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PIPELINE GAS DEMONSTRATION PLANT

Phase I
ABBREVIATED VERSION OF
CONCEPTUAL COMMERCIAL PLANT DESIGN.

VOLUME 1.

SECTION 1
EXECUTIVE SUMMARY:

SECTION 2.

COMMERCIAL PLANT DESCRIPTION

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The original version of this report was published as FE-2012-027 in May 1978 and contained proprietary information from various process licensors. In order to provide the Technical Information Center with a non-proproetary document to publish, it was necessary to delete portions of this information in as complete and consistant a format as possible. Some of these deletions, however, will be apparent, particularly in the Detailed Area Concept and Descriptions and the Plant Operating Concept.

CONCEPTUAL COMMERCIAL PLANT DESIGN

The Conceptual Commercial Plant Design Report (CCD) describes the ICGG Conceptual Commercial Plant which has evolved from the work accomplished for Phase I, Task I, Conceptual Design and Evaluation of Commercial Plant, under Contract No. EF-77-C-01-2012. The CCD has been developed in detail from the Tentative Baseline Design (FE-2012-004, August 5, 1977) submitted as the initial Commercial Plant Design and contains the results and recommendations of the Process Evaluation Report (FE-2012-027, May 1978) and the Revised Tentative Baseline Design (FE-2012-038)). The CCD is described in seven sections as follows:

Section 1 - Executive Summary

This section provides an overview of the Conceptual Commercial Plant Design Report.

Section 2 - Commercial Plant Description

This section presents a brief description of the plant, its design basis, specifications for design, an overview of the plant control concept, process flexibility, design maturity and risks, and an assessment of the commercial availability and reliability of the items of major process equipment.

Section 3 - Environmental Considerations

This section describes the present environmental setting for the plant and discusses the impact of construction and operations on this environment.

Section 4 - Detailed Area Concept and Descriptions

This section describes the 20 plant areas that make up the ICGG Conceptual Commercial Plant. Process flows, descriptions, design basis, equipment specifications, utility requirements, etc., are provided for each plant area.

Section 5 - Plant Operating Concept

This section provides a description of the plant personnel and plant operations, an outline of start up and shutdown procedures, and a brief description of plant shakedown, system testing, maintenance, safety and laboratory support.

Section 6 - Products and Byproducts

This section describes the products and byproducts which will be produced by the Commercial Plant and discusses their marketability.

Section 7 - Economic Assessment

This section presents an economic assessment of the Conceptual Commercial Plant including estimated capital requirements, operating costs, a discounted cash flow analysis to determine the required gas selling price, and an analysis of the sensitivity of the gas selling price to various economic factors.

THE ILLINOIS COAL GASIFICATION GROUP

1.0 EXECUTIVE SUMMARY

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1.0 EXECUTIVE SUMMARY

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The Conceptual Commercial Plant Design Report (CCD) defines the final Commercial Plant Baseline which has been developed from the Tentative Baseline Design FE-2012-004, August 1977, the Process Evaluation Report FE-2012-027, May, 1978, and the Revised Tentative Baseline Design, FE-2012-038, August 1978. Incorporated in the final conceptual baseline are the results and recommendations of comprehensive analyses and studies which were made by the Illinois Coal Gasification Group to increase operating flexibility, reduce risk and enhance cost effectiveness of the ICGG Conceptual Commercial Plant which utilizes the COGAS Process for producing synthetic pipeline gas (SPG) from coal.

The comprehensive analyses and studies in conjunction with the successful implementation of the Technical Support Plan have confirmed that:

- The COGAS Process is ready for demonstration.
- The technical risk is inherently low and there is a high probability of operating feasibility and economic viability for the Commercial Plant.
- The use of commercially proven process technology and commercially available components has been maximized to reduce technical risk.
- The integration of multiple processes is technically feasible and desirable resulting in a high thermal yield.
- The process is safe, reliable and environmentally acceptable.
- The plant is inherently flexible having a high turn-down ratio. The design changes required in order to process various coal types have been identified and are achievable.

The CCD report was submitted to the U.S. Department of Energy (DOE) as the final contract deliverable for Phase I, Stage I, Task I: Conceptual Design and Evaluation of Commercial Plant, under Contract No. EF-77-C-01-2012.

THE ILLINOIS COAL GASIFICATION GROUP

1.0 EXECUTIVE SUMMARY

FE/2012/Z/80/06
July 1980

1.1 SUMMARY

The first step in the development of the Conceptual Commercial Plant Design was the preparation of the Tentative Baseline Design (TBD), FE-2012-004, August 1977. The TBD included the following:

- Design Data Tabulation
- Process Flow Diagrams
- Material and Energy Balances
- Process Descriptions

The TBD was expanded to the Baseline Process Concept, presented in Section 5.0 of the Process Evaluation Report (PER), FE-2012-027, May 1978, (Abbreviated version published as FE-2012-096, May 1980) through the preparation of:

- Preliminary Equipment Specifications
- Steam Power Balances
- Utility Balances
- Reagent Summaries
- Conceptual Layout Drawings

Estimates of installed cost, total capital requirement, operating cost and gas selling price were prepared to define the Baseline Economic Evaluation presented in Section 6.0 of the PER.

Thus, a complete technical and economic baseline was developed for the optimization and evaluation studies undertaken. ICGG used this information as a tool to:

- Define area and process subsystem performance requirements.
- Select viable alternatives to the Baseline Process Concept.
- Assess the technical and economic impact of each alternative on an area by area basis or on a total plant basis as appropriate.

Process analysis studies were conducted for the Conceptual Commercial Plant at three performance levels:

- Overall Plant

1.1 SUMMARY - continued

- Process Areas
- Area Subsystems

Process trade-off studies were conducted on an area basis in 11 of the 20 plant areas. In all, 35 alternative unit processes were considered. Similarly, 17 process design studies were performed on subsystems in 9 areas.

The evaluation criteria for the selection or rejection of alternatives included capital requirements, operating costs and appropriate technical considerations. A general philosophy of conservatism was employed in all of the evaluations. This approach is in accord with ICGG's criteria for selecting systems which have:

- Proven Commercial Applications
- Good Reliability and Maintainability
- Definable Cost Elements
- Minimum Environmental Impact

Total plant impact was also evaluated by adjusting the baseline economics and assessing the "ripple" effect in other plant areas.

Following the completion of the PER, the preparation of the Revised Tentative Baseline Design (RTBD), FE-2012-038, August 1978, was undertaken to incorporate the numerous recommendations derived from the trade-off studies and the comprehensive design analysis for process changes and equipment replacements into an integrated plant possessing high thermal efficiency and favorable economics. In unison with this effort, revised mass and energy balances based on the latest pilot plant data were factored into the evolving design. During the process of integration, it became obvious that the cumulative impact of all the changes mandated a reevaluation of the recommendations made in the PER for Areas 105, 106 and 108. The ensuing in depth studies resulted in additional modifications which were incorporated in the RTBD.

The Conceptual Commercial Plant Design (CCD) is based on processes described in the results and recommendations of the Process Evaluation Report conducted for Task I. The changes necessitated by their subsequent integration into the Conceptual Commercial Plant Design are summarized in Table 1.1-1.

Table 1.1-1 - Sheet 1 of 4

COMPARISON OF TENTATIVE BASELINE DESIGN AND CONCEPTUAL COMMERCIAL PLANT DESIGN

Area No.	Description	Tentative Baseline Design	Conceptual Commercial Plant Design
102	COAL PREPARATION		
	Coal Dryer	Fluid bed drying to 7% moisture with flue gas from coal-fired dryer furnace.	No drying under normal operation. Standby dryer for excessively wet coal feed.
	Pressurizing System	Lock hopper feeding system.	Fuller-Kinyon Pump
103	PYROLYSIS & GASIFICATION		
	Auxiliary Furnace for Pyrolysis Steps 1 & 2	Direct Heating	Direct Heating
	Solids Transport	Use quenched pyrolysis gas for transport.	Use quenched pyrolysis gas for transport.
	Slag Removal	Initial slag removal system designed by United Conveyor.	Slag removal system modified as suggested by United Conveyor.
	Pittsburgh Coal Pyrolysis	-----	Oxidation in multiple stages.
	Mixing Section	TBD Design	Lift tube diameter reduced; mechanical design improved.
104	OIL RECOVERY AND TREATMENT		
	Oil-Solids Separation	Oil filtration, H-Oil Process	Vacuum distillation, H-Oil Process
	Oil Treatment	Syncrude as byproduct.	Fuel oil and naphtha as by-products.

Table 1.1-1 - Sheet 2 of 4

COMPARISON OF TENTATIVE BASELINE DESIGN AND CONCEPTUAL COMMERCIAL PLANT DESIGN

Area No.	Description	Tentative Baseline Design	Conceptual Commercial Plant Design
104	OIL RECOVERY AND TREATMENT (continued)		
	Ebullated Bed Reactor	TBD Concept	Reduced number of reactors.
	Number of Trains Downstream of Ebullated Bed	Three trains	Single train
105	GAS PURIFICATION	Conceptual Selexol Process with Light Oil Wash	Shell Sulfinol with ADIP. Light oil wash was eliminated; light hydrocarbons are now processed into SPG in Area 107.
106	HYDROGEN GENERATION	Three-stage CO Shift, with CO_2 Removal and Single-stage Methanation	Split stream feed, four CO shift stages, CO_2 removal (Benfield), and pressure swing adsorbers for hydrogen stream purification.
107	SHIFT AND METHANATION	R. M. Parsons Co., Combined Shift & Methanation Process with Auxiliary Fuel Oil Firing	R. M. Parsons, Modified Combined Shift & Methanation Process: The recommended process is further modified to process the light hydrocarbons in the feed stream. Pipeline gas compression was relocated from Area 109 to Area 108 and final methanation is performed at 1095 psig. Use of auxiliary fuel oil eliminated.

Table 1.1-1 - Sheet 3 of 4

COMPARISON OF TENTATIVE BASELINE DESIGN AND CONCEPTUAL COMMERCIAL PLANT DESIGN

Area No.	Description	Tentative Baseline Design	Conceptual Commercial Plant Design
108	BULK CO_2 REMOVAL AND GAS COMPRESSION	Conceptual Selexol Process	Benfield Process: pipeline gas compressors relocated from Area 109.
109	GAS COMPRESSION AND DEHYDRATION	Glycol Dehydration	Glycol dehydration: pipeline gas compressor relocated to Area 108.
110	FLUE GAS POWER RECOVERY		
	Flue Gas Expanders	Twelve single-stage expanders	Six two-stage expanders
	Electric Generator	No generator	Use electric generator
	Generator Configuration	Flue gas expander drives the process air compressor only. No electric generator. Separate steam turbine driven flue gas oxidizer power generator.	Combined generator for steam turbine and flue gas expander. The process air compressor will also be combined with these. This eliminates the flue gas oxidizer power generator system used in baseline.
111	SO_2 REMOVAL	Wellman-Lord (Davy Powergas)	FMC Double Alkali Process
112	SULFUR RECOVERY	Claus Plant to recover elemental sulfur only	Claus Plant plus sulfuric acid plant for production of either byproduct.
116	WATER SUPPLY	Mechanically cleaned bar screen for large debris removal. Mechanically cleaned traveling screen for removal of solids >1/8". Chlorine and cationic	In-line strainer added to minimize suspended solids delivery to plant site. Type of raw water intake to be determined

Table 1.1-1 - Sheet 4 of 4

COMPARISON OF TENTATIVE BASELINE DESIGN AND CONCEPTUAL COMMERCIAL PLANT DESIGN

Area No.	Description	Tentative Baseline Design	Conceptual Commercial Plant Design
116	WATER SUPPLY (continued)	polymer injection systems. Systems of pumps to pump water through 20 mile pipeline to plant. Imported electric power; fuel oil for emergency power generation.	from local use recommedations and government regulations.
117	WATER TREATMENT SYSTEMS		
	Water Softening and Demineralization	Cold lime-soda softening with recarbonation followed by clarification and filtration for cooling tower, process, low pressure boiler make up, and potable water after chlorination. Carbon adsorption and fixed bed demineralized for high pressure boiler make up.	Dealkalization instead of cold lime-soda softening. Anthracite instead of sand filtration. Moving bed instead of fixed bed demineralization.
118	WATER TREATMENT AND DISPOSAL	Biotreatment only for Phenolic Waste; Separate Evaporation of Inorganic Wastes	Evaporation of phenolic waste plus biotreatment; separate evaporation of inorganic aqueous wastes. Provisions for impounding rain water run off and subsequent treatment, if contaminated.

1.2 COMMERCIAL PLANT DESCRIPTION

Section 2 of the CCD provides a description of the Conceptual Commercial Plant included as subsections:

2.1 Design Basis And Considerations
2.2 General Specifications
2.3 Plant Descriptions
2.4 Control Concept
2.5 Process Flexibility
2.6 Design Maturity And Risk
2.7 Equipment And Material Considerations
2.8 Plant Reliability

1.2.1 Design Basis and Considerations

Subsection 2.1 presents the design basis for the Conceptual Commercial Plant. The objectives for the Conceptual Commercial Plant were:

- To obtain a comprehensive process design based on the maximum use of proven commercially available components and equipment.
- To obtain reliable estimates of the costs to produce the primary product and byproducts.
- To identify the characteristics and requirements for a Demonstration Plant.

The more salient criteria of the design basis were:

Site Location	Perry County, Illinois
Feedstocks	25,935 TPD Illinois No. 6 coal 4,960 KW Electric Power 16.52 MM GPD Water
Product	264.53 MM SCFD SPG HHV 951 Btu/SCF
Byproducts	16,823 bbl/d Fuel Oil 3,815 bbl/d Naphtha 47.9 TPD Anhydrous Ammonia 2,178 TPD 93.2% Sulfuric Acid (or 682 TPD Sulfur)
Gaseous Wastes	108,127 TPD Desulfurized Flue Gas 8,273 TPD Carbon Dioxide 666 TPD Thermal Oxidizer Vent

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.1 Design Basis And Considerations - continued

Solid Waste Products (On Site Disposal)	2,983.4 TPD Slag 1,890.1 TPD $CaSO_3$ Sludge 68.0 TPD Water Treatment Sludge 86.0 TPD Soluble Salts 88.2 TPD Ash 39.1 TPD Lime Grits
Liquid Waste Products	Zero liquid discharge of process wastes
Thermal Efficiency	65.3%
Plant Effectiveness	90.4% (330 days of operation annually)

Compositions and/or properties of the feedstock and waste effluent streams are included in Section 2.0.

1.2.2 General Specifications

The Commercial Plant will be built in accordance with applicable codes and standards to assure the quality of the materials, fabrication and construction for the components, systems and structures comprising this plant. Outline specifications are included in Subsection 2.2 which illustrate the nature of these standards and to denote the type of materials that are being considered for the plant. Outline specifications are included for:

- Civil
- Electrical
- Instrumentation
- Piping

1.2.3 Plant Description

The ICGG Commercial Plant Concept is a self contained, grassroots facility which will product 264.53 million standard cubic feet per day (MMSCFD) of synthetic pipeline gas from Illinois No. 6 coal. The plant is divided into 20 areas with several areas having multiple process trains. Table 1.2.3-1 lists the 20 plant areas and identifies the number of process trains in each area.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.3 Plant Description - continued

Table 1.2.3-1

Number of Trains in Commercial Plant

Area Number		No. of Trains
101	Coal Unloading and Handling	1
102	Coal Preparation	3
103	Pyrolysis and Gasification	3
104	Oil Recovery and Treatment	3
105	Gas Purification	3
106	Hydrogen Generation	1
107	Shift and Methanation	3
108	Bulk CO_2 Removal and Gas Compression	3
109	Gas Dehydration	1
110	Flue Gas Power Recovery	3
111	SO_2 Removal	1
112	Sulfur Recovery	1
113	Ammonia Recovery	1
114	Thermal Oxidizer and Flare	1
115	Utilities	1
116	Water Supply	1
117	Water Treatment Systems	1
118	Waste Treatment and Disposal	1
119	Fire Protection System	1
120	Facilities	1

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.3 Plant Description - continued

The resulting Commercial Plant Concept is illustrated by the simplified block flow diagram in Figure 1.2.3-1. A brief process description follows:

Area 101 - Coal Unloading and Handling

Run of mine coal is delivered to the plant either by overland conveyor or by unit train. The Coal Unloading and Handling area is a single train system with facilities to receive the coal on an intermittent basis, crush it to 1-1/2' x 0", store it in outdoor piles for 30 days, and reclaim and deliver it to Area 102, Coal Preparation, on a continuous basis.

Area 102 - Coal Preparation

Coal feed from the storage area is split into 3 parallel streams, crushed, screened to a minus 10 mesh size and elevated into a storage silo. Fuller-Kinyon pumps raise the pressure of the coal leaving the silo from atmospheric to operating pressure, and feed the coal to the first stage pyrolysis vessel in Area 103.

Area 103 - Pyrolysis and Gasification

The Pyrolysis and Gasification area is the heart of the Commercial Plant. It is here that coal is converted into raw oil and synthesis gas which, after treatment, become the major plant products. Ground, sized coal is fed to the first stage pyrolysis vessel. The coal is dried and devolatilized in 4 pyrolysis stages to produce char and pyrolysis gas. Char then enters the gasifier where it reacts with steam to produce additional gas. Gasifier gas is recycled to pyrolysis to supply heat and becomes part of the gas leaving pyrolysis. The mixture of gasifier gas and pyrolysis gas is sent to Area 104, Oil Recovery and Treatment. Ungasified char fines are burned in the combustor and supply heat to the gasifier through a char recycle stream. Flue gas leaving the combustor flows to Area 110, Flue Gas Power Recovery. The ash from the feed coal is rejected from the combustor as slag, quenched and is sent to land-fill.

Area 104 - Oil Recovery and Treatment

Gas leaving the pyrolysis section of Area 103 is quench-cooled in a series of venturi scrubbers to condense the oil and water vapors. The liquid from each scrubber is decanted, and the water is cooled and recycled with the excess water going to Ammonia Recovery, Area 113. Uncondensed synthesis gas flows to Area 105, Gas

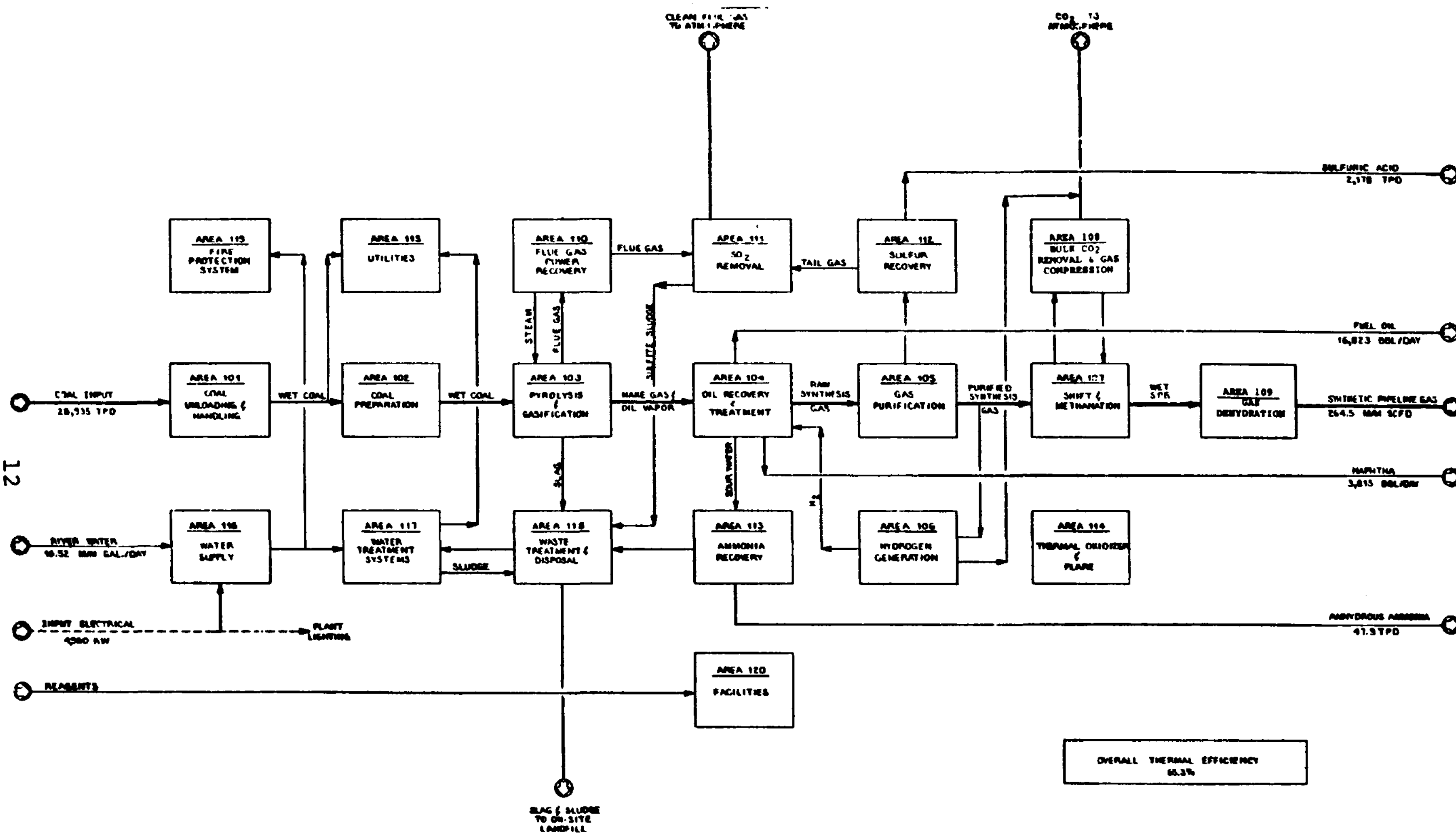

Figure 1.2.3-1 ICGG Conceptual Commercial Plant Simplified Block Flow Diagram.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.3 Plant Description - continued

Area 104 - Oil Recovery and Treatment

Purification. Oil recovered in the decanters is dehydrated, then stored or sent to an H-Oil® reactor for hydrotreating. Hydrotreated oil is further processed to yield a No. 4 fuel oil and naphtha.

Area 105 - Gas Purification

In this area, the uncondensed synthesis gas from Area 104, Oil Recovery and Treatment, is first compressed to 465 psig. Acid gases such as H_2S and CO_2 are removed from the gas stream and concentrated in the Shell Sulfinol and ADIP Processes, and sent to Area 112, Sulfur Recovery, for further treatment. The synthesis gas stream leaving Area 105, rich in carbon monoxide and hydrogen, is split; the bulk of it flows to Area 107, Shift and Methanation, while the remainder is sent to Area 106, Hydrogen Generation.

Area 106 - Hydrogen Generation

This area provides the hydrogen required for hydrotreating the oil in Area 104. Purified synthesis gas feed is received from Area 105, preheated and the last traces of sulfur compounds are removed. The gas then passes through four converters where carbon monoxide is reacted with steam to form hydrogen and carbon dioxide. This gas stream then passes through a Benfield carbon dioxide absorber to remove CO_2. The gas is then fed to a ten bed, pressure swing adsorption unit for enrichment from 85% to 97% hydrogen through the removal of methane, ethane and carbon monoxide.

Area 107 - Shift and Methanation

The purified synthesis gas feed to this area from Area 105, Gas Purification, first passes through two zinc oxide beds to remove residual sulfur. It then passes through Parsons' combined shift-methanation, wherein a portion of the CO is reacted with steam to produce H_2 for the methanation reaction. One part carbon monoxide and three parts of hydrogen then react to produce methane. After the sixth stage of shift-methanation, the gas is sent to Area 108, Bulk CO_2 Removal and Gas Compression. After the CO_2 is removed, the gas is compressed, returned to Area 107 and passed through a final stage of methanation to reduce the carbon monoxide level. The gas then leaves Area 107 and flows to Area 109, Gas Dehydration.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.3 Plant Description - continued

Area 108 - Bulk CO_2 Removal and Gas Compression

In this area, carbon dioxide is removed from the methanated gas by solvent scrubbing. The gas which has been scrubbed of CO_2 using the Benfield Process is compressed before being returned to Area 107 for final methanation. The solvent is regenerated for reuse, while the carbon dioxide is vented to the atmosphere.

Area 109 - Gas Dehydration

Gas from Area 107, which is saturated with water, is fed to a dehydration column where water vapor is removed in a glycol solution. The glycol is regenerated for reuse, while the water is sent to Area 118, Waste Treatment and Disposal. Dehydrated synthetic pipeline gas flows to the gas pipeline.

Area 110 - Flue Gas Power Recovery

Flue gas from the combustor in Area 103 enters the Flue Gas Oxidizer where the combustibles, (CO, H_2, and H_2S) and char fines are burned to generate steam. Hot gas leaving the oxidizer is cooled, and cleaned then expanded through turbines. These expander turbines drive air compressors, which supply the air to the oxidizer and to the combustor in Area 103, and electric generators. Additional heat is recovered by generating steam and the flue gas stream is sent to Area 111, SO_2 Removal.

Area 111 - SO_2 Removal

Gas streams containing SO_2 flow from Area 115, Utilities, Area 110, Flue Gas Power Recovery, and Area 112, Sulfur Recovery, for treatment in Area 111. Flue gas is stripped of SO_2 using the FMC Double Alkali Process and then vented to the atmosphere.

Area 112 - Sulfur Recovery

Gas streams rich in H_2S are received from Area 105, Gas Purification and Area 113, Ammonia Recovery, and processed into elemental sulfur in a Claus plant. Molten sulfur is then converted into sulfuric acid and sent to storage. Vent gases from the Claus plant and Sulfuric Acid plant flow to Area 111, SO_2 Removal.

Area 113 - Ammonia Recovery

Sour water produced in Area 103, Pyrolysis and Gasification, and Area 104, Oil Recovery and Treatment, is processed to recover anhydrous ammonia using the Phosam-W Process. The sour water is stripped with steam to remove ammonia and H_2S. Stripped water

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.3 Plant Description - continued

Area 113 - Ammonia Recovery

flows to Area 118, Waste Treatment and Disposal, while stripped gas is routed through an ammonia scrubber to remove the ammonia in an ammonium phosphate solution. The remaining gas (H_2S and H_2O) is sent to Area 112, Sulfur Recovery. The rich solution from the ammonia scrubber is then stripped of its ammonia, and lean phosphate solution is thus regenerated and recycled. Ammonia is condensed and sent to storage in Area 120.

Area 114 - Thermal Oxidizer and Flare

Thermal Oxidizer - Waste streams from collection points in the plant are piped to this area. Liquid and gas are separated and fed to the thermal oxidizer, where they are mixed with combustion air, ignited and burned. Auxiliary fuel is used as needed to insure complete combustion.

Flare - Any off spec product from the plant is sent to the flare. The gas first enters a knock out drum where the entrained oil is separated and pumped to a raw oil storage. The gas then enters the flare where it is burned.

Area 115 - Utilities

This area provides the utilities needed to operate the plant. Included in Area 115 are the following systems:

- Instrument Air
- Plant Air
- Cooling Tower
- Condensate Return Units
- Auxiliary Boiler
- Inert Gas Generation
- Emergency Power Generation
- Main Power Generation Steam Drive

Area 116 - Water Supply

Water is withdrawn from the Mississippi River through bar screens to prevent large debris from entering the system. It then passes through in-line strainers to eliminate smaller debris. Screened water enters the pipeline where chlorine is injected. It is then pumped 20 miles to the plant site where it enters Area 117, Water Treatment Systems.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.3 Plant Description - continued

Area 117 - Water Treatment System

The incoming river water is treated to provide cooling water make up, process and potable water, and high and low pressure boiler feed water make up. All of the raw water is subjected to clarification and filtration. This treatment is adequate for some of the cooling tower make up and quench make up. The remainder of the clarified and filtered water is either dealkalized or demineralized. The dealkalized water is used as potable water (after chlorination), general purpose process water, partial cooling tower make up water, and low pressure boiler feedwater make up. The demineralized water is used for high pressure boiler feedwater make up and provides one third of the cooling tower make up.

Area 118 - Waste Treatment and Disposal

Waste streams from throughout the plant are treated in Area 118. Oily waste streams from plant separators, plant drains, knockout drums and Oil Recovery are fed to an API separator. Oil is returned to Area 104 while the waste is cooled in aeration basins and mixed with plant sanitary wastes and treated in a biotreatment plant. The treated water is used as cooling tower make up and sludge is sent to landfill. Water from Area 113 is treated in an evaporator. Recovered water is sent to Area 117 for treatment and use as boiler feed water. The solids from the evaporator are impounded in a lined, pond. Dissolved inorganic solids are treated in a second evaporator. The water and solids streams are handled in the same way as the corresponding streams from the first evaporator. Holding ponds are provided for storm water run off. If contaminated, the water is treated; if not, it is used as raw make up.

Area 119 - Fire Protection

Water is received directly from the river water pumping station or from the water holding pond which holds a 5 day supply for emergency use. Water is pumped to plant users through a distribution system. Users include fire hydrants, hose stations and sprinkler systems.

Area 120 - Facilities

This area includes the administration buildings, maintenance shops, laboratory, personnel facilities in all areas, railroad facilities, roads and parking facilities, security fencing, and warehouse space. Storage is also provided for major plant products, byproducts and make up chemical reagents.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.4 Control Concept

The basic overall control for the operation of the Commercial Plant will be achieved through a number of Area Control Centers, with the necessary degree of coordination provided by the centralized Supervisory and Operations Center. Primary controls for the operation of the plant will be located in the Area Control Centers and will be the reponsibility of the operator in the area. Personnel in the Supervisory and Operations Center will have the responsibility for the overall operation of the plant and the coordination of inter-area activities. The salient design criterion for the plant control and instrumentation design will be to provide automatic control for optimization of plant and personnel performance.

Automation of the plant with a process computer will:

- Reduce manpower and operation costs
- Optimize Plant Operation
- Provide an early alert of potential trouble

Specialized systems will be required for plant start up, particularly in the pyrolysis-gasification area plus related downstream areas. The logic of the system will permit alternates to be selected by the operator, but the exact manipulation of the valves, rate changes and interlocking will be the function of the system. For shutdown, an automatic emergency system will be included as part of the instrumentation. Since the shutdown procedures will be quite involved, a small programmable controller will be employed to provide multiple, rapid responses required to effect an orderly emergency shutdown.

The control and instrumentation systems for the majority of the process areas have been proven commercially in numerous installations. A few of the areas will have a combination of proven and new designs incorporated into them. These areas, which are identified in Section 2.0, will utilize available, proven system designs from commercial analogs to minimize new system design risks.

1.2.5 Process Flexibility

The Conceptual Commercial Plant Design feed coal is Illinois No. 6 coal with a HHV of 12,400 Btu/lb, dry. Table 1.2.5-1 summarizes the size, ultimate analysis, moisture content and heating value of the coal upon which the Commercial Plant material balance is based. The total coal feed, on an as received basis, is also listed together with the plant product and byproduct yields.

1.2 COMMERCIAL PLANT DESCRIPTIONS

1.2.5 Process Flexibility - continued

The process concept is adaptable to a Western subbituminous coal or a Pittsburgh No. 8 coal as the plant feed. Design modifications or capacity changes are required, however, in coal drying, pyrolysis, oil recovery and treatment, and in other plant areas such as Sulfur Recovery and Ammonia Recovery. Tables 1.2.5-1, 1.2.5-2, 1.2.5-3 and 1.2.5-4 summarize the results of changing coal types.

Compositions and quantities of principal waste products discharged by the plant as a function of coal feeds are presented in Subsection 2.5. Means of disposing of the waste products in an environmentally acceptable way are discussed in Section 3. Because disposal will be on site, the cost of disposal is inherent in the annualized operating costs for the plant.

Processing of alternate coal feeds, such as Western subbituminous and Pittsburgh No. 8 seam, will require modification to the equipment in the pyrolysis area. These modifications are described in Table 2.5-3 and the accompanying text. Process operating conditions for the major components comprising this subsystem are also given as a function of the coal characteristics represented by the three coal feeds considered.

1.0 EXECUTIVE SUMMARY

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1.2 COMMERCIAL PLANT DESCRIPTION

1.2.5 Process Flexibility - continued

Table 1.2.5-1

Summary of
Composition, and Yield for Alternative Cost Feeds

	Coal Type		
	Illinois No. 6 Seam	Western Subbituminous	Pittsburgh No. 8 Seam
Size (as received)	6" x 0"	6" x 0"	6" x 0"
Ultimate Analysis, % (Dry Basis)			
C	69.00	65.53	76.25
H	4.70	4.34	5.26
N	1.30	0.70	1.46
S	3.80	1.15	3.33
O	9.30	14.29	6.09
Ash	11.90	13.99	7.61
TOTAL	100.00	100.00	100.00
Moisture Content, %	10.0	25.5	4.0
Higher Heating Value (Btu/lb, Dry)	12,400	11,230	13,850
Product/Byproduct Yields (Per 1,000 TPD of coal, as received)			
SPG, MM SCFD	10.2	8.51	12.6
Fuel Oil, bbl/d	649	244	704
Naphtha, bbl/d	147	81	85
Sulfuric Acid/Sulfur, TPD	84/26.3	20.3/6.4	81.8/25.6
Ammonia, TPD	1.85	0.59	1.48

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.5 Process Flexibility - continued

Table 1.2.5-2

Comparison of Coal Requirements,
Byproduct Yields and Thermal Efficiency
For A Commercial Plant

Feedstocks	Illinois No. 6	Western Subbituminous	Pittsburgh No. 8
Coal Input, TPD	25,935	31,079	21,031
Water, MMGPD	16.52	16.52	16.52
Electricity, KW	4,960	4,960	4,960
Products, Byproducts			
SPG, MMCF/D	264.53	264.53	264.53
Fuel Oil, bbl/d	16,823	7,570	14,804
Naphtha, bbl/d	3,815	2,518	1,793
Sulfuric Acid, TPD	2,178	632	1,721
Anhydrous Ammonia, TPD	47.9	18.2	31.1
Thermal Efficiency	65.3%	60.1%	63.3%

1.0 EXECUTIVE SUMMARY

FE/2012/Z/80/06
July 1980

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.5 Process Flexibility - continued

Table 1.2.5-3

Capital Requirement Summary
Alternative Coal Feeds
(MM$)*

Capital Cost Category	Illinois** No. 6 Seam	Western Subbituminous	Pittsburgh No. 8 Seam
Construction Plans and Drawings	$ 75.445	$ 69.369	$ 72.420
Site Preparation	10.000	10.000	10.000
Plant Construction	1,043.496	964.861	1,004.343
Construction Engineering	70.369	64.703	67.548
Subtotal - Plant Investment Cost	1,199.310	1,108.933	1,154.311
Contingency	177.368	164.002	170.713
Land****	2.039	2.039	2.039
Start Up	26.695	6.253	16.271
Administration	4.150	4.150	4.150
Working Capital	30.857	25.425	28.673
Royalties	20.000	20.000	20.000
Catalyst and Chemicals	12.154	6.601	9.951
Total Capital Requirement***	$1,472.573	$1,337.403	$1,406.108

* Mid 1978 dollars

** Economic Assessment, Section 7.0

*** Interest during construction is not included per DOE guidelines

**** Assumed Cost

1.2.5 Process Flexibility - continued

Table 1.2.5-4

Operating Cost Summary
Alternative Coal Feeds
(MM$/yr)*

Operating Cost Category	Illinois** No. 6 Seam	Western Subbituminous	Pittsburgh No. 8 Seam
Coal	$195.563	$ 87.689	$146.092
Labor	23.138	23.443	22.994
Catalysts and Chemicals	20.769	11.280	17.005
Insurance and Taxes	7.837	7.837	7.837
Maintenance Repairs and Replacements	30.426	27.319	28.879
Utilities	1.060	1.060	1.060
Other Operating Supplies	2.293	2.384	2.250
Gross Operating Cost	281.086	161.012	226.117
Less Byproduct Credits	(146.096)	(64.048)	(116.080)
Net Operating Cost	$134.990	$ 96.964	$110.037
Coal Cost $/Ton • Discount Rate = 9% • Federal Income Tax = 0 • Straight Line Depreciation	$22.85	$8.55	$21.05
Gas Cost (Selling Price), $/MM Btu	$ 4.00	$3.31	$ 3.58

* Mid 1978 dollars

** Economic Assessment, Section 7.0

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.6 Design Maturity and Risks

The ultimate goal of the Demonstration Plant Program is the development of information which will permit the construction of a Commercial Plant with a minimum of risk. To this end, the requirements for design and construction of a Commercial Plant have been identified and evaluated in terms of:

- Critical process assumptions used in the development of the process design
- Process steps where the technology is lacking
- Reaction vessels for which materials of construction are uncertain
- Elements of the plant for which design procedures are inadequate

The characteristics of the Demonstration Plant will be tailored to yield the required confirmation of critical assumptions, elimination of questionable areas and reduction of residual risks to a minimum. Critical assumptions to be confirmed in the Demonstration Plant are identified in Subsection 2.6 along with an assessment of risk. Table 1.2.6-1 addresses critical process assumptions not verifiable in the Demonstration Plant. A current assessment of risk for various items is shown in Table 1.2.6-2.

1.2 COMMERCIAL PLANT DESCRIPTION

1 2.6 Design Maturity and Data - continued

Table 1.2.6-1

Critical Process Assumptions Not Verifiable in Demonstration Plant

Assumptions	Comments
Area 101	
Method for coal delivery	Long term coal supply contracts will determine methods required.
Area 104	
Stability of petroleum product price structure	No reason to believe the price structure will become unfavorable.
Limitation on NO_x emissions by EPA	Predicted NO_x emissions from fuel oil 40% below current regulations.
Area 116	
Quality of water source will not deteriorate	Ever tightening regulations will tend to improve water quality. Increased silt loading does not constitute a serious problem.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.6 Design Maturity and Data - continued

Table 1.2.6-2

Identification and Assessment of Risks

Risk Description	Assessment
Area 102	
Fuller-Kinyon pumps for coal pressurization	Low
Area 103	
Agglomeration in pyrolysis	Low
Ash balance in gasifier	Negligible
Fines balance in gasifier-combustor	Low
Char circulation control valve	Low
Mixing section mechanical design	Moderate
Flue gas combustible levels	Moderate
Vertical slagging cyclone combustor	Low
Area 104	
Catalyst life in ebullating bed	Low
Area 107	
Shift and methanation	Moderate
Area 110	
Flue gas oxidizer availability	Low
Expander erosion	Low
Expander deposition	Low
Area 118	
Quantity and composition of waste streams	Moderate

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.7 Equipment and Material Considerations

Equipment

The number of non-duplicated items of major process equipment in the Conceptual Commercial Plant design is in excess of 700. From these, 45 are considered to be critical items of equipment and are identified in Subsection 2.7. Of these critical items, the following have been classified as components whose design and operation are uncertain because of lack of historical data:

- Combustor
- Combustor Mixing Section
- Combustor Lift Tube
- Methanators numbers 1 to 6
- Final Methanator
- Two-stage Expander for Air Compressor
- Flue Gas Oxidizer

The uncertainity associated with these items exists because of lack of operating histories. Design difficulties are not anticipated.

Finally, from the total list of equipment, only the Flue Gas Oxidizer has been established as "not commercially available".

Materials

As with equipment, the Commercial Plant will utilize to the fullest, materials of construction that are available from a multiplicity of sources and in ample supply. No unusual or rare materials are identifiable during this conceptual stage of the design.

Most of the materials of construction for equipment and piping in hostile environments have proven their resistance to abrasion and chemical attack in numerous commercial installations. Even in those instances where historical data are not available, guidance is available from pilot plant operations.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.7 Equipment and Material Considerations - continued

Materials

On the basis of this type of information and/or the service conditions, the materials of construction will be selected. To describe the selection procedure for all the numerous environments to be encountered in the plant would make this report unnecessarily voluminous. However, an example describing the considerations given to the service conditions before the selection of the materials of construction is finalized is provided in Subsection 2.7. This is representative of the procedure to be followed for all but routine selections of materials.

1.2 COMMERCIAL PLANT DESCRIPTION

1.2.8 Reliability

The subsystems and equipment comprising the process areas in the Commercial Plant are identical to or have commercial analogs which have consistently provided on stream factors in excess of 90% in numerous installations for many years. The purpose of the study conducted was not to confirm what already is known but to evaluate the reliability of these subsystems and equipment in their new applications in pyrolysis, gasification and adjunct areas. Because of the scarcity of factual information required for the conventional approach to a reliability evaluation, methodology was developed and the necessary values established using published information, industrial experience and engineering judgment. All items of equipment in the areas studied were considered in the evaluation.

The engineering approaches to be used in the design, engineering and estimating of the Commercial Plant are also common to the petroleum refinery. The codes and standards are identical. Therefore, it is to be expected that the use of the same technology, methodology and suppliers of commercially available equipment and materials will yield availabilities in the Commercial Plant similar to those experienced in commercial analogs in refineries.

To achieve a reliability estimate under these circumstances, it was necessary to use a theoretical rather than a factual basis. The analytical method used for estimating the pertinent reliability and availability factors in this analysis is based on statistical methods presented in various standard texts on system reliability.

Subsection 2.8 shows that for three trains of the Commercial Plant there is a 90% probability of achieving a production rate factor of 0.9.

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.1 Present Environmental Setting

While the Commercial Plant Site has not been precisely defined, it is assumed to be in the immediate vicinity of the Demonstration Plant. Because of this, data obtained from the baseline monitoring program for the Demonstration Plant are used in describing the present environmental setting of the Commercial Plant where applicable.

The Commercial Plant Site will be located in the southwest corner of Perry County and will encompass approximately 1300 acres. It is about one and one half miles east of Willisville and three miles south of Cutler, about 60 miles southeast of St. Louis, Missouri.

The Mississippi River is approximately 17 miles west of the site and will provide all of the water for the plant. The water will be piped from an intake on the Mississippi River south of Chester, Illinois. The water to be withdrawn is an insignificant fraction of the river flow. Water quality values for most parameters are well within standards for general use.

The site vicinity is generally within the drainage basin of Pipestone Creek, part of the Big Muddy River Basin. The site drains by seepage into the ground, and little if any runoff from the site proper reaches the small streams in the area.

Field tests have shown that aquifers in the bedrock should be largely unaffected by leachates from the site. However, shallow aquifers in the surficial deposits and water quality in Pipestone Creek could be affected by flow through permeable overburden strata or by lateral flow along the rock's surface.

The humid continental climate of the site region is temperate with warm summers and cool winters. Periods of extreme heat or cold are not likely to persist. Extreme weather including high winds, glaze ice, hail, fog and tornadoes have occurred in the site area, but these are infrequent.

The site region is designated as an attainment area for total suspended particulates and sulfur dioxide and is an unclassifiable area for carbon monoxide, photochemical oxidants and nitrogen oxides.

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.1 Present Environmental Setting - continued

Extensive literature searches and studies were made to determine the aquatic, ecology setting of the Mississippi River and the seismic setting. Field surveys and investigations were conducted by Gibbs and Hill and other subcontractors to accurately determine the existing conditions for: topography, soils, geology, and hydrology (including surface water quality).

Major findings of these activities were: (a) Meteorological measurements taken on site indicate a close correlation with historic data from existing Air Measuring Stations in the area; (b) there are no rare or endangered species of flora or fauna in the areas of the Plant site, the water pipeline route or the Mississippi River raw water intake location; and (c) the proposed site lies within an active seismic area.

Measurements of ambient noise levels were taken and found to range from 43.0 to 69.6 dBA, A-weighted, at the site and in the vicinity.

Archaeological studies revealed several sites of limited significance along the right of way. Further studies are required to meet Federal legislative requirements, but it is anticipated that no realignment of the right of way will be necessary.

Socio-economic studies were made by contacting state agencies, local commissions and by reviewing U.S. Census reports. The existing conditions are described for the following subjects: Land Use, Population, Labor and Income, Economic Conditions, and Community Services and Transportation.

Major findings of these studies indicate: (a) an existing labor force is available within normal commuting distances; (b) adequate transportation, medical, police and fire protection facilities exist; (c) there are excess housing units available; (d) only the schools in Perry County are close to their maximum capacity, the other eleven surrounding counties have adequate capacities; and (e) area economic conditions would be benefited by Plant construction.

The visual character of the site and right of way was also studied and no unique features were identified which might be endangered by plant construction.

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.2 Environmental Effects of Construction

There will be temporary and minor impacts on the environment due to construction of the plant, pipeline, and water intake structure.

The principal impacts on air quality will result from dust production and exhaust emissions. Other impacts will result from burning of natural debris and by burning of fuels in temporary construction boilers.

The two principal sources of noise during construction will be construction machinery and equipment and construction traffic. Because of the rural, sparsely populated character of the site area, the noise impact will be minimal.

Construction clearing of vegetation and construction noise and activity may temporarily disturb wildlife by changing habitat conditions. These impacts will be minimal and will not affect any rare or endangered plants or animals. Clearing and construction will probably result in a temporary increase in suspended solids, turbidity and siltation in the adjacent and onsite ditches. Dredging at the intake structure may also result in these temporary local conditions at the Mississippi River. A small number of aquatic organisms in the streams along the right of way will be damaged or destroyed during construction. However, disturbed areas will be restored and impacts will be temporary.

Construction will remove 1300 acres of partially reclaimed strip mine land from use as part time grazing land. There may be minor land use conversion in the site vicinity for commercial and residential use.

There will be few, if any, effects on the permanent population of the site area during construction because nearly all work force needs can be met by recruiting from the local work force within the surrounding twelve county area.

The construction program will provide a significant number of directly and indirectly related jobs for the work force in the surrounding area. This will greatly benefit the economic conditions of a great number of people in the impact area in payroll, retail trade, and taxes.

There will be only a minor impact on housing, education, medical and public health care, police and fire protection services in the area. No expansion of these community services will be necessary for construction. Transportation systems in the site area and region are sufficient for the construction program.

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.2 Environmental Effects of Construction - continued

Since the site has been strip mined, no impacts on archaeological resources are anticipated. However, construction of the water pipeline may impact such resources. Where encountered during construction, these resources will be studied, documented and if necessary, protected. The visual aspects of plant construction will not be out of character with existing mining and coal preparation activities in the region. Construction of the pipeline may have a minor temporary impact on the character of vegetated sections of the right of way.

1.3.3 Environmental Effects of Operation

Operation of the Commercial Plant is anticipated to have primarily positive effects on the natural and socioeconomic environment. Adverse impacts are anticipated to be minor and within acceptable standards in all cases.

Although there will be a number of emissions to the atmosphere, operation will not prevent the attainment or maintenance of national and secondary ambient air quality standards.

Plant generated noise will not exceed Illinois Pollution Control Board noise limitations and will conform to OSHA standards for the workplace.

Impacts on terrestrial ecology will be minimal and will be due principally to loss of habitat at the proposed solid waste disposal landfill area on the site. The water pipeline right of way would receive no lasting environmental impact.

Since the plant is designed for zero discharge of liquid wastes and the water pipeline will be buried, there will be no impact on the aquatic environment of the plant site or right of way. There will be a minimal impact on the local environment of the Mississippi River at the intake due to entrainment of planktonic organisms.

The conversion of the partially reclaimed strip mined site from part time grazing to industrial use will result in a significant increase in the productivity of the land. No adverse impacts on existing or projected site vicinity and regional land use patterns due to plant operation are anticipated.

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.3 Environmental Effects of Operation - continued

A total 1075 workers will be permanently employed at the plant. About 70 of these would relocate to the Plant area. About 850 to 900 additional employment opportunities will be indirectly generated by the plant operations. Approximately $20.8 million annual payroll will be disbursed almost exclusively to employees in the impact area, thereby generating $8 to $10 million and 220 to 250 new jobs in retail sales. These are strong positive effects for the twelve county area.

Based on 1977 tax rates, the plant could yield more than $14 million in real estate tax revenues. Retail sales generated by the plant payroll will yield additional tax revenues to impact area counties.

The existing housing, educational, medical and public health care, and police and fire protection facilities and services are adequate for the minor increase in demand anticipated as a result of plant operations.

There will be no impacts on archaeological resources or unique visual features as a result of plant operation. The plant will, however, be highly visible to the surrounding area; but, due to the character of the existing visual setting, this would not constitute an adverse impact.

Irretrievable resources committed to the plant include the materials and human energy to construct and operate the plant and the feedstocks and makeup chemicals consumed.

Regarding toxic and carcinogenic considerations, analyses of the disposition of potentially harmful trace elements discharged from the Plant shows that the devices installed in the plant to collect solid particulates should effectively control the contamination of the environment by trace elements. Burial of slag and treated solid wastes should pose no danger to underground aquifers. Equilibrium concentrations of trace metals in scrubbing waters should be low enough to enable reuse of the water within the plant. The synthetic pipeline gas will be free of trace elements.

1.3.4 Workplace Safety and Environmental Effects of Accidents

Work place safety is concerned with minimization of potential dangers during Plant construction, and particularly during operation, including physical injury and possible exposure to toxic or carcinogenic chemicals. This will be accomplished by utilizing system

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.4 Workplace Safety and Environmental Effects of Accidents - cont'd.

safety techniques during the design, construction and operation of the plant. Special attention will be paid to designing all facilities in accordance with recognized safety and industry codes as well as compliance to all OSHA requirements.

Safety requirements will be ensured by constant on-site supervision to enforce all safety standards established by ICGG. The ICGG Product Assurance Director will be responsible for the complete safety and training program through representation on the job site by a Safety Engineer and a Safety and Health Engineer.

Environmental effects of accidents will be minimized by proper design and incorporation of safety features such as safe spacing, or location, of facilities and diking areas where hazardous spills could occur, with spray or foam systems also covering the areas.

1.3.5 Preoperational and Operational Monitoring Programs

Environmental monitoring will generally fall into six broad categories as follows:

1) Baseline: As described previously in this summary to determine the existing conditions or setting for each environmental discipline.

2) Construction: Surveillance necessary to assure that all permit conditions, regulatory agency requirements and mitigating measures are being fulfilled during construction. Of primary importance under this activity will be the noise monitoring of construction equipment and the archaeological monitoring along the pipeline right of way.

3) Preoperational: To provide the baseline quantification of those constituents in the soil, water, air and biological tissues which will, or may, be emitted during, or are associated with plant operation and which are regulated by law or are of public health concern.

4) Operational: A continuation of preoperational monitoring during the service life of the plant, to determine any departure from baseline conditions, its magnitude and extent.

1.3 ENVIRONMENTAL CONSIDERATIONS

1.3.5 Preoperational and Operational Monitoring Programs - continued

5) Process: To monitor waste streams and emissions for the service life of the Plant, in order to determine levels of regulated substances and compounds of public health concern.

6) Workplace: To assure the safety of working areas, their freedom from toxic substances and conformity with all regulatory agency requirements.

Monitoring during operation will assure conformity with emission, air quality and OSHA standards. It will detect any leaching or seepage into ground or surface water and will determine levels, if any, of potentially toxic and carcinogenic compounds in waste streams and leachates.

1.3.6 Environmental Benefits and Costs

The most important benefit resulting from the Commercial Plant is the production of pipeline gas and fuel oil from coal, which will yield more energy and emit fewer contaminents than if the coal was utilized directly in coal burning power stations.

A total (indirect plus direct) of 85,466 worker years of employment will be created by the project. Total earnings per year (direct plus indirect) will increase by $88.5 million during construction and by $46.0 million during operation of the plant.

The operational impacts of the plant will not significantly impact aquatic or terrestrial habitats. All discharges to the atmosphere will be in compliance with existing regulations. There will be no detrimental effects attributable to plant discharges under these conditions. There will be no irreversible commitments of land or scarce resources.

Measurable benefits outweigh measurable costs. The unmeasurable benefits (availability of less environmentally damaging fuels) far outweigh the unmeasurable costs.

The construction and operation of the Commercial Plant is a beneficial and economic allocation of society's resources. There are no environmental cost constraints which would prevent the construction of the Commercial Plant.

1.4 DETAILED AREA CONCEPT AND DESCRIPTION

The ICGG Conceptual Commercial Plant is a self contained, grass roots facility designed to produce 264.53 million standard cubic feet per day (SCFD) of synthetic pipeline gas from Illinois No. 6 coal. Run of mine (ROM) coal, raw water and miscellaneous catalysts and chemicals constitute the total feed to the plant. All utilities including electric power are produced on site, except electricity needed to operate the river water pumping station and plant security lighting. Byproducts from the plant are in finished, marketable form and include fuel oil, naphtha, anhydrous ammonia, and sulfuric acid or elemental sulfur. Major waste streams exiting the process are slag, water treatment sludges, carbon dioxide, calcium/sulfite sludge, and desulfurized flue gas. Aqueous wastes are evaporated and recycled internally, thus, facilitating essentially "zero" discharge.

The facility, as shown in Figure 1.2.3-1, is divided into 20 plant areas each containing one or more unit process systems. Area designations and the number of trains in each area are shown in Table 1.2.3-1.

The ICGG Conceptual Commercial Plant Design includes those unit process subsystems selected by the process analyses which evaluated the economic and technical aspects of competitive processes for the various areas of the plant. Section 4.0 is divided into 20 subsections, one for each area of the plant. Each of the 20 subsections is further subdivided into 10 subsections as follows (X = 1 through 20 and represents the respective plant area):

4.X.1 - Design Basis

This subsection presents design criteria in detail for the area. For example, in Shift and Methanation, Area 107, the process scheme, number of trains, feed streams, bulk methanation and final methanation are described.

4.X.2 - Process Descriptions and Flow Diagrams

This subsection provides:

- Comprehensive process flow charts, schematics and mass balances for the area including the chemical composition of the steady state process streams.
- Comprehensive overall energy balances for the area including the enthalpies of entering and exiting streams.
- Comprehensive description of the process steps and complete integrated plant operation on Illinois No. 6, high sulfur coal.

1.4 DETAILED AREA CONCEPT AND DESCRIPION

4.X.3 - Pressure-Temperature Diagrams

This subsection contains the pressure-temperature diagrams which show the process operating conditions for the various components comprising the area when the plant is processing Illinois No. 6 coal. In most of the areas, these conditions will not change when an alternate coal is being utilized as feedstock. The change in conditions that will be necessary in Pyrolysis and Gasification are discussed in Subsection 2.5.

4.X.4 - Energy Balance

This subsection provides a detailed energy balance for the area identifying the contributing components and quantifying the contribution of each.

4.X.5 - Utility Requirements

This subsection delineates the utility usage in the area as a function of the individual items of major process equipment. Overall utility consumption diagrams depicting plant wide usage are included in Subsection 2.3.

4.X.6 - Reagent Summary

This subsection references the pertinent section of the report wherein the chemicals and catalysts required for the operation are identified and usages quantified.

4.X.7 - Control Parameters

This subsection briefly describes the principal parameters in the area which will be controlled for successful plant operation. Subsection 2.4 contains a description of the critical instrumentation and control equipment required for the plant and describes the concept of automation.

4.X.8 - Piping and Instrumentation Drawings

Piping and Instrumentation drawings are included in this subsection showing the basic control concept.

4.X.9 - Equipment Specifications

This subsection provides sizes, materials of construction, proposed fabrication techniques for special items, schematic sketches showing main internal and external features of major vessels and detailed specifications for important

1.4 DETAILED AREA CONCEPT AND DESCRIPTION

4.X.9 - Equipment Specifications - continued

mechanical equipment items in the plant. Preliminary specifications including sizes and/or capacities and materials of construction are also included for the remaining items of process equipment.

4.X.10 - Layout Drawings

The layout drawings showing the process equipment arrangement concept for the area are contained in this subsection.

1.5 OPERATING CONCEPT

1.5.1 Staffing, Management and Training

It is assumed that at the end of a successful period of operation of the ICGG Demonstration Plant that ICGG will proceed with a Commercial Plant Project. Based on a preliminary analysis of plant requriements, the numbers and skills of personnel needed were estimated. An organization structure was devised to assure proper management control. The organization is divided into four major groups totaling 1,075 employes. They are grouped as follows:

• Administration	67 employes
• Operation	415 employes
• Maintenance	520 employes
• Engineering Services	73 employes
Total	1,075 employes

A manning schedule showing the function of the 1,075 employes is included in Subsection 5.1.

Additional particulars for the organization, principal responsibilities of key management personnel, and a typical program outline for personnel training are also described in Subsection 5.1.

1.5.2 Normal Operator Activities

Operators of the Conceptual Commercial plant will be directly responsible for the operation of the equipment and processes in their assigned areas. Operational duties are primarily normal operation of the equipment, shutdown of equipment, and corrective action for abnormal conditions.

The Commercial Plant will staff 84 operators and chief operators on each shift, each with a different job assignment. Each operator will be thoroughly trained not only in general operating techniques and process, but also in the specific characteristics of the equipment in his area and his responsibility.

1.5 OPERATING CONCEPT

1.5.2 Normal Operator Activities - continued

Typical examples of specific operator duties are contained in Subsection 5.2 of this report. Detailed work outlines and job descriptions such as these will be developed for each of the 84 operating positions as well as the other staff positions for the Commercial Plant. The operator responsibilities and equipment types to be operated are expected to be similar to those suggested by the example shown in Subsection 5.2.

1.5.3 System Operating Interactions

The Commercial Plant proposed by ICGG is an integrated processing facility. As with any integrated oil refinery or chemical plant, it is highly dependent upon operation of other units in the processing train. Peak efficiency of the overall plant operation requires the smooth operation of all processing units.

Since the Commercial Plant will contain three semi-independent trains, the upset or failure of one of the component sections of one train does not upset the entire plant to such magnitude, as in the case of a single train plant. Single process sections are provided for Utilities, Hydrogen Generation, Gas Compression, Gas Dehydration, SO_2 Removal, Sulfur Recovery and Ammonia Recovery.

Also discussed in subsection 5.3 are the impacts of abnormal operations in the various process systems and utility areas, and the consequences if timely corrective action is not taken.

1.5.4 Shakedown and System Testing

Construction of a large processing plant like the Commercial Plant is completed in stages. Units will be completed in accordance with a construction schedule that will be developed based on material and manpower availability, and the sequential requirements of start up.

To expedite start up, individual pieces of equipment and plant subsections will be taken over from the contractor as soon as they are mechanically complete, and shakedown and system testing will be conducted. Detailed plans for the commissioning and start up sequence will be continuously updated and efforts coordinated between construction and operating personnel to expedite turnover of units in the proper sequence.

1.5 OPERATING CONCEPT

1.5.4 Shakedown and System Testing - continued

Completed units will be checked for operability and defects in materials and workmanship by test running. Lines will be flushed, system integrity checked functionally, and all equipment and instrumentation operated.

Ideally, the systems checkout will be sequenced so that those units necessary for the operation of others will be started first. Thus, one subsystem builds upon the next, until finally, as the last unit is completed, the plant is ready for start up.

Examples of shakedown testing and plant system testing are given in Subsection 5.4.

1.5.5 Initial Plant Start Up

Subsection 5.5 describes the Commercial Plant start up in three segments.

Initial Start Up - from a cold, empty plant where new process systems are checked, accepted for operation, commissioned and the plant process systems sequentially started up by train, ending with integrated operation of the entire Commercial Plant.

Normal Start Up - from a cold, empty plant that has been shut down, cooled and emptied for maintenance and brought back to design operating condition by sequential start up of plant process systems, by plant train.

Restart - is a special start up case where production in one train has been temporarily stopped by a process malfunction, the malfunction corrected and the train process systems sequentially restarted while the plant is still hot.

An outline of start up procedures and one time manpower, equipment and start up requirements are also identified in Subsection 5.5.

1.5.6 Shutdown

The two classes of Commercial Plant shutdown are Normal (Scheduled) and Emergency (Unscheduled).

- Normal shutdown includes the annual plant turnaround for maintenance and inspection.

1.5 OPERATING CONCEPT

1.5.6 Shutdown - continued

- Emergency shutdown is any unscheduled production outage, usually the result of the failure of one of the integrated plant systems. Restart, with the plant still hot, will follow repair of the system malfunction. Restart is addressed in subsection 5.6.2. Emergency shutdown of the entire three train Commercial Plant will be a rare occurence. Failure of a process system in one train only, causing temporary shutdown of that train, is anticipated.

  Subsection 5.6 presents outline procedures for each.

1.5.7 Maintenance

Three types of maintenance work would be involved in a Commercial Plant. There are:

- Periodic preventive maintenance activities
- Daily corrective and breakdown maintenance
- Shutdown (or turnaround) preventive and corrective maintenance

The scheduling of plant maintenance will be the function of the Maintenance Area Planners. Frequencies of preventive maintenance required will be developed as a result of reliability and maintainability analyses for various items of equipment. Ultimate frequencies may change on a learning curve basis as more plant experience is gained. Scheduling of preventive maintenance, other than turnaround, performed as "daily work" items will be done by the Maintenance Area Planner assisted by an administrative computer program.

A major portion of preventive maintenance will be peformed during the turnaround periods. Critical path analysis using an administrative computer program will be used to schedule necessary materials, manpower and equipment to minimize downtime.

Corrective maintenance will be necessary on a day-to-day basis. Such maintenance will be initiated by a maintenance work order prepared by operating personnel. The work orders will specify priority required. Maintenance Area Planners will schedule necessary men, arrange material deliveries from plant warehouse stock or purchase of materials and their delivery and schedule equipment necessary for the accomplishment of the task.

1.5 OPERATING CONCEPT

1.5.7 Maintenance - continued

ICGG plans an adequate maintenance staff to accomplish both daily preventive and corrective maintenance required. The services of a maintenance contractor will be required to assist in the work required for the turnaround shutdown.

1.5.8 Laboratory Support

In the Commercial Plant, the laboratory will serve primarily to monitor the process streams, supply analytical data needed for control of the process and perform special tests as needed.

A schedule of selected analyses that will be performed on a routine basis is provided in Subsection 5.8.

1.5.9 Safety

Safety will be a prime consideration during the design, construction and operation of the Commercial Plant. Three distinct aspects under the general heading of "Safety" will be addressed, namely:

System Safety

- Process and Equipment Design
- Personnel Training
- Safety Inspection
- Hazard Identification
- Code Compliance

Safety and Health

- Accident Prevention
- Accident Investigation/Correcton
- Safety Training (First Aid, Fire, etc.)
- OSHA Compliance
- Safety Inspections

Safety - Medical Aspects

- Carcinogenics

1.5 OPERATING CONCEPT

1.5.9 Safety - continued

System Safety - Safety and Health

"System Safety" refers to the elimination of system hazards through design, construction and operating techniques developed with consideration of safety as a prime ingredient. "Safety and Health" refers to the elimination of general plant hazards and establishment of safe, healthful working conditions for plant personnel. In the proposed program, System Safety will consider specific systems hazards, such as process fluids, interaction and location of process area, equipment failure, emergency procedures and operator and maintenance personnel training. Safety and Health will consider working conditions and safety training during all three phases of effort for the Commercial Plant.

The medical aspects of safety will be deeply involved with the effects of plant materials upon the physical systems of personnel and will be the responsibility of the ICGG Product Assurance Director.

Safety - Carcinogenic

The medical and hygiene literature report evidence that coal tars and coke oven gas may be carcinogenic and care must be taken to maintain a high degree of material confinement for personnel protection. In the design and operation of the Commercial Plant, provisions will be made for protecting the safety and health of the operators and maintenance personnel in any operation where exposure to carcinogens is possible. In addition to the protective provisions that will be incorporated in the design of the plant, stringent safety and health safeguards for operational and maintenance personnel will be required.

Organization

Because of the diversity of the safety efforts, a team of specialists will be utilized, with a phase in of their respective safety disciplines as required by the program. Director of the overall system's safety and safety and health efforts will be the responsibility of the ICGG Product Assurance Director. Since the safety effort will require coordinated action, primarily between ICGG, the A/E subcontractor and the construction subcontractor the safety organization has been arranged as shown by Figures 5.9-1 and 5.9-2 in subsection 5.9.

1.5 OPERATING CONCEPT

1.5.9 Safety - continued

Hazards Specification

The hazards investigation during the detailed design will pinpoint those areas where specialized system safety efforts will be required. Most specific potential hazards have been identified in the Hazard Specifications attached to Subsection 5.9. This document establishes the preliminary hazard classification of process materials to be found in the Commercial Plant. It establishes preliminary data references to the life hazards and fire explosion hazards of these materials, precautionary handling and safety techniques, and, where necessary, methodology of personnel protection. It also establishes preliminary electrical classifications for all locations in which specific process materials are handled. In addition, this document lists other hazards which must be addressed in detail in the design engineering phase of this program.

1.6 PRODUCTS AND BYPRODUCTS

1.6.1 Synthetic Pipeline Gas (SPG)

The primary product of the Commercial Plant is synthetic pipeline gas and the principal byproducts are fuel oil and naphtha. Other byproducts are anhydrous ammonia and sulfuric acid . If favorable market conditions exist, the plant has the capability of also producing elemental sulfur. Daily net production rates for the plant are:

- Synthetic Pipeline Gas — 264.53 MM SCF
- Fuel Oil — 16,823 bbl
- Naphtha — 3,815 bbl
- Anhydrous Ammonia — 47.9 tons
- Sulfuric Acid or Elemental Sulfur — 2,178 tons 93.2% sulfuric acid or 682 tons elemental sulfur

The composition, quantity and HHV of the SPG are given in Table 1.6.1-1.

Table 1.6.1-1

Composition, Quantity and HHV of SPG

Component	% Volume
CO_2	0.14
CO	9 ppmV
H_2	0.57
H_2O	0.01
CH_4	94.00
Ar	0.04
N_2	5.24
	100.00
Total, MM SCFD	264.53
Total, BTU/d	251.54×10^9
Average M. weight	16.639
HHV, dry, Btu/SCF	951.0
HHV, wet, Btu/SCF (7 lb H_2O/MMSCF)	950.9

1.6 PRODUCTS AND BYPRODUCTS

1.6.2 Fuel Oil

The Commercial Plant will produce 16,823 barrels per day of No. 4 Fuel Oil with a heating value of 18,583 Btu/lb. The fuel oil meets the ASTM specifications for No. 4 Fuel Oil described in Regulation D369-76. Furthermore, the fuel oil meets the 0.15 lb of sulfur per million Btu standard set in Appendix A of ICGG/DOE contract No. EF-77-C-01-2012 and also meets the estimated future NO_x emission standards for fuel oils in the United States.

1.6.3 Naphtha

The Commercial Plant will produce 3,815 barrels per day of naphtha with a heating value of 19,750 Btu/lb.

The only specification set for the naphtha byproduct stream was a nitrogen concentration of 1 ppmV or less and a 400°F ASTM distillation end point. The byproduct naphtha represents a feedstock naphtha, which may be further fractionated into a broad range of petrochemical feeds.

1.6.4 Anhydrous Ammonia

Anhydrous ammonia is recovered at the rate of 47.94 TPD as a byproduct in Area 113 with the Phosam-W̄ Process of which 0.04 TPD is used internally in the Waste Treatment and Disposal Area, Area 118. The remaining 47.9 TPD is exported from the plant as a byproduct. The ammonia is in a liquid state and has a 99.99% purity.

1.6.5 Sulfuric Acid/Elemental Sulfur

The sulfuric acid plant in the Sulfur Recovery Area, Area 112, produces sulfuric acid at the rate of 2,192 TPD of which 2,178 TPD is available for sale with 14 TPD being used within the plant. The plant is capable of producing elemental sulfur as an alternate, if the market demand and price so dictate. At the normal rate, 682 TPD of elemental sulfur can be produced.

The sulfuric acid has a concentration of 93.2%. The elemental sulfur is 99.9% pure and can be shipped either as a liquid or as a crushed solid.

1.6 PRODUCTS AND BYPRODUCTS

1.6.6 Marketability of Primary Product

The need to reduce the United States future dependence on foreign energy sources, review of future supply/demand projections, and pricing of alternate energy sources are important reasons which support the marketability of SPG.

Subsection 6.6 describes the marketability of SPG nationally and for Illinois.

1.6.7 Marketability of Byproducts

The marketable plant byproducts include: fuel oil, naphtha, anhydrous ammonia and sulfuric acid (or elemental sulfur). The annual revenues from these byproducts are significant and represent a credit of 146 million dollars to the annual operating cost.

Subsection 6.7 describes the market potential for the byproducts from the Commercial Plant.

1.7 ECONOMIC ASSESSMENT

The capital requirements and operating costs for the Conceptual Commercial Plant are based on a site in Perry County, Illinois. This provides the basis for fixing various economic factors such as the cost of coal, cost of labor, labor productivity, transportation, etc. Due to the conceptual nature of the project, no specific site characteristics have been assigned for estimating construction costs; i.e., average site preparation costs and land costs and normal foundation requirements have been assumed for evaluation purposes.

The plant investment cost, total capital requirements, gross operating cost and net operating cost are summarized in Table 1.7-1. A detailed breakdown of capital requirement and operating costs is summarized in Tables 1.7-2 and 1.7-3, respectively.

SPG Cost

Specific guidelines for two cases calculating the required SPG selling price are summarized below; and are detailed in section 7.

Case 1

- Federal Income Tax = 0
- Discount Rate = 9%
- Straight Line Depreciation

Case 2

- Federal Income Tax = 48%
- Discount Rate = 12%
- Sum of Years Digit Depreciation

Case #1	Selling Price	$ 3.95/MM Btu
Case #2	Selling Price	6.42/MM Btu

The SPG Cost was computed using a Discounted Cash Flow (DCF) analyses which determines the lowest selling price (plant tailgate) which will recover all costs incurred during the 25 year project life.

General guidelines for the DCF Revenue Requirement Analysis is shown in Subsection 7.5.1.

The SPG Cost can be influenced by many variables. DOE guidelines identify coal cost and discount rate as two variables requiring additional analysis.

Table 1.7-4 summarizes the results of coal cost and discount rate sensitivity for Case 1 (see Subsection 7.5.3).

1.7 ECONOMIC ASSESSMENT - continued

Table 1.7-5 summarizes the results of coal and discount rate sensitivity for Case 2 (See subsection 7.5.3).

Table 1.7-1

ICGG Conceptual Commercial Plant
Final Baseline Design Economics

Plant Investment Cost, $MM	$ 1199.3
Total Capital Requirement, $MM	$ 1482.9
Operating Costs	
Gross Operating Cost, $MM/yr	$ 281.1
Byproduct Credits, $MM/yr	(146.1)
Net Operating Cost, $MM/yr	$ 135.0

The basis for the estimates presented in Tables 1.7-1, 1.7-2 and 1.7-3.

- Mid 1978 Dollars
- 20 year Commercial Plant Design Life
- 330 Day Operating Year
- Coal $1/MM Btu or $22.32/Ton (11,160 btu/lb dry coal)

1.7 ECONOMIC ASSESSMENT - continued

Table 1.7-2

ICGG Commercial Plant Capital Requirements

Capital Requirement Category	Category Cost (Thousands of Dollars)
Construction Plans and Drawings	$ 75,445
Site Preparation	10,000
Plant Construction	1,043,496
Construction Engineering	70,369
Subtotal Plant Investment Cost	1,199,310
Contingency	177,368
Land	2,039
Start Up	26,695
Administration	4,150
Working Capital	30,857
Paid Up Royalties	20,000
Chemicals and Catalysts	12,154
TOTAL Capital Requirement	1,472,573

Table 1.7-3

Annual Operating Cost for Commercial Plant

Cost Classification	Annual Cost (Thousands of Dollars)
Coal	$195,563
Labor	23,138
Chemicals and Catalysts	20,769
Insurance and Taxes	7,837
Repairs and Replacements	30,426
Utilities	1,060
Other Operating Supplies	2,293
Gross Operating Cost	$281,086
Less Byproducts (Credit)	(146,096)
Net Operating Cost	$134,990

1.7 ECONOMIC ASSESSMENT - continued

Table 1.7-4
Case 1
Effect on SPG Cost due to change in Variable

Variable	Percent change in Variable	Effect on SPG Cost ¢/MM Btu	Effect on SPG Cost Percent
Coal Cost ($1/MM Btu base case)			
	-20%($0.80/MM Btu)	-46	-11.6
	+25%($1.25/MM Btu)	+57	+14.5
	+50%($1.50/MM Btu)	+115	+29.1
Discount Rate (9% base case)			
	-33.3% (6%)	-60	-15.2
	+33.3% (12%)	+62	+15.7
	+66.7% (15%)	+155	+39.2

Table 1.7-5
Case 2
Effect on SPG Cost due to change in Variable

Variable	Percent change in Variable	Effect on SPG Cost ¢/MM Btu	Effect on SPG Cost Percent
Coal ($1/MM Btu base case)			
	-20% ($0.80/MM Btu)	-46	-7.2
	+25% ($1.25/MM Btu)	+57	+8.9
	+50% ($1.50/MM Btu)	+115	+17.9
Discount Rate (12% base case)			
	-50% (6%)	-241	-37.5
	-33.3% (9%)	-132	-20.6
	+25% (15%)	+156	+24.3

Sensitivity analysis were made to determine the response to SPG cost with noted changes in variables.

1.7 ECONOMIC ASSESSMENT - continued

Additional sensitivity analysis for Cases 1 and 2 of the DOE guidelines is shown in Table 1.7-6.

Table 1.7-6

Sensitivity of Other Commercial Plant Variables

Variable	Selling Price $/MMBTU Case 1	Case 2
Net Operating Cost (base case $133,417M)		
o +30%	$4.43	$6.90
o +15%	$4.19	$6.66
o base case	$3.95	$6.42
o -15%	$3.71	$6.18
o -30%	$3.47	$5.94
Fuel Oil/Naphtha Credit (base case $106,645M)		
o +30%	$3.58	$6.05
o +15%	$3.78	$6.25
o base case	$3.95	$6.42
o -15%	$4.16	$6.63
o -30%	$4.36	$6.82
On Stream Efficiency (base case 90.4%-330 days/yr.)		
o 70% (256 days/yr.)	$4.86	$8.04
o 80% (292 days/yr.)	$4.37	$7.15
o base case	$3.95	$6.42
o 99% (361 days/yr.)	$3.71	$5.96
Total Gross Investment (base case $1,472,573)		
o +30%	$4.65	$7.86
o +15%	$4.30	$7.14
o base case	$3.95	$6.42
o -15%	$3.60	$5.70
o -30%	$3.25	$4.98

1.7 ECONOMIC ASSESSMENT - continued

Table 1.7-6 - continued

Sensitivity of Other Commercial Plant Variables

Variable	Selling Price $/MMBTU Case 1	Selling Price $/MMBTU Case 2
Zero (0) fuel oil and naphtha credit, with total BTU's (124.97 x 10^{12}) used in computing selling price	$3.48	$5.12
Capital related portion of selling price assuming zero (0) operating expense zero (0) revenue	$2.34	$4.81
Inflation of 6% per year assumed during plant operation-years 6-25	$3.11	$4.84

Typical ICGG member company guidelines include:

- Desired return on capital = 11.25%
- Percent of Debt = 50%
- State Income tax = 4%
- Investment tax credit = 10%
- Bond interest rate = 9%
- Federal income tax rate = 48%
- Property tax rate = 1%
- Double declining balance depreciation

Using these guidelines and the given capital and operating costs for the Conceptual Commercial Plant (base case) the selling price (plant tailgate) is $5.08/MMBTU.

2.0 COMMERCIAL PLANT DESCRIPTION

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2.0 COMMERCIAL PLANT DESCRIPTION

2.1 DESIGN BASIS AND CONSIDERATIONS

This section presents the overall design basis for the Commercial Plant. Recommendations presented in the Process Evaluation Report (PER) have been incorporated into the design, along with critical process modifications that resulted from integrating the PER recommendations.

The Conceptual Commercial Plant is assumed to be in Perry County, Illinois with access to Illinois No. 6 seam coal and Mississippi River water.

Overall Plant

Feedstocks

25,935 TPD Illinois No. 6 Seam Coal
4,960 KW Electric Power
16.52 MM GPD Water

Product

264.53 MM SCFD SPG

Byproducts

16,823 bbl/d Fuel Oil
3,815 bbl/d Naphtha
47.9 TPD Ammonia
2,178 TPD Sulfuric Acid
(or 682 TPD Sulfur)

Solid Waste Products
(To on site disposal)

2,983.4 TPD Slag
1,890.1 TPD $CaSO_3$ Sludge
68.0 TPD Water Treatment Sludge
86.0 TPD Soluble Salts
88.2 TPD Ash
39.1 TPD Lime Grits

Liquid Waste Products

Zero liquid discharge of process wastes.

2.1 DESIGN BASIS AND CONSIDERATIONS - continued

Overall Plant

Gaseous Waste Products

108,127 TPD Desulfurized Flue Gas
8,272.9 TPD Carbon Dioxide Vent
666.3 TPD Thermal Oxidizer Vent

Coal Feed

Type - Illinois No. 6 Bituminous
Size - 6" x 0" (as received)

Ultimate Analysis % (Dry Basis)

C	69.0
H	4.7
N	1.3
S	3.8
O	9.3
Ash	11.9
Total	100.0

Moisture Content - 10%
Higher Heating Value (Btu/lb Dry) - 12,400

Raw Water

Source - Mississippi River

Analysis	mg/l
Total Hardness as $CaCO_3$	254
Total Dissolved Solids	381
Suspended Solids	400
Calcium as $CaCO_3$	82
Magnesium as $CaCO_3$	82
M-Alkalinity as $CaCO_3$ (Total)	157

2.1 DESIGN BASIS AND CONSIDERATIONS - continued

Raw Water	Analysis	mg/l
	Sulfate	101
	Silica	15
	pH	7.4-7.9
	Transportation - 20 miles via overland pipeline.	
Electric Power Input	13,800 V, 3 Phase, 60 Cycle For plant lighting and river water pumping station.	
Synthetic Pipeline Gas (SPG)	Component or Property	
	CH_4, Mole %	94.00
	CO_2, Mole %	0.14
	CO	9 ppmv
	H_2, Mole %	0.57
	CO_2 Plus Inerts, Mole %	5.42
	H_2O Vapor, lb/MM SCF	6.53
	Hydrocarbon, Dew Point	-40°C max.
	Total Sulfur, lb/Billion Btu	Neg.
	Wobbe No.	1,258.6
	Lifting Index	0.993
	Flashback Index	0.982
	Yellow Tip Index	1.000
	HHV, Dry, Btu/SCF	951.0
	Pressure, psig	1,061.0

2.1 DESIGN BASIS AND CONSIDERATIONS - continued

Fuel Oil	Approx. ASTM Spec.	No. 4
	Avg. Mol Wt	226
	Pour Point	-30°F
	Flash Point	175°F
	Distillation Range, TBP	244° to 1000°F
	°API	13.89
	UOP Characterization	10.51
	HHV, Btu/lb	18,583
	Nitrogen % Max.	0.5
	Sulfur lb/MM Btu Max.	0.15
Naphtha	Avg. Mol Wt	93.6
	Flash Point	-40°F
	Distillation Range, TBP	100° to 402°F
	°API	49.09
	UOP Characterization	11.15
	HHV, Btu/lb	19,750
	Nitrogen ppmv	<1

Anhydrous Ammonia

Impurity Conc., ppm by Weight	
H_2O	100 Max
Oil	2 Max
CO_2	3 Max
Cl_2	2 Max
H_2S	Trace

Sulfuric Acid — Commercial Grade

93.2% H_2SO_4 by Weight

Sulfur
(Alternate to Sulfuric Acid) 682 TPD

2.1 DESIGN BASIS AND CONSIDERATIONS - continued

Slag

Analysis	Weight %
CaO	4.6
MgO	1.4
Fe_2O_3	16.7
SiO_2	53.0
Al_2O_3	17.4
C	<0.1
TiO	0.9
Na_2O	3.1
K_2O	2.2
SO_3	0.6
Total	100.0

Disposal in on site landfill, unlined.

Calcium Sulfite Sludge

Analysis	Weight %
$CaSO_3 \cdot 1/2\ H_2O$	54.75
H_2O	42.77
Na_2SO_3	0.74
Na_2SO_4	1.49
Fly Ash	0.25
Total	100.00

Ultimate disposal in lined pond, on site.

Water Treatment Sludge Cake

Analysis	Weight %
Polymer	0.3
H_2O	79.4
River Solids	20.3
Total	100.00

2.1 DESIGN BASIS AND CONSIDERATIONS - continued

Water Treatment Sludge Cake

Ultimate Disposal - Mixed with ash and slag in on site landfill.

Soluble Salts (from raw water feed and reagent make up)

Analysis	Weight %
Solid Salts	98.65
H_2O	1.18
Oil	0.17
Total	100.00

Ultimate disposal in lined covered pond, on site.

Desulfurized Flue Gas

Analysis	Volume %
CO_2	17.0
H_2O	12.6
O_2	2.3
N_2	67.5
Ar	0.6
SO_2	254 ppmv (300 Max)
Total	100.0

Ultimate Disposal - Atmosphere

Carbon Dioxide Vents

Analysis	Volume %
CO_2	51.26
H_2O	48.53
H_2	0.04
CH_4	0.17
Total	100.0

Ultimate Disposal - Atmosphere

2.0 COMMERCIAL PLANT DESCRIPTION

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2.1 DESIGN BASIS AND CONSIDERATIONS - continued

Thermal Oxidizer Vent	Analysis	Volume %
	CO_2	19.2
	H_2O	10.4
	O_2	1.6
	N_2 + Ar	68.8
	SO_2	246 ppmV
	Total	100.0

Ultimate Disposal - Atmosphere

2.2 GENERAL SPECIFICATIONS

The plant will be built to codes and standards applicable to a plant of this nature. These general civil and architectural, electrical, instrumentation and piping specifications are intended to illustrate the nature of these standards and how they will be employed in the actual plant design. They are conceptual in nature and will be developed in detail at the outset of the definitive design phase when the design parameters are precisely defined.

The specifications that have been included in this subsection are as follow:

Outline Specification	Attachment
Civil	A
Electrical	B
Instrumentation	C
Piping	D

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ATTACHMENT A

OUTLINE SPECIFICATION

CIVIL

FOR

THE ILLINOIS COAL GASIFICATION GROUP

CONCEPTUAL COMMERCIAL PLANT

ATTACHMENT A

OUTLINE SPECIFICATION
CIVIL

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ATTACHMENT A

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OUTLINE SPECIFICATION
CIVIL

1.0 General

1.1 It is the intent of this specification to establish major design criteria and general materials of construction. This document is not all inclusive and is not intended to restrict deviations in design or choice of materials which may be dictated by considerations not envisioned at this time.

2.0 Design Criteria

2.1 Codes, Standards and Regulations

a. Occupational Safety and Health Administration
b. Uniform Building Code - 1976
c. American National Standard Institute A58.1-1972 for Wind Load Design
d. AISC Specification and Code
e. ACI Specification and Code
f. ASTM Specification
g. CRSI Specifications and Code
h. NFPA Specifications and Code
i. SSPC Specifications and Code
j. Applicable State and Local Codes

2.2 Soil

a. Bearing Value: 5,000 psf
b. Site: Rough graded area suitable for construction.
c. Frost Line: 3'-6" below grade.

2.3 Live Loads

Equipment loads in combination with the following uniform live loads, minimum:

a. Piping: 15 psf on floors and 10 psf on roofs.
b. Wind: 25 psf up to 30', 30 psf - 30' to 49', 40 psf - 50' to 99', 45 psf - 100' to 499'
c. Access Platforms: 100 psf
d. Stairs and Landings: 100 psf
e. Floors on Fill: 500 psf
f. Elevated Floors: 125 psf
h. Roof: 20 psf

2.4 Earthquake Design: UBC - Zone 3

OUTLINE SPECIFICATION
CIVIL

2.0 Design Criteria

2.5 Concrete

a. Design: ACI 318 Building Code Requirements for Reinforced Concrete (Work Stress Design)
b. Reinforced Steel: ASTM A615, Grade 60.
c. Welded Wire Fabric: ASTM A185
d. Strength:
   4,000 psi minimum @ 28 days for all floor slabs.
   3,000 psi minimum @ 28 days for all other work.
e. Anchor Bolts: ASTM A36 or A151 1020
f. Finishes:
   Unexposed or Below Grade: Rough form finish.
   Exposed Vertical Surfaces: Rubbed finish.
   Horizontal Surfaces of Equipment Bases or Pads: Wood float finish.
   Interior Floor Slabs: Troweled finish, liquid hardener and sealer on floors receiving no other finishes. Broom finish working and traffic area.

2.6 Structural Steel

a. Design, Fabrication and Erection: AISC Specification
b. Type: ASTM A36
c. Shop and Field Connections: Welded or bolted.
   Bolting:
   Major Connections: High strength bolts, ASTM A325X with threads in the shear plane.
   Minor Connections: Unfinished bolts, ASTM A307.
   Welding: AWS Code, E70XX Series electrodes.

3.0 General Materials of Construction

3.1 Superstructure: Structural steel columns, beams, girders, girts and purlins.

3.2 Floor Slabs on Grade: Reinforced concrete over vapor barrier and compacted granular fill.

3.3 Elevated Floors and Platforms:

a. Reinforced Concrete
b. Figured Plate: Steel 1/4" minimum thickness with a raised pattern welded in place, except where removal is required.
c. Grating: Galvanized steel, plain bearing bars, galvanized clips.

3.4 Siding:

a. Uninsulated prefinished ribbed metal 1/2" nominal depth.
b. Insulated metal siding system.

3.5 Roof Deck: Metal ribbed steel, 1-1/2" nominal depth.

3.6 Roofing: Smooth surface built up over insulation and vapor barrier.

4.0 Facilities

4.1 Administration building will be a steel framed building of insulated metal siding with the front wall of brick masonry construction or similar facing to architecturally enhance the appearance of the building. The roof will have a metal roof deck and will be a built-up roof with roof drains.

4.2 Maintenance building will be of concrete block construction with a metal roof deck and built-up roof with roof drains. A service crane will be provided. A masonry partition will separate the area which will be used as the fire and emergency vehicle garages.

4.3 Warehouse will be a prefabricated, insulated metal building. Doors will be provided to permit easy access by delivery trucks and lift trucks.

4.4 Laboratory building will be a prefabricated, insulated metal building.

4.5 All of the above buildings will provide lunch rooms, lockers, and shower and toilet facilities for plant personnel, as required.

4.6 Guardhouses will be of concrete block construction with a metal roof deck and built-up roof with roof drains.

4.7 Plant Fence: 6' high galvanized steel chain link fabric with galvanized posts and accessories.

4.8 Storm Sewer: Underground storm sewer system. Cast iron pipe will be placed under buildings and will run into reinforced concrete manholes. Reinforced concrete pipe will be placed between manholes.

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CIVIL

4.0 Facilities

4.9 Plant Roads: A flexible bituminous asphalt pavement. 20' or 30' wide with 2' shoulders. The roads will be constructed on a prepared subgrade and will consist of a base and surface course adequate for heavy truck loads.

4.10 Parking Facilities: Adequate parking spaces will be provided, with construction similar to that used for plant roads.

4.11 Railroad Spur: The site will be provided with a standard gauge track using ballast and wood tie construction. Ample sidings will be provided to give loading or unloading service to the site.

4.12 Finish Grading: Grade the area level to eliminate all holding pockets and any physical hindrance of access, yet provide adequate drainage.

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OUTLINE SPECIFICATION

ELECTRICAL

FOR

THE ILLINOIS COAL GASIFICATION GROUP

CONCEPTUAL COMMERCIAL PLANT

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1.0 General

1.1 It is the intent of this specification to establish major design criteria and general materials of construction. This document is not all inclusive and is not intended to restrict deviations in design or choice of materials which may be dictated by considerations not envisioned at this time.

1.2 The following documents will be prepared in accordance with the scope of work for this project:

Distribution Single-Line Diagrams
4160 Volt MCC Single-Line Diagrams
430 Volt MCC Single-Line Diagrams
Elementary Diagrams
Instrument One-Line Diagrams
Power, Lighting, Grounding, Instrument and Control Plan
Sections and Details
Lighting Fixture and Panel Schedules
Standard Details - Power, Lighting and Grounding
Electrical Installation Specifications
Calculations Covering Lighting and Power
Relay Coordination Calculations and Curves
Communications and Telephone Plans
Fire and Emergency Alarm Systems Plan and Wiring Diagrams
Communications System Plan and Wiring Diagrams
Electrical Equipment Room Layouts
480 Volt MCC Arrangement and Data Sheets
Unit Substation Arrangement and Data Sheets
480 Volt MCC Specification Sheet
Unit Substation Specification Sheet

2.0 Codes, Standards and Regulations

2.1
a. National Electric Code (NEC)
b. National Electrical Safety Code (NESC)
c. National Fire Protection Association (NFPA)
d. Uniform Building Code
e. ANSI Specifications
f. API Codes and Specifications
g. FIA Codes and Specifications
h. FM Codes and Specifications
i. IEEE Codes and Specifications
j. JIC Codes and Specifications
k. NACE Codes and Specifications

2.1 Continued

l. NEMA Codes and Specifications
m. OIA Codes and Specifications
n. UL Codes and Specifications
o. OSHA Codes and Regulations
p. FCC Codes and Regulations
q. ISA Codes and Specifications
r. FAA Regulations
s. State and local codes

3.0 Scope of Work

3.1 Furnish complete drawings and documents in sufficient detail to provide an economical, reliable and safe distribution system consisting of, but not limited to, the following:

a. One 15 KV, 3 phase, 60 Hz, metal clad, indoor air circuit breaker switchgear. Switchgear to be connected to a main 13.8 KV steam turbine driven generator and three expander flue gas generators. Switchgear to include main and feeder breakers, as required, and all protective relays, metering and generator control devices including synchronizing devices.

b. One 15 KV, 3 phase, 60 Hz, metal clad, indoor air circuit breaker switchgear to be connected to a gas-fired turbine start up generator. Switchgear to contain main and feeder breakers, as required, all protective relays, metering and generator control devices and connected to main bus of Item 3.1a. Switchgear to be located in Area 115A.

c. Three lineups of 15 KV, 3 phase, 60 Hz, metal clad indoor air circuit breaker switchgear connected to three flue-gas expander driven generators. Switchgear to contain main and feeder breakers, as required, all protective relays, metering and generator control devices. Switchgear to be located in Area 110.

d. One 15 KV, 3 phase, 60 Hz, metal clad, indoor air circuit breaker switchgear. Include one air circuit breaker and synchronizing devices for paralleling power from the main bus Item 3.1a to local utility, and all protective relays and metering devices. Switchgear to be located in Area 115C.

e. One area substation consisting of one 15 KV, metal clad, indoor switchgear; one outdoor, oil-filled, 13.8-4.16 KV, 3 phase, 60 Hz, transformer; one outdoor, oil-filled, 13.8-.48 KV, 3 phase, 60 Hz, transformer; one 4.16 KV,

3.1 Continued

indoor, metal clad, switchgear; one 480 V, indoor switchgear and required number of 4160 and 480 V indoor motor control centers. Equipment shall include all protective relays and metering devices. This substation shall receive power from the local utility company and shall be located in Area 116.

f. One area substation containing one 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 4.16 KV, indoor, metal clad switchgear; one 480 V, indoor switchgear and required number of 4160 and 480 V indoor motor control centers. Substation equipment shall contain all necessary protective relays and metering devices, and shall receive power from Item 3.1a. Substation to be located in Area 101.

g. One area substation consisting of two 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; two 13.8-.48 KV, 3 phase, 60 Hz, oil-filled transformers; one double-ended, indoor, metal clad, 4.16 KV switchgear; one double-ended, indoor, 480 V switchgear and required number of 4160 and 480 V motor control centers. Substation equipment shall include all protective relays and metering devices and shall receive power from Item 3.1a. Substation shall be located in Area 111.

h. One area substation consisting of one dry type, 13.8-4.16 KV, 3 phase, 60 Hz transformer; two dry type, 13.8-.48 KV, 3 phase, 60 Hz transformers; one 4160 V, indoor, metal clad switchgear; two lineups of 480 V, indoor switchgear and required number of 4160 and 480 V motor control centers. The 4160 V transformer and switchgear shall form a common lineup with Item 3.1b. The 480 V transformers shall be indoor bus connected to Item 3.1b and shall form a common lineup with their associated 480 V switchgear. Substation equipment shall include all protective relays and metering devices and shall be located in Area 115A.

i. One area substation consisting of two 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; two 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; one double-ended, 4160 V, indoor metal clad switchgear; one double-ended, 480 V, indoor switchgear and required number of 4160 and 480 V motor control centers. Substation shall receive its power from Item 3.1a. Substation equipment shall include all protective relays and metering devices and shall be located in Area 115D.

3.1 Continued

j. One area substation consisting of two 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; two 13.8-.48 KV, 3 phase, 60 Hz outdoor, oil-filled transformers; one double-ended, 4160 V, indoor, metal clad switchgear; one double-ended, 480 V, indoor switchgear and required number of 4160 and 480 V motor control centers. Substation equipment shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 115E.

k. One area substation consisting of two 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; one 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one double-ended, 4160 V, indoor, metal clad switchgear; one 480 V, indoor switchgear and required number of 4160 and 480 V, indoor motor control centers. Substation equipment shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 115F.

l. One area substation consisting of two 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; two 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; one double-ended, 4160 V, indoor, metal clad switchgear; one double-ended, 480 V indoor switchgear and required number of 4160 and 480 V, indoor motor control centers. Substation shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 117.

m. One area substation consisting of one 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 4160 V, indoor, metal clad switchgear; one 480 V, indoor switchgear and required number of 4160 and 480 V motor control centers. Substation equipment shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 119.

n. One area substation consisting of one 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 480 V, indoor switchgear and required number of 480 V, indoor motor control centers. Substation equipment

3.1 Continued

shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 120D.

o. One area substation consisting of one 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 480 V, indoor switchgear and required number of 480 V, indoor motor control centers. Substation shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 120J, with the exception that 480 V MCC's will be located in Area 120G and 120J.

p. One area substation consisting of one 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; one 4160 V, indoor, metal clad switchgear; one 480 V, indoor switchgear and required number of 4160 and 480 V, indoor motor control centers. Substation equipment shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 106.

q. One area substation consisting of one 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformer; two 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; one 4160 V, indoor, metal clad switchgear; one double-ended, 480 V, indoor switchgear and required number of 4160 and 480 V, indoor motor control centers. Substation shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1a, and shall be located in Area 104.

r. Three area substations, each consisting of two 13.8-4.16 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; four 13.8-.48 KV, 3 phase, 60 Hz, outdoor, oil-filled transformers; one double-ended, 4160 V, indoor, metal clad switchgear; two lineups of 480 V, indoor, double-ended switchgear and required number of 4160 and 480 V, indoor motor control centers. Substation equipment shall include all protective relays and metering devices. Substation shall receive its power from Item 3.1c, with switchgear and motor control centers located in a common building with Item 115C.

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4.0 Distribution System

4.1 Voltages

a. Distribution System voltage shall be 13.8 KV, 3 phase, 60 Hz, resistive grounded neutral, obtained from nine possible sources. These sources are one main power generator, six flue gas generators, the local utility, and one standby emergency generator.

b. Utilization voltages will be 4160 V, 3 phase, 60 Hz and 480 V, 3 phase, 60 Hz, resistive grounded neutral, obtained from transformation of the 13.8 KV distribution voltage.

c. Control voltage - 120 V, 1 phase, 60 Hz.

d. Lighting voltage - 120/208 V, 3 phase, 4 wire, 60 Hz for general and operating areas.
- 480/277 V, 1 phase, 60 Hz for outdoor flood, parking lot, and perimeter lighting.

e. Instrumentation voltage - 120 V, 1 phase, 60 Hz.
- DC power as required for special instruments.

4.2 Method of Distribution

a. 13.8 KV power distribution and cable description in Division II or nonhazardous areas shall be stranded copper, three conductor, shielded, 15 KV cable, EPR (90°C) insulation, with armor and PVC jacket overall, run in ladder type cable trays.

b. 13.8 KV power distribution in Division I areas shall be stranded copper, single conductor, shielded, 15 KV cable, EPR (90°C) insulation, run in galvanized rigid steel conduit.

c. 4160 V power distribution in Division II or nonhazardous areas shall be stranded copper, three conductor, non-shielded, 5 KV cable, EPR (90°C) insulation, with armor and PVC jacket overall, run in ladder type cable trays.

d. 4160 V power distribution in Division I areas shall be stranded copper, single conductor, non-shielded 5 KV cable, EPR (90°C) insulation, run in galvanized rigid steel conduit.

4.2 Method of Distribution - continued

e. 480 V power distribution cable #410 and larger in Division II or nonhazardous areas shall be stranded copper, three conductor, 600 V, thermoplastic type THHN (90°C) insulation, with armor and PVC jacket overall, run in ladder type cable trays.

f. All other 480 V power distribution shall be stranded copper, single conductor, 600 V cable, thermoplastic type THHN (90°C) insulation, run in galvanized rigid steel conduit.

g. Control cable shall be stranded copper, single conductor, 600 V with thermoplastic type THHN (90°C) insulation, run in galvanized rigid steel conduit.

h. Lighting cable shall be stranded copper, single conductor, 600 V with thermoplastic type THHN (90°C) insulation, run in galvanized rigid steel conduit.

i. Instrumentation cable shall be stranded copper, single conductor, 600 V with thermoplastic type THHN (90°C) insulation, run in galvanized rigid steel conduit.

j. Minimum wire sizes shall be as follows:

Power	#12 AWG
Lighting	#12 AWG
Control	#14 AWG
Fixture	#14 AWG Type SF-2
Instrumentation	#14 AWG or as recommended by instrument manufacturer.

k. Color coding - Power and control cables shall be color coded as required by NEC.

l. Raceways - Cable trays shall be hot dipped, galvanized steel, 9 in. rung spacing, ladder type with 6 in. side runners and sufficient metal for grounding in accordance with NEC. Conduit shall be rigid, hot-dipped, galvanized steel, minimum 3/4 in. exposed and 1 in. embedded. Cable trays shall be supported from service rack structural members or building steel. Conduit shall be supported from auxiliary attachments on service racks and building steel. Where no service racks or building steel are available, additional T-type supports shall be added. In highly corrosive areas, PVC coated conduit may be necessary. That requirement will be determined on an area to area basis.

OUTLINE SPECIFICATION
ELECTRICAL

5.0 Motors

5.1 Horsepower and Voltage Range

a. 250 hp and larger shall be 4160 V, 3 phase, 3 wire, 60 Hz.

b. 1/2 hp through 200 hp shall be 460 V, 3 phase, 3 wire, 60 Hz.

c. Nonprocess motors less than 1/2 hp shall be 120 V, 1 phase, 60 Hz.

d. Process motors less than 1/2 hp shall be 460 V, 3 phase, 60 Hz.

e. Motors 100 hp and larger shall have individual 120 V space heaters for moisture control.

This horsepower and voltage range criteria shall apply to all process and nonprocess motors, including those supplied with package units.

5.2 Controls

a. 4160 V motor (induction) starters shall be NEMA Class E2, fusible, magnetic contactor type with individual 120 V control transformer and all necessary protective devices; housed in a free standing, metal enclosed structure 1 high construction. Synchronous motor starters shall be similar in construction.

b. 480 V motor starters shall be combination type, minimum NEMA Size 1, with instantaneous magnetic adjustable trip, minimum 25,000 A symmetrical interrupting capacity, three ambient compensated melting alloy manual reset overloads, 120 V control transformer; and housed in a free standing, metal enclosed NEMA 1, Class 1, Type B, all copper bus, motor control center.

c. 120 V motors shall be controlled by manual motor starters with overload devices.

d. Power and control wires shall be in common conduit where power wires do not exceed 6 AWG. Where power wires are larger than 6 AWG, they shall be run in separate conduit from the control wires.

5.2 Controls - continued

e. Control wires shall be separated from signal, communication, instrumentation, DC, thermocouple, and special vendor supplied cables or wires.

f. Where start/stop functions for motors are remote or automatic, a lockout stop push button will be installed at the motor.

6.0 Voltage Drop

6.1 The voltage drop on 480 V and 4160 V feeder circuits shall not exceed 3%, based on connected load.

6.2 The voltage drop on 120/208 V lighting panel board feeders shall not exceed 2% and branch circuits shall not exceed 3%, for a total of 5% drop for feeders and branch circuits.

7.0 Grounding

7.1 A complete grounding system will be installed within the plant battery limits and at the plant water intake pumping station in accordance with Article 250 of the National Electrical Code.

7.2 All electrical equipment, buildings, process vessels containing hazardous or static generating fluids, belt or air conveying systems, service racks, and other equipment necessary for personnel safety shall be connected to the grounding system.

7.3 Resistance for the plant grounding system shall be 25 ohms or less.

7.4 Grounding of current carrying equipment such as motors shall be accomplished by an insulated green ground cable run in conduit with the power cable. For 4160 V motors, grounding shall be accompanied by an additional insulated green ground cable connected directly to the plant grounding system.

7.5 Grounding conductors shall be copper, Type TW, green insulated. Minimum conductor size shall be #4/0 AWG for the plant grounding system, buildings, and service racks; and #2 AWG for vessels and noncurrent carrying equipment. Ground conductors for current carrying equipment shall be sized according to Article 250 of the NEC.

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8.0 Lightning Protection

8.1 A lightning protection system using lightning rods and conductors shall be installed for buildings or structures where required according to the NEC and NFPA 78-1977 (ANSI).

9.0 Lighting

9.1 A complete lighting system shall be designed and installed for all buildings, process areas, fence lines, roadways, tank storage areas, transformer yards, walkways, and utility areas.

9.2 Illumination levels shall be in accordance with the Illumination Society of America (ISA) recommendations and guidelines.

9.3 The following types of fixtures shall be used:

Outdoor Process Areas (Except Hydrogen) - High Pressure Sodium
Indoor Process Areas (Except Hydrogen) - High Pressure Sodium
Hydrogen Process Areas (Indoor and Outdoor) - Incandescent
Storage and Unloading Areas - High Pressure Sodium
Roadway and Perimeter - High Pressure Sodium
Parking Lots - High Pressure Sodium
Transformer Yards - High Pressure Sodium
Aeration Areas - High Pressure Sodium
Coal Unloading and Conveying Areas - High Pressure Sodium
Plant Water Intake Area - High Pressure Sodium
Warehouses and Maintenance Areas - High Pressure Sodium
Utility Areas - High Pressure Sodium
Gate Houses and Offices - Fluorescent
Control Rooms - Fluorescent
Electrical Rooms - Fluorescent
Safety Showers and Eyebaths - Incandescent
Janitor Rooms - Incandescent
Heating and Ventilating Rooms - Fluorescent
Walkways and Personnel Doors - High Pressure Sodium
Laboratories - Fluorescent
Gate Houses - Fluorescent

9.4 Lighting fixtures shall be in accordance with the electrical hazardous area classification in which they are installed.

9.5 Outdoor lighting systems, except emergency, safety showers and eyebath fixtures, shall be controlled by photocells and contactors.

9.6 Indoor lighting systems, except fixtures connected to the emergency system, shall be controlled by breakers in lighting panels and toggle switches.

10.0 Emergency Lighting

10.1 Emergency lighting generally shall be accomplished by connecting selective fixtures of the general lighting system to two sources of power; one normal and one from standby (diesel-driven) generators via automatic transfer switches.

10.2 In areas or buildings where it would not be feasible to run standby power feeders, emergency lighting shall be accomplished by use of 120 V AC - 6 V DC wall-mounted units using sealed batteries operating sealed beam incandescent lamps.

11.0 Emergency Power

11.1 Emergency power for start up, critical process motor controls, instrumentation and lighting shall be obtained from a standby generator.

11.2 In control or instrumentation situations where absolutely no loss of power may be tolerated, continuous power shall be accomplished by the use of AC-DC-AC inverters.

12.0 Lighting Panels

12.1 Lighting panels shall be located in nonhazardous areas where possible.

12.2 Panels shall contain one main, 3 phase, magnetic breaker and a combination of 15A and 20A, 1 phase and/or 3 phase magnetic feeder breakers of various sizes as required.

12.3 Breakers feeding the safety shower, eyebath and emergency lighting shall have their handles maintained in closed position by mechanical means to avoid indiscriminate switching.

12.4 All panels shall contain a complete circuit directory.

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ELECTRICAL

13.0 Push Button and Pilot Light Stations

13.1 Push button and pilot light stations located in hazardous areas (except hydrogen) shall be the explosion proof, factory sealed type.

13.2 Push button and pilot light stations located in hydrogen production or utilization areas shall be the explosion proof, oil filled type.

13.3 All other stations shall be NEMA rated to correspond to the areas in which they are located.

14.0 Receptacles

14.1 Convenience outlets located in hazardous areas shall be explosion proof, delayed action, grounded, factory sealed, 125V, 20A, 2 wire, 3 pole, duplex, NEMA 5 configuration.

14.2 Convenience outlets located in outdoor nonhazardous areas shall be weatherproof, grounded, 125V, 20A, 2 wire, 3 pole, duplex, NEMA 5 configuration.

14.3 Convenience outlets located indoors, except hazardous areas, shall be general purpose grounded, 125V, 20A, 2 wire, 3 pole, duplex, either surface or flush mounted.

14.4 Plugs shall be compatible with the outlets specified in 14.1, 14.2 and 14.3.

14.5 Welding receptacles shall be the same in all areas for compatibility. They shall be 60A, 3 wire, 4 pole, 600V AC with attached 100A frame main circuit breaker and housed in an explosion proof enclosure.

14.6 Welding plugs shall be compatible with receptacles specified in 14.5.

15.0 Communication Systems

15.1 Telephone

a. An empty telephone conduit system shall be provided for future cable installation by the local telephone company.

b. Minimum 1" galvanized, rigid steel conduit shall be used.

15.1 Telephone - continued

c. Telephone junction boxes shall be provided at necessary locations.

d. A fish cord shall be left in all conduits for future cable pulling.

15.2 Paging and Audible

a. A combination paging, voice transmitting and receiving system shall be installed in all process, utility, control, and service areas, as required.

b. Equipment and devices shall meet the hazardous classification in which they are located.

16.0 Fire and Emergency Alarm Systems

16.1 A plant wide fire alarm system shall be furnished and this system shall contain a centralized control panel, manual stations, automatic initiating devices and audible alarms as required to provide a complete fire alarm system.

16.2 A plant wide emergency alarm system shall be furnished and installed. The alarm system shall be initiated by manual stations and/or detectors that may be necessary. These devices shall be separate and distinct from the fire alarm devices.

17.0 Power Factor Correction

17.1 The power system shall be studied later in the design stage to determine if power factor correction is required and also the best method to obtain the desired power factor level.

18.0 Aircraft Warning Lights

18.1 The requirement for and installation of aircraft warning lights or navigational signals shall be in accordance with the Federal Aviation Authority (FAA) Regulation Dept. 77 and Advisory Circulars (FAA) 70/7460-IE and 70/7460-2G.

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19.0 Cathodic Protection

19.1 Cathodic protection of pipelines, vessels, clarifiers, and other corrosion potential equipment shall be provided as required. Protection may take the form of alloying, coatings, sacrificial anodes, or impressed current.

20.0 Electrical Heat Tracing

20.1 Electrical heat tracing will be furnished, as required, complete with thermostats, heating cable and all necessary material to comply with process requirements. Material and equipment shall meet the hazardous classification of the areas in which they are to be installed.

21.0 Hazardous Area Classification

21.1 Electrical hazardous area classification shall be in accordance with the plant hazard specification and the area classification plan drawings.

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ATTACHMENT C

OUTLINE SPECIFICATION

INSTRUMENTATION

FOR

THE ILLINOIS COAL GASIFICATION GROUP

CONCEPTUAL COMMERCIAL PLANT

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OUTLINE SPECIFICATION INSTRUMENTATION

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OUTLINE SPECIFICATION INSTRUMENTATION

1.0 Intent

1.1 Minimum criteria for quality of the instrumentation are covered by this specification. Only the basic and more significant features of the instruments are described. Design details not specified will follow the same general quality standards established herein.

2.0 Scope

2.1 This specification includes all instrumentation shown on the flow diagrams, along with other instrumentation accessories which are necessary for proper operation and control of the processes shown. In cases of conflict, the flow diagrams are the governing documents.

2.2 Individual specifications for particular instruments or materials of construction for a given application are not included.

2.3 Workmanship and installation are not covered.

3.0 Identification of Instruments

3.1 Engineering diagrams will identify instruments by means of the ISA standard flow plan symbols and item number. Only the components necessary to depict the instrumentation function will be shown.

3.2 Instrument diagrams will show all the components of a loop and its installation location.

ATTACHMENT C

OUTLINE SPECIFICATION
INSTRUMENTATION

4.0 Design Criteria

4.1 Codes, Standards and Regulations

Mandatory Codes

a. Illinois EPA Codes
b. Illinois Health and Safety Act Codes
c. ICC General Order 192-R
d. Illinois LPG Rules and Regulations
e. Illinois Well Pump Installation Code
f. NEDA Codes and Specifications
g. CAA Codes and Specifications
h. FWPA Codes and Specifications
i. NCA Codes and Specifications
j. OSHA Codes and Specifications
k. FCC Rules and Regulations

Consensus Codes

a. AGA Codes and Specifications
b. ANSI Codes and Specifications
c. API Codes and Specifications
d. ASME Codes and Specifications
e. FIA Codes and Specifications
f. FM Codes and Specifications
g. ISA Codes and Specifications
h. JIC Codes and Specifications
i. National Electric Code
j. National Electrical Safety Code
k. National Fire Protection Agency Codes and Specifications
l. NEMA Codes and Specifications
m. OIA Codes and Specifications
n. UL Codes and Specifications
o. Uniform Building Code

4.2 Specific degree and type of instrumentation will depend upon the application. Generally, the system will be selected to fit a digital computer control system. Computer compatible devices will be used throughout except for the independent controls or for those loops which are not conceivably practical to integrate into a computer system. Instrumentation guidelines are as follows:

a. Digital computer system will be used in the Supervisory and Operations Center. The computer system will monitor the overall plant operation. It may be utilized also for process control. The terminals for process control would be located in the Area Control Rooms. Other terminals, peripheral items and

4.2 Continued

accessories may be located where warranted to assemble the desired system. Digital computers may be located in some Area Control Rooms. The digital system components and arrangement will be specified based upon process and equipment design, plant operation requirements and computer system equipment availability at the time of detailed design.

b. Trend recorders will be available for all important variables. Generally, utilities which do not affect the process will not be recorded. Some variables may be recorded for managerial, legal, or other purposes. Recording capacity will allocate some units for selective intermittent investigative use.

c. Indication of other variables, equipment status and alarm status will be dependent upon the significance of the required indication. Cathode ray tubes, digital indicators, analog indicators, and direct reading meters or gauges will be used as pertinent to the application.

d. Accuracy of measurement will be adequate for the application. In general, normal industrial accuracy of 1% of scale range will be adhered to. If compensation for changes of temperature, barometric pressure, etc., is necessary to attain the required accuracies, this compensation shall be integral and automatic.

4.3 Materials of construction for instruments or instrument parts which contact the process fluid will be identical or application-wise superior to those specified for the process or equipment, except in those applications where the design features of an instrument prescribe the use of other construction materials. Construction materials shall be suitable for use in the ambient environment.

4.4 Pressure and temperature ratings of instruments or components which are an integral part of the closed system (such as control valves or float cages) will conform with the ratings of the process system of which they are a part. If an instrument is connected to the process by means of a lead line in dead-end service, it will have a pressure rating equal to that of the process system to which it is connected at the actual working temperature of the instrument.

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INSTRUMENTATION

4.5 Chart drives used in instruments will be determined by the location or occupancy as defined by the National Electric Code covering hazardous locations:

a. Nonhazardous areas and Class I and II, Division 2, areas will be equipped with general purpose electric chart drives suitable for the conditions.

b. Class I and II, Divison 1, areas will be equipped with mechanical or Division 1 rated chart drives.

4.6 Accessories for each instrument will be furnished as follows, to the extent that they are applicable: chart ink, charts, manometer fluids, clock key, etc.

4.7 Acceptable types of instruments are listed below:

a. Panel mounted recorders will be mounted flush to panel front.

b. Circular chart recorders will have 12" diameter charts (nominal).

c. Multi-point strip chart recorders will have 7" or 11" minimum width charts. Miniature strip chart recorders will have 4" charts.

4.8 Electrical power connections to instruments in hazardous areas will be provided with switches as follows: (a) instruments requiring power for chart drives or illumination only will be grouped approximately six to a switch; (b) those requiring power for other purposes will have individual switches. Instruments in general purpose areas will be connected by rubber covered flexible leads and 3-wire twist-lock type electric plugs or hard-wired. All instruments requiring electrical power shall be specified for operation on 120V, 60 Hz, single phase, AC current, or from a low voltage direct current power supply powered from 120V, 60 Hz, single phase.

4.9 Centralized control will be employed whenever its use improves the operability of the plant.

4.10 Accessibility of the instruments will be adequate for both maintenance and operation. Items which must be visible for operation will be accessible by platforms, catwalks, or ships ladders. Items which require frequent access for maintenance only may be provided with a ladder or other simple means of access.

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5.0 Instrument Panels or Cubicles

5.1 Materials of construction will be rolled steel plate or sheets, 1/8" minimum thickness.

5.2 Design of the units will provide adequate bracing to make them self-supporting.

5.3 Surface of the complete unit will be smooth and blemish-free.

5.4 Nameplates of laminated phenolic plastic with engraved lettering will be supplied for each instrument.

5.5 Mounting of the units will render them free of vibration. They will be rigidly and independently installed by bolting to steel supports.

5.6 Location of instruments on the face of the panel will be as follows:

a. Indicators - 7'-6" maximum from the floor to the center of the instrument.

b. Recorders or controllers - 3'-6" to 5'-6" from the floor to the center of the instrument.

5.7 Clearance will be a minimum of 5' in front of the panel and 3' in the rear.

5.8 Access to rear of panels will be adequate. Panels 8' or longer shall have egress at both ends.

5.9 Electrical wiring will be suitable for the application and will conform to the National Electric Code. Generally, standard duty No. 14, or larger, thermoplastic Type TW, 600 V insulated wire will be used. It will be run in rigid conduit, flexible metal conduit, electrical metallic tubing, or square duct (metal or plastic). Voltages shall not exceed 125 V. Electric signal wires and cables will be shielded and/or grounded as required. Signal wires (analog or digital), special cables, thermocouple and resistance temperature measurement wires will be run separately (isolated or shielded as required, independent of power and control wiring. Line splices are not permitted; all connections will be at terminal boards or by plug-type connectors. Factory supplied special cords and connectors will be used for instruments designed for this type of interconnection.

5.10 Air lines, except the header, will be 1/4" O.D. tubing.

5.11 Test connections will be provided at the panel on all instruments which are directly connected to the process lines.

5.12 Outdoor panels will have adequate weather protection and be suitable for ambient hazard conditions. Clearance between front or back of unit and nearest obstruction will be at least 5'.

6.0 Control and Transmission Equipment

6.1 Operating medium on all pneumatic control and transmission systems will be dry compressed air working through the standard ISA pressure range of 3 to 15 psig. Valves controlled via electric signals may have 6 to 30 psig diaphragms or 80 psig cylinders.

6.2 Controller action will be such that the system is fail-safe. That is, upon failure of air supply or power, the control element will move in the direction which presents the least hazard.

6.3 Remote transmission to control room instruments will be used for all process measurements. Process fluids will not be piped directly to the control room. Analyzer sample streams may be piped to the analyzer room.

6.4 Transmission and control signals will be limited to the following:

a. Pneumatic - 3 to 15 psig.

b. Analog electric signals - 4 to 20 ma DC, isolated (ungrounded), suitable to operate with a 600 ohm load.

c. Thermocouple - Standard ISA thermocouple calibrations.

d. Special measurement instrument signals which must be used as is or transduced after transmission; e.g. resistance temperature measurement, magnetic flowmeter signal.

e. Digital analog electric signals such as speed or turbine flowmeters.

OUTLINE SPECIFICATION
INSTRUMENTATION

6.4 Continued

f. Digital signals for data transmission to the digital computer system(s) or for multiplexing data transmission system. These signals will be determined by the equipment selected.

6.5 Multiplexing data transmission will be used when economically and/or technically superior to other transmission techniques.

7.0 Temperature Instruments

7.1 Unit of measurement shall be degrees Fahrenheit, °F.

7.2 Selection of the type of temperature instrument for a given application will be governed by the temperature, location of measurement and type of transmission signal required.

7.3 Thermowells will, in general, be used on all temperature measuring elements where element removal would necessitate a shutdown. They will be made of a corrosion-resistant material.

7.4 Electronic types: Recorders will have a minimum pen speed of 12 seconds full scale. Multi-record instruments will have a minimum fixed cycle printing speed of 15 seconds per point and a maximum number of twelve points. The types of thermocouples and resistance bulbs as well as the variety of recorder ranges will be kept to a minimum.

7.5 Thermocouple wire and extension wire used will be ISA standard types. Wire gage will be as recommended in ISA Recommended Practice RP 1.3. Extension wire will be polyvinyl insulated unless excluded by temperature conditions. Connections will be made only on terminals in junction boxes. All wires to thermo-electric elements will be run in separate conduits or wireways which are totaly independent of circuits which may be of higher voltage.

7.6 Terminal heads will be provided for the connection of thermal element and extension leads. They will be of weatherproof construction with screwed cover.

7.7 Fluid-filled thermal systems will be supplied with capillary tubing which is made of heavy corrosion-resistant material or is covered with corrosion-resistant armor. The length will not exceed 100'. Capillaries will be run in raceways, protected against mechanical damage and insulated from sources of heat. Overrange protection will be provided whenever overranging is probable.

7.8 Industrial thermometers will be the bimetallic type with 5" or 6" diameter dial, heavy-duty, weatherproof case and stainless steel stem (except where use is prohibited by the application).

8.0 Pressure Instruments

8.1 Units of measurement shall be pounds per square inch, inches of water, inches of mercury vacuum, millimeters of mercury or microns of mercury absolute.

8.2 Pressure gages will conform to the following specifications:

a. Local mounted - 1/2" NPT bottom connection, size 4-1/2". Measuring system will be made of a corrosion-resistant material.

b. Pneumatic receiver gages - size 4-1/2".

c. Hazardous material gages (noxious fluids or pressures over 500 psig) shall be solid-front type with blow-out disc in the back.

8.3 Protectors will be furnished for all pressure instruments which are on process materials which are corrosive, polymerizable, or in the form of a slurry.

9.0 Overpressure Relief and Venting

9.1 Closed systems composed of vessels, mechanical equipment and piping will be protected by suitable pressure relieving devices to prevent the equipment from being exposed to pressure higher than that for which it was designed.

9.2 Vacuum relief devices will be provided for all equipment which may be subjected to pressure below atmospheric unless the system is designed for full vacuum operation.

9.3 Applicable code will be determined from the legal requirements or other sections of these specifications. It will be strictly followed with respect to the construction and installation of relieving devices.

9.4 Capacity of the relieving devices will conform to the OSHA, ASME Pressure Vessel Code or the recommendations of API RP-520.

9.5 Flammable liquids will be considered to be liquids with a closed cup flash point of less than 100°F.

9.6 Design Pressures

a. Pressure systems, including pressure vessels, pressure piping, and all other equipment or equipment components which are subjected to pressure, shall be designed for maximum allowable working pressures which are adequate. The criterion of adequacy in this instance shall be that the difference between the maximum normal operating pressure and the maximum allowable working pressure is sufficiently large to effect the conditions stipulated below.

1. Relief valves shall operate satisfactorily and shall not "simmer" or leak.

2. There shall be no unnecessary discharge of costly or hazardous fluids such as might occur on minor fluctuations in the process pressures during start up or abnormal operation.

3. When conventional relief valves are used on a pressure system, the minimum margin between the maximum normal operating pressure and the maximum allowable working pressure shall be as tabulated in Table 9.6-1, except that when a margin of less than 5 psi is indicated then 5 psi must be used.

b. Rupture discs may be used in place of or in addition to relief valves. When discs are used on a pressure system, the minimum margin between the maximum normal operating pressure and the maximum allowable working pressure shall be as tabulated below. This table applies to discs made of ductile material other than stainless steel.

Type of Service	Percent of Operating Pressure
Non-pulsating pressures with temperature at disc not exceeding atmospheric	1 50
Mild pulsating pressures	1 75
Large pulsating pressures or where temperature at disc exceeds atmospheric	2 00

Table 9.6-1

Minimum Margin Between Operating Pressure and Maximum Allowable Working Pressure (As Percent of Operating Pressure)

Relief Valve Type and Service	CLASS I* Water, Steam, Heavy Hydrocarbons		CLASS II* Air and other heavy gases		CLASS III* H_2, NH_4, Refrig. vapors, Dowtherm, Light Hydrocarbon	
Operating Temp., °F	Below 450°F	Above 450°F	Below 450°F	Above 450°F	Below 450°F	Above 450°F
Full Nozzle - Flanged						
Non-pulsating Service						
Short Direct Dischg. Line	7.0	8.5	8.5	11.0	11.0	14.0
Long or Manifold Dischg.	8.5	11.0	11.0	14.0	14.0	18.0
Pulsating Service						
Short Direct Dischg. Line	14.0	18.0	17.5	23.5	25.0	33.0
Long or Manifold Dischg.	18.0	24.0	22.5	30.0	33.0	45.0
Semi-nozzle - Screwed						
Non-pulsating Service						
Short Direct Dischg. Line	11.0	14.0	17.5	23.5	25.0	33.0
Long or Manifold Dischg.	14.0	18.0	21.0	28.0	29.0	39.0
Pulsating Service						
Short Direct Dischg. Line	17.5	23.5	25.0	33.0	33.0	45.0
Long or Manifold Dischg.	22.5	30.0	33.0	45.0	45.0	64.0

*In general, Class I fluids have a viscosity of 0.3 cp or greater, Class II fluids 0.018 to a 0.3 cp, and Class III fluids less than 0.018 cp. Where a fluid would exist as a vapor when at operating temperature and atmospheric pressure, consider the fluid to be in the vapor state in making the above classification.

9.6 Design Pressures - continued

c. Special types of safety relief valves or rupture discs have been developed for certain applications which do not require as much margin as specified there. In such cases, written guarantees shall be secured from the manufacturers that the devices will perform satisfactorily in the specific application.

10.0 Flow Instruments

10.1 Units of measurement for flow rate meters will be U.S. gallons per minute for liquids, pounds per hour for steam and vapors, standard cubic feet per hour for gases, and pounds or tons per hour for solids.

10.2 Charts and scales of square-root type meters to be graduated 0-10.

10.3 Selection of type of flow rate measuring device will be based on the following considerations:

a. General process and utility service -- where practicable, a flat plate concentric orifice will be used in conjunction with a mercuryless type differential pressure meter.

b. Locally mounted flow indicators on lines up to approximately 2" size may be rotameters for non-hazardous low pressure and low temperature streams. Glass rotameters will have protective shields.

c. Turbine meters, positive displacement meters, magnetic flow meters, vortex shedding meters, sonic flowmeters, propeller meters, venturi tubes, flow nozzles or flow tubes will be employed when their use is indicated by engineering considerations.

10.4 Orifice plates will be fabricated of corrosion-resistant material and will be fabricated and installed according to ISA, AGA, and ASME recommendations. All pertinent information will be stamped on the orifice tab. The d/D ratio shall be between 0.20 and 0.70 except for special applications.

10.5 Orifice taps will be flange type on pipe sized 2" and larger, except that they may be radius type on 8" and larger. Corner taps will be limited to pipe sizes less than 2".

10.6 Compressible fluids will be metered at a point in the system where the static pressure is most nearly uniform and where pulsations are at a minimum.

10.7 Pulsation will be reduced to the limits necessary to secure the required metering accuracy. Special devices for this purpose will be provided as determined by engineering analysis.

10.8 Positive displacement meters will be used where:

a. Totalizing only is required and
b. The flow rate is less than about 250 gpm, or
c. Wide turndown is necessary,
d. High accuracy is required,
e. Batch predetermination is needed.

10.9 Velocity meters will be used where:

a. Totalizing only is required and
b. The flow rate is over approximately 250 gpm, or
c. Head loss through the meter must be kept to a minimum.

11.0 Level Instruments

11.1 Units of measurement will, in general, be restricted to percent of level measurement range.

11.2 Float type and displacement type liquid level devices will be externally mounted in a cage where removal of the float would necessitate shutdown of the process. Where necessary, shut-off valves will be provided for isolating the cage from the associated process equipment. Motion transmission generally will be the packless type. Stilling wells will be provided for internally mounted floats and displacers where turbulence and vortexing of the process fluid exists.

11.3 Head type level meters will be the mercuryless type with packless type motion transmission.

11.4 Sonic, nuclear, capitance or other types may be used when warranted by engineering considerations.

12.0 Gage Glasses

12.1 Tubular type may be used for level and interface applications only if all of the following conditions exist:

12.1 Continued

a. The fluid is nonhazardous and breakage will not endanger personnel or equipment.

b. The gage location is such that danger of breakage from external causes will be a minimum.

c. The internal pressure does not exceed 150 psig for lengths up to 60", 140 psig up to 70", or 130 psig up to 72".

d. Rupture would not cause a shutdown.

12.2 Transparent type flat gage glasses will be used for level and interface applications on:

a. Services which preclude the use of tubular gage glasses.

b. High viscous liquids.

c. Fluids which are corrosive or erosive to glass (steam over 350 psig, caustic, etc.), in which case special protectors for the glass will be specified.

12.3 Reflex type flat gage glasses will be used for level applications on:

a. Services which preclude the use of tubular gage glasses.

b. Nonviscous liquids.

c. Fluids which are not corrosive or erosive to glass.

12.4 Gage valves will normally be of the angle type with excess flow check valves. Where fouling of the excess flow check valves may be expected, they may be omitted.

13.0 Analyzers (pH, Density, Composition, Etc.)

13.1 General: Instruments used for measuring the chemical or physical properties of a process stream will be of the type that continously analyzes the process fluid, if practicable. To avoid unnecessary shutdowns, the sensitive element will be located in a sample line and not in the main process stream, unless some other method can be used to accomplish this end.

14.0 Manual Controllers

14.1 Pneumatic operation of remote valves or other devices will be by means of a unitized loading station consisting of a loading pressure indicator, a sensitive pilot-operated regulator and/or a manual selector valve.

14.2 Electric operation of remote devices will be by means of a suitable switch or manual operator along with appropriate signal lights, meters, or other visual indications of condition.

14.3 Hydraulic operation of remote devices will be by means of a suitable valve or operator along with appropriate signal lights, pressure gage or other visual indication of condition.

15.0 Control Valves

15.1 Line connections on valve bodies will conform to the type used for the piping system in which they are installed. Flange connections may be used in lieu of threaded connections.

15.2 Size will be chosen so that the control valve will not limit the maximum capacity of all the process equipment and enough marginal capacity must be provided to satisfactorily cope with the occasional upsets or disturbances to which the process is subject, yet the valve will not be oversized as to cause unstable flow conditions.

15.3 Bypass throttle valve, with block valves before and after the control valve, will be furnished where continuity of the process operation is imperative even when the controller or valve motor has failed. A continuously connected handwheel operator may be furnished as an alternate to the three-way bypass assembly.

15.4 Valve positioners will be used in the following applications on throttling control valves:

a. Valves 6" size and larger.

b. Multiple valve operation where booster relay will not suffice.

c. The lag in the control loop is one minute or more.

d. Unbalanced forces acting on valve stem exceed the force produced by 2 psig acting on the diaphragm.

15.5 Mounting: Design of valves shall be such that they may be mounted in any plane without the use of an auxiliary support for the motor assembly and without adversely affecting the operation.

15.6 Stability: Design and construction shall permit operation with stability throughout full stroke, with full size trim, on cold water service, with a pressure drop as indicated below, and flow in the direction recommended by the manufacturer, using the manufacturer's approved actuator.

Cast Iron

1" to 8" V-port or 1" to 6" contoured plugs	250 psig

Steel and Stainless Steel

1" and under single seated with contoured plugs	400 psig
1" to 1-1/2" double seated with contoured plugs	600 psig
2" double seated with contoured plugs	600 psig
3" to 8" double seated with V-port plugs	600 psig

15.7 Body Assembly

a. Materials shall be as follows for the material type specified:

Cast Iron	ASTM A126, Class B or C
Cast Steel	ASTM A216, Grade WCB
Forged Steel	ASTM A105, or A181
Cast 304 Stainless Steel	ASTM A351, Grade CF8
Cast 316 Stainless Steel	ASTM A351, Grade CF8M
Bronze	ASTM B62

b. Dimensions: Flanged bodies shall have face-to-face dimensions per ISA RP4.1.

c. Flanges for bonnets and blind heads shall be furnished with retained gaskets and shall be guided into body for alignment. Bonnets and blind heads on steel and stainless steel shall be attached with bolts (or studs) and nuts. Cap screws may be used on cast iron only. No gasket compound, grease, etc., may be used.

d. Pressure rating: Flanged valves shall have pressure-temperature rating at least equal to applicable ANSI standard for flanges specified. Screwed valves shall have a minimum rating of 600 psi ANSI standard. These ratings apply to body only and not bellows seal, etc. They are minimum values regardless of rating shown in item specification.

15.8 Bonnet Assembly

a. Bonnet and blind head shall be of the same material as the body. Steel forgings may be used on cast steel or cast iron bodies.

b. Packing such as Teflon, Grafoil, or Teflon-asbestos, which requires no lubrication, will be used unless this type packing is not feasible. For other cases, a suitable packing with a plug lubricator and isolating valve will be used. For valves handling highly toxic, highly corrosive or extremely valuable materials, bellows seal or double packing will be furnished.

c. Teflon V-ring packing shall consist of solid Teflon rings under controlled compression. The compression spring shall be of corrosion-resistant material not attacked by the process fluid.

d. Teflon-asbestos packing shall consist of asbestos yarn thoroughly impregnated with suspensoid Teflon and woven into yarn.

e. Packing nut or packing flange shall be designed so that the motor assembly may be removed without disturbing packing adjustment is preferred. Austenitic stainless steel flange bolts and nuts are preferred, alloy steel is acceptable.

f. Auxiliary stuffing box: When bellows sealed, Saunders patent or equivalent valves are specified, they are to be equipped with an auxiliary stuffing box to prevent leakage in case of bellows or diaphragm failure. A telltale hole shall be provided below stuffing box, tapped 1/4", and fitted with steel barstock pipe plug.

g. Radiation fins or extension bonnet shall be provided if the specified fluid operating temperature is above the recommended operating temperature of the packing. They are part of the bonnet and are therefore of the same material. When welded construction is used, they shall be of seamless pipe or barstock. Pressure welding shall be per ANSI B31.1.

15.9 Actuators may be electric, hydraulic, or pneumatic. The actuators will be selected to be unenergized or low pressure for the "fail-safe" or shutdown process condition.

15.9 Continued

a. Electric actuators will conform to the hazard equipment requirements of the location.

b. Hydraulic actuators will conform to the National Fluid Power Association standards.

c. Pneumatic diaphragm actuators will operate with 3 to 15 psig or 6 to 30 psig instrument air acting upon the diaphragm.

d. Pneumatic piston actuators will be operated with nominal 100 psig instrument air. The actuators shall be rated for 125 psig or more, and sized for 60 psig air. The actuators will conform to the National Fluid Power Association standards. The actuator for throttling applications will be supplied with a positioner having a 3 to 15 psig or 4 to 20 ma DC input signal. Single or double acting actuators are acceptable.

e. Travel indicators will be supplied for all control valves except solenoid operated valves. The indicators will be calibrated for approximate indication of 0, 25, 50, 75 and 100% of travel.

f. Actuator positioners will be designed to operate the final control element actuator from a 3 to 15 psig pneumatic or a 4 to 20 ma DC electric control signal.

g. Hysteresis of the valve assembly will be less than 0.4%; i.e., a control signal change greater than 0.4% will cause the valve to move.

h. Linearity of travel shall be within 1% of full stroke.

16.0 Alarm System

16.1 General: Where necessary, each operation control center in the plant will contain an alarm system to give a visual and audible signal when an unusual operating condition approaching an emergency occurs, and in some cases to initiate automatically an action, such as valve closure, to prevent or reduce further upset.

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INSTRUMENTATION

17.0 Instrument Air

Instrument air will be supplied oil-free at a nominal 100 psig and ambient temperature with a dew point of - 40°F or lower.

17.1 Isolated instruments or those located in small isolated groups will be supplied with 20 psig instrument air using a combination filter-dripwell-regulator with integral relief valve. Air consumption through the regulator shall be limited to the effective capacity of the regulator. All instruments supplied through a single regulator will be located within a radius of approximately 10'.

17.2 Large groups of instruments arranged close together, as on some instrument panels, may be supplied with air through a large, well-drained, 20 psig header. Dual filters and regulators will be used in conjunction with 3-way cocks to allow either set to be used without interruption of air supply. Regulators will have integral relief features and have an excess capacity of 20%. One spare take-off will be provided for each 5' of header. A 0 to 30 psig pressure gage will be mounted on the header to facilitate adjustment of the reducing valves.

17.3 Lubricators will be provided where required.

18.0 Instrument Piping

18.1 Impulse lines from the process take-off up to and including the shut-off valves will conform to the specifications for the line or equipment to which they are attached. The process line take-off will not be less than 1/2" pipe up to the shut-off valve. Beyond the valve and up to the instrument panel the connecting lines will be 1/2" or larger pipe, or 3/8" tubing.

18.2 Instrument air lines for transmission and control will be tubing of 1/4" O.D. polyethylene in suitable size bundles. Supply lines to large users will be 3/8" O.D. or larger, as required.

18.3 Tubing fittings will be tubing swage type.

18.4 Valves shall be used on all air supply lines to instruments.

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INSTRUMENTATION

18.5 Design of instrument piping will provide that the lines be grouped where possible and properly supported. Impulse lines will be sloped to insure proper operation of the instrument. Vents and drains will be furnished where necessary.

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July 1980

ATTACHMENT D

OUTLINE SPECIFICATION

PIPING

FOR

THE ILLINOIS COAL GASIFICATION GROUP

CONCEPTUAL COMMERCIAL PLANT

FE/2012/Z/80/06
July 1980

ATTACHMENT D

OUTLINE SPECIFICATION
PIPING

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OUTLINE SPECIFICATION
PIPING

1.0 General

1.1 This specification establishes the quality and characteristics of the materials to be used for utility and process piping. This document is not all inclusive and is not intended to restrict deviations in design or choice of materials which may be dictated by considerations not envisioned at this time.

2.0 Codes and Standards

2.1 Applicable sections of the following mandatory codes and standards shall be followed in the specification of piping materials for the Commercial Plant. Concensus codes may be stipulated for enforcement subject to engineering judgement.

2.2 Mandatory Codes

a. ICC General Order 192R
b. Illinois LPG Law, Rules and Regulations
c. Illinois State Plumbing Code
D. OSHA Codes and Regulations

2.3 Concensus Codes

a. ANSI Specifications
b. API Codes and Specifications
c. ASME Codes and Specifications
d. ASTM Codes and Specifications
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SPECIFICATION NO. P1.162
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 600 PSIG @ 500 DEG. F

CONSTRUCTION: FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2 AND UNDER	1.17	C.S. A106 GR. B SMLS., SCH.40.
		2" TO 10" INCL.	1.9	C.S. A53 GR. B SMLS., SCH.40.
		12" TO 16" INCL.	1.11	C.S. A53 GR. B ERW, 0.375 WALL.
		18" TO 20" INCL.	1.12	C.S. A53 GR. B ERW, 0.500 WALL.
		24" SIZE	1.178	C.S. A53 GR. B ERW, SCH.40.
		30" SIZE	1.163	C.S. A53 GR. B ERW, 0.750" WALL.
FITTINGS		1-1/2" AND UNDER	2.14	F.S. A105, SOCKET WELD, 3000#.
		2" TO 10" & 24" SIZE	2.1	C.S. BUTT WELD, A234 GR.WPB, SCH.40.
		12" TO 16" INCL.	2.3	C.S. BUTT WELD, A234 GR.WPB, 0.374" WALL.
		18" TO 20" INCL.	2.4	C.S. BUTT WELD, A234 GR.WPB, 0.500" WALL.
		30" SIZE	2.29	C.S. BUTT WELD, A234 GR.WPB, 0.750" WALL.
UNIONS & FLANGES		1-1/2" AND UNDER	3.15	F.S. UNION, A105, SOCKET WELD, 3000#.
		2" TO 10" & 24" SIZE	4.18	C.S. WELD NECK, A105, 300# ANSI B16.5 R.F., BORED SCH.40.
		12" TO 16" INCL.	4.20	C.S. WELD NECK, A105, 300# ANSI B16.5 R.F., BORED 0.375" WALL.
		18" TO 20" INCL.	4.21	C.S. WELD NECK, A105, 300# ANSI B16.5 R.F., BORED 0.500 WALL.
		30" SIZE	4.159	C.S. WELD NECK, A105, 300# MSS-SP-44 R.F., BORED 0.750" WALL.
VALVES	SHUT-OFF	2" AND UNDER	5.55	F.S. GATE, A105, O.S.&Y., SOCKET WELD, 800#.
		3" TO 30" INCL.	5.39	C.S. GATE, A216-WCB, O.S.&Y., FLANGED 300# ANSI B16.5 AND B16.10.
	THROTTLE	2" AND UNDER	6.20	F.S. GLOBE, A105; O.S.&Y., SOCKET WELD, 800#
		3" TO 12" INCL.	6.33	C.S. GLOBE, A216-WCB, O.S.&Y., FLANGED 300# ANSI B16.5 AND B16.10.
	CHECK	2" AND UNDER	7.31	F.S. CHECK, A105, BALL TYPE, SOCKET WELD, 800#
		3" TO 24" INCL.	7.37	C.S. CHECK, A216 GR. WCB, SEING TYPE, FLANGED 300# ANSI B16.5 AND B16.10.
JOINT MAT'L.				
GASKETS			19.27	STAINLESS STEEL SPIRAL WOUND, ASBESTOS FILLED, 3/16" THK.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR.B7

NOTES:
1) USE ITEM 2.147, C.S. A106 SCH.80 NIPPLES, AT INSTRUMENT CONNECTIONS.
2) USE SCH.80 PIPE, ITEM NO. 1.18, IN CONDENSATE (HC) SERVICE FOR SIZES 1-1/2" AND SMALLER.
3) ALL GATE VALVES 16" AND LARGER TO BE GEAR OPERATED.

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SPECIFICATION NO. P1.163
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 50 PSIG @ 300 DEG. F

CONSTRUCTION: 2" AND UNDER-SCREWED: 3" AND OVER-FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE (SEE NOTE 3)		1-1/2" AND UNDER	1.13	C.S. A106 GR. A OR B SMLS, SCH.40
		2" TO 10" INCL.	1.5	C.S. A53 TYPE S OR E, SCH.40
		12" TO 36" INCL.	1.7	C.S. A53 TYPE S OR E, 0.375" WALL.
FITTINGS		2" AND UNDER	2.9	A.I., A197, SCREWED 300# SSP
		3" TO 10" INCL.	2.1	C.S. BUTT WELD, A234 GR. WPB, SCH.40
		12" TO 36" INCL.	2.3	C.S. BUTT WELD, A234 GR. WPD, 0.375" WALL.
UNIONS & FLANGES		2" AND UNDER	3.2	M.I. SCREWED UNION, A197, 300# SSP
		3" TO 24" INCL.	4.1	C.S. SLIP-ON, A105, 150# ANSI B16.5 R.F.
			4.2	C.S. SLIP-ON, A105, 150# ANSI B16.5 F.F.
		30" TO 36"	4.160	C.S. SLIP-ON, A105, 150# MSS-SP-44 F.F.
VALVES	SHUT-OFF	2" AND UNDER	5.1	BRONZE GATE, B62, INSIDE-SCREW RISING STEM, SCREWED 125# SSP.
		3" TO 36" INCL.	5.15	C.I. GATE, A126 CL.B, IBBM, O.S.&Y., FLANGED 125# ANSI B16.1 AND B16.10, GEAR OPERATED 16" AND OVER.
	THROTTLE	2" AND UNDER	6.5	BRONZE GLOBE, B62, INSIDE-SCREW RISING STEM, SCREWED, 125# SSP
		3" TO 10" INCL.	6.17	C.I. GLOBE, A126 CL.B, IBBM,).S.&Y., FLANCED 125# ANSI B16.1 AND B16.10
	CHECK	2" AND UNDER	7.1	BRONZE CHECK, B62, SWING TYPE, SCREWED 125# SSP.
		3" TO 24" INCL.	7.10	C.I. CHECK, A126 CL.B, IBBM, SWING TYPE, FLANGED 125# ANSI B16.1 AND B16.10.
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL.-SEAL OR EQUAL
GASKETS			19.1	COMPRESSED WHITE ASBESTOS 1/16" THICK.
BOLTS			21.1	MACHINE BOLTS WITH HEX NUTS A307 GR.B.

NOTES:
1) USE ITEM 4.2 AT CAST IRON VALVES AND EQUIPMENT.
2) USE ITEM 2.147, C.S. A106 SCH. 80 NIPPLES, AT INSTRUMENT CONNECTIONS.
3) USE ITEM 1.14, C.S. A106 SCH. 80 PIPE, IN SIZES 1-1/2" AND SMALLER, IN CONDENSATE (LC OR TC) SERVICES.

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SPECIFICATION NO. P1.164
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 150 PSIG @ 500 DEG. F

CONSTRUCTION: 2" AND UNDER-SCREWED; 3" AND OVER-FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.13	C.S. A106 GR. A OR B SMLS, SCH.40
		2" TO 10" INCL.	1.5	C.S. A53 TYPE S OR E, SCH.40
		12" TO 30" INCL.	1.7	C.S. A53 TYPE S OR E, 0.375" WALL
FITTINGS		2" AND UNDER	2.9	M.I., A197, SCREWED 300# SSP.
		3" TO 10" INCL.	2.1	C.S. BUTT WELD, A234 GR. WPB, SCH.40.
		12" TO 30" INCL.	2.3	C.S. BUTT WELD, A234 GR. WPB, 0.375" WALL.
UNIONS & FLANGES		2" AND UNDER	3.2	M.I. SCREWED UNION, A197, 300# SSP.
		3" TO 24" INCL.	4.1	C.S. SLIP-ON, A105, 150# ANSI B16.5 R.F.
		30" SIZE	4.160	C.S. SLIP-ON, A105, 150# MSS-SP-44.
VALVES	SHUT-OFF	2" AND UNDER	5.3	BRONZE GATE, B61, INSIDE-SCREW RISING STEM, SCREWED, 200# SSP.
		3" TO 30" INCL.	5.37	C.S. GATE, A216 GR. WCB, O.S.&Y, FLANGED 150# ANSI B16.5 AND B16.10, GEAR OPERATED 16" AND OVER.
	THROTTLE	2" AND UNDER	6.1	BRONZE GLOBE, B61, INSIDE-SCREW RISING STEM, SCREWED, 200# SSP.
		3" TO 14" INCL.	6.31	C.S. GLOBE, A216 GR. WCB, O.S.&Y., FLANGED 150# ANSI B16.5 AND B16.10.
	CHECK	2" AND UNDER	7.2	BRONZE CHECK, B61, SWING TYPE, SCREWED, 200# SSP.
		3" TO 16" INCL.	7.36	C.S. CHECK, A216 GR. WCB, SWING TYPE, FLANGED 150# ANSI B16.5 AND B16.10.
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL-SEAL OR EQUAL.
GASKETS			19.1	COMPRESSED WHITE ASBESTOS, 1/16" THICK.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR. BT.

NOTES:
1) USE ITEM 2.147, C.S. A106 SCH. 80 NIPPLES, AT INSTRUMENT CONNECTIONS.
2) USE ITEM 1.14, C.S. A106 SCH. 80 PIPE, IN SIZES 1-1/2" AND SMALLER, IN CONDENSATE (MC) SERVICE.

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SPECIFICATION NO. P1.165
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 100 PSIG @ 100 DEG. F

CONSTRUCTION: 2" AND UNDER-SCREWED; 2-1/2" AND OVER-FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.13	C.S. A106 GR. A OR B, SMLS, SCH40.
		2" TO 10" INCL.	1.5	C.S. A53 TYPE S OR E, SCH.40.
		12" TO 24" INCL.	1.7	C.S. A53 TYPE S OR E, 0.375" WALL
		30" TO 48" INCL.	1.164	C.S. A283 WELDED, GR. A OR B, 0.375" WALL.
FITTINGS		2" AND UNDER	2.9	M.I. A197, SCREWED, 300# SSP
		3" TO 10" INCL.	2.1	C.S. BUTT WELD, A234 GR. WPB, SCH.40.
		12" TO 36" INCL.	2.3	C.S. BUTT WELD, A234 GR. SPB, 0.375" WALL.
(SEE NOTE 4)		42" TO 48" INCL.	——	MITER FROM PIPE
UNIONS & FLANGES		2" AND UNDER	3.2	M.I. SCREWED UNION, A197, 300# SSP
		3" TO 24" INCL.	4.1	C.S. SLIP-ON, A105, 150# ANSI B16.5 R.F.
			4.2	C.S. SLIP-ON, A105, 150# ANSI B16.5 F.F.
		30" TO 48" INCL.	4.160	C.S. SLIP-ON, A105, 150# MSS-SP-44
VALVES	SHUT-OFF	2" AND UNDER	13.2	BRONZE BALL VALVE, SCREWED, 150#
		3" TO 48" INCL.	11.1	D.I. BUTTERFLY, A395, LUG BODY, HANDLE OPERATED 8" AND UNDER, GEAR OPERATED 10" AND OVER, FOR USE WITH 150# ANSI FLANGES.
	THROTTLE	2 AND UNDER	6.5	BRONZE GLOBE, B62, INSIDE-SCREW RISING STEM, SCREWED 125# SSP.
		3" TO 10" INCL.	6.17	C.I. GLOBE, A126 CL. B, IBBM, O.S.&Y., FLANGED 125# ANSI B16.5 AND B16.10.
	CHECK	2" AND UNDER	7.2	BRONZE CHECK, B62, SWINGTYPE, SCREWED 125# SSP.
		3" TO 48"	7.13	C.I. CHECK, A126 CL.B, WAFER TYPE, SPRING LOADED, RATED 125#, FOR USE WITH 150# ANSI FLANGES.
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL.-SEAL OR EQUAL.
GASKETS			19.8	RED RUBBER, 1/8" THICK.
BOLTS			21.1	MACHINE BOLTS WITH HEX NUTS A307 GR.B
			21.7	CAP SCREWS, HEX HEAD, A307 GR.B.

NOTES:
1) USE ITEM 4.2 AT CAST IRON VALVES AND EQUIPMENT.
2) USE ITEM 21.7 WITH ITEM 11.1 ONLY.
3) USE ITEM 2.147, A106 SCH.80 NIPPLES, AT INSTRUMENT CONNECTIONS.
4) MITERED ELBOWS TO BE FABRICATED PER AWWA C-208, TABLE 2, 5 PIECE TYPE.

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SPECIFICATION NO. P1.166

 REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 125 PSIG @ 150 DEG. F

CONSTRUCTION: 2" AND UNDER-SCREWED; 3" AND OVER-FLANGED AND COUPLES

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		10" AND UNDER	1.2	GALV. C.S. A120, SCH.40.
FITTINGS		2" AND UNDER	2.12	GALV. M.I., A197, SCREWED, 300# SSP.
		3" TO 10" INCL.	2.95	GALV. M.I., A197, VICTAULIC GROOVED TYPE.
UNIONS & FLANGES		2" AND UNDER	3.8	GALV. M.I. UNION, A197, SCREWED, 300# SSP
		3" TO 10" INCL.	3.38	M.I. COUPLING, A197, VICTAULIC STYLE 77.
		3" TO 10" INCL.	4.13	GALV. C.S., A105, THREADED, 150# ANSI B16.5 F.F.
VALVES	SHUT-OFF	2" AND UNDER	5.1	BRONZE GATE, B62, INSIDE-SCREW RISING STEM, 125# SSP.
		3" TO 10" INCL.	5.15	C.I. GATE, A126 CL.B, IBBM, O.S.&Y., FLANGED 125# ANSI B16.1.
	THROTTLE			
	CHECK			
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL-SEAL OR EQUAL
GASKETS			19.8	RED RUBBER, 1/8" THICK
BOLTS			21.1	MACHINE BOLTS WITH HEX NUTS A307 GR.B.

NOTES: 1) USE ITEM 2.150, GALV. A120 SCH.80 NIPPLES, AT INSTRUMENT CONNECTION.

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SPECIFICATION NO. P1.166

 REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 125 PSIG @ 150 DEG. F

CONSTRUCTION: 2" AND UNDER-SCREWED; 3" ANDOVER-MECHANICAL JOINT

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		2" AND UNDER	1.2	GALV. C.S. A120, SCH.40
		3" AND OVER	1.77	C.I. PRESSURE PIPE, CLASS 150 A21.6 OR A21.8, MECHANICAL JOINT, A21.8, WITH GASKET BOLTS AND DUCTILE IRON RETAINER GLAND.
FITTINGS		2" AND UNDER	2.12	GALV. M.I., A197, SCREWED, 300# SSP.
		3" AND OVER	2.99	C.I. PRESSURE FITTINGS, MECH. JOINT A21.11, SHORT BODY PATTERN A21.10, GLASS 250#, COMPLETE WITH GASKET, BOLTS AND DUCTILE IRON RETAINER GLAND
UNIONS & FLANGES		2" AND UNDER	3.8	GALV. M.I. UNION, A197, SCREWED, 300# SSP.
VALVES	SHUT-OFF	2" AND UNDER	5.1	BRONZE GATE, B62, INSIDE SCREW-RISING STEM, 125# SSP
		3" AND OVER	5.24	C.I. GATE, A126 CL.B, IBBM, MECH. JOINT ENDS, SQUARE OPERATING NUT, AWWA PATTERN, 150# CWP.
	THROTTLE			
	CHECK			
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL-SEAL OR EQUAL.
GASKETS				
BOLTS				

NOTES: 1) USE STREET BOX, ITEM 30.23, WITH ITEM 5.24.

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Piping Materials

SPECIFICATION NO. P1.169

REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 750 PSIG @ 500 DEG. F

CONSTRUCTION: 2" AND UNDER SOCKET WELD; 3" AND OVER FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.18	C.S. A106 GRADE B SMLS. SCH.80.
		2" THRU 16" INCL.	1.9	C.S. A53 GRADE B SMLS. SCH.40.
FITTINGS		2" AND UNDER	2.14	F.S. A105, SOCKET WELD 3000# WOG.
		3" TO 16" INCL.	2.1	C.S. BUTT WELD A234 GR. WPB, SCH.40.
UNIONS & FLANGES		2" AND UNDER	3.15	F.S. UNION A105, SOCKET WELD 3000# WOG.
		3" TO 16" INCL.	4.28	C.S. WELD NECK, A105, 600# ANSI B16.5 R.F., BORED FOR SCH.40.
VALVES	SHUT-OFF	2" AND UNDER	5.55	F.S. GATE, A105, O.S.&Y., SOCKET WELD 800#
		3" TO 16" INCL.	5.44	C.S. GATE, A216 GR. WCB, O.S.&Y., PRESSURE SEAL BONNET, 600# RATING, BUTT WELD, ENDS BORED FOR SCH.40, GEAR OPERATED 8" AND OVER.
	THROTTLE	2" AND UNDER	6.20	F.S. GLOBE, A105, O.S.&Y., SOCKET WELD, 800#
		3" TO 16" INCL.	6.70	C.S. GLOBE, A216 G.R. WCB, O.S.&Y., PRESSURE SEAL BONNET, RATED 600#, BUTT WELD, ENDS BORED FOR SCH.40, GEAR OPERATED 8" AND OVER.
	CHECK	2" AND UNDER	7.31	F.S. CHECK, A105, BALL TYPE, SOCKET WELD 800# SSP.
		3" TO 16" INCL.	7.70	C.S. CHECK, A216 GR. WCB, O.S.&Y., PRESSURE SEAL BONNET, RATED 600#, BUTT WELD, ENDS BORED FOR SCH.40.
JOINT MAT'L.				
GASKETS			19.27	STAINLESS STEEL SPIRAL WOUND, ASBESTOS FILLED, 3/16" THICK.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR.B7.

NOTES: 1) USE ITEM 2.147, A106 SCH.80 NIPPLES, AT INSTRUMENT CONNECTIONS.

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SPECIFICATION NO. P1.170
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 1500 PSIG @ 420° DEG. F

CONSTRUCTION:

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.18	C.S. A106 GRADE B SMLS. SCH.80.
		2" THRU 20"	1.10	C.S. A53 GRADE B SMLS. SCH.80.
FITTINGS		2" AND UNDER	2.14	F.S. A105, SOCKET WELD 3000# WOG
		3" TO 20" INCL.	2.2	C.S. BUTT WELD, SCH.80.
UNIONS & FLANGES		2" AND UNDER	3.15	F.S. UNION A105, SOCKET WELD 3000# WOG.
		3" TO 20" INCL.	4.161	CS. WELD NECK, A105, 900# ANSI B16.5 $.J., BORED FOR SCH.80.
VALVES	SHUT-OFF	2" AND UNDER	6.55	F.S. GLOBE, A105, Y-PATTERN, O.S.&Y., SOCKET WELD, 1500#
		3" TO 20" INCL.	5.45	C.S. GATE, A216 GR. WCB, O.S.&Y., PRESSURE SEAL BONNET, 900# RATING, BUTT WELD, ENDS BORED FOR SCH.80., GEAR OPERATED 8" AND OVER.
	THROTTLE	2" AND UNDER	6.55	F.S. GLOBE, A105, Y-PATTERN, O.S.&Y., SOCKET WELD, 1500#.
		3" TO 6" INCL.	6.56	C.S. GLOBE, A216 GR. WCB, O.S.&Y., PRESSURE SEAL BONNET, 900# RATING, BUTT WELD, ENDS BORED FOR SCH.80, GEAR OPERATED 8" AND OVER.
	CHECK	2" AND UNDER	7.53	F.S. CHECK, A105, PISTON TYPE, SOCKET WELD, 1500# SSP.
		3" TO 8" INCL.	7.45	C.S. CHECK, A216 GR.WCB, TILTING DISC, PRESSURE SEAL CAP, 900# RATING, BUTT WELD, ENDS BORED FOR SCH. 80.
JOINT MAT'L.				
GASKETS			19.40	C.S. OCTAGONAL RING ANSI B16.20, MAX. BRINNEL OF 120.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR.B7.

NOTES:

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SPECIFICATION NO. P1.174
REV.

ITEM		SIZE	ITEM	DESCRIPTION
PRESSURE AND TEMPERATURE LIMITATIONS: 180 (150) PSIG @ 100 (125) DEG. F				
CONSTRUCTION: 3/4" AND UNDER-SOCKET WELD: 1" AND OVER-FLANGED AND WELDED				
PIPE		1-1/2" AND UNDER	1.13	C.S. A106 GR. A OR B SEAMLESS, SCH. 40
		2" TO 10" INCL.	1.5	C.S. A53, TYPE S OR E, SCH. 40
FITTINGS		3/4" AND UNDER	2.16	F.S., A105, SCREWED 3000 LB. WOG
		1" TO 1-1/2" INCL	2.14	F.S., A105, SOCKET WELD, 3000 LB. WOG
		2" TO 10" INCL.	2.1	C.S. BUTT WELD, A234 GR. WPB, SCH. 40
UNIONS & FLANGES		3/4" AND UNDER	3.15	F.S. A105 SOCKET WELD UNION, 3000 LB. WOG
		1" TO 10" INCL.	4.1	C.S., SLIP-ON, 150 LB. ANS1 B16.5 R.F.
VALVES	SHUT-OFF	3/4" AND UNDER	9.21	D.I. NON-LUBRICATED PLUG, A395, TEFLON SLEEVE, WRENCH OPERATED, SCREWED, 150# RATING.
		1" TO 10" INCL.	9.22	D.I. NON-LUBRICATED PLUG, A395, TEFLON SLEEVE, FLANGED 150# ANS1 B16.5 & B16.10, WRENCH OPERATED 3" AND UNDER, GEAR OPERATED 4" AND LARGER.
	THROTTLE	3/4" AND UNDER	6.10	F.S. GLOBE, A105, O.S.&Y, SCREWED, 800#
		1" TO 10" INCL.	6.3.	C.S. GLOBE, A216 GR. WCB, O.S.&Y., FLANGED 300# ANS1 B16.5 and B16.10.
	CHECK	3/4" AND UNDER	7.30	F.S., A105, BALL TYPE, SCREWED, 800#
		1" TO 10" INCL.	7.36	C.S. CHECK, A216 GR. WCB, SWING TYPE, FLANGED 150# ANS1 B16.5 and B16.10
JOINT MAT'L.		FOR SCREWED JOINTS	20.12	TEFLON TAPE
GASKETS			19.1	COMPRESSED WHITE ASBESTOS 1/16" THICK.
BOLTS			21.1	MACHINE BOLTS WITH HEX NUTS A307 GR. B.

NOTES:

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Piping Materials

SPECIFICATION NO. P1.176
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 1100 PSIG @ 350 DEG. F

CONSTRUCTION: FLANGE AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.18	C.S. A106 GR.B SMLS., SCH.80.
		2" TO 8" INCL.	1.10	C.S. A53 GR.B SMLS. SCH.80.
		12" TO 24" INCL.	1.138	C.S. A53 GR.B SMLS. SCH.60.
FITTINGS		1-1/2" AND UNDER	2.14	F.S. A105, SOCKET WELD, 3000#
		2" TO 8" INCL.	2.2	C.S. BUTT WELD, A234 GR. WPB, SCH.80.
		12" TO 24" INCL.	2.28	C.S. BUTT WELD, A234 GR. WPB, SCH.60.
UNIONS & FLANGES		2" AND UNDER	3.15	F.S. UNION, A105, SOCKET WELD, 800#.
		3" TO 24" INCL.	4.186	C.S. SLIP-ON, A105, 600# ANSI B16.5 RING JOINT.
VALVES	SHUT-OFF	2" AND UNDER	5.55	F.S. GATE, A105, SOCKET WELD, 800#.
		3" TO 8" INCL.	5.99	C.S. GATE, A216 GR. WCB, O.S.&Y., 600# RATING, PRESSURE SEAL BONNET, BUTT WELD, ENDS BORED FOR SCH.80, GEAR OPERATED IN 8" SIZE.
		10" TO 24" INCL.	5.100	C.S. GATE, A216 GR. WCB, O.S.&Y., 600# RATING, PRESSURE SEAL BONNET, BUTT WELD, ENDS BORED FOR SCH.60, GEAR OPERATED.
	THROTTLE	2" AND UNDER	6.20	F.S. GLOBE, A105, SOCKET WELD, 800#.
		3" TO 8" INCL.	6.88	C.S. GLOBE, A216 GR. WCB, O.S.&Y., 600# RATING, PRESSURE SEAL BONNET, BUTT WELD, ENDS BORED FOR SCH.80, GEAR OPERATED IN 8" SIZE.
		10" TO 18" INCL.	6.89	C.S. GLOBE, A216 GR. WCB, O.S.&Y., 600# RATING, PRESSURE SEAL BONNET, BUTT WELD, ENDS BORED FOR SCH.60, GEAR OPERATED.
	CHECK	2" AND UNDER	7.31	F.S. CHECK, A105, BALL TYPE, SOCKET WELD, 800#
		3" TO 8" INCL.	7.45	C.S. CHECK, A216 AGR. WCB, PRESSURE SEAL CAP, TILTING DISC, RATED 900#, BUTT WELD, ENDS BORED FOR SCH.80.
		10" TO 20" INCL.	7.99	C.S. CHECK, A216 GR. WCB, PRESSURE SEAL CAP, TILTING DISC, RATED 900#, BUTT WELD, ENDS BORED FOR SCH.60.
GASKETS			19.40	C.S. OCTAGONAL RING ANSI B16.20, MAX. BRINNEL OF 120.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR.B7.

NOTES:

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SPECIFICATION NO. P1.180
REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 2665 PSIG @ 700 DEG. F

CONSTRUCTION: FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.176	C.S. A106 GR. B SMLS. SCH.160.
		2" TO 16" INCL.	1.179	C.S. A53 GR. B SMLS. SCH.160.
FITTINGS		16" AND UNDER	2.181	C.S. BUTT WELD, A234 GR. WPB, SCH.160.
FLANGES		1-1/2" AND UNDER	4.182	C.S. SOCKET WELD, A105, 1500# ANSI B16.5 R.J.
		2" TO 16" INCL.	4.183	C.S. WELD NECK, A105, 1500# ANSI B16.5 R.J., BORED FOR SCH.160.
VALVES	SHUT-OFF (SEE NOTE 1)	2" AND UNDER	5.95	F.S. GATE, A105, O.S.&Y., SOCKET WELD, 1500#
		3" TO 14" INCL.	5.96	C.S. GATE, A216 GR. WCB, O.S.&Y., FLANGED 1500# ANSI B16.5 R.J.
	(SEE NOTE 3)	2" AND UNDER	9.64	C.S. PLUG, A216 GR. WCB, LUBRICATED TYPE, SOCKET WELD, 1500#.
		3" SIZE	9.65	C.S. PLUG, A216 GR. WCB, LUBRICATED TYPE, 1500# RATING, BUTT WELD, BORED FOR SCH.160.
		4" TO 10"	9.66	C.S. PLUG, A216 GR. WCB, LUBRICATED TYPE, 1500# RATING, BUTT WELD, BORED FOR SCH.160, GEAR OPERATED.
	THROTTLE (SEE NOTE 1)	2" AND UNDER	6.55	F.S. Y-PATTERN GLOBE, A105, O.S.&Y., SOCKET WELD, 1500#.
		3" TO 6" INCL.	6.86	C.S. GLOBE, A216 GR. WCB, O.S.&Y., FLANGED 1500# ANSI B16.5 R.J.
	CHECK	2" AND UNDER	7.53	F.S. CHECK, A105, PISTON TYPE, SOCKET WELD 1500#
		3" TO 8" INCL.	7.89	C.S. CHECK, A216 GR. WCB, LIFT ANGLE TYPE, PRESSURE SEAL CAP, 1500# RATING, BUTT WELD, BORED SCH. 160.
	(SEE NOTE 1)	3" TO 16" INCL.	7.90	C.S. CHECK, A216 GR. WCB, SWING TYPE, BOLTED COVER, FLANGED 1500# ANSI B16.5 R.J.
JOINT MAT'L				
GASKETS			19.40	C.S. OCTAGONAL RING ANSI B16.20, MAX BRINNEL OF 120.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR. B7.

NOTES:
1) USE GATE, GLOBE AND SWING CHECK VALVES IN HMO SERVICE ONLY: USE BALANCE OF VALVING IN HMS SERVICE ONLY.
2) USE 6 DIA. BENDS IN PLACE OF ELBOWS IN HMS SERVICE ONLY.
3) USE ROCKWELL #921 LUBRICANT WITH LUBRICATED PLUG VALVES.

Piping Materials

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SPECIFICATION NO. P1.184

REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 20 PSIG @ 650 DEG. F

CONSTRUCTION: 2" AND UNDER-SCREWED; 3" AND OVER FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.13	C.S. A106 GR. A OR B SMLS, SCH.40.
		2" TO 10" INCL.	1.5	C.S. A53 TYPE S OR E. SCH.40.
		12" TO 38" INCL.	1.7	C.S. A53 TYPE S OR E, 0.375" WALL.
FITTINGS		2" AND UNDER	2.9	M.I. A197 SCREWED 300# SSP.
		3" TO 10" INCL.	2.1	C.S. BUTT WELD, A234 GR. WPB, SCH.40.
		12" TO 36" INCL.	2.3	C.S. BUTT WELD, A234 GR. WPB, 0.375" WALL.
UNIONS & FLANGES		2" AND UNDER	3.2	M.I. SCREWED UNION A197, 300# SSP.
		3" TO 24"	4.1	C.S., SLIP-ON, A105, 150# ANSI B16.5 R.F.
		30" AND 36" SIZE	4.160	C.S., SLIP-ON, A105, 150# MSS-SP-44.
VALVES	SHUT-OFF	2" AND UNDER	5.31	C.S., A105, UNION BONNET SCREWED, 800#.
		3" TO 36" INCL.	11.27	C.S. BUTTERFLY, A216 GR. WCB, 316 S.S. DISC, METAL SEATS, LUG BODY, FOR USE WITH 150# ANSI FLANGES, POSISEAL OR EQUAL.
	THROTTLE			
	CHECK			
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL-SEAL OR EQUAL.
GASKETS			19.1	COMPRESSED WHITE ASBESTOS, 1/16" THICK.
BOLTS			21.1	MACHINE BOLTS WITH HEX NUTS A307 GR. B.

NOTES:

Piping Materials

FE/2012/Z/80/06
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SPECIFICATION NO. P1.282

REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 538 / 120 PSIG @ 300 / 1000 DEG. F

CONSTRUCTION: 1-1/2" AND UNDER-SCREWED: 2" AND OVER FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1-1/2" AND UNDER	1.47	S.S. A312 TP304, SMLS OR WLD., SCH. 40S.
		2" TO 24" INCL.	1.46	S.S. A312 TP304, SMLS OR WLD., SCH. 10S
		30" TO 48" INCL.	1.136	S.S. A312 TP304, WELDED, 0.250" WALL
FITTINGS		1-1/2" AND UNDER	2.40	S.S. A182 GR. F304, SCREWED, 2000
		2" TO 24" INCL.	2.45	S.S. A403 GR. WP304, BUTT WELD, SCH. 10S
(SEE NOTE 1)		30" TO 48" INCL.	----	MITER FROM PIPE
UNIONS & FLANGES		1-1/2" AND UNDER	3.29	S.S. UNION A182 GR. F304, SCREWED, 3000#
		2" TO 24" INCL.	4.65	S.S. A182 GR. F304, SLIP-ON, 300# ANS1 B16.5R.F.
		30" TO 48" INCL.	4.163	S.S. A182 GR. F304 SLIP-ON, 300# MSS-SP-44
VALVES	SHUT-OFF	1-1/2" AND UNDER	5.86	S.S. GATE A351 GR. CF8, O.S.&Y., SCREWED 300#.
		2" TO 24" INCL,	5.87	S.S. GATE A351 GR. CF8, O.S.&Y., FLANGED 300# ANS1 B16.5 AND B16.10, GEAR OPERATED 16" AND OVER.
		30" TO 48" INCL.	11.20	S.S. BUTTERFLY A351 GR. CF8M, METAL SEATED, LUG BODY, FOR USE WITH 300# ANS1 FLANGES, POSISEAL OR EQUAL.
	THROTTLE	1-1/2" AND UNDER	6.82	S.S. GLOBE A351 GR. CF8, O.S.&Y., SCREWED 300#.
		2" TO 6" INCL.	6.83	S.S. GLOBE A351 GR. CF8, O.S.&Y., FLANGED 300# ANS1 B16.5 AND B16.10.
	CHECK	1-1/2" AND UNDER	7.82	S.S. LIFT TYPE, A351 GR. CF8, O.S.&Y., SCREWED 300#.
		2" TO 16" INCL.	7.83	S.S. SWING TYPE, A351 GR' CF8, O.S.&Y., FLANGED 300# ANS1 B16.5 & B16.10
JOINT MAT'L.		FOR SCREWED JOINTS	20.11	CYL-SEAL OR EQUAL.
GASKETS			10.27	STAINLESS STEEL SPIRAL WOUND, ASBESTOS FILLED, 3/16" THICK.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR. B7.

NOTES: 1) MITERED ELBOWS TO BE FABRICATED PER AWWA C-208, TABLE 2, 5 PIECE TYPE.

Piping Materials

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SPECIFICATION NO. P1.283

REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 2700 PSIG @ 800 DEG. F

CONSTRUCTION:

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		1/2" AND 3/4"	1.139	S.S. A312 TP374H SMLS, SCH. 80
		1" THRU 16" INCL	1.140	S.S. A312 TP347H SMLS, SCH. 160.
FITTINGS		3/4" THRU 1-1/2" INCL.	2.179	S.S. A182 GR. F347H, SOCKET WELD 6000#
		2" THRU 16" INCL (SEE NOTE 1)	2.180	S.S. A403 GR. WP347H, BUTT WELD, SCH. 160.
UNIONS & FLANGES		3/4" THRU 1-1/2"	4.169	S.S. A182 GR. F347H, SOCKET WELD 2500# ANSI B16.5 RING JOINT.
		2" THRU 16" INCL	4.169	S.S. A182 GR. F347H WELD NECK, 2500# ANSI B16.5 RING JOINT, BORED FOR SCH. 160.
VALVES	SHUT-OFF (SEE NOTE 2)	1" THRU 3"	9.58	S.S. PLUG, A296 GR. CF8M, LUBRICATED TYPE, RATED 2500#, B.W., ENDS BORED SCH. 160.
		3" THRU 8"	5.89	S.S. GATE, A296 GR. CF8M, O.S.&Y., 2500# B.W., ENDS BORED FOR SCH. 160, GEAR OPERATED 6" AND OVER.
	(SEE NOTE 4)	4" THRU 10"	9.63	S.S. PLUG A351 GR. CF8M, LUBRICATED TYPE, RATED 2500#, B.W., ENDS BORED SCH. 160
	THROTTLE	2" AND UNDER	6.79	S.S. GLOBE A182 GR. F316, Y-PATTERN, WELDED BONNET, RATED 2500#, SOCKET WELD.
	CHECK	2" AND UNDER	7.79	S.S. A182 GR. F316, SPRING LOADED PISTON TYPE, SOCKET WELD, RATED 2500#.
		3" THRU 16" INCL	7.80	S.S. A351 GR. CF8M, TILTING DISC TYPE, PRESSURE SEAL CAP, RATED 2500#, B.W., ENDS BORED SCH.160
		3" THRU 16" INCL	7.81	S.S. A351 GR. CF8M, PISTON TYPE, PRESSURE SEAL CAP, RATED 2500#, B.W., ENDS BORED SCH. 160.
JOINT MAT'L.				
GASKETS			19.39	S.S. OCTAGONAL RING ANSI B16.20, MAX. BRINNEL OF 150
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR. B7.

NOTES:
1) USE 6 DIA. BENDS IN PLACE OF ELBOWS IN HOS SERVICE.
2) USE ROCKWELL #921 LUBRICANT WITH LUBRICATED PLUG VALVES.
3) USE PISTON TYPE CHECK VALVES, ITEM 7.81, IN HOS SERVICE ONLY.
4) USE ITEM 9.63 IN HOS SERVICE ONLY.

Piping Materials

FE/2012/Z/80/06
July 1980

SPECIFICATION NO. P1.284

REV.

PRESSURE AND TEMPERATURE LIMITATIONS: 525 PSIG @ 800 DEG. F

CONSTRUCTION: FLANGED AND WELDED

ITEM		SIZE	ITEM	DESCRIPTION
PIPE		14" AND UNDER	1.141	S.S. A312 TP304L SMLS, SCH. 80S
		16" size	1.142	S.S. A312 TP304L SMLS, 0.500" WALL
FITTINGS		1-1/2" AND UNDER	2.36	S.S. A182 GR. F304L, SOCKET WELD, 3000#
		2" TO 14" INCL	2.177	S.S. A403 GR. WP304L, BUTT WELD, SCH. 80S
		16" SIZE	2.178	S.S. A403 GR. WP304L, BUTT WELD, 0.500" WALL.
UNIONS & FLANGES		1-1/2" AND UNDER	3.28	S.S. UNION A182 GR. F304L, SOCKET WELD, 3000#
		2" TO 14" INCL	4.166	S.S. A182 GR. F304L, WELD NECK, 600# ANSI 16.5 R.F., ORED SCH. 80S
		16" SIZE	4.167	S.S. A182 GR. F304L, WELD NECK, 600# ANSI B16.5 R.F., BORED 0.500" WALL.
VALVES	SHUT-OFF	2" AND UNDER	9.59	S.S. PLUG, A351 GR. CF3M, LUBRICATED TYPE, RATED 600#, SOCKET WELD.
		3" AND 4" SIZES	9.60	S.S. PLUG, A351 GR. CF8M, LUBRICATED TYPE, FLANGED 600# ANSI B16.5 R.F., WRENCH OPERATED
		6" TO 12" INCL	9.61	S.S. PLUG, A351 GR. CF8M, LUBRICATED TYPE, FLANGED 600# ANSI B16.5 R.F., GEAR OPERATED
		14" AND 16" SIZES	11.24	S.S. BUTTERFLY A351 GR. CF8M, METAL SEATS. LUG BODY, FOR USE WITH 600# ANSI FLANGES. POSISEAL OR EQUAL.
	THROTTLE			
	CHECK	2" AND UNDER	7.78	S.S. A182 GR F316, SPRING LOADED PISTON TYPE, SOCKET WELD, RATED 600#.
		3" TO 8" INCL.	7.85	S.S. A351 GR. CF8M, LIFT TYPE BOILTED COVER, FLANGED 600# ANSI B16.5 R.F.
JOINT MAT'L				
GASKETS			19.27	STAINLESS STEEL SPIRAL WOUND, ASBESTOS FILLED, 3/16" THICK.
BOLTS			21.3	ALLOY STEEL STUD BOLTS WITH HEX NUTS A193 GR. B7.

NOTES:
1) WALL THICKNESS INCLUDES A CORROSION ALLOWANCE OF 0.125" EXCEPT IN 16" SIZE WHICH INCLUDES AN ALLOWANCE OF 0.119".
2) USE ROCKWELL #921 LUBRICANT WITH LUBRICATED PLUG VALVES.
3) USE 6 DIA. BENDS IN PLACE OF ELBOWS IN MOS SERVICE.

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2.3 PLANT DESCRIPTION

The ICGG Commercial Plant, using the COGAS Process, is a self-contained, grass roots facility designed to produce 264.53 MM standard cubic feet per day (SCFD) of substitute pipeline gas (SPG) from Illinois No. 6 coal. Run-of-mine (ROM) coal, raw water and miscellaneous catalysts and chemicals constitute the total feed to the plant. All utilities including electric power are produced on site, except electricity needed for lighting and the river water pumping station. Byproducts from the plant are in finished, marketable form and include a fuel oil, a naphtha stream, anhydrous ammonia, and either sulfuric acid or sulfur. Major waste streams exiting the facility are slag, water treatment and sulfite sludges, carbon dioxide, and desulfurized flue gas. Aqueous wastes are evaporated and recycled internally, thus facilitating essentially "zero discharge".

The facility, as shown on Block Flow Diagram No. 100-100-1 and Site Plot Plan Drawings No. 100-200-1,6, is divided into twenty processing areas, each containing one or more unit process trains. Area designations are:

Area	Description
101	Coal Unloading and Handling
102	Coal Preparation
103	Pyrolysis and Gasification
104	Oil Recovery and Treatment
105	Gas Purification
106	Hydrogen Generation
107	Shift and Methanation
108	Bulk CO_2 Removal and Gas Compression
109	Gas Dehydration
110	Flue Gas Power Recovery
111	SO_2 Removal
112	Sulfur Recovery

2.3 PLANT DESCRIPTION - continued

Area	Description
113	Ammonia Recovery
114	Thermal Oxidizer and Flare
115	Utilities
116	Water Supply
117	Water Treatment Systems
118	Waste Treatment and Disposal
119	Fire Protection System
120	Facilities

Because of equipment size limitations, the main processing areas are composed of three parallel trains. These include Area 102, Coal Preparation; Area 103, Pyrolysis and Gasification; Area 104, Oil Recovery and Treatment; Area 105, Gas Purification; Area 107, Shift and Methanation;* Area 108, Bulk CO_2 Removal and Gas Compression;* and Area 110, Flue Gas Power Recovery. The remaining areas are basically single train with multiple equipment items provided on an "as required" basis. A brief description of the function of each of the twenty processing areas follows.

2.3.1 Area 101 - Coal Unloading and Handling

ROM coal is delivered to the plant by overland conveyor and by unit train. The coal unloading and handling area is a single train system with facilities to receive the coal on an intermittent basis, crush it to 1-1/2" x 0", store it in outdoor piles for 30 days, reclaim it and deliver it to Area 102, Coal Preparation, on a continuous basis.

*The gas compression section of Area 108 and the final methanation section of Area 107 are single train.

2.3 PLANT DESCRIPTION

2.3.2 Area 102 - Coal Preparation - continued

Coal from the storage area is fed to each of three parallel trains, crushed, screened to a minus 10 mesh size and elevated into a storage silo. A Fuller-Kinyon pump feeding system raises the pressure of the coal from atmospheric to about 50 psig and feeds the coal to the first stage pyrolysis vessel in Area 103. A Fluid-Flo Dryer is provided in each line for use if the surface moisture is too high for direct crushing and screening.

2.3.3 Area 103 - Pyrolysis and Gasification

The pyrolysis and gasification area is the heart of the Commercial Plant. It is here that coal is converted into the raw oil and synthesis gas which, after treatment, become the major plant products. Ground, dried coal is fed from the Fuller-Kinyon pump system to the first stage pyrolysis vessel. The coal is devolatilized in four pyrolysis stages to produce char and pyrolysis gas. Char then enters the gasifier, where it reacts with steam to produce additional gas. Gasifier gas is returned to pyrolysis to supply heat and becomes part of the gas leaving pyrolysis. Pyrolysis gas containing evolved oil vapors is then sent to Area 104, Oil Recovery and Treatment. Ungasified char fines are burned in the combustor and supply heat to the gasifier through a char recycle stream. Flue gas leaving the combustor flows to Area 110, Flue Gas Power Recovery. The ash in the feed coal is rejected from the combustor as slag and is sent to a landfill after quench.

2.3.4 Area 104 - Oil Recovery and Treatment

Gas leaving the pyrolysis section of Area 103 is quench cooled in a series of venturi scrubbers to condense the oil and water vapors. The liquid from each scrubber is decanted and the water is cooled and recycled with the excess water going to Ammonia Recovery, Area 113. Uncondensed synthesis gas flows to Area 105, Gas Purification. Oil recovered in the decanters is dehydrated by heat, followed by flash separation of water and dissolved gas from the oil. Dehydrated oil is then stored or sent to hydrotreating. Hydrotreating involves treating the oil with hydrogen (from Area 106) in an ebullating bed catalytic reactor, followed by a flash and separation of vapor and liquid phases.

2.3 PLANT DESCRIPTION - continued

2.3.4 Area 104 - Oil Recovery and Treatment

The liquid phase is fractionated to produce a middle distillate fuel oil. The overheads from Fractionation are combined with the vapor phase from the first step hydrotreating and the bottoms are sent to vacuum distillation, which produces a seal oil for use in the process and more middle distillate fuel oil product. The heavy bottoms, containing solids, are sent to Area 103, Pyrolysis and Gasification, to be burned in the combustor supplying part of the heat required for the process.

The vapor phase is passed through a fixed bed hydrotreater and the heavier components are condensed, separated and also combined with the fuel oil product. The lighter components are condensed and stabilized to produce byproduct naphtha.

2.3.5 Area 105 - Gas Purification

In this area, the uncondensed synthesis gas from Area 104, Oil Recovery and Treatment, is first compressed to 465 psig. Acid gases such as COS, H_2S and CO_2 are removed from the gas stream by the Sulfinol Process. The ADIP Process is used to concentrate the H_2S in the acid gas stream and this acid gas is sent to Area 112, Sulfur Recovery, for further treatment. The purified synthesis gas stream leaving Area 105, rich in carbon monoxide and hydrogen, is split; the bulk of it flows to Area 107, Shift and Methanation, while the remainder is sent to Area 106, Hydrogen Generation.

2.3.6 Area 106 - Hydrogen Generation

This area provides the hydrogen required for hydrotreating the oil in Area 104. Purified synthesis gas feed, received from Area 105, is preheated and the last traces of sulfur compounds are removed in zinc oxide beds. The gas then passes through four shift converters, in series, where carbon monoxide is reacted with steam to form hydrogen and carbon dioxide. This gas stream then passes through a carbon dioxide absorber to remove CO_2, followed by molecular sieves to remove impurities. The hydrogen product is then sent to make up compressors in Area 104.

2.3 PLANT DESCRIPTION - continued

2.3.7 Area 107 - Shift and Methanation

The purified synthesis gas feed to this area from Area 105, Gas Purification, first passes through two zinc oxide beds to remove residual sulfur. It then passes through six stages of shift/methanation, wherein a portion of the CO is reacted with steam to produce H_2 for the methanation reaction. One part carbon monoxide and three parts of hydrogen then react to produce methane. After the sixth stage of shift/methanation, the gas is sent to Area 108, Bulk CO_2 Removal and Gas Compression. After the CO_2 is removed, the gas is compressed and returned to Area 107, where it passes through a final stage of methanation to reduce the carbon monoxide level to 0.1% max. The gas then leaves Area 107 and flows to Area 109, Gas Dehydration.

2.3.8 Area 108 - Bulk CO_2 Removal and Gas Compression

In this area, carbon dioxide is removed from the methanated gas by the Benfield Process. The gas contacts the hot carbonate solution in the CO_2 absorber. The gas which has been scrubbed of CO_2 is compressed and returned to Area 107 for final methanation. The solvent is regenerated for reuse in the absorber, while the carbon dioxide is vented to the atmosphere.

2.3.9 Area 109 - Gas Dehydration

Cooled gas from Area 107, which is saturated with water, is then fed to a dehydration column where water vapor is removed in a glycol solution. The glycol is regenerated for reuse, while the water is sent to Area 118, Waste Treatment and Disposal. Dehydrated SPG flows directly to the gas pipeline.

2.3.10 Area 110 - Flue Gas Power Recovery

Flue gas from Area 103 first enters the Flue Gas Oxidizer where it is burned to recover heat from combustibles and generate high pressure steam. Flue gas is then cleaned of most remaining particulate matter and expanded through expander turbines to near atmospheric pressure. These expander turbines are used to drive air compressors which supply combustion air to the oxidizer and to the combustor in Area 103. Excess expander power is used to generate electricity. After additional heat is removed, the flue gas stream is sent to Area 111, SO_2 Removal.

2.3 PLANT DESCRIPTION - continued

2.3.11 Area 111 - SO_2 Removal

The flue gas from Area 110, Flue Gas Power Recovery, and the sulfur contaminated gases from Area 112, Sulfur Recovery, flow to Area 111 for treatment in an FMC-Double Alkali FGD Process. The contaminated gases are contacted with a sodium sulfite solution in a venturi scrubber to remove SO_2, and then are exhausted to the atmosphere. The rich solution is regenerated with the addition of lime, producing a slurry of sodium salts and insoluble calcium salts. The calcium salts are separated and transported to landfill on site. Intermittent sulfur contaminated gases from Area 102, Coal Preparation, and Area 115, Utilities, will also be processed through this area.

2.3.12 Area 112 - Sulfur Recovery

Gas streams containing sulfur as H_2S are processed to produce elemental sulfur in a Claus plant. Acid gas streams bearing H_2S are received from Area 105, Gas Purification, and Area 113, Ammonia Recovery. The combined acid gas stream is fed to a reaction furnace where one third of the H_2S is burned with air to produce SO_2. The stream then passes through a series of Claus reactors where H_2S and SO_2 react catalytically to produce sulfur and water. The gas, after each reaction stage, is cooled to condense product sulfur and is then reheated prior to entering the next reactor. The tail gas from the last Claus reactor is incinerated to convert all sulfur compounds to SO_2, and is then sent to Area 111, SO_2 Removal.

The liquid sulfur is pumped to the Sulfuric Acid Plant for production of 66° Baumé sulfuric acid by burning the sulfur to SO_2, oxidizing SO_2 to SO_3 catalytically, and combining SO_3 with H_2O. Another processing option is to cool the liquid sulfur in a flaker to produce flake sulfur as a saleable byproduct.

2.3.13 Area 113 - Ammonia Recovery

Sour water produced in Area 103, Pyrolysis and Gasification, and Area 104, Oil Recovery and Treatment, is processed to recover anhydrous ammonia in the Phosam-W Process. The sour water is stripped with steam to remove ammonia and H_2S. Stripped water flows to Area 118, Waste Treatment and Disposal, while stripper gas is processed in an ammonia scrubber to remove the ammonia

2.3 PLANT DESCRIPTION - continued

2.3.13 Area 113 - Ammonia Recovery

in an ammonium phosphate solution. The remaining gas (H_2S and H_2O) is sent to Area 112, Sulfur Recovery. The rich solution from the ammonia scrubber is then stripped of its ammonia and lean phosphate solution is regenerated and recycled. Anhydrous ammonia is condensed after fractionation and sent to storage in Area 120, Facilities, for ultimate sale.

2.3.14 Area 114 - Thermal Oxidizer and Flare

Thermal Oxidizer

Waste streams from collection points in the plant are piped to this area. Liquid and gas are separated in an incinerator feed tank, fed separately to the thermal oxidizer, mixed with combustion air, and ignited and burned. Auxiliary fuel and steam are used as needed to insure complete combustion.

Flare

Any off spec product SPG from the plant is sent to the flare. The gas first enters a knockout drum where the entrained oil is separated and pumped to raw oil storage. The gas then enters the flare, where it is burned. Steam is added to ensure complete oxidation.

2.3.15 Area 115 - Utilities

This area provides the utilities needed to operate the plant. Included in Area 115 are the following systems:

- Instrument Air
- Plant Air
- Cooling Tower
- Condensate Return Units
- Auxiliary Boiler
- Inert Gas Generation
- Emergency Power Generation - Diesel Drive
- Main Power Generation - Steam Drive

2.3 PLANT DESCRIPTION - continued

2.3.16 Area 116 - Water Supply

Water is withdrawn from the Mississippi River through bar screens to prevent large debris from entering the system. It then passes through self cleaning traveling screens to eliminate smaller debris. Screened water enters the pipeline, where chlorine and cationic polymer are injected. It is then pumped 20 miles overland to the plant site where it enters Area 117, Water Treatment Systems.

2.3.17 Area 117 - Water Treatment Systems

The incoming river water is treated to produce cooling water make up, process, potable water, and high and low pressure boiler feed water make up. All of the raw water is subjected to softening/clarification and sand filtration. This is adequate for cooling tower make up and low pressure boiler feed water make up. Potable water is also chlorinated. Water which is to be used as make up to the high pressure boiler feed water system is also subjected to carbon filtration and deionization.

2.3.18 Area 118 - Waste Treatment and Disposal

Aqueous waste streams from throughout the plant are treated in Area 118 with the particular treatment tailored to suit the composition of each stream. Oil bearing streams from various drains and separators are fed to a DAF separator. The separated oil is fed to Area 104 while the water is cooled and mixed with sanitary waste and treated in a biotreatment plant. The treated water is used as cooling tower make up and the sludge is sent to an on site landfill with the slag from Area 103. Cooling tower blowdown and spent deionizer reagent are treated in an eight effect evaporator. The solids are sent to an on-site impoundment, while the water is returned to form part of the boiler feed water. Water containing suspended solids from Area 117 is treated in a sludge dewatering system along with sludge from the biotreatment section. Water flows to the cooling tower as make up and the solids are sent to landfill. Phenolic waste streams are treated in a ten effect evaporator. The solids are pyrolyzed, with the organic vapors fueling the thermal oxidizer in Area 114, and the remaining solids are sent to an on site impoundment. The evaporator distillate is condensed and sent to the Boiler Feed Water System.

2.3 PLANT DESCRIPTION

2.3.19 Area 119 - Fire Protection System

Water is received directly from the river water pumping station and stored in a holding pond. Water is pumped to plant users through a distribution system. Users include fire hydrants, hose stations, and sprinkler systems.

2.3.20 Area 120 - Facilities

This area includes the administration building, maintenance shop, laboratory, personnel facilities in all areas, railroad facilities, roads and parking facilities, security fencing, and warehouse space. Storage is also provided for major plant products, byproducts and make up chemical reagents.

2.3.21 Plant Utility Flow Diagrams

Total plant utility requirements for cooling water, process water, fuel oil and steam at various pressure levels are shown as a function of the individual users on utility flow diagrams. Also included on the utility flow diagrams are a water-waste water treatment block flow diagram, an overall steam supply network and a plantwide steam power balance. These diagrams, which are described in the following list, are included in this subsection.

Diagram Number	Case	Title
7051-100-120-1	CC	Water-Waste Water Treatment Block Flow Diagram
7051-100-120-2	CC	Cooling Water I
7051-100-120-3	CC	Cooling Water II
7051-100-120-4	CC	Process Water
7051-100-120-5	CC	Overall Steam Supply
7051-100-120-6	CC	Steam-Power Balance
7051-100-120-7	CC	50 PSIG Steam Generators and Users I

2.3 PLANT DESCRIPTION - continued

2.3.21 Plant Utility Flow Diagrams

Diagram Number	Case	Title
7051-100-120-8	CC	50 PSIG Steam Generators and Users II
7051-100-120-9	CC	100 PSIG Steam Generators and Users
7051-100-120-10	CC	150 PSIG Steam Generators and Users
7051-100-120-11	CC	600 PSIG Steam Generators
7051-100-120-12	CC	600 PSIG Steam Generators and Users
7051-100-120-13	CC	1500 PSIG Steam Generators and Users I
7051-100-120-14	CC	1500 PSIG Steam Generators and Users II
7051-100-120-15	CC	Fuel Oil

2.4 CONTROL CONCEPT

2.4.1 Plant Control and Instrumentation Concepts

Control and instrumentation systems will be a major element in the design of the Commercial Plant. Control and instrumentation systems' emphasis will be different than that of the Demonstration Plant. This is because:

- Integration of three trains in the Commercial Plant.
- Larger size of plant and equipment.
- Greater communication requirements between area operators and the central operations center.
- A higher level of automatic control and systems integration is required.
- Shift from procurement of investigative data to plant optimizing data.

Basic Control Concept

The basic overall control concept of the Commercial Plant is that there will be a number of Area Control Centers supervised by one Supervisory and Operations Center. Primary controls for the areas will be located in the area control rooms. The operator(s) in the area control rooms will be responsible for the routine control activities of their area. In addition, key area operating information will be transmitted from each process area to the Supervisory and Operations Center. This facility will be an overall control center for the plant. Personnel at this location will not be directly involved in routine operating controls. Their primary duties will be to supervise the overall operation of the facility and to coordinate inter-area activities. The control and instrumentation emphasis will be to provide an automatically controlled plant for optimization of the plant and personnel performance.

Area Control Centers Concept

Controls within a plant area will be operated from various locations depending on their criticality.

Categories are:

- Independent Controls
- Specialized Control Panels
- Area Control Rooms

2.4 CONTROL CONCEPT

2.4.1 Plant Control and Instrumentation Concepts - continued

Independent Controls

Some applications will require only local, self-contained, or self regulating equipment. Typical examples would be:

- Level controls on surge tanks or bins.
- Temperature controls on storage tanks.
- Pressure regulating valves.

Specialized Control Panels

Certain pieces of process equipment will include specialized control panels furnished with the equipment. Typical examples are the hydrogen compressors in the oil treatment area, boilers, etc.

Area Control Rooms

The bulk of an area's control equipment will be operable from the Area Control Room. For each area, dynamic process variables (flows, pressures, temperatures, etc.) will generally take the form of automatic control loops. This will permit the operator to establish a setpoint for a controlled variable. The automatic controller then maintains the desired value until changed by the operator. Presently, this approach to process control can be implemented using either conventional analog controllers or digital computers. It is anticipated that area control loops will be hybrid combinations of both analog and digital equipment. Technological advances will have an impact on the particular class of control equipment.

Since most parameters will be controlled from the Area Control Rooms, safeguards will be implemented to assist the operator in his activities. Critical control variables will be either displayed or indicated on the control panel. Alarm status indication will be provided.

Shutdown systems, which are initiated by an area operator, will include push buttons to start the procedure. Where several valves, or other final control elements, must be quickly moved to a specified position in a particular sequence during shutdown, logic systems will be provided to accomplish these functions. Whenever safety shutdown is involved, the logic system itself will reflect

2.4 CONTROL CONCEPT

2.4.1 Plant Control and Instrumentation Concepts - continued

Area Control Rooms

fail safe design considerations. Operator participation in the shutdown procedure will be limited to ensuring that the necessary sequence is followed exactly.

In addition to the normal control equipment, the area operator may have either a CRT or hardcopy terminal for communication with the central control computer. Through the terminal an area operator can receive selective information on operations in other areas which may affect his own area control.

Depending on the quantity of important variables in an area, data concentrators will be used to gather and transmit information. The function of the concentrator is to minimize the cost of field wiring by being located near the field devices, thereby reducing long runs of cable placement. Usage of the concentrator is totally dictated by economic evaluation of the control device location. Overall control data flow is shown as Figure 2.4.1-1.

Supervisory and Operations Center Concept

At the Supervisory and Operations Center, personnel will be involved with the control of overall plant operations. Extensive use of automation techniques will be used to support the operation of this facility. For the most part, incoming variable data will be received by the digital control computer in the center. The computer will be programmed to accumulate data for production reports, product analyses, and alarm reporting.

During normal operations, Center Operators will mainly be concerned with coordination between areas and overall plant operations. Data reports, in the form of area key parameter analysis, plant material balances, etc., will be available on demand from the computer to support this effort. In addition, duties of the Center Operators will include overall monitoring of areas.

As alarm or abnormal conditions are reported the Center Operators will communicate with the Area Control Rooms to keep abreast of corrective strategy being employed to allow the operation to return to normal. In addition, the Center Operators will advise other process areas of any pending imbalance resulting from the off-normal operation in a related area.

Auxiliary equipment in the Center includes overall security monitoring. This will require communication with plant access road security stations. In addition, there may be a need for closed circuit television monitoring of unattended areas.

2.4 CONTROL CONCEPT

2.4.1 Plant Control and Instrumentation Concepts

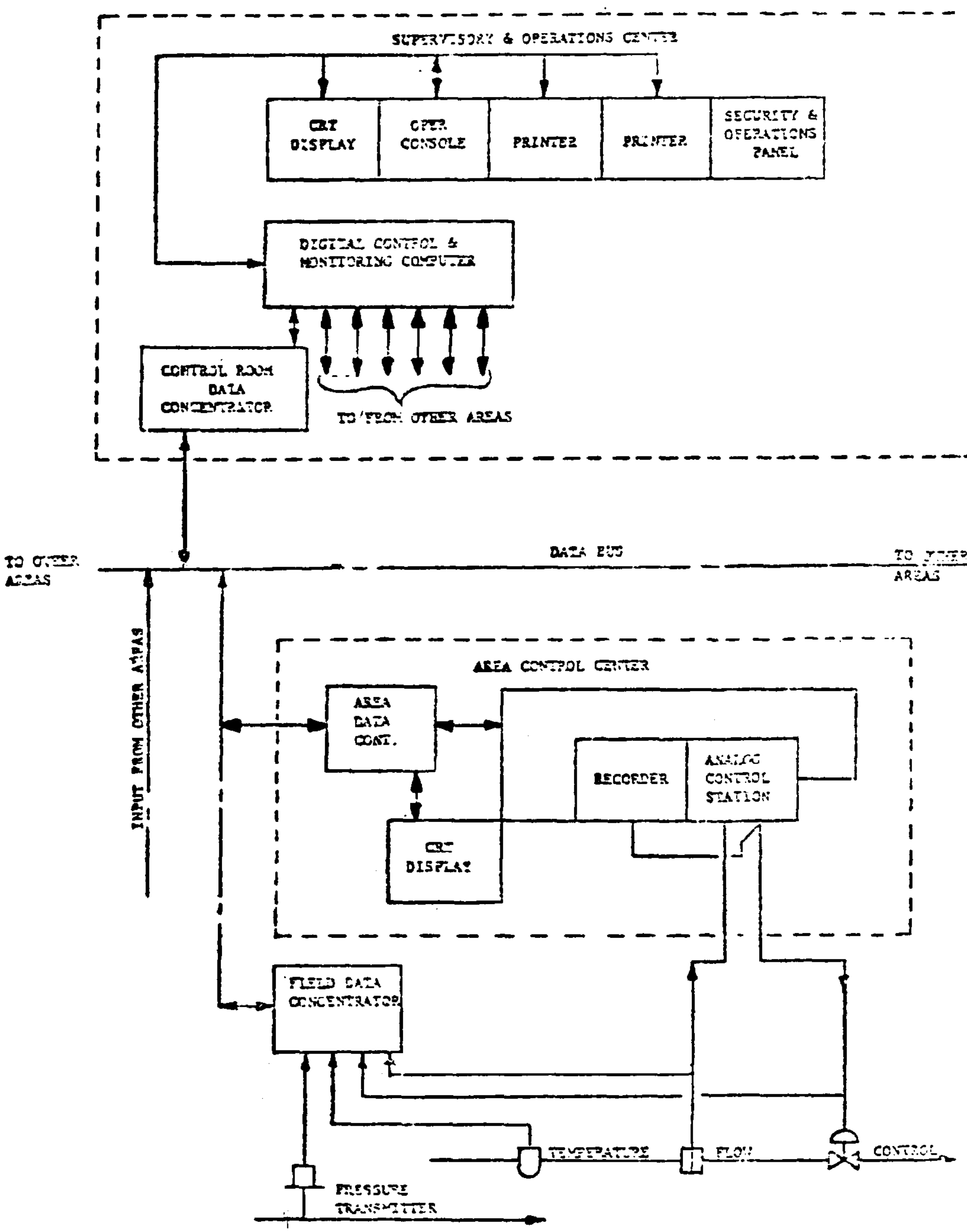


Figure 2.4.1-1
Commercial Plant Controls

2.4 CONTROL CONCEPT

2.4.1 Plant Control and Instrumentation Concepts - continued

Computer and Specialized Systems Concept

With regard to state of the-art instrumentation, the process computer is by far the most important aspect of the modern control system. The process computer can be expected to:

- Reduce manpower and operating costs.
- Optimize plant operation.
- Give early warning of potential trouble.

Reduce Manpower and Operating Costs

Automation of the plant with a process computer will reduce manpower and other costs while maximizing the quanitity and quality of the products.

Optimize Plant Operation

The increasing costs of energy and raw materials has made industry intensify its efforts for process optimization. The calculational ability of the computer makes it superior to standard analog controls for everything from basic process control to maximizing plant efficiency. Computer capabilities have made the desired plant control integration practical.

Give Early Warning of Potential Trouble

The computer can be used to check and automatically identify a large variety and number of variables. Any variable measurement approaching or outside its normal limits can be identified for corrective action.

To obtain the best advantage, the plant will be designed for process computer control. Retrofit of a process computer at a later date could be much more expensive and complicated. Instrumentation generally will be computer compatible.

It is anticipated that specialized systems will be provided for plant start up, particularly in the pyrolysis-gasification area plus related downstream areas. These systems will do the necessary interlocking to insure that valves are in the proper position, etc., before proceeding to the next step of the start up. In addition, controlled variables will be regulated to maintain the proper rate changes during start up (e.g. heatup of refractory lined vessels).

2.4 CONTROL CONCEPT

2.4.1 Plant Control and Instrumentation Concepts - continued

With parallel process streams in the critical process areas, there are many alternate techniques which can be used during start up. The start up logic will permit alternates to be selected by the operator, but the exact manipulation of valves, rate changes, and interlocking will be performed by the start up logic system.

Automatic emergency shutdown equipment is included as part of the plant's control equipment. Due to the complexity of the multiple train process areas in the plant, shutdown safety control equipment will be sophisticated. In particular, special attention will be paid to areas where a common process area affects the multi-stream process areas. The shutdown system will be structured to permit common lines to operate if only one of a parallel stream line initiates the shutdown. For example, a gasifier shutdown will not cause coal handling to cease in the coal unloading and handling area. However, the feed rate must be reduced to reflect the plant throughput change. Similarly, the sulfur recovery area will continue to operate but at a reduced rate of feed. In addition, the safety shutdown equipment will act to isolate a shutdown stream by closing interconnecting lines between parallel streams. Since the shutdown procedures are rather involved, a small programmable controller will probably represent an economical and reliable package for this function.

2.4 CONTROL CONCEPT

2.4.2 Area Control and Instrumentation Concepts

The control and instrumentation systems of the various process areas are in different stages of development at this time. For most areas within the plant, the process designs are based on proven commercial plant design and experience. The control and instrumentation systems for these plants have also been proven. Control and instrumentation system design for these areas of the Commercial Plant will be based on the latest system design during the detailed design phase.

Several of the process areas have a combination of proven and new designs incorporated into them. The control concept for these areas will be to integrate, wherever feasible, the new process control systems into the proven area design. This concept will utilize available proven system designs and minimize new system design. A few of the process areas are based on pilot plant development and experience. The basic control and instrumentation systems for these areas have been established during the pilot plant operation. These control and instrumentation systems, along with the operating experience gained in the Demonstration Plant, will be used in the design of the Commercial Plant. Table 2.4.2-1 is a summary of the current status of the process areas' control and instrumentation systems design.

2.4 CONTROL CONCEPT

2.4.2 Area Control and Instrumentation Concepts - continued

Table 2.4.2-1

Control and Instrumentation System Status

Area No.	Area Name	CPSDO[1]	PPSDO[2]	NSDR[3]	Remarks
101	Coal Unloading & Handling	X			
102	Coal Preparation	X		X	Feed pumps not tested at system operating pressure. See Subsection 2.4.3.
103	Pyrolysis & Gasification		X		
104	Oil Recovery & Treatment	X			
105	Gas Purification	X			
106	Hydrogen Generation	X			
107	Shift & Methanation		X		
108	Bulk CO_2 Removal & Gas Compression	X			
109	Gas Dehydration	X			
110	Flue Gas Power Recovery	X			
111	SO_2 Removal	X			
112	Sulfur Recovery	X			
113	Ammonia Recovery	X			
114	Thermal Oxidizer and Flare	X			
115	Utilities	X			
116	Water Supply	X			
117	Water Treatment Systems	X			
118	Waste Treatment and Disposal	X		X	Phenol Waste Evaporator, new system
119	Fire Protection System	X			
120	Facilities	X			

Note 1: Commercial Plant Systems Developed and Operating.
Note 2: Pilot Plant System Developed and Operated.
Note 3: New System Development Required.

2.4 CONTROL CONCEPT

2.4.3 Special Considerations and Equipment Requirements

Within the overall plant design there are several areas of special interest to the control and instrumentation systems designer. Some of these interests will deal with system design and others with instrument and control equipment design. Some areas of special consideration are:

- As addressed above, in Subsections 2.4.1 and 2.4.2, most of the process area designs are commercially available. It will be a major element of the total plant design to integrate these existing systems and the newly developed systems into a comprehensive functional complex. Within many areas there are multiple lines of equipment which must be controlled for unit operation. A thorough knowledge of the area process operation and its role in the total plant operation makes this integration possible.

- Process and atmospheric analytical instrumentation will be highest priority equipment. Considerable effort will be devoted to select equipment and systems having maximum utility and reliablity. This effort will help to assure safe plant operation and employee well being.

- The pyrolysis and gasification area will require a high level of control and instrumentation design. This is the largest area for which commercial plant experience is lacking, although commercial analogs and pilot plant experience are available. This area also has several equipment services which will require special design effort (i.e. high temperature valve applications, and in-situ high temperature analyzer measurements).

- Flue gas oxidizer system design, although new, should parallel basic boiler control logic. The interaction of the various heat exchanges with load changes will be studied to assure control adequacy.

- Power recovery compressor-generator systems equivalent to the required flue gas power recovery air compressor system have been developed and are in operation. These systems, however, must be designed to the specific mechanical equipment and operating conditions. Detail engineering analysis will facilitate the development of the required control and instrumentation system.

2.5 PROCESS FLEXIBILITY

Summary

The Conceptual Commercial Plant Design feed coal is Illinois No. 6 seam bituminous with a HHV of 12,400 Btu/lb, dry. It is received at the plant as 6" x 0" run of mine (ROM) size coal that is prewashed at the mine site. Delivery is by overland conveyor and/or unit train. Table 2.5-1 summarizes the size, ultimate analysis, moisture content, and heating value of the coal upon which the Commercial Plant material balance is based. The total coal feed, on an as received basis, is also listed together with the plant product and byproduct yields.

The cost of coal delivered to the plant site is estimated at $22.85/T as received. The plant investment cost, total capital requirement and annual operating costs necessary to process the coal into pipeline quality gas are summarized in Tables 2.5-4 and 2.5-5 It is expected that normal variations in composition, heating value, etc., within the Illinois No. 6 seam will produce only small changes in process yields and economics.

The process concept is adaptable to most coals including a Western Subbituminous or a Pittsburgh No. 8 seam coal, the alternate coals proposed for testing in the Demonstration Plant. The only sections of the plant requiring design modifications are the coal drying section of Coal Preparation and the pyrolysis section of Pyrolysis and Gasification. The modifications in coal drying are due to economical considerations rather than process considerations. Changes required in pyrolysis were extensively piloted in the COED project. In addition, the capacities of Oil Recovery and Treatment and other byproduct recovery areas such as sulfuric acid/sulfur and ammonia would change. These changes are a direct result of changing the coal rank as well as its composition and heating value. Table 2.5-1 summarizes the impact on yield when Western Subbituminous coal or Pittsburgh No. 8 seam coal are processed.

The most striking difference in yields is the quantity of fuel oil produced. The three coals require different feed rates in order to achieve an identical plant SPG output. With these differing feed rates Western coal yields 38% of the fuel oil produced with Illinois coal, while Pittsburgh coal yields 8.5% more. Pittsburgh coal, on the other hand, is rich in volatile matter but is highly agglomerating and must be slightly preoxidized before it is pyrolyzed. This preoxidation step oxidizes volatile matter and

2.5 PROCESS FLEXIBILITY - continued

Table 2.5-1

Summary of
Coal Type, Composition and Yield

Type	Illinois* No. 6 Seam	Western Subbituminous	Pittsburgh No. 8 Seam
Size (as received)	6" x 0"	6" x 0"	6" x 0"
Ultimate Analysis, % (Dry Basis)			
C	69.00	65.53	76.25
H	4.70	4.34	5.26
N	1.30	0.70	1.46
S	3.80	1.15	3.33
O	9.30	14.29	6.09
Ash	11.90	13.99	7.61
TOTAL	100.00	100.00	100.00
Moisture Content, %	10.0%	25.5%	4.0%
Higher Heating Value (Btu/lb, Dry)	12,400	11,230	13,850
Product/Byproduct Yields (Per 1,000 TPD of coal, as received)			
SPG, MM SCFD	10.2	8.51	12.6
Fuel Oil, bbl/d	649	244	704
Naphtha, bbl/d	147	81	85
Sulfuric Acid/Sulfur, TPD	84/26.3	20.3/6.4	81.8/25.6
Ammonia, TPD	1.85	0.59	1.48

* Base Case

2.5 PROCESS FLEXIBILITY - continued

Summary - continued

causes a decrease in the net oil yield. Differences in byproduct sulfuric acid or sulfur between the three coal types is a direct function of the feed coal sulfur content.

The impact of coal type on the plant investment cost is closely associated with the quantity of fuel oil produced and the feed coal moisture and sulfur content. Thus, Illinois No. 6 seam coal, with its high fuel oil production, high sulfur content, and moderate moisture, is highest in investment cost. For Western coal, the high cost of coal drying is offset by cost savings derived due to its lower sulfur content and fuel oil production, resulting in the lowest investment cost among the three coals. In the case of Pittsburgh coal, although a fifth pyrolysis stage is required due to the agglomerating nature of the coal, its fuel oil production, sulfur content and drying requirements are lower than with Illinois coal. Therefore, the investment cost for Pittsburgh coal lies between the costs for Illinois and Western coals.

Annual operating cost and SPG selling price were estimated for Western and Pittsburgh coals in the same manner as described in Section 7.0 for the Illinois No. 6 seam coal base case. Variations in feed coal quantity and cost coupled with differences in investment capital requirements resulted in a $0.69/MM Btu difference in gas cost between Illinois No. 6 seam coal and Western Subbituminous and $0.42/MM Btu difference between Illinois No. 6 seam coal and Pittsburgh No. 8 coal. These differences are highly dependent on coal prices and byproduct oil credit.

All economic evaluations for the three coal feeds are based on a plant design as presented in Section 4.0 of this report. Cost impacts for processing Pittsburgh and Western Subbituminous coals were estimated from this base concept.

Design Modifications

Modifications to the base concept for processing Pittsburgh No. 8 seam coal and Western Subbituminous coal were based on preliminary material balance information developed for this report. Table 2.5-2 and Figures 2.5-2, 2.5-3 and 2.5-4 present the plant feeds and resulting product and byproduct yields for Illinois, Western and Pittsburgh seam coals.

2.5 PROCESS FLEXIBILITY - continued

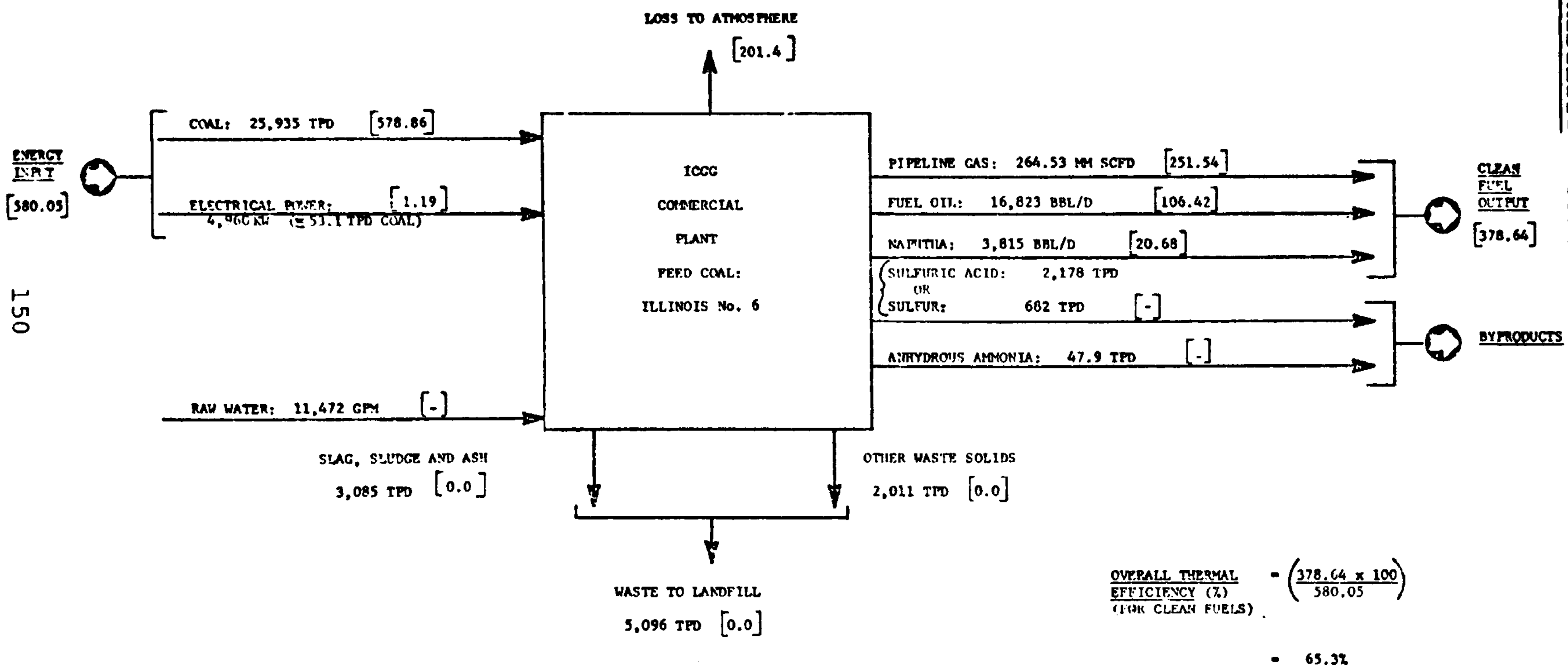
Table 2.5-2

Comparison of Coal Requirements, Byproduct Yields And Thermal Efficiency For A Commercial Plant

Feedstocks	Illinois No. 6	Western Subbituminous	Pittsburgh No. 8
Coal Input, TPD	25,935	31,079	21,031
Water, MMGPD	16.52	16.52	16.52
Electricity, KW	4,960	4,960	4,960
Products, Byproducts			
SPG, MMCF/D	264.53	264.53	264.53
Fuel Oil, bbl/d	16,823	7,570	14,804
Naphtha, bbl/d	3,815	2,518	1,793
Sulfuric Acid, TPD	2,178	632	1,721
Anhydrous Ammonia, TPD	47.9	18.2	31.1
Thermal Efficiency	65.3%	60.1%	63.3%

Figure 2.5-2

Overall Energy Balance for Conceptual Commercial Design with Illinois No. 6 Coal



LEGEND:

1.	[ ]	= BILLION BTU's PER DAY
2.	TPD	= SHORT TONS PER DAY
3.	MM SCFD	= MILLION STANDARD CUBIC FEET PER DAY
4.	BBL/D	= BARRELS PER DAY
5.	KW	= KILOWATTS
6.	GPM	= GALLONS PER MINUTE

Figure 2.5-3

Overall Energy Balance for Conceptual Commercial Design with Western Subbituminous Coal

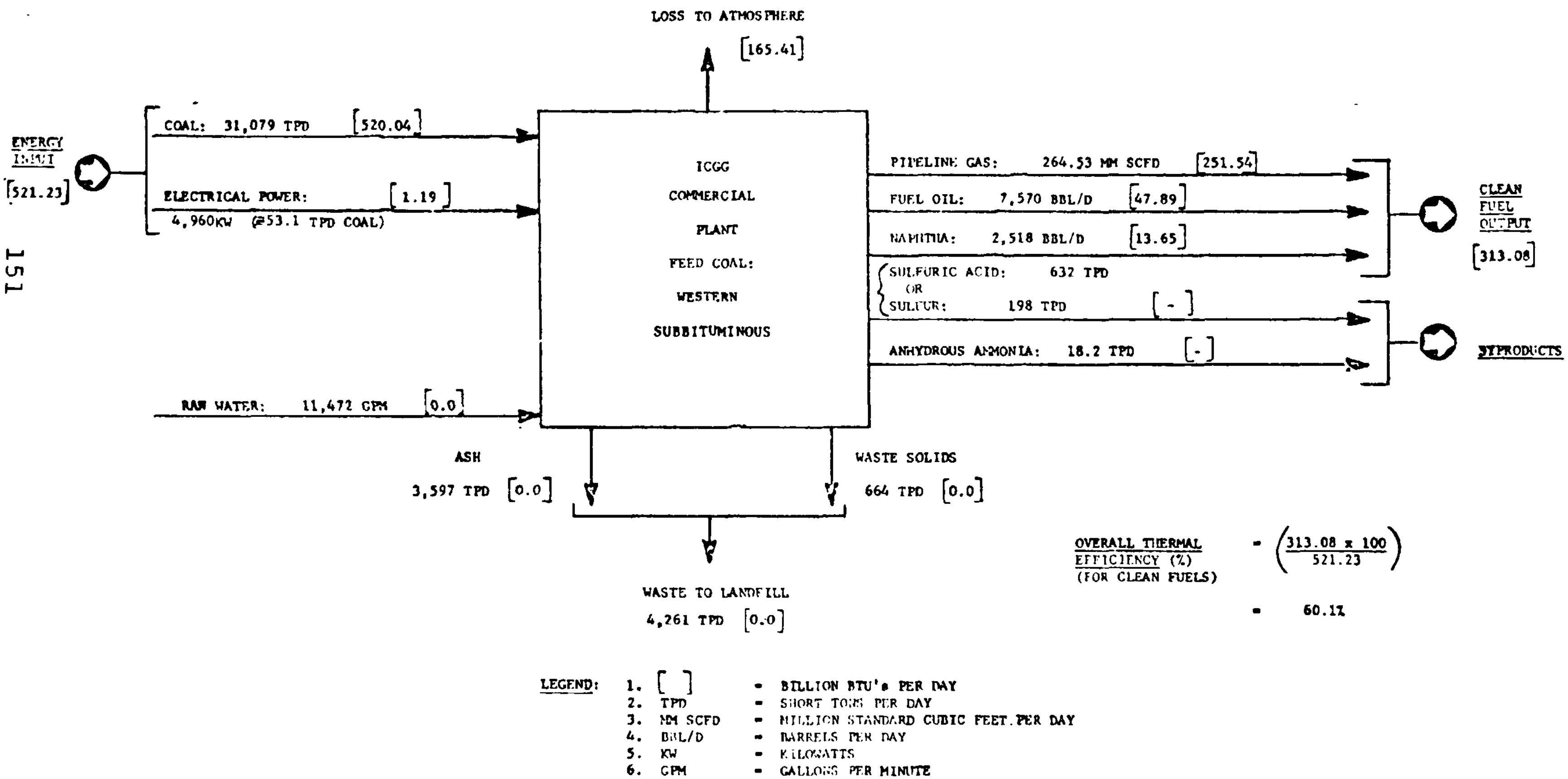
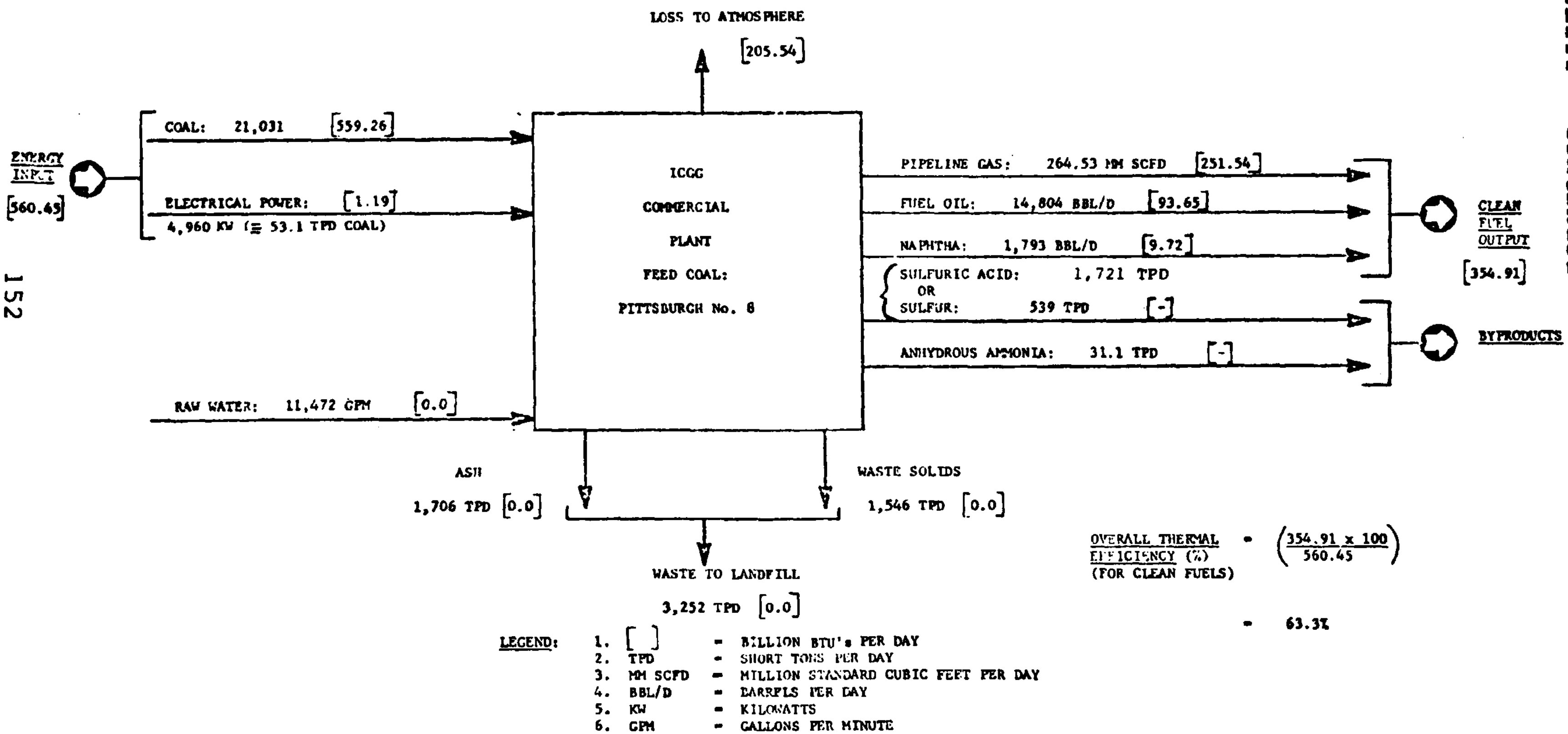


Figure 2.5-4

Overall Energy Balance for Conceptual Commercial Design with Pittsburgh No. 8 Coal



2.5 PROCESS FLEXIBILITY - continued

Design Modifications - continued

Processing Western Subbituminous coal in the Commercial Plant requires modifications in Coal Preparation, and Pyrolysis and Gasification (Areas 102 and 103) and changes in capacity in the Oil Recovery and Treatment, Hydrogen Generation, SO_2 Removal, Sulfur Recovery and Ammonia Recovery Area (Areas 104, 106, 111, 112 and 113 respectively). Since the feed coal moisture content is high (25.5%), it is more economical to dry the coal ahead of pyrolysis.

The production of raw pyrolysis oil for Western coal is lower than either Illinois No. 6 or Pittsburgh No. 8 seam coals. This impacts the capacity of the Oil Recovery and Treatment Area and its satellite area, Hydrogen Generation. These process areas remain basically unchanged, but their capacity and number of trains decrease.

Similarly, the sulfur content of Western coal is lower than the other types and the impact is felt in the SO_2 Removal and Sulfur Recovery Areas. The quantity of the flue gas to the SO_2 Removal Area is only slightly lower but the SO_2 concentration is less than one fourth as high. Thus, the gas scrubbing equipment changes are small while solution handling and other systems change downward in capacity. The Sulfur Recovery Area capacity is approximately one third that of the Illinois No. 6 seam case.

Since the plant SPG capacity is the same in all three cases, changes in the gas processing areas are small. Design modifications to the water and utility systems to tailor the process for a western site were not undertaken.

The procedure for modifying the base case to process Pittsburgh No. 8 seam coal is similar to that described for Western coal. The overall material balance (Figure 2.5-4) indicates a net reduction in coal feed and moisture content compared to Illinois No. 6 seam coal. This reduction results in capacity decreases in the Coal Unloading and Handling and Coal Preparation Areas. Pittsburgh seam coal is highly agglomerating and must be preoxidized and passed through an additional pyrolysis stage.

2.5 PROCESS FLEXIBILITY

Design Modifications - continued

As indicated in Table 2.5-1, the fuel oil yield per 1000 TPD of coal is higher for the Pittsburgh coal than for the Illinois; but the SPG yield is also higher for Pittsburgh, resulting in a much lower coal feed for the same amount of SPG being produced. Therefore, the oil yield in barrels per day is lower for the Pittsburgh case, and so also is the naphtha yield. Thus, capacity changes are necessary in the Oil Recovery and Treatment and Hydrogen Generation Areas. Feed coal sulfur content of the Pittsburgh seam coal is also lower than Illinois coal and capacity changes are required in SO_2 Removal and Sulfur Recovery Areas. The capacity of the Ammonia Recovery area is also reduced by about one third. Design modifications of the water and utility systems were not undertaken.

Economic Impact

The economic impact of the design modifications discussed in the preceding paragraphs was estimated from the material balances (Figures 2.5-3 and 2.5-4) and the Economic Assessment (Section 7.0) for the Illinois No. 6 seam coal. Table 2.5-4 summarizes the total capital requirement subdivided into eleven categories. Since the site characteristics are assumed to be identical in all three cases, land and site preparation costs remain unchanged. Changes in process area subsystems involving capacity and the number of trains resulted in a decrease in construction plans and drawings, construction engineering, start up, working capital, interest during construction, contingency, catalysts and chemicals as well as plant construction costs. Royalty costs were assumed to be the same for all three cases.

Operating costs for the three coals are summarized in Table 2.5-5. The Illinois case costs were adjusted for design modifications in all but two cost categories: Insurance and Taxes, and Utilities. Since the plant site characteristics, SPG production, and utility systems are the same in all three cases, operating costs for these factors are assumed to be the same.

Inspection of Table 2.5-4 reveals that the major operating cost differences are in coal cost and byproduct credits. Costs for Western and Pittsburgh coal include freight charges consistent with that allocated for Illinois No. 6 seam coal. They do not include long distance hauling from North Dakota or Pennsylvania. It was assumed that the plant would be located on a site identical to the Illinois site but centrally located within the respective alternate coal fields. It was assumed that site associated costs such as land, site preparation, coal transportation, environmental constraints, labor rates and water supply were equal for the purposes of this analysis.

2.5 PROCESS FLEXIBILITY - continued

Table 2.5-4

Capital Requirement Summary
Alternative Coal Feeds
(MM$)

Capital Cost Category	Illinois** No. 6 Seam	Western Subbituminous	Pittsburgh No. 8 Seam
Construction Plans and Drawings	$ 75.445	$ 69.369	$ 72.420
Site Preparation	10.000	10.000	10.000
Plant Construction	1,043.496	964.861	1,004.343
Construction Engineering	70.369	64.703	67.548
Subtotal - Plant Investment Cost	$1,199.310	$1,108.933	$1,154.311
Contingency	$ 177.368	$ 164.002	$ 170.713
Land****	2.039	2.039	2.039
Start Up	26.695	6.253	16.271
Administration	4.150	4.150	4.150
Working Capital	30.857	25.425	28.673
Royalties	20.000	20.000	20.000
Catalyst and Chemicals	12.154	6.601	9.951
Total Capital Requirement***	$1,472.573	$1,337.403	$1,406.108

* Mid-1978 dollars

** Economic Assessment, Section 7.0

*** Interest during construction is not included per DOE guidelines

****Assumed Cost

2.5 PROCESS FLEXIBILITY - continued

Table 2.5-5

Operating Cost Summary
Alternative Coal Feeds
(MM$/yr)*

Operating Cost Category	Illinois** No. 6 Seam	Western Subbituminous	Pittsburgh No. 8 Seam
Coal	$195.563	$ 87.689	$146.092
Labor	23.138	23.443	22.994
Catalysts and Chemicals	20.769	11.280	17.005
Insurance and Taxes	7.837	7.837	7.837
Maintenance Repairs and Replacements	30.426	27.319	28.879
Utilities	1.060	1.060	1.060
Other Operating Supplies	2.293	2.384	2.250
Gross Operating Cost	$281.086	$161.012	$226.117
Less Byproduct/(Credits)	(146.096)	(64.048)	(116.080)
Net Operating Cost	$134.990	$ 96.964	$110.037
Coal Cost $/Ton	$22.85	$8.55	$21.05
● Discount Rate = 9%			
● Federal Income Tax = 0			
● Straight Line Depreciation			
Gas Cost (Selling Price), $/MM Btu	$ 4.00	$3.31	$ 3.58

* Mid-1978 dollars

** Economic Assessment, Section 7.0

2.5 PROCESS FLEXIBILITY - continued

Economic Impact - continued

The decrease in byproduct credits is a direct result of the lower fuel oil, naphtha, sulfuric acid and ammonia yields from Western and Pittsburgh coal compared to Illinois No. 6 coal. Other minor operating cost differences are due to chemical costs and investment related costs such as the cost of maintenance and supplies.

Differential operating costs between the three coals are highly dependent on coal costs and byproduct credits. Increase in coal costs for the Western Subbituminous and the Pittsburgh seam cases, or an increase in oil byproduct credit, would improve the relative economics of the Illinois No. 6 seam case.

Environmental Impact

In the case of Western Subbituminous coal, in spite of its "low" sulfur content, the flue gas generated by its combustion is estimated to contain about 600 ppm SO_2 and will have to be treated before its emission to atmosphere. Thus, the types of treatment rendered the different emissions from plants for the three coals are expected to be the same. The exact method and extent of treatment will differ, depending on the case. Therefore, the types of emissions for Western Subbituminous and Pittsburgh No. 8 coals will be the same as Illinois No. 6 coal (Section 3.0), although the exact quantities, while environmentally acceptable, will be different. Table 2.5-6 summarizes the major waste streams and their estimated quantities for the three coals.

Table 2.5-6

Summary of Waste Streams* for Illinois No. 6 and Estimates of Similar Wastes for Western Subbituminous and Pittsburgh No. 8 Coals

Area No. and Name	Description of the Waste Stream	Illinois No.6	Western Subbituminous	Pittsburgh No.8
Area 101, Coal Unloading and Handling	Coal particulates at various transfer points in coal handling.	7.81 lb/hr	9.4 lb/hr	6.3 lb/hr
Area 103, Pyrolysis and Gasification	Slag to landfill.	2,983 TPD	3,960 TPD	1,950 TPD
Area 104, Oil Recovery and Treatment	Flue gas from fuel oil fired heaters. Composition similar in all cases.	30,143 lb/hr	13,600 lb/hr	26,500 lb/hr
Area 106, Hydrogen Generation	CO_2 waste stream with trace hydrocarbons. Composition similar in all cases.	187,171 lb/hr	103,000 lb/hr	152,000 lb/hr
Area 111, SO_2 Removal	Flue gas to atmosphere. Components of flue gas for Western and Pittsburgh coals same as those for Illinois coal. Relative amounts will vary. SO_2 quantities and concentrations will be at environmentally acceptable levels.	9,010,546 lb/hr	7,280,000 lb/hr	8,127,000 lb/hr
	SO_2 scrubbing sludge.	157,509 lb/hr	35,700 lb/hr	85,700 lb/hr
Area 120, Facilities	Hydrocarbon vapor loss to atmosphere from storage tanks.	20.1 lb/hr	9 lb/hr	18 lb/hr

* Only major and continuous streams have been summarized here to illustrate the impact of the type of coal on the waste streams. Only total flow rates are provided; detailed compositions are not given. See Table 3.3.-3 for a complete breakdown of waste streams and their compositions for Illinois coal.

2.6 DESIGN MATURITY AND RISKS

The ultimate goal of the Demonstration Plant Program is the development of information which will permit the construction of a Commercial Plant with a minimum of risk. To this end the requirements for design and construction of a Conceptual Commercial Plant have been identified and evaluated in terms of basic process information, materials of construction, availability of reliable commercial equipment, and design and fabrication techniques. All phases of the Demonstration Plant Program will be tailored to yield the required confirmation of assumptions, elimination of questionable areas, and reduction of residual risks to a minimum. A discussion or identification of risks and steps taken to reduce or eliminate them follows for the individual plant areas. Steps necessary for further risk reduction and the consequences of negative results in critical areas of the Demonstration Plant Program will also be discussed.

A summary of scaleup factors from Demonstration Plant to Commercial Plant, or current commercial analog to Commercial Plant is presented in Fig. 2.6-1 for those process areas which are considered to be the most developmental.

2.6.1 AREA 101 - Coal Unloading and Handling

Assumptions

1. It has been assumed that coal will be delivered by unit train and/or overland conveyor. When a Commercial Plant is actually to be built, the actual means of delivery will be tied down by contract with the supplier.

2. A composition has been assumed for coal pile run-off water. This is based on the analysis of samples furnished by Southwestern Illinois Coal Corp. Variations of this composition will not effect design in this area. Effects on waste treatment are discussed in 2.6.18.

3. A composite coal analysis has been assumed based on coal in the area of the Demonstration Plant. Significant variation in moisture, ash and sulfur content would affect size of drying, ash handling and sulfur removal areas. Effects are discussed in these areas.

Identified Risks

1. There are none in this area. Commercial equipment of suitable size is available.

Figure 2.6-1 Scale Factors - Demonstration to Commercial Plant or Present Day Commercial Analog to Commercial Plant

AREA UNIT	PRESENT DAY COMMERCIAL ANALOG	DEMONSTRATION PLANT	COMMERCIAL PLANT (1 TRAIN)	SCALEUP COMM: PRESENT DAY	SCALEUP COMM: DEMO
Flue Gas Power Recovery					3.6
• Flue Gas Oxidizer				1.4	3.5
• Tertiary Separator (multiple cyclones)				1.7 Total 1 for each cyclone	3.6 Total 1 for each cyclone
• Expander				2.1	1.8
Coal Preparation				1	3.9
• Dryer (intermittant)	9600 TPD			0.9	3.9
• Grinder	15000 TPD			0.75	3.9
• Screens	2400 TPD			1	1
Pyrolysis and Gasification					3.9
• Pyrolyzers	58' diam. - Fluid Cat Cracker Regenerator			<1	1.9
• Gasification-Combustion					3.7
Gasifier	58' diam - Fluid Cat Cracker Regenerator			<1	1.9
Combustor	30' diam - Utility Boiler @ 1 atm			<7	1.8

Sheet 1 of 2

Figure 2.6-1 Scale Factors - Demonstration to Commercial Plant or Present Day Commercial Analog to Commercial Plant

AREA UNIT	PRESENT DAY COMMERCIAL ANALOG	DEMONSTRATION PLANT	COMMERCIAL PLANT (1 TRAIN)	SCALEUP COMM: PRESENT DAY	SCALEUP COMM: DEMO
Lift Tube	Fluid Cat Cracker			1	1.9
Circulation Lines	Fluid Cat Cracker			1	1.4
Cyclones, primary flue gas	Fluid Cat Cracker			1	1
Oil Recovery & Treatment					3.7
• Venturi Scrubber	150,000 acfm - Commercial Scrubbers			0.8	1.8
• Hydrotreating-Ebullating Bed	H-Oil Commercial			0.9	2.2
• Hydrotreating-Fixed Bed	Commercial Hydrotreaters			1	3.5

Sheet 2 of 2

2.6 DESIGN MATURITY AND RISKS

2.6.2 AREA 102 - Coal Preparation

Assumptions

1. Illinois No. 6 seam coal was assumed to have 10 percent moisture content based on data published by the Illinois Geological Survey and samples from the Captain Mine, which will provide the coal for the Demonstration Plant. An auxiliary dryer is provided to predry any coal that contains more moisture and is too wet to grind, screen and pressurize. The Stage I pyrolyzer has enough capacity to handle normal variations in feed coal moisture.

2. It was assumed that Illinois No. 6 seam coal with 10 percent moisture content can be handled satisfactorily in grinders and screens. This is based on grinding and screening operations with as received Illinois No. 6 seam coal in the 600 TPD FMC Formcoke Plant. If not, run-of-mine coal can be predried in the auxiliary dryer mentioned above.

Identified Risks

1. Coal Pressurizing

The Fuller-Kinyon solids pressurizing feed pump, which was selected for coal feeding is a standard model, but has not been tested on coal at the capacities required, although other solids have been pumped at higher rates against the same discharge pressures. Its use with coal may, therefore, be considered a low technical risk. An experimental program using a Fuller-Kinyon pump at Morgantown Energy Technical Center was proposed which will pump Western subbituminous and Illinois No. 6 seam coal of the size consists specified to 50 psig, the required pressure level for the Conceptual Commercial Design (CCD). Results from this program will reduce the technical risk to an even lower level. The Demonstration Plant design includes a lock hopper system as a back-up to the Fuller-Kinyon pump. The lock hopper system is commercially available and is a no-risk, but higher cost, coal pressuring system.

2.6.3 AREA 103 - Pyrolysis and Gasification

Assumptions

1. It was assumed that the mathematical models developed to describe the process reactions, conditions and analyses on pilot plant data will be valid at the slightly higher pressures to be used in the Demonstration Plant. Pressure has no effect on the operation of the Pyrolysis Section. Because gas flows through the pyrolysis

2.6 DESIGN MATURITY AND RISKS

2.6.3 AREA 103 - Pyrolysis and Gasification - continued

section are higher than they were in the COED pilot plant, the oil partial pressures are the same in the CCD as they were in the COED pilot plant. Oil partial pressure, not total pressure, is the important parameter affecting oil condensation and yields in pyroylysis. Pressure also has a negligible effect in the Gasification Section. Pressure has no effect on gasification rate, so that pilot plant results are directly applicable to the CCD for the gasifier. Increased pressure increases combustion rates and thus will improve combustor operability.

2. It was assumed that the pyrolysis and gasification sections, which were piloted separately, can be integrated without problems. In the integrated system the last pyrolysis stage in COGAS feeds char forward to the gasifier. Hot gas from the gasifier is cycled back to the last pyrolysis stage to supply fluidizing gas and pyrolysis heat. Thus, waste heat in the gasifier make-gas is used beneficially in the Process. This same function, i.e. of supplying fluidizing gas and heat, was well demonstrated in the multi-stage operation of the pyrolysis pilot plant in which hot gas was recycled to a lower temperature stage to fluidize that stage and provide required pyrolysis heat. Also char from the lower temperature stage was fed forward to the vessel which produced the hot gas. Control of this type of operation was well demonstrated in the pyrolysis pilot plant with a number of different coal feeds.

Identified Risks

1. Agglomeration in Pyrolysis

The design of and the selection of operating conditions for the Pyrolysis Section are based on the design conditions which were shown to prevent agglomeration problems in the COED pilot plant program. The basic scheme used multistage, fluidized bed pyrolysis to precondition the coal in low temperature stages, so that it can be fed to higher temperature stages. The use of preoxidation is avoided because it reduces pyrolysis yields. The number of stages required depends on the agglomerating tendency of the coal being processed, the more agglomerating the coal, the more stages required. The number of stages required is based on 10 years experimental work in the COED program. Pyrolysis conditions are chosen to prevent agglomeration and are based on conditions demonstrated in the COED program. Therefore, the technical risk of agglomeration in pyrolysis is low.

2.6 DESIGN MATURITY AND RISKS

2.6.3 AREA 103 - Pyrolysis and Gasification - continued

Identified Risks

Char recycle is used to provide heat to the cooler pyrolysis stages and to dilute the feed coal to reduce agglomeration. Char recycle rates in the CCD are within the envelope of those that were used successfully in COED.

Fluidizing velocities are at the upper boundary of the envelope of velocities demonstrated in COED. Higher velocities improve operability by reducing the possibility of agglomeration.

Solids residence times are within the range of those demonstrated by the COED program. During COED operations, the long residence times, were usually dictated by vessel geometry. Although most bench scale work, pyrolyzing in large excesses of gas, indicated that devolatilization of coal takes place in seconds, many COED runs showed that char devolatilized in an oil-rich atmosphere may be still sticky after 15-45 minutes. Whether this is a time or a condensation phenomenon is not known. The CCD conditions were chosen to duplicate successful COED operating conditions.

Mixing of feed coal into the pyrolyzers to prevent local agglomeration is based on COED experience and is analogous to commercial FCC and fluid coker practice. Consultants R. W. Pfeiffer and D. Geldart were employed to confirm and improve the design basis. The design was modelled in a 2 dimensional cold model as well as in the large Gasifier Combustor Cold Model. Modifications to the coal inlet nozzles would be relatively minor and inexpensive, should the present design be insufficient. There is flexibility in the design to increase transport gas flows, which would improve mixing.

2.6 DESIGN MATURITY AND RISK

2.6.3 AREA 103 - Pyrolysis and Gasification - continued

Identified Risks

2. Ash Balance in Gasifier

Inability to achieve a better than 90% closure of the pilot plant ash balance in most runs, indicated a possible risk in the knowledge of ash disposition. Flue gas sampling indicated no undetected loss as ultra fine particulates or volatiles. In pilot plant Test 22, a 200 hour run, ash balance closure was 94% and it was evident that closure problems were due to the impact of start up and shutdown inventory measurements in the shorter runs.

The equilibrium ash content of the gasifier bed and circulating char in the CCD is within the envelope of ash contents demonstrated in the pilot plant. The Demonstration and Commercial Plant designs are more flexible than the pilot plant design in that a portion of the circulating char may be burned in the combustor to control the bed ash content at any desired level. The feasibility of burning bed char in the combustor was demonstrated in the pilot plant. Because this flexibility was not included in the pilot plant, control of the bed ash content by this technique in the pilot plant was not possible. The CCD includes a debris removal system in the gasifier, which is based on the pilot plant design, to prevent the buildup of high ash material in the gasifier. The technical risk of ash buildup in the system and lack of control of ash level is negligible.

3. Fines Balance in the Gasifier

The potential risk that fines production will exceed fuel requirements and cause operability or economic problems has been carefully considered. Fines production rate is based on data from the pilot plant for Illinois char. Pilot plant data were correlated by assuming an attrition mechanism, making mass balances around each size fraction, and correlating the resulting attrition rates to operating conditions. A computer program for calculating the fines balance was then written for the Demonstration and Commercial Plants to predict equilibrium size consists and dust losses. This program was verified by subsequent pilot plant operation. The fuel collection system is designed to minimize dust losses by using fines as fuel for the combustor. The design flexibility reduces the significance of fines production rate on the process.

2.6 DESIGN MATURITY AND RISKS

2.6.3 AREA 103 - Pyrolysis and Gasification - continued

3. Fines Balance in the Gasifier

Although fines production rate is based on an analysis of pilot plant data, variations in coal feedstock (Illinois char and Rexco char had different attrition rates in the pilot plant) and the effect of scale up produce some technical risk in the base fines production rate. If the actual rate is significantly higher than the base rate, dust losses with the make gas to Area 104 and with the flue gas to Area 110 will increase. Dust lost with the make gas is captured in condensing oil and recycled to the process with the vacuum tower bottoms from hydrotreating. Thus, increased dust losses with the make gas have little effect on process thermal yield. Increased dust losses with the flue gas will result in increased loadings to the tertiary separator and expanders. Efficiency data from vendors of tertiary separators, which were confirmed in the pilot plant tests of the Flue Gas Test Train, indicate that the higher than baseline dust loadings to the tertiary separators can be accommodated without increasing the dust loading to the expanders beyond vendor specifications based on Fluid Cat Cracker (FCC) performance. As discussed under Area 110, a higher (than FCC) dust loading could be accepted. Therefore, the technical risk is low that the CCD will be significantly out of balance with respect to fines, or that operability or economic problems will result.

4. Char Circulation Control Valve

Char circulation control valve design is based on modified versions of the slide and plug valves in commercial use on fluid catalytic crackers at temperatures up to 1400°F. Such valves can withstand short excursions to 1700°F. Crane Corp. and Tapco International, the leading suppliers of such valves in the U.S., have confirmed the feasibility of modifying their designs for the CCD service. However, since such valves have not been demonstrated commercially, there is a low technical risk as to the suitability of such valves for a commercial plant. The Demonstration Plant Program will either prove the suitability of such valves or result in the development of a suitable valve.

2.6 DESIGN MATURITY AND RISKS

2.6.3 AREA 103 - Pyrolysis and Gasification - continued

5. Mixing Section Mechanical Design

Design of the mixing section is critical to the operability of the gasification section. There is a negligible technical risk that the mixing section will not function as required by the process. This is because the mixing section design is based on the design that has proven to be successful in the pilot plant in preventing slagging and agglomerating at the point where char and hot flue gas mix.

6. Flue Gas Combustible Levels

The design and operation of the flue gas oxidizer in Area 110 is dependent on the quantity of combustibles, primarily CO and H_2, in the flue gas from the lift tube. There is a risk an inaccurate prediction of the flue gas combustibles will lead to a sizing error in the flue gas oxidizer, or an understatement of thermal loss.

The quantity of combustibles in flue gas is based on pilot plant data. The pilot plant was operated with supplemental hydrocarbon fuels to preheat combustion air that are not required in the Demonstration or Commercial Plants. This resulted in a higher quantity of steam in the combustor off gas, more reaction of this steam with circulating char, and higher combustible levels than would be expected in the Demonstration or Commercial Plants. Consequently, pilot plant data were corrected to reflect this fact. Because of the complexity of flow patterns in the lift tube, a mathematical model for the lift tube (LTMM) was developed. The LTMM is based on operations of the pilot plant lift tube and one half scale cold model. LTMM parameters were adjusted to fit pilot plant and cold model data, and then the LTMM was used to indicate the effect of scale up on flue gas combustibles. The results indicate that the quantity of flue gas combustibles should decrease with scale up. Therefore, there is a moderate risk that the level of combustibles to the flue gas oxidizer will be lower than the design value. The flue gas oxidizer design is based on the maximum combustibles anticipated, and if values are lower than expected, constant operating conditions can be maintained by burning auxiliary fuel.

2.6 DESIGN MATURITY AND RISKS

2.6.3 AREA 103 - Pyrolysis and Gasification - continued

6. Flue Gas Combustible Levels - continued

The economic risk of incorrectly estimating flue gas combustibles level is low. Process studies on the effect of flue gas combustibles level on gas price indicate that there is no penalty for combustibles, as long as the steam and power produced in the Flue Gas Power Recovery Area are not in excess of the total plant requirements. The overall plant utility balance indicates that the entire plant is slightly deficient in steam and power. Therefore, flue gas combustibiles in excess of the design base pose no economic penalty.

7. Vertical Slagging Cyclone Combustor

The risks of operating a slagging cyclone combustor at system pressure and of incorrectly estimating heat losses were considered. Combustor design is based on European commercial experience with vertical, slagging cyclone utility boilers that have been operated in sizes exceeding COGAS commercial requirements, but at one atmosphere rather than five atmospheres pressure, and on the operation of the COGAS pilot plant. The problems of extrapolation of current commercial designs to pressurized operation are primarily mechanical in nature. Because similar problems have been handled in other pressurized equipment, the technical risks are low.

Heat losses were calculated by EVT (Energie-und Verfahrenstechnik GmbH), the leading supplier of vertical cyclone boilers in Europe, based on their standard design equations for commercial, vertical, slagging, cyclone boilers. EVT's calculations were confirmed independently by CURL, who scaled up pilot plant data. The slagging combustor uses water cooling to protect the shell from the high temperatures and corrosive action of molten ash. The resulting heat losses, which go to the raising of steam in the shell, are a significant portion of the furnace heat release. Process studies indicate that there is no economic penalty for this steam production, as long as the steam produced does not exceed the steam requirements for the total plant. Since the overall plant utility balance indicates that the total plant is slightly steam deficient, there is no economic penalty associated with the combustor heat losses.

Heat release rates (combustion intensity) were estimated by EVT based on their experience in designing commercial vertical slagging cyclone boilers. Comparable heat release rates were demonstrated in the pilot plant.

2.6 DESIGN MATURITY AND RISKS

2.6.4 AREA 104 - Oil Recovery and Treatment

Assumptions

1. It was assumed that three stages of venturi scrubbing with water will produce an oil and solids free synthesis gas suitable for compression, purification and upgrading to SPG in Areas 105, 107, 108 and 109. The assumption is based on COED pilot plant operations, which used water scrubbing to recover oil and char solids from product gas, and on information from vendors. Research-Cottrell and Ingersoll-Rand confirmed that three stages of high efficiency venturi scrubbing can reduce particulate loadings in the raw synthesis gas to very low levels that can be tolerated in multi-stage, centrifugal compressors.

2. It has been assumed that the present pricing structure for petroleum products, which favors the production of low sulfur, No. 4 fuel oil and naphtha over syncrude, will not change in the future to favor syncrude. A slipstream, fixed bed hydrotreater to produce syncrude has been proposed for the Demonstration Plant to develop the data needed to design a commercial hydrotreating section for the production of syncrude, should the pricing structure change between now and the time a commercial plant is built.

3. It was assumed that the current EPA emission regulations for NO_x emissions from fuel oil combustion. 0.3 lb $NO_x/10^6$ Btu, will not be tightened by more than 40 percent. There are no regulations concerning the nitrogen content of fuel oils. However, there are Federal EPA emission limit regulations for new steam generators of 250 million Btu/h heat input or larger, which indirectly limit the nitrogen content of fuel oils marketed for this use. Although there are large fuel oil markets which do not fall under this regulation and can tolerate higher nitrogen levels, it is desirable that the Commrecial and Demonstration Plant process designs produce fuel oil products which can satisfy these emission regulations. The nitrogen level chosen for the fuel oil, 0.36 wt percent, will result in NO_x emissions less than 0.42 lb per million Btu.

4. It was assumed that hydrotreating yields for Illinois No. 6 seam coal derived oil can be extrapolated from HRI's bench scale experimental data on Western Kentucky coal derived oil. The ratios of heteroatom removal, reaction rate constants and C_1 and C_3 yields from COED fixed bed hydrotreating operations with oils derived from Illinois No. 6 and Western Kentucky coals were assumed to hold constant for ebullating bed processing of the two oils. This is based on COED and HRI experience. HRI assumed that the respective rates at which all oils would crack were the same as that of the oil derived from the Western Kentucky coal. Their rationale for this was that hydrocracking is primarily a thermal effect.

2.6 DESIGN MATURITY AND RISKS

2.6.4 AREA 104 - Oil Recovery and Treatment - continued

Assumptions

HRI has scaled up its ebullated catalyst bed hydrocracking reactor system from bench scale to commercial operation three times: The Cities Services Demonstration Plant, Kuwait National Petroleum Company Commercial Unit, and Petroleos Mexicanos Commercial Unit. HRI, based on their previous scale up experiences; will guarantee the yields for the ebullating bed reactor for the Commercial and Demonstration Plants.

Identified Risks

1. Catalyst Life in Ebullating Bed

Since catalyst activity has been tested over relatively short periods, there will be some uncertainty as to catalyst life over extended operation. There is no technical risk in underestimating catalyst life because the catalyst makeup and withdrawal system can maintain a constant catalyst activity in the ebullated bed, regardless of catalyst deactivation rates, and has sufficient flexibility to accommodate any reasonable variations in catalyst life. The economic risk of short catalyst life is small because the contribution of hydrotreating catalyst cost to overall plant operating costs is very small.

2.6.5 AREA 105 - Gas Purification

Assumptions

1. There are basically no assumptions in this area other than those inherent in the amount of sulfur, nitrogen and trace element contamination in the feed coals.

Identified Risks

1. Since a long term supply contract for coal would be established for a commercial plant, the expected variations in coal composition would be known. The purification processes are well proven over a wide range of gas compositions. No risks are evident in this area.

2.6 DESIGN MATURITY AND RISKS

2.6.6 AREA 106 - Hydrogen Generation

Assumptions

1. There are no significant assumptions in this areas.

Identified Risks

1. Processing steps are well proven commercially and no risks have been identified.

2.6.7 AREA 107 - Shift and Methanation

Assumptions

1. There are no significant assumptions in this area.

Identified Risks

1. The shift and methanation system selected for the Demonstration Plant has been operated on a pilot scale only. Although a scale up of about 18:1 (based on diameter) is contemplated for the reactors, this is not considered to be excessively high for fixed bed reactors. A moderate technical risk is assigned to the scale up to demonstration plant size. However, no specific areas of concern are visualized. If no problems are encountered in the demonstration phase, a scale up of 2:1 (based on diameter) is planned for the Commercial Plant reactors. This scale up represents negligible risk for this type of equipment.

2. The catalyst performance is subject to moderate technical risk because there is no direct commercial experience. However, R. M. Parsons spent four years of development effort in bench scale and pilot plant testing to reduce this risk to an acceptable level. Problems associated with the presence of chlorine and heavy metals in coal derived gases have been solved by removing them in the top of the sulfur guard (ZnO bed) with a commercially available absorbent, before they enter the converters.

2.6.8 AREA 108 - Bulk CO_2 Removal and Gas Compression

Assumptions

1. There are no significant assumptions in this area.

Identified Risks

1. The proposed Benfield process and equipment have been well demonstrated commercially and no risk is foreseen.

2.6 DESIGN MATURITY AND RISKS

2.6.9 AREA 109 - Gas Dehydration

Assumptions

1. There are no significant assumptions in this area.

Identified Risks

1. There are no identified risks in this area.

2.6.10 AREA 110 - Flue Gas Power Recovery

Assumptions

1. It was assumed that the vendor's cyclone efficiencies and the fines balance mathematical model for Area 103 predict the flue gas dust loading with reasonable accuracy. Variation in dust loading has little effect on the heat load of the flue gas oxidizer, since combustion of char fines represents only 3 percent of the heat duty. Variation in dust loading will have an effect on expander blade life, but an increase of as much as 100 percent could be tolerated without significant effect on turbine maintenance cost.

2. It was assumed that the dust size consist entering the tertiary separator is the same as the dust size entering the flue gas oxidizer. No data are available on the effect of combustion in the flue gas oxidizer on the exit particle size of the fly ash. The size is assumed to remain unchanged on the basis that agglomeration is as likely to occur as size reduction. The mass flow of minus 10 micron particles would have to be doubled before a significant effect on turbine blade wear would occur, and this is considered unlikely.

3. It is assumed that the erosivity of an ash particle is no greater than a catalyst particle in FCC Power Recovery Systems. Since fly ash of the type produced in the flue gas oxidizer is not available, utility boiler fly ash is assumed to be the worst case ash particle likely to be experienced. Since the size, shape, and mechanical properties of a fused fly ash particle are generally comparable to catalyst, this assumption is considered valid. However, confirmation of this assumption is to be obtained by a planned comparative erosivity test to be made between boiler fly ash and catalyst dust by Carrier Corporation.

4. It is assumed that blade erosion in the second stage of the expander will not be significantly worse than in the first stage. There had been questions about this assumption based on early experience with multistage gas turbines operated on coal combustion products, in which the downstream stator blades were eroded more severely than the first stage. However, the design of an axial entry, two stage, FCC type expander is markedly different from the type of

2.6 DESIGN MATURITY AND RISKS

2.6.10 AREA 110 - Flue Gas Power Recovery - continued

multi stage turbines tested in the early program. The FCC expander vendors have conducted recent design studies which gave them sufficient confidence to proceed with the design and marketing effort for two stage expanders for FCC refinery use. Such machines are expected to be in commercial operation within the next few years.

Identified Risks

1. Flue Gas Oxidizer Availability

The flue gas oxidizer was identified as an item which is not normally commercially available. Commercial flue gas oxidizers do not operate at the pressure required for this process. However, commercial analogs exist in atmospheric CO boilers and in pulverized coal utility boilers. Certain features must be custom designed for this application, namely a pressure shell, soot blower penetrations, and high temperature burners. At least one qualified vendor is known to be willing to design and furnish the unit for the Demonstration Plant and Commercial Plant.

2. Expander Erosion

There is a small technical risk that erosion of turbine blades may be more severe than anticipated, due to one or more of the assumptions mentioned above. Since FCC expanders, which are a model for this process design, are capable of achieving a 5 year blade life, there is considerable allowance for poorer performance under COGAS conditions. The maintenance costs of blade change are not a significant part of plant operating cost. The minimum design requirement is that the blades last for at least a year, so as to avoid an unnecessary shutdown in advance of the annual maintenance shutdown. Thus, performance under system conditions can be 2-3 times worse than FCC performance without a serious effect on plant operability or economics. This is judged to be a low risk item.

3. Expander Deposition

There is some risk that the inlet temperature selected for the expander may be too high to prevent the formation of turbine deposits. The temperature selected was based on the experience of other prior programs, and is limited. Techniques are available to deal with deposition if it is a problem. These include reduction in inlet turbine temperature through use of the built in flue gas oxidizer exit temperature control, use of additives in the flue gas oxidizer, and turbine cleaning techniques. The Demonstration Plant will be fully operable without operation of the power recovery expander, and experience gained in operation of the Demonstration Plant will provide a design basis for future commercial plants.

2.6 DESIGN MATURITY AND RISKS

2.6.11 AREA 111 - SO_2 Removal

Assumptions

1. It is assumed that carbon in the particulates in the flue gas stream is essentially oxidized in the flue gas oxidizer and that 90% of the solids entering the tertiary separator are removed.

2. It is assumed that EPA emission standards currently in effect in Illinois will be applicable to the Commercial Plant.

Identified Risks

The FMC Double Alkali SO_2 Removal System has been operated successfully on a commercial scale and is not considered to be a risk.

2.6.12 AREA 112 - Sulfur Recovery

Assumptions

There are no assumptions in this area.

Identified Risks

There are no identified risks in this area.

Commercial operation of the Claus process and sulfuric acid plants have been well documented.

2.6.13 AREA 113 - Ammonia Recovery

Assumptions

It has been assumed that the organic content of the sour water stream is essentially phenol. If there are any organics which are significantly more volatile than phenol they may leave the system with the H_2S stream and go into the Claus plant where they will eventually be oxidized.

Identified Risks

There are no identified risks in this area.

2.6 DESIGN MATURITY AND RISKS

2.6.14 AREA 114 - Thermal Oxidizer and Flare

Assumptions

1. It has been assumed that the maximum amount of gas going to the flare at any time will be equal to the quantity of raw gas leaving the decanters when one train is operating at capacity. It is difficult to achieve a flare of this magnitude and a larger flare is highly unlikely. In the event of a significantly higher flow, unburned gas would be discharged to the atmosphere for a brief period.

2. It is assumed that an oxidizer sized for a petroleum refinery with a liquid product capacity equal to the liquid product of the COGAS plant will be adequate. More specifically, a 100 gpm stream consisting of 50% oil and 50% water plus a small gas stream will be fed to each oxidizer. If this flow is exceeded for a brief time, the excess will be diverted to a surge tank. If the waste stream turns out to be significantly higher, on a sustained basis, an additional oxidizer will be required.

Identified Risks

There are no technical risks other than those related to capacity as directed above.

2.6.15 AREA 115 - Utilities

Assumptions

There are no assumptions in this area.

Identified Risks

There are no identified risks in this area.

2.6.16 AREA 116 - Water Supply

Assumptions

It has been assumed that the quality of the raw water source, the Mississippi River, will not deteriorate in the time frame of the Commercial Plant operation.

Identified Risks

There are no identified risks in this area.

2.6 DESIGN MATURITY AND RISKS

2.6.17 AREA 117 - Water Treatment Systems

Assumptions

See 2.6.16

Identified Risks

There are no identified risks in this area.

2.6.18 AREA 118 - Waste Treatment and Disposal

Assumptions

1. It has been assumed that the total volumetric flow of waste is 20% greater than that estimated from pilot plant flows.

2. It has been assumed that each known contaminant is present in 20% greater quantity than that measured in the pilot plant.

3. It has been assumed that about 4% of the organics in the stripper bottoms are oils and grease, and the rest are phenolics.

4. It has been assumed that chlorides in the aqueous waste are equal to chlorides in the feed coal based on typical analysis

5. It has been assumed that BOD of the aqueous waste is 2 lbs per lb of phenolics.

6. It has been assumed that waste solids consisting of slag, ash, and press cake sludges will meet leachability criteria established by environmental regulations.

Identified Risks

The design of the waste treatment facilities must be considered a moderate technical risk since information as to quantities and components of certain waste streams is not firm. Risk is reduced by making conservative assumptions and utilizing statistical information from similar facilities associated with petroleum refineries. Firm information will be obtained during Demonstration Plant operation.

2.6 DESIGN MATURITY AND RISKS

2.6.19 AREA 119 - Fire Protection Systems

Assumptions

There are no assumptions in this area.

Identified Risks

There are no identified risks in this area.

2.6.20 AREA 120 - Facilities

Assumptions

There are no assumptions in this area.

Identified Risks

There are no identified risks in this area.

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.1 Noncommercially Available Equipment

The Commercial Plant Concept has been prepared on the basis of utilizing to the maximum extent possible the technology, methodology, materials and equipment that fall within the scope of existing industrial practice and commercial availability. In the Commercial Plant Concept, care was taken in the specifications for equipment so that the equipment sizes did not exceed the size of equipment that has already been built for the same or similar applications. The definition of "commercially available" extends beyond the familiar "off the shelf" categorization that is used to designate short delivery items such as pumps, motors and agitators. It also includes components such as reactor vessels, heat exchangers and mass transfer columns which require custom designing for special applications. For the identification of noncommercially available components, commercially available equipment is defined as any item which satisfies the following criteria:

- Can be designed using currently available accepted methodology and materials.
- Can be fabricated or manufactured using industrially accepted techniques.
- Industrial operating experience on equipment of similar size or capacity encompasses or requires limited extrapolation to include the operating envelope proposed for the equipment without extensive developmental engineering test work.
- Reputable and qualified manufacturers or fabricators have submitted quotations or have expressed their ability to fabricate and a willingness to quote on the equipment.

A review of the equipment list for the Conceptual Commercial Plant reveals that only the Flue Gas Oxidizer, Item 110-44101-1,3, does not comply with these criteria. Although vendors have expressed confidence in their ability to design and construct a satisfactory unit, a design development effort is necessary to deal with the pressurized design and to prepare a valid quotation.

An order of magnitude estimated cost for the Flue Gas Oxidizer was obtained from a qualified manufacturer based on his expertise in the field supplemented by preliminary engineering studies.

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS - continued

2.7.2 Major And/Or Critical Components

Major and/or critical components are defined as those equipment items which characterize the function of the process subsystem and constitute an indispensable element in its description. Of the 700 plus equipment items identified in the Equipment Specifications included in Section 4, only a limited number conform to this criterion and these are as follows:

Table 2.7.2-1

Major and/or Critical Components

Item Number	Description
101-43109	Stacker Reclaimer
102-46101	Coal Grinder
102-47102	Fuller-Kinyon Pump
103-33101	First-Stage Pyrolyzer
103-33102	Second-Stage Pyrolyzer
103-33103	Third-Stage Pyrolyzer
103-33104	Fourth-Stage Pyrolyzer
103-33105	Gasifier
103-33106	Combustor
103-34102	Combustor Mixing Section
103-35103	Combustor Lift Tube
104-32103	Fractionator
104-32105	Vacuum Tower
104-33101	H-Oil® Reactor
104-33102	Hydrotreater
104-42104	First-Stage Make Up Hydrogen Compressor
104-42105	Second-Stage Make Up Hydrogen Compressor

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.2 Major And/Or Critical Components - continued

Table 2.7.2-1 - continued

Major and/or Critical Components

Item Number	Description
105-32201	Contactor
105-32203	Stripper
105-42201	Gas Compressor w/Auxiliaries
106-32202 to 106-32205	Nos. 1, 2, 3 and 4 Shift Converters
106-32207	CO_2 Absorber
106-47202	Hydrogen Purification Adsorption System
107-32501 to 107-32506	Nos. 1, 2, 3, 4, 5 and 6 Methanators
107-32507	Final Methanator
108-32101	CO_2 Absorber
108-42105	Syn. Gas Compressor w/Accessories
110-42102	Air Compressor w/Dusty Gas Expander
110-44101	Flue Gas Oxidizer
110-45102	Tertiary Separator
111-47201	Venturi Scrubber
112-47101	Claus Plant
112-47103	Sulfuric Acid Plant
113-32101	Sour Water Stripper
113-32102	Ammonia Removal Scrubber
113-32104	Ammonia Fractionator

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.2 Major And/Or Critical Components - continued

With the exception of the equipment in Areas 103, 104, 107 and 110; and the Fuller-Kinyon pumps in Area 102, the equipment and processes comprising the Conceptual Commercial Plant have successfully proven themselves in numerous commercial installations. Well documented[1,2,3] 90 plus percent on stream times certainly dispel any doubts regarding the adequacy of design methodology or operating availability for Areas 101, 102 (except as noted above), 105, 106, 108, 111, 112, and 113. For the equipment in Areas 103, 104 and 110, published papers and records from the petroleum industry provide historical data for fluid catalytic crackers, fluid bed coking and hydrodesulfurization units, the commercial analogs of Pyrolysis and Gasification (Area 103), Oil Treatment (Area 104) and certain elements of the Power Recovery System (Area 110). The pressure operation of the Flue Gas Oxidizer and the two stage characteristic of the expander drive for the air compressor do not have existing commercial analogs and, therefore, are categorized as somewhat uncertain with respect to design and operation. Also in this category are the combustor, including mixing section and lift tube. For Area 107, R. M. Parsons' experience with similar systems, bench scale tests, pilot plant tests and process guarantees provide assurance that sufficient design data is available for a successful scale up. However, there are no commercial installations for the bulk conversion of synthesis gas into SPG. Thus, the methanators are placed in this category.

In summary, then, critical items with uncertainty in design and operation are identified as:

Item Number	Description
102-47102	Fuller-Kinyon Pump
103-33106	Combustor
103-34102	Combustor Mixing Section
103-35103	Combustor Lift Tube
107-32501 to 107-32506	Nos. 1, 2, 3, 4, 5 and 6 Methanators
107-32507	Final Methanator
110-42102	Air Compressor - Two Stage Dusty Gas Expander Section Only
110-44101	Flue Gas Oxidizer

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.2 Major And/Or Critical Components - continued

In all instances the uncertainty exists because of the absence of historical data with respect to the operation.

2.7.3 Redundancy

The extent of the redundancy designed into the Conceptual Commercial Plant is based principally on the practices followed in the chemical industry and petroleum refineries which have consistently produced on stream availabilities of 90 plus percent. These excellent results have been achieved through the judicious selection of commercially proven equipment for installation in the plant and the implementation of a comprehensive maintenance program.

In general for the Conceptual Commercial Plant, the principle of installed spares has been applied to continuously operating rotating equipment such as process pumps and relatively small blowers and compressors. Identifiable examples of this rule are the provisions of multiple char transfer lines, a spare slag crushing system and a spare Fuller-Kinyon Pump; items which are subject to severe operating conditions.

Redundancy has also been employed in Area 108, Bulk CO_2 Removal and Gas Compression, to assure continuity of flow of the synthetic pipeline gas to the consumer. Here two compressors are normally operating to increase the pressure of the gas to approximately 1100 psig. A third unit, capable of handling 50% of the plant throughput, and identical to the other two machines, is the installed spare. Similarly, because of the importance of the instrument air supply to the plant, a spare compressor and drying system have been provided. The entire instrument air system is additionally backed up by the plant air system utilizing the plant air dryers provided for winter operation.

In some areas redundancy is desirable but not practical. An excellent example of this situation is the hot valves for solids handling in a hostile environment in Area 103, Pyrolysis and Gasification. In instances such as this, uninstalled spares will be stored in the warehouse for immediate availability, when and if the need arises, to facilitate replacement and minimize downtime.

Because of the conceptual nature of the design, the extent of redundancy, particularly for instrumentation and piping subsystems, cannot be completely identified at this time. As details are developed during definitive engineering, likely areas for redundancy will be uncovered, evaluated and satisfied if the need is confirmed.

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.3 Redundancy - continued

This approach on redundancy, in conjunction with other considerations described elsewhere in this section, is expected to provide the 90 plus percent on-stream operation experienced by commercial analogs.

2.7.4 Description of Material Selections

The coal handling, coal conversion, and flue gas handling areas (Areas 101, 102, 103 and 110) will be the areas with the shortest design life and the highest maintenance costs due to effects of erosion and corrosion. In designing these areas, the materials of construction and types of equipment will be specified that should provide the best service based on the experience in industries that approximate the applications, as well as data obtained from operating pilot plants and from the government and industry supported research programs. Such "Materials for Fossil Fuel Processing" programs are underway at the National Bureau of Standards, Battelle Labs, Illinois Institute of Technology, Southwest Research Institute and University of California at Berkley under the sponsorship of the Department of Energy, Metal Properties Council, National Association of Corrosion Engineers and others.

The selection of materials of construction for the various systems and components is based on criteria such as: the material being handled (erosion, corrosion); operating conditions (pressure, temperature, flow rates); and economics versus service life. The selection can best be exemplified by describing the selection of the materials for the pyrolysis vessels.

In the four-stage pyrolysis system, coal is heated in stages, driving off moisture and recoverable volatiles and producing a solid char for the gasification system feed material.

In the first stage of pyrolysis, the coal is heated by means of a hot inert gas, driving off most of the carry-over water and a small amount of volatiles. The conditions to be considered in selecting a material of construction for this first stage pyrolyzer include:

- The relatively low operating temperature and pressures.
- The water carried over by the coal is slightly acidic due to sulfur, and may contain other contaminants such as chlorides.

These conditions indicate that the vessel may be of fusion-welded construction and fabricated of carbon steel with a suitable corrosion allowance. The vessel will be externally insulated.

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.4 Description of Material Selections - continued

The internal cyclones will be fabricated of similar materials with refractory cements on areas subject to erosion.

In the second-stage pyrolyzer, coal is heated further, releasing volatile effluents along with any residual moisture. The basic operation and conditions are similar to Pyrolyzer No. 1, except that the increased temperature has changed the corrosivity problem by the presence of sulfates and sulfides. Experience has shown that carbon steels may be marginal in service at these temperatures. The shell of Pyrolyzer No. 2 will be fabricated of a silicon bearing carbon steel (Type A-515) and alumunized for increased resistance to sulfates and sulfides. Where erosion may be experienced, wear plates of 410 SS, or equivalent, will be installed. The internal cyclones will be fabricated of similar materials with refractory cements on areas subject to erosion. The vessel will be externally insulated.

In the third stage, the char is heated further. The heating medium in the third and fourth stages is raw synthesis gas from the gasifier in contrast to the relatively inert gas in the previous stages. The increased content of hydrogen sulfide, hydrogen and other products of dissociated coal in the stream, in addition to the solids, at this temperature require the use of alloying elements such as chromium in the steel. A chrome-moly steel has been selected for the vessel material in the third-stage pyrolyzer. An insulating refractory lining is used to reduce the wall temperature to suitable design levels. The internal cyclones will be fabricated of similar materials with possible alternates of type 410 SS or 304 SS.

In the fourth stage of pyrolysis, the basic operation and conditions are similar to the third stage, except for the higher temperature. Therefore, the fourth-stage vessels and internal cyclones will also be fabricated of chrome-moly steels with refractory linings. The choice of materials of construction for the pyrolysis section is based on anticipated conditions.

The selection of equipment will be based on experience in similar applications. In the cases where there are no direct correlations, the selections will be based on applications which approximate the required service. A typical example is the valves for controlling solids flow.

2.7 EQUIPMENT AND MATERIAL CONSIDERATIONS

2.7.4 Description of Material Selections - continued

One uncertainty in predicting the service life for the gasification section valves is the effect of increased temperature. One vendor, Crane, has recommended using conventional FCC designs and replacing 304 SS with high temperature alloys such as HK-40 or Incoloy 800. The performance of hard-faced sliding surfaces at gasifier temperatures is another unknown.

Of secondary importance is the difference in erosivity between cracking catalyst and char. Even if the char is more erosive than cracking catalyst, and no data exists to confirm this supposition, the erosiveness is more than offset by the lower flow rates for gasification service.

In summary, based on analogous service in FCC units, a service life in excess of one year can probably be expected for the solids control valves in the gasification section of Area 103.

References

(1) Guide to Refinery Operating Cost, W. L. Nelson, pp. 83-89, The Petroleum Publishing Company, Tulsa, Okalahoma, 3rd Edition 1976.

(2) Flexicoker Prototype Demonstrates Successful Operation; J. P. Matula, B. V. Molstedt and D. F. Ryan paper presented at API, Division of Refining Meeting, Chicago, Illinois, May 13, 1971.

(3) Hydrocarbon Processing, Vol. 47, No. 9, p. 152, September 1968.

2.8 RELIABILITY

The subsystems and equipment comprising the process areas in the Commercial Plant are identical to or have commercial analogs which have consistently provided on-stream factors in excess of 90% in numerous installations for many years. The purpose of the study conducted was not to confirm what already is known but to evaluate the reliability of these subsystems and equipment in their new applications in pyrolysis, gasification and adjunct areas. Because of the scarcity of factual information required for the conventional approach to a reliability evaluation, methodology was developed and the necessary values established using published information, industrial experience and engineering judgment. All items of equipment in the areas studied were considered in the evaluation. The general conclusions of this study are summarized in Figures 2.8.2-1 and 2.8.2-2. Figure 2.8.2-1 graphically depicts the relationship between on-stream factors (fraction of available time) and the probability of achieving each which has been developed for each train of the Commercial Plant. Of greater significance is Figure 2.8.2-2 which shows that for three trains of the plant the production rate factor (fraction of rated capacity) of 0.90 has a probability of 90%.

Suggestions for design modifications to improve the reliability of the system are included in Subsection 2.8.2.

2.8.1 Introduciton

Reliability is defined as the probability that a piece of equipment or subsystem will provide the required performance satisfactorily for a designated time period under specified service conditions. Reliabilities are expressed either as decimals or percentages. The reliability of a piece of equipment or subsystem depends on the individual reliabilities of its constituent parts and is equal to the product of the reliabilities of each of its parts. Similarly, the reliability of a large system is represented by the product of the individual reliabilities of the components comprising the system. Mathematically, the expression relating the reliability or probability P that a component will operate successfully to the end of a time period t is $P = e^{-\lambda t}$ where λ is the failure rate or the reciprocal of the mean time between failures.

2.8 RELIABILITY

2.8.1 Introduction - continued

Since the reliability of a component is significantly affected by factors such as pressure, temperature, stream compositions, humidity, corrosive atmosphere, dust, etc., it is essential that the data be collected under conditions the same or very similar to the application being considered. There are two main approaches to the determination of the necessary failure rate data. The first is to obtain the data directly from a statistically valid number of installations of the type of equipment being studied. The second is to obtain failure rate data for the elements from which the equipment is manufactured and calculate its reliability as described previously.

Because of the conceptual nature of this design for the Commercial Plant much of the equipment, particularly those items of a rotary nature, has not been sufficiently defined to establish with even a degree of certainty the final identity of the major equipment components that will be utilized in the final assembly. At this time even the manufacturer is unknown.

In spite of the lack of details major equipment suppliers of equipment for the chemical process industry were contacted in an effort to establish the reliability of representative equipment and subsystems or, if the information was unavailable, to obtain rate of failure data for the components parts. The greater percentage of the suppliers replied that they did not have a structured reliability program, either at the subtier or final product level. Other suppliers were responsive to our request with their concept of reliability data, but the majority of the documents received contained generic information which claimed that the supplier had been producing equipment for a significant number of years and had experienced relatively few known failures. Practically all of the good data is for specific instrument and electronic components which are not yet identified in this design.

Unfortunately, most manufacturers of equipment seem to operate using the premise that, if they have no knowledge of the failure of their equipment, the equipment can be considered to be extremely reliable.

If component reliability data do not exist, it can only be derived by means of statistical procedures using actual failure rates from extensive test programs. This approach is not only expensive but extremely time consuming.

2.8 RELIABILITY

2.8.1 Introduction - continued

What this all leads to is a situation where it is impossible to accurately evaluate the reliability of process facilities by the direct approach because of the lack of the essential rate of failure statistics. The best information available in the process area with respect to reliability is the more encompassing category of availability. Dr. W. L. Nelson has published in the Oil and Gas Journal over the past several years, on-stream factors and duration of run data for petroleum refining units. This information is included in a book, Guide to Operating Costs, published in 1976 by The Petroleum Publishing Company of Tulsa. The listed plant availabilities encompass both shutdowns because of failure and scheduled plant maintenance periods. The engineering approaches to be used in the design, engineering and estimating of the Commercial Plant are also common to the petroleum refinery. The codes and standards are identical. Therefore, it is to be expected that the use of the same technology, methodology and suppliers of commercially available equipment and materials will yield availabilities in the Commercial Plant similar to those experienced in commercial analogs in refineries.

Similar information for equipment installations in the coal industry, electrical power generation and chemical plants confirms a high availability for the commercial analogs.

For these reasons the evaluation of the reliability is centered on the pyrolysis and gasification section of the plant which encompasses part of Area 102, all of Area 103, Area 104 except for hydrotreating, part of Area 105, Area 110, and Area 111. All of the equipment items in the areas studied have been considered in the system summary.

2.8.2 Methodology

The analytical method used for estimating the pertinent reliability and availability factors in this analysis is outlined below, and is based on statistical methods presented in various standard texts on system reliability (1)(2)(3)(4)(5).

Definitions

A system is a collection of interacting components arranged in some sequence. A "series" component is one whose failure causes the system to fail (partially or totally). A "parallel" component is

2.8 RELIABILITY

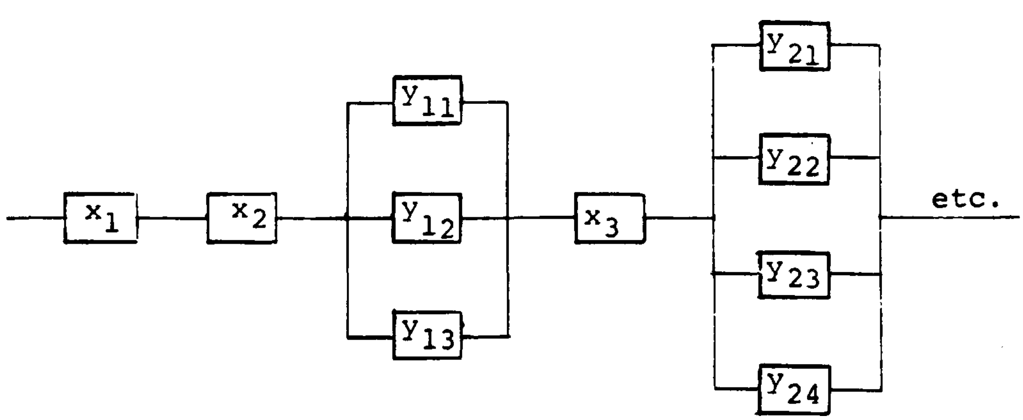
2.8.2 Methodology - continued

Definitions - continued

one whose failure causes the system to fail (partially or totally), if and only if such failure is coincident with the failure of a pre-specified number of other "parallel" components. A "parallel" set is a collection of "parallel" components so arranged that the set, and hence the system, fails (partially or totally) if and only if all the components of the set fail simultaneously. A "null" component is one whose failure has no bearing on the state of the system. In the analysis that follows "null" components are ignored.

Analytical Analysis of a System

Let the series components be designated by x_i (where i designates the series component number, i = 1,2....,r) and the parallel set components by y_{jk} (where j designates the parallel set number, j = 1,2....,s; and k designates the parallel component number of the specified set, k = 1,2....,t). For simplicity, it will be assumed that y_{jk} is a single component, although in practice it could be composed of a number of components in series. A typical system might look something like:



2.8 RELIABILITY

2.8.2 Methodology - continued

Analytical Analysis of a System - continued

Let P_i = the probability of x_i being operable.

P_{jk} = the probability of y_{jk} being operable.

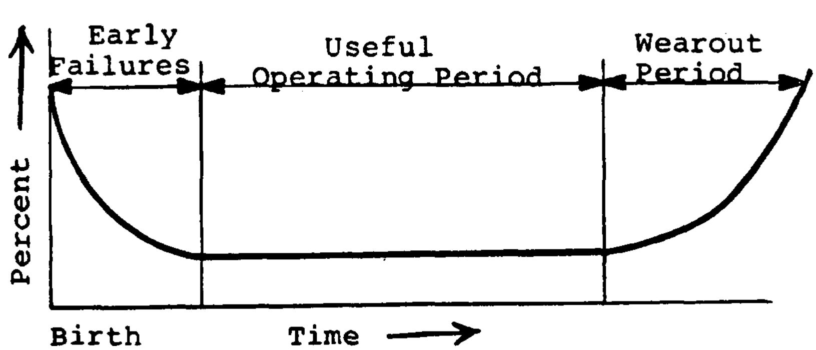
P_s = the probability of the system (composed of x_i's and Y_{jk}'s) being operable.

Then it can be shown that:

$$P_s = \left(\prod_{i=1}^{r} P_i\right)\left[\prod_{j=1}^{s}\left(1-\prod_{k=1}^{t}(1-P_{jk})\right)\right] \qquad (1)$$

The most convenient and applicable expressions for P_i and P_{jk} are based on the assumption that the a priori odds of a component failing or not failing is constant throughout its useful life. (This is similar to the case where the probability of tossing a coin to show a head is 1/2). The assumption of constant probability of failure (or success) is reasonable for the case where the system is well maintained and operable. It corresponds roughly to the flat part of the typical mortality curve for equipment observed by the process industry (1)(3)(4).

Mortality Rate - % per year



2.8 RELIABILITY

2.8.2 Methodology - continued

Analytical Analysis of a System - continued

This analysis is therefore based on expected experience after the plant (system) has been debugged; that is, after start-up and all the latent equipment or installation defects have been deleted and corrected. Additionally, it is based on good maintenance practice, including preventive maintenance and external, on-the-run equipment testing, and on reasonably steady and intelligent operation.

In the case where the probability of an event occuring is sufficient and the number of trials is limited, the probability of r events (for example) occurring in n trials is rigorously given by the Binomial Distribution Law.

$$P(r;n) = \binom{n}{r} p^r (1-p)^{n-r} \tag{2}$$

where

p = a priori probability of a single event occuring.
n = Number of trails (viz, tosses of a coin).
r = Number of events (viz, tosses showing heads).
P(r;n) = Probability of r events out of n trials (viz, r heads in n tosses).

In applying this to a system reliability evaluation, two situations pertain. The odds of a single component failure occurring is small, and the number of trials (instances when a failure can occur) is large. Under these conditions, the Binomial Distribution Law reduces to the Poisson Distribution.

$$P(r;n) = \frac{\rho^r e^{-pn}}{r!} \tag{3}$$

If p, the probability of a failure is expressed as failures per hour, the n would be expressed as hours. Any other consistent set of units can be used.

2.8 RELIABILITY

2.8.2 Methodology - continued

Reliability of the System

The basic question asked of the reliability analysis is "what is the probability that the system, and hence all of its non-null series components and non-null parallel sets, will operate for t consecutive hours without failure?" This probability applied to each component, will be that for $n = t_o$ and $r = 0$ in equation (3), or

$$P(t_o) = e^{-\lambda t_o} \tag{4}$$

Where λ is a parameter reflecting the frequency of failures for a specific component. Applying equation (4) to equation (1) and designating λ_i for the failure-frequency parameter of series component i, and jk for the failure-frequency parameter of parallel component jk, gives:

$$P_s(t_o) = \left(\prod_{i=1}^{r} e^{-\lambda_i t_o}\right)\left[\prod_{j=1}^{s}\left(1-\prod_{k=1}^{t}\left(1-e^{-\lambda_{jk} t_o}\right)\right)\right] \tag{5}$$

This expresses the probability of the system operating t_o (hours) without interruption. Hence this equation measures the reliability of the system for any specified continuous operating time.

Availability of the System

Equally important is knowledge as to the expected availability of the system. There are two measures of availability:

- On-Stream Factor expressed as a fraction is the operating time divided by the available time.
- Production Factor expressed as a fraction is the expected actual production during the available time divided by the design (or capacity) production during the same time period.

2.8 RELIABILITY

2.8.2 Methodology - continued

Availability of the System - continued

In the event of failure of a series component or a parallel set, there will be an operating outage equal to the time either to repair the failed component or set or to activate the standby or back-up facility. The latter can be ignored in most cases except for the compressor-expander-turbine train in Area 110. In this case, failure of the expander will require the shutdown of Areas 103 and 110 and the isolation of the expander; then, Area 103 and 110 can be started up with the turbine picking up the load formerly carried by the expander. For all the events, in the long run the average time to bring the system back into operation will be the weighted repair time of all the components, using as weighting factors for each component or set, the probability of failure of that component or set. Expressed otherwise,

$$t_r = \text{Average repair time} = \frac{\text{weighted sum of all the repair times for each component and each set}}{\text{sum of all the weighting factors}}$$

Or, expressed in mathematical terms:

$$t_r = \frac{\sum_{i=1}^{r}(1-P_i)R_i + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}(1-P_{jk})\right]\left[\sum_{k=1}^{t} R_{jk}\right]}{\sum_{i=1}^{r}(1-P_i) + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}(1-P_{jk})\right]} \qquad (6)$$

2.8 RELIABILITY

2.8.2 Methodology - continued

Availability of the System - continued

where

R_i = repair time for series component i (i = 1,2,...,r)

R_{jk} = repair time for parallel set j (j = 1,2,...,s) which is equal to the sum of the repair times of all the components (k) in that set (k = 1,2,...,t).

$1 - P_i$ = weighting factor for the repair time, R_i, of series component i = probability that series component i fails = 1 - probability that component i runs.

$\prod_{k=1}^{t} (1-P_{jk})$ weighting factor for the repair time of parallel set j = probability that parallel set j fails = probability that all the components in that set fail simultaneously = product of the probabilities that each component of the set fails.

Combining equations (4) and (6) gives the following equation which relates the average repair time t_r to the expected operating time t_o:

$$t_r = \frac{\sum_{i=1}^{r}\left(1-e^{-\lambda_i t_o}\right)R_i + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}\left(1-e^{-\lambda_{jk} t_o}\right)\right]\left[\sum_{k=1}^{t} R_{jk}\right]}{\sum_{i=1}^{r}\left(1-e^{-\lambda_i t_o}\right) + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}\left(1-e^{-\lambda_{jk} t_o}\right)\right]} \qquad (7)$$

The on-stream factor by definition is

$$F = \frac{\text{operating time}}{\text{total time}}$$

or

$$F = \frac{t_o}{t_o + t_r} \qquad (8)$$

2.8 RELIABILITY

2.8.2 Methodology - continued

Availability of the System - continued

Where t_o is any pre-selected continuous operating time, and t_r is the corresponding average repair time to correct a failure of the components in the system which caused the system to fail. The probability P_s of achieving this on-stream factor is equal to the probability of achieving t_o continuous on-stream hours (years), and this is given by equation (5). The graphical relationship betwen F and P_s is shown in Figure 2.8.2-1 for the system under study. This relationship is preliminary, since it is based on tentative assignments for λ_i and λ_{jk} (component failure rate parameters) which are extrapolations of limited experience in the chemical process industry, combined with published data (3)(4)(6)(7). Additionally, it is based on the RTBD design, and does not reflect system reliability improvements which may be achieved by design changes such as

- Additional redundancy.
- Manifolding of the three process lines at key points.

The evaluation of such changes should be made as a follow-up to this t_o study.

The production factor by definition is:

$$G = \frac{\text{total production during available time}}{\text{design (capacity) production during that available time}}$$

$$G = \frac{\text{design (capacity) production during } t_o + \text{ reduced production during } t_r}{\text{design (capacity) production during } t_o + t_r}$$

2.8 RELIABILITY

2.8.2 Methodology - con't

Figure 2.8.2-1
On-Stream Factor vs Probability

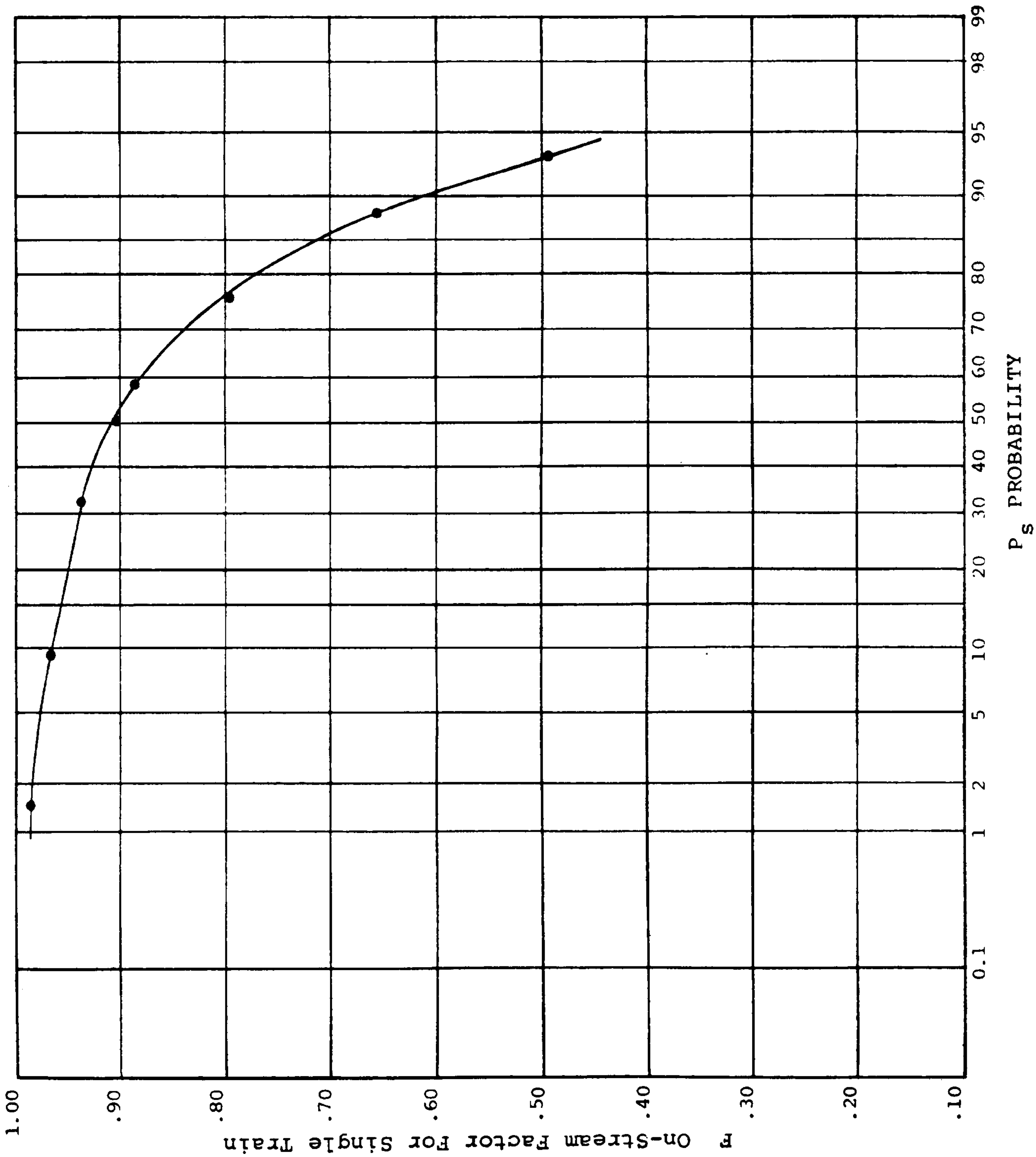


Table 2.8.2-1 (Sheet 1 of 4)

Estimated Failure Rate Frequencies

Area	Item No.	Description	T*	R**	i	j	k	S***	Basis of Estimate For		
									Prob.of Cont. Service	For Years	Code
103	41105 A,B	Venturi Cir. Pumps (Motor Drive)	0.14	50	83	12	1,2	0	50%	5	(3)
	31104	Venturi Cooler	Neglect	No effect	84			1.0	-	-	-
	45111,9	Venturi Scrubber	0.045	20	85			0	80%	5	(1)(2)
	35115,7	Venturi Scrubber Separators	0.002	20	86			0	90%	50	(1)(2)(3)
	34109	Decanter	0.002		89			1.0	90%	50	(1)(2)(3)
	36101	Oil-Fines Slurry Tank	0.002		90			1.0	90%	50	(1)(3)
	39101	Oil-Fines Agitator	0.022		91			1.0	80%	10	(1)(2)
	42103	Inert Transport Gas Compressor	0.074	50	92			0	80%	3	(1)(2)(3)
	42103	Turbine Drive	0.045	50	93			0	80%	5	(1)(2)(3)
	33105	Gasifier	0.022	175	94			0	80%	10	(1)(2)
	45105	Gasifier Cyclone Set	0.011	175	104 - 119			0	90%	10	(1)(2)
	45106		0.011	175	120 - 135			0	90%	10	(1)(2)
	33106	Combustor	0.07	150	140			0	50%	10	(1)(2)(3)
	33106	Cooling Coils	0.11	100	141			0	80%	2	(1)(2)(3)
	33106	Steam Drum	0.007	w/i -	141			0	80%	30	(1)(2)(3)
	44101 A,B	Circulating Water Pumps (1-spare)	0.14	70	141	16	1,2	0	50%	5	(1)(2)(3)
	34102		0.11	175	145			0	80%	2	(1)(2)
	35103	Combustor Lift Tube	0.07	75	147			0	50%	10	(1)(2)
	45107	FC-Cyclone Set	0.022	175	148 - 165			0	90%	5	(1)(2)
104	45001	Venturi Scrubber I	0.045	20	215			0	80%	5	(1)(2)
	35001	Quench Separator	0.002	20	216			0	90%	50	(1)(2)(3)
	41001 A,B	Scrubber I Pump Motor Drive (1 spare	0.14	40	-	27	1,2	0	50%	5	(1)(2)(3)
	45002	Venturi Scrubber II	0.045	20	217			0	80%	5	(1)(2)
	35003	Quench Separator II	0.002	20	218			0	90%	50	(1)(2)(3)
	41002 A,B	Scrubber II Pump Motor Drive (1 spr)	0.14	40	-	28	1,2	0	50%	5	(1)(2)(3)
	35009	Separator	0.002	20	221			0	90%	50	(1)(2)(3)
	45003	Venturi Scrubber III	0.045	20	222			0	80%	5	(1)(2)
	35005	Separator III	0.002	20	223			0	90%	50	(1)(2)(3)
	41003 A,B	Scrubber III Pump Motor Drive (1 Sp)	0.14	40	-	30	1,2	0	50%	5	(1)(2)(3)
	35002	Oil Decanter	0.011	20	224			0	80%	20	(1)(2)(3)
	31104	Product Gas Cooler	0.15	50		32	1,2,3	0/0.7	50%	5	(1)

Table 2.8.2-1 (Sheet 2 of 4)

Estimated Failure Rate Frequencies

Area	Item No.	Description	T*	R**	i	j	k	S***	Basis of Estimate For: Prob. of Cont. Service	For Years	Code
104	35108	Product Gas KO Drum	0.002	20	225			0	90%	50	(1)(2)(3)
	31105	Dehydrator Feed Preheater	0.15	50		33	1,2,3,4	0/0.8	50%	5	(1)(2)
	36101	Oil Dehydrator	0.011	25	230			0	80%	20	(1)
	39101	Oil Dehydrator Agitator Motor Drive	-	25	-			0	-	-	-
	41104 A,B	Dehydrator Recycle Pump Motor Drive (1-spare)	0.14	40	-	32	1,2	0	50%	5	(1)(2)(3)
	44102	Dehydrator Oil Condensor	Neglect	50	-			1.0	-	-	-
	35109	Dehydrator Oil KO Drum	Neglect	20	-			1.0	-	-	-
	41105 A,B	Oil Cond. Oil Pump Motor Drive (1-spare)	0.14	40	-	33	1,2	0	50%	5	(1)(2)(3)

Table 2.8.2-1 (Sheet 3 of 4)

Estimated Failure Rate Frequencies

Area	Item No.	Description	λ*	R**	Indices i	Indices j	Indices k	q***	Basis of Estimate For: Prob. of Cont. Ser.	Basis of Estimate For: Code
105	42202A,B,C,D	Product Gas Compressor	0.074	100	-	34	1,2,3,4	0/0.75	80%	(1)(2)(3)
		Intercooler	-	50	-	-	1,2,3,4	0/0.75	-	-
		Turbine Drive	0.045	60	-	-	1,2,3,4	0/0.75	80%	(1)(2)(3)
110	44101	FG Oxidizer	0.187	150	199	-	-	0	-	
	48101	Blowdown Unit	-	50	-	-	-	0	-	-
	45102	Tertiary Collector	0.007	150	201	-	-	0	90%	(1)(2)
	45103	Separator Cyclone								
	42102	Expander	0.35	24	-	17	1,2	0.5	50%	(4)
	42102	Air Compressor	0.074	16	-	18	1,2	0.5	80%	(3)
	42102	Turbine	0.045	16	-	19	1,2	0.5	80%	(3)
	42102	Generator	0.10	16	-	20	1,2	0.5	80%	(3)
	33101	Bypass Orifice Chamber (1-unit)	0.01	-	204	-	-	0	90%	(1)(2)
	44102	Waste Heat Recovery Unit								
	48104	Blowdown Unit	-	50	-	-	-	0	-	-
111	42202 A,B,C	Scrubber Blowers (1-Spare)	0.1	25	-	21	1,2	0/0.5	80%	(1)
	47201	Venturi Scrubber (2-units)	0.045	40	-	22	1,2	0/0.5	80%	(1)(2)
		Cyclone Separators (2-units)	0.045	40	-	22	1,2	0/0.5	80%	(1)(2)
		Cyclone Separators Demister	0.045	40	-	22	1,2	0/0.5	80%	(1)(2)
		Cyclone Separators Spray Nozzles 2 unit	0.045	40	-	22	1,2	0/0.5	80%	(1)(2)
		Cyclone Separators Water Pumps 1 spare	0.045	40	-	22	1,2	0/0.5	80%	(1)(2)
	34204	Scrubber Recirculating Tank	Neglect	No	213	-	-	1.0	-	-
	41203 A,B,C	Venturi Scrubber Pump Motor Drive (1-spare)	0.14	50	-	23	1,2,3	0	50%	(1)(2)(3)
	41204	Scrubber Bleed Pump Motor Drive	0.14	20	-	24	1,2	0	50%	(1)(2)(3)
	41201	SA Transfer Pump Motor Drive 1-spare	0.14	20	-	25	1,2	1.0	50%	(1)(2)(3)
	41202	SA Hydration Pump Motor Drive 1-unit	0.14	20	-	26	1,2	1.0	50%	(1)(2)(3)
	31201	FG Reheater	-	50	-	-	-	1.0	-	-
	31201	Gas Line to 31201	w/i -	214						
	31201	Gas Line from 31201	w/i -	214						
	48205	Stack	0.004	5000	214	-	-	0	80%	(1)

* Failure frequency parameter - failures per year
** Mean repair time - hours per failure
*** Production after failure - fraction of capacity

CODE:
(1) Econergy Associates Experience
(2) Engineering Consensus Opinion
(3) Published Information
(4) Extrapolated from published information
(5) Scaled down from information screw feeders.

Table 2.8.2-1 (Sheet 4 of 4)

Estimated Failure Rate Frequencies

Area	Item No.	Description	*	R**	Indices i	Indices j	Indices k	Indices β'***	Basis of Estimate For: Prob. of Cont. Ser.	Basis of Estimate For: For Years	Basis of Estimate For: Code
102	43110 A,B	Coal Silo Feeder	0.25	8	-	1	1,2	0	80%	1	(1)
	43105	Pulverized Coal Conveyor	0.05	4	1	-	-	0	80%	5	(1)
	43119	Pulverized Coal Elevating Conveyor	0.05	4	2	-	-	0	80%	5	(1)
	47102 A,B,C	Fuller-Kinyon Pump (1-Spare)	1.40	16	-	2	1,2,3	0/0.5	50%	0.5	(5)
	47102 A,B	On-Off Valve	0.011	8	-	3	1,2	0	90%	10	(1)
	47102 A,B	Diverter Valve	0.011	8	-	4	1,2	0	90%	10	(1)
	47102 A,B	Pressurizing Gas Compressor (1 spare)	0.035	24	-	5	1,2	0	90%	3	(3)
103	33101	1st Stage Pyrolyzer	0.005	100	3	-	-	0	80%	50	(2)
		Heater	0.032	100	4	-	-	0	80%	7	(1)
		Steam Supply	-	-	-	-	-	-	-	-	-
		Condensate Trap	-	-	-	-	-	-	-	-	-
	45101	Primary Cyclones Sets	0.007	100	5,6,7	-	-	0	90%	15	(1)
	33102	2nd Stage Pyrolyzer	0.005	100	13	-	-	0	80%	50	(1) (2)
	33103	3rd Stage Pyrolyzer	0.011	150	20	-	-	0	80%	20	(1) (2)
	33104	4th Stage Pyrolyzer	0.011	150	45	-	-	0	80%	20	-
	44101	Aux. Furnace Air Compressor	0.074	60	78	-	-	0.99	80%	3	(1) (3)
	44101	Turbine Drive (Condensing)	0.045	60	79	-	-	0.99	80%	5	(1) (3)
	44101	Auxiliary Furnace	0.110	100	80	-	-	0.80	80%	2	(1)
	44101	Oil Supply	-	-	-	-	-	0.80	-	-	-
	42101	Recycle Gas Compressor	0.074	60	81	-	-	0	80%	3	(1) (3)

2.8 RELIABILITY

2.8.2 Methodology - continued

Availability of the System - continued

$$G = \frac{(g_{CAP.})(t_o) + (g_{RED.})(t_R)}{(g_{CAP.})(t_o + t_R)}$$

$$G = \frac{t_o + \frac{g_{RED.}}{g_{CAP.}} t_R}{t_o + t_R} \qquad (9)$$

$$G = \frac{t_o + g' t_R}{t_o + t_R}$$

where:

g_{red} = mean expected reduced production rate due to a series component or a parallel set failure

g_{cap} = design or capacity production rate

g' = mean expected reduced production rate as a fraction of design (capacity) rate.

2.8 RELIABILITY

2.8.2 Methodology - continued

Availability of the System - continued

The mean expected reduced rate is estimated in the same way as t_r. That is, it is equal to

$$g' = \text{Average reduced rate} = \frac{\text{weighted sum of all the reduced rates for each component and for each set}}{\text{sum of all the weighting factors}}$$

Or, expressed in mathematical terms:

$$g' = \frac{\sum_{i=1}^{r}(1-P_i)\,g'_i + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}(1-P_{jk})\right] g'_{jk}}{\sum_{i=1}^{r}(1-P_i) + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}(1-P_{jk})\right]} \tag{10}$$

Combining this with equation (4), this can be expressed in terms of continuous operating time, t_o, as:

$$g' = \frac{\sum_{i=1}^{r}(1-e^{-\lambda_i t_o})\,g'_i + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}(1-e^{-\lambda_{jk} t_o})\,g'_{jk}\right]}{\sum_{i=1}^{r}(1-e^{-\lambda t_o}) + \sum_{j=1}^{s}\left[\prod_{k=1}^{t}(1-e^{-\lambda_{jk} t_o})\right]} \tag{11}$$

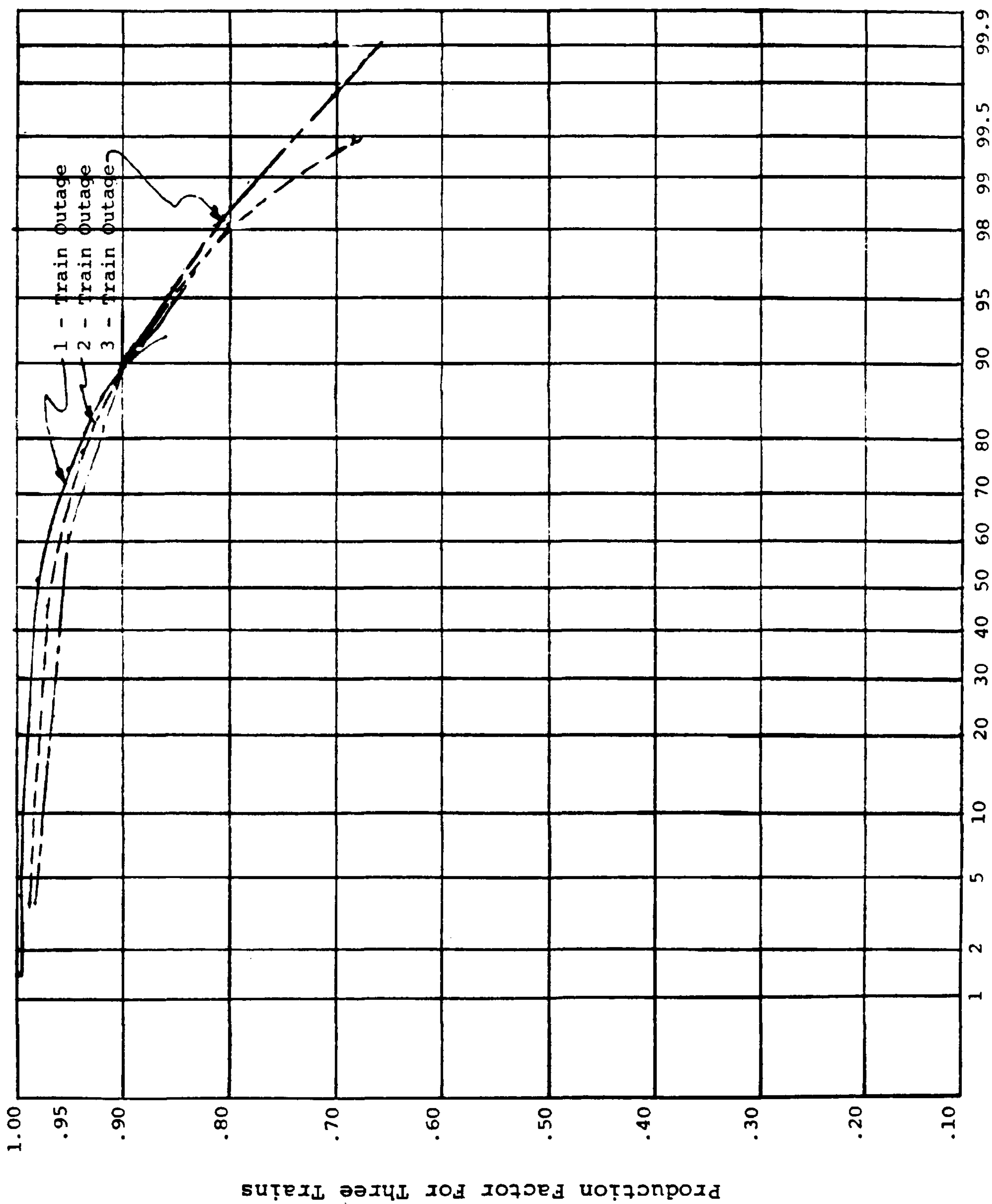
Substituting g' from equation (11), t_r from equation (7) and t_o as assigned into equation (9), gives the expected production factor. The probability of achieving this production factor is equal to the probability P_s of achieving t_o continuous on-stream hours (years), and is given by equation (5). The graphical relationship between G and P_s for the three train Commercial Plant is shown in Figure 2.8.2-2. This graph was developed using the data in Table 2.8.2-1 and the relationship derived above.

2.8 RELIABILITY

2.8.2 Methodology - con't

Figure 2.8.2-2

Production Factor vs Probability



2.8 RELIABILITY

2.8.2 Methodology - continued

Failure Rate Data

These data are not generally available for two basic reasons.

- Because of the large size of equipment involved, failure rate experience is usually limited to small samples, not statistically valid, or is non-existent because scheduled shutdowns for overhaul is imperative to avoid excessive economic costs because of unscheduled shut-down (because of failure), or
- Because much of the experience available has either not been analyzed by the firms who have that experience or is not available outside of the firms who have that experience and who have correlated the data.

There is, however, a limited amount of data which can be extrapolated to this study. These include published data for utility plants; electrical, hydraulic and mechanical equipment; and personal experience with similar process equipment (3)(4)(6)(7).

Assignments for the failure-rate parameters, λ_i and λ_{jk} (equations 5 et seq.), based on these sources are listed in Table 2.8.2-1 which presents the sequencing of all the non-null components of the system under study. This system includes:.

. Area 102 - starting with the coal silo feeders, plus

. Area 103 - all, plus

. Area 104 - except for hydrotreating, plus

. Area 105 - Product gas compressors plus

. Area 110 - all, plus

. Area 111 - all

Noted in Table 2.8.2-1, for each component in these areas, are the estimated turnaround (repair) times and estimated probability of achieving the stated uninterrupted operating time based on published data and/or extrapolations of process industry experience. From this estimated probability, the repective value of λ_i or λ_{jk} is calculated from equation (4). For example, if the industry

2.8 RELIABILITY

2.8.2 Methodology - continued

Failure Rate Data - continued

standard turnaround time is 3 years, as for gas turbines (under steady load) and it is assumed that this turnaround time will be achievable 80% of the time without an unscheduled shut-down for repairs, then one obtains from equation (4):

$$P(t_0) = 0.8 = e^{-\lambda(3\,\text{yrs.})}$$

λ = 0.074 failures per year.

Added refinements to the failure-rate data in Table 2.8.2-1 are desirable, but, presently, it is believed that these represent reasonable expectations.

Basic to all these component reliability data is the tacit assumption that human operating errors are minimal, and the system operates steadily, and is not shut down frequently.

Repair Time Data

Times to repair components are also shown in Table 2.8.2-1 for all components of the subject system. These repair time assignments were developed by discussions with chemical industry representatives as to the repair needs of each component in the event of failure, and by reference to some limited published data for large utility plants (6)(7).

Reduced Production Rate Data

These data are noted in Table 2.8.2-1 and are based on the process requirements for the system being considered. Failure of some of the components of the system will shut the system down. Failure of others will have a limited effect on the system production capacity. Only the λ_i's and λ_{jk}'s for components whose failure causes complete shutdown are considered in estimating the On-Stream Factor. All of the λ_i's and λ_{jk}'s are considered in estimating the Production Factor.

2.8 RELIABILITY

2.8.2 Methodology - continued

Suggestions for Design Modifications

Noted below are some areas where additional redundancy might be considered as a means for improving the reliability of the system. These will usually appear as a stand-by spare (located in parallel with the running unit) to enable picking up the load if the running unit fails.

1. Solids removal system from the Flue Gas Oxidizer (consider complete parallel spare)

2. Transport gas compressor - product gas (consider manifolding of three trains)

3. Product gas compressors - (consider manifolding of three trains)

4. Main air compressors - (consider manifolding of three trains)

5. Auxiliary furnace air compressors - (consider tie-in with main air compressor for stand-by back up)

2.8.3 Commercialization and Availability

In general, the design of the Commercial Plant is based on the use of commercially proven units. Of the 20 plant areas only Area 103, Pyrolysis and Gasification, Area 104, Oil Recovery and Treatment, Area 107, Shift and Methanation, and Area 110, Flue Gas Power Recovery contain elements which have not demonstrated their availability in identical applications in commercial installations. The extensive commercialization of processes and/or equipment used in the areas can best be illustrated by the following:

2.8 RELIABILITY

2.8.3 Commercialization and Availability - continued

Area 101 - Coal Unloading and Handling

The reliability of the equipment comprising the coal unloading and handling system has been demonstrated thoroughly by the extended histories of proven commercial operation. Power generating plants and coke oven plants have operated stacking and reclaiming systems for more than forty years with demonstrated capacities and capabilities comparable to the Conceptual Commercial Plant requirements. These items of mechanical equipment are all commercially available from multiple-source vendors.

Area 102 - Coal Preparation, Drying and Grinding

Large scale commercial coal drying, crushing and screening operations similar to the system specified for the Commercial Plant have been used extensively in the coal and coke industries. A conservative design approach has been taken in the specification of the system to ensure reliable operation. Convincing evidence of reliability is provided by the many years of satisfactory performance obtained from the equipment in the indicated service.

Area 103 - Pyrolysis and Gasification

The majority of the equipment items selected for use in this area are custom fabricated but their commercial analogs have proven reliability in refineries and other industries. In the case of the pyrolyzers, there are 12 years of semi-commercial experience by FMC in its Form Coke process. Similar commercial analogs have been employed for Flexicoking and Fluid Bed Coking. Continuous run times of 19 months (9) have been reported for the latter. Fluidized bed reactors were first used in the petroleum industry dating back to the early 1940's. Such reactors up to 60 feet in diameter are in use today as fluid catalytic crackers and have demonstrated availabilities in excess of 95 percent (10). Slagging cyclone combustors have had wide commercial use for the coal fired power plants. More than 80 such combustors, generally of the horizontal design, have been in operation in the United States. A vertical design is favored for the COGAS application, and these have been used in boilers in Europe with pulverized coal as fuel. Such units were built as large as 30 feet in diameter, well above the size needed for the Commercial Plant.

2.8 RELIABILITY

2.8.3 Commercialization and Availability - continued

Area 104 - Oil Recovery and Treatment

Three commercial H-Oil® Plants, which are analagous to the Oil Treatment Area, have been built. The two larger plants are still in operation while the smaller one is being maintained as a standby. One of the larger plants features two H-Oil® Reactors in parallel and has a design capacity of 14,500 bbl/day of 975°F residual oil at a 70 percent weight basis conversion of the crude input to product oil. The other large plant has a capacity of 18,500 bbl/day of residual feed. The oil treatment area is also similar to the hydrodesulfurization process, which is extensively used in commercial applications for treating high sulfur petroleum distillates and gas oils. Units in these services have reported availabilities of 90 percent for at lease 22 installations (11).

Area 105 - Gas Purification

Since 1964, the Sulfinol Process has been widely applied for removing sulfur compounds and carbon dioxide from gas streams. There are more than 120 Sulfinol units worldwide of which 90 are in the United States and Canada.

The ADIP Process has been available since 1959 for commercial applications in acid gas treatment. Worldwide there are more than 125 units in operation of which approximately 85 are for gas treating.

Components such as pumps are spared to ensure continuity of operation in case of maintenance requirements or component failure. No other system redundancy is provided because of the high historical on-line experience and the relative simplicity of the Sulfinol and ADIP Processes. Twelve units in gas desulfurization service have reported availabilities in excess of 99%.

Area 106 - Hydrogen Generation

The catalysts for the hydrogen generation process step have been used extensively in processes employing the CO shift reaction. United Catalysts' G-3A catalyst has been used in nearly 400 commercial installations while the C18HC catalyst for low temperature applications has been utilized in approximately 60 hydrogen and ammonia plants.

2.8 RELIABILITY

2.8.3 Commercialization and Availability - continued

Area 106 - Hydrogen Generation -continued

The Benfield Activated Hot Carbonate Process has been used for CO_2 removal from ammonia synthesis gas, crude hydrogen and other synthesis gases for over 20 years. At least 69 commercial hydrogen plants using this process have been built.

The first successful PSA hydrogen purification unit was started up in 1966. Since that time over 40 units have been contracted for by Union Carbide of which 8 have been on stream for over 5 years.

An availability review of hydrogen generation plants using shift conversion indicates that on-line times over 90% have been experienced by at least 6 plants. Equipment specified for the Commercial Plant is essentially the same as is used in other commercial facilties. Therefore, equivalent availabilities are anticipated.

Area 107 - Shift and Methanation

The RMProcess for the Shift and Methanation was derived from natural gas reforming technology which has been used commercially for ammonia production for over 20 years. As in reforming, a high temperature, thermally stable catalyst is provided in a fixed bed to accelerate the reaction. The only significant differences between the two applications are the amount of methanation performed and the quantity of steam added for control purposes. Thus the processing scheme and equipment required have been commercially proven many times over and the reliability of the equipment demonstrated by high on-stream factors. Only the performance of the catalyst is being extrapolated from pilot plant data.

Based on the extensive catalyst development program and their broad experience in methane reforming, R. M. Parsons is now offering the combined shift and methanation process commercially backed by performance guarantees.

Scale up of a catalytic fixed bed reaction system is direct and presents no design problem of any substance. Numerous commercial analogs have been designed using bench scale or pilot plant data, constructed and successfully operated, thus confirming the validity of scale up for systems of this type.

2.8 RELIABILITY

2.8.3 Commercialization and Availability - continued

Area 108 - Bulk CO_2 Removal and Gas Compression

The Benfield Process is commercially available and has been used for the same or similar service as that in which it will function in the Commercial Plant. At least 29 Benfield units are performing in natural gas service with feed compositions and pressure levels similar to those specified for the Commercial Plant. The historical high on-stream times and the simplicity of the Benfield Process provide basic assurance of the high reliability of the system.

Area 109 - Gas Dehydration

A triethylene glycol system is the most inexpensive and reliable way to dehydrate natural gas. These systems have been the industry standard for almost 30 years and are used extensively by the ICGG member companies. Historically, glycol dehydration plants have been in service since 1946 and today the number of units world-wide probably exceeds 10,000. The huge popularity of these units and the high on-stream times obtained demonstrates the reliability of the components comprising the system.

Area 110 - Flue Gas Power Recovery

The primary design basis for the Flue Gas Power Recovery Area exists in the system used for fluid catalytic cracking (FCC) power recovery in the petroleum industry. The configuration and functioning of the two systems are very similar. There are at least 12 such systems in commercial operation built by two American manufacturers, Ingersoll-Rand and Elliot. Additional systems are on order. These systems utilize single-stage expanders as large as 22,000 horsepower. Turbine blade life as long as five years is now being achieved.

The two factors most responsible for the success of FCC power recovery systems are the development of high efficiency tertiary separators and a specific expander design tolerant of the dust concentrations encountered. The first commercial scale tertiary separator successfully demonstrated was a proprietary design consisting of a large array of small axial cyclones. Two other vendors now offer competing designs using larger, conventional, tangential entry cyclones. These have also been proven in commercial use. The dust loadings produced by these tertiary separators represent the highest collection efficiency obtainable from inertial type separators.

2.8 RELIABILITY

2.8.3 Commercialization and Availability - continued

Area 110 - Flue Gas Power Recovery - continued

To enable the FCC expanders to withstand this comparatively high dust loading, the manufacturers took specific design measures. An axial entry is used to distribute the incoming dust uniformly throughout the gas passage. To accomodate the axial entry, the rotor (1 or 2 stage) is overhung on the end of the shaft. Aerodynamics are kept conservative, and the blades are made thick and rugged to withstand erosive wear.

Until recently, FCC systems operated at a low enough pressure that the expander vendors did not have to utilize a multi-stage turbine design. However, with continuing interest by refinery operators in higher pressure operation, two expander vendors have recently produced designs for two-stage expanders. These designs follow the single-stage precedent closely, utilizing two overhung rotors and the same axial entry, aerodynamics, and blade design principles. With the knowledge gained on erosive wear, study of particle trajectories, and evidence of particle size reduction in the first stage, blade life of a two-stage expander is projected to equal that of conventional single-stage machines. Such machines are being quoted to refinery customers.

The successful operation of a blast furnace-top pressure power generating plant using an expander turbine and generating 500 KW of electric power has been reported (12). The turbine described is a four-stage axial flow type which receives the gas containing dust at a design pressure and temperature of 19 psig and 500°C respectively.

Area 111 - SO_2 Removal

The FMC Double Alkali process is commercially available and has been used in services similar to that planned for the ICGG Commercial Plant. This process is being used extensively in Japan where two 450 MW units are now in operation. In the United States there has been considerable interest in this process for industrial power plant applications. Two utility boiler installations using the Double Alkali process are under construction, and one is in the planning stage. This system has been included in the reliability evaluation described in Subsection 2.8.2.

2.8 RELIABILITY

2.8.3 Commercialization and Availability - continued

Area 112 - Sulfur Recovery

Both Claus plants and sufuric acid plants have been available for many years in capacities comparable to the Commercial Plant. The process licensor for the Conceptual Commercial Plant has engineered more than 260 sulfur recovery plants for the extraction of elemental sulfur from sour, natural, refinery and other process waste gases. Reported availabilities for 8 units exceed 91%. Approximately 40 sulfuric acid plants have been engineered by the process licensor since 1966 and erected throughout the world.

Area 113 - Ammonia Recovery

The Phosam technology was originally developed to recover anhydrous ammonia from coke oven gas. The Phosam-$\overline{W}$ Process represents the same technology but applied to ammonia bearing sour waters. The first commercial Phosam plant began operation in 1968 and now there are seven commercial units in operation. In addition, there is one five-year successful operation for the recovery of ammonia from a sour water waste stream. At least one of the eight operating plants has demonstrated capacity greater than the Commercial Plant requirements. Operation of these plants has proven the performance and reliability of the installations.

Area 114 - Thermal Oxidizer and Flare

Area 115 - Utilities

Area 116 - Water Supply

Area 117 - Water Treatment Systems

Area 118 - Waste Treatment and Disposal

Area 119 - Fire Protection System

Area 120 - Facilities

These areas represent an application of existing commercial technology and will be composed of equipment, such as flares, compressors, demineralizers, boilers, pumps, filters, etc. of commercially proven operational reliability.

2.8 RELIABILITY

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