
By-Products, HHV	
Sulfur	130
Ammonia	186
Subtotal Product and By-Products	11,063
Consumption and Losses	5,964
Total Distribution	17,027
Cold Gas Efficiency, Percent	63.1
Plant Thermal Efficiency, Percent	65.0

TABLE 9.4
SUMMARY OF TOTAL PLANT INVESTMENT
(mid-1982)

	Eastern
On-Site Units ($MM)	
Coal Preparation	36.60
Gasification & Quench	248.40
Acid Gas Removal	119.70
Methane Recovery	84.90
Base Onsite FCI	489.60
Project Contingency @ 15.0%	73.44
On-Site FCI with PC	563.04
Off-Site Units ($MM)	
Sulfur Recovery	87.00
Coal Storage & Reclaiming	18.10
Waste Water Treatment	36.50
Plant Water System	48.90
Steam & Power	213.20
Solids Disposal	10.70
Refrigeration	69.00
Catalyst Recovery	81.10
Subtotal	564.50
General Facilities	135.10
Base Offsite FCI	699.60
Project Contingency @ 15.0%	104.94
Off-Site FCI with PC	804.54
Base FCI	1189.20
Direct FCI, Incl. PC	1367.58
Direct Facilities Construction Investment	1367.58
Home Office Fees	186.49
Total Facilities Construction Investment	1554.07

TABLE 9.5
SUMMARY OF CAPITAL AND OPERATING COSTS
(zero PDA, 90% Stream Factor, mid-1982 dollars)

	Eastern
Capital Costs, $MM	
Total Facilities Construction Investment	1554.07
Initial Charge of Catalyst & Chemicals	20.90
Paid-Up Royalties	1.52
Start-Up Costs	91.70
Total Plant Investment	1668.19
Operating Costs, $MM/YR	
Fuel -- Coal	210.51
Ash & Solid Waste Disposal	7.33
Catalyst & Chemicals	87.14
Purchased Water -- Raw Water	3.08
Direct Labor	
Process Operating Labor	4.51
Maintenance Labor	39.35
Overhead Cost	
Benefits	10.97
Supervision	10.97
General Plant	19.74
Corporate	13.16
Supplies	2.19
Maintenance Supplies	26.23
Local Taxes and Insurance	23.31
Total Variable Operating Costs/Year	247.98
Total Gross Operating Costs/Year	458.49
Total By-Product Credits/Year	76.38
Total Net Operating Costs/Year	382.11

TABLE 9.5 (CONTD.)

SUMMARY OF CAPITAL AND OPERATING COSTS

(zero PDA, 90% Stream Factor, mid-1982 dollars)

	Eastern
Working Capital, $MM	
Coal Storage -- 44 days	25.38
Materials and Supplies	13.99
Spare Parts	9.00
Total Working Capital - Consumables & Spare Pats	48.36
Levelized Constant Dollar Cost-of-Gas (PDA=0)	$6.871/MM BTU

TABLE 9.6

CALCULATION OF CONTRIBUTION TO GAS COST
EXXON GASIFICATION

Coal Type	Pittsburgh # 8
Evaluator	M.W.Kellogg Co.
Project Report No.	FE-2777-31
Date Published	July 1982
Plant Capacity	250 Billion Btu/day SNG

CAPITAL COSTS :	$ MM (Mid-1982)
Installed Equipment	248.4
Contingency @ 15%	37.3
Direct Facility Constr Investment	285.7
Home-Office costs @ 12%	34.3
Total Facility Constr Investment	319.9
Royalties	15.0
Total Plant Investment	334.9

OPERATING COSTS :			$/hr
Steam(500 psig)	1,468,500 #/hr	@ $ 5.50/ 1000 lb.	8076.8
Oxygen	0.0 #/hr	@ $36.00/ 2000 lb.	0.0
Electricity	10,000 Kw	@ $ 0.05/ Kwh	500.0
Cooling water	10,000 Gpm	@ $ 0.10/ 1000 Gal	60.0
Chemicals and Catalysts			5683.0
Steam Credit(1500 psig)	0.0 #/hr	@ $ 5.50/ 1000 lb.	0.0
TOTAL			14319.8

Total Operating Cost, $ MM/yr at 100 % Stream factor = 5.2 MM $/Yr

CONTRIBUTION TO GAS COSTS :	Specific Cost, $/MM Btu-Yr	Charge Rate, Year	Contribution, $/MM Btu
Capital Related	4.08	0.089	0.36
Operating	0.06	1.000	0.06
Total			0.43

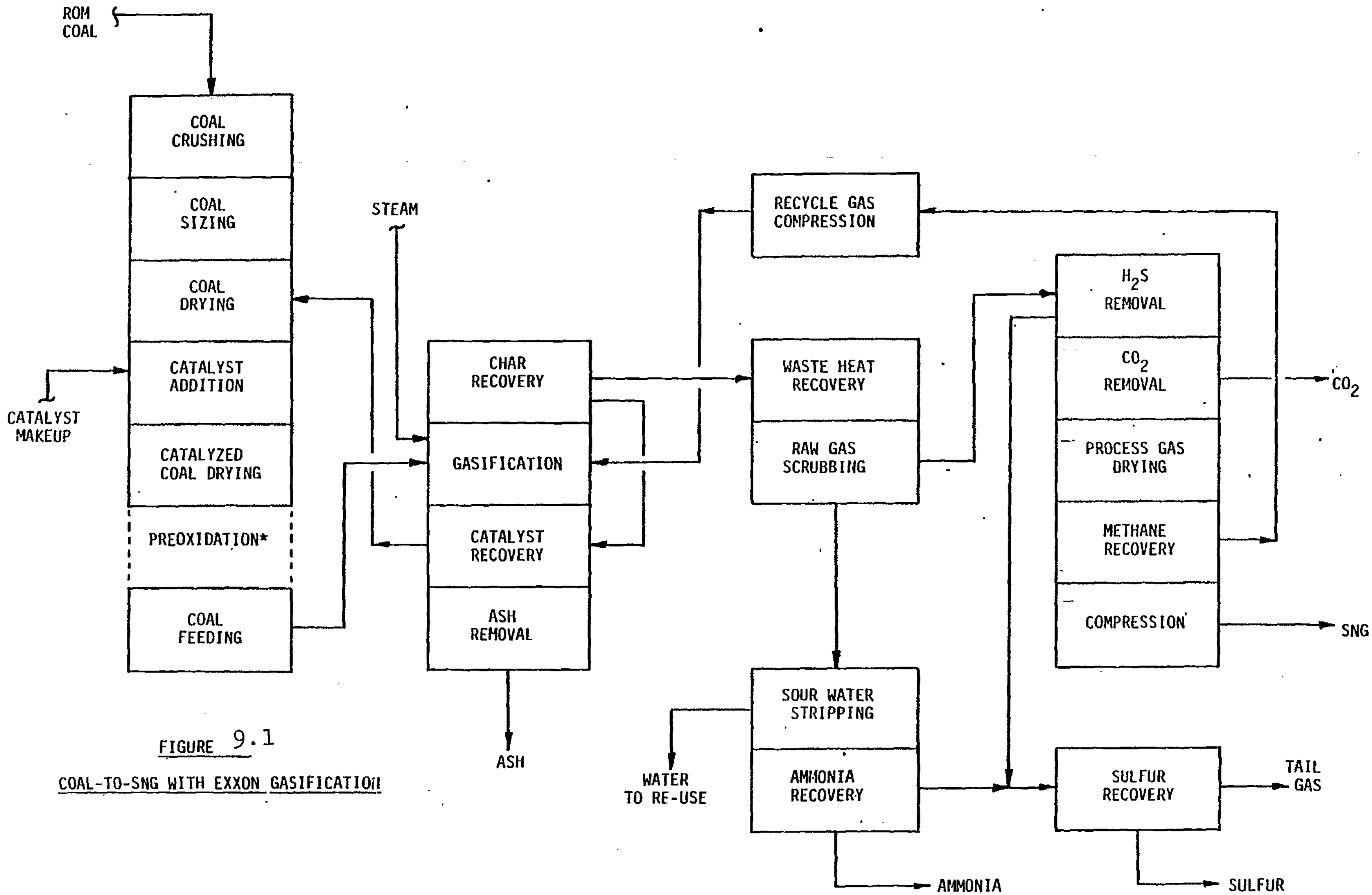


FIGURE 9.1

COAL-TO-SNG WITH EXXON GASIFICATION

*Required for Caking Coals

10.0 REFERENCES

1. "Joint Coal Gasification Research Program," Program History 1972-1982, by M. W. Kellogg Co., for DOE/GRI, 1982.

2. "Exxon Catalytic Coal Gasification Process Development Program," Final Project Report FE-2777-31, Exxon Research and Development Company, November 1981.

3. Hans Nie, "Exxon Catalytic Coal Gasification Process," Paper presented at Executive Coal Gas Conference/Europe '82, October 19-22, 1982.

STATUS SUMMARY

SHELL GASIFICATION

SHELL COAL GASIFICATION PROCESS (SCGP)

1.0 GENERAL INFORMATION

- **Developers:** Shell Internationale Petroleum Maatschappij (SIPM) B.V., The Hague, Netherlands and Shell Oil Company One Shell Plaza, P. O. Box 2469, Houston, Texas 77001

- **Type:** The Shell Coal Gasification Process (SCGP) uses an oxygen blown, upflow entrained bed reactor with gasification at elevated pressure under slagging conditions, with a cold recycle gas stream to quench the product gas.

- **PDU Facility:** A 6-metric tons per day (MTPD) unit has operated at Royal Dutch Shell's laboratories since December 1976 and a 150 MTPD gasifier has operated at Deutsche Shell's Harburg refinery since November 1978.

- **Conditions:** The 6 MTPD PDU has operated at pressure levels ranging from 300 to 600 psig with reactor outlet temperature in the range of 2500-2700°F. The 150 MTPD pilot plant operates at 430 psig and 2700°F.

- **Coal Type:** The process is suitable for processing a wide variety of coals and petroleum coke. Pulverized coal (90% less than 90 microns) is required. The coal is dried to a moisture content of 1 to 6 wt% to reduce oxygen consumption and to improve gas quality.

- **Products:** A high quality synthesis gas, essentially consisting of hydrogen and carbon monoxide (93-98 vol% for oxygen gasification), is formed. Tars, phenols and hydrocarbons heavier than C_1 are absent.

1.0 GENERAL INFORMATION (CONTD.)

- Application: Considered more suitable for production of medium-BTU gas than SNG since no CH_4 is produced.

- Status:
  a) A 250 to 400-tpd unit is being planned for construction by Shell Oil, USA, jointly with several equity partners. The unit, to be located at Deer Park, Texas, is scheduled for startup in 1987.

  b) Shell Oil's plans to construct a 1000-ton/day facility in Moerdijk, Holland and/or Wilhelmshaven, West Germany have been terminated.

2.0 PROCESS DEVELOPMENT

The Shell Coal Gasification Process has been in development since 1973. Both SIPM and Krupp Koppers participated in the initial development of SCGP by utilizing Shell's background in the Shell oil gasification process and Krupp-Koppers' experience in building numerous coal gasification plants employing the Koppers-Totzek process. This led to the two pilot units of 6 MTPD and 150 MTPD capacities, respectively. The 150 MTPD unit was built by Krupp-Koppers and operated by Deutsche Shell AG. The 6-TPD unit has logged more than 6000 hours of operation while the 150 MTPD unit has logged over 5500 hours of coal gasification with the longest run of over 1000 hours. The SCGP is suitable for a wide variety of feedstocks, as discussed in Section 3.0.

To optimize the process, emphasis is being given to the continued development of the following process areas:

- Dry Coal Feeding
- Burner Design
- Quench System
- Waste Heat Boilers
- Ash Recycle
- Gas Cleanup
- Refractory Lining

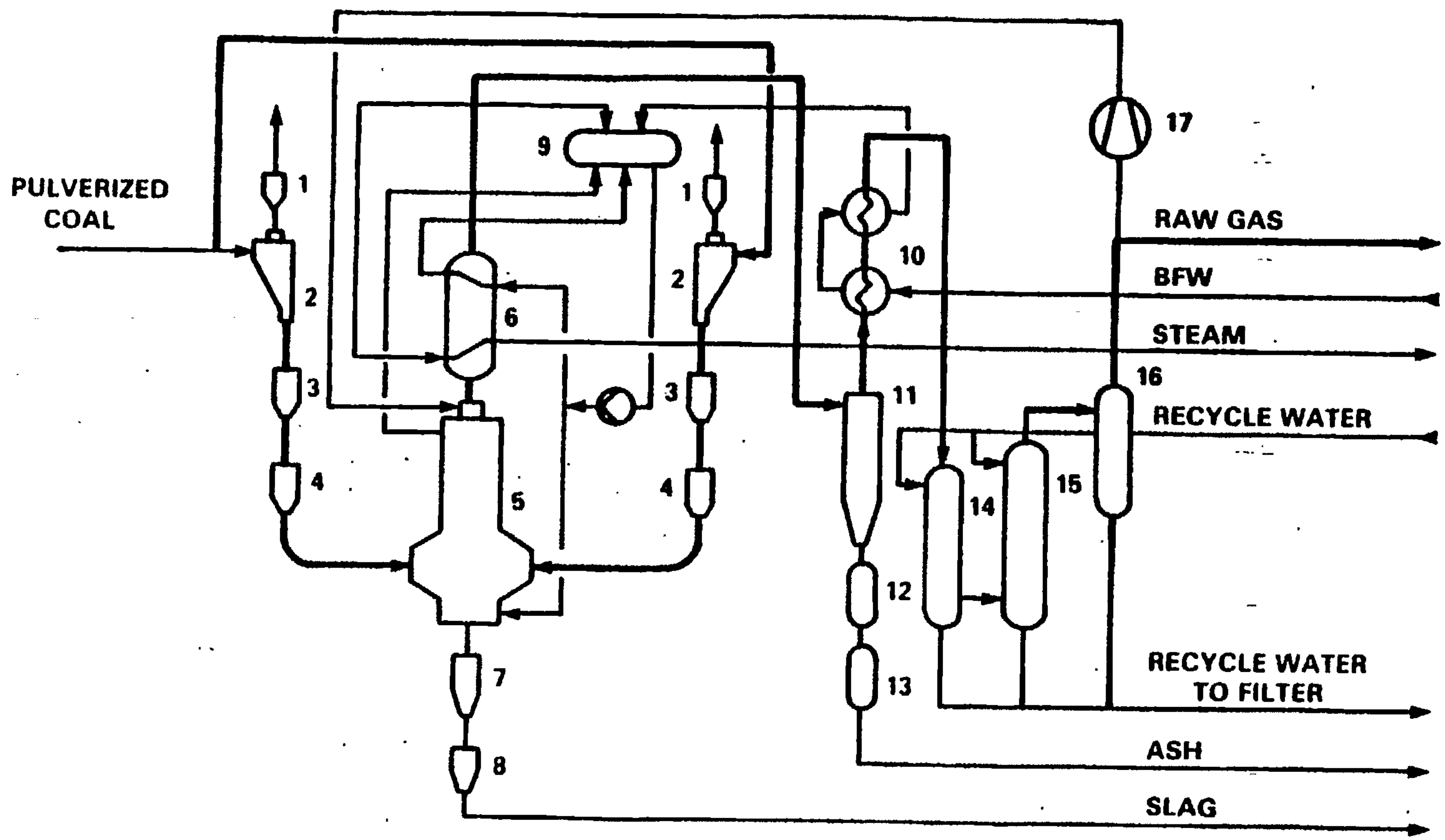
3.0 FEEDSTOCKS TESTED

The SCGP is considered to be suitable for a wide range of coal types including bituminous coal (Illinois #6), sub-bituminous coal (Wyodak), brown coal and coal liquefaction vacuum bottoms. It is considered suitable for processing low rank coals because it utilizes a dry coal-feeding system. Two U.S. coals, Illinois #5 and Texas lignite, were extensively tested in both the 6 MTPD and 150 MTPD pilot units. In addition, the following coals have been tested in the 6 MTPD PDU.

- German Coals
  - Goetelban
  - Rheinbraun
  - Griesborn
  - Auguste Victoria
- Acland Coal (Australia)
- Rietspruit Coal (South Africa)
- Athabasca Fluid Coke (Canada)
- Pittsburgh Coal (U.S.A.)

4.0 PROCESS DESCRIPTION

The Shell Coal Gasification Process (SCGP) as shown in Figure 1, is based on the principle of entrained bed gasification at elevated pressure under slagging conditions. The coal is ground to a fine size (90% less than 90 microns) and dried to a moisture content of 1-6 wt%. Drying of pulverized coal is necessary to promote pneumatic transport, to minimize oxygen consumption in the gasifier and to improve the quality of the product gas. The dry coal is fed to the gasifier via a coal feeding system consisting of the receiving hopper, the lockhopper and the feed hopper. Transport gas for the coal could be either nitrogen or syngas, depending on whether the product gas is used as fuel gas or syngas. Dry coal with oxygen and high pressure steam are fed into the gasifier through one or two diametrically opposed burner pairs. The residence time in the gasification reactor is of the order of a few seconds. Flame temperatures can be as high as 3272°F to 3632°F and reactor outlet temperatures are 2552°F to 2732°F. The reactor shell is protected from hot gases by a tube wall in which high pressure saturated steam is generated and the tube wall is, in turn, protected by a thin layer of refractory material.



1 COAL FILTER

2 CYCLONE HOPPER

3 LOCK HOPPER

4 FEED HOPPER

5 GASIFIER

6 WASTE HEAT BOILER

7 SLAG BREAKER

8 SLAG LOCK HOPPER

TEAM DRUM

10 BFW PREHEATER

11 CYCLONE

12 ASH HOPPER

13 ASH LOCK HOPPER

14 VENTURI

15 SCRUBBER

16 H.P. SEPARATOR

17 RECYCLE GAS COMP OR

Figure 1
Shell Coal Gasification Process.

4.0 PROCESS DESCRIPTION (CONTD.)

The molten slag flows freely down the reactor walls into a water-filled compartment, where it solidifies as glass-like granules, which are crushed in a submerged mill. The slag is then lockhoppered out to atmospheric pressure.

Hot raw gas, containing ash and unconverted particulates, is partially cooled after exiting the gasifier reactor by mixing with cool, clean recycled synthesis gas. The quenched raw gas, at a temperature below the softening temperature of the entrained ash particulates, enters the waste heat boiler, where it is cooled to 600°F producing saturated high pressure steam.

The entrained particulates, which have been solidified during the gas cooling step, are removed in a solids removal system consisting of a cyclone and two scrubbers in series. The majority of the entrained solids are removed by the cyclone located downstream of the waste heat boiler. These are designed such that most of the solids are recirculated to the feed lockhoppers. Gas exiting the cyclones is sent through a low level heat recovery section after which the gas temperature is still well above its dew point. The gas then enters a venturi scrubber and then a trayed scrubber to remove the remaining solids. Gas leaving the final scrubber has a solids content of 1 mg/Nm^3 and a temperature of 100-175°F.

5.0 PERFORMANCE DATA

The SCGP is expected to be able to gasify fuels with high ash (up to 40%) and sulfur (up to 8% by weight) without difficulty. Typical operating data for several coal types are provided in Table 5.1.

The test results from the 6 MTPD and 150 MTPD pilot plants are summarized below.

- Run Length data (thru June 1983)

Total on stream time	=	5500 hours (150 MTPD)
	=	6000 hours (6 MTPD)
Longest run		>1000 hours (150 MTPD)

- Gasifier Performance

Pressure	=	300-600 psig
Temperature	=	2540-2730°F
Carbon Conversion	=	98-99%
Cold Gas Efficiency	=	82%
Gasifier Thermal Efficiency	=	94-97%

5.0 **PERFORMANCE DATA** (CONTD.)

Oxygen Demand	=	0.9-1.0 tons/ton MAF coal (hard coals)
Steam Demand	=	0.08 tons/ton MAF coal (hard coals)
	=	None (brown coal or lignites)
H_2/CO ratio	=	0.55 - 0.45
Heating value of gas	=	300 Btu/SCF (oxygen-blown)

TABLE 5.1
PERFORMANCE DATA FOR SEVERAL FEEDSTOCKS

Feedstock	Illinois #6 Bituminous	Wyodak Sub-bituminous	Coal Liquefaction Vacuum Bottoms	German Brown Coal	Auguste Victoria German Coal (Bituminous)
Coal Analysis, Wt % MAF:					
Carbon	78.1	75.6	87.1	67.5	85.5
Hydrogen	5.5	6.0	5.7	5.0	5.2
Oxygen	10.9	16.8	3.3	26.5	6.5
Sulfur	4.3	0.9	2.4	0.5	1.1
Nitrogen	1.2	0.7	1.5	0.5	1.7
	100.0	100.0	100.0	100.0	100.0
Ash, Wt % as rec'vd	12.0	5.9	17.6	6.4	5.6
Moisture, Wt %:					
As Received	6.5	35.0	0.0	60.0	6.5
To Gasifier	2.0	2.0	0.0	5.0	2.0
Heating Value, BTU/lb, LHV	12,095	7,380	12,645	4,295	12,890
Rates, ST/Net MMSCF ($CO+H_2$):					
Total Coal Input	17.9	25.3	15.4	42.6	15.6
Coal to Gasifier	14.9	15.3	15.4	19.5	14.0
Oxygen (99%) Input	12.5	12.3	12.7	13.5	13.4
Steam Input	1.12	0.37	2.68	0.62	2.0
Efficiencies, % LHV:					
Gasifier Thermal Efficiency	83	83	83	79	83
Coal to Raw Gas Efficiency	78	77	77	72	78

TABLE 5.1 (CONTD). PERFORMANCE DATA FOR SEVERAL FEEDSTOCKS

Feedstock	Illinois #6 Bituminous	Wyodak Sub-bituminous	Coal Liquefaction Vacuum Bottoms	German Brown Coal	Auguste Victoria German Coal (Bituminous)
Raw Gas Composition, Vol %:					
Water	1.5	2.6	2.1	11.3	2.2
Hydrogen	31.6	32.5	33.6	26.9	30.8
Carbon Monoxide	64.0	62.8	61.8	55.0	64.7
Carbon Dioxide	0.8	1.3	1.0	6.1	1.2
Methane	—	—	0.1	—	—
H_2S and COS	1.4	0.3	0.7	0.2	0.3
Nitrogen	0.5	0.3	0.5	0.3	0.6
Argon	0.2	0.2	0.2	0.2	0.2
	100.0	100.0	100.0	100.0	100.0

Source: Reference #1

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACTS

- Due to the high operating temperature of SCGP, no tars, phenols, or hydrocarbons heavier than C_1 are produced.
- All the water streams can be recycled for reuse in process or used for cooling tower make-up.
- The slag from the SCGP exhibits low levels of leachability and could be used as a road building material or disposed of by landfill.

7.0 COMMERCIAL DESIGN PLANS

- At present Shell's plans include the installation and operation of a 250-400 tpd coal gasifier. No definite plans exist beyond this demonstration unit although in the past Shell had indicated that 1,000-2,000 tpd prototype units may be commissioned in the late eighties. The ultimate capacities for a single gasifier are expected to be increased stepwise to 2,500 tpd after the lower capacity gasifiers have been successfully demonstrated.
- Fluor has performed a detailed engineering and economic evaluation of Shell-based integrated gasification - combined cycle (IGCC) power plants for EPRI. This evaluation, utilizing Illinois #6 and lignite feedstocks, represents the first publicly available evaluation of SCGP for a U.S. location (5). The study results are as follows:

	Illinois #6	Texas Lignite
Overall System Efficiency (coal to power) % of coal HHV	37.17	34.19
Net Heat Rate, BTU/KWH	9,182	9,983

8.0 ADVANTAGES/DISADVANTAGES

- Advantages

  - Wide range of feedstocks.
  - Dry feeding system which allows processing of high moisture coals (lignites).
  - No liquid by-products.
  - Relatively high thermal efficiency.
  - Low CO_2 and impurities in the product gas.

- Disadvantages

  - Pre-drying of coal necessary for economic reasons.
  - High oxygen consumption compared to Lurgi, but lower than Texaco.
  - May not be suitable for SNG production because of absence of methane in product gas and high oxygen consumption.

9.0 SUMMARY OF TECHNICAL/ECONOMIC EVALUATION

A report prepared by Economic Assessment Service (International Energy Agency) gives technical/economic information for coal-to-SNG plant using Eastern coal. (6) Results of this study are summarized below:

- Table 9-1 Description of Case
- Table 9-2 Plant Performance Data
- Table 9-3 Summary of Total Plant Investment
- Table 9-4 Annual Operating Costs Summary
- Table 9-5 Gas Cost Summary
- Table 9-6 Calculation of Contributions to Gas Cost

- Figure 9-1 Block Flow Diagram for Coal-to-SNG (Typical)

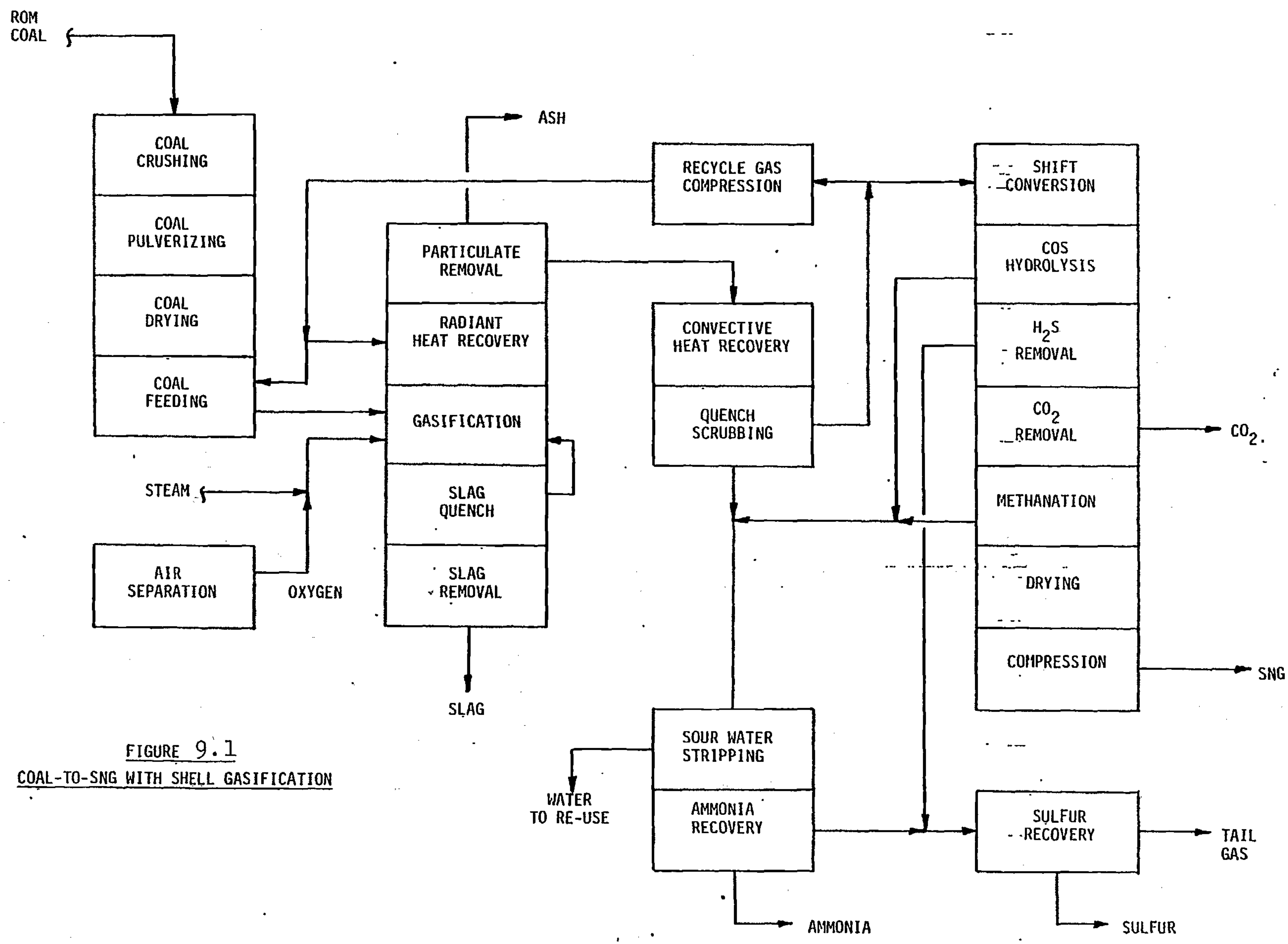


FIGURE 9.1
COAL-TO-SNG WITH SHELL GASIFICATION

TABLE 9-1 (Ref.6)

DESCRIPTION OF CASE

Coal Type		Eastern (Pittsburgh Seam) Bituminous
Evaluation Contractor		IEA Economic Assessment Service
Project Report No.		EAS Report E2/80
Date Published		January 1983
Cases Evaluated:	Shift	With conventional shift conversion unit
	HCM	With BGC combined shift/methanation unit

Coal Properties:

Proximate Analysis, Wt%, as received:

Moisture	6.0
Volatile Matter	31.9
Fixed Carbon	51.5
Ash	10.6
	100.0

Ultimate Analysis, Wt%, dry basis:

Carbon	71.50
Hydrogen	5.02
Nitrogen	1.23
Oxygen	6.53
Sulfur	4.42
Ash	11.30
	100.00

Heating Value, HHV, as received, BTU/lb	12,400

TABLE 9-2 (Ref. 6)

PLANT PERFORMANCE DATA

	Shift Case	HCM Case
Plant Capacity, MMM BTU/day	250	250
Flow Rates, tons/hour:		
Coal to Gasifiers	626	630
Coal to Boilers	57	25
Total Coal Input	683	655
Oxygen to Gasifiers	490	493
Steam to Gasifiers	11	11
Product Gas Rate, dry MMSCFD	270	262
Plant Thermal Efficiency, %	55.8	59.1
Raw Gas Properties:		
Composition, dry vol %:		
Hydrogen	26.8	
Carbon Monoxide	68.5	
Carbon Dioxide	0.5	
Methane	1.8	
Nitrogen & Argon	0.7	
H_2S and COS	1.7	
	100.0	
Heating Value, HHV, BTU/SCF	331	

TABLE 9-3 (Ref. 6)

SUMMARY OF TOTAL PLANT INVESTMENT COSTS

	Shift Case	HCM Case
COSTS, mid-1979, $MM:		
Coal Handling & Preparation	76	77
Gasification, Shift and Gas Cooling	384	286
Oxygen Plant	236	238
Acid Gas Removal and Sulfur Recovery	295	329
Methanation (or HCM), Compression & Drying	75	105
Ash and Sludge Handling	20	20
Process Condensate Treatment	51	2
Steam and Power	142	124
Cooling Water System	26	24
Balance of Plant	179	165
Total Facility Construction Investment (TFCI)	1,484	1,370
Project Contingency (PC, 15%)	223	205
TFCI with PC	1,707	1,575
Initial Charge of Catalysts and Chemicals	10	6
Paid-Up Royalties	43	39
Startup Costs (Note 1)	22	21
TOTAL PLANT INVESTMENT	1,782	1,641
Working Capital (Notes 1 & 2)	90	80

NOTES:

1. Assuming coal cost at $1.00/GJ or $26.15/ST.
2. Assuming 10% DCF rate-of-return.

TABLE 9-4 (Ref. 6)

ANNUAL OPERATING COSTS SUMMARY

	Shift Case	HCM Case
OPERATING COSTS, mid-1979, $MM/year:		
Coal (Note 1)	146.67	140.56
Purchased Water (Note 2)	3.23	3.30
Catalysts and Chemicals	10.45	9.14
Operating Labor	6.08	6.08
Maintenance (Note 3)	63.15	58.26
Insurance and Local Taxes	51.20	47.24
Gross Operating Costs	280.78	264.58
Byproduct Credits:		
Export Power (Note 4)	0.00	5.34
NET ANNUAL OPERATING COSTS	280.78	259.24

NOTES:

1. Coal cost = $1.00/GJ or $26.15/ST.
2. Water cost = $0.76/1000 US gallons.
3. Maintenance materials and labor are each 2% of TFCI per year.
4. Power value = $0.04/KWH.

TABLE 9-5 (Ref. 6)

SUMMARY OF GAS COSTS

GAS COSTS, $/MMBTU, mid-1979:
(Zero PDA)

	Shift Case	HCM Case
DCF Rate of Return:		
5%	6.23	5.76
10%	8.73	8.06
15%	12.23	11.27
Coal Price, $/ST:		
26.15	8.73	8.06
52.30	10.72	9.96
78.45	12.70	11.85

NOTE:

Calculations made assuming a tax rate of 48%, a 10% investment tax credit and use of SOYD depreciation method.

TABLE 9-6

CALCULATION OF CONTRIBUTION TO GAS COST
SHELL GASIFICATION

Coal Type	Illinois # 6
Evaluator	International Energy Agency & EPRI
Project Report No.	E2/80 & EPRI AP-3129
Date Published	Jan.1983 & June
Plant Capacity	250 Billion Btu/day SNG

CAPITAL COSTS :	$ MM (Mid-1982)
Installed Equipment	376.0
Contingency @ 15%	56.4
Direct Facility Constr Investment	432.4
Home-Office costs @ 12%	51.9
Total Facility Constr Investment	484.3
Royalties	20.0
Total Plant Investment	504.3

OPERATING COSTS :			$/hr
Steam(450 psig)	24,200 #/hr	@ $ 5.50/ 1000 lb.	133.1
Oxygen	1,804,600 #/hr	@ $36.00/ 2000 lb.	32482.8
Electricity	17,360 Kw	@ $ 0.05/ Kwh	868.0
Cooling water	150 Gpm	@ $ 0.10/ 1000 Gal	0.9
Steam Credit(1500 psig)	2,373,000 #/hr	@ $ 5.50/ 1000 lb.	-13051.5
TOTAL			20433.3

Total Operating Cost, $ MM/yr at 100 % Stream factor = 7.5 MM $/Yr

CONTRIBUTION TO GAS COSTS :	Specific Cost, $/MM Btu-Yr	Charge Rate, Year	Contribution, $/MM Btu
Capital Related	6.14	0.089	0.55
Operating	0.09	1.000	0.09
Total			0.64

10.0 REFERENCES

1. McCullough, G. R., Roberts, S.C., Van der Burgt, M. J., "Shell Coal Gasification Process," Energy Progress, Vol. 2, No. 2, June 1982, pp 69-72.

2. Synfuels Weekly - "Shell Revamps Coal Gas Development Plans; Mulls Demo," June 11, 1982, Page 1.

   "Shell Achieves Uninterrupted 950-hour Run in Harburg Coal Gas Demonstration Plant." February 11, 1983, Page 3.

3. Nager, M. et al. Evaluation of U.S. Coal Performance in the Shell Coal Gasification Process (SCGP), Research Project RP 2094-1, EPRI AP-2844 Vol. 1 and 2, Final Report, February 1984.

4. Vogt, E.V, and Van der Burgt, M.J., "Status of Shell-Koppers Process," CEP, March 1980, pp 65-72.

5. Hartman, J. J., et al., "Shell-based Gasification-Combined-Cycle Power Plant Evaluation," AP-3129, Final Report, June 1983.

6. Teper, M., Hemming, D.F. and Ulrich, W.C., "The Economics of Gas from Coal," Economic Assessment Service (EAS) of IEA Coal Research, EAS Report E2/80, January 1983.

STATUS SUMMARY

U-GAS GASIFICATION PROCESS

U-GAS GASIFICATION PROCESS

1.0 GENERAL INFORMATION

- **Developer:** Institute of Gas Technology (IGT) and Gas Development Corporation (GDC)
  3424 South State Street
  Chicago, Illinois 60616

- **Type:** Single-stage, air-or oxygen-blown, pressurized, fluidized bed, agglomerating ash gasifier.

- **PDU:** 24 TPD pilot plant at IGT facilities.

- **Conditions:** PDU operates at 1750° to 1900°F (in fluid bed) and 20 to 50 PSIG. Projected commercial SNG conditions: 1875°F, 450 PSIG.

- **Coal Type:** A wide variety of coals can be accepted as feedstocks; most testing has involved Illinois basin coals. See Section 3 for listing.

- **Products:** Synthesis gas contains CO, H_2, and CO_2, along with 4 to 5 vol% CH_4. No tars, phenols or hydrocarbons heavier than C_1 are produced. Ash is rejected as agglomerates.

- **Applications:** Suitable for low, medium and high Btu gas, combined cycle electric power generation; less competitive for hydrogen, methanol, or ammonia because of the necessity to reform methane.

- **Status:** Section 7.0 (commercial design plans) describes previous and current efforts relative to commercial-scale plants. The pilot plant is intact, and a smaller pressurized unit is being erected for use in design basis verification.

2.0 PROCESS DEVELOPMENT

The U-Gas process is a result of research dating back to about 1943, when work began on coal gasification and fluidization at IGT. A 6-inch (diameter) fluidized bed reactor was built in 1947 to investigate the gasification of coal/coke fines. A pilot plant gasifier with a capacity of 18 TPD of coal at 100 PSIG was built in 1950 as part of the HYGAS project.

A 4-foot-diameter, near-atmospheric pressure gasifier was constructed in 1974 and operated until mid-1976 with funding from the Office of Coal Research and the American Gas Association as part of the HYGAS project. This low-pressure gasifier was built to test the concepts of elutriated fines return, carbon utilization, and ash agglomeration using metallurgical coke or char from COED pilot plant as feedstock. During these tests, several process and mechanical changes made to the pilot plant resulted in an improved design. Important milestones of this period were:

- Demonstration of the operability of the gasifier system.
- Perfection of the technique of ash agglomeration and entrained fines recycle (using metallurgical coke feedstock).
- Demonstration of the feasibility of achieving high carbon conversion (in the range of 95%) by utilizing the ash agglomeration technique.
- Operation of the gasifier with both steam-air and steam-oxygen.

As a result of these encouraging results, the U.S. ERDA granted a new contract in 1976 to sponsor modification of the pilot plant to enable feeding of coal to the gasifier and conducting extended-duration tests. Tests were performed in this "U-Gas" pilot plant during 1977 and January 1978, air-blown using Illinois #6 caking coal and sub-bituminous coals. In late 1977 the U.S. DOE selected Memphis Light, Gas and Water Division's (MLGW) proposal to design, construct and operate an industrial fuel gas demonstration plant based on the U-Gas process. During the 15 months following January 1978, 16 air- and oxygen-blown tests were conducted on W. Kentucky #9 coal to establish the design basis for MLGW's demonstration plant. The MLGW plant is designed to operate at 90 PSIA pressure and to produce 50 billion Btu/day of medium-btu gas to be distributed by pipeline to commercial users. A chronological

2.0 PROCESS DEVELOPMENT (CONTD.)

listing of the process development activities in the pilot plant are given in Table 2-1.

TABLE 2-1 TESTING HISTORY IN THE U-GAS PILOT PLANT

PERIOD	NUMBER OF TESTS	FUNCTION
1974	9	Equipment Shakedown
1974-1975	53	Process Feasibility
1975	13	Testing High-Reactive Small-Size Feed
1977	4	Shakedown of Modified Pilot Plant
1977	7	Testing High-Reactive Feedstock
1977	6	First Bituminous Coal Trial Tests
1978	8	Testing Unwashed High-Ash Feedstock
1978-1981	24	Demonstration/Commercial Plant Design Data
1980	3	Testing Highly Caking Feedstock
1981	3	Coal Verification Tests with Different Feedstocks for Clients

Planned further development of the U-Gas process, under support of the Charbonnages de France, involves testing of a 200 metric ton/day fluidized bed at pressures to 500 PSIG.

3.0 FEEDSTOCKS TESTED

- Coals:
  Western Kentucky #9, Bituminous
  Western Kentucky #11, Bituminous
  Illinois #6, Bituminous
  Pittsburgh #8, Bituminous
  Montana, Sub-Bituminous
  Wyoming, Sub-Bituminous
  Lignite

  Polish, Bituminous
  Australian, Bituminous
  French

- Chars:
  Western Kentucky coals
  Illinois #6 coal

- Metallurgical Coke

4.0 PROCESS DESCRIPTION

The U-Gas gasifier (Figure 4-1) is a vertical cylindrical reactor with two external cyclones for returning the elutriated fines to the bed. A sloped grid at the bottom, containing an inverted cone, serves as the oxidant and steam distributor and the agglomerated ash outlet.

In the process, washed or run-of-mine coal (1/4 inch x 0) is dried to the extent required for handling purposes. It is then pneumatically fed into the side of the gasifier from a lockhopper system. Within the fluidized bed, coal reacts with oxygen (or air) and steam at a temperature of 1,750 to 1,900^{o}F. The temperature of the bed depends on the type of coal feed and is controlled by adjustment of the steam/oxygen mixture to maintain non-slagging conditions at all times. The operating pressure of the process may vary between 20 and 600 PSIA depending on the ultimate use of the product gas; the pressure should be optimized for each particular system. At the specified conditions, coal is gasified rapidly, producing a gas mixture of primarily hydrogen, carbon monoxide, carbon dioxide, methane and water vapor. Because reducing conditions are always maintained in the bed, the sulfur present in the coal is converted to hydrogen sulfide and carbonyl sulfide.

As fresh coal gasifies, the ash concentration of individual particles in the bed increases although the gross bed ash content remains constant during steady state operation. As the ash concentration increases, the particles agglomerate into approximately spherical particles and are selectively removed from the bed. The fluidizing gas enters the reactor at two points: 1) through the gas distributor plate, a sloping grid at the bottom of the bed; and 2) through the ash-discharge device located at the center of the distributor plate. The ratio of oxygen-to-steam in the two gas entry streams is such that a greater oxygen-to-steam ratio is maintained in the ash-discharge region. By this mechanism, a higher temperature is maintained in the central zone at the bottom of the bed, wherein ash particles selectively stick to each other in their incipient softening temperature. The agglomerates grow until they can no longer be supported by the gas rising through the ash-discharge device. They are removed and discharged from the bed into water-filled ash hoppers from which they are then withdrawn as a slurry. Thereby, the gasifier achieves the same low level of carbon losses in the discharge ash that is generally associated with slagging gasifiers.

4.0 PROCESS DESCRIPTION (CONTD.)

The fines elutriated from the fluidized bed are separated from the product gas in two stages of external cyclones. The fines from the first stage are returned to the bed while the fines from the second stage are returned to the ash-discharge zone where they are gasified to extinction. They then gasify and agglomerate with the bed ash and are discharged as agglomerates. The product gas is free of tars, phenols and hydrocarbons heavier than C_1, simplifying the heat recovery and purification steps.

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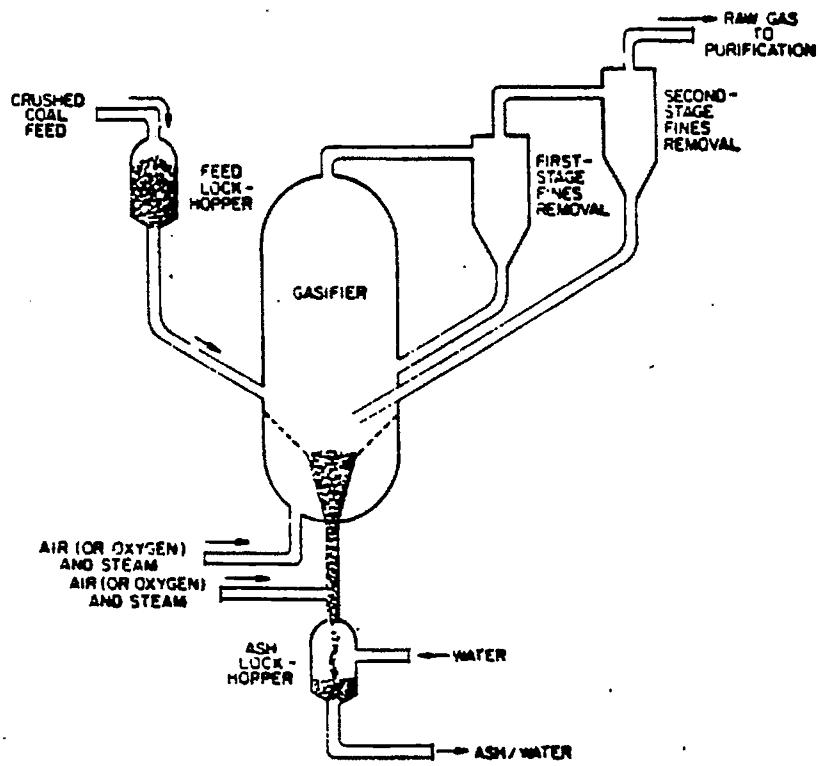

Figure 4-1
U-GAS GASIFIER

5.0 SAMPLE PDU OPERATING DATA

Operation Mode:	Air-Blown	Oxygen-Blown	Oxygen-Blown
Feedstock Type	Illinois #6	ROM W. Kentucky	Washed W. Ky.
Run Duration, hr	12	168	153
Pressure, psia	21	22.5	57.5
Bed Temperature, °F	1821	1815	1850
Coal Feed Rate, lb/hr (dry)	792	1005	1510
Steam Feed Rate, moles/hr	16.5	69.5	160
Oxygen Feed Rate, moles/hr	6.6	19.9	38.4
Superficial Velocity, ft/sec	2.3	4.0	3.4
Ash Discharge Rate, lb/hr	40	207	133
Agglomerate ash content, wt %	72.6	65.7	91.7
Coal utilization efficiency, % (See note 1.)	82	81	86
Product Gas:			
Composition, dry vol. %.			
Carbon Monoxide	18.8	28.6	22.6
Carbon Dioxide	10.9	22.1	29.5
Hydrogen	16.4	45.6	43.1
Methane	1.0	2.6	4.0
Nitrogen	52.9	1.1	0.8
HHV, BTU/SCF	123	266	253

NOTES:

1. Based on coal input compared with carbon lost in ash discharge and fines.
2. Source of data: Reference 2.

6.0 BY-PRODUCTS AND ENVIRONMENTAL IMPACTS

- The process does not produce any hydrocarbon liquids, thus reducing the process condensate treatment requirements.
- The ash, as spherical agglomerates, does not contain significant amounts of carbon and can probably be disposed of by landfill.

7.0 COMMERCIAL DESIGN PLANS

The preliminary design of MLGW plant was completed at the end of 1979 and detailed design was started in February 1980. In June, 1981 the new (Reagan) administration transferred funding for all commercial plant projects to the newly-formed Synthetic Fuels Corporation (SFC) from DOE. MLGW applied and received price and loan guarantees from SFC, but has not assembled the required equity partners.

In 1982, VEG - Gas Institute of the Netherlands had selected the U-Gas process as the basis for a small, high pressure gasification pilot plant to be in Amsterdam. Also, Gaz de France had selected the U-Gas process to produce medium-btu gas from a variety of coal feedstocks. Neither of these projects is currently active.

In June 1983, Charbonnages de France (CdF) selected the U-Gas process as the coal gasification technology to be utilized commercially and licensed worldwide by CdF as a U.S./French effort. The initial work planned is to design and construct a 200 metric ton/day gasifier to be located at Mazingarbe in Northern France to further refine the technology for French application. Startup of this demo gasifier is scheduled for late 1986. It is anticipated that the first commercial application by CdF will be for production of ammonia and/or methanol using French coal.

8.0 SUMMARY OF TECHNICAL/ECONOMICAL EVALUATIONS

- Results of technical and economic evaluations of U-Gas coal gasification process for production of 250 billion Btu/day SNG (7). Cost tables have been updated from 3rdQ' 1980 to 2ndQ' 1982.

LIST OF TABLES

8.0 SUMMARY OF TECHNICAL/ECONOMIC EVALUATIONS (CONTD.)

LIST OF FIGURES

TABLE 8.1

DESCRIPTION OF CASE

COAL TYPE	Pittsburgh #8
Location Basis	Eastern U.S.A.
Evaluating Contractor	M. W. Kellogg Co.
Date Published	July 1981

COAL PROPERTIES:

Proximate Analysis, wt. %:	
Moisture	6.0
Volatile Matter	31.9
Ash	10.6
Fixed Carbon	51.5
	100.0
Ultimate Analysis (dry), wt %:	
Carbon	71.50
Hydrogen	5.02
Oxygen	6.53
Nitrogen	1.23
Sulfur	4.42
Ash	11.30
	100.00
Heating Value, HHV, BTU/lb	13,190

TABLE 8.2

COAL-TO SNG PLANT OVERALL MATERIAL BALANCE

FEEDSTOCK	Pittsburgh #8 Coal
INPUTS, M lb/hr:	
Coal (MF) to Gasifiers	1,236.9
to Boilers	122.9
Oxygen to Gasifiers	622.1
Combustion Air:	
To Boilers	2,126.4
To Sulfur Plant	376.5
To Flue Gas Treatment	7.2
Raw Water Supply	4,430.0
TOTAL INPUTS	8,962.0
OUTPUTS, M lb/hr:	
SNG Product	487.8
Sulfur from:	
Sulfur Recovery	50.6
Flue Gas Treating	5.4
Ammonia Byproduct	8.3
Gas to Stack	4,387.2
Ash from Gasifiers	126.3
from Boilers	27.0
Evaporation Losses:	
Raw Water Pond	44.3
Cooling Tower	3,523.0
Solids from Water Treatment	50.7
Water to Solids Disposal	202.8
Miscellaneous Losses	48.6
TOTAL OUTPUTS	8,962.0

TABLE 8.3

COAL-TO-SNG PLANT OVERALL ENERGY BALANCE

FEEDSTOCK	Pittsburgh #8 Coal
INPUTS: (MMBTU/hr, HHV)	
Coal to Gasifiers	15,337.6
Coal to Boilers	1,524.0
TOTAL INPUTS	16,861.6
OUTPUTS: (MMBTU/hr, HHV)	
SNG Product	10,413.0
Sulfur Byproduct	226.2
Ammonia Byproduct	75.6
SUBTOTAL	10,714.8
Consumption and Losses	6,146.8
TOTAL OUTPUTS	16,861.6
EFFICIENCIES, %	
Plant Cold Gas	61.8
Plant Thermal	63.5

TABLE 8.4

SUMMARY OF GASIFIER FLOWS AND COMPOSITIONS

Flow Rates, lb/1000 lb coal:

Steam @ 1,000 deg F	799
Oxygen (98%) @ 400 deg F	526
CO_2 Transport Gas @ 280 deg	141
Ash Agglomerates	102.1
Fines to Cyclones	1070
Fines Recycled	1040
Fines Loss	30

Product Gas:

Rate, lb mol/1000 lb coal	112.95
Composition, vol%:	
Carbon Monoxide	27.83
Carbon Dioxide	15.90
Hydrogen	26.68
Water	20.71
Methane	6.91
Hydrogen Sulfide	1.08
Nitrogen	0.48
Carbonyl Sulfide	0.05
Ammonia	0.36
	100.00

Solid Discharges:

Stream	Agglomerates	Fines
Composition, wt%:		
Carbon	6.5	57.90
Hydrogen	0.1	0.45
Sulfur	0.1	1.20
Nitrogen	0.3	0.45
Ash	93.0	40.00
	100.0	100.0

TABLE 8.5

250 BILLION BTU/DAY COAL-TO-SNG FACILITY

FACILITIES CONSTRUCTION INVESTMENT

	$MM (2Q82)	%
ONSITE FACILITIES:		
Coal Preparation	49.9	13.3
Gasification & Quench	66.7	17.8
Shift and Methanation	23.9	6.4
H_2S Removal	48.0	12.8
CO_2 Removal	42.5	11.3
Drying and Compression	11.3	3.0
CO_2 Supply System	13.4	3.6
Sulfur Recovery	55.5	14.8
Sour Water Stripping	8.9	2.4
Ammonia Recovery	5.6	1.5
BASE ONSITE FCI	325.7	87.0
Project Contingency (15%)	48.9	13.0
ONSITE FCI WITH PC	374.6	100.0
OFFSITE FACILITIES:		
Flue Gas Treatment	46.7	8.4
Air Separation	173.2	31.2
Boilers & Superheaters	73.3	13.2
Power Generation	22.1	4.0
Water Pretreatment	10.9	2.0
Boiler Feedwater System	13.5	2.4
Coal Receiving	19.4	3.5
Cooling Water System	19.0	3.4
Solids Disposal	15.8	2.8
Wastewater Evaporater	7.6	1.4
SUBTOTAL	401.5	72.4
General Facilities	80.8	14.6
BASE OFFSITE FCI	482.3	87.0
Project Contingency (15%)	72.3	13.0
OFFSITE FCI WITH PC	554.6	100.0
TOTAL FCI WITH PC	929.2	

TABLE 8.6

250 BILLION BTU/DAY COAL-TO-SNG FACILITY

SUMMARY OF FACILITIES CONSTRUCTION INVESTMENT (TFCI)

	$MM (2Q82)	%
ONSITE FACILITIES:		
Base FCI	325.7	31.3
Project Contingency (PC)	48.9	4.7
Onsite FCI with PC	374.6	36.0
OFFSITE FACILITIES:		
Plant Areas	401.5	38.6
General Facilities	80.8	7.8
Base FCI	482.3	46.3
Project Contingency (PC)	72.3	6.9
Offsite FCI with PC	554.6	53.3
Direct FCI without PC	808.0	77.6
with PC	929.2	89.3
Engineering & Design Costs	55.7	5.4
Contractor's Overhead & Profit	55.7	5.4
TOTAL FACILITY CONSTRUCTION INVESTMENT	1,040.6	100.0

TABLE 8.7

250 BILLION BTU/DAY COAL-TO-SNG FACILITY

SUMMARY OF CAPITAL COSTS

	$MM, 2Q82
CAPITAL COSTS:	
Total Facilities Construction Investment, with PC	1,040.7
Initial Charge of Catalysts and Chemicals	40.6
Paid-Up Royalties	8.7
Startup Costs	64.0
Total Plant Investment	1,154.0
WORKING CAPITAL:	
Coal Storage Inventory	25.1
Materials & Supplies	9.3
Spare Parts	10.0
Working Capital (Consumables and Spare Parts)	44.4

TABLE 8.8

250 BILLION BTU/DAY COAL-TO-SNG FACILITY

SUMMARY OF FIRST YEAR OPERATING COSTS (100% Stream Factor)

	$MM/year (2Q82)	%
Fuel (Coal) cost, first year	208.4	65
Solid waste disposal	2.0	1
Catalysts & chemicals	7.4	2
Purchased (raw) water	3.5	1
Direct Labor:		
Operations	4.5	1
Maintenance	24.6	8
Overhead Costs:		
Benefits	7.3	2
Supervision	7.3	2
General Plant	13.1	4
Corporate	8.7	3
Supplies	1.4	0
Maintenance supplies	16.4	5
Local taxes & insurance	15.6	5
Total Variable Operating and Maintenance Costs, First Year (VO&M)	111.8	35
ANNUAL OPERATING COST	320.2	100
Byproduct Credits:		
Sulfur	22.3	7
Ammonia	5.5	2
SUBTOTAL	27.8	9
TOTAL NET OPERATING COST	292.4	91

NOTES:
1. Coal Price is $35.00/ST.
2. Sulfur Price is $100.00/LT.
3. Ammonia Price is $150.00/ST.
4. Raw Water Price is $0.75/1000 gallons.
5. Process Labor Rate is $10.30/hour (8760 hours/year).
6. Stream Factor for operation = 0.9.

TABLE 8.9

250 BILLION BTU/DAY COAL-TO-SNG FACILITY

LEVELIZED CONSTANT-DOLLAR COST OF GAS (Without PDA)

	$/MMBTU	Percent
LEVELIZED COSTS, Mid-1982:		
Capital-related Cost	1.21	23.3
Variable Operating and Maintenance Costs	1.32	25.4
Fuel Cost	2.84	54.7
Byproduct Credits	-0.30	-5.7
Working Capital:		
Consumables & Spare Parts	0.08	1.6
Net Accounts Receivable	0.03	0.7
LEVELIZED, CONSTANT-DOLLAR COST-OF-GAS	5.20	100.0

TABLE 8.10

CALCULATION OF CONTRIBUTION TO GAS COST
U-GAS GASIFICATION

Coal Type	Pittsburgh # 8
Evaluator	M.W.Kellogg Co.
Project Report No.	FE-2778-45
Date Published	July 1981
Plant Capacity	250 Billion Btu/day SNG

CAPITAL COSTS :

	$ MM (Mid-1982)
Installed Equipment	66.7
Contingency @ 15%	10.0
Direct Facility Constr Investment	76.7
Home-Office costs @ 12%	9.2
Total Facility Constr Investment	85.9
Royalties	15.0
Total Plant Investment	100.9

OPERATING COSTS :

			$/hr
Steam(750 psig)	988,400 #/hr	@ $ 5.50/ 1000 lb.	5436.2
Oxygen	662,100 #/hr	@ $36.00/ 2000 lb.	11917.8
Electricity	22,545 Kw	@ $ 0.05/ Kwh	1127.3
Cooling water	10,410 Gpm	@ $ 0.10/ 1000 Gal	62.5
Steam Credit(1500 psig)	603,200 #/hr	@ $ 5.50/ 1000 lb.	-3317.6
TOTAL			15226.1

Total Operating Cost, $ MM/yr at 100 % Stream factor = 5.6 MM $/Yr

CONTRIBUTION TO GAS COSTS :

	Specific Cost, $/MM Btu-Yr	Charge Rate, Year	Contribution, $/MM Btu
Capital Related	1.23	0.089	0.11
Operating	0.07	1.000	0.07
Total			0.18

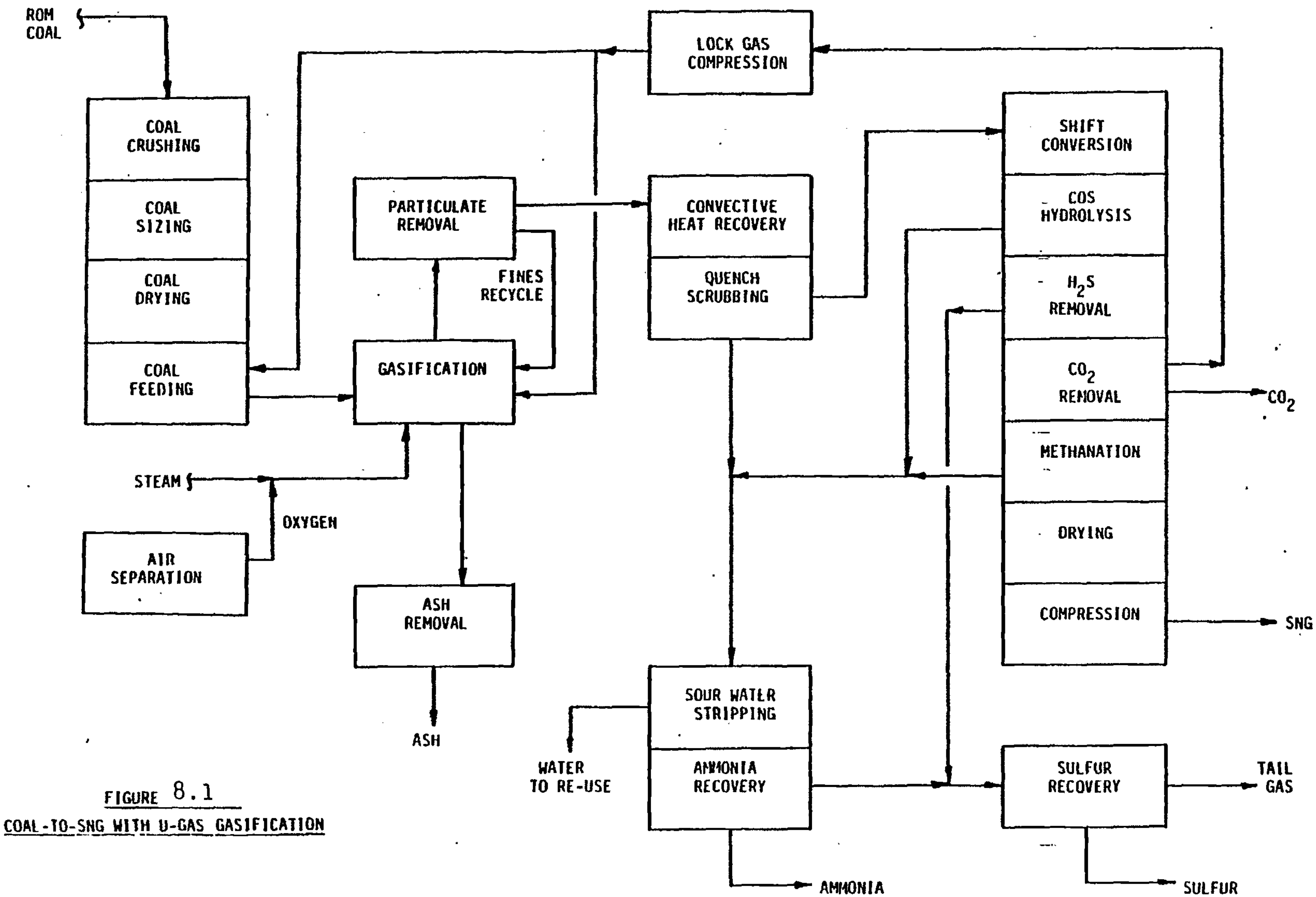

FIGURE 8.1
COAL-TO-SNG WITH U-GAS GASIFICATION

9.0 ADVANTAGES AND DISADVANTAGES

- Advantages
  - Applicable to a wide variety of coals
  - High carbon conversion
  - No tar, phenol or oil produced
  - Agglomerated Ash
  - High turndown ratio
  - High capacity per gasifier
- Disadvantages
  - High caking coals need pretreatment
  - Technology not proven on large scale unit
  - Close temperature control required to achieve agglomeration.

10.0 REFERENCES

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5. Parekh, R.D., "Handbook of Gasifiers and Gas Treatment Systems," prepared for U.S. DOE, WD-TR-821008-010, September 1982.
6. In-House Data on U-Gas Pilot Plant Operations Provided by IGT.
7. Bostwick, L. E., et al., "Technical and Economic Comparisons of the Westinghouse and I.G.T. U-Gas Coal Gasification Processes," by M. W. Kellogg Company, for DOE/GRI, FE-2778-45, July 1981.
8. "SYNFUELS", July 8, 1983, Page 1.

11.0 COMPARISON OF PERFORMANCE/DESIGN PARAMETERS

The GRI/Advisors Planning and Strategy (GAPS) Committee was established to develop a plan for guiding of research in the area of fossil fuel gasification. As an initial step, the committee has developed a procedure for evaluating fossil fuel gasification processes by setting up performance criteria to evaluate processes. This allows the identification of specific advantages and disadvantages of various processes and to establish research goals for process improvement and new process development. The "MUSTS" in gasification technology are shown in Table 11-1. The technical criteria and standards developed for gasification technology appear in Table 11-2. A brief description and explanation of the same is provided where appropriate. Tables 11-3 and 11-4 summarize the performance of the eight (Lurgi, GKT, Texaco, BGC/Lurgi, Westinghouse, Exxon, Shell and U-Gas) gasification processes. All the data in these tables are extracted from the respective status summary reports and from the public sources; wherever necessary, engineering judgement has been applied in consolidating the information. It should be noted that these data are based on current publicly available resources; as more data are developed or made available to the public by the licensors, these tables could be updated. Footnotes at the end of the tables are provided for additional clarification.

TABLE 11-1

'MUSTS' IN GASIFICATION TECHNOLOGY SELECTION

The gasification technology being considered must:

1. Be capable of processing at least two types of coal (i.e., Anthracite, Bituminous, Sub-bituminous or Lignite found in the contiguous U.S.A.

2. In the context of SNG manufacture, show a plant cold gas efficiency of at least 57% and a plant thermal efficiency of at least 59%.

3. Generate only residues which are disposable using available technology, i.e., solid residues suitable for landfill without major environmental control, liquid residues convertible to disposable effluents and gaseous residues convertible to ventable effluents.

4. Require no exotic materials of construction.

5. Be developed such that the basic process concept is confirmed.

TABLE 11-2

TECHNICAL CRITERIA AND STANDARDS FOR COAL GASIFICATION TECHNOLOGY

CRITERION	DESCRIPTION	STANDARD	EXPLANATION
1.0 Feedstock Processing Capability			
1.1 Coal Types	Ability to process two or more types of coal.	> 2	Performance must be established with at least two coal types.
1.2 Plant Fines Utilization	Plant design should not call for export of undersized fines.	100%	Allowance can be made for losses during transport/storage: all fines not fed to gasifiers should go to boilers; electric power export not allowed by Guidelines.
1.3 Size Consist	Degree of crushing, grinding and screening required.	-2" +1/4"	Acceptance of wide size distribution is desirable; index vs. Lurgi.
1.4 Pretreatment	Chemical modification of feedstock.	None	Pretreatment, e.g. oxidation, is not desirable.
1.5 Drying	Removal of feedstock moisture.	None	Use of coal with any moisture content is desirable.
2.0 Carbon Conversion			
2.1 Gross Conversion	Fraction of coal carbon converted to gas & liquid within gasifier.	95 %	Basis: Median value.
2.2 Syngas yield	Molar ratio of contained + potential CH_4 to carbon in coal feed.	37.1% (L)	$(CH_4+(CO+H_2)/4)$/coal carbon, based on Dry-bottom Lurgi.
3.0 Process Efficiencies			
3.1 Plant Cold Gas	Net SNG/total coal to plant, HHV.	57 %	Basis: Dry-bottom Lurgi, Eastern coal.
3.2 Plant Thermal	(Net SNG + byproducts)/total coal to plant, HHV.	59 %	Basis: Dry-bottom Lurgi, Eastern coal.
4.0 Combustible By-products			
4.1 Gasifier Fines	Solids from the gasifier which contain carbon but are not recycled.	None	Fines production lowers carbon conversion; compare as ratio of fines/coal feed.
4.2 Gasifier Liquids	C5+ hydrocarbons coproduced.	None	Liquids produced reduce specific make of gas and increase waste treatment requirements; as weight ratio of liquids/coal feed.

TABLE 11-2

TECHNICAL CRITERIA AND STANDARDS FOR COAL GASIFICATION TECHNOLOGY

(continued)

CRITERION	DESCRIPTION	STANDARD	EXPLANATION
5.0 Reagent Utilization			
5.1 Oxygen		0.8	Lb/lb MAF coal; lower ratios desired.
5.2 Steam	Used in gasification section.	0.5	Lb/lb MAF coal; lower ratios desired.
5.3 Catalyst & Chemicals	Reagents used to promote gasification.	17.15	As \$(1982)/1000 lb MAF coal; based on replacing 0.8 lb O2/lb + 0.5 lb steam/lb at \$36/ton and \$11/ton, respectively
6.0 Selectivity			
6.1 To Methane	Molar ratio of CH_4 in raw gas to carbon in coal feed.	0.15	Basis: Dry-bottom Lurgi; desirable to exceed standard.
6.2 H_2/CO Ratio	Molar ratio in raw gas.	1.0/3.1	Standard allows direct or conventional methanation, without shifting.
7.0 Impact on SNG Plant Design			
7.1 Number of Process Blocks		< 22	Relative to Dry-bottom Lurgi.
7.2 Complexity		Less	Index relative to Dry-bottom Lurgi.
7.3 Utilities & Reagents	For balance-of-plant; cost/ton of dry coal.	13.24	Relative to Dry-bottom Lurgi.
7.4 Flexibility	Ability to accomodate alternate choices in other process steps.	More	Index relative to Dry-bottom Lurgi.
7.5 Design Viability	Number of extrapolations of key parameters for other process steps.	Minimum	Desirable that gasifier does not call for unproven designs of other steps.
8.0 Gasifier Integrability			
8.1 Feed preparation	Number of steps to prepare ROM coal for gasification.	2	
8.2 Raw Gas Handling	Number of steps to prepare raw gas for conventional further processing.	2	
8.3 Residue Disposal	Number of steps to prepare residue(ash) for disposal.	2	

TABLE 11-2

TECHNICAL CRITERIA AND STANDARDS FOR COAL GASIFICATION TECHNOLOGY

(continued)

CRITERION	DESCRIPTION	STANDARD	EXPLANATION
9.0 Throughput			
9.1 Vessel Capacity	Tons coal/day, per gasifier.	900	Basis: Mark IV Lurgi gasifier.
10.0 Process Techniques			
10.1 Equipment Available	Use of equipment which is readily available or requires minimal extrapolation from proven ranges.	Yes	
11.0 Materials of Construction			
11.1 Availability	M/C available at reasonable cost.	Yes	
11.2 Gasifier Shell/ Lining Life	Shell should be structural steel; Refractory should have one year life.	C.S./1 YR	
11.3 W. H. Recovery System Life	M/C to have service life of 5+ years, using proven materials.	5 years	
12.0 Complexity			
12.1 Gasifier Stages	Number of reaction stages(coal beds to accomplish gasification).	1	
12.2 Gasification Area Steps	Number of unit operations.	6	Basis: Dry-bottom Lurgi; Desirable to reduce that number.
12.3 Area Recycles	Return of unreacted solids and/or liquid byproducts to gasifier.	1	Allows for fines recycle.
12.4 Mechanical	Internal moving parts,baffles,etc.	None	Index relative to Westinghouse.
13.0 Severity			
13.1 Temperature	Maximum in gasifier vessel	1200 F	
13.2 Pressure		250-600 psig	
14.0 Controllability			
14.1 Control System	Use existing control techniques or only minimal extrapolations.	Yes	Index relative to Dry-bottom Lurgi.
14.2 Turndown	Fraction of normal rate to which flows can be reduced without loss of stability.	50 %	
14.3 Response	Respond adequately to significant variations in key design parameters.	More	Index relative to Dry-bottom Lurgi.

TABLE 11-2

TECHNICAL CRITERIA AND STANDARDS FOR COAL GASIFICATION TECHNOLOGY

(continued)

CRITERION	DESCRIPTION	STANDARD	EXPLANATION
15.0 Reliability			
15.1 Standby Requirement	Requirement of spare gasifiers.	6/7	Basis: Lurgi for Great Plains
15.2 Consequence of Failures	Liklihood that loss of key reactant flow would severely damage gasifier or associated equipment.	Low	
15.3 Maintenance Extent	Extent to which repairs and/or adjustments are necessary relative to typical process equipment.	Less	Index relative to Dry-bottom Lurgi.
16.0 Environmental Considerations			
16.1 Solid Effluents	Number of steps other than mixing and impoundment required.	None	
16.2 Liquid Effluent	Number of steps required other than stripping and waste water evaporation.	None	
16.3 Gaseous Effluent	Number of steps other than dust removal, tail gas treatment and incineration required.	None	

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TABLE 11-3

PERFORMANCE OF GASIFICATION TECHNOLOGIES VS. CRITERIA

CRITERIA AND SUBCRITERIA	EXPLANATION	LURGI	GKT	TEXACO	BGC/LURGI
1.0 FEEDSTOCK PROCESSING CAPABILITY					
1.1 Coal Types	Standard types of contiguous USA.	Can process lignite and non-caking coals.	Can process all types of coal.	Can process all types but must limit moisture.	Can process all coal types except highly-caking.
1.2 Plant Fines Utilization	% of ROM coal sizes used as feedstock.	Feed + 1/4 in. upto 7-10% -1/4in. acceptable	No lower limit on coal size.	No lower limit on coal size.	Feed + 1/8 in. upto 25-35% -1/8in acceptable
1.3 Size Consist		-2 in + 1/4 in	-20 mesh	-14 mesh	-2 in + 1/8 in
1.4 Pretreatment		Not required.	Not required.	Not required.	Not required.
1.5 Drying		Not required for upto 35%	To 2 - 8% req'd.	Req'd for high-moisture coals.	Not required.
2.0 CARBON CONVERSION					
2.1 Gross Conversion	Of coal carbon.	99%	90%(E) 98%(L)	95 - 98%	99%
2.2 Syngas Yield	((CO+H2)/4)+CH4 from coal carbon.	37.0%(E) 37.1%(L)	31.8%(E)	29.8%(E)	39.7%(E)
3.0 PROCESS EFFICIENCIES					
3.1 Plant Cold Gas	SNG vs. Net Coal Input to Plant.	57%(E) 66%(W) 65%(L)	52%(E)	55%(E)	60%(E)
3.2 Plant Thermal	SNG + Byproducts vs. Net Coal Input to Plant.	59%(E) 67%(W) 66%(L)	53%(E)	56%(E)	62%(E)
4.0 COMBUSTIBLE BYPRODUCTS					
4.1 Gasifier Fines		None.	Produces fines.	None.	None.
4.2 Gasifier Liquids	Lb/Lb MAF Coal	0.029	None.	None.	0.20

TABLE 11-3 (Cont'd)

PERFORMANCE OF GASIFICATION TECHNOLOGIES VS. CRITERIA

CRITERIA AND SUBCRITERIA	EXPLANATION	LURGI	GKT	TEXACO	BGC/LURGI
5.0 REAGENT UTILIZATION					
5.1 Oxygen	Lb/Lb MAF coal	0.4 - 0.7(E) 0.36(W) 0.36(L)	0.95(E) 0.86(W)	1.1(E)	0.6(E)
5.2 Steam	Lb/Lb MAF coal	1.90(E) 1.34(W) 1.80(L)	0.35(E) 0.18(W)	None required.	0.4(E)
5.3 Catalysts and Chemicals	Value, $/K# MAF Coal	None required.	None required.	None required.	Fluxing agent. (?????)
6.0 SELECTIVITY					
6.1 To Methane	Mol CH4 per mol of coal carbon.	0.17(E) 0.15(L)	0.001(E)	0.003(E)	0.074(E)
6.2 H2/CO Ratio	Ratio, mol/mol, in raw syngas.	2.57(E) 2.48(L)	0.63(E) 0.56(W)	0.9(E)	0.44(E)
7.0 IMPACT ON SNG PLANT DESIGN					
7.1 Number of Process Blocks		24	24	21	27
7.2 Complexity	Index.	1.0	0.8	0.9	1.0
7.3 Utilities and Reagents	Value, $ per ton of coal feed.	$13.24(E) $ 4.44(W) $ 2.76(L)	No data.	$7.26(E)	$9.58(E)
7.4 Flexibility	Index.	1.0	1.1	1.1	1.0
7.5 Design Viability	Extrapolations.	None required.	None required.	None required.	None required.

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TABLE 11-3 (Cont'd)

PERFORMANCE OF GASIFICATION TECHNOLOGIES VS. CRITERIA

CRITERIA AND SUBCRITERIA	EXPLANATION	LURGI	GKT	TEXACO	BGC/LURGI
8.0 GASIFIER INTEGRABILITY					
8.1 Feed Preparation	No.of operations	4	5	4	5
8.2 Raw Gas Handling	No.of operations	4	5	4	4
8.3 Residue Disposal	No.of operations	3	2	2	2
9.0 THROUGHPUT					
9.1 Vessel Capacity	Per gasifier.	900 - 1100 TPD	850 TPD	1000 TPD	1875 (?) TPD
10.0 PROCESS TECHNIQUES					
10.1 Equip't Available	Standard vessels.	Yes	Yes	Yes	Yes
11.0 MATERIALS OF CONSTRUCTION					
11.1 Availability	None exotic.	Yes	Yes	Yes	Yes
11.2 Gasifier Shell Material		C Steel	C Steel	C Steel	C Steel
11.3 Waste Heat Recovery System	Expected life.	5 years.	5 years.	No comm'l demo.	Same as Lurgi.
12.0 COMPLEXITY					
12.1 Gasifier Stages		Single stage.	Single stage.	Single stage.	Single stage.
12.2 Gasification Area Steps Required	No. of steps	6	5	5	6
12.3 Area Recycles	Gas, liquid, and/or solid.	1 recycle.	No recycle.	1 recycle.	1 recycle.
12.4 Mechanical	Index.	[illegible]	0.5	0.5	0.75

TABLE 11-3 (Cont'd)

PERFORMANCE OF GASIFICATION TECHNOLOGIES VS. CRITERIA

CRITERIA AND SUBCRITERIA	EXPLANATION	LURGI	GKT	TEXACO	BGC/LURGI
13.0 SEVERITY					
13.1 Temperature	deg F	1800-2500 Combus. 1150-1500 Gasif. 700-1100 Exit	3300-3500 React. 2750 Exit	2200-2900 Gasif.	800-950 Exit
13.2 Pressure	psig	350 - 450	Atmos.+	300 - 1200	450
14.0 CONTROLLABILITY					
14.1 Control System	Index.	1.0	1.0	1.0	1.0
14.2 Turndown	% of full rate.	25%	30%	50%	25%
14.3 Response	Index.	1.0	0.9	0.9	1.0
15.0 RELIABILITY					
15.1 Standby Requiremts	Active/total.	6/7	6/7	5/6	9/10
15.2 Consequence of Failures	Risk involved.	Low	Low	Low	Low
15.3 Maintenance Extent	Index.	1.0	1.1	1.0	1.0
16.0 ENVIRONMENTAL CONSIDERATIONS					
16.1 Solid Effluents	Extra steps.	None.	None.	None.	None.
16.2 Liquid Effluents	Extra steps.	Three steps.	None.	None.	Three steps.
16.3 Gaseous Effluents	Extra steps.	None.	None.	None.	None.

TABLE 11-4

PERFORMANCE OF GASIFICATION TECHNOLOGIES VS. CRITERIA

CRITERIA AND SUBCRITERIA	EXPLANATION	WESTINGHOUSE	EXXON	SHELL	U-GAS
1.0 FEEDSTOCK PROCESSING CAPABILITY					
1.1 Coal Types	Standard types of contiguous USA.	Can process all types of coal.	Probably can process all types of coal.	Can process all types of coal.	Can process all types of coal.
1.2 Plant Fines Utilization	% of ROM coal sizes used as feedstock.	Feed must be 90% + 100 mesh.	Feed must be 90% + 100 mesh.	No lower limit on coal size.	Feed must be 90% + 100 mesh.
1.3 Size Consist		-1/4 in + 100 m	-1/8 in + 100 m	90% - 200 mesh	-1/4 in + 100 m
1.4 Pretreatment		None required.	Preoxidation for caking coals.	None required.	None required.
1.5 Drying		Must limit surface moisture.	Req'd before & after catalyst addition.	To 2 - 6% req'd.	Must limit surface moisture.
2.0 CARBON CONVERSION					
2.1 Gross Conversion	Of coal carbon.	95 - 97%	85 - 90%	98 - 99%	96-97%
2.2 Syngas Yield	((CO+H2)/4)+CH4 from coal carbon.	40.1%(E) 32.4%(L)	46.5%(E)	37.0%(E) 35.0%(W)	39.2%(E)
3.0 PROCESS EFFICIENCIES					
3.1 Plant Cold Gas	SNG vs. Net Coal Input to Plant.	63.5%(E) 61%(W) 62%(L)	62%(E)	56%(E)	62%(E)
3.2 Plant Thermal	SNG + Byproducts vs. Net Coal Input to Plant.	65.5%(E) 62%(W) 63%(L)	64%(E)	57%(E)	63%(E)
4.0 COMBUSTIBLE BYPRODUCTS					
4.1 Gasifier Fines		0.081 #/# coal	Catalyst contam, landfilling ?	None produced.	0.024 #/# coal
4.2 Gasifier Liquids		None produced.	None produced.	None produced.	None produced.

TABLE 11-4 (Cont'd)

PERFORMANCE OF GASIFICATION TECHNOLOGIES VS. CRITERIA

CRITERIA AND SUBCRITERIA	EXPLANATION	WESTINGHOUSE	EXXON	SHELL	U-GAS
5.0 REAGENT UTILIZATION					
5.1 Oxygen	Lb/Lb MAF coal	0.68(E) 0.7(L)	None required.	0.9 - 1.0(E)	0.63(E)
5.2 Steam	Lb/Lb MAF coal	0.4(E) 0.43(L)	1.5(E)	0.08(E)	0.96(E)
5.3 Catalysts and Chemicals	Value, $/K# MAF Coal.	None required.	29.10	None required.	None required.
6.0 SELECTIVITY					
6.1 To Methane	Mol CH4 per mol of coal carbon.	0.14(E) 0.11(L)	0.52(E)	0.001(E)	0.132(E)
6.2 H2/CO Ratio	Ratio, mol/mol, in raw syngas.	0.62(E) 0.57(W) 0.89(L)	3.5(E)	0.50(E)	0.96(E)
7.0 IMPACT ON SNG PLANT DESIGN					
7.1 Number of Process Blocks		23 Blocks.	23 Blocks.	24 Blocks.	22 Blocks.
7.2 Complexity	Index.	0.75	0.95	0.8	0.75
7.3 Utilities and Reagents	Value, $ per ton of coal feed.	$5.37(E)	$14.58(E)	$5.77(E)	$5.92(E)
7.4 Flexibility	Index.	1.1	0.8	1.1	1.1
7.5 Design Viability	Extrapolations.	None required.	None required.	None required.	None required.

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