FE-2542-10(Vol.1)
Distribution Category UC-89

PHASE I: THE PIPELINE GAS DEMONSTRATION PLANT

DESIGN AND EVALUATION OF COMMERCIAL PLANT

VOLUME 1

EXECUTIVE SUMMARY

Continental Oil Company
High Ridge Park
Stamford, Connecticut 06904

Prepared for the
U.S. Department of Energy
Division of Coal Conversion
under Contract EF-77-C-01-2542

&B

TABLE OF CONTENTS

ABSTRACT

Contract No. EF-77-C-01-2542 between Continental Oil Company and the U.S. Department of Energy requires Continental Oil to design, construct and operate a Demonstration Plant capable of converting bituminous caking coal into pipeline quality gas. One of the assignments under the contract is to prepare a preliminary process and engineering design, plant capital estimate, and economics, technical, and environmental assessments for a commercial-sized plant.

A Commercial Plant has been designed to manufacture 241.7 million standard cubic feet per stream day of 960 Btu/SCF pipeline quality gas from 21,367 tons per day of Illinois No. 6 coal, including the coal requirements for both gasification and steam/power generation. The product gas is estimated to cost $6.60 per million Btu for industrial financing (12% DCF, 20-year life) and $5.14 per million Btu for public utility financing (average over 20 years). The total plant investment is estimated to be 1.1 billion dollars.

The Commercial Plant is based on commercially-proven processes and technology except for the gasification and methanation steps. The gasification process is based on technology held by British Gas Corporation and Lurgi Kohle und Mineraloeltechnik GmbH. The innovative features of this process applied to bituminous caking coals is being determined on a large pilot plant at Westfield, Scotland. The methanation technology is held by Conoco Methanation Company and was demonstrated on a semi-commercial scale in 1973-74 at Westfield, Scotland.

The plant is designed for "zero" waste water discharge and for minimal discharge of pollutants to the atmosphere. The plant will substantially contribute income and will add jobs to the area in which it is located. The process makes good use of the local coal resource by converting it into a clean gaseous fuel.

1.0 INTRODUCTION

Continental Oil Company and the United States Department of Energy executed Contract No. EF-77-C-01-2542 on May 27, 1977. This contract requires Continental Oil, as Contractor, to analyze, design, construct, test, evaluate, and operate a Demonstration Plant capable of converting high-sulfur bituminous caking coal to a pipeline quality gas.

The contract specifies that the work shall proceed in three phases:

- Phase I - Development and Engineering
- Phase II - Demonstration Plant Construction
- Phase III - Demonstration Plant Operation

The contractual stated cost of Phase I is 24.2 million dollars. The estimated budgetary costs for Phases II and III in 1975 dollars are 170 and 176 million dollars, respectively. More accurate cost estimates for these two phases will be established during Phase I.

Phase I costs are financed entirely by the United States Government. Phase II and III costs will be shared equally by the United States Government and private industry.

Work on Contract No. EF-77-C-01-2542 started on July 1, 1977. One of the task assignments (Task I of Phase I) under the contract is the preparation of a preliminary design of a commercial scale plant based on the process to be demonstrated. The Commercial Plant design was completed in April, 1978. The design consists of a process engineering design, a project engineering design, estimates of capital and operating costs, an economic evaluation, an evaluation of the environmental impact of the plant and process, and a technical assessment of the process.

This report summarizes the work undertaken and completed under Task I. Details of the Task I effort are included in three additional volumes which will be issued separately:

- Volume 2: Process and Project Engineering Design
- Volume 3: Economic Anlaysis and Technical Assessment
- Volume 4: Environmental Assessment and Site Requirements

The Commercial Plant design consists of 21 separate sections which are interconnected, as required, with piping and conveyors. These sections are identified below:

Primary Process Units for Gas Production

Section 100C: Coal and Flux Handling and Preparation
Section 200C: Air Separation
Section 300C: Gasification
Section 400C: Shift Conversion
Section 500C: Gas Cooling
Section 600C: Rectisol
Section 700C: Methanation
Section 800C: Product Gas Compression and Drying

By-product Recovery Process Units

Section 900C: Sulfur Recovery
Section 1000C: Slag Handling and Disposal
Section 1100C: Gas Liquor Separation
Section 1200C: Phenol Extraction
Section 1300C: Ammonia Recovery

Off-site Units

Section 2000C: Water Treatment and Steam Generation
Section 2400C: Cooling Water System
Section 2500C: Plant and Instrument Air System
Section 2700C: Waste Water Treatment
Section 3000C: Flare and Incinerator Facilities
Section 3100C: Tankage
Section 3200C: Shipping and Receiving
Section 4000C: Support Facilities

This summary report presents the highlights of the Task I effort. It includes a simplified process description and conclusions resulting from the economic, technical, and environmental assessments of the process and technology.

2.0 PROCESS DESCRIPTION

The process selected for demonstration by Continental Oil Company has high potential for gasifying high-sulfur bituminous caking coals in an economically and environmentally acceptable manner to produce a clean pipeline quality gas. Such coals, particularly those in the Appalachian Region, are difficult to gasify because of their low reactivity.

This is one of the reasons that the slagging gasifier was selected for the process. Slagging gasification is effected at high temperatures so that the reactivity of the coal is a minor factor in the gasification process. At the same time, a high thermal efficiency is attained by the countercurrent heat exchange between upward flowing gases and a descending bed of coal in the gasification reactor.

The Commercial Plant has been designed to manufacture 241.7 million standard cubic feet per stream day of pipeline quality gas from 16,879 tons per day of Illinois No. 6 coal. An additional 4,488 tons per day of coal are consumed as fuel for on-site steam/power generation.

Illinois No. 6 coal was selected for the Commercial Plant design because this coal is representative of large coal reserves found in Illinois, Indiana, and Kentucky. It is a bituminous caking coal. Other large reserves of bituminous caking coals which can be gasified by the selected process may be found throughout Appalachia in Pennsylvania, West Virginia, Ohio, Virginia, and further south. In fact, the experimental part of the project and the proposed Demonstration Plant are specifically aimed at key Appalachian coal seams.

The properties of the specific coal used for the plant design are shown in Table 1.

The Commercial Plant has been designed to produce a gas product having the following properties:

Gross Heating Value, Btu/SCF	960
Molecular Weight	16.22
Water Content, Lbs/MM SCF, Maximum	7
H_2S, Grains/100 SCF, Maximum	0.25
Total Sulfur, Grains/100 SCF, Maximum	1.0
Composition, Volume%	
Methane	94.29
Hydrogen	2.45
Carbon Monoxide	0.00
Carbon Dioxide	0.80
Nitrogen	2.46
Total	100.00

TABLE 1

PROPERTIES OF COAL FOR PLANT DESIGN

Type	Illinois No. 6
Proximate Analysis	**Weight Percent**
Moisture	12.08
Ash	13.27
Volatiles	30.80
Fixed Carbon	43.85
	100.00
Ultimate Analysis (DAF Basis)	
Carbon	76.55
Hydrogen	5.26
Oxygen	10.92
Nitrogen	1.11
Sulfur	5.95
Chlorine	0.21
	100.00
Coal Heating Value (DAF Basis)	13,650 Btu/Lb
Ash Fusion Characteristic (Reducing)	**°F**
Softening Point	1,911
Melting Point	1,980
Flow Point	2,575

This gas is completely interchangeable with natural gas. The blending of such gases and the acceptance of the blended product by consumers were convincingly demonstrated in a Methanation Program carried out at Westfield, Scotland, in 1973-74.

A simplified block flow diagram of the process is presented in Drawing No. 1911-50-00901 on page 19. This diagram shows the interconnection among the various sections of the plant. The quantity of all input and output streams is also shown. An overall heat and material balance for the Commercial Plant is presented in Table 2.

TABLE 2

OVERALL HEAT & MATERIAL BALANCE

PIPELINE GAS COMMERCIAL PLANT

	Mass Flow Rate Lb/Hr	Gross Heating Value Million Btu/Hr	Per Cent of Heat Value
Input			
Coal to Gasification	1,406,566	14,332.50	79.00
Coal to Boilers	374,000	3,810.95	21.00
Excess Coal Fine	563,707	(Note 1)	-
Total Coal Input	2,344,273	18,143.45	100.00
Flux	69,154	-	-
Air to Air Separation Plant	3,182,671	-	-
Raw Water	6,102,022	-	-
Combustion Air	4,289,242	-	-
Chemicals	7,721	-	-
Total Input	15,995,083	18,143.45	100.00
Products			
Pipeline Gas	430,325	9,666.79	53.28
Naphtha	14,988	265.64	1.46
Oil	21,873	373.24	2.06
Crude Phenols	5,712	73.29	0.40
Anhydrous Ammonia	4,010	38.77	0.21
Sulfur	76,566	307.40	1.70
Sodium Sulfate Purge	3,835	-	-
Coal Fines	563,707	(Note 1)	-
Subtotal Products	1,121,016	10,725.13	59.11
Waste and Vent Streams			
Air Separation Plant Vents	2,443,583	-	-
Combustion & Dryer Vents	6,487,821	-	-
Cooling Tower & Steam System Water to Atmosphere	5,475,300	-	-
Slag to Landfill	251,451	2.42	0.01
Misc. Waste Solids to Landfill	123,140	-	-
Net Water Loss	92,772	-	-
Subtotal Vents & Wastes	14,874.067	2.42	0.01
Heat Loss to Air Cooling	-	2,120.55	11.69
Evaporative Cooling & Heat Loss	-	5,246.36	28.92
Heat of Flux Calcination	-	48.99	0.27
Total Output	15,995.083	18,143.45	100.00

NOTES:

1. The excess coal fines which are sold have not been included in the plant heat balance to avoid distorting the plant efficiencies. These coal fines are an additional feed and product of 5,744.01 Million Btu/Hr.

2.1 Primary Process Units for Gas Production

There are eight primary process units which convert run-of-mine (ROM) coal to the finished pipeline quality gas. These units are listed by section identification in the Introduction. The function of these primary process units is to convert by chemical reactions the carbon and hydrogen in the coal to methane. The weight ratio of carbon to hydrogen in the coal is 14.55 to 1.00 whereas the ratio of carbon to hydrogen in methane is 2.98 to 1.00. Thus, the process must increase the proportion of hydrogen present in the coal to that required for the gas. The process effects this change in the ratio by reacting water with the carbon in the coal to increase the availability of hydrogen and by oxidizing a portion of the carbon in the coal to form carbon dioxide which is removed and vented from the process.

A secondary, but equally important, function of the process is to convert by chemical reactions the sulfur, nitrogen, oxygen, and other non-hydrocarbon elements present in the coal into compounds which can be removed from the gas product. In general, this is done by converting the sulfur to hydrogen sulfide, the nitrogen to ammonia and gaseous nitrogen, and the oxygenated aromatic elements to phenols and water. The inorganic materials present as ash in the coal are removed as a molten slag from the gasifier.

Section 100C: Coal and Flux Handling and Preparation

ROM coal (5" x 0) is transported by overland conveyor from a nearby mine or mines to the plant site. Coal is stored at the plant site in two piles. One pile which serves as dead storage contains a 23-day supply for the plant. This pile provides an emergency coal reserve for times when the coal mine(s) may not be operating. The other pile which is the source of day-to-day coal feed to the plant contains a 7-day supply. This pile will be continually consumed and replenished during plant operations.

The gasifier requires a sized coal feed (2" x 1/4"). ROM coal is crushed and screened to produce the requisite sized coal. Only 60 percent of the ROM coal can be processed to produce this feed. The balance is a coal fines product (1/4" x 0). Part of the coal fines are used as fuel in the steam/power plant. The balance must be sold to outside users for fuel purposes. Most of the coal fines (over 90 percent) are produced during coal mine operations. Underground mining is required for Illinois No. 6 coal, and this type of mining produces more coal fines than does surface mining.

Limestone is required in the gasification process to control the viscosity of the molten slag. Sized limestone is transported to the plant site by truck or rail. It is mixed with the sized coal feed, and the mixture is transported by conveyors to the gasifier feed bunkers.

Petroleum coke is required for start-up of the gasifiers. Sized coke is transported to the plant site by truck or rail. Silo storage is provided for the sized coal feed, limestone, coke, and coal fines.

Section 100C is a single-train operation, but spare equipment has been provided, where necessary, to assure a continuous supply of coal and limestone feed to the gasifiers.

Section 200C: Air Separation

The gasification process requires relatively pure oxygen (98%) to convert the coal to the desired synthesis gas. Any nitrogen present in the oxygen passes through the gas conversion processes and appears in the final gas product as a diluent which adversely reduces its heating value.

The air separation process included in the Commercial Plant is the conventional process for separating oxygen from air by means of low temperature fractionation. Section 200C consists of three separate independent trains. Each train is designed to produce 2,803 tons per day of oxygen.

Section 300C: Gasification

The Gasification Section consists of 12 British Gas/Lurgi slagging gasifiers. The 12 gasifiers make up three independent trains. Each train consists of three operating and one spare gasifiers.

The British Gas/Lurgi slagging gasifier is based on new technology developed by British Gas Corporation of London, England, and Lurgi Kohle und Mineraloeltechnik GmbH of Frankfurt, Federal Republic of Germany. This gasifier is a fixed-bed, slagging gasifier. It has been designed to operate at 450 psia.

The major reactants fed to the gasifier are:

	Lb/Hr
Illinois No. 6 coal (2" x 1/4")	1,406,566
Limestone	69,154
Steam (550 psig, 750°F)	461,673
Oxygen (98%)	648,288
Recycled Tar	102,000

The combined coal and flux stream from Section 100C is fed to the top of the gasifier through lock hoppers, a device which permits feeding solids into a high-pressure vessel. Steam and oxygen are introduced into the bottom of the gasifier through tuyeres. Tar recovered downstream is recycled to extinction to the top of the gasifier and through the tuyeres.

The coal reacts with the steam and oxygen at elevated temperatures in the bottom of the gasifier to produce a synthesis gas which flows upward countercurrently to the downward flow of coal. This countercurrent flow measurably improves the thermal efficiency of the gasifier. The hot gases effect the devolatilization reactions and drive off the coal moisture in the top of the gasifier. The resultant crude synthesis gas exits at the top of the gasifier.

The exiting gas is immediately quenched and scrubbed in a wash cooler by a recirculating gas liquor stream. This opeation removes dust and tar from the gas stream. The gas stream then passes through a waste heat exchanger for additional cooling. Condensation of liquids occurs in this exchanger, and low-pressure steam is produced as a by-product.

The cooled gas is transferred by interconnecting piping to the Shift Conversion Section.

The gasifier is water jacketed to control the temperature of its shell. This jacket produces high-pressure steam (428 psig, 475°F) which is injected into the crude synthesis gas downstream of the waste heat exchanger.

The high temperature in the bottom of the gasifier melts the coal ash and limestone to form a liquid slag which is removed from the bottom of the gasifier through a tap hole. The slag falls into a water quench vessel where it is rapidly cooled and solidified to form a material resembling frit. The solidified slag is periodically removed from the quench vessel via a lock hopper and is transferred to Section 1000C for dewatering and disposal.

<u>Section 400C: Shift Conversion</u>

The composition of crude synthesis gas produced in the Gasification Section is shown below:

	Mol %	Lb/Hr
Hydrogen	25.69	47,784
Carbon Monoxide	58.52	1,512,532
Carbon Dioxide	6.44	261,606
Methane	6.09	90,174
C_nH_m	0.50	16,687
Nitrogen	0.71	18,378
Hydrogen Sulfide	1.93	60,640
Organic Sulfur	0.12	6,643
Subtotal Dry Gas	100.00	2,014,444
Water	-	545,543
Other Components	-	40,054
		2,600,041

This gas must be treated in several downstream processes in order to produce the desired pipeline gas product. The hydrogen sulfide, organic sulfur compounds, water, and other components must be removed from the gas. Those other components include phenols, ammonia, naphtha, and tar oil.

In addition, reactions which convert the hydrogen, carbon oxides, and C_nH_m to methane must be effected. These reactions are listed below:

$$3H_2 + CO = CH_4 + H_2O$$

$$4H_2 + CO_2 = CH_4 + 2H_2O$$

$$C_nH_m + (2n-m/2)H_2 = nCH_4$$

The crude synthesis gas does not contain enough hydrogen to effect these reactions. The shift reaction, shown below, is used to produce additional hydrogen:

$$CO + H_2O = H_2 + CO_2$$

While this reaction produces additional carbon dioxide so that the shifted gas would still be hydrogen deficient, the excess carbon dioxide can be removed from the gas by the Rectisol Process.

The shift conversion process included in the Commercial Plant utilizes a cobalt molybdenum catalyst in fixed-bed reactors to effect the shift reaction. An excess of high pressure superheated steam is injected into the gas to drive the shift reaction to the right.

The Shift Conversion Section consists of three separate independent trains plus one spare train. A spare train is provided so that the catalyst in the reactors can be periodically regenerated without reducing the plant production during regeneration periods. Each train consists of four reactors in a series-parallel arrangement. A by-pass line around the reactors provides a method for controlling the amount of shift conversion.

The shifted gas is transferred by interconnecting piping to the Gas Cooling Section. A small amount of condensed oily gas liquor (other components) is produced in Section 400C. This gas liquor is transferred to the Gas Liquor Separation Section.

Section 500C: Gas Cooling

The shifted gas is cooled to 95°F in Section 500C in order to prepare it for processing in the Rectisol Section. The cooling also yields additional gas liquor which is transferred to the Gas Liquor Separation Section.

The Gas Cooling Section consists of three separate independent trains. The gas is cooled in vertical tube heat exchangers in which the tube walls are washed with reinjected gas liquor to prevent fouling and plugging with condensing tars and oils. Heat is recovered in the cooling action to generate high-pressure superheated steam for use in the Gasification Section, to generate low-pressure steam, and to heat boiler feed water.

The cooled, shifted gas is transferred to the Rectisol Section by interconnecting piping.

Section 600C: Rectisol

The purpose of the Rectisol Section is to produce a purified synthesis gas having the requisite composition for the methanation process. The Rectisol Section accomplishes the following:

a. Reduces sulfur content of the synthesis gas to less than 0.1 ppm by volume;

b. Reduces the carbon dioxide content of the synthesis gas to about two volume percent, thus yielding a gas which is essentially in hydrogen balance for the methanation reactions;

c. Removes all naphtha and water from the synthesis gas;

d. Produces a hydrogen sulfide rich acid gas stream which can be fed to a Claus unit for sulfur recovery; and

e. Produces a carbon dioxide gas stream which can be incinerated and vented to the atmosphere without violating environmental regulations.

The Rectisol process is a solvent absorption process. The process operates at sub-zero temperatures and uses methanol as the solvent.

The cooled shifted gas enters the Rectisol Section. It is further cooled in refrigerated exchangers. It then flows into the pre-wash section of the H_2S Absorber. Naphtha and water are removed from the gas in the pre-wash section. The gas next flows into the main section of the H_2S Absorber to effect hydrogen sulfide removal. The gas then flows into the CO_2 Absorber where carbon dioxide is removed. The resultant purified gas is transferred by interconnecting piping to the Methanation Section.

The various methanol streams containing dissolved naphtha, hydrogen sulfide, and carbon dioxide are processed by flash regeneration, azeotropic distillation, and stripping to recover the methanol for re-use in the process and to yield the naphtha by-product, the hydrogen sulfide rich gas stream, and the carbon dioxide gas stream which are transferred to Sections 3100C, 900C, and 3000C, respectively.

The Rectisol Section consists of three separate independent trains.

<u>Section 700C: Methanation</u>

The purified synthesis gas from the Rectisol Section is fed to the 3-train Methanation Section for conversion of the hydrogen, carbon oxides, and non-methane hydrocarbons into methane. Hydrogen reacts with the carbon oxides and non-methane hydrocarbons over nickel catalyst to form methane by the reactions listed previously in the process description of Section 400C.

Each train in the Methanation Section consists of three primary fixed-bed reactors in a series-parallel arrangement and a final cleanup reactor. The feed to the primary reactors is mixed with methanated recycle gas which serves as a heat sink to control the temperature rise in these reactors.

The methanation reactions are exothermic, and heat is recovered with waste heat boilers. The waste heat boilers generate 1,806,000 pounds per hour of high-pressure steam. This is approximately 40 percent of the plant requirements.

The methanated gas is transferred by interconnected piping to Section 800C for compression and drying.

Section 800C: Product Gas Compression and Drying

This is the final processing step in the manufacture of the pipeline quality product gas. The product gas from the Methanation Section is compressed to 1,025 psig, and final traces of water are removed in a conventional triethylene glycol absorption process.

Section 800C consists of three separate independent trains. The outputs from the three trains are combined, metered, and delivered to a pipeline gas transmission system for subsequent distribution to consumers.

2.2 By-Product Recovery Process Units

Five sections of the Commercial Plant are required to recover by-products produced in the process for sale or disposal. These by-products and the quantities produced are listed below:

	Tons/Day
Sulfur	919
Ammonia	48
Mixed Phenols	73
Naphtha	180
Tar Oil	262
Slag	3,017

The naphtha is produced in the Rectisol Section. Recovery of other by-products is discussed below.

Section 900C: Sulfur Recovery

The sulfur is recovered from the hydrogen sulfide rich acid gas stream produced in Section 600C and from smaller hydrogen sulfide containing gas streams produced in Sections 1100C and 1200C. A conventional Claus process is used to recover the sulfur by the reaction:

$$2H_2S + SO_2 = 3S + 2H_2O$$

Section 900C consists of three separate independent trains. Each train has three Claus reactors in series and a high conversion to sulfur is attained. The unconverted tail gas from the Claus process is fed to the coal-fired boilers in Section 2000C for incineration. The flue gas from the boilers is scrubbed in a Wellman-Lord Unit, and the recovered sulfur dioxide is recycled to the Claus process.

The recovered liquid sulfur is stored in Section 3100C and is subsequently sold.

Section 1000C: Slag Handling and Disposal

The slag-water mixture from the gasifiers in Section 300C is transferred to Section 1000C for dewatering. The excess water is pumped to the Waste Water Treatment Section. The dewatered slag is transported by trucks to a solid waste disposal area. An effort will be made during Phase III of the Demonstration Plant project to develop markets for the slag.

Section 1000C is designed as a single-train unit.

Section 1100C: Gas Liquor Separation

Gas liquor condensates from Section 300C, 400C, 500C, and 600C are processed in the Gas Liquor Separation Section. Dusty tar, clear tar, tar oil, and dissolved acid gases are removed from the gas liquor in this section. The clarified gas liquor is then transferred to Section 1200C and subsequently to Section 1300C for phenol and ammonia recovery.

Section 1100C is a single-train unit, but spares for critical pieces of equipment are provided. This section consists of a series of separators (settlers) which separate tar and tar oil from the gas liquor. The separators operate at atmospheric pressure; so the gas liquor is de-gassed prior to entering the separators.

The dusty and clear tars are recycled to the gasifiers in Section 300C, and there is no net tar production. The tar oil is transferred to Section 3100C for storage and subsequent sale. The acid gas from de-gassing is sent to Section 900C for sulfur recovery.

Section 1200C: Phenol Extraction

The clarified gas liquor from the Gas Liquor Separation Section is processed in this section to recover phenols. The Phenosolvan Process is used for this purpose. In this process, the gas liquor is contacted with isopropyl ether solvent in a countercurrent, multi-stage extractor. The solvent dissolves the phenols, and the resultant solution is processed in a distillation column for recovery of solvent and to produce a mixed phenols stream. The phenols are pumped to storage in Section 3100C.

Most of the recovered phenols are subsequently sold, but a small amount (about 6% of the total) is used as auxiliary fuel for the incinerator in Section 3000C. The Phenosolvan Process recovers 99.5 percent of the monovalent phenols and about 55 percent of the multivalent phenols present in the gas liquor.

The dephenolized gas liquor (raffinate) is pumped to the Ammonia Recovery Section for recovery of ammonia and then to the Waste Water Treatment Section for removal of the remaining phenols. No phenols are discharged from the plant.

A small gas stream containing hydrogen sulfide is produced in the Phenol Extraction Section. This gas stream is transferred by interconnecting piping to the Sulfur Recovery Section.

The Phenol Extraction Section consists of two separate independent trains, each of which can process 57.5 percent of the normal gas liquor production. Storage for the feed gas liquor is provided so that one train can be shut down for maintenance without shutting down the upstream process units.

Section 1300C: Ammonia Recovery

The Chemie Linz - Lurgi (CLL) Process is used to recover liquid ammonia from the dephenolized gas liquor. The CLL and Phenosolvan processes are integrated to conserve heat and to minimize investment costs.

The front end of the Ammonia Recovery Section consists of two separate independent trains which include the deacidification, stripping, and acid gas scrubbing portions of the CLL Process. Both trains feed into a single train which consists of the ammonia absorption, purification, and liquefaction portions of the process.

The liquid ammonia is pumped to storage in Section 3100C and is subsequently sold.

2.3 Off-Site Units

The Commercial Plant contains seven sections which include all the off-site facilities required to operate the process units. These off-site facilities are in general, conventional design and include the following facilities:

- Raw water treatment
- Boiler feed water treatment
- Coal-fired steam plant
- Electrical power generation
- Cooling water system
- Plant and instrument air system
- Waste water treatment
- Flares
- Incinerators
- Tankage
- Shipping and receiving facilities
- Buildings
- Roads
- Fences
- Railroad yard
- Electrical power distribution
- Communications
- Fire alarm system
- Firewater system
- Sewers

Two of these facilities are worthy of note. The coal-fired steam plant uses the Wellman-Lord Process for stack gas scrubbing. This is a regenerative absorption process which removes about 94 percent of the sulfur dioxide from the flue gas before it is emitted to the atmosphere through the stack. The cleaned stack gas contains only 250 ppm by volume of sulfur dioxide.

The waste water treatment facilities are designed for zero discharge of waste water and a maximum recycle and re-use of water in the plant. The waste water treatment facilities consist of conventional methods such as gravity separation, air flotation, aeration, neutralization, filtration, biological treatment, and active carbon absorption. In addition, facilities to attain zero discharge are provided. These consist of a multiple effect evaporator and a Carver-Greenfield evaporator.

The electrical power, steam, and cooling water requirements for the Commercial Plant are summarized by sections in Table 3.

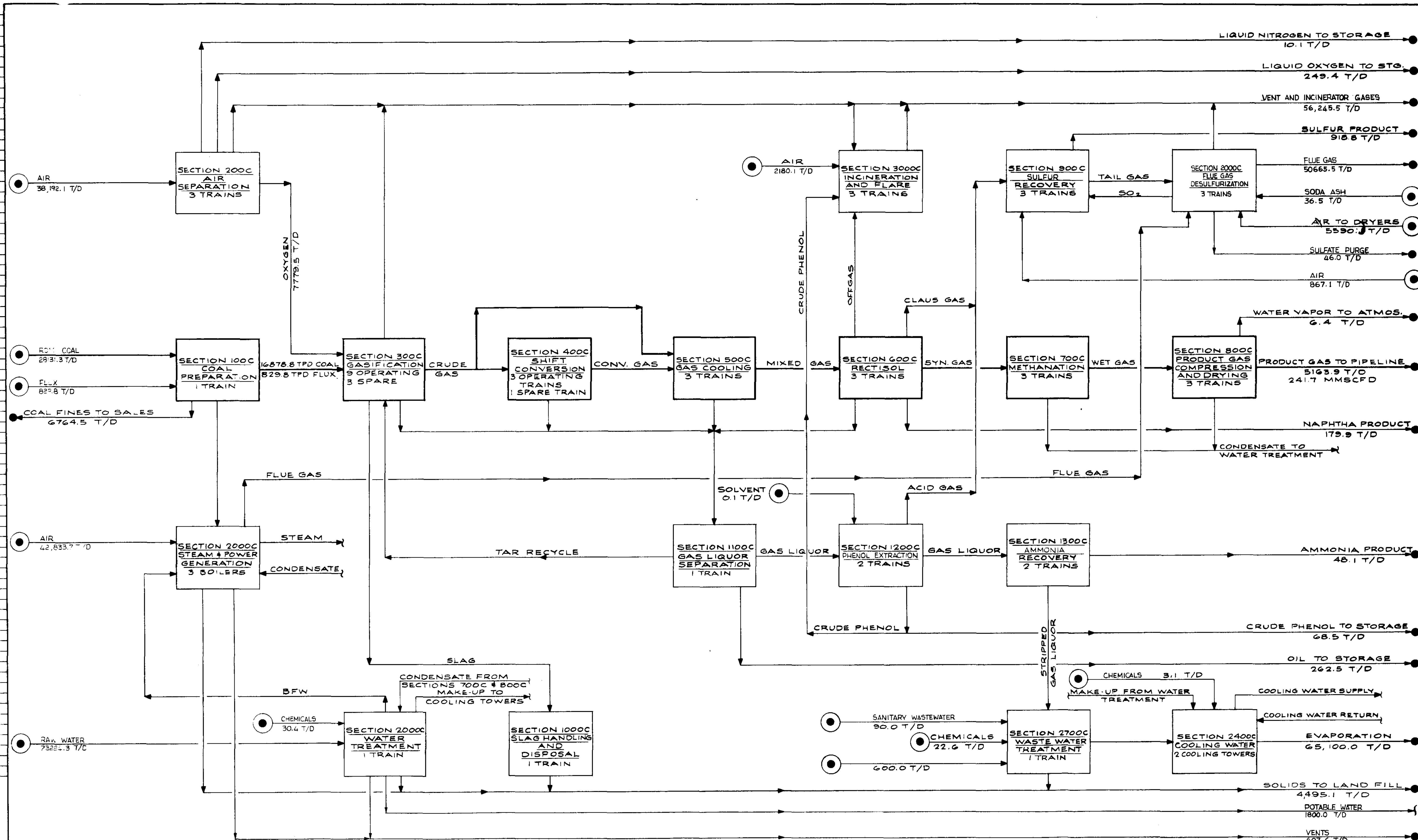
TABLE 3

SUMMARY OF POWER AND UTILITY REQUIREMENTS

Section	Electrical Power KW	STEAM CONSUMPTION, 1,000 LBS/HR **				Cooling Water 1,000 gpm
		1,500 psig Super-heated	550 psig Super-heated	110 psig Satu-rated	35 psig Satu-rated	
Coal and Flux Handling and Preparation	3,012	-	-	-	-	-
Air Separation*	-2,004	1,226.6	-	-	-	122.0
Gasification	1,303	-	461.7	-	-	13.9
Shift Conversion	10	-	914.9	-	-	-
Gas Cooling	950	-	-	-	-	4.6
Rectisol and Refrigeration	18,000	-	945.1	362.2	-	61.2
Methanation	615	-	201.2	-	-	13.6
Product Gas Compression and Drying	449	-	256.2	-	-	19.9
Sulfur Recovery	1,291	-	-	-	-	0.1
Slag Handling and Disposal	350	-	-	-	-	-
Gas Liquor Separation	1,659	-	-	-	10.1	3.9
Phenol Extraction	450	-	-	5.7	17.6	0.6
Ammonia Recovery	540	-	15.1	78.1	172.9	5.2
Water Treatment and Steam Generation	23,473	1,524.0	343.1	40.2	322.0	42.4
Cooling Water System	10,620	-	150.2	-	-	0.1
Plant and Instrument Air System	570	-	-	-	-	0.2
Waste Water Treatment	3,150	-	-	7.0	430.0	31.7
Flare and Incinerator Facilities	980	-	-	6.9	-	-
Tankage, Shipping and Receiving	10	-	-	-	-	-
Buildings, Firewater System, etc.	1,654	-	-	-	8.5	-
Plant Total	67,082	2,750.6	3,287.5	500.1	961.1	319.4

*The air separation unit is a net producer of electrical power.

** Some sections generate steam in heat recovery exchangers; steam production is not shown on this table but may be found in FE-2542-10, Volume 2



TASK I

COMMERCIAL PLANT

DEPARTMENT OF ENERGY COAL CONVERSION DIVISION WASHINGTON, D.C.	PIPELINE GAS DEMONSTRATION PLANT NOBLE COUNTY, OHIO CONTRACT No. EF-77-C-01-2542	SIMPLIFIED BLOCK FLOW DIAGRAM OVERALL PLANT ALL SECTIONS
CONOCO COAL DEVELOPEMENT COMPANY STAMFORD, CONNECTICUT	FOSTER WHEELER ENERGY CORPORATION 110 SOUTH ORANGE AVENUE LIVINGSTON, NEW JERSEY	DRAWN CPB DATE 4/11/78 FWEC CONTRACT No. 15-1911 CHECKED DATE SCALE NONE SH. 1 OF 1 APPROVED DATE DWG No. 1911-1-50-00901 0

FORM NO. 138-104C

2.4 Key Plot Plan

The Key Plot Plan for the Commercial Plant is shown as Drawing No. 1911-1-01-1. This drawing orients all sections of the plant to their respective locations within the perimeter fence. Land area requirements for the plant are 2,540 acres. The overall positioning of equipment provides in-line flow from receipt of the ROM coal to the product gas pipeline.

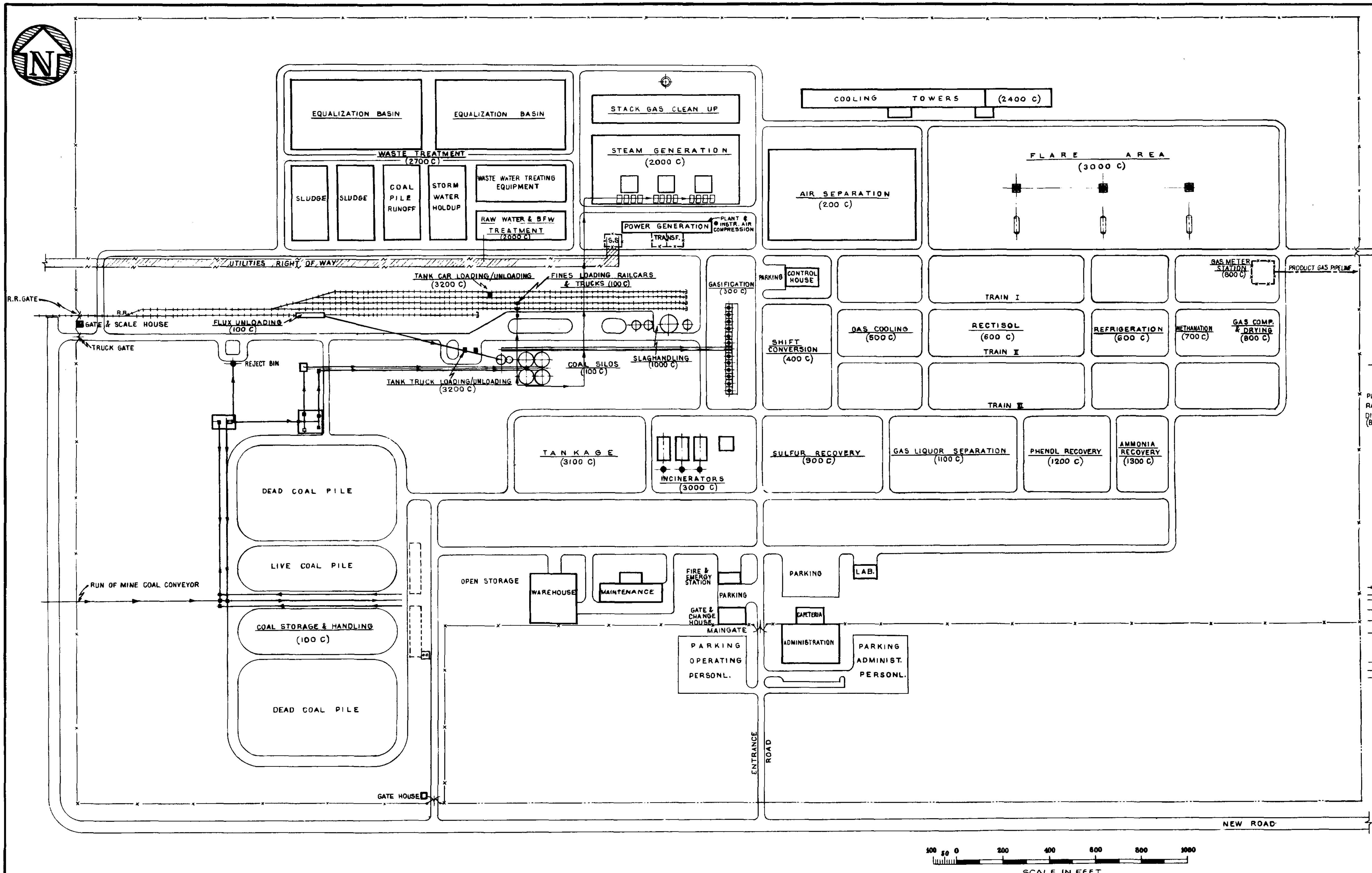
The utility and air processing units supporting the on-site processes are adjacent to the gasification section minimizing costly interconnecting piping. By-product streams from the main process area flow into and through the adjacent recovery units with in-line flow of recovered products directed to tankage. The by-products are pumped through interconnecting piping to truck and rail shipping facilities.

Shipping and receiving is centralized on the western side of the plant. Both rail and truck facilities are provided. The number and length of rail sidings provides for an orderly movement of rail cars. Truck traffic can be controlled in an orderly manner for handling removal of slag, ash, biological, and landfill waste solids.

Waste treatment facilities have been compactly located on the northwest corner. Flows into this area are primarily the underground sewer networks. A utilities right-of-way is indicated for incoming raw water and a power tie-in with the public utility grid.

The cooling tower and flare area are adjacent to process equipment served and are oriented with respect to anticipated prevailing winds to direct effluent plumes away from the process area equipment.

The administration and other buildings are located at the front of the plant. Their orientation minimizes personnel movement and isolates services such as maintenance, laboratory, and fire/emergency so that these services are readily accessible to the plant areas and equipment which they serve.



LAND AREA REQUIREMENTS

ITEM	ACRES
PLANT AS SHOWN	480
RAILROAD MARSHALLING YARD	10
DISPOSAL OF SOLID WASTE (BASED ON 12 FT. DEPTH)	1800

LEGEND

- RAILROAD
- ROADS
- FENCE
- PROPERTY LINE
- PLANT GATES
- S.S. ELECTRICAL SUBSTATION
- CONVEYORS
- UTILITIES RIGHT OF WAY

21

TASK I

COMMERCIAL PLANT

DEPARTMENT OF ENERGY
COAL CONVERSION DIVISION
WASHINGTON, D.C.

CONOCO COAL DEVELOPMENT COMPANY
STAMFORD, CONNECTICUT

PIPELINE GAS DEMONSTRATION PLANT
NOBLE COUNTY, OHIO
CONTRACT No. EF-77-C-01-2542

FOSTER WHEELER ENERGY CORPORATION
110 SOUTH ORANGE AVENUE
LIVINGSTON NEW JERSEY

KEY PLOT PLAN
OVERALL PLANT
SECTION 4000C

DRAWN: C.I.	DATE 1-17-78	FWEC CONTRACT No. 15-1911	
CHECKED: TED	DATE 3-28-78	SCALE: BAR SCALE	SH. 1 OF 1
APPROVED: JJS	DATE 3-24-78	DWG No. 1911-1-01-1	A

A	3-27-78	FINAL ISSUE

3.0 ECONOMIC ANALYSIS

There are two methods for financing a coal gasification plant — public utility financing and private industrial financing. Since both public utilities and industrial firms have expressed interest in constructing coal gasification plants, an economic analysis of both methods of financing has been made.

The erected cost of the Commercial Plant, by sections, is summarized in Table 4. The total erected plant cost is 919 million dolalrs including 440 million dollars for the process units, 293 million dollars for the off-site units, and 186 million dollars for indirect costs. The cost of the Gasification Section is 47 million dollars, or only about six percent of the direct plant cost. By comparison, the cost of the Water Treatment and Steam Generation Section (steam/power plant) is 183 million dollars, or 25 percent of the direct plant cost. It is therefore economically more promising to give increased attention to the technology and design of downstream gas processing and the power source for drivers than to gasification (see Section 4.0).

The comparative low cost for the Gasification Section is indicative of the high efficiency and high throughputs attainable with the British Gas/Lurgi slagging gasifier.

Table 5 summarizes the total capital requirements for public utility financing of the Commercial Plant. Total capital requirements are 1.47 billion dollars including 146 million dollars for contingency, 203 million dollars for capitalization of interest during construction (allowance for funds), 42 million dollars for working capital, and 58 million dollars for start-up costs.

The guidelines for calculation of gas costs by the public utility method of financing are those developed for process comparisons in the AGA-DOE conceptual commercial coal gasification plant studies. The guidelines used herein are:

Project Operating Life	20 Years
Depreciable Life	20 Years
Depreciation Type	Straight Line
Debt/Equity Ratio	75/25
Percent Interest on Debt	9%
Percent Return on Equity	15%
Federal Income Tax	48%

The gas sales price, based on these guidelines, is projected to be $6.38 per million Btu of the pipeline quality gas product during the first year of service. The average price of gas over the projected 20-year life of the plant is $5.14 per million Btu. These costs are based on first quarter, 1978 dollars, and zero inflation is assumed.

A breakdown of the factors involved in obtaining the above prices is shown in Table 6. This table shows the costs or credits in dollars per million Btu. This table indicates that for the average gas price, the items contributing to the cost of gas are:

1. Cost of Coal (48%)

2. Other Materials and Operating Costs (25%)

3. Return of Plant Capital Investment (38%)

4. Income Tax (7%)

5. By-products (18% credit)

Table 7 summarizes the total capital requirements for industrial financing of the Commercial Plant. Total capital requirements are 1.3 billion dollars including 146 million dollars for contingency, 76 million dollars for working capital, and 50 million dollars for start-up costs. Total capital requirements for industrial financing are less than the requirements for public utility financing because of capitalization of interest during construction under public utility financing. This is partially offset by a higher working capital allowance for industrial financing.

The base guidelines for the calculation of gas costs by the industrial method of financing have been set by DOE. This method, also known as the discounted cash flow (DCF) method, is a common technique for appraisal of projects. It relates future earnings to their present day value. The method discounts future dollars to the equivalent amount of current dollar value based on an interest factor or DCF rate of return. The guidelines set by DOE for the base case calculations are:

Project Operating Life	20 Years
Depreciable Life	16 Years
Depreciation Type	Sum-of-the-Years Digits
DCF Rate of Return	12%
Income Tax Rate	48%
Coal Cost	$1.00 per million Btu

The gas sales price, based on these guidelines, is projected to be $6.60 per million Btu of the pipeline quality gas product.

DOE also requested a gas price calculation assuming a zero Federal income tax burden at a DCF rate of return of 9 percent. These criteria result in a computed gas sales price of $4.85 per million Btu of gas product.

A breakdown of the factors involved in obtaining the above prices is shown in Table 8. This table shows the costs or credits in dollars per million Btu. This table indicates that for the base case, the major items contributing to the cost of gas are:

1. Cost of Coal (37%)

2. Return of Plant Capital Investment (35%)

3. Income Tax (21%)

4. By-products (14% credit)

All other factors combined contribute only 21 percent to the cost of gas. In comparing the two cases requested by DOE, it should be noted that two factors were changed simultaneously. Since the DCF rate of return was changed from 12 percent to 9 percent in the zero income tax case, the cost of gas decreased due to both the tax reduction ($1.41 per million Btu) and the reduction in capital charges (0.34 per million Btu).

The average cost of gas by public utility financing is less than that by industrial financing because of the differences and assumptions imposed on the calculations. Public utility financing assumes a highly leveraged capitalization whereas the discounted cash flow method does not consider the source of capital. This difference results in much less income taxes and moderately less capital charges for public utility financing.

While the cost of gas from coal gasification is high compared to present day prices for natural gas — five to seven dollars per million Btu vis a vis about two dollars per million Btu for natural gas, the cost of gas from coal gasification is comparable to the expected future costs of foreign LNG and North Slope natural gas. Furthermore, the cost of delivered energy from coal gasification is only about 50 percent of the cost of delivered energy from new coal-fired electrical power plants.

TABLE 4

ERECTED PLANT COST SUMMARY

Section	Million Dollars* Direct Material	Sub-contract	Direct Labor	Total
Coal & Flux Handling & Preparation	-	32.670	-	32.670
Air Separation	-	106.700	-	106.700
Gasification	39.925	2.848	4.181	46.954
Shift Conversion	39.013	3.623	9.140	51.776
Gas Cooling	6.421	0.921	1.704	9.046
Rectisol	86.104	8.993	20.039	115.136
Methanation	21.565	2.858	4.369	28.792
Product Gas Compression & Drying	10.117	1.170	1.808	13.095
Sulfur Recovery	4.618	0.806	1.317	6.741
Slag Handling and Disposal	-	2.650	-	2.650
Gas Liquor Separation	5.568	4.915	1.940	12.423
Phenol Extraction	4.311	0.825	1.056	6.192
Ammonia Recovery	5.494	0.751	1.481	7.726
Process Units Subtotal	223.136	169.730	47.035	439.901
Water Treatment & Steam Generation	8.174	173.263	1.463	182.900
Cooling Water System	4.575	7.408	2.880	14.863
Plant & Instrument Air System	0.357	0.023	0.087	0.467
Waste Water Treatment	1.690	21.656	1.229	24.575
Flare and Incinerator Facilities	7.134	1.746	2.100	10.980
Tankage	1.272	2.341	0.515	4.128
Shipping and Receiving	0.646	0.163	0.325	1.134
Support Facilities	26.038	17.743	10.127	53.908
Off-site Subtotal	49.886	224.343	18.726	292.955
Subtotal Direct Cost	273.022	394.073	65.761	732.856
Construction Indirects (130% Direct Labor)				85.490
Productivity (50% Direct Labor + Indirects)				75.625
Capital Spare Parts				3.200
Soil Consultant Expenses				0.080
Environment Research & Technology Consultant				1.350
Bond, All Risk Insurance & Sales/Use Tax				20.250
Erected Plant Cost				918.851

*First quarter, 1978 dollars.

TABLE 5

TOTAL CAPITAL REQUIREMENTS FOR PUBLIC UTILITY FINANCING

		Million Dollars*
Total Plant Investment		
Erected Plant Cost		918.9
Engineering and Design Costs		51.5
Subtotal		970.4
Project Contingency, 15% of Subtotal		145.6
Offeror's Admin. & Construction Engineering		4.7
Subtotal		1,120.7
Land		5.3
Total Plant Investment		1,126.0
Initial Charge of Catalysts and Chemicals		14.3
Paid-Up Royalties		28.7
Allowance for Funds Used During Construction (Total Plant Investment x 2 years x 9%)		202.7
Start-Up Costs		57.5
Working Capital		
Raw Materials	8.1	
Materials and Supplies	10.1	
Net Receivables	23.4	
Total Working Capital		41.6
Total Capital Requirements		1,470.8

*First quarter, 1978 dollars.

TABLE 6

PRODUCT GAS COST FOR PUBLIC UTILITY FINANCING

	Gas Cost, Dollars Per Million Btu*	
	First Year Of Service	Average Cost Of Service
Coal Cost at $1.00/Million Btu	2.471	2.471
Other Raw Materials	0.078	0.078
Catalyst and Chemicals	0.200	0.200
Labor and Benefits	0.288	0.288
Administration and General Overhead	0.173	0.173
Maintenance and Operating Supplies	0.137	0.137
Local Taxes and Insurance	0.397	0.397
Annual Royalties	0.013	0.013
Gross Operating Cost	3.757	3.757
Less By-Product Credits**	-0.929	-0.929
Net Operating Cost	2.828	2.828
Income Taxes	0.649	0.342
Return on Equity and Depreciation	1.636	1.303
Interest on Debt	1.265	0.667
Total Gas Cost	6.378	5.140

Gas Production Rate = (241.7 MM SCFD) (330 Days/Yr) (960 Btu/SCF)
= (79,761 MM SCF Per Year) (960 Btu/SCF)
= 76.571 x 10^{12} Btu/Year

*First quarter, 1978 dollars.
**Includes the sale of excess coal fines at $0.90 per million Btu.

TABLE 7

TOTAL CAPITAL REQUIREMENTS FOR INDUSTRIAL FINANCING

	Million Dollars*
Total Plant Investmnet	
Erected Plant Cost	918.9
A&E Contractor's Profit	4.3
A&E Engineering and Design	39.1
Lurgi Engineering and Design Cost	8.1
Subtotal	970.4
Project Contingency, 15% of Subtotal	145.6
Offeror's Admin. & Construction Engineering	4.7
Subtotal	1,120.7
Initial Charge of Catalysts and Chemicals	14.3
Paid-Up Royalties	28.7
Total Plant Investment	1,163.7
Start-Up Costs	50.5
Land Aquisition Cost	5.3
Working Capital (Base Case)	76.1
Total Capital Requirements	1,295.6

*First quarter, 1978 dollars.

TABLE 8

PRODUCT GAS COST FOR INDUSTRIAL FINANCING

DCF METHOD

Case	Gas Cost, Dollars Per Million Btu* 12% DCF 48% Income Tax	9% DCF Zero Income Tax
Coal Cost @ $1.00 Million Btu	2.471	2.471
Other Raw Materials	0.078	0.078
Catalysts and Chemicals	0.200	0.200
Labor and Benefits	0.222	0.222
Administration and General Overhead	0.044	0.044
Maintenance and Operating Supplies	0.405	0.405
Local Taxes and Insurance	0.304	0.304
Annual Royalties	0.013	0.013
Gross Operating Costs	3.737	3.737
Less Byproduct Credits**	-0.929	-0.929
Net Operating Costs	2.808	2.808
Interest on Land and Working Capital	0.095	0.074
Average Income Tax	1.412	-
Average Capitalization of Investment	2.290	1.969
Total Gas Cost	6.605	4.851

Gas Production Rate = (241.7 MM SCFD) (330 Days/Yr) (960 Btu/SCF)
= (79,761 MM SCF Per Year) (960 Btu/SCF)
= 76.571 x 10^{12} Btu/Year

*First quarter, 1978 dollars.
**Includes the sale of excess coal fines at $0.90 per million Btu.

4.0 TECHNICAL ASSESSMENT

A coal gasification process based on the British Gas/Lurgi slagging gasifier is potentially the most favorable process for manufacturing medium-Btu fuel gas or pipeline quality gas from low reactivity, bituminous caking coal. Capital costs per unit gas production are comparatively low for this gasifier, and thermal efficiency is high because of a high steam conversion in the gasifier.

The Commercial Plant, as designed, produces 10,725 million Btu per hour of products from 14,332 million Btu per hour of coal feed to the gasifiers. A comparison of the heating value of the coal feed and products is shown below:

	Million Btu/Hr	Percent
Coal Feed to Gasifiers	14,332	100.0
Products		
Pipeline Gas	9,667	67.5
Naphtha	266	1.8
Tar Oil	373	2.6
Phenols	73	0.5
Ammonia	39	0.3
Sulfur	307	2.1
Total Products	10,725	74.8

The overall plant thermal efficiency is appreciably lower than the process thermal efficiency, shown above, because of the energy required for driving the various pumps and compressors. As shown on Table 2 of Section 2.0 of this report, the overall plant thermal efficiency is 59.1 percent.

The overall plant efficiency could be increased by recent experience on the pilot plant gasifier and by an improved design for the steam/power plant. Design of the gasifier was completed prior to operation of the pilot plant gasifier at Westfield, Scotland, on bituminous caking coals. Subsequent data on such coals has shown that 10 percent less oxygen is required for gasification than is specified in the Commercial Plant design. The reduced oxygen requirements would result in a smaller-sized air separation plant, and less energy would be required to operate the compressors in this plant.

The power source for drivers in the Commercial Plant is a coal-fired boiler generating 1,500 psig, 900°F steam. The steam is used to drive turbines on the large compressors and turbo-generators. This type of power source consumes 3,811 million Btu per hour of coal for fuel. Fuel requirements for a better designed steam plant would be appreciably less. By installing a typical high-pressure boiler of the type operated by public utilities to generate electrical power at 38 percent efficiency and by using electrical drivers, the fuel requirements for drivers would be reduced to less than 2,400 million Btu per hour. This in turn would increase the overall plant thermal efficiency to 64 percent.

This latter power source was not evaluated in the Commercial Plant design studies. It is apparent that a detailed design study would show that this type of power plant or a combined cycle power plant would improve the overall thermal efficiency of the Commercial Plant.

Most of the processes selected for inclusion in the Commercial Plant are based on commercially-proven technology, and the technical risk associated with them is minimal. Those sections based entirely on commercially-proven technology and equipment are listed below:

Section 100C:	Coal and Flux Handling and Preparation
Section 200C:	Air Separation
Section 500C:	Gas Cooling
Section 600C:	Rectisol
Section 800C:	Product Gas Compression and Drying
Section 900C:	Sulfur Recovery
Section 1000C:	Slag Handling and Disposal
Section 1100C:	Gas Liquor Separation
Section 1200C:	Phenol Extraction
Section 1300C:	Ammonia Recovery
Section 2400C:	Cooling Water System
Section 2500C:	Plant and Instrument Air System
Section 3000C:	Flare and Incinerator Facilities
Section 3100C:	Tankage
Section 3200C:	Shipping and Receiving
Section 4000C:	Support Facilities

The technical risk associated with the remaining five sections is discussed below. The purpose of the Demonstration Plant is to reduce the technical risk associated with much of the new technology which has been included in the Commercial Plant design.

4.1 Section 300C: Gasification

Design of the Gasification Section is based on emerging new technology developed by British Gas Corporation and Lurgi Kohle und Mineraloeltechnik GmbH. The major equipment items in this section are the lock hoppers, the gasifier, the wash cooler (crude gas quench vessel), and the waste heat exchanger.

The British Gas/Lurgi slagging gasifier is a modification of the standard Lurgi dry-bottom gasifier which has been in commercial operations since 1936. The top portion of the slagging gasifier is similar in design to the Lurgi dry-bottom gasifier. The bottom portion has been developed by British Gas for slagging operations. The development of the slagging gasifier has proceeded through a small process development unit and is now in the large pilot plant stage.

The large pilot plant is located in British Gas Corporation's Westfield Development Centre at Westfield, Scotland. This pilot plant effort was sponsored by 13 American industrial firms during a 3-year period covering 1974-1977. This effort showed that low-caking coals (Scottish Frances coal) can be successfully processed in the slagging gasifier to produce a crude synthesis gas suitable for conversion to pipeline quality gas.

The pilot plant effort is now being focused on the gasification of U.S. bituminous caking coals such as Ohio No. 9 and Pittsburgh No. 8 coals. This effort is being financed by DOE as part of the Phase I Demonstration Plant program. To date this program has disclosed the following:

a. The slagging gasifier produces a crude synthesis gas which can be processed to yield a high-Btu pipeline quality gas;

b. The ash from bituminous coals can be fluxed to produce a free-flowing slag which can be easily removed from the gasifier; and

c. High coal throughput rates are attainable.

The areas which involve some degree of technical risk remaining at this time in the slagging gasifier for the processing of bituminous caking coals are listed below:

a. Prevention of uncontrolled coke formation in the shaft of the gasifier above the tuyeres at high throughputs;

b. Formation of free iron in the slag pool on the hearth of the gasifier and splattering of slag in the slag quench vessel so that it adheres to quench vessel internals; and

c. Operating life of materials of construction in the bottom of the gasifier.

Data being obtained from the current pilot plant program are providing design information which is expected to reduce this risk. In fact, British Gas and Lurgi are confident that a gasifier which can satisfactorily process Appalachian coals can be designed.and this design will be evaluated in the Demonstration Plant. Information obtained during Phase III operations of the Demonstration Plant can be expected to resolve any remaining technical problems associated with the gasifier.

The lock hoppers, wash cooler, and waste heat exchanger included in the Gasification Section are essentially identical to comparable equipment which has been in service for over 40 years in the numerous Lurgi dry-bottom gasifier installations. There is minimal technical risk associated with these equipment items.

4.2 Section 400C: Shift Conversion

Shift conversion processes have been in commercial operation for many years, and this commercial experience includes plants which process crude synthesis gases produced by the Lurgi dry-bottom and the Koppers-Totzek gasifiers. There is essentially no technical risk in the basic shift conversion process and equipment.

There is one potential problem, polymerization of unsaturated hydrocarbons, associated with shift conversion of the crude synthesis gas from a British Gas/Lurgi slagging gasifier.

The hydrogen content of this synthesis gas is relatively low, and the gas contains some unsaturated heavy hydrocarbons. These unsaturated hydrocarbons can potentially polymerize and rapidly plug the catalyst bed in the first shift reactor. Hydrogen inhibits polymerization, but the feed gas to the first shift reactor may not contain enough hydrogen to inhibit polymerization sufficiently. This potential problem has been considered in the plant design. A slip stream of the gasifier synthesis gas is processed through a cooling step in which the heavy hydrocarbons are removed by condensation. This slipstream is then sent to the first shift reactor where the hydrogen content is increased by a factor of two. The converted slipstream is then combined with the remaining synthesis gas to give an overall concentration that is suitable as a shift conversion feed to the remaining reactors without further hydrocarbon control.

This method of design is expected to reduce the technical risk associated with the shift conversion process to a minimum. The design will be evaluated in the Phase III Demonstration Plant program.

4.3 Section 700C: Methanation

Methanation technology, per se, is well known and is practiced in many commercial operations, but it has not been used commercially for manufacturing pipeline quality gas from synthesis gas produced in a coal gasification process.

However, a methanation demonstration program associated with coal gasification was successfully implemented at Westfield, Scotland, in 1973 and 1974. Continental Oil Company designed a semi-commercial scale methanation unit which was installed in an operating coal gasification facility at Westfield. Feed to the methanation unit was produced in a standard Lurgi dry-bottom gasifier and was purified in a small Rectisol unit designed by Lurgi Mineraloeltechnik GmbH. British Gas Corporation implemented the demonstration program.

The methanation unit produced some two million standard cubic feet per day of pipeline quality gas. The unit was operated over a period of approximately nine months, and one extended run of over 2,900 hours was successfully completed. No operating problems with the methanation process or equipment were encountered during this extended run.

The gas product was commingled with natural gas and distributed to local consumers. No consumer complaints were received even though at times the commingled gas product contained more than 70 percent manufactured pipeline quality gas.

While there is a small technical risk associated with scaling-up the semi-commercial unit, this risk will be resolved in the Phase III operations of the Demonstration Plant.

4.4 Section 2000C: Water Treatment and Steam Generation

The boiler feed water system, raw water treatment process, and coal-fired steam boiler are conventional units, and there is essentially no technical risk associated with them.

The stack-gas cleanup system associated with the steam plant uses the Wellman-Lord Process for sulfur dioxide recovery. The Wellman-Lord Process is based on new technology, and it is a regenerable process. While the process is being operated in power plants in Indiana and Japan, commercial experience with it is somewhat limited at this time; so there is a modicum of technical risk associated with it.

By the time a commercial coal gasification plant is constructed, the additional commercial experience obtained for the Wellman-Lord Process should alleviate most of the remaining technical risk.

4.5 Section 2700C: Waste Water Treatment

The Waste Water Treatment Section consists of conventional facilities which produce a waste water discharge stream meeting current environmental regulations. In addition, it contains facilities for attaining zero discharge of waste water.

The key units for zero discharge are multi-stage and Carver-Greenfield evaporators. While these types of evaporators are used commercially, there is no commercial experience with them in treating waste water from a coal gasification facility. Therefore, potential problems such as scaling and foaming exist in using these evaporators in this service. It is recommended that semi-commercial units be constructed and operated in treating waste water from coal gasification prior to constructing the large units required for a commercial coal gasification plant.

5.0 ENVIRONMENTAL ASSESSMENT

The Commercial Plant has been designed for construction and operation in Montgomery County, Illinois, but the design can be readily modified for other locales. A specific plant site within Montgomery County has not been selected. Consequently, an environmental study required for EPA permits and for an Environmental Impact Statement has not been made. Such a study is a prerequisite to constructing the Commercial Plant.

The plant has been designed for zero discharge of waste water; so only gaseous emissions to the atmosphere and solid waste disposal will have an adverse effect on the surrounding environment. The Commercial Plant design incorporates the best available technology to keep these adverse effects to a minimum.

Table 9 summarizes the composition and quantity of the normal gaseous emissions to the atmosphere from operating the Commercial Plant. The bulk of the emissions originate in the Air Separation Section (nitrogen), the steam plant (scrubbed stack gas), the incinerator (stack gas), and the cooling water towers (water vapor). The major emissions are nitrogen, carbon dioxide, and water vapor. The only pollutants emitted are a small amount of sulfur dioxide (2,702 lb/hr) in the steam plant and incinerator stack gases and a very small amount of methane (64 lb/hr) at the flare. All gaseous emissions meet current EPA regulations and guidelines.

A number of solid wastes are produced in the Commercial Plant. These are listed below by sections:

Section	Solid Waste	Lb/Hr
1000C	Slag	251,451
2000C	Coal Ash	46,265
	Vacuum Filter Dewatering Solids	7,765
	Sulfate Purge	3,835
2700C	Sludge and Coal Ash	65,275

These solid wastes will be buried on the plant site in land fill operations. About 90 acres per year will be uncovered for the land fill operations. The top soil will be removed and temporarily stored. After the land fill operations in a given area have been completed, the top soil will be replaced, and the land will be re-planted.

The land fill operations will use the best available technology to minimize leaching and groundwater contamination.

TABLE 9

COMPOSITION AND QUANTITY OF NORMAL GASEOUS EMISSIONS

Pounds per Hour

	Section 200C:	Section 300C: Gasification		Section 800C:	Section 2000C: Steam Generation		Section 3000C:		
	Air Separation	Lock Hoppers	Quench Vent	Gas Drying	Stack Gas	Dryer Vent	Incinerator	Flare	TOTAL
Nitrogen & Rare Gases	2,336,432	-	1	-	2,763,995	353,090	139,573	-	5,593,091
Oxygen	57,219	-	77	-	136,342	106,892	7,024	-	307,554
Carbon Dioxide	-	3,965	967	-	911,550	1,264	1,588,954	-	2,506,700
Sulfur Dioxide	-	-	-	-	2,356	-	346	-	2,702
Methane	-	-	-	-	-	-	-	64	64
Water Vapor	19,782	-	116	534	407,878	38,393	17,540	6,900	491,143
Total	2,413,433	3,965	1,161	534	4,222,121	499,639	1,753,437	6,964	8,901,254
Temperature, ^{o}F	94	68	250	220	180	120	350	75	-

Note: The cooling water towers and steam system emit 5,475,300 pounds per hour of water vapor to the atmosphere.

The Commercial Plant is expected to be located in a rural area. About 480 acres of land are required for constructing the plant. An additional 1,800 acres are required for solid wastes disposal over the 20-year life of the plant. Some 260 acres are needed to provide a buffer zone around the plant.

The Mississippi River near Wood River, Illinois, is the primary source of water for the plant. The daily flow at this point is 9 billion gallons; the plant requirements are 17.6 million gallons per day. Thus, the plant water requirements will have little impact on the river.

The plant will have a direct and positive impact on the economic well-being of the area in which it is located. The plant will employ 676 people, and the annual payroll will exceed 13 million dollars. Some 2,000 construction workers on the average will be employed during the 4-year construction period.

6.0 INDEX FOR TASK I INFORMATION

The Statement of Work for Contract No. EF-77-C-01-2542 lists the information which is to be included in the Task I, Design and Evaluation of Commercial Plant, reports. The FE-2542-10 volume in which the requisite information may be found is identified below:

	Volume No. FE-2542-10
Overall Block Flow Diagram	2
Overall Heat and Material Balance	2
Thermal Efficiency	1 & 2
Section (Sub-system) Material Balances	2
Process Flowsheets	2
Stream Compositions, Flow Rates, Temperatures and Pressures	2
Process Descriptions	2
Equipment Lists	2
Plot Plan	2 & 4
Site Requirements	2 & 4
Composition of Products	2 & 4
Composition of Waste Streams	2 & 4
Steam Balance	2
Water Balance	2
Power Requirements	1 & 2
Chemical & Catalyst Requirements	2 & 3
Plant Personnel Requirements	3
Plant Investment Estimate	3
Cost of Product Gas	3
Economic Analysis	3
Environmental Impact	4
Technical Assessment	3

)VERNMENT PRINTING OFFICE: 1979-640-092/589