FE-2012-096
May 1980

MASTER

PIPELINE GAS DEMONSTRATION PLANT

Phase I

ABBREVIATED VERSION OF

PROCESS EVALUATION REPORT
CONCEPTUAL COMMERCIAL PLANT

SECTION 1
EXECUTIVE SUMMARY

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PROCESS EVALUATION REPORT

CONCEPTUAL COMMERCIAL PLANT

This Process Evaluation Report (PER) contains the results and recommendations of comprehensive analyses and studies which were made to optimize the ICGG Commercial Plant Baseline Process Concept for producing synthetic pipeline gas (SPG) from coal. Design studies to optimize the thermal efficiency and economic attractiveness of the COGAS Process Areas of the plant were conducted along with design studies and trade-off studies of available process subsystems to complement the COGAS Process Areas. The results, recommendations and description of the work accomplished in developing the PER are contained in six separately bound sections of the PER which are summarized as follows:

Section 1 - Executive Summary

This section provides an overview of the total PER and presents results, recommendations and conclusions in a brief format.

Section 2 - Process Analysis - Commercial Plant Concept

This section gives a brief description of plant size, configuration, feedstocks, operating conditions, products and by-products for the Commercial Plant Concept.

Section 3 - Process Design Studies

This section describes various design studies which were conducted to optimize the COGAS Process Areas and other plant areas.

Section 4 - Trade-off Studies

This section describes those trade-off studies which were made to select processes which would best complement the COGAS Process Areas and provide the most efficient and economical Commercial Plant Concept.

Section 5 - Baseline Process Concept

This section describes the ICGG Commercial Plant Baseline Process Concept which was developed from the Tentative Baseline Design (TBD) and was used as a standard for measuring the results of the Process Design Studies and Trade-off Studies.

Section 6 - Baseline Economic Evaluation

This section describes an economic evaluation which has been performed for the Commercial Plant Baseline Process Concept, described in Section 5.

THE ILLINOIS COAL GASIFICATION GROUP

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The original version of this report was published as FE-2012-027 in May 1978 and it contained proprietary information from various process licensors. In order to publish this as non-proprietary document, it was necessary to delete portion of this information. Much effort was devoted to provide all significant information in as complete and consistant a format as possible. Some of these deletions, however, will be apparent, particularly in the areas of Process Design Studies, Trade Off Studies, and Baseline Process Concepts.

1.0 EXECUTIVE SUMMARY

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1.1 SUMMARY

The Process Evaluation Report (PER) studies confirmed the technical and economic feasibility of the Commercial Plant concept, and significant improvements were identified for several areas of the plant. Total capital requirements were reduced by 14% relative to the baseline economics presented in Section 6.0. More importantly, a substantial increase in process thermal efficiency (62.4% to 68%) coupled with a change in byproduct outputs produced a 16.9% reduction in net operating cost. These combined savings (in end 1977 dollars) resulted in an 80¢/MM Btu decrease in the estimated gas selling price. Marketability studies indicate that a gas selling price of $3.79/MM Btu (as opposed to $4.59/MM Btu for the TBD), projected by using DOE guidelines, is at a level where synthetic pipeline gas (SPG) can be considered a viable alternate source of gas supply. The results, recommendations and description of the work accomplished in developing the PER follow:

1.1.1 Development of the PER

The first step in the development of the Commercial Plant Concept was the preparation of the Tentative Baseline Design (TBD), which was submitted to ERDA in August, 1977. The TBD included the following:

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

The TBD was expanded to the Baseline Process Concept, presented in Section 5.0 of this report, 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 this report.

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

1.1 SUMMARY

1.1.1 Development of the PER - continued

- 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 when appropriate

Process analysis studies were conducted on the commercial plant concept at three perfomance levels:

- Overall Plant
- Process Areas
- Area Subsystems

Process trade-off studies were conducted on an area basis in twelve of the twenty plant areas. In all, thirty-five alternative unit processes were considered. Similarly, seventeen process design studies were performed on subsystems in nine 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.

1.0 EXECUTIVE SUMMARY

1.1 SUMMARY

1.1.2 Results

The major economic impact of the process evaluation was a decrease in SPG cost (in end 1977 dollars) from $4.59 to $3.79/ MM Btu's. This resulted from increasing process thermal efficiency from 62.4% to 68% and decreasing total capital investment by approximately $200 million. Although some changes to tbe baseline concept were recommended in all plant areas five are most notable:

- Fuel oil and naphtha are now produced as plant by-products rather than syncrude.
- Light hydrocarbons are processed into SPG and not recovered as a separate by-product.
- Sulfur is processed into sulfuric acid by-product rather than elemental sulfur, however, the plant will still have the flexibility to produce either product as market conditions dictate.
- Sodium sulfate by-product was eliminated when a non-regenerable SO_2 removal process (Double Alkali) was selected.
- A mixed sludge of calcium sulfite and sulfate must now be disposed of in an on-site landfill.

These and other recommendations resulted in a 5.6% increase in SPG production coupled with a 14.4% decrease in feed coal requirements. Table 1.1-1 compares the feedstocks, products and by-products for the revised process baseline against the original baseline. Note that the SPG output in Btu's for the revised baseline (256.68 x 10^9 Btu/d) is approximately equal to the combined output of SPG and light hydrocarbons (244 x 10^9 Btu/d + 15.17 x 10^9 Btu/d) for the baseline. The SPG output increases from 256 to 271 MMSCFD while the heating value decreases slightly from 951 to 946 Btu/SCF.

1.0 EXECUTIVE SUMMARY

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1.1 SUMMARY

1.1.2 Results - continued

Table 1.1-1

Summary of Feedstocks and Product Yields for Baseline and Revised Baseline Designs

Feedstocks	Baseline (TBD)	Baseline Revised by PER
Illinois No. 6 Coal	28,733 TPD	25,111 TPD
Electricity	4,960 KW	4,960 KW
Water	16.28 MM GPD	16.28 MM GPD
Products		
Electricity	34,248 KW	30,688 KW
Sulfur	931 TPD	--
Ammonia	66.1 TPD	46.2 TPD
Sodium Sulfate	63.1 TPD	--
Light H.C.	697,704 lb/d (15.17×10^9 Btu/d)	--
H_2SO_4	--	2,382 TPD
SPG	256.64 MM SCFD (244.08×10^9 Btu/d)	271.2 MM SCFD (256.68×10^9 Btu/d)
Syncrude	7,314,984 lb/d (24,041 bbl/d)	--
Naphtha	--	888,960 lb/d (3,236 bbl/d)
Fuel Oil	--	5,685,000 lb/d (16,676 bbl/d)

1.0 EXECUTIVE SUMMARY

1.1 SUMMARY

1.1.2 Results - continued

Table 1.1-2 presents the composition, quantity and HHV for the SPG that will be produced by the Conceptual Commercial Plant as a result of the process evaluation.

The fuel oil meets the ASTM specifications for No. 4 fuel oil as described in regulation D369-76. The ASTM standards for fuel oil ar recognized as official commercial standards. Furthermore, the product fuel oil meets the 0.15 lb sulfur per million Btu standard set in Appendix A of the ICGG/DOE contract, and also meets the potential future NO_x emission standards for fuel oils in the United States. The naphtha by-product stream has a nitrogen concentration of < 0.1 wt %, a sulfur concentration of <0.01 wt % and an ^{o}API of 49.0.

Major waste streams exiting the facility are slag, water treatment and SO_2 Removal sludges, carbon dioxide and desulfurized flue gas. Aqueous wastes are treated and recycled thereby producing an essentially "zero liquid discharge" plant.

Following completion of the PER, a Revised Tentative Baseline Design (RTBD) will be developed for the Commercial Plant. The preparation of the RTBD will be based upon the results of the twelve trade-off studies and seventeen process design studies conducted for the PER.

Preliminary work which has been initiated on the RTBD indicates some changes from the PER recommendations will be required to achieve the most efficient integration of all process areas. These deviations will be described and documented in the RTBD Report. These changes are a result of differences in the material and energy balances between the Baseline Concept (TBD) and the RTBD. The process areas that will be affected are Gas Purification, Hydrogen Generation, Bulk CO_2 Removal, and Sulfur Recovery. The RTBD will include the recommended changes and will constitute the basis for the Conceptual Commercial Plant Design Report and thus will provide the basis for the Detailed Process Design-Demonstration Plant (Task II).

1.0 EXECUTIVE SUMMARY

1.1 SUMMARY

1.1.2 Results - continued

Table 1.1-2

Composition, Quantity, and HHV of SPG*

	% Volume
CO_2	0.279
CO	0.003
H_2	1.245
H_2O	0.015
CH_4	93.314
C_2H_4	0.0
C_2H_6	0.0
C_3H_6	0.0
C_3H_8	0.0
C_4H_{10}	0.0
Ar	0.037
N_2	5.107
	100.000

Total, lb/hr	493,235
Total, lb Moles/hr	29,773.2
Total, MM SCFD	271.17
Total, Btu/day	256.68×10^9
Average M. weight	16.566
HHV, dry, Btu/SCF	946.4
HHV, wet, Btu/SCF (7 lb H_2O/MMSCF)	946.3

*Based on recommended changes as a result of the process evaluation studies.

1.1 SUMMARY

1.1.3 Process Description

The ICGG Commercial Plant Concept resulting from the process evaluation is a self-contained, grass roots facility which will produce 271 million standard cubic feet per day (MMSCFD) of synthetic pipeline gas (SPG) from Illinois No. 6 seam coal. The plant is divided into twenty areas with several areas having multiple process trains. Table 1.1-3 lists the twenty Plant Areas and identifies the number of process trains in each area.

The resulting commercial plant concept is illustrated by the simplified block flow diagram in Figure 1.1-1. 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 three 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 four pyrolysis stages during which pyrolysis gas is formed. The resulting 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. Ungasifier 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.

1.0 EXECUTIVE SUMMARY

1.1 SUMMARY

1.1.3 Process Description - continued

Table 1.1-3

Number of Trains in Commercial Plant

Area Number	Area Name	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	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

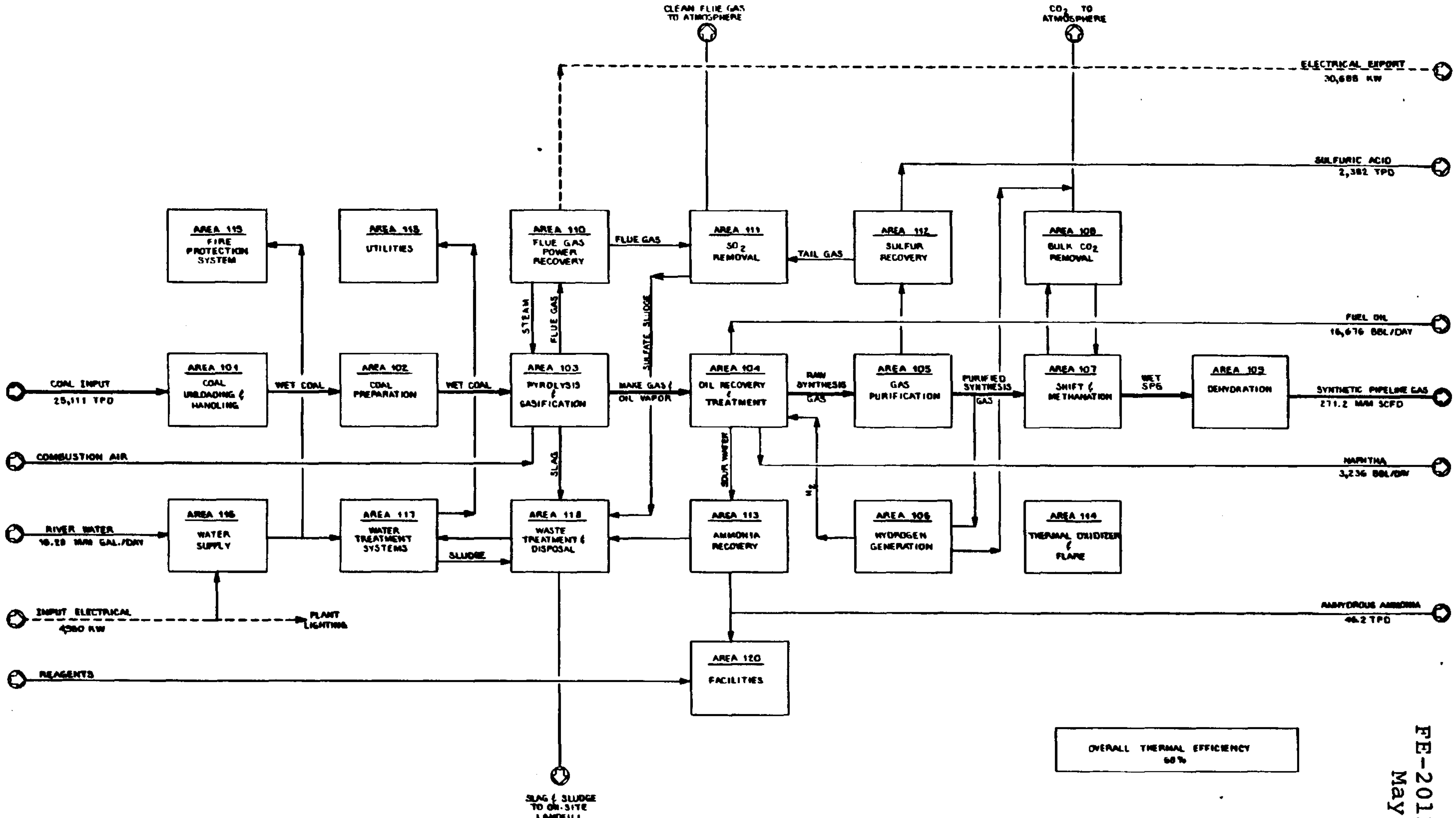

Figure 1.1-1

Revised Process Concept
ICGG Commercial Plant

1.0 EXECUTIVE SUMMARY

1.1 SUMMARY

1.1.3 Process Description - continued

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, then stored or sent to hydrotreating. Hydrotreated oil is further processed to yield a No. 4 fuel oil and naphtha and then sent to storage in Area 120.

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 using the Sulfinol Process and acid gas is 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 shift 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. It is then reheated and passed through a single-stage methanator to convert any residual carbon monoxide to methane. The hydrogen product is sent to make-up compressors in Area 104.

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 Parson's 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. After the CO_2 is removed, the gas is returned to Area 107, compressed and passed through a final stage of methanation to boost the heating value, reducing the carbon monxide level to 0.1%. The gas then leaves Area 107 and flows to Area 109, Gas Dehydration.

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1.1 SUMMARY

1.1.3 Process Description - continued

Area 108 Bulk CO_2 Removal

In this area, carbon dioxide is removed from the methanated gas by solvent scrubbing. The gas which has been scrubbed of CO_2 is returned to Area 107 for compression and final methanation. The solvent is regenerated in the Selexol regenerator for reuse in the absorber, while the carbon dioxide is vented to the atmosphere.

Area 109 Gas Dehydration

Gas from Area 107 is compressed to approximately 1070 psig and cooled to 100^{o}F. The gas, which is saturated with water at these conditions, 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 synthetic pipeline gas (SPG) 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, H_2, H_2S and char fines are burned to generate steam. Hot gas leaving the oxidizer is cooled, cleaned and expanded through expander turbines. These expander turbines are used to drive air compressors which supply the air to the oxidizer and to the combustor in Area 103. After additional heat is recovered, 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 102, Coal Preparation, 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 containing sulfur as either SO_2 or H_2S are processed to produce sulfuric acid. H_2S bearing gas streams are received from Area 105, Gas Purification and Area 113, Ammonia Recovery. The sulfuric acid is produced as a saleable by-product. Elemental sulfur can also be produced for sale.

1.1 SUMMARY

1.1.3 Process Description - continued

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 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, 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 raw oil storage. The gas 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
- Refrigeration System-Freon 12
- Inert Gas Generation
- Emergency Power Generation-Diesel Drive
- 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 and cationic polymer are injected. It is then pumped 20 miles to the plant site where it enters Area 117, Water Treatment Systems.

1.1 SUMMARY

1.1.3 Process Description - continued

Area 117 Water Treatment Systems

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

Area 118 Waste Treatment and Disposal

Aqueous waste streams from throughout the plant are treated in Area 118. Streams from plant separators, plant drains, knock out drums and oil recovery are fed to an API separator. Oil is returned to Area 104 while the water 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 makeup and the sludge is sent to landfill. Sour water from Area 113 is treated in a vapor-compression evaporator with the water being sent to Area 117 for treatment for use as boiler feed water. The solids and phenolics from the evaporator are sent to storage for final use as boiler fuel.

Area 119 Fire Protection

Water is received directly from the river water pumping station or from the water holding pond which holds a five day's 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 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, by-products and make up chemical reagents.

1.0 EXECUTIVE SUMMARY

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1.1 SUMMARY

1.1.4 Conclusions

Review of proven natural gas reserves coupled with future demand projections clearly indicate a deficit in the 1980's time frame and a need for supplements to existing domestic supplies. Possible alternate gas supply sources in the next five years together with estimated selling prices include:

Alternate Gas Sources	Estimated City Gate Prices End 1977 Dollars
Mexican Gas	3.25
Alaskan Gas	4.32
LNG Trunkline	3.57
LNG Tenneco	3.85

The range of alternative prices places the ICGG Commercial Plant SPG cost at a level where it can be considered a viable alternate source of supply.

The results of the process evaluation clearly indicate the technical and economic viability of a commercial plant based on the COGAS Process.

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

This section provides a description of the Baseline Conceptual Commercial Plant with regard to size, configuration feedstocks, catalysts, waste products, operating conditions, and quality and yield of product and by-products.

1.2.1 Plant Size and Degree of Modularization

The Commercial Plant consists of three parallel trains for the main processing areas (Areas 102, 103, 104, 105, 107, 108 and 110) and single trains for all other areas. For a plant of this magnitude, economic, technical feasibility, and operational flexibility factors favor the multiple train configuration. The design philosophy has been to select equipment capacities or sizes in the range of those commercially available.

As a result of this approach, Area 103 is divided into three parallel trains. The other major areas (Areas 102, 104, 105, 107, 108 and 110) are similarly divided into three trains for flexibility; convenience; and ease of logistics during normal operation, start-up and shutdown. Single trains are selected for the remaining process areas of the plant.

1.2.2 Coal Type, Size, Composition and Cost

The Conceptual Commercial Plant Design feed coal is Illinois #6 seam bituminous with a HHV of 12,400 Btu/lb. dry. Table 1.2-1 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 by-product yields.

The process concept is adaptable to a Western Subbituminous or a Pittsburgh #8 seam coal as the plant feed. Design modifications are required, however, in coal drying, pyrolysis, oil recovery and treatment, and in other by-product recovery areas such as light hydrocarbons, sulfur, ammonia and sodium sulfate. Table 1.2-1 summarizes the impact on yield and plant economics when Western Subbituminous coal or Pittsburgh #8 seam coal are processed.

All economic evaluations for the three coal feeds are based on a plant design as presented in Section 5.0 of this report. Cost impacts for processing Pittsburgh and Western Subbituminous coals were estimated from this baseline process concept.

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.2 Coal Type, Size, Composition and Cost - continued

Table 1.2-1
Summary
Effects of Varying Coal Feedstock

Type	**Illinois #6 Seam	Western Sub-bituminous	Pittsburgh #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	13.95	7.60
TOTAL	100.00	99.96	99.99
Moisture Content %	10.0%	25.5%	4.0%
Higher Heating Value (Btu/lb, dry)	12,400	10,307	13,850
Coal Feed, TPD*** as received	28,733	29,636	20,314
Coal Cost (End 1977 Dollars) $/Ton (as received)	22.50	8.55	21.05

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.2 Coal Type, Size, Composition and Cost - continued

Table 1.2-1
Summary
Effects of Varying Coal Feedstock - continued

	**Illinois #6 Seam	Western Sub-bituminous	Pittsburgh #8 Seam
Product/By-Product Yields (Per 1,000 TPD of coal)			
SPG, MM SCF/D	8.0	8.6	12.6
Syncrude, BBL/D	849	213	673
Light Hydrocarbon, BBL/D	159	114	148
Sulfur, TPD	32	8	30
Ammonia, TPD	2.3	0.5	2.2
Sodium Sulfate, TPD	2.2	0.5	2.2
Overall Thermal Efficiency %	62.4	58.6	61.7
Plant Investment* Cost, MM$ (End 1977)	1,450.5	1,365.2	1,317.8
Total Capital* Requirement MM$****	1,757.8	1,654.1	1,596.3
Annual Operating* Cost MM$/yr	157.02	114.2	134.94
Gas Cost* $/MM Btu	4.59	3.91	4.07

* End - 1977 dollars

** Baseline design coal

*** TPD of coal to product 256 MMSCF/D

****Includes interest during construction

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.3 Waste Product: Types, Amount and Treatment

A list of effluents discharged from the Commercial Plant Baseline Design (see Section 5.0) is tabulated in this subsection. Gases and vapors vented to the atmosphere are within the standards established by the State of Illinois Environmental Protection Agency and appropriate Federal agencies. Solid effluents will be disposed of in an on-site landfill operation. Aqueous wastes and other liquid effluents are treated and recycled within the plant complex to provide zero liquid discharge. This anticipated requirement of the State of Illinois is met by evaporation of concentrated waste streams in a multiple effect unit. Recovered water is returned to the process while dissolved solids are disposed of in a lined pond.

The remainder of this section summarizes the treatment and ultimate destination of the major plant effluents. Possible differences between the baseline concept and the Revised Tentative Baseline Design (RTBD) as a result of selected process evaluation studies are discussed.

1.2.4 Process Operating Conditions

The rationale for selection of the primary operating conditions are discussed together with those changes proposed for the Revised Tentative Baseline Design. Some of the operating conditions which were analyzed are as follows:

- Area 102: Coal Preparation

  Coal feed rate
  Coal temperature and moisture content
  Coal size consist
  Coal pressurization requirement

- Area 103: Pyrolysis and Gasification

  Pressure
  Pressure balance
  Temperature

- Area 104: Oil Recovery and Treatment

  Pressure
  Temperature
  Purity of recycle gas from hydrotreating
  Make-up hydrogen rate
  Liquid velocity for hydrotreating

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.4 Process Operating Conditions - continued

- Areas 105 through 109: Gas Processing

  Pressure
  Temperature

- Area 110: Flue Gas Power Recovery

  Flue gas oxidizer exit temperature
  Flue gas oxidizer exit gas oxygen content
  Expansion ratio for dusty gas expanders

- Areas 111 through 113: Other Processing Areas

  Pressure
  Temperature

- Areas 114 through 120: Utilities, Storage and Other Facilities

  These areas consist of utility systems and storage facilities. Since such systems are relatively standard for any major processing facility, a discussion of process operating conditions is not presented in this section. Details are available, however, in Section 5.0, Baseline Process Concept.

1.2.5 Catalyst Information

Summary

Catalysts are used to enhance reaction kinetics in four areas of the commercial plant baseline design. Table 1.2-2 summarizes the type of catalyst, estimated service life, reactivation mode and the ultimate means of disposal. Table 1.2-3 summarizes the catalyst selection as a result of process design studies included in Sections 3.0 and 4.0 of the PER. Comparison of Tables 1.2.2 and 1.2.3 shows that the types of catalysts in certain areas have been changed as a result of the trade-off studies as well as the expected service life for certain catalysts.

Table 1.2-2
Catalyst Information
Commercial Plant Baseline Design Concept

Plant Area	Catalyst	Initial Charge (cu.ft.)	Annual Usage (cu.ft.)	Service Life (yrs)	Reactivation	Ultimate Disposal
Area 104 Oil Recovery & Treatment						
Ebullated Bed Hydrotreating	American Cyanamid	150 cu. ft. including fixed bed catalyst	600 cu. ft. including fixed bed catalyst	0.25	None	Landfill disposal after hydrocarbon burn-off
Fixed Bed Hydrotreating	American Cyanamid			0.25	None included. Partial regeneration is possible by controlled burn-off of contaminates.	Landfill disposal or return to supplier for nickel content
Area 106 Hydrogen Generation						
Shift Conversion	Girdler G-3A	7700	1540	5	None	Landfill disposal
Trim Methanation	Girdler G-65	970	970	1	None	Landfill disposal or return to supplier for nickel content
Area 107 Shift & Methanation						
Combined Shift & Methanation	Parsons Ni-Base	37380	17820	2	None	Landfill disposal or return to supplier for nickel content
Area 112 Sulfur Recovery						
Claus Reaction	Activated Alumina	5642	1880	3	None included. Partial regeneration is possible by controlled burn-off of contaminates.	Landfill disposal

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.5 Catalyst Information

Table 1.2-3
Catalyst Information and Recommendations*

Plant Area	Catalyst	Service Life (yrs)
Area 104 Oil Recovery & Treatment		
Ebullating Bed Hydrotreating	American Cyanamid	0.8
Vapor Phase Fixed Bed Hydrotreating	American Cyanamid	1
Area 106 Hydrogen Generation		
Shift Conversion	Girdler G-3A	5
Low Temperature Shift	Catalysts & Chemicals C18HC	2
Trim Methanation	Girdler G-65	2
Area 107 Shift & Methanation		
Combined Shift & Methanation	Parsons Ni-base	2
Area 112 Sulfur Recovery		
Claus Reaction	Activated Alumina	3

*See Subsections 3.3, 4.3, 4.4 and 4.9 of this report.

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.6 Design Service Life

The design service life and the expected maintenance costs of process areas, equipment and other items are difficult to determine without experience in similar service. The design, construction and operation of the Demonstration Plant will provide the data that will permit a more accurate estimate of service life and maintenance costs for a Commercial Plant.

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 Berkeley under the sponsorship of the Department of Energy, Metal Properties Council, National Association of Corrosion Engineers and others. Specific examples of materials selection are given in Subsection 2.6.1, Materials and Equipment Selection.

The areas other than those listed above are similar to many refinery and/or chemical plant standard operations. The design service life and maintenance costs for these areas can be predicted with a fair degree of accuracy. The annual maintenance cost for the baseline design has been estimated for each area as a percentage of the total constructed cost. The maintenance cost for the total facility is approximately $46.4 million per year or 3.7% of the $1258.1 million base.* The maintenance cost for areas other than Areas 101, 102, 103 and 110 is approximately 2.54% of the total constructed cost, which compares favorably with the 2.25% experienced by the refinery industry.

* This base represents the total constructed cost of $1,263,959,000 less the insurance and procurement cost of $5,881,000, each of which is in end 1977 dollars.

1.0 EXECUTIVE SUMMARY

FE-2012-096
May 1980

1.2 PROCESS ANALYSIS: COMMERCIAL PLANT CONCEPT

1.2.7 Yield and Quality of Products and By-Products

The primary product of the Commercial Plant is synthetic pipeline gas (SPG). For the baseline design of the plant, the major (or energy-bearing) by-products are syncrude, electricity, and light hydrocarbons. The other by-products are elemental sulfur, anhydrous ammonia, and sodium sulfate.

Although the relative yields of the SPG and liquid hydrocarbons (syncrude, light hydrocarbons) can be altered somewhat by modifying the conditions of pyrolysis (see Sub-section 2.4); yields change significantly only when the type of feed coal is varied. For example, as described in Sub-section 2.2, the yields of syncrude from a facility designed to produce 256 MM SCFD of SPG are 24,401, 6,322, and 13,683 barrels per day for the Illinois No. 6, Western Subbituminous, and Pittsburgh No. 8 coals, respectively.

Similarly, the yield of by-products such as sulfur or ammonia is governed mainly by the sulfur and nitrogen contents of the feed coal. That is, for a given amount of sulfur entering the plant with the feed coal, some is in the flue gases leaving the plant (within EPA emmission standards) some is converted to sodium sulfate in the SO_2 Removal area, while the majority is recovered as the elemental sulfur by-product. The yield also depends on the relative efficiencies of the Sulfur Recovery and SO_2 Removal Areas (see Subsections 2.7.5 and 2.7.6).

As a result of the trade-off studies, a process configuration different from the baseline design is being recommended for the Commercial Plant. The new configuration will produce fuel oil and naphtha as the major by-products, and sulfuric acid (or sulfur) and anhydrous ammonia as the other by-products. The primary product, SPG, will remain essentially unchanged.

Subsections 2.7.1 through 2.7.6 describe the yield and quality of the product and by-products, and the impact of the process trade-off studies. The impact illustrates how the products are affected by the types of processes employed. Table 1.1.1 in this Executive Summary compares the process yields for the baseline and revised baseline designs.

1.3 PROCESS DESIGN STUDIES

Table 1.3-1 provides a summary of the process design studies including a description of the baseline concept, alternatives evaluated and recommendations.

Table 1.3-1

Summary of Process Design Studies
(Condensed from Section 3.0)

Area No.	Area Name	Area Subsystem	Baseline Concept	Alternatives Evaluated	Recommendations
102	Coal Preparation	Coal Dryer	Fluid Bed Drying to 7% moisture with flue gas from coal fired dryer furnace.	(1) No Drying (10% moisture in coal to pyrolysis) (2) Flash Drying to 3% moisture with flue gas from Area 110 (3) 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	(1) Fuller-Kinyon Pump (2) Lock Hopper Feeding System	Fuller-Kinyon Pump
103	Pyrolysis and Gasification	Auxiliary Furnace for pyrolysis steps 1 & 2	Direct Heating	(1) Direct Heating (2) Indirect Heating	Direct Heating
		Solids Transport	Use Quenched Pyrolysis Product Gas for Transport	(1) Use Quenched Pyrolysis Product Gas for Transport (2) Use Gasifier Gas for Transport	Use Quenched Pyrolysis Product Gas for Transport
		Mixing Section Vent	TBD-Design	(1) TBD Concept (2) Alternate Design	Alternate Design which conserves steam
		Slag Removal System	Slag Removal System with two parallel lock hoppers for the combustor.	None	Slag Removal System modified by eliminating two parallel lock hoppers for the combustor and introducing miscellaneous design improvements suggested by United Conveyor.
		Pittsburgh Coal Pyrolysis	--	(1) Oxidation (2) No oxidation with one additional stage	Oxidation with four stages
		Mixing Section	TBD Design	None	Lift tube diameter reduced, mechanical design improved.
		Char Cooling and Dump System	Included External Char Coolers	(1) Cool char in vessels (2) Include External Char Coolers	Cool char in vessels

Table 1.3-1

Summary of Process Design Studies
(Condensed from Section 3.0)

Area No.	Area Name	Area Subsystem	Baseline Concept	Alternatives Evaluated	Recommendations
104	Oil Recovery and Treatment	Third-Stage Venturi Scrubber in Oil Recovery	Venturi Scrubber	(1) Venturi Scrubber (2) Electrostatic Precipitator	Venturi Scrubber
		Oil-Solids Separation	Oil Filtration	(1) Vacuum Distillation (2) Oil Filtration	Vacuum Distillation
		Oil Treatment	Syncrude as the product	(1) Fuel Oil and Naphtha as Products (2) Syncrude as the Product	Fuel Oil and Naphtha as Products
		Ebullated Bed Reactor	TBD Concept	(1) TBD Concept (2) Reduced number of reactors	Reduced number of reactors
		Number of Trains Downstream of Ebullated Bed	Three Trains	(1) Single Train (2) Three Trains	Single Train
110	Flue Gas Power Recovery	Flue Gas Expander	Two Single-Stage Expanders	(1) One Two-Stage Expander (2) Two Single-Stage Expanders	One Two-Stage Expander
		Electric Generator	No Generator	Use Electric Generator to recover excess power from flue gas.	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.	(1) Combined Generator for Steam Turbine and Flue Gas Expander (2) Separate Generators for Steam Turbine and Flue Gas Expander	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.

Sheet 2 of 3

Table 1.3-1

Summary of Process Design Studies (Condensed from Section 3.0)

Area No.	Area Name	Area Subsystem	Baseline Concept	Alternatives Evaluated	Recommendations
114	Thermal Oxidizer and Flare	None	Thermal oxidizer provided for the purpose of disposing of dirty oil spills. Low heat content gas streams to the thermal oxidizer have not yet been identified. Flare sized to handle an emergency evacuation for one train of the plant.	None	Update design of thermal oxidizer and flare as better definition of input streams becomes available.
116	Water Supply	None	Mechanically cleaned bar screen for large debris removal. Mechanically cleaned travelling screen for removal of solids >1/8". Chlorine and cationic polymer injection systems. Systems of pumps to pump water through 20 mile pipeline to plant. Imported electric power; fuel oil for emergency power generation.	None	Install in-line strainer in the pipeline to minimize suspended solids delivery to plant site. Type of raw water intake to be determined from local user recommendations 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 demineralization for high pressure boiler make-up.	(1) Zeolite softening. Moving bed demineralizers for high pressure boiler water treatment, and fixed bed condensate polishing. (2) Excess lime-soda softening - recarbonation - filtration for potable and process water. Weak acid cation exchange for cooling tower and low pressure boiler water make-up. (3) Lime-soda softening as in baseline concept.	Zeolite softening. Moving bed demineralizer. Fixed bed condensate polishing system.
119	Fire Protection System	None	System incorporating water supply, pumping and hardware, distribution, detection, and foam extinguishing equipment.	None	Optimization of routing, sizing, and facility location is necessary once the plant layout is finalized.
120	Facilities	Oil Storage Tanks	Fixed roof tanks	(1) Floating roof tanks (2) Fixed roof tanks	Vapor pressure data at storage temperature and distillation curve data not available at time of report. Selection will be made when this information becomes available.

Sheet 3 of 3

1.4 TRADE-OFF STUDIES

Table 1.4-1 provides a summary of the trade-off studies including a description of the baseline concept, alternatives evaluated and recommendations.

Table 1.4-1

Summary of Area Trade-off Studies
(Condensed from Section 4.0)

Area No.	Area Name	Baseline Design	Alternatives Evaluated	Recommended Design
101	Coal Unloading and Handling	Stacker/Reclaimer	(1) Stacker/Reclaimer (2) Separate Stacker/Separate Reclaimer (3) Overhead Stacking Conveyor, Rotary Plow Tunnel Reclaim System	Stacker/Reclaimer
105	Gas Purification	Conceptual Selexol Process with Light Oil Wash	(1) Modified Selexol Process with Light Oil Wash (2) Benfield with ADIP Process and Light Oil Wash (3) Sulfinol with ADIP Process and Light Oil Wash (4) Rectisol and Benfield Processes	Modified Sulfinol Process: 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	(1) Alternate 2: Split Stream Feed, Four CO Shift Stages, CO_2 Removal (Benfield), and Single Stage Methanation (2) Alternate 1: Single Stream Feed, Two CO Shift Stages, CO_2 Removal (Benfield), and Single Stage Methanation	Alternate 2: Split Stream Feed, Four CO Shift Stages, CO_2 Removal (Benfield), and Single Stage Firm Methanation
107	Shift and Methanation	R. M. Parsons Co., Combined Shift & Methanation Process with Auxiliary Fuel Oil Firing	(1) R. M. Parsons Co., Modified Combined Shift & Methanation Process (2) Catalysts & Chemicals, Inc., Conventional Shift with Hot Gas Recycle Methanation Process (3) R. M. Parsons Co., Combined Shift & Methanation Process (4) Girdler Chemical, Inc., Conventional Shift with with Cold Gas Recycle Methanation Process	R. M. Parsons, Modified Combined Shift & Methanation Process: The recommended process is a further modified version to process the light hydrocarbons in the feed stream. Pipeline Gas Compressor was relocated from Area 109 to Area 107 and final methanation is performed at 1100 psig. Use of auxiliary fuel oil eliminated.
108	Bulk CO_2 Removal	Conceptual Selexol Process	(1) Selexol Process (2) Benfield Process (3) Sulfinol Process	Selexol Process
109	Gas Compression and Dehydration	Glycol Dehydration	(1) Glycol Dehydration (2) Molecular Sieves	Glycol Dehydration; pipeline gas compressor relocated to Area 107.
110	Flue Gas Power Recovery	Flue Gas Oxidiser, Tertiary Separator and Dusty Gas Expander	Water quench particulate removal, sulfur removal, catalytic oxidation and clean gas expander.	Flue Gas Oxidizer, Tertiary Separator and Dusty Gas Expander

Sheet 1 of 2

Table 1.4-1 - continued

Summary of Area Trade-Off Studies
(Condensed from Section 4.0)

Area No.	Area Name	Baseline Design	Alternatives Evaluated	Recommended Design
111	SO_2 Removal	Wellman - Lord	(1) Double Alkali (2) UOP - Copper Oxide (3) Wellman - Lord (4) Lime Scrubbing	Double Alkali
112	Sulfur Recovery	Claus Plant	(1) Davy Powergas Inc. Sulfuric Acid Plant (2) R. M. Parsons Co., Claus Plant	Davy Powergas Inc.: Claus Plant plus Sulfuric Acid Plant for production of either by-product.
113	Ammonia Recovery	USS Phosam-$\overline{W}$ Process	(1) USS Phosam-$\overline{W}$ Process (2) Chevron WWT Process	USS Phosam-$\overline{W}$ Process
115	Utilities - Turbine Drive Condensers	Shell & Tube Exchangers with Cooling Water	(1) Shell & Tube Exchangers with Cooling Water (2) Wet Surface Air Coolers (3) Dry Surface Air Coolers	Shell & Tube Exchangers with Cooling Water
	Utilities - Alternative Plant Fuels	Fuel Oil; Light Hydrocarbons Recovered as By-product	(1) Fuel Oil w/o Light Hydrocarbon Recovery (2) Light Hydrocarbons supplemented by Fuel Oil (3) Purchased Fuel Oil (4) Synthesis Gas (5) SPG (6) Coal	Fuel Oil w/o Light Hydrocarbon Recovery
118	Waste Treatment and Disposal	Biotreatment Only	(1) Vapor Compression Evaporation (Resource Conservation Co.) and Biotreatment (2) Resin Extraction (Rohm & Haas) and Biotreatment (3) Solvent Extraction (Chem Pro) and Biotreatment (4) Biotreatment Only	Vapor Compression Evaporation (Resource Conservation Co.) and Biotreatment

1.5 BASELINE PROCESS CONCEPT

The Baseline Process Concept for the ICGG Commercial Plant includes those unit process subsystems selected initially for the Tentative Baseline Design (TBD) before trade-off evaluations and process design studies were undertaken. The Baseline Process Concept in Section 5.0 together with the corresponding Baseline Economic Evaluation in Section 6.0 forms the technical and economic baseline against which process alternatives were evaluated.

The ICGG Commercial Plant, (Baseline Process) using the COGAS Process, is a self contained, grass roots facility designed to produce 256 million standard cubic feet per day (SCFD) of synthetic 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 to operate the river water pumping station and plant security lighting. By-products from the plant are in finished, marketable form and include a synthetic crude oil, a light hydrocarbon stream, anhydrous ammonia, sodium sulfate and flaked sulfur. Major waste streams exiting the facility are slag, water treatment sludges, carbon dioxide, and desulfurized flue gas. Aqueous wastes are evaporated and recycled internally, thus, facilitating essentially "zero discharge".

The Facility, as shown in Figure 1.5.1 is divided into twenty processing areas each containing one or more unit process systems. Area designations and the number of trains in each area are shown in Table 1.5.1.

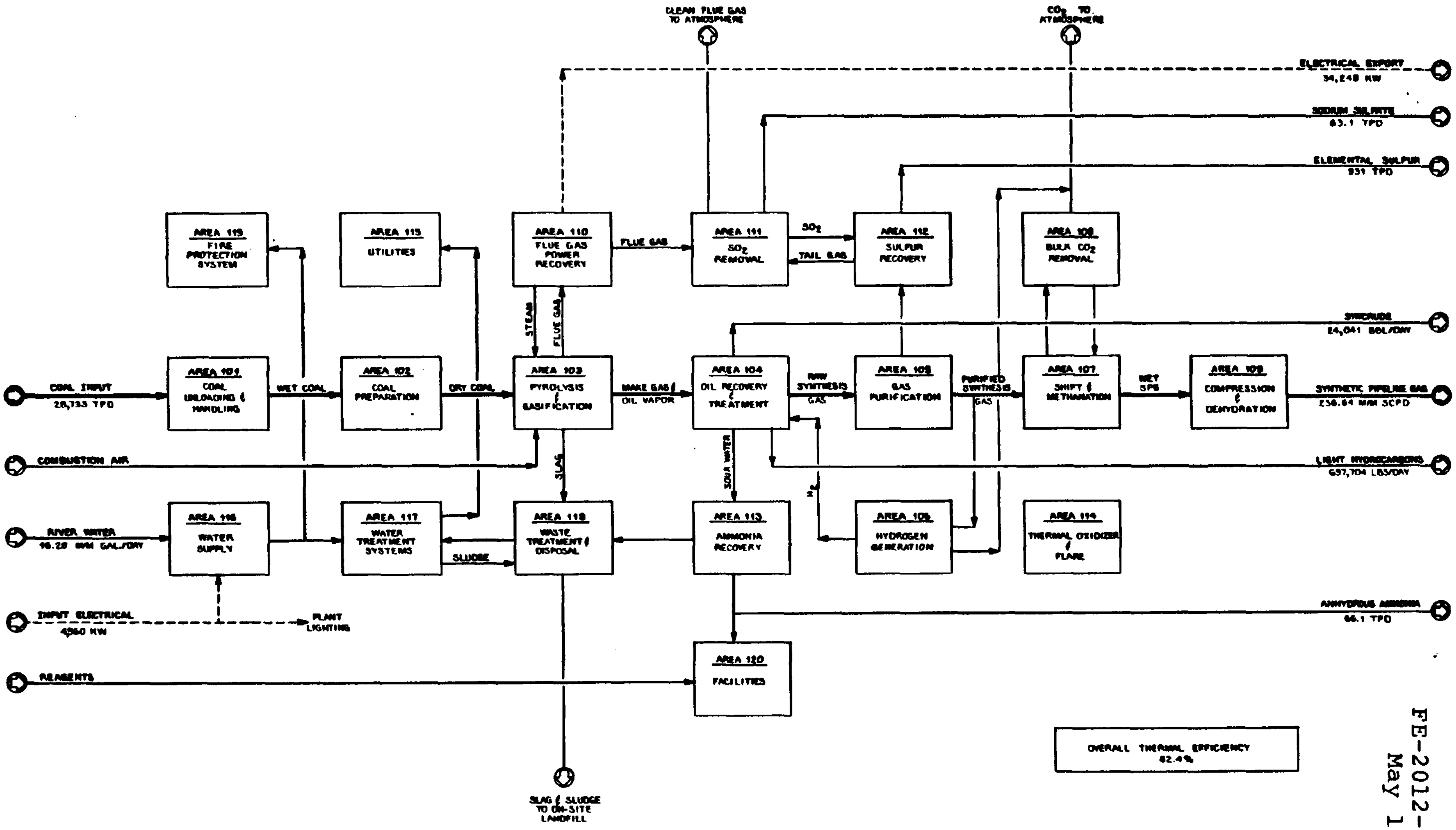

Figure 1.5-1

Baseline Process Concept
ICGG Commercial Plant

1.5 BASELINE PROCESS CONCEPT - continued

Table 1.5-1

Number of Trains in Commercial Plant

Area Number	Area Name	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	3
109	Gas Compression and 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 System	1
118	Waste Treatment and Disposal	1
119	Fire Protection System	1
120	Facilities	1

1.5 BASELINE PROCESS CONCEPT - continued

Due to 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 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 Section 5 follows.

Section 5 is subdivided into 9 subsections. Each subsection presents a detailed breakdown of the 20 plant areas selected initially for the TBD. Recommended changes in these subsections resulting from process studies and trade-off studies are summarized in Subsections 1.3 and 1.4 respectively.

Subsection 5.1 Facility Description

Provides detailed description of plant areas such as coal handling and preparation, pyrolysis and gasification, oil recovery and treatment, process treatment areas, utilities, etc.

Subsection 5.2 Design Basis

Presents design criteria requirements in detail for each area of the plant. For example, in Area 107 - Shift and Methanation, the process scheme, number of trains, feed streams, bulk methanation and final methanation are highlighted.

Subsection 5.3 Process Description

Provides detailed information on the process technique used in each area to accomplish the desired objective. For example, the process scheme for coal preparation consists of four basic functions in Area 102 as follows:

- Predrying
- Screening and crushing
- Storage
- Pressurizing

1.5 BASELINE PROCESS CONCEPT - continued

Subsection 5.4 Process Flow Diagrams

Provides breakdown of energy and material flows into and out of each process area.

Subsection 5.5 Utility Requirements

Describes utility requirements by plant area. The total plant electric power summary is as follows:

Total In-Plant Generation	213,308 KW
Process Power Usage	179,060
Excess Power for Export	34,248
Purchased Power	
• River Water Pumping Station	1,360
• Plant Lighting	3,600
Total Purchased Power	4,960 KW

Subsection 5.6 Energy Balance

Provides a detailed energy balance of each area.

Subsection 5.7 Reagent Summary

Lists the Chemical and Catalysts requirements by area in units, initial charge and annual usage.

Subsection 5.8 Equipment List

Provides an equipment list for the areas designated as proprietary and a detailed equipment listing for the remaining areas including number required, type, size, product to be handled, operating conditions (temperature and pressure) and materials of construction.

Subsection 5.9 Plot Plans and Layout Drawings

Includes site plot plan and seven (7) plot plans of specific plant areas.

Twenty two (22) layout drawings are included illustrating the plant layout.

1.6 BASELINE ECONOMIC EVALUATION

The economic impact of the process evaluation studies is summarized in Table 1.6-1. Plant investment costs and total capital requirements were reduced by $174.8 MM and $217.4 MM, respectively. Similarly, net annual operating costs decreased by $22.7 MM/year. The cumulative effect of these savings is a reduction in SPG cost from $4.59 to $3.79 per MM Btu.

Table 1.6-1

ICGG Conceptual Commercial Plant
Comparative Economics

Investment Requirements	Baseline Design	Recommended Design*
Plant Investment Cost, $MM	1,450.5	1,275.7
Total Capital Requirement, $MM	1,757.8	1,540.4
Operating Costs		
Gross Operating Cost, $MM/yr	302.6	271.8
By-product Credits, $MM/yr	(145.6)	(137.5)
Net Operating Cost, $MM/yr	157.0	134.3
SPG Cost, $/MM Btu	4.59	3.79

The basis for the estimates presented in Table 1.6-1 is:

- Year End 1977 Dollars
- 20-Year Commercial Plant Design Life
- 330-Day Operating Year
- $22.50/Ton Coal Cost

* Based on Process Evaluation Results.

1.6 BASELINE ECONOMIC EVALUATION - continued

Plant investment cost in Table 1.6-2 is the sum of costs for construction plans and drawings, site preparation, plant construction (including equipment and materials) and construction engineering. Total capital requirement include plant investment plus costs for land, plant start-up, administration, working capital and interest during construction.

Capital cost savings were obtained, primarily, by process changes in three plant areas:

- Area 104 - Oil Recovery and Treatment. Production of fuel oil and naphtha rather than syncrude reduced the number of processing trains and the number of high-pressure hydrotreaters.

- Area 105 - Gas Purification. Elimination of the light hydrocarbon recovery system and its associated storage facilities.

- Area 111 - SO_2 Removal. Selection of the Double Alkali Process and elimination of the sodium sulfate by-product.

The decrease in annual operating cost was a direct result of the increase in overall thermal efficiency (62.4% to 68%). Coal costs account for more than the 68% of the gross operating cost and 14.4% less coal is now required to produce 5.6% more gas. This was primarily the result of processing the light hydrocarbons into SPG instead of collecting them as a separate by-product and as a result of the reduced hydrogen requirement due to producing fuel oil and naphtha as compared to syncrude. The economic impact is reflected in the by-product credit shown in Table 1.6-1.

The SPG cost is the sum of net operating costs plus capital related charges. The prices reported in Table 1.6-1 were computed on a net present value analysis basis using the "revenue requirement" method. In accordance with contractual guidelines, estimates were based on a 9% discount rate and 20-year straight-line depreciation. This method determines the lowest gas selling price which will recover all costs incurred during the 25-year project life (5 years for plant construction and 20 years of operation).

1.6 BASELINE ECONOMIC EVALUATION - continued

Table 1.6-2

ICGG Commercial Plant Capital Requirements

Capital Requirement Category	Baseline Design, $M	Recommended* Design, $M
Construction Plans and Drawings	$ 91,391	$ 91,391
Site Preparation	10,000	10,000
Plant Construction	1,263,959	1,097,504
Construction Engineering	85,136	76,813
Subtotal Plant Investment Cost	$1,450,486	$1,275,708
Land	1,438	1,438
Start-up	34,704	24,481
Administration	3,500	3,500
Working Capital	60,474	52,966
Interest During Construction	207,238	182,299
Total Capital Requirement in End 1977 Dollars	$1,757,840	$1,540,392

* Based on Process Evaluation Results.

1.6 BASELINE ECONOMIC EVALUATION - continued

The SPG cost can be influenced by many variables. The ones with the greatest impact on the cost of gas as determined for the Baseline Concept are:

- Coal Cost
- Overall Thermal Efficiency
- Plant Stream-Time Efficiency (Percentage of time the plant is operating at design rate)
- Discount Rate
- Total Capital Requirement
- Syncrude Price

Sensitivity analyses were made to determine the response of the SPG cost to changes in these variables. The results of these analyses are briefly summarized in Table 1.6-3 to show the range of sensitivity considered for each variable and the corresponding change in SPG cost. Baseline values are included for quick comparison.

1.6 BASELINE ECONOMIC EVALUATION - continued

Table 1.6-3
ICGG Commercial Plant
Summary of Sensitivity Analyses

Variable	Baseline Value	Values Considered	Corresponding Range of SPG Cost* ($/MM Btu)
Coal Cost	$22.50/Ton	$15 to $35/Ton	3.71 to 6.07
Overall Thermal Efficiency	62.4%	50 to 75%	6.14 to 3.55
Plant Stream-Time Efficiency	330 Days/Year	256 to 361 Days/yr.	5.60 to 4.30
Discount Rate	9%	6 to 12%	3.92 to 5.41
Total Capital Requirement Less Interest during Construction	$1,551MM	$1,085 to $2,016MM (-30% to +30%)	3.80 to 5.39
Syncrude Price	$13.78/Bbl	$10.78 to $16.78/bbl	4.90 to 4.30

* Baseline Synthetic Pipeline Gas Cost = $4.59/MM Btu

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