**U.S. DEPARTMENT OF ENERGY
PITTSBURGH ENERGY TECHNOLOGY CENTER**

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**DIRECT COAL LIQUEFACTION
BASELINE DESIGN
AND
SYSTEM ANALYSIS**

CONTRACT NO. DEAC22 90PC89857

Received OSTI
JUL 24 1992

**QUARTERLY REPORT
JANUARY - MARCH, 1991**

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**APRIL, 1991
PITTSBURGH, PENNSYLVANIA**

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May 6, 1991

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Pittsburgh, PA 15236

Attention: Mr. Swenam Lee
Project Manager

Subject: D.O.E. Coal Liquefaction
Base Line Design and System Analysis
Contract No. DE-AC22 90PC89857
Bechtel Job No. 20952
Quarterly Status Report
Letter No. BLD-052

Dear Mr. Lee:

Attached for your information are three copies of the subject Quarterly Status Report covering the December 24, 1990 through March 17, 1991 reporting period. Copies to other members, as required by the contract are separately and directly transmitted.

Please note that all information contained herein should be considered preliminary pending issue of the final tasks reports.

This report does not contain any confidential information which, as agreed, would have been segregated in the appendix of this report.

If you have any questions or comments on this Quarterly Status Report please contact me.

Sincerely yours,

Sam N. Habash
Project Manager

Attachment

cc: Martin Byrnes, DOE/PETC
Robert Hamilton, DOE/PETC
A. B. Schachtschneider, AMOCO
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1. INTRODUCTION

Effective May 16, 1990, Bechtel with Amoco as subcontractor, initiated a study to develop a computer model for a base line direct coal liquefaction design for the U.S. Department of Energy's (DOE) Pittsburgh Energy Technology Center (PETC). The project is for a duration of 18 months with an approved budget of \$2 MM. This study is under DOE contract No. DE-AC22 90PC89857.

The primary objective of the study is to develop a computer model for a base line direct coal liquefaction design based on two stage direct coupled catalytic reactors. This primary objective is to be accomplished by completing the following:

- A base line design based on previous DOE/PETC results from Wilsonville pilot plant and other engineering evaluations
- A cost estimate and economic analysis
- A computer model incorporating the above two steps over a wide range of capacities and selected process alternatives
- A comprehensive training program for DOE/PETC Staff to understand and use the computer model
- A thorough documentation of all underlying assumptions for baseline economics, and
- A user manual and training material which will facilitate updating of the model in the future

The progress made during any particular quarter is published in a quarterly report following the end of the calendar quarter. The report consists of the following four sections:

- Introduction
- Summary
- Technical Progress Report (By Tasks)
- Key Personnel Staffing Report.

Introduction (Continued)

Any confidential information will be presented in the quarterly report as a separate section under the heading "confidential". As agreed by DOE/PETC, information included in the confidential section will be treated confidential by DOE/PETC and its contractors.

This report is Bechtel's third quarterly progress report and covers the period of December 24, 1990 through March 17, 1991 which is the reporting period covered by the three already published monthly status reports.

2. SUMMARY

Effective May 16, 1990, Bechtel initiated this study, with Amoco as subcontractor, as an assignment from the U.S. Department of Energy (DOE)'s Pittsburgh Energy Technology Center (PETC). The objective of the study is to develop a computer model for a baseline direct coal liquefaction design based on two stage direct coupled catalytic reactors. The study is for a period of 18 months with an approved total budget of \$2MM.

This is Bechtel's third quarterly progress report and covers the period (as requested and approved by DOE/PETC) of December 24, 1990 through March 17, 1991. This reporting period was previously covered by three already published monthly status reports.

The report contains accomplishments made during this time period in all the Tasks scheduled for the period i.e., Tasks I, II, IV and V. As per schedule, the major focus, however, was on Task II, IV and V. Therefore, the accomplishments included in this report are predominantly for these three tasks.

The accomplishments are presented in the report on Task by Task basis for all the Tasks covered during this reporting period.

In Task I (which defines the project) the Project Management Plan Draft Report was completed and subsequently updated incorporating the comments and suggestions of DOE/PETC and their contractors. The final version was sent to DOE/PETC for their approval and subsequently published in August, 1990. The approved copy was the deliverable for the Task.

Project Management Plan report covers the overall scope of work, the methodology of managing the cost and schedule of the project (configuration management), program administration, the deliverables during various phases of work and the definition of the baseline configuration.

In Task II the following activities were accomplished:

- Completed selection of coal gasification technology (Texaco vs Shell) and selected Texaco technology to include in this study.
- Updated simulations of coal liquefaction and hydrotreating.
- Developed water balance for the Coal Liquefaction Plant and the Hydrotreaters.

- Prepared process flow diagrams for licensed and open art units (Plants 2,3,4,5,6,8,9, 9-01 and 10).
- Completed simulations of the water wash and amine treating towers in the Gas Plant and Hydrogen Purification Unit.
- Obtained HRI report containing results of their work on certain sections of plant #2 (coal liquefaction reactor and primary separation of), per Bechtel's contract with HRI. The report is being reviewed by Bechtel/Amoco team.
- Developed feed stream summary and material balances for the Sulfur Plant.
- Completed sizing of equipment for the Naphtha and Gas Oil Hydrotreaters, and atmospheric and vacuum towers for coal liquefaction.
- Obtained information from UOP on the Membrane Permeation unit and the Pressure Swing Adsorption (PSA) unit for Hydrogen Purification (Plant 6)
- Completed sizing equipment for Coal Liquefaction Plant (Plant 2), Naphtha Hydrotreater (Plant 4) and Gas Oil Hydrotreater (Plant 5)
- Completed final pass of the simulation of coal liquefaction vacuum distillation tower, naphtha hydrotreater and gas oil hydrotreater.
- Completed final pass of the simulation of the fractionator of the gas oil hydrotreater.
- Completed simulation of the water wash tower for the hydrogen purification unit.
- Completed catalyst and chemical requirements for the Coal Liquefaction Plant (Plant 2), Naphtha Hydrotreater (plant 4), Gas Oil Hydrotreater (Plant 5), Hydrogen Production by Coal Gasification (Plant 9) and Critical Solvent Deashing Unit (Plant 8)
- Completed water and utility summary for Sulfur Plant (Plant 11), and water summary for Hydrogen Production by Coal Gasification (Plant 9), Gas Plant (Plant 3), and Hydrogen Purification (Plant 6)
- Completed Utility Summary for Critical Solvent Deashing Unit (Plant 8) and Air Separation Plant (Plant 10)
- Completed equipment summaries for Coal Liquefaction Plant (Plant 2), Naphtha Hydrotreater (Plant 4) and Gas Oil Hydrotreater (Plant 5)

- Completed onstream factor, operating manpower requirement and plot area for Coal Liquefaction Plant (Plant 2), Critical Solvent Deashing (Plant 8), Hydrogen Production by Coal Gasification (Plant 9), Air Separation Plant, (Plant 10) and Sulfur Recovery Plant (Plant 11)
- Obtained commitment from UOP to receive data pertinent to MEROX technology by end of March, 1991.
- Continued final simulation for the Gas Plant (Plant 3)
- Revised material balances for Ammonia and Dephenolization plants
- Initiated sizing equipment for Plant 20 (Raw Material Receiving, Storage and Product Tankage)
- Issued a modified version of Design Criteria.
- Developed preliminary equipment sizing for the Ammonia Unit.
- Incorporated comments from USX on the material balance for the Ammonia Unit.
- Revised the equipment sizes for the dephenolization process based on final feed composition from process plants section of the complex.
- Developed flow schematics for PHOSAM-W and Dephenolization Processes.
- Received quotes from Babcock and Wilcox, ABB Raymond and Fuller for grinding and drying of coal in Plant 1.4.
- Developed an overall utility balance, less electric, for Plants 2, 4 and 5.
- Completed preliminary draft report on environmental regulations.

In Task IV the following were accomplished:

- Algorithms for capital costs and multiple train requirements continue to be incorporated into the models as they are developed.

In Task V the following activities were accomplished:

- Fortran block models and report writers were developed for ROSE-SR Critical Solvent Deashing Unit Plant 8.1 and high pressure part of Hydrogen Purification Plant (Plant 6), called Plant 6.1 (Hydrogen Purification by Membrane Permeation). The low pressure part of Plant 6, which will be called Plant 6.2, (Hydrogen Recovery by Pressure Swing Adsorption) will be handled in a separate Fortran block model.

- Assembling of individual plant models into the total plant simulation model is continued. So far, Plant 1 (including the 2 alternate coal cleaning options), Plant 268 (the combined block model for Plants 2, 6.1 and 8), Plant 4 (the naphtha hydrotreater) and Plant 5 (the gas-oil hydrotreater) have been integrated into the total plant model.
- An improved elemental balanced yields model was developed for Plant 2, the coal liquefaction plant. This reactor yields model was developed based on the HRI report for the Plant 2 coal liquefaction reactors. This model was incorporated in the Plant 268 model. Two additional yields models were also developed, one to be used with the kinetic model, and the other with the alternate vent gas separation case.
- Fortran block models and report writers were developed for Plant 4, the naphtha hydrotreater, and Plant 5, the gas-oil hydrotreater.
- With completion of the hydrotreaters, preliminary models are available for each of the basic process units in the baseline design. Simultaneously assembling these plant models to develop the total plant simulation model has been started.
- Work on modeling of alternative process options was initiated during this reporting period. This involved modeling of the two coal cleaning options (spherical agglomeration and heavy media separation).
- Logic for Plant 31 (Utilities Plant) has been developed. This logic has been implemented in three Fortran subroutines in a stand-alone program. These subroutines will be the heart of the Fortran user block model for the utilities plant.
- Subcontract work on developing elemental balance capability and a cost model interface continues at Simulation Sciences. Basic programming on the capital cost portion has been completed. However, the report writer still needs to be developed and be interfaced with and attached to ASPEN/SP.
- Development of logic for the steady-state kinetic model for the two stage coal liquefaction reactor system is continued. A spreadsheet version of the model has been developed for predicting Wilsonville operations. This will be further tested and later incorporated into a Fortran sub-block for Plant 2. In the next phase, a commercial size predictive model will be developed.

In Task VI the following was accomplished:

- Facilities have been reserved for conducting ASPEN training beginning on October 28, 1991. The training will continue through November 1, 1991.

3. TECHNICAL PROGRESS (BY TASKS)

In order to carry out this Study efficiently, the Study has been divided in seven major tasks. Task I defines the project. Task II develops the baseline design. Task III develops the capital, operating and maintenance costs. Task IV develops the mathematical model necessary for the process computer simulation model. Task V develops and verifies the process simulation model. Task VI documents the process simulation model and training. Task VII is a level of effort task for project management, technical coordination and other miscellaneous support functions.

During this reporting period (December 24, 1990 through March 17, 1991) several accomplishments were made in Tasks II, IV and VI. These accomplishments are included in this report task by task.

Task I was completed during the first quarterly reporting period. The accomplishment of Task I was documented in the Project Management Plan published in August, 1990. It was also presented in the first quarterly report, covering the period of May 16, 1990 through August 19, 1990).

3.1 TASK I

Task I defines the scope and the methodology of accomplishing the project. It sets the objectives of the project and defines the paths to accomplish those objectives.

As mentioned earlier in Section 3, Task I was completed during the first quarterly reporting period and accomplishments were documented in the Project Management Plan issued in August, 1990.

The Project Management Plan report is comprised of the following 9 sections:

- Executive Summary
- Background/Introduction
- Study Objective
- Overall Scope Of Work
- Configurational Management
- Program Administration
- Deliverables
- Baseline Configuration
- Appendix/Project Procedure Booklet
List Of Contents

The report completing Task 1 was published on time schedule. Detailed accomplishments of Task I were included in the first quarterly report (May 16, 1990 through August 19, 1990) of the project.

3.2 TASK II

Task II concerns the development of the baseline design of the coal liquefaction facility. This part of the study includes the acquisition of process licensor information, incorporation of various processing options into the design, and developing the design of the on-site processing units and offsite facilities (including storage and loading, utilities, and waste handling).

In this task certain plants are handled as packaged plants (or blocks) with an overall heat and material balance only.

3.2.1 Status Update on Process Plants

During this reporting period, several process plants were updated. Status of such updating is included in this section of the report.

3.2.1.1 Coal Liquefaction (Plant 2)

The information package on the Catalytic Two-Stage Liquefaction (CTSL) process for this study was received from HRI. The report contains material balances, equipment sizing or costs, process descriptions, and process sketches for two cases: the baseline design case and the vent gas separation option. The information included is on the slurry and hydrogen heaters, the reaction system, the high pressure separators, and the recycle hydrogen compressor. Simulations of the slurry preparation system, primary separator system (both high and low pressure), and the product distillation system (both atmospheric and vacuum towers) were completed using Simulation Science's PROCESS software. Major equipment was sized for the plant and an equipment summary was developed. Simplified process flow drawings were prepared. A water balance, catalyst and chemical requirements, operating manpower requirements, and plot area were developed and summarized.

Design Basis

Coal Feed. The coal to be fed to the coal liquefaction plant is washed and dried Illinois No. 6 coal (Burning Star Mine) from Plant 1, the Coal Preparation Plant. Analysis of the basis coal is presented in Table 3.1.

Coal feed to Plant 2 is approximately:

<u>Basis</u>	<u>Per Train</u>	<u>Total</u>
MF basis	3,420 TPSD	17,102 TPSD
MAF basis	3,028 TPSD	15,140 TPSD

Moisture in the dried coal feed is 2.0 wt. %.

Process. The process used will be close-coupled, catalytic-catalytic, two-stage coal liquefaction (CTSL by HRI) with ashy recycle, recycle of extract from the critical solvent deashing plant, and recycle of 850°F+ to extinction.

The maximum size reactor will process a feed rate of 3,028 TPSD (MAF basis), producing approximately 13,031 BPSD of liquid products (C₅-850°F). Five trains of the maximum size operating at capacity will be required to reach the proposed production of approximately 60,000 BPSD.

Nominal Reaction Conditions. Nominal coal liquefaction conditions will be:

Reactor Inlet Pressure, psig	3200
Reactor Outlet Pressure, psig	3000
Hydrogen Partial Pressure, psia (outlet of Stage 2 reactor)	1950
Coal Feed, lb MAF/lb catalyst/hr	1.12
Solvent/Coal Ratio, (MAF wt. basis)	2.454
Solvent, wt. %	
Distillate (1000°F-)	38.0
Residuum (1000°F+)	49.9
Ash + Unconverted Coal	12.1
Slurry Tank Temperature, °F	400
Reaction Temperature, °F	
Stage 1	790
Stage 2	760

Table 3.1

**Analysis of Feed Coal to Liquefaction
Illinois No. 6 (Burning Star Mine)**

Proximate Analysis (wt. %, Dry Basis)

Volatile Matter	42.0
Fixed Carbon	46.5
Ash	11.5

Ultimate Analysis (wt. %, Dry Basis)

Carbon	70.0
Hydrogen	4.6
Sulfur	3.0
Nitrogen	1.4
Ash	11.5
Chlorine	0.1
Oxygen (by difference)	9.4

Sulfur Forms (wt. %, Dry Basis)

Pyrite	1.0
Sulfitic	0.1
Organic	1.9

Ash Composition (wt. % oxidized)

Phosphorus pentoxide, P_2O_5	0.2
Silica, SiO_2	49.8
Ferric Oxide, Fe_2O_3	17.6
Alumina, Al_2O_3	19.2
Titania, TiO_2	1.0
Lime, CaO	6.3
Magnesia, MgO	1.0
Sulfur Trioxide, SO_3	2.9
Potassium Oxide, K_2O	2.0
Sodium Oxide, Na_2O	0.5
Undetermined	-0.5

Note: The data above was taken from the RFP and adjusted for the difference in ash content (11.47%) as opposed to the RFP (10.5%).

Catalyst. Catalyst for the coal liquefaction process will be Amocat 1C in both stages. The catalyst has a bulk density of 35 lb/cf. Catalyst addition rates are specified to be 3.0 lb of catalyst per ton of MAF coal feed for the first stage reactor and 1.5 lb of catalyst per ton of MAF coal feed for the second stage reactor.

Hydrogen Makeup. Makeup hydrogen gas is available at the pressure required for the coal liquefaction plant at a temperature of 110°F. The composition of the makeup hydrogen is approximately 99.0% (vol.) hydrogen and 1.0% (vol.) methane.

Yields. Yields from the coal liquefaction plant are presented in Table 2 below:

Table 3-2

Coal Liquefaction Yields

Yields (Wt. % MAF Coal Feed)	First Stage Outlet	Overall
H ₂ S	2.00	2.86
H ₂ O	7.10	9.51
NH ₃	0.95	1.39
CO	0.04	0.06
CO ₂	0.09	0.14
C ₁	0.91	1.84
C ₂	0.74	1.43
C ₃	0.85	1.52
C ₄	0.40	0.79
C ₅ -350°F	8.00	16.12
350-450°F	4.90	7.51
450-650°F	6.76	25.11
650-850°F	15.20	21.36
850-1000°F	18.52	0.66
1000°F+	26.80	8.39
Unconverted Coal	10.20	7.21
Phenols	0.24	0.30
Ash	12.96	12.96
Hydrogen Consumption	3.70	6.20

Product Quality. The API gravity of the product cuts from the first stage and second stage reactors is given in Table 3 below:

Table 3-3

Product Quality

<u>Product Cuts</u>	<u>Gravity (°API)</u>	
	<u>First Stage</u>	<u>Overall</u>
C ₅ -350°F	44.5	45.5
350-450°F	24.5	25.0
450-650°F	13.5	14.0
650-850°F	5.0	6.0
850-1000°F	-1.6	-1.5
1000°F+	-11.5	-10.5

Process Description

Plant 2 consists of several sections. These are: Slurry Preparation, Liquefaction Reaction, Primary Separation and Product distillation. Figure 3-1 is the flow sheet for the first two section of the plant.

Slurry Preparation. Coal, which has been pulverized and dried in Plant 1.4, is mixed with recycled oil from downstream plants to form a slurry for feed to the coal liquefaction reactors. The recycle oil used as solvent for the process comes from four sources: slurry oil from the Slurry Hold Tank, the bottoms from the Atmospheric Distillation Tower, the lower sidestream product (850-1000°F) from the Vacuum Distillation Tower, and the extract product from the Critical Solvent Deashing Plant (ROSE-SM), Plant 8.

Slurry preparation consists of prewetting and mixing. The prewetting occurs in a twin screw mixer in which the 850-1000°F product, which has been cooled in air-fin exchanger (E102) to 180°F, is sprayed on the pulverized coal as it is being turned over in the mixer. This mixture is then fed into the Mix Tank (C101) where it is mixed with the solvent from the other three sources. Those oils are cooled in an exchanger producing 600 psig steam (E101) before entering the Mix Tank. The tank is mixed with a high-speed agitator. Coal slurry flows to the Slurry Surge Tank (C102) which also contains a mixer to keep the coal in the slurry. The Surge Tank is vented through a scrubber (C103), where the vapors are contacted with a portion of the solvent. The vapors from the scrubber are cooled in an air-fin exchanger (E103) to 130°F and separated into three phases in the Slurry Overhead Receiver (C104). The vapor from

that drum is sent as fuel to the Hydrogen Heater (F102). The hydrocarbon liquid is sent to the Atmospheric Tower. The sour water stream is withdrawn to the Sour Water Flash Drum (C116) and eventually to Plant 34.

Material from the Slurry Surge Tank is pumped by two Slurry Booster Pumps (G103) operating in parallel to the suction of three high pressure reciprocating Reactor Feed Pumps (G105) in parallel. About one-third of the flow from the Slurry Booster Pumps is recycled back to the Slurry Surge Tank to help eliminate dead spots in the tank where coal can settle out of the slurry. The Reactor Feed Pumps move the coal slurry through the Slurry Feed Heater (F101) to the reactors.

Liquefaction Reaction. As shown in Figure 3-1, the make-up hydrogen stream is combined with the internal recycle hydrogen stream from the Recycle Hydrogen Compressor (K101). The combined hydrogen stream is first preheated by exchange against the reactor effluent in exchangers E107 and E106. A portion of this hydrogen stream is injected into the coal slurry feed at the inlet to the Slurry Feed Heater (F101) in order to reduce the possibility of coke formation in the heater. Injection of hydrogen into the coal feed slurry also tends to reduce the viscosity of the slurry mixture and results in a lower pressure drop in the slurry feed heater coil. The hydrogen and coal slurry mixture is heated and then fed to the First Stage Reactor (C105). The remaining reactor hydrogen stream is fed to the First Stage Reactor after being heated in the Hydrogen Heater (F102).

The coal slurry-hydrogen mixture from the Slurry Feed Heater and the hydrogen stream from the Hydrogen Heater are introduced into the bottom of the First Stage Reactor. The reactor operates at approximately 790°F average reactor temperature and 3050 psig. The reactor operating temperature is controlled by adjusting the Slurry Feed heater outlet temperature to achieve the desired conversion level in the reactor.

Effluent from the First Stage Reactor is quenched with cold hydrogen from the recycle hydrogen compressor and introduced into the bottom of the Second Stage Reactor (C106). The interstage quench hydrogen flow rate is controlled to maintain the Second Stage Reactor in heat balance at 760°F average reactor temperature. The reactors incorporate the principle of the ebullated-bed operation. The entire mass in the reactor is held in a fluidized ebullated state by recirculating coal-oil slurry from the top of the reactor through the Ebullating Pump (G108 and G109) and back into the bottom of the reactor. The ebullated bed ensures the reactor's near isothermal operation under the extreme exothermic reactions involved. Since the coal particles are much finer than the extrudate catalyst, a separation can be made between these solids such that the coal and ash particles are entrained with the liquid-gaseous reactor effluent products, while the catalyst remains behind in suspension in the reactor.

Figure 3-1

Plant 2 Slurry Preparation / Reaction

Primary Separation. As shown on the flow sheet on the following page (Figure 3-2) the effluent from the top of the Second Stage Reactor is sent directly to the Hot High Pressure Separator (C107) at 760°F and 3000 psig. The overhead vapor, after being separated from the slurry, is cooled to 550°F in exchange with recycle and makeup hydrogen in exchanger E106 and enters the Warm High Pressure Separator (C110). The temperature of the separator is set high enough to prevent precipitation of ammonium salts. The overhead of the warm separator is cooled to 130°F in exchange with recycle and makeup hydrogen in exchanger E107 and in air-fin exchanger E109 before entering the Cold High Pressure Separator (C113). Wash water is injected ahead of the air-fin cooler for control of ammonium salt deposition as the vapor is cooled. The vapor from that separator is compressed in the Recycle Hydrogen Compressor (K101) and returned to the reactors as recycle hydrogen. A portion of the stream is purged from the system to the Hydrogen Purification Unit (Plant 6) to prevent the build-up of methane and other non-condensables in the system. The water phase is withdrawn to the Sour Water Flash Drum (C116) and eventually to Plant 34 for recovery of anhydrous ammonia.

The liquid from the Hot High Pressure Separator is flashed to 100 psig in the Hot Low Pressure Separator (C108). The vapor from the Hot Low Pressure Separator is cooled from 750°F to 450°F in exchange with the Warm Low Pressure Separator liquid (E104) and in an exchanger producing 150 psig steam (E105). The mixed vapor-liquid stream then enters the Warm Low Pressure Separator (C111) along with the liquid from the Warm High Pressure Separator. The temperature of the separator is set high enough to prevent precipitation of ammonium salts. The vapor from the Warm Low Pressure Separator is cooled to 130°F in an air-fin cooler (E110) and enters the Cold Low Pressure Separator (C114) along with the liquid from the Cold High Pressure Separator. Wash water is injected ahead of the air-fin cooler for control of ammonium salt deposition. The vapor from this separator is sent to the Hydrogen Purification Plant, the liquid is sent to the Product Distillation Feed Flash Drum (C117), and the water phase is sent to the Sour Water Flash Drum (C116). The liquid from the Warm Low Pressure Separator is heated by the feed to that vessel in exchanger E104 and sent to the Product Distillation Feed Flash Drum. The liquid from the Hot Low Pressure Separator is further flashed to 20 psig in the Recycle Slurry Hold Drum (C109). The vapor is cooled in air-fin exchanger E108 and sent to the Recycle Slurry Hold Drum Overhead Accumulator. The vapor from this drum is sent to Plant 6, the liquid is sent to the Product Distillation Surge Drum, and the water phase is sent to the Sour Water Flash Drum. Some of the liquid from the Recycle Slurry Hold Drum is pumped as recycle solvent back, using pump G110 to the coal slurry tank with the remainder being sent to the Product Distillation Surge Drum.

[illegible]

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Product Distillation. A schematic of the product distillation system is shown in the Figure 3-3. The liquid products from the three low pressure separators in the coal liquefaction plant are sent to the Product Distillation Feed Flash Drum (C117) from where the combined stream is pumped through the Atmospheric Feed Heater (F103) to the Atmospheric Distillation Tower (C118). Vapors from the surge drum are vented directly to the atmospheric tower. Two products are taken from the Atmospheric Tower Overhead Accumulator (C120): a naphtha product (IBP - 350°F) which is sent as feed to the Naphtha Hydrotreater; and a sour water stream which is sent to the Wash Water Surge Drum (C115) on the Coal Liquefaction Plant. An overhead vapor stream from the overhead accumulator is compressed by Compressor (K102) and sent to Plant 6. A sidestream product (350°F+) is withdrawn from a sidestream stripper (C119) and sent as feed to the Gas Oil Hydrotreater via cold (110°F) intermediate tankage. The bottoms stream off the atmospheric tower is pumped to two dispositions: as recycle solvent back to the Coal Slurry Tank with the remainder being sent to the Vacuum Feed Heater (F104) ahead of the Vacuum Distillation Tower (C122). Three products are taken overhead from the vacuum tower: a light gas oil product (450°F+) which is sent to the Gas Oil Hydrotreater via the same intermediate tankage as the atmospheric sidestream product; an overhead vapor stream which is compressed and sent to Plant 6; and a sour water stream which is sent to the wash water surge drum on the Coal Liquefaction Plant. An upper sidestream product (≈550°F - 850°F) is withdrawn and sent to the Gas Oil Hydrotreater via hot (400°F) intermediate tankage. A lower sidestream product (850°F - 1000°F) is withdrawn from a sidestream stripper (C123) and sent as recycle solvent back to the Coal Slurry Tank. The vacuum tower bottoms stream is sent to the solids-liquids separation unit, Plant 8.

3.2.1.2 - Gas Plant (Plant 3)

The process flow scheme for the Gas Plant was changed during this quarter. Originally, the flow scheme for the plant was to compress and treat miscellaneous offgas streams and charge them to the absorber-deethanizer tower for recovery of propane and heavier hydrocarbons. The overhead vapor stream off this tower would then be sent to a pressure swing absorption (PSA) unit in Plant 6 for recovery of hydrogen with the tail gas from the PSA unit being sent to the fuel gas system. Because the feed to the absorber-deethanizer was approximately 70% (mol) hydrogen, it was not possible to design the tower with an acceptable recovery of propane. Therefore, the flow scheme was changed to send all the offgas streams to Plant 6 for compression, treating, and processing through the PSA unit first and then send the PSA tail gas to the absorber-deethanizer. This process allowed design of the tower for a high recovery (>90%) of propane. The updated flow scheme is shown in Figure 3-4.

The simulation of the Gas Plant and sizing of the major equipment was completed. The equipment summary and the utility summary were developed. The unit has been developed as a two-train plant for reliability purposes.

A vertical strip of 15 small, square images showing various patterns and textures, likely representing different types of paper or fabric. The patterns range from solid colors to complex, abstract designs.

Figure 3-4

Process Description

The Gas Plant is charged with tail gas stream from the Hydrogen Purification Plant PSA unit in Plant 6. The feed to the PSA unit is a mixture of offgases from various plants within the coal liquefaction complex, including coal liquefaction, naphtha hydrotreating, and gas oil hydrotreating. The gases are compressed and treated in a water wash tower and an amine absorber tower prior to entering the PSA unit.

The tail gas is then sent to Plant 3 and charged to a combined lean oil absorber/deethanizer tower to recover the liquids (propane and heavier hydrocarbons) in the stream. The tower is operated at 160 psig. Cool lean oil is mixed with the absorber overhead gas before entering the overhead cooler and the precontactor drum for separation of the lean oil and the absorber overhead vapor. This precontacting step improves the recovery of light hydrocarbons by providing a separation at the lowest possible temperature. The liquid from the precontactor is fed to the top tray of the tower and the vapor is sent to the fuel gas system. The tower has a reboiler to strip the ethane and lighter components from the rich oil exiting the bottom of the tower. An intercooler (essentially a pumparound circuit) is included on the tower just below the gas feed tray to improve the efficiency of the absorption process. Hydrotreated naphtha product is the lean oil.

Rich oil from the absorber/deethanizer tower is sent the lean oil stripper tower to remove the light hydrocarbons (propane and butanes) from the lean oil. Lean oil from the tower is returned to the absorber/deethanizer via heat exchange with the rich oil feed to the stripper and cooling in an air-fin exchanger. A purge of the lean oil is included to remove pentanes and heavier hydrocarbons, which are recovered from the gas streams, from the system. This purge stream is sent to the Naphtha Hydrotreater feed tank.

The overhead product from the stripper is fed to a depropanizer to separate the feed into two LPG products (propane and mixed butanes). The two products are sent to individual MEROX units for the removal of trace sulfur compounds prior to going to product storage.

3.2.1.3 - Naphtha Hydrotreater (Plant 4)

The simulation for the Naphtha Hydrotreater was completed and the major equipment was designed. An equipment summary and simplified process flow diagram were developed. The utility summary, water summary, catalyst and chemical requirements were also developed. The unit has been developed as a two-train plant for reliability purposes.

Process Description

Reaction and Separation Section. Feed is pumped from intermediate tankage directly to heat exchange with the reactor effluent. Hydrogen is then mixed with the heated feed prior to entering the reactor preheater, where the mixture is raised to the reactor inlet temperature. The feed/hydrogen mixture enters the fixed bed reactor, which operates at a pressure of 1000 psig. The reactor effluent passes through heat exchange with the cold feed, through an air-fin cooler, and to the high pressure separator. Wash water is injected into the reactor effluent line prior to the air-fin cooler for control of ammonium salts. Hydrogen rich vapor is compressed and returned to the front end of the unit to mix with makeup hydrogen and the unit feed. A purge gas stream is sent to the Gas Plant to remove light hydrocarbons from the system. Sour water is removed from the high pressure separator to be eventually sent for ammonia recovery. The hydrocarbon liquid is flashed to 185 psig to remove light hydrocarbons, which are sent to the Gas Plant. The low pressure separator liquid is then sent to product distillation.

Product Distillation. The low pressure separator liquid is preheated with the product from the fractionator before entering the tower. The overhead vapor from the tower is partially condensed and only a vapor product is withdrawn for further processing at the Gas Plant. The fractionator has a fired heater for a reboiler. The bottoms naphtha product is cooled and sent to product storage.

3.2.1.4 - Gas Oil Hydrotreater (Plant 5)

The simulation for the Gas Oil Hydrotreater was completed and the major equipment was designed. An equipment summary and simplified process flow diagram were developed. The utility summary, water summary, and catalyst and chemical requirements were also developed. The unit has been developed as a two-train plant for reliability purposes.

Process Description

Reaction and Separation Section. Cold feed is pumped from intermediate tankage through heat exchange with the sidestream product of the atmospheric tower of the Coal Liquefaction Plant. Hot feed is pumped from intermediate tankage directly to the Gas Oil Hydrotreater and is mixed with the preheated cold feed. The mixed feed is pumped up to reactor pressure in a booster pump driven by an hydraulic expander turbine. The mixed feed is sent through heat exchange with the reactor effluent. Recycle and makeup hydrogen are mixed and heated first in heat exchange with the reactor effluent and then in a fired heater. The hydrogen is then mixed with the heated feed prior to entering the fixed bed reactors, which operate at a pressure of 2600 psig. The reactor effluent passes through sequential heat exchange with the cold feed, hydrogen gas, and the hot low pressure separator liquid before being sent to the hot

high pressure separator. The vapor from the hot high pressure separator is cooled in an air-fin exchanger and is sent to the cold high pressure separator. Wash water is injected into the reactor effluent line prior to the air-fin cooler for control of ammonium salts. Hydrogen rich vapor from the cold high pressure separator is compressed and returned to the front end of the unit to mix with makeup hydrogen. A purge hydrogen stream is sent to Plant 6 to remove light hydrocarbons from the system. Sour water is removed from the cold high pressure separator to be eventually sent for ammonia recovery. The hydrocarbon liquid is sent to the hot low pressure separator. The liquid from the hot high pressure separator is sent to an hydraulic expander turbine driving the feed booster pump before going to the hot low pressure separator. The hot low pressure separator liquid passes through heat exchange with the reactor effluent and is then sent to product distillation. The hot low pressure separator vapor is cooled in an air-fin exchanger and sent to the cold low pressure separator. The vapor from this separator is sent to Plant 6, and the liquid is sent to product distillation. Sour water is removed from the cold low pressure separator to be eventually sent for ammonia recovery.

Product Distillation. Liquid from the hot low pressure separator is flashed to remove light hydrocarbon gases which are sent to Plant 6. The liquid is preheated in exchange with the product fractionator bottoms and charged as the lower feed to the fractionator. Liquid from the cold low pressure separator is the upper feed to the fractionator. The overhead of the tower has three products: an overhead vapor stream which is sent to Plant 6; an unstabilized liquid product; and a water stream which is recycled to the wash water system. The overhead liquid is sent to an outboard stabilizer for correcting the initial boiling point of the 350-450°F product. The overhead of the stabilizer has a vapor product which is sent to Plant 6 and a liquid product which is sent to the Naphtha Hydrotreater product distillation section. The stabilized 350-450°F product is sent to final storage. The sidestream off the main fractionator is steam-stripped to correct the initial boiling point, cooled, and sent to finished product storage (450-650°F). The bottoms product is sent to heat exchange with the lower feed to the fractionator, cooled, and sent to finished product storage (650-850°F).

3.2.1.5. - Hydrogen Purification (Plant 6)

As mentioned in the status of Plant 3 (Gas Plant), the process flow scheme for the Hydrogen Purification Plant has been changed. The flow scheme for the recovery of hydrogen from the high pressure purge gas streams is basically unchanged. The only modification is the reduction in feed pressure to the membrane unit from full system pressure of approximately 2900 psig to a maximum of 1500 psig. This change was a result of the process information received from UOP on the membrane unit. The flow scheme for the recovery of hydrogen from the low pressure offgas streams is changed to include the compression of the low pressure gases, the water wash tower to recover ammonia, and the amine tower to remove acid gases for feed to Plant 11.

The treated gas stream is then fed to the PSA unit with the resulting tail gas being sent to Plant 3 for light hydrocarbons recovery. The updated flow scheme is shown in Figures 3-5 and 3-6.

Information on the membrane and PSA units were received from UOP. The simulations for low pressure gas compressor, the water wash towers, and the amine treater towers in the Hydrogen Purification Plant was completed and the major equipment was designed. An equipment summary was developed. The utility summary, water summary, and catalyst and chemical requirements were also developed. The unit has been developed as a two-train plant for reliability purposes.

Process Description

The Hydrogen Purification Plant has two sections: (1) recovery of purified hydrogen from high pressure purge gas streams in membrane separation units, and (2) recovery of purified hydrogen from low pressure offgas streams in pressure swing absorption (PSA) units. The flow scheme is shown in the attached Figure 3-5 and 3-6.

High Pressure Purge Gas by Membrane (Plant 6.1)

Purge Gas Scrubbing. The portion of the cold high pressure separator vapor which is purged from the Coal Liquefaction Plants is sent to Plant 6. The sour gases are sent first to a water wash tower to remove ammonia. Because of the small amount of ammonia in the wash water, this water stream is recycled back to Plant 2 for use as wash water ahead of the air-fin coolers in the coal liquefaction separation train. The gas stream exiting the water wash tower is sent to the amine treater for the removal of carbon dioxide and hydrogen sulfide. The rich amine is sent to a common amine regeneration system located in the low pressure recovery section of the plant. The capacity for the water wash and amine treater towers are provided in two parallel trains for reliability.

Membrane Separation Unit. The scrubbed high pressure purge gas is sent to membrane separation units for hydrogen recovery. This process was selected because the pressure of the hydrogen and nonpermeate products is much higher than for a pressure swing absorber, thus saving recompression costs (both capital and operating). The hydrogen product at 99.0% (mol) purity will be compressed and combined with the makeup hydrogen from Plant 9. The purified hydrogen streams from the PSA unit and the membrane unit are combined and compressed in the second stage hydrogen compressor, driven by an electric motor. The discharge of the second stage compressor is cooled in an air-fin exchanger. A third stage of compression is required to achieve the makeup hydrogen system pressure of 3500 psig. The discharge stream is cooled in an air-fin exchanger before exiting the plant to the makeup hydrogen system. The nonpermeate product is sent to the PSA units for recovery of residual hydrogen.

Figure 3-5

Plant 6.1 High Pressure H₂ Recovery

Low Pressure Offgas by PSA (Plant 6.2)

Low Pressure Gas Compression. Miscellaneous gas streams are recovered from Coal Liquefaction (Plant 2), the Naphtha Hydrotreater (Plant 4), and the Gas Oil Hydrotreater (Plant 5). The low pressure gases (less than 180 psig) are sent to the Low Pressure Gas Compressor. The compressor will have a suction pressure of 5 psig and an intermediate suction of 40 psig. The compressor discharge will be at 250 psig. All of the gas streams will be at approximately 100°F and thus will not require cooling before entering the suction knockout drum. Any liquid recovered should be essentially water and will be sent to the wash water drum in Plant 2. The discharge from the compressor will be cooled and any liquids recovered in the knockout drum will also be essentially water and be sent to the Plant 2 wash water drum. The flow scheme is described in Figure 3-6.

Low Pressure Gas Scrubbing. Gases exiting the gas compressor discharge knockout drum are sent first to a water wash tower to remove ammonia. The ammonia water is sent to Plant 34 for the recovery of anhydrous ammonia. The gas stream exiting the water wash tower is sent to the amine treater for the removal of carbon dioxide and hydrogen sulfide. The rich amine is sent to a common amine regeneration system. The capacity for the water wash and amine treater towers are provided in two parallel trains for reliability. The flow schematic of the Amine Regeneration section is shown in Figure 3-7.

Pressure Swing Absorption Unit. This section of the plant is fed the low pressure gas (200 psig) from the overhead stream from the amine treater and the membrane nonpermeate product. Pressure swing absorption (PSA) will be used for this service because of the high recovery of hydrogen. The hydrogen product is at a minimum purity of 99.0% (mol). The product from the PSA unit is compressed from 190 psig to 500 psig in motor-driven reciprocating compressors. This first stage of compression takes the lower pressure stream up to the product pressure of the membrane separation unit. The first stage discharge is cooled in an air-fin exchanger. The hydrogen stream will be compressed and sent to Plant 6.1 for further compression to 3500 psig. The PSA tail gas stream will be compressed to 200 psig and sent to the Gas Plant for recovery of propane and heavier hydrocarbons.

Figure 3-6

Plant 6.2 Low Pressure H₂ Recovery

Figure 3-7

Plant 6.2 Amine Regeneration

3.2.1.6 - Solids-Liquids Separation (Plant 8)

A list of major equipment was developed. The utility summary, water summary, catalyst and chemical requirements, operating manpower and plot area requirements were also developed.

Process Description

The simple operation of the ROSE-SR process is illustrated schematically on the Process Flow Sketch of Plant 8.1 (Figure 3-8). The feedstock is charged through a mixer Y101, where it is contacted with light hydrocarbon solvent at elevated temperature and pressure. A portion of the solvent is mixed with the feed in Y101, and the remainder of the solvent enters through a separate solvent inlet that provides countercurrent solvent flow. The mixture passes to the asphaltene separator, C101, where the heavy asphaltene/solids fraction drops out of solution and is withdrawn as a liquid from the bottom of the separator. The asphaltene and residual solvent pass through heater F101 to flash tower C102, where the solvent is flashed and stripped from the asphaltene product.

The solvent-DAO phase flows from the top of C101 through heat exchanger E101, where it is heated by the circulating solvent before entering heater F102. The temperature is elevated above the critical temperature of the solvent before the solvent-DAO mixture enters the DAO separator.

At this increased temperature, the DAO is virtually insoluble in the solvent. Therefore, a phase separation occurs in the DAO separator, C103. The DAO phase is withdrawn from the bottom of C103 and stripped of its solvent in tower C104. The substantially DAO-free supercritical solvent provides a significant part of the enthalpy needed to increase the temperature of the overhead stream from C101 to the conditions in C103. This circulating solvent flows overhead from C103 through exchanger E101, giving up heat to the solvent-DAO solution from C101. The circulating solvent is further cooled in exchanger E102 before returning to C101 via the solvent circulation pump G101. In many applications, E102's process duty is negligible, though the exchangers are sized to handle operational upsets such as an increased charge temperature. E102 is oversized to enable the ROSE unit to handle upsets in charge temperature. The solvent circulation pump G101 develops only the differential pressure necessary to overcome the separator system pressure drop.

The small amount of solvent dissolved in the heavy phases from vessels C101 and C103 (between 7% and 15% of the total extraction solvent) is recovered by conventional stripping in C102 and C104. The recovered solvent is condensed in E103 and then collected in the solvent surge drum C105. This small flow of solvent is pumped by the recycle solvent pump G102 into the large flow of high-pressure circulating solvent upstream of the solvent circulation pump, G101.

PROCESS FLOW SKETCH

ROSE - SR PROCESS

PLANT 8.1

Material Balance

The overall material balance for the Critical Solvent Deashing Unit is presented below in Table 3-4.

TABLE 3-4
Overall Material Balance

<u>Component</u>	<u>Flow Rates</u> <u>lb/hr</u>		<u>Ash</u> <u>Concentrate</u>
	<u>Feed</u>	<u>Extract</u>	
H ₂ O	14	14	.0
850°F-	14,232	14,230	0
850-1000°F	130,493	121,510	8,985
1000°F+	710,994	603,170	107,824
Unconverted Coal	101,709		101,709
Ash	<u>172,149</u>	<u> </u>	<u>172,149</u>
Total	1,129,592	738,924	390,668
Tons/day	13,555	8,867	4,688
B/D 1000°F-	50,838		

3.2.1.7 - Hydrogen Production by Coal Gasification (Plant 9)

Information was received from Shell on their coal gasification process. This information was developed and evaluated against that developed in the previous quarter on the Texaco process. The evaluation reached the conclusion that the Texaco process was preferred for this application. All succeeding work was done on the Texaco process. An equipment summary and simplified process flow diagram were developed. The utility summary, water summary, catalyst and chemical requirements, operating manpower, and plot area requirements were also developed.

Design Basis

Plant 9 is designed to gasify 4,688 ton/day of Ash Concentrate from ROSE-SR Plant and 5,312 ton/day of coal. Most of the syngas from the gasifiers is used to produce 450 MMSCFD of 99.5 volume percent hydrogen product used for the coal liquefaction and hydrotreating plants. Syngas in excess of the above requirement is used for medium Btu fuel gas.

Feed Streams

- 4,688 TPD ash concentrate from Plant 8.1 (ROSE-SR)
- 5,312 TPD clean coal from Plant 1 (Coal Preparation)
- 8,250 TPD of 99.5 volume percent oxygen from Plant 10 (Air Separation)

Feed analysis and compositions are presented in Table 3-5.

Product Streams

- 450 MMSCFD of 99.5 volume percent hydrogen
- 53 MMSCFD of medium Btu fuel gas
- 28 MMSCFD of acid gas containing H_2S as feed to Sulfur Plant (Plant 11)
- 407 MMSCFD of stripped CO_2 waste gas for discharge to the atmosphere
- 2892 TPD (dry basis) of slag and soot to landfill disposal

Product compositions are presented in Table 3-6.

Gasifier Yields

- For ash concentrate, 33 SCF of $CO + H_2$ per pound of dry and ash-free feed
- For clean coal, 38.7 SCF of $CO + H_2$ per pound of dry and ash-free feed
- Average about 96% carbon conversion to syngas. Unconverted carbon is rejected with slag

TABLE 3-5

GASIFICATION FEED STREAMS

Illinois No.6 Coal

Ultimate Analysis, %(wt.), Dry Basis

Carbon	71.0
Hydrogen	4.8
Nitrogen	1.4
Sulfur	3.2
Oxygen	8.1
Ash	11.5

HHV, Btu/lb	10,951
-------------	--------

Ash Mineral Analysis, % (wt.)

SiO ₂	49.8
Fe ₂ O ₃	17.6
Al ₂ O ₃	19.2
TiO ₃	1.0
CaO	6.3
MgO	1.0
SO ₃	2.9
K ₂ O	2.0
Na ₂ O	0.5
P ₂ O ₅	0.2
Undetermined	-0.5

Ash Concentrate

Composition, % (wt.)

850-1000°F	2.3
1000°F +	27.6
Unconverted Coal	25.8
Ash	44.3

HHV, Btu/lb	8,457
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Ultimate Analysis, % (wt.), Dry Basis

Carbon	48.3
Hydrogen	2.9
Nitrogen	1.1
Sulfur	3.1
Oxygen	0.3
Ash	44.3

TABLE 3-6

Product Compositions for Coal Gasification Plant

	<u>H₂ from Plant 9 Mol%</u>	<u>Medium Btu Gas Mol%</u>	<u>H₂S-Rich Off-Gas Mol%</u>	<u>CO₂ Off-Gas Mol%</u>	
H ₂ O	0.0	0.0	0.44	1.84	
H ₂	99.90	74.15	2.71	0.43	
CO	0.0	12.29			
CO ₂	0.0	4.12	63.17	89.52	2.14 0.09
AR+N ₂	0.10	8.66	1.52	8.11	
C ₁	0.0	0.78	0.0	0.01	
H ₂ S	0.0	0.0	29.96	0.0	
COS	<u>0.0</u>	<u>0.0</u>	<u>0.06</u>	<u>0.0</u>	
Total					
#-Mol/hr	49,705	5,823	3,069	44,662	
MSCFD	453	53	28	407	

Selection of Coal Gasification Technology

Two coal gasification technologies, the Texaco and Shell processes, have been evaluated for synthesis gas production in Plant 9. The block flow diagram for these two processes are presented on Figure 3-9.

The major differences between these two processes are as follows:

	TEXACO	SHELL
1.	Feed Type	
	Molten coal or coal slurry	Dried and pulverized coal to 70-90% through 200 mesh.
2.	Operating Conditions	
	High pressure process. Pressure up to 1100 psig.	Low to medium pressure process. Pressure up to 400 psig.
3.	Gasifier Construction	
	Vertical cylindrical pressure vessel with refractory lining	Horizontal ellipsoidal vessel. Gasifier shell has a double-walled construction, the inner shell is refractory lined
4.	Heat Removal Methods	
	Direct quench syngas with water in the gasifier and gas scrubber	Recover heat by generating steam in the waste heat boilers
5.	Shift Conversion	
	Produce sufficient steam in the syngas for shift reaction	Steam injection is required for shift reaction to occur
6.	Hydrogen Production	
	Produces higher H_2/CO ratio (0.75) syngas. Less shift conversion required.	Produces low H_2/CO ratio (0.43) syngas which requires more shift catalyst for shift conversion to reach the same H_2 production.

TEXACO

SHELL

7. **Horsepower for Hydrogen Compression**

Higher pressure process. Less horsepower required.

Low pressure process requires more horsepower for hydrogen compression

8. **Water Requirement**

Relatively poor quality condensate from the gas cooling sections can be used for direct quenching of syngas

More boiler feed water of higher quality is required for steam generation in the gasifier and waste heat boiler

9. **Ability to handle ROSE bottoms**

Its pilot plant had demonstrated that the ash-containing residues obtained from the H-Coal liquefaction plant were processed efficiently

No pilot plant result has been reported for H-Coal liquefaction residues

10. **Commercial Plant Experience**

Several large size commercial plants have been operated successfully since 1980's

Only small demonstration plants have been built

For high pressure hydrogen production, Texaco's gasification process has lower capital and utility costs, and has demonstrated that it can process H-Coal liquefaction residues successfully. Therefore, the Texaco technology is recommended for this project as the coal gasification process for Plant 9.

Process Description

Plant 9 consists of seven trains (5 operating and 2 spare) of gasification, five trains of shift conversion and gas cooling, five trains of gas purification, and six trains of hydrogen compression. Process flow diagrams are presented on Flowsheets, Figures 3-10, 3-11 and 3-12.

Figure 3-9

Block Flow Diagram – Hydrogen Production by Coal Gasification

Scheme 1 – Texaco Gasification

Scheme 2 – Shell Gasification

START UP HEATER

Figure 3-12

Gasification. Ash concentrate from Plant 8.1 (ROSE-SR) and coal from Plant 1 (Coal Preparation) is fed with water and a special additive to a grinding mill. The slurry from the grinding mill discharges to a slurry run tank.

The slurry feed from slurry feed pumps and oxygen feed from the Air Separation Plant (Plant 10) combine at the gasifier burner and enter the gasification chamber. This chamber operates at about 950 psig and 2500°F. About 92-95% of the carbon in the coal is converted to gaseous products, and the ash in the coal is slagged.

The gas with the molten slag is quenched in water at the bottom of the chamber. The slag is collected in a slag lock hopper connected to the base of the gasifier. Slag accumulations in the lock hopper are dumped into a sump. Slag dumped into the pit settles to the bottom. From the sump, the partly clarified soot slurry is pumped to a flash system to removed H₂S and other odorous material. The settled slag is dragged over the incline of the drag conveyor.

Synthesis gas leaving the gasifier is further cleaned in a water scrubber to remove the residual slag particles.

Water and condensate collected in the gas cooling system and in the soot water system are recycled to the scrubber.

The size of the gasifier is limited by economic considerations and experience factors. Seven gasifiers of the largest design are included in the base-line design, including two spares to ensure continuous operation at the design capacity.

Shift Conversion and Gas Cooling. The clean syngas from the gas scrubber goes to the shift converter where about 97-98% of the carbon monoxide is converted to hydrogen. The shift reaction is highly exothermic. A high temperature favors fast reaction rates but results in unfavorable equilibrium conditions. Initial stages will be designed to achieve high reaction rates at the highest allowable outlet temperature. The maximum allowable outlet temperature must be below the catalyst sintering point and within the limits for practical vessel design. The last reactor temperatures are kept low to obtain the low CO level in the product gas. The inlet temperature to each reactor stage must be kept above the water dew point to avoid catalyst being deactivated in the presence of liquid water.

A system with a multiple reactor design has been developed with the number of stages and trains, and operating conditions being optimized for minimum cost. To accommodate the required capacity, five trains each with three reaction stages were needed as limited by maximum reactor vessel diameter.

The catalyst chosen is either BASF's K8-11 or Haldor Topsoe's type SSK. Both catalysts operate in the sulfide form, thereby permitting handling of sulfur-bearing gas.

The heat of reaction is removed by a steam generator producing 600 psig steam from the first stage, a steam generator producing 150 psig steam from the second stage, and steam generators producing 150 psig and 50 psig steam from the third stage.

The shifted gas is further cooled against boiler feedwater, air, and cooling water and flows to the Hydrogen Purification section for acid gas removal. Process condensate is separated in the hot and warm receivers and pumped to the gas scrubbing and quench sections of the plant.

Hydrogen Purification and Compression. The Rectisol process removes H_2S and CO_2 by physical absorption of acid gas in methanol at relatively low temperature.

The feed gas is first prewashed by water in a water wash tower to remove NH_3 in the gas stream. The feed gas then enters at the bottom of a two-stage contactor where it is contacted with the methanol solution. In the first stage some of the CO_2 and practically all of the H_2S and COS are removed. In the second stage, which is above the first stage, the bulk of the CO_2 is removed.

The rich solvent which contains acid gas is regenerated by pressure reduction in the flash drums. The rich solvent is withdrawn from the flash drums and enter a stripper where the bulk of the CO_2 is stripped from the rich solvent by using nitrogen as the stripping gas.

The methanol leaving the stripper is completely regenerated in a reboiler regeneration column. The lean methanol withdrawn from the bottom of this column is fed to the top of the two-stage contactor. The acid gas, which contains all of the H_2S in the feed gas and some CO_2 , is stripped from this column and sent to sulfur plant.

The fully regenerated methanol from the bottom of the reboiler regeneration column contains all the water in the feed gas. To purge this water, a slip stream is charged to the methanol-water separator column where dry methanol is driven overhead. The overhead vapor is fed to the H_2S stripper. The bottoms from the methanol-water separator is water. A part of this stream is cooled and used for washing traces of methanol vapor from the tail gas (CO_2) stream. The balance is waste water.

The treated gas from the two-stage contactor flows to a pressure swing adsorption unit where the hydrogen is upgraded to a purity of 99.9%. The hydrogen is then compressed and delivered to the coal liquefaction and hydrotreating plants.

3.2.1.8 - Air separation (Plant 10)

Information on the packaged air separation units has been received from Lotepro Corporation. A process flow sketch was developed. A list of major equipment was developed. The utility summary, operating manpower, and plot area requirements were also developed.

Description of Process

The air separation package plants are cryogenic units producing oxygen at 99.5% (mol) purity and nitrogen at 99.9% (mol) purity. Oxygen will be delivered at the pressure required by the selected coal gasification process. Nitrogen will be used for purging, blanketing, and other utility purposes and will be delivered to the utility system at 150 psig. Liquid nitrogen will also be produced off the Air Separation Plant and stored for use during periods of high nitrogen demand.

Plant 10 consists of five parallel trains each sized for 45 MMSCFD of oxygen. Each train can operate independently and uses a low pressure cycle type process. The process features an air compressor to compress the inlet air, direct contact cooling to remove the heat of compression from the air, molecular sieve units to purify the air, fractionation columns to obtain the high purity gaseous oxygen, an expander compressor to provide the refrigeration needed for the process, and an oxygen compressor to pressurize the oxygen product for use in the Coal Gasification Plant.

3.2.1.9 Sulfur Plant (Plant 11)

The material balance for the Sulfur Plant was developed and the major equipment was sized for the open art units. Five Claus trains were specified with four required for capacity and the fifth as an on-line spare. An equipment summary and simplified process flow diagrams were developed. The utility summary, water summary, catalyst and chemical requirements, operating manpower, and plot area requirements were also developed.

Design Basis

Plant Capacity

Number of Trains	
o Operating	4
o Design	5
Design capacity per train	180 LT/D
Total Plant 11 Capacity	
o Operating (4 trains)	720 LT/D
o Design (5 trains)	900 LT/D

Feed Composition

Table 3-7

Feed Composition for Sulfur Plant

<u>Stream Component</u>	<u>Acid Gas from Plant 3 mol/hr</u>	<u>Acid Gas from Plant 9.1 mol/hr</u>	<u>Acid Gas from Plant 9.3 mol/hr</u>	<u>Acid Gas from Plant 34 mol/hr</u>	<u>Total Feed mol/hr</u>
H ₂	53.04	13.50	0.0	62.28	128.8
H ₂ S	239.20	26.10	893.40	868.09	2026.8
CO ₂	4.32	140.50	1798.40	33.86	1977.1
N ₂	0.0	0.90	45.30	6.61	52.8
NH ₃	0.0	0.30	0.0	1.18	1.5
CH ₄	8.15	0.0	0.0	0.0	8.2
CO	0.0	65.80	0.0	0.0	65.8
H ₂	0.0	83.20	0.0	0.0	83.2
COS	0.0	0.90	0.80	0.0	1.7
Phenols	0.0	0.0	0.0	0.15	0.2
Other HCs	0.0	0.0	0.0	1.80	1.8
Total	304.71	331.20	2737.90	973.97	4347.8

Product Compositions

Table 3-8

Product Compositions for Sulfur Plant

<u>Stream Component</u>	<u>Vent Gas mol/hr</u>	<u>Liquid Sulfur mol/hr</u>
H ₂ O	444.4	0.0
H ₂ S	2.0	0.0
CO ₂	2124.4	0.0
N ₂	4612.8	0.0
H ₂	249.2	0.0
Liquid Sulfur	<u>0.0</u>	<u>2026.5</u>
Total	7432.8	2026.5
Total sulfur, LT/D 0.7		694.8

Yields

- Minimum sulfur recovery for Claus sulfur plant is 95%.
- Total sulfur recovery for Plant 11 is 99.9%.

Typical Sulfur Industry Specifications

- Sulfur 99.5% minimum
- Carbon 0.2% maximum
- Ash 50. ppm maximum
- H₂S 50. ppm maximum
- SO₂ 50. ppm maximum
- Color Bright yellow
- Arsenic, Selenium, Tellurium Commercially free

Process Description

Sulfur Plant. The sulfur recovery plant has been designed in accordance with the principles of the classic "Claus" reaction. About one-third of the hydrogen sulfide (H₂S) in the feed is oxidized to form sulfur dioxide (SO₂) and water (H₂O). The sulfur dioxide then reacts with the remaining hydrogen sulfide to form elemental sulfur and water vapor. Ammonia (NH₃) is oxidized to nitrogen and water. In addition to the

reactions noted above, a small part of the feed hydrogen sulfide dissociates to free hydrogen and elemental sulfur. Any hydrocarbons in the acid gas feed are oxidized in the thermal reactor to carbon monoxide (CO), carbon dioxide (CO₂) and water.

The acid gas and the SCOT recycle acid gas are combined and routed to the acid gas knock-out drum. The knock-out drum is designed to removed entrained sour water and condensed hydrocarbons from the acid gas streams.

The vapor stream, from the acid gas knock-out drum, is fed to the acid gas preheater, where the stream is heated to about 450°F. The hot gas is then fed to the acid gas injector, located on the front chamber of the thermal reactor.

Combustion air is supplied by the air blower to the acid gas injector to oxidize some of the H₂S to SO₂ and H₂O. The quantity of air is controlled to achieve a ratio of H₂S to SO₂ of 2:1. During this reaction, the thermal reactor first and second chamber temperatures are about 2400°F and 2200°F, respectively. The combustion air is heated to about 450°F in the air preheater to help maintain the 2200°F overall thermal reactor temperature.

The hot combustion gas from the thermal reactor second chamber enters a two-pass waste heat boiler. The boiler is designed to cool the hot gas to about 600°F and to generate 150 psig steam. The cooled gas from the boiler enters the thermal sulfur condenser. Most of the sulfur produced in the thermal reactor is condensed as the gas is cooled in the thermal condenser. The thermal condenser is a steam generator and the heat removed from the hot gases generates 50 psig steam. Liquid sulfur is separated from the gas in a separation chamber at the outlet end of the condenser. The condensed sulfur drains to a sulfur seal pot in a sulfur day tank through a steam jacketed drain leg. The seal pot maintains a liquid sulfur seal to prevent the process gas from escaping through the sulfur drain legs.

The cooled gas from the thermal condenser flows to the first reheater. The gas is heated to about 450°F by 600 psig steam.

The hot gas from the first reheater flows downward through the first catalyst converter where the reaction of SO₂ with H₂S occurs over a fixed bed of alumina catalyst. Since the reaction is exothermic, the temperature will rise across the bed. The temperature rise will be the greatest in this reactor because of the higher concentration of reactants present.

The reactor product gas, containing newly formed elemental sulfur, leaves the reactor and enters the first sulfur condenser. The bulk of the sulfur formed in the first catalyst converter is condensed and is drained to the sulfur day tank through a steam jacketed drain leg. Steam at 50 psig is generated on the shell side of the condenser.

The cooled gas from the first condenser flows to the second reheater where it is heated to about 420°F by 600 psig steam. Since the concentration of the reactants are lower in the feed to the second catalyst converter than in the feed to the first, less reaction takes place and the temperature rise across the second converter is lower.

Hot effluent gas from the second converter bed enters the second sulfur condenser. The bulk of the sulfur formed in the second converter is condensed and drained to the sulfur day tank through the third steam jacketed drain leg. Steam at 50 psig is generated on the shell side of the condenser. The cooled gas from the second sulfur condenser flows to the third reheater. This reheater has the same function as the other reheaters, and uses 600 psig saturated steam as a heating medium to heat the third catalyst converter feed to about 400°F.

The third catalyst converter is similar to the first and second catalyst converters. Since the concentration of H_2S and SO_2 is very low in the feed to the third reactor bed, a relatively small amount of sulfur is formed in this stage. The reaction that takes place in this stage results in a very small temperature rise across the catalyst bed. The sulfur formed in the catalyst converter is condensed in the third sulfur condenser and is drained to the sulfur day tank through a steam-jacketed drain leg. The cooled gas (tail gas) from the third sulfur condenser flows to the SCOT tail gas treating unit.

SCOT Unit. The fundamental reaction in the Hydrogenation Section of the SCOT Unit are hydrogenation of the SO_2 and elemental sulfur. Most of the COS and CS_2 present in the reactor are hydrolyzed by the water vapor in the tail gas.

The sulfur plant tail gas is heated to over 500°F in the SCOT feed heater. The temperature of this stream is controlled to the desired SCOT reactor inlet temperature by means of a temperature controller, which regulates the amount of natural gas or syngas that is fed to the SCOT burner as fuel.

Syngas is added to the feed heater outlet to provide the necessary hydrogen for the hydrogenation of the SO_2 and elemental sulfur to H_2S .

The heated gases then pass downward through the reactor catalyst bed where the SO_2 , elemental sulfur and other sulfur containing compounds (such as COS) are converted to H_2S , CO_2 , CH_4 , and water vapor. To assure the complete reduction of the sulfur compounds to H_2S , an excess above the stoichiometric requirement of hydrogen is fed to the reactor. The reactions are exothermic and cause a temperature rise across the reactor.

The hot gases leaving the SCOT reactor are cooled to about 320°F in the SCOT waste heat exchanger. The waste heat exchanger is a steam generator and the heat removed from the hot gases generates 50 psig steam.

The cooled gases leaving the waste heat exchanger are further cooled to about 100°F by contact with water in the quench tower. The gases enter the quench tower below the tower packing and flow upward, countercurrent to the cool quench water. The quench water is fed to the tower above the packing at a temperature of about 100°F. The temperature of the quench water is raised to about 150°F as it cools the gases in the column. The quench water from the bottom of the column is then pumped by the quench water pumps, through the quench water cooler, where it is cooled before being returned to the top of the tower. The quench water bleed stream is the excess water contained in the quench tower feed gas that is condensed in the quench tower.

The quench tower overhead gas stream enters the SCOT absorber below the bottom tray and flows upward through the absorber countercurrent to the MDEA solution flowing down through the absorber.

Lean MDEA solution at about 100°F is fed to the top of the absorber. The solvent flows downward through the absorber, contacting the gas stream flowing upward and absorbing nearly all of the H_2S and part of the CO_2 from the gas stream. The treated vent gas then leaves the top of the absorber at about 100°F and is directed to the incinerator.

A vent gas analyzer is provided to advise the operator of the SCOT Unit clean up efficiency, H_2S and CO_2 , and the amount of excess hydrogen in the vent gas.

Rich solvent is withdrawn from the absorber bottom and is pumped to the SCOT stripper through the lean/rich exchanger. The rich solvent enters the column above tray 5 (from the top). The stripper is heated by a reboiler using 50 psig steam.

The stripper overhead vapor is cooled to about 120°F in the reflux condenser (an air cooler), and collected in the reflux drum. The gas from the top of the reflux drum contains H_2S , CO_2 , and H_2O and is routed to the sulfur plant as acid gas feed.

The lean solvent leaves the stripper bottom and flows through the lean/rich exchanger. Lean solvent from the exchanger is pumped to the SCOT absorber by the lean solvent pumps. The lean solvent stream from the pump discharge is cooled to about 100°F in the lean solvent cooler and is fed to the top of the absorber.

Incinerator. The incinerator uses a natural draft burner to provide the heat and air necessary for the combustion of the effluent gases. The design combustion temperature is maintained by burning natural gas or syngas as fuel. The SCOT vent gas is routed below the incinerator burner to achieve maximum turbulence and contact with the oxygen (air) at high temperature.

During normal operations, the sulfur plant tail gas flows to the SCOT unit and only the SCOT vent gas is combusted in the incinerator. The design conditions for proper

combustion of the SCOT vent gas is 25% excess air at a temperature of about 1200°F. The combustion products are discharged to the atmosphere through a 280 foot stack. A stack gas analyzer is provided to monitor the SO₂ in the stack.

3.2.2 Status Update on Support Facilities

During this reporting period several support facilities plants were updated. The status of these updates are discussed below.

3.2.2.1 Coal Grinding and Drying (Plant 1.4)

Coal Cleaning (Plant 1), must be pulverized and dried before being obtained from coal slurried in the Coal Liquefaction Plant (Plant 2).

The clean coal coming into Plant 1.4 is 1-1/2x0 in size and contains a maximum of 15 percent moisture. When leaving Plant 1.4 the pulverized coal, contains less than 2 percent moisture. It has a consistency of 99.5% passing a 28 mesh screen and 50% passing a 200 mesh screen. The plant consists of two air heaters and two grinding mills for each of the five liquefaction trains (ten in operation and two spares) with a nominal capacity of 17,100 TPD of coal on a dry basis.

Design Basis

The nominal capacity of the Coal Crushing and Drying Unit, on a dry basis is 17,100 TPD, to meet the needs of the downstream units. The plant will operate 7 days a week, 24 hours a day. The analysis of the clean coal and the properties of the pulverized coal are given in Table 3-9. The operating capacity of each train is 75 tons per hour.

**Table 3-9
Analysis of Clean Coal**

ANALYSIS	CLEAN COAL	CRUSHED COAL
Moisture, Total	5-15%	2%
Moisture, Max	15%	
Size, Inches or Mesh	1-1/2x0	
Through 28 Mesh		99.5%
Through 200 Mesh		50.0%
Hard Grove Index, Assumed	55	
Ash	11.47%	
Sulfur	3.41%	
Pyritic Sulfur	1.33%	
Heating Value, BTU/LB	12,300	

PLANT DESCRIPTION

Washed coal is conveyed to the Pulverizer Feed Bins from the Coal Cleaning Plant (Plant 1). Twelve 300-ton feed bins, one for each of the pulverizers, are provided to ensure a steady feed to the crushers.

The twelve pulverizers are each rated at 75 TPH. Ten are normally operating with two spares. The following paragraphs describe one of the twelve identical trains, which are illustrated in Figure x.

A weigh belt feeder located below the pulverizer feed bin, delivers clean coal to the Pulverizer. The pulverizer is designed to simultaneously crush and dry the coal. The roller mill's large rollers rotate around the grinding table, which crush and grind the coal. The ground coal spills over the table's edge and is carried by a stream of rising hot nitrogen gases to an integral classifier. The hot gases cause an immediate evaporation of the moisture in the coal. The classifier, located immediately above the mill, rejects large particles which fall back to the table for further grinding.

Gases from the Dust Collector Fan are recycled to the in-line recycle Air Heater, which supplies heat for the process. This heater is fired with fuel gas. The hot gases are tempered with make-up nitrogen to about 660°F before entering the mill. The ground particles and the gas stream are pulled from the pulverizer through the multistage Baghouse where the coal solids are recovered. The recovered particles and dust are transferred by screw conveyor to the 600 ton Coal Dust Storage Bin.

Gas is exhausted from the baghouse by the dust collector fan. The major part of the exhaust gas is recycled back to the heater. The remaining gas is vented to the atmosphere through a bag filter.

STATUS

The following vendors were contacted for quotations to crush and dry this material with their equipment:

- A.B.B. Raymond
- Babcock and Wilcox
- Fuller
- Williams Crushing

Williams Crushing declined to quote. They would have required 24 pulverizers to satisfy our requirements. Thus they deemed that their equipment did not fit our requirements.

Babcock and Wilcox quoted only their pulverizers. The sales engineer sized their own equipment and was out of the office for several weeks. Everyone else claimed no knowledge of the proposal. When contacted, after his return, he claimed others were to get quotes on their buy out items. Since it was then too late for these quotes their proposal was considered non responsive.

A.B.B. Raymond and Fuller quoted complete packages. Evaluation of the two quotations have not yet been completed.

3.2.2.2. Sewage and Effluent Water Treatment Systems - Plant 34

Process Design

Sour Water Treating

Dephenolization is a process technology development of LTV Corporation, licensed by the Packaged Plants Division of Glitsch Inc., for phenols recovery from sour water. This is accomplished by means of liquid-liquid extraction, in which the phenols are recovered as a salable product consisting of phenol and its homologs, cresols and xlenols. The phenols are extracted from the sour water with an organic solvent. The solvent is recovered by fractionation from the extracted phenols.

ARISTECH PHOSAM-W is a development technology of USX Corporation, licensed by USX Engineers and Consultants Inc. (UEC). The process removes free ammonia and acid gases from the sour waters. In the absorber the ammonia is chemically absorbed from the sour water stripper vapors by a circulating water solution of ammonium phosphate.

In the stripper, the ammonia is recovered from the solution and the solution is regenerated for feed to the absorber.

The aqueous ammonia vapor from the stripper overhead is condensed and fed to the fractionator where it is distilled under pressure to produce a high quality anhydrous product.

Design Basis

The capacity of the Dephenolization unit is 2160 GPM of concentrated sour water from the Coal Liquefaction Plant (Plant 2). Feed composition to the Dephenolization unit used in this design is given in Table 3-10. Approximately 45 TPSD of phenols is recovered from this unit. Dephenolated water is combined with ammonia rich steams from the hydrotreaters to go to the PHOSAM-W unit which has a capacity of 2350 GPM. Feed compositions and quantities used in this design are given in Table 3-11. Roughly 237 TPSD of anhydrous ammonia is recovered in this process. The yields of both plants are based on the Breckinridge 4 Train plant and have been reviewed by the licensors and deemed as reasonable.

Table 3-10
Feed Stream to Dephenolization

Component	Concentrated Water	From Plant #2
	pounds/hour	wt. %
CO ₂	1,426	0.13
H ₂ S	28,655	2.65
H ₂ O	1,028,818	95.22
NH ₃	17,307	1.60
PHENOLS	3,785	0.35
ORGANICS	497	0.05
METHANE	<u>18</u>	--
TOTAL	1,080,522	100.00

Table 3-11
Feed Streams to Ammonia Recovery

COMPONENT	Pounds/Hour				
	DEPHENOLED SOUR WATER	PLANT #2 SOUR WATER	HYDROTHER SOUR WATER	SEPARATOR SOUR WATER	TOTAL FEED
NITROGEN	185	--	--	--	185
CO ₂	1,426	1	--	64	1,490
H ₂ S	28,655	6	276	649	29,585
FREE NH ₃	17,307	28	2,045	471	19,850
ORGANICS	489	--	--	--	489
PHENOLICS	161	--	--	--	161
HCN	16	--	--	--	16
WATER	1,029,062	789	74,301	19,309	1,123,460
SOLVENT	<u>11</u>	--	--	--	<u>11</u>
TOTAL	1,077,312	823	76,621	20,491	1,175,247

The predicted product quantities and compositions for the Dephenolization are presented in Table 3-12. The phenol stream will have a minimum purity of 95.0 percent mixed Phenols.

Table 3-12
Dephenolization Product Streams

<u>COMPONENT</u>	<u>Pounds/Hour</u>	
	<u>PHENOLS</u> <u>(TAR ACIDS)</u>	<u>EXTRACTED WATER</u>
CO ₂	--	1,426
NITROGEN	--	185
H ₂ S	--	28,655
H ₂ O	114	1,029,062
HCN	--	16
NH ₃	--	17,307
PHENOLS	3,624	161
ORGANICS	8	489
SOLVENT	4	11
METHANE	--	<u>18</u>
TOTAL	3750	1,077,330

Table 3-13 presents the predicted product quantities and compositions from the PHOSAM-W process. The anhydrous ammonia stream will have a minimum purity of 99.0 percent.

Table 3-13
Phosam-W Product Streams

Pounds/Hour			
<u>Component</u>	<u>Acid Gas</u>	<u>Anhydrous NH₃</u>	<u>Stripped Water</u>
NITROGEN	185	--	--
CO ₂	1,490	--	--
H ₂ S	29,564	--	21
FREE NH ₃	20	19,608	222
ORGANICS	489	--	--
PHENOLICS	14	--	147
HCN	--	--	16
WATER	3,685	169	1,119,606
SOLVENT	11	--	--

Process Description

Sour water is processed first through the Dephenolization process followed by the PHOSAM-W process. To insure a continuous supply of hydrogen sulfide feed for the Sulfur Plant (Plant 10), two PHOSAM-W units are specified and individual pieces of equipment are spared as required to ensure reliability.

Dephenolization Section - Phenol bearing sour water from the Coal Liquefaction Plant (Plant 2) is pumped to the Saturation Column where the light ends are stripped out and sent to the Solvent Stripper. (See Figure 3-13) A side stream is sent to the Solvent Recovery Scrubber. The sour water is then charged to the top of the Extraction Column, where it is counter-currently contacted with solvent. Raffinate (dephenolized water) is fed to the Solvent Stripper Column, where entrained solvent is removed by distillation. The dephenolized water is pumped to the PHOSAM-W process for ammonia removal. The gaseous solvent stripper overhead is returned to the bottom section of the Saturation Column.

Figure 3-13

**PROCESS FLOW SKETCH
DEPHENOLIZATION**

Extract from the top of the Extraction Column flows under interface control, to maintain a constant interface level between extract and liquor at the top of the Extractor, to the Solvent Distillation Column. The Solvent Distillation Column separates the solvent and the extracted phenols. The overhead product is condensed and is pumped back to the Extractor as recycle solvent. A side stream of the overhead product is pumped back to the column as reflux. The bottoms product is pumped to the Phenol Column.

The Phenol Column operates under vacuum to reduce the solvent content of the crude phenols to less than one percent. The overhead product is condensed and sent to the Solvent Distillation Column, with a side stream returned to the Phenol Column as reflux. The bottoms product is circulated to the Solvent Recovery Scrubber with a side stream being cooled as phenol product and sent to storage in Tankage (Plant 20).

Gaseous overhead product from the Solvent Recovery Scrubber is returned to the Saturation Column and the bottoms product is recycled to the Phenol Column.

Sour Water Stripping and Ammonia Recovery - Sour water from the Dephenolization unit is combined with the sour water from the Fractionation Units (Plant 2) and the Hydrotreaters (Plants 4 and 5). The combined feed is preheated against the PHOSAM-W H₂S Stripper Feed/Bottoms Exchanger. The feed is then charged to the unit's H₂S Stripper where acid gas and free ammonia is stripped from the water. (See Figure 3-14) The stripped water is then cooled and preferentially returned to the process units for reprocessing or to the Wastewater Treatment area for further treatment. Heat for the stripper is supplied by a 150 psig steam reboiler.

The H₂S Stripper overhead vapor goes to the Ammonia Absorber where it is contacted with recirculated ammonium phosphate solution. Vapors released from the rich solution in the PHOSAM Contactor contain some ammonia and essentially all of the entrained acid gases. These vapors are recycled to the spray section of the absorber to recover the ammonia and purge the system of acid gases. About 75 percent of the ammonia is recovered here. The remaining vapors flow upward through trays where the ammonia is counter-currently scrubbed with lean ammonium phosphate solution returning to the top of the absorber from the regeneration section of the plant. The solution with the absorbed ammonia, drains from the bottom tray into the absorber sump.

The vapor leaving the Ammonia Absorber contains approximately 6,000 ppmv ammonia. It passes to the Acid Air Cooler where enough ammoniacal water is condensed to lower the ammonia content of the gas to less than the specified 1,000 ppmv. The gas then passes to the Sulfur Plant (Plant 10). The ammoniacal water is recycled back to the H₂S Stripper with the sour water feed.

The net flow of the rich absorber solution is taken off the discharge of the Absorber Circulation Pump and heated against the hot lean solution from the bottom of the

Figure 3-14

PROCESS FLOW SKETCH
PHOSAM-W AMMONIA RECOVERY

PHOSAM-H₂S Stripper Bottoms/Lean Solution Exchanger. The heated rich solution is flashed in the PHOSAM Contactor to remove acid gases which are recycled to the Ammonia Absorber.

The rich solution, now free of acid gases, is pumped from the PHOSAM Contactor and preheated in the upper section of the PHOSAM-Ammonia Stripper Condenser. The preheated rich solution flows to the PHOSAM-Ammonia Stripper which operates at elevated pressure.

The PHOSAM-Ammonia Stripper removes the absorbed ammonia and the lean solution is recycled to the Ammonia Absorber. The Ammonia Absorber Reboiler is heated with 600 psig steam, to provide the necessary heat for the stripper. The hot, lean solution is cooled first against the PHOSAM Feed Exchanger, then to preheat the sour water feed to the stripper and finally it is cooled with cooling water before entering the top of the Ammonia Absorber.

The overhead vapor from the PHOSAM-Ammonia Stripper, containing 10 to 20 weight percent ammonia passes through the two section PHOSAM-Ammonia Stripper Condenser. The vapor is cooled and partially condensed in the upper section by exchange with the stripper feed. Cooling water condenses the remaining vapor in the lower section. The PHOSAM-Ammonia Stripper pressure is automatically controlled by running the lower section as a flooded condenser. The condensed aqueous ammonia is maintained at its boiling point with a warm vapor by pass. The condensate flows by gravity to the PHOSAM Stripper Overhead Drum. A small stream of sodium hydroxide is continuously metered into the overhead drum by the Caustic Metering Pump to prevent trace amounts of CO₂ and H₂S from collecting in the fractionator. The sodium hydroxide combines with the acid gases to form salts which leave with the bottoms stream from the Ammonia Fractionator.

The aqueous ammonia is pumped from the PHOSAM Stripper Overhead Drum into Ammonia Fractionator where it is fractionated into an overhead anhydrous ammonia product (99.5% NH₃ min.) and a bottoms product containing a small amount of ammonia. The alkaline, pressurized hot water from the bottom of the fractionator is flashed directly into the bottom of the H₂S Stripper to provide a portion of the boil-up requirement. The Ammonia Fractionator Reboiler is heated with 600 psig steam and provides the necessary stripping vapor for fractionation of the ammonia and water. The overhead vapor is condensed with cooling water and the tower pressure controlled via a flooded condenser. Part of the overhead product is used for reflux to the top of the fractionator and the rest goes to Tankage (Plant 20).

3.2.3. ENVIRONMENTAL COMPLIANCE STRATEGY

This section summarizes the major Federal and Illinois environmental considerations that will need to be addressed in the coal liquefaction study during the pre-construction, construction, and operation phases of the proposed southern Illinois commercial scale coal liquefaction facility.

The proposed plant, which is a baseline process configuration contains a two-stage catalytic-catalytic closed coupled reactor with ash recycle and ROSE-SR deashing with no residuum product. The facility will produce approximately 60,000 BPSD of liquid products plus propane and mixed butane, and will be sited at the mouth of the coal mine (#6 Illinois coal). Other by-products generated from the plant manufacturing operations (e.g. sulfur, ammonia, and phenol) will be sold as marketable products.

The Illinois Environmental Protection Agency (IEPA) can assist in the identification and understanding of the pollution control requirements which apply to the project. They can also assist in the review of the adequacy of the proposed pollution control measures. When permits are required, the IEPA can further aid in identifying the material to be assembled for permit applications and in expediting review of the applications once submitted.

The IEPA's handling of individual air, water, and solid and hazardous waste permits is coordinated for significant projects, and also when requested by an applicant. This assures that a project is fully permitable by the IEPA before any single permit will be issued. It also means that development of one aspect of a project will not begin until all aspects of the project are adequately addressed at the conceptual level. Coordination can be achieved either by submitting all applications at the same time, or by supplying a comprehensive project plan with the first application.

The U.S. Environmental Protection Agency authorizes the IEPA to act on most permit applications within 90 days. This period is extended to 180 days for permit applications involving the development of a landfill, or when public notice and opportunity for public hearing are required by state or federal regulations as anticipated for this project.

Although environmental regulations, standards, and design considerations relative to the proposed coal liquefaction facility have been provided in this document, the final acceptability from the regulatory agencies will be determined at the time of permit submittal. After subsequent discussions with the various regulatory agencies the performance requirements and regulatory applicability can be better defined.

There are several pertinent environmental policies and regulations which need to be addressed. These are grouped under eight categories as shown below:

- 3.2.3.1 National Environmental Policy Act (NEPA)
- 3.2.3.2 Air pollution Control Regulations
- 3.2.3.3 Solid and Hazard Waste Regulations
- 3.2.3.4 Water Pollution Control Regulations
- 3.2.3.5 Toxic Substances Control Act
- 3.2.3.6 Occupational Safety and Health Act (OSHA)
- 3.2.3.7 Noise Regulations
- 3.2.3.8 Federal Aviation Administration (FAA) Policies

3.2.3.1 NATIONAL ENVIRONMENTAL POLICY ACT (NEPA)

The National Environmental Policy Act (NEPA) provides for the consideration of environmental consequences of federal actions. Under this Act, all federal agencies must submit an Environmental Impact Statement (EIS) for any project that directly or indirectly affects the human environment and uses federal funding, federal land leasing, or requires federal permits for operation.

NEPA also created a Council for Environmental Quality (CEQ). It is the duty of this council to review all environmental impact statements and make recommendations on the environmental merits of federal actions. The council also develops and recommends policies to enhance the environmental quality of the United States.

Environmental Impact Statements

Federal agencies begin to assess the environmental impact of a project when they begin the technical and economic feasibility studies. If this initial assessment indicates a significant environmental effect, the agency prepares a draft EIS to be circulated with the project proposal. The United States Environmental Protection Agency (EPA) has been designated as the lead agency for the EIS. The draft EIS should contain a discussion of the following topics:

- a complete description of the proposed project
- a discussion of both the positive and negative effects on the environment
- a discussion of the relationship of the proposed action to land use plans and policies
- an evaluation of primary, secondary, direct and indirect environmental impacts
- a thorough discussion of alternatives to the proposed action including environmental consequences

- any unavoidable negative environmental effects such as air or water pollution
- the relationship between the short and long-term effects of the project
- other interests and considerations that might offset the negative environmental aspects of the proposed action

The draft EIS must first receive an internal review by the initiating agency. Next, it is sent for review to other federal agencies having jurisdiction or special expertise in fields affected by the project. The EPA must also review each draft EIS prepared. The state and local agencies in the area of the proposed project are also provided with copies of the draft EIS. The draft should be made available to interested private citizens or groups of citizens. Each of the above groups may submit written comments and recommendations for improvements to, or alternatives for, the project under consideration. If a significant number of comments are received, a public hearing will be held on the EIS draft. The EIS process typically requires a significant amount of design and detailed engineering and operating information to support the impact assessment activities.

At the conclusion of the review process, a final draft EIS is prepared. It should include references to responsible opposing points of view raised in the review period. A copy or summary of all comments received during the review period should be attached to the final draft. A copy of the final draft EIS should be sent to each reviewer and to the EPA. Ten copies of the EIS and five copies of the comments should be sent to the Council for Environmental Quality (CEQ). A period of ninety days is then allowed for further comments before the CEQ makes a final recommendation on the proposal.

Activities Authorized by the Army Corps of Engineers

The Army Corps of Engineers regulation 33 CFR 320 outlines the general criteria used to evaluate all Corps permit applications. This regulation is designed to protect wetlands, floodplains, navigation, surface and groundwater quality, fish and wildlife, and historical and archaeological resources.

Wetlands Protection

The Corps regulates activities in wetlands to avoid adverse impacts, where possible, and to minimize destruction and to preserve the values of wetlands pursuant to Executive Order 11990 entitled "Protection of Wetlands." The Corps will consider whether the proposed activity is primarily dependent on being located in or in close proximity to the aquatic environment and whether feasible alternative sites are available. The Corps will also consult with various federal agencies to assess the cumulative effects of activities in the region. Avoidance or minimization of impacts on wetlands is an appropriate project strategy. Mitigation considerations are required if there is an impact on wetlands.

Floodplain Management

The Corps of Engineers has established regulations for activities in the floodplain, pursuant to Executive Order 11988 on Floodplain Management. An evaluation must be performed of the activities located in a 100-year floodplain which require a Department of the Army permit to protect the public interest. An evaluation is necessary in order to determine if alternatives exist to avoid possible adverse effects and, if not, to decide if development in the floodplain should occur.

Fish and Wildlife

Consideration of the impact of the activity on fish and wildlife is a major concern of the Army Corps of Engineers. In accordance with the Fish and Wildlife Coordination Act, the Corps of Engineers will consult with the Regional Director, U.S. Fish and Wildlife Service, and the head of the agency responsible for fish and wildlife for the state in which the work is to be performed, with a view to the conservation of wildlife resources by prevention of their direct and indirect loss and damage due to the activity proposed in a permit application. They will give much emphasis to these views on fish and wildlife considerations in evaluating the application. The applicant will be urged to modify his proposal to eliminate or mitigate any damage to such resources, and in appropriate cases, the permit may be conditioned to accomplish this purpose.

Rivers and Harbors Act

Section 10 of the Rivers and Harbors Act gives the Army Corps of Engineers a mandate to prohibit the obstruction or alteration and construction of any structure in or over any navigable water of the United States without a permit.

Water Quality

Applications for permits for activities which may affect water quality and discharge of dredge or fill material will be evaluated for compliance with applicable effluent limitations, water quality standards, and management practices during the construction, operation, and maintenance of the proposed activity. State certification of compliance with applicable effluent limitations and water quality standards required under provisions of the Clean Water Act will be considered conclusive with respect to water quality considerations unless the Regional Administrator of the U.S. Environmental Protection Agency advises of other water quality aspects to be taken into consideration. Any permit issued may be conditioned to implement water quality protection measures.

The Corps of Engineers will not issue a permit for structures of work which would interfere with adjacent properties or water resource projects. Interferences such as increased siltation or erosion and reduced general public access or right of navigation must be avoided.

Fish and Wildlife Coordination Act

The Fish and Wildlife Coordination Act authorizes the Secretary of the Interior to:

- Provide assistance to and cooperate with federal, state and public or private agencies in the development, rearing, and stocking of all species of wildlife resources and their habitat, in controlling losses of the same from disease or other causes, in minimizing damages from over-abundant species, in providing public shooting and fishing areas, including easements across public lands for access, and in carrying out other measures necessary to affect the purposes of said sections;
- To make surveys and investigations of the wildlife of the public domain, including lands and waters or interest therein and;
- To accept donations of land and contributions of funds in furtherance of the purposes of said sections.

Of particular relevance to new industrial facilities are provisions within the Act that require any permitting agency or department to consult with the U.S. Fish and Wildlife Service with a view to the consequences of the proposed action upon the wildlife resources. Examples of the type of actions proposed by the industrial applicant would be impounding, diverting or controlling waters, and discharge of sewage and industrial wastes.

The Secretary of the Interior, through the Fish and Wildlife Service and the Bureau of Mines, is authorized to make such investigations as deemed necessary to determine the effects of such actions upon wildlife.

Endangered Species Act

The Endangered Species Act charges all federal agencies with the responsibility to aid in the protection of the species listed as endangered in the United States. In addition to prohibiting actions against endangered species by private citizens, the Act prohibits federal agencies from funding or authorizing a project which jeopardizes any one of the species. This includes entering into a cooperative agreement such as an agreement to supplement a project of private industry or local government with federal funds. It authorizes funds for research on U.S. endangered species and describes procedures for adding a species to the list. It mandates that all federal agencies shall cooperate with state agencies in programs that benefit endangered species, including those for the identification of critical habitats. The Act does not void state laws designed to protect wildlife. For instance, states may compile endangered species lists more inclusive than the federal list, or may define more stringent criteria for certain species than those contained in the federal Act.

Wild and Scenic Rivers Act

The Wild and Scenic Rivers Act establishes requirements applicable to water resource projects affecting wild, scenic, or recreational rivers within the National Wild and Scenic Rivers System, as well as rivers designated on the National Rivers Inventory to be studied for inclusion in the National System. Under the Act, a federal agency may not assist, through grant, loan, license, or otherwise, the construction of a water resources project that would have a direct and adverse effect on the scenic, recreational, or fish and wildlife values for which a river in the National System was established.

Farmland Protection Policy Act

The Farmland Protection Policy Act (FPPA) requires federal agencies to use criteria developed by the U.S. Department of Agriculture to:

- Identify and take into account the adverse effects of their programs on the preservation of farmlands from irreversible conversion to other uses which result in its loss as an environmental or essential food production resource;
- and consider alternative actions that could lessen such adverse impacts.

If categories of important farmlands, which include those defined in both the FPPA and EPA policy, are identified in the project area, both direct and indirect effects of the undertaking on the project area and immediate environs shall be evaluated. Adverse effects shall be avoided or mitigated to the extent possible.

Archaeological and Historic Preservation Act

The National Historic Preservation Act directs that "the historical and cultural foundations of the nation shall be preserved as a living part of our community life and development...".

Title I, Section 101 of the Act provides for a National Register of districts, sites, buildings, structures, and objects significant in American history, architecture, archaeology, and culture.

Title I, Section 106 requires that any federal agency having direct or indirect jurisdiction over any undertaking (including the granting of licenses and permits) shall take into account the effects of the undertaking on any National Register property.

Of particular relevance are procedures that require a review process in which the agency proposing the undertaking, the State Historic Preservation Officer, the Council on Historic Preservation, and interested organizations and individuals participate. The process is designed to assure that alternatives to avoid or mitigate an adverse impact on a National Register property are adequately considered in the planning processes.

In all likelihood, this process would result in a Memorandum of Agreement between the industrial developer, the Federal Council, and the State Historic Preservation Officer that outlines a development plan that maximizes the preservation and/or recovery of historically or culturally significant articles.

3.2.3.2 AIR POLLUTION CONTROL REGULATIONS

Major new construction of facilities in the United States must be in accordance with a variety of air quality regulations and standards. Existing standards are based on criteria that limit the increase in existing levels of pollutants at the proposed site and set absolute upper limits that cannot be exceeded.

National Ambient Air Quality Standards (NAAQS)

These standards define levels of ambient air quality which the Environmental Protection Agency (EPA) judges to be necessary to protect the public health and welfare from any known or anticipated adverse effects of a pollutant. Standards cover particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, ozone, non-methane hydrocarbons, and lead. For each specific pollutant, an area (usually a county or air quality region) is classified as "attainment", "unclassified", or "non-attainment" based on compliance with ambient standards for the aforementioned pollutants. Attainment areas are ones in which compliance has been demonstrated with the NAAQS for specific pollutants while, in contrast, non-attainment areas are ones in which the NAAQS have not been met for certain pollutants. Primary standards have been established for the protection of human health, and secondary standards for the protection of human welfare. Table 3-14 lists both sets of standards.

The location of the proposed DOE Coal Liquefaction facility will significantly affect the extent of regulatory applicability and air permitting that will be necessary. New sources located in areas designated as attainment or unclassified for specific pollutants require a Prevention of Significant Deterioration (PSD) review (requirements of which are discussed later. In areas designated as nonattainment for certain pollutants, new sources must perform a nonattainment area (NAA) review and may also possibly need to apply for a state permit. Discussions with the Illinois EPA indicate that there are currently few (if any) non-attainment areas located in the south central region of Illinois. It is therefore likely that a non-attainment area review may not be necessary. Once a specific candidate site is selected, this determination can be finalized.

Table 3-14 NATIONAL AMBIENT AIR QUALITY STANDARDS

AVERAGING PERIOD	PRIMARY STANDARD		SECONDARY STANDARD	
	$\mu\text{g}/\text{m}^3$	ppm	$\mu\text{g}/\text{m}^3$	ppm
Carbon Monoxide				
8-hour	10000	9	10000	9
1-hour	40000	35	40000	35
Nitrogen Dioxide				
Annual arithmetic	100	0.053	100	0.053
Particulate Matter				
Annual geometric	50		50	
24-hour	150		150	
Sulfur Dioxide				
Annual arithmetic	80	0.03		
24-hour	365	0.14		
3-hour			1300	0.5
Ozone				
1-hour	235	0.12	235	0.12
Nonmethane Hydrocarbons				
3-hour	160	0.24	160	0.24
Lead				
Calendar quarter	1.5		1.5	

It is entirely possible for one new source to be required to perform a PSD review for some pollutants in addition to performing a NAA review for others. The basic rule is that a major new plant is subject to PSD requirements if it is built in a clean area, and subject to nonattainment requirements if built in a dirty area; but, a new plant can be subject to both PSD and nonattainment reviews if:

- cross-boundary effects would cause emissions from a plant in a PSD area to impact a nonattainment area or vice versa; or
- the plant's location is classified as PSD regarding certain pollutants, but classified as nonattainment regarding other pollutants.

If a new plant is subject to both PSD and nonattainment, it may be required to undergo two separate reviews; one by the federal EPA (PSD review) and one by the state agency (nonattainment review).

As part of the air permit reviews described above, the applicant will also need to address the emission standards established by the EPA for specific industrial categories (New Source Performance Standards) and specific highly toxic pollutants (National Emission Standards for Hazardous Air Pollutants). The relevant EPA emission standards applicable to a coal liquefaction facility are described in greater detail in sections under the headings "New Source Performance Standards" and "National Emission Standards for Hazardous Air Pollutants".

Prevention of Significant Deterioration (PSD)

The main purpose of a PSD review is to prevent deterioration of existing clean (attainment) areas, as classified in the regulations. Within a NAAQS attainment or unclassified area (as determined for each specific pollutant), a PSD review is required prior to the construction of new "major sources" of emissions. A source is "major" if it has the "potential to emit" any one of the criteria or non-criteria pollutants listed in Table 3-15 in excess of 250 tons per year (or 100 tons per year if the source is on the special list of 28 industrial categories as detailed in the Clean Air Act). Once a source is classified as "major" for any one criteria pollutant, then a PSD review is also necessary for all other pollutants which are in excess of their associated De minimis emission rates as detailed in Table 3-15. Furthermore, a PSD review is also required for a modification to an existing major source if the increase in emissions resulting from the modification exceeds the De minimis emission rates shown in Table 3-15.

Table 3-15 **DEMINIMIS EMISSION LIMITS**

POLLUTANTS	DEMINIMIS EMISSION RATE tons/year
Carbon Monoxide §	100
Nitrogen Oxides §	40
Particulate Matter §	15
Sulfur Dioxide §	40
Organics §	40
Hydrogen Sulfide	10
Carbonyl Sulfide (as TRS) §	10
Fluorides	3
Beryllium §	0.0004
Lead	0.6
Mercury	0.1
Sulfuric Acid Mist	7
Vinyl Chloride	1

§
a PSD review is required for these pollutants.

Under the PSD program, maximum allowable increases, or "increments", in ambient pollutant concentrations must also not be exceeded. Increments may be depleted for specific pollutants due to prior permit applications being submitted. If existing or proposed facilities have filed for a PSD permit, they may have used up a portion of the increment. Table 3-16 lists the PSD Increments for each area classification (Class I thru Class III).

Since the proposed south central Illinois facility will most likely be a major source located in an attainment area (as per the Illinois EPA), a PSD review will probably be necessary. The PSD permit application for the facility could be structured so that the boilers in the Steam Generation Plant could burn either coal or medium BTU fuel gas. For coal combustion, the boilers would emit primarily particulate matter and sulfur dioxide. During combustion of the medium BTU fuel gas, the same boilers would emit primarily nitrogen oxides and carbon monoxide. As Table 3-17 illustrates, emission control methods were provided for each of these pollutants. The proposed coal liquefaction facility will be required to implement the best available control technology. The Illinois EPA will perform the PSD application review and will issue the PSD permit under a "Delegation of Authority" from the USEPA following the technical review and public participation phases of the permitting process.

The preparation of a PSD permit application may take from six months to over a year (not including one year of preconstruction monitoring which may be required as part of an Ambient Air Quality Analysis), depending on the availability of necessary data. The state agency may require an additional six months to process the permit application prior to final approval. Figure 3-15 illustrates the timing involved in obtaining a PSD permit.

The following elements are necessary in a PSD review:

- Ambient Air Quality Analysis
- Air Quality Impact Analysis
- Additional Impacts Analysis
- Best Available Control Technology (BACT) Analysis

Table 3-16

PSD INCREMENTS AND SIGNIFICANT IMPACT LEVELS

AVERAGING PERIOD	CLASS I INCREMENT μg/m3	CLASS II INCREMENT μg/m3	CLASS III INCREMENT μg/m3	SIGNIFICANT IMPACT LEVEL μg/m3
Carbon Monoxide				
8-hour				500
1-hour				2000
Nitrogen Dioxide				
Annual arithmetic	2.5	25	50	1
Particulate Matter				
Annual geometric	5	19	37	1
24-hour	10	37	75	5
Sulfur Dioxide				
Annual arithmetic	2	20	40	1
24-hour	5	91	182	5
3-hour	25	512	700	25

Table 3-17, Part 1

POSSIBLE AIR EMISSION POINTS AND CONTROL METHODS

<u>Air Emission Point Identification</u>	<u>Pollutant</u>	<u>Control Technology</u>	<u>Control Efficiency/Reference</u>
Fluid Bed Combustion (FBC)	PM	Electrostatic Precipitators	99.80%
H2 Heaters	PM	None	NA
Slurry Heaters			
Fractionator Heaters	PM	None	NA
Hydrotreating Heaters	PM	None	NA
Transfer Houses	PM	Enclosed, Spray and Baghouses	99.80%
Transfer Houses	PM	Enclosed, Spray and Baghouses	99.80%
Coal Pulverizing and Drying	PM	Baghouses	99.80%
Active Storage Pile	PM	Chemical Spray	80.00%
Inactive Storage Pile	PM	Surfactant	80.00%
Dried Coal Storage Vent	PM	Baghouses	99.8%
Stacker	PM	Chemical Spray	80.00%
Haul Road	PM	Covered Trucks & Paved Roads	NA
Non-Hazardous Landfills	PM	NA	NA
Coal Conveyors	PM	Covered	90.00%
Boiler Stacks	SO2	Wellman-Lord FGD	92.38%
H2 Heaters	SO2	None	NA
Slurry Heaters	SO2	None	NA
Fractionator Heaters	SO2	None	NA
Hydrotreating Heaters	SO2	None	NA

PM: PARTICULATE MATTER

Table 3-17, Part 2

POSSIBLE AIR EMISSION POINTS AND CONTROL METHODS

CO2 Stripper	CO	NA	NA
Boiler Stacks	CO	NA	NA
H2 Heaters	CO	NA	NA
Slurry Heaters	CO	NA	NA
Fractionator Heaters	CO	NA	NA
Hydrotreating Heaters	H2S	NA	NA
Boiler Stacks	NOx	Proper Boiler Design	40.00%
H2 Heaters	NOx	NA	10.00%
Slurry Heaters	NOx	NA	10.00%
Fractionator Heaters	NOx	NA	10.00%
Hydrotreating Heaters	NOx	NA	10.00%
Boiler Stacks	VOC	NA	NA
H2 Heaters	VOC	NA	NA
Slurry Heaters	VOC	NA	NA
Fractionator Heaters	VOC	NA	NA
Hydrotreating Heaters	VOC	NA	NA
600# Steam	VOC	NA	NA
Intermediate Storage Tanks	VOC	Floating Roofs and Temperature Constant	NA
Final Products Storage Tanks	VOC	Floating Roofs and Temperature Constant	NA
Tank Cars/Truck Loading	VOC	Vapor Recovery System	NA
Fugitives (drains, seals valves)	VOC	Dual Seals and Good Maintenance	NA
Boiler Stacks	Fluorides	ESP and Wet Scrubber	99.80%
Boiler Stacks	Beryllium	ESP and Wet Scrubber	99.80%
Boiler Stacks	Lead	ESP and Wet Scrubber	99.80%
Boiler Stacks	Mercury	ESP and Wet Scrubber	99.80%

VOC: VOLATILE ORGANIC COMPOUND

Figure 3-15

Timing for a PSD Permit (1)

(1) This figure illustrates the typical timing requirements as indicated in the regulations and confirmed through conversations with the Illinois EPA. Individual permits may require more or less time than that indicated above depending on the complexity of the source(s) to be permitted.

Ambient Air Quality Analysis

One year of preconstruction monitoring may be necessary to determine present air quality unless dispersion modeling demonstrates that maximum projected ground level concentrations due to the facility will be less than the De minimis concentrations contained in Table 3-18.

Air Quality Impact Analysis

A 5-year dispersion modeling analysis must be conducted to determine if new pollutant emissions will cause or contribute to a violation of the NAAQS or PSD increment.

Additional Impacts Analysis

An additional impacts analysis must be conducted to assess the predicted impacts from the new source on visibility, soils, and vegetation, in primarily Class I areas such as national parks.

Best Available Control Technology (BACT) Analysis

In the PSD review process for major sources, Best Available Control Technology (BACT) must be addressed to determine the extent of equipment and procedures which will be used to control emissions. The following sections detail possible equipment specifications and emission limits which may be required as a result of the BACT analysis. References to other applicable regulations are provided in each of the following sections. However, BACT may require more stringent emission limits than those contained in the referenced regulations. Table 3-17 details the Best Available Control Technology (BACT). The USEPA presently requires a top-down BACT approach to analyzing control equipment requirements.

Sulfur Dioxide (SO₂) Emissions

Control of sulfur dioxide emissions will be divided into two categories: bulk sulfur removal and residual sulfur removal.

Table 3-18

**DEMINIMIS CONCENTRATIONS BELOW WHICH
PRECONSTRUCTION MONITORING MAY NOT BE REQUIRED**

POLLUTANTS	DEMINIMIS CONCENTRATION $\mu\text{g}/\text{m}^3$	MAXIMUM AVERAGING TIME hours
Carbon Monoxide	575	8
Nitrogen Oxides	14	annual
Particulate Matter	10	24
Sulfur Dioxide	13	24
Reduced Sulfur Compounds	10	1
Hydrogen Sulfide	0.04	1
Carbonyl Sulfide (as TRS)	10	1
Fluorides	0.25	24
Beryllium	0.0005	24
Lead	0.1	24
Mercury	0.25	24
Vinyl Chloride	15	24

For bulk sulfur removal, the highest percentage of control (permit application) may be offered by combusting the off-gases of both the Claus and incinerator within the boiler, cycling the resultant SO_2 back through the Claus units, and treating the remaining residual SO_2 with one of the methods mentioned below. Other bulk sulfur removal/recovery methods are limited with respect to their applicability to the H-coal liquefaction process.

For residual sulfur removal, a wider selection of alternatives is available. First analysis indicates that any of the following may be viable residual SO_2 control alternatives:

- low sulfur fuel
- wet flue gas desulfurization (FGD) utilizing one of the following reagents: lime, limestone, sodium, or dual alkali.
- dry flue gas desulfurization (FGD); eg. spray dryer absorber with a rotary atomizer.

SO_2 emission limits applicable to a coal liquefaction facility are contained in the following regulations, details of which are discussed later.

- Illinois Sulfur Emission Standards and Limitations; Subpart B - New Fuel Combustion Emission Sources
- NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units
- NSPS Subpart J - Petroleum Refineries (Claus Sulfur Recovery)

Particulate Matter (PM) Emissions

Sources within the coal liquefaction project which could potentially contribute to particulate matter emissions are:

- Process and boiler off-gases
- Coal conveying, handling and fugitive emissions

Particulate matter emission limits applicable to a coal liquefaction facility are contained in the following regulations:

- Illinois Particulate Matter Emission Standards and Limitations; Subpart D - PM Emissions from Incinerators; Subpart E - PM Emissions from Fuel Combustion Emission Sources; Subpart K - Fugitive PM Emissions
- NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units
- NSPS Subpart E - Incinerators
- NSPS Subpart J - Petroleum Refineries
- NSPS Subpart Y - Coal Preparation Plants

Process and Boiler Particulate Matter (PM) Emissions

The following control strategies are viable alternatives for controlling the process and boiler particulate matter emissions from a coal liquefaction facility:

- Cold and Hot Side Electrostatic Precipitators (ESP)
- Fabric Filters (Baghouses)

For the control of fly ash from coal-fired boilers requiring high collection efficiency, the use of cold side electrostatic precipitators and baghouses typically represent BACT for process and boiler particulate matter emissions.

Coal Conveying, Handling and Fugitive Emissions

For coal conveying throughout the plant, BACT typically involves all conveyors being covered and transfer points and stations being enclosed and exhausted to local dust collection systems (usually baghouses). In order to minimize emissions, conveyors should be designed to have moderate belt speeds with minimal transfer points and minimal transfer drop distances. Use of water and surfactant suppression sprays from the screening bin and partially covering the conveyors are effective dust control methods which may also be required as BACT.

Coal Drying and Pulverizing Areas

Emissions from the coal dryer and pulverizing area should be controlled by utilization of dust collection baghouse systems and pneumatic conveying systems for pulverized coal conveying.

If possible, dust collected from the dust collection systems should be charged back on to the belt conveyors so that minimal dust emissions will be produced from this operation.

Coal Storage and Stacking

Emissions from coal storage areas are primarily from the load-in process. The drop height of the material should be reduced to minimize the fugitive emissions. A water and surfactant spray system may also be utilized to reduce emissions. Wetting chemicals sprayed during conveying and stacking retain their effectiveness in storage. Wetting agents retain surface moisture for extended periods thereby preventing dusting during storage.

The coal (and ash) storage facilities should be enclosed and should exhaust to a local dust collection system (usually a baghouse).

For dead coal storage piles, the top and sides of the piles should be covered with surface crusting agents after compaction.

Other Minor Sources of Particulate Matter

Other minor sources of particulate matter will most likely be controlled separately for practical reasons, e.g. using small local collection systems instead of using ductwork and fans for transport to other areas of the plant. Unlike large, custom-designed collection systems, these local collection systems are small packaged systems that are typically permitted as achieving BACT.

Carbon Monoxide (CO) Emissions

CO emissions are expected from the main boiler stacks, the process heater stacks, and the process CO₂ waste gas stream from the gasification and purification processes. Boilers and heaters are designed by the manufacturers for optimum combustion efficiency and this design inherently minimizes the production of carbon monoxide. There are no specific external controls or associated emission limits available for carbon monoxide. In addition, there are no existing or proposed limits for CO associated with the New Source Performance Standards (NSPS) as identified in 40 CFR Part 60. Therefore, optimum boiler and heater design should be representative of BACT. Based on the low CO emission rate, the stack height, and the high exit velocity, ground level impacts from the CO₂ waste gas stream should be minimal.

Carbon monoxide emission limits applicable to a coal liquefaction facility are contained in the following regulations:

- Illinois Carbon Monoxide Emission Standards and Limitations; Subpart B - Fuel Combustion Emission Sources; Subpart C - Incinerators; Subpart N - Petroleum Refining and Chemical

Nitrogen Oxides (NO_x) Emissions

Nitrogen oxides emissions are expected from the main boiler stacks and the process heater stacks at the proposed coal liquefaction facility. The following technologies have been demonstrated or are being investigated to control NO_x emissions:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Fluidized Bed Combustion (FBC)
- Combustion Modifications including:

Flue Gas Recirculation
Low Excess Air (LEA)
Wet Flue Gas Denitrification (FGDN)
Overfire Air (OFA)
Low NO_x Burners
Burners Out of Service (BOOS)
Reburning with Natural Gas
Staged Combustion

Recent BACT determinations indicate that NO_x emission limits for recently permitted coal-fired units range from 0.3 to 0.6 lb/MMBTU.

NO_x emission limits applicable to a coal liquefaction facility are contained in the following regulations:

- Illinois NO_x Emission Standards and Limitations; Subpart B - New Fuel Combustion Emission Sources
- NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units

Volatile Organic Compound (VOC) Emissions

The VOC emissions are expected from the product and intermediate product storage tanks, and from equipment leaks at the proposed coal liquefaction facility. The following regulations contain design specifications pertinent to storage tanks and equipment leaks:

- Illinois Organic Material Emission Standards and Limitations; Subpart B - Organic Emissions from Storage and Unloading Operations; Subpart C - Organic Emissions from Miscellaneous Equipment
- NSPS for petroleum storage vessels
- NSPS for equipment leaks
- NSPS for SOCM operations
- NESHAP for equipment leaks

Beryllium

Emissions of beryllium from the coal liquefaction facility (particularly the boiler stacks) are expected to be significant (greater than 0.0004 tons per year), based upon an earlier study. The control techniques utilized on the boilers to control particulate matter (PM) emissions will, at the same time, control beryllium and other heavy metal emissions. Beryllium emission limits applicable to a coal liquefaction facility are contained in the following regulation:

- **NESHAP for Beryllium**

Air Quality Nonattainment Area (naa) Review and Illinois State Air Regulations

The basic provision is that in any area where an ambient air quality standard is being violated (nonattainment), no major new source can be constructed without a permit, which shall impose stringent control requirements and require sufficient emission "offsets" to assure progress toward compliance.

Sources subject to nonattainment requirements include any new plant (or modification) with potential emissions equal to or greater than 100 tons per year of particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, or volatile organic compounds.

Typically, the permit requirements of a nonattainment review fall under the jurisdiction of the state agency. Therefore, the permit requirements for a nonattainment review and any applicable Illinois state air regulations have been summarized in the following sections. The nonattainment permit requirements are as follows:

- **Emission offsets** - enforceable reductions in existing sources of pollution, which exceed anticipated emissions from the new source.
- **LAER** - Lowest Achievable Emission Rate, which determines the extent of equipment necessary to control emissions, as defined case by case under tight standards.
- **Other sources in compliance** - all other plants in the state owned or operated by the same company must be on approved compliance schedules.

- Compliance with the applicable SIP - this is applied overall to the State's program. State Implementation Plans (SIPs) developed by the states and approved by the EPA contain the actual abatement requirements devised to reduce air pollution as necessary to achieve compliance with the NAAQS. New plants will be subject to requirements of any applicable SIP. These normally specify both limitations on allowable emissions and procedural requirements for preconstruction review. Since many SIPs have been revised repeatedly, care must be used to verify currently applicable SIP revisions.

The State of Illinois Environmental Protection Agency (IEPA) has developed ambient air quality standards identical to the National Ambient Air Quality Standards (NAAQS) listed in Table 3-14. Illinois also has new source standards but, like the United States Environmental Protection Agency, the State has not developed standards specifically for coal liquefaction plants. Those sections of the Illinois State Air Regulations relevant to equipment that is similar to that contained in coal liquefaction plants are detailed below.

Visible and Particulate Matter Emission Standards and Limitations

Subpart B - Visual Emissions

212.122(a) No person shall allow the emission of smoke or other particulate matter into the atmosphere from any new fuel combustion emission source with actual heat input greater than 73.2 MW (250 mmbtu/hr), having an opacity greater than 20 percent.

Subpart D - Particulate Matter Emissions from Incinerators

The following rules would apply to the waste sludge incinerator at the proposed coal liquefaction facility.

212.181(a) No person shall allow the emission of particulate matter into the atmosphere from any incinerator burning more than 27.2 Mg (60,000 lbs) of refuse per hour to exceed 115 mg (0.05 gr/scf) of effluent gases corrected to 12 percent carbon dioxide.

212.181(b) No person shall allow the emission of particulate matter into the atmosphere from any incinerator burning more than 0.907 Mg (2000 lbs) but less than 27.2 Mg (60,000 lbs) of refuse per hour to exceed 183 mg (0.08 gr/scf) of effluent gases corrected to 12 percent carbon dioxide.

212.181(d) No person shall allow the emission of particulate matter into the atmosphere from all other new incinerators to exceed 229 mg (0.1 gr/scf) of effluent gases corrected to 12 percent carbon dioxide.

Subpart E - Particulate Matter Emissions from Fuel Combustion Emission Sources

This rule would apply to any boilers, heaters or other fuel combustion devices using solid fuel exclusively at the proposed coal liquefaction facility.

212.204 No person shall allow the emission of particulate matter into the atmosphere from any new fuel combustion emission source using solid fuel exclusively to exceed 0.15 kg of particulate matter per MW-hr of actual heat input (0.1 lbs/mmbtu) in any one hour period.

Subpart K - Fugitive Particulate Matter

212.304(a) All storage piles of materials with uncontrolled emissions of fugitive particulate matter in excess of 45.4 Mg per year (50 T/year) which are located within a facility whose potential particulate emissions from all sources exceed 90.8 Mg per year (100 T/year) shall be protected by a cover or sprayed with a surfactant solution or water on a regular basis, as needed.

212.305 All conveyor loading operations to storage piles shall utilize spray systems, telescope chutes, stone ladders, or other equivalent methods.

212.307 All unloading and transporting operations of materials collected by pollution control equipment shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods.

212.308 Crushers, grinding mills, screening operations, bucket elevators, conveyor transfer points, conveyors, bagging operations, storage bins and fine product truck and railcar loading operations shall be sprayed with water or a surfactant solution, utilize choke-feeding or be treated by an equivalent method.

212.313 If particulate collection equipment is operated, emissions from such equipment shall not exceed 68 mg/dscm (0.03 gr/dscf).

Sulfur Emission Standards and Limitations

Subpart B - New Fuel Combustion Emission Sources

The following rules would apply to any boilers, heaters, or other fuel combustion devices using solid fuel exclusively at the proposed coal liquefaction facility.

214.121(a) No person shall allow the emission of sulfur dioxide into the atmosphere in any one hour period from any new fuel combustion emission source greater than 73.2 MW (250 mmbtu/hr), burning solid fuel exclusively, to exceed 1.86 kg of sulfur dioxide per MW-hr of actual heat input (1.2 lbs/mmbtu).

214.122(a) No person shall allow the emission of sulfur dioxide into the atmosphere in any one hour period from any new fuel combustion emission source with actual heat input smaller than, or equal to, 73.2 MW (250 mmbtu/hr), burning solid fuel exclusively, to exceed 2.79 kg of sulfur dioxide per MW-hr of actual heat input (1.8 lbs/mmbtu).

214.301 No person shall allow the emission of sulfur dioxide into the atmosphere from any process emission source to exceed 2000 ppm.

Organic Material Emission Standards and Limitations

Subpart B - Organic Emissions from Storage and Loading Operations

For the proposed coal liquefaction facility, these rules would apply to several of the product and intermediate product storage tanks since the sizes of the tanks and the vapor pressures of the liquids fall into the categories prescribed by this subpart.

215.121 No person shall allow the storage of any volatile organic liquid with a vapor pressure of 17.24 kPa (2.5 psia) or greater at 294.3 K (70°F) or any gaseous organic material in any stationary tank, reservoir, or other container of more than 151 cubic meters (40,000 gal) capacity unless such container:

- is a pressure tank capable of withstanding the vapor pressure of such liquid or the pressure of the gas; or
- is equipped with one of the following vapor loss control devices: (1) a floating roof which rests on the surface of the volatile organic liquid and is equipped with a closure seal or seals between the roof edge and the tank wall; or (2) a vapor recovery system consisting of a vapor gathering system capable of collecting 85% or more of the uncontrolled volatile organic material that would otherwise be emitted to the atmosphere; and a vapor disposal system capable of processing such volatile organic material so as to prevent its emission to the atmosphere.

215.122(a) No person shall allow the discharge of more than 3.6 kg/hr (8 lbs/hr) of organic material into the atmosphere during the loading of any organic material from the aggregate loading pipes of any loading facility having through-put of greater than 151 cubic meters per day (40,000 gal/day) into any railroad tank car, tank truck, or trailer unless such loading facility is equipped with submerged loading pipes.

215.122(b) No person shall allow the loading of any organic material into any stationary tank having a storage capacity of greater than 946 liters (250 gal), unless such tank is equipped with a permanent submerged loading pipe.

215.123(b) No owner or operator of a stationary storage tank with a capacity greater than 151.42 cubic meters shall allow the storage of any volatile petroleum liquid unless:

- the tank is equipped with one of the vapor loss control devices specified in Section 215.121;
- there are no visible holes, tears, or other defects in the seal or any seal fabric or material of any floating roof;
- all openings of any floating roof deck, except stub drains, are equipped with covers, lids or seals.

215.124(a) No owner or operator of a stationary storage tank equipped with an external floating roof shall allow the storage of any volatile petroleum liquid in the tank unless:

- the tank has been fitted with a continuous secondary seal extending from the floating roof to the tank wall (rim mounted secondary seal);
- each seal is intact and uniformly in place around the circumference of the floating roof between the floating roof and the tank wall;
- the accumulated area of gaps exceeding 0.32 centimeter (1/8 inch) in width between the secondary seal and the tank wall shall not exceed 21.2 square centimeters per meter of tank diameter (1.0 square inch per foot of tank diameter);
- emergency roof drains are provided with slotted membrane fabric covers (or equivalent) across at least 90 percent of the area of the opening;
- openings are equipped with projections into the tank which remain below the liquid surface at all times.

Subpart C - Organic Emissions from Miscellaneous Equipment

215.141(a) No person shall use any single or multiple compartment effluent water separator which receives effluent water containing 757 liter/day (200 gal/day) or more of organic material from any equipment processing, refining, treating, storing or handling organic material unless such water effluent separator is equipped with air pollution control equipment capable of reducing by 85% or more the uncontrolled organic material emitted to the atmosphere.

215.142 No person shall allow the discharge of more than 32.8 ml (2 cubic inches) of volatile organic liquid with vapor pressure of 17.24 kPa (2.5 psia) or greater at 294.3 K (70°F) into the atmosphere from any pump or compressor in any 15 minute period at standard conditions.

215.143 No person shall allow the emission of organic material into the atmosphere from any vapor blowdown system or any safety relief valve unless such emission is controlled to 10 ppm equivalent methane (molecular weight 16.0) or less, or by combustion in a smokeless flare.

Carbon Monoxide Emission Standards and Limitations

This rule would apply to any boilers, heaters, or other fuel combustion devices at the proposed coal liquefaction facility.

Subpart B - Fuel Combustion Emission Sources

216.121 No person shall allow the emission of carbon monoxide into the atmosphere from any fuel combustion emission source with actual heat input greater than 2.9 MW (10 mmBtu/hr) to exceed 200 ppm, corrected to 50 percent excess air.

Subpart C - Incinerators

The following rule would apply to the waste sludge incinerator at the proposed coal liquefaction facility.

216.141 No person shall allow the emission of carbon monoxide into the atmosphere from any incinerator to exceed 500 ppm, corrected to 50 percent excess air.

Subpart N - Petroleum Refining and Chemical

This rule would apply to the CO₂ waste gas stream from the gasification and purification process at the proposed coal liquefaction facility.

216.361(a) No person shall allow the emission of a carbon monoxide waste gas stream into the atmosphere from a petroleum or petrochemical process unless such waste stream is burned in a direct flame afterburner or carbon monoxide boiler (or other equivalent air pollution control equipment) so that the resulting concentration of carbon monoxide in such waste gas stream is less than or equal to 200 ppm corrected to 50 percent excess air.

Nitrogen Oxide Emission Standards and Limitations

This rule would apply to any boilers, heaters, or other solid fossil fuel-firing devices at the proposed coal liquefaction facility.

Subpart B - New Fuel Combustion Emission Sources

217.121 No person shall allow the emission of nitrogen oxides into the atmosphere in any one hour period from any new fuel combustion emission source with an actual heat input equal to or greater than 73.2 MW (250 mmbtu/hr) to exceed the following:

- for solid fossil fuel firing, 1.08 kg/MW-hr (0.70 lbs/mmbtu) of actual heat input.

New Source Performance Standards (NSPS)

Emission standards have been established for specific industrial categories. Standard criteria are based on proven best available control technology for each listed industry. Since NSPS have not been established specifically for coal liquefaction facilities, the NSPS for similar facility processes have been presented below as guidelines for the coal liquefaction facility.

Subpart Db - Industrial-Commercial-Institutional Steam Generating Units

This subpart applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hr). These rules would apply to any of the boilers, heaters, or other coal-combusting devices at the proposed coal liquefaction facility meeting the heat input requirements described earlier.

Sulfur Dioxide (SO₂) Limits

No owner or operator of an affected facility that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 10 percent of the potential sulfur dioxide emission rate (90 percent reduction) and that

contain sulfur dioxide in excess of the emission limit determined according to the formula contained in the regulations.

No owner or operator of an affected facility that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 20 percent of the potential sulfur dioxide emission rate (80 percent reduction) and that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input.

No owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of sulfur dioxide emissions, shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 50 percent of the potential sulfur dioxide emission rate (50 percent reduction) and that contain sulfur dioxide in excess of the emission limit determined according to the formula contained in the regulations.

Compliance with the emission limits and percent reduction requirements is determined on a 30-day rolling average basis.

Particulate Matter (PM) Limits

No owner or operator of an affected facility which combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere any gases that contain particulate matter in excess of the following emission limits:

- 22 ng/J (0.05 lb/million Btu) heat input if the affected facility combusts only coal, or if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent.
- 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Nitrogen Oxides (NO_x) Limits

No owner or operator of an affected facility that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of the specific emission limits associated with this subpart as detailed in Table 3-19.

Subpart E - Incinerators

This subpart applies to each incinerator of more than 45 metric tons per day charging rate (50 tons per day).

Table 3-19

**NSPS SUBPART Db - NITROGEN OXIDE LIMITS
(30-DAY ROLLING AVERAGES)**

STEAM GENERATOR TYPE	EMISSION LIMIT ng/J	EMISSION LIMIT lb/mmbtu
Natural Gas and Distillate Oil		
Low heat release	43	0.1
High heat release	86	0.2
Residual Oil		
Low heat release	130	0.3
High heat release	170	0.4
Coal		
Mass-feed stoker	210	0.5
Spreader stoker and fluidized bed combustion	260	0.6
Pulverized coal	300	0.7
Lignite	260	0.6
Coal-derived synthetic fuels	210	0.5

No owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO₂.

Subpart J - Petroleum Refineries

This subpart applies to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. For the proposed coal liquefaction facility, this subpart would apply to the hydrotreatment stages and the Claus sulfur recovery plant.

Particulate Matter (PM) Limit

No owner or operator shall discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

- Particulate matter in excess of 1.0 lb/1000 lb of coke burn-off in the catalyst regenerator.
- Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

Carbon Monoxide (CO) Limit

No owner or operator shall discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

Sulfur Oxides Limits

No owner or operator subject to this subpart shall discharge any gases into the atmosphere from any Claus sulfur recovery plant of 20 long tons per day (LTD) or less containing in excess of:

- 0.025 percent by volume of sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system, or a reduction control system followed by incineration, or
- 0.030 percent by volume of reduced sulfur compounds and 0.0010 percent by volume of hydrogen sulfide calculated as sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by a reduction control system not followed by incineration.

Each owner or operator subject to this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

- With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent, or
- Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/1000 kg coke burn-off.

Subpart Kb - Volatile Organic Liquid Storage Vessels

This subpart applies to each storage vessel with a capacity greater than or equal to 40 cubic meters that is used to store volatile organic liquids (VOLs). For the proposed coal liquefaction facility, this rule would apply to many of the product and intermediate product storage tanks since the sizes of the tanks and the vapor pressures of the liquids fall into the categories prescribed by this subpart.

The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 cubic meters containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 cubic meters but less than 151 cubic meters containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

A fixed roof in combination with an internal floating roof meeting the following specifications:

The internal floating roof shall rest or float on the liquid surface inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

- A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal).
- A mechanical shoe seal.

- Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof.

Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. Each penetration of the internal floating roof for the purpose of sampling shall be a sampling well with a slit fabric cover that covers at least 90 percent of the opening.

Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

An external floating roof meeting the following specifications:

Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

- The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. The seal shall completely cover the annular space between the edge of the floating roof and tank wall.
- The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion.

Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface.

Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times except when the device is in actual use.

Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

Rim vents are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

Automatic bleeder vents and rim space vents are to be gasketed.

Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

The roof shall be floating on the liquid at all times except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled.

A closed vent system and control device meeting the following specifications:

The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background.

The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.

Subpart Y - Coal Preparation Plants

This subpart applies to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal-cleaning equipment, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems. For the proposed coal liquefaction facility, each of these affected facilities will process more than 200 tons of coal per day and therefore the rules in this subpart apply to the proposed coal liquefaction facility.

No owner or operator shall cause to be discharged into the atmosphere from any thermal dryer, gases which:

- contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).
- exhibit 20 percent opacity or greater.

No owner or operator shall cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

- contain particulate matter in excess of 0.040 g/dscm (0.018 gr/dscf).
- exhibit 10 percent opacity or greater.

No owner or operator shall cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

Subpart VV - Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

The rules in this subpart would apply to the specific types of equipment listed below which would be used at a coal liquefaction facility, particularly the equipment in those stages of the process where product and intermediate product is being produced, transported, or stored.

Design specifications are contained in the regulations for the following types of equipment:

- Pumps in light liquid service.
- Compressors.
- Pressure relief devices in gas/vapor service.
- Sampling connection systems.
- Open-ended valves or lines.
- Valves in gas/vapor service or in light liquid service.
- Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors.

- Closed vent systems and control devices for the above equipment.

Subparts NNN and RRR - Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation and Reactor Processes

The rules of this subpart would apply to the reactor and hydrotreatment equipment to be used at the proposed coal liquefaction facility.

The provisions of this subpart apply to each affected facility that is part of a process unit that produces any of the chemicals listed in the regulation as a product, co-product, by-product, or intermediate. Applicability will be determined by evaluating each pertinent stream for chemicals contained in the list.

For distillation processes, the affected facility is any of the following for which construction, modification, or reconstruction commenced after December 30, 1983:

- Each distillation unit not discharging its vent stream into a recovery system.
- Each combination of a distillation unit and the recovery system into which its vent stream is discharged.
- Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

For reactor processes, the affected facility is any of the following for which construction, modification, or reconstruction commenced after June 29, 1990:

- Each reactor process not discharging its vent stream into a recovery system.
- Each combination of a reactor process and the recovery system into which its vent stream is discharged.
- Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

Each owner or operator shall either:

- Reduce emissions of total organic compounds (TOC) less methane and ethane by 98 weight-percent, or to a TOC concentration (less methane and ethane) of 20 ppmv, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

- Combust the emissions in a flare that meets the requirements of NSPS; or
- Maintain the TRE Cost Index Value (as calculated in the regulation) greater than 1.0 without the use of VOC emission control devices.

The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit shall operate according to manufacturer's specifications the following equipment:

- A temperature monitoring device equipped with a continuous recorder and having an accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius, or ± 0.5 degrees Celsius, whichever is greater.
- Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox.
- Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.
- A flow indicator that provides a record of vent stream flow to the incinerator at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the inlet of each incinerator and before being joined with any other vent stream.

The owner or operator of an affected facility that uses a flare to seek to comply with the TOC emission limit shall operate according to manufacturer's specifications the following equipment:

- A heat sensing device, such as an ultra-violet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.
- A flow indicator that provides a record of vent stream flow to the flare at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the flare and before being joined with any other vent streams.

The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with the TOC emission limit shall operate according to manufacturer's specifications the following equipment:

- A flow indicator that provides a record of vent stream flow to the boiler or process heater at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the inlet of each boiler or process heater and before being joined with any other vent stream.
- A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of ± 1 percent of the temperature being measured expressed in degrees Celsius, or ± 0.5 degrees Celsius, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.
- Monitor and record the periods of operation of the boiler or process heater if the design heat input capacity of the boiler or process heater is 44 MW (150 million Btu/hr) or greater. The records must be readily available for inspection.

Subpart QQQ - VOC Emissions from Petroleum Refinery Wastewater Systems

Design specifications for the following petroleum refinery wastewater systems are contained in the regulations:

- Individual drain systems.
- Junction boxes and sewer lines.
- Oil-water separators.
- Closed vent systems and control devices for the above listed equipment.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

The EPA has established specific emission standards for several highly toxic pollutants. Details of these standards are described below for each regulated pollutant.

Subpart C - Beryllium

Emissions to the atmosphere from stationary sources shall not exceed 10 grams of beryllium over a 24-hour period, or shall meet an ambient concentration limit on beryllium in the vicinity of the stationary source of 0.01 micrograms per cubic meter, averaged over a 30-day period. For the proposed coal liquefaction facility, this rule would apply to emissions primarily from the boiler stacks.

Subpart F - Vinyl Chloride

The concentration of vinyl chloride in each exhaust gas stream from any equipment used in vinyl chloride formation and/or purification is not to exceed 10 ppm averaged for a 3-hour period (proposed: 5 ppm). For the proposed coal liquefaction facility, this rule would apply to emissions primarily from the boiler stacks.

Subpart V - Equipment Leaks of Volatile Hazardous Air Pollutants (Fugitive Emission Sources)

The rules in this subpart would apply to the specific types of equipment listed below which would be used at a coal liquefaction facility, particularly the equipment in those stages of the process where product and intermediate product is being produced, transported, or stored.

Pumps (in fluid service)

- Each pump shall be monitored monthly to detect leaks.
- Each pump shall be visually inspected each calendar week for indications of liquids dripping from the pump seal.
- When a leak is detected, it shall be repaired no later than 15 calendar days after it is detected.
- A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the monthly monitoring requirements.
- Any pump that is designated for no detectable emissions (less than 500 ppm above background) is exempt from the monthly monitoring and 15-day repair requirements.

- If any pump is equipped with a closed-vent system capable of capturing and transporting any leakage from the seal(s) to a control device, then it is exempt from these requirements.

Compressors (in fluid service)

- Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of process fluid to the atmosphere.
- Each compressor seal system shall be:
 - operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
 - equipped with a barrier fluid system that is connected by a closed-vent system to a control device; or
 - equipped with a system that purges the barrier fluid into a process stream with zero VHAP emissions to the atmosphere.
- Each barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.
- Each sensor shall be checked daily or shall be equipped with an audible alarm.
- If any compressor is equipped with a closed-vent system capable of capturing and transporting any leakage from the seal(s) to a control device, then it is exempt from these requirements.

Pressure Relief Devices in Gas/Vapor Service

- Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions (less than 500 ppm above background).
- After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions (less than 500 ppm above background) no later than 5 calendar days after each pressure release.
- Any pressure relief device that is equipped with a closed-vent system capable of capturing and transporting leakage from the pressure relief device to a control device is exempt from these requirements.

Sampling Connection Systems

Each sampling connection system shall be equipped with a closed-purge or closed-vent system which will:

- return the purged process fluid directly to the process line with zero VHAP emissions to the atmosphere; or
- collect and recycle the purged process fluid with zero VHAP emissions to the atmosphere; or
- be designed and operated to capture and transport all of the purged process fluid to a control device.

Open-ended Valves (one side in contact with process fluid and one side open to atmosphere)

- Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve.
- The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
- When a double block and bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves.

Valves (in fluid service)

- Each valve shall be monitored monthly to detect leaks.
- When a leak is detected, it shall be repaired no later than 15 calendar days after the leak is detected.
- A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- Any valve that is designated for no detectable emissions (less than 500 ppm above background) is exempt from the monthly monitoring requirements.

Pressure Relief Devices and Flanges in Liquid Service

- Pressure relief devices in liquid service and flanges and other connectors shall be monitored within 5 days if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.
- When a leak is detected, it shall be repaired no later than 15 calendar days after it is detected.
- The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

Product Accumulator Vessels

Each product accumulator vessel shall be equipped with a closed-vent system capable of capturing and transporting any leakage from the vessel to a control device.

Closed-vent Systems and Control Devices

- Vapor recovery systems (eg. condensers, absorbers, etc.) shall be designed and operated to recover the organic vapors vented to them with an efficiency of 95 percent or greater.
- Enclosed combustion devices shall be designed and operated to reduce the VHAP emissions vented to them with an efficiency of 95 percent or greater, or to provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 degrees C.
- If flares are used they will comply with the requirements of Section 60.18 of the National Emission Standards for Hazardous Air Pollutants (NESHAP).
- Owners or operators of the control devices that are used to comply with these provisions shall monitor these control devices to ensure that they are operated and maintained in conformance with their design.
- Closed-vent systems and control devices used to comply with these provisions shall be operated at all times when emissions may be vented to them.

1990 Amendments to the Clean Air Act

On November 15, 1990, President Bush signed into law the 1990 Amendments to the Clean Air Act. The Amendments are divided into four main titles dealing with attainment and maintenance of air quality standards (smog), motor vehicles and alternative fuels, toxic air pollutants, and acid deposition (acid rain). Other titles outline permit and enforcement requirements and provisions for phasing out chemicals that

contribute to the depletion of the ozone layer. The following sections will discuss in general terms these titles as they relate to coal liquefaction facilities.

Title III - Air Toxics

Congress established a list of 189 toxic chemicals that must be controlled. Any facility releasing over 10 tons per year of a listed chemical or 25 tons of any combination of listed chemicals would be classified as a major emission source and would be subject to controls. For each category of point sources (chemical plants, oil refineries, steel mills, etc.) EPA must issue a standard for maximum available control technology (MACT). About 250 source categories will be subject to the regulations.

The EPA is to have standards available for at least 41 source categories within two years, and all of them within three years after they are issued. Compliance will be managed through a permit program. The target is 90% reduction of toxic air emissions by the year 2000.

Title IV - Acid Rain

To control acid rain, sulfur dioxide (SO_2) emissions must be reduced. About 111 utility power plants, mostly in the eastern U.S., are the targets of these reductions. Beginning in 1995, the plants would have to reduce SO_2 emissions below 2.5 pounds per million BTU of power generated. By the year 2000, the SO_2 emission rate would have to be below 1.2 pounds per million BTU generated.

Also under the acid rain provisions, EPA is required by 1993 to establish standards reducing nitrogen oxides (NO_x) by approximately 2 million tons per year. The standards will be based on low- NO_x burner technology.

Chemical Hazard Assessment and Chemical Accidents

Each owner of a facility that handles extremely hazardous substances must prepare an engineering study of the facility to identify possible hazards to public health. These studies must be made available to the public and local emergency planning agencies.

EPA is authorized to promulgate prevention regulations for chemical accidents. The bill also establishes a Chemical Safety Board to investigate chemical accidents.

Permitting and Enforcement

The EPA is required to issue new permit regulations within one year. The individual states which operate the permit programs have four years to include those regulations in their programs. Permits will be issued to include an entire facility, rather than individual units, and will have to be renewed every five years.

Table 3-20

IDENTIFIABLE SOLID AND HAZARDOUS WASTES

<u>SOURCE</u>	<u>WASTE IDENTIFICATION</u>
Coal Crushing/Washing	Refuse
Gasifier	Ash, Slag, and Soot
FBC	Fly Ash, Bottom Ash
Water Treatment	Sludge
Miscellaneous	Facility Refuse and Flotsam
Wastewater Treatment	Filter Cake and Salts*

* Considered a possibly hazardous waste due to the potential presence of heavy metals.

Hazardous Waste

The hazardous wastes generated from the facility will be collected daily (e.g., once during every eight hour shift) to minimize on-site storage. These wastes will be placed on off-road rear dump trucks specifically used to haul only hazardous waste, and disposed in an on-site landfill designed to accept hazardous waste. The leachate and run-off generated during the operation of the landfill will be placed in the leachate pond, and in turn will be pumped to the facility's wastewater treatment plant.

Permitting and Engineering Requirements

The following sections outline the permitting and engineering requirements that are applicable to the on-site management and disposal of solid and hazardous wastes that have a potential to be generated at the proposed facility.

Solid Waste

In Section 21(d)(1) of the Illinois Environmental Protection Act, it specifies that no person shall conduct any waste storage, waste treatment, or waste disposal without a permit granted by the agency. However, no permit would be required for any waste generated by a facility that is treated, stored, or disposed within the site of the facility (not applicable to hazardous waste). Since the solid wastes that will be generated at the proposed facility will be stored and disposed of on-site, the permitting requirements of Part 807, Subpart B of the Illinois Solid and Special Waste Management Regulations will not be required for the proposed facility. This exemption, however, does not preclude the facility from complying with the sanitary landfill requirements specified in Part 807, Subpart C of the regulations. These regulations require that the sanitary landfill (e.g., cells) be designed, operated, and maintained to meet the following requirements.

1. All refuse shall be deposited into the toe of the fill or into the bottom of the trench.
2. As rapidly as refuse shall be deposited into the toe of the fill, it shall be spread and compacted into layers not to exceed a depth of two feet.
3. The slope of the working face shall be maintained at a ratio of no greater than two horizontal to one vertical.
4. A daily cover consisting of at least six inches of compacted suitable material shall be placed on all exposed refuse at the end of each day of operation.
5. Areas within the landfill in which no refuse will be deposited for a period of at least 60 days shall have a 12-inch intermediate cover made of suitable materials.

6. After a landfill has been filled to capacity, a final cover must be placed on top of the entire unit no later than 60 days following the placement of refuse in the final lift. The final cover must be at least two feet of compacted suitable material.
7. No hazardous waste shall be placed within the sanitary landfill unless it is authorized by a permit.
8. When designing and developing the sanitary landfill, the following requirements shall be met:
 - Adequate shelter, sanitary facilities, and emergency communications must be provided at the landfill area.
 - Sufficient roads must be constructed to allow orderly operation within the landfill site.
 - The landfill area must have fencing, gates, or other measures to control access to the site.
 - Adequate measure for fire protection (Agency approved) must be provided at the landfill site.
 - The landfill must be designed to adequately monitor and control leachate (e.g., primary leachate collection system).
 - The landfill must be designed to adequately control dust.
 - An operational safety program (Agency approved) shall be followed by all personnel working within the landfill site.
9. During the development and operation of the landfill, emissions and discharge of any contaminants into the environment that cause violation of air and water quality regulations, respectively, shall be prohibited.

Hazardous Waste

Landfilling of hazardous waste requires that the facility obtain a hazardous waste permit as required in Section 703.121 of the Illinois Hazardous Waste Management Regulations. In addition, on-site treatment of hazardous waste may also need to be performed at the facility which, in turn would also require a permit. For a new facility, physical construction of a hazardous waste management unit(s) shall not begin unless the facility has submitted both a Part A and Part B of the permit application and received a final effective hazardous waste permit under the Resource Conservation and Recovery Act (RCRA). The permit application for both the Part A and Part B must

be submitted at least 180 days before physical construction of the hazardous waste unit. Figure 3-16 illustrates the timing that is necessary to obtain a hazardous waste disposal permit. Conversations with the Illinois EPA indicate that many applications take as long as 2-3 years before a permit is granted after the application is complete. In addition, this permit application must address the information contained in Section 703, Subpart D of the regulations as follows.

1. Contents of Part A Application (Section 703.181): Note: The Part A Application requirements can usually be obtained in a form format that is distributed by the authorized state agency. The information required in this form corresponds to the following information required in the Part A application.
 - The description of the activities conducted by the applicant which require it to obtain the RCRA permit.
 - Name, mailing address and location of the facility for which the application is submitted.
 - The latitude and longitude of the facility.
 - The operator's name, address, telephone number, ownership status and status as Federal, State, private, public, or other entity.
 - The name, address and phone number of the owner of the facility.
 - Indication of facility status (e.g., new or existing).
 - Listing of all permits or construction approvals received or applied for under the following programs: Underground Injection Control (UIC) permits; National Pollutant Discharge Elimination System (NPDES) permits; Prevention of Significant Deterioration (PSD) permits; Nonattainment programs; NESHAP Preconstruction approvals; Ocean Dumping permits; Dredge or Fill permit; or other relevant environmental permits.
 - A topographic map extending 1609 meters (one mile) beyond the property boundaries of the source depicting the following:
 - a. outline of facility and all intake and discharge structure;
 - b. each hazardous waste treatment, storage, and disposal unit;
 - c. each underground injection well;
 - d. those wells (including drinking water wells) listed in public record or otherwise known to the applicant; and
 - e. surface water bodies and springs within 402 meters from the facility property.

Figure 3-16

Timing for a Hazardous Waste Disposal Permit (1)

(1) This figure illustrates the typical timing requirements as indicated in the regulations and confirmed through conversations with the Illinois EPA. Individual permits may require more or less time than that indicated above depending on the complexity of the source(s) to be permitted. Conversations with the Illinois EPA indicate that many of these types of applications take as long as two to three years before a permit is granted after the application is complete.

- A brief description of the nature of the business.
 - A description of the processes to be used for treating, storing, and disposing of hazardous waste, and the design capacity of such items.
 - A specification of the hazardous waste listed or designated under Section 721 of these regulations.
2. Contents of the Part B Application Section 703.182 to 188, and 200 to 207: The following detailed information must be addressed and/or submitted with the Part B application.
- General information required in the Part B application consists of the following items:
 - a. general facility description;
 - b. chemical and physical analysis of the hazardous waste to be handled in the unit(s) in accordance with Section 724.113 of the regulations;
 - c. a copy of the waste analysis plan that meets the requirements in Section 724.113(c);
 - d. a description of the security procedures and equipment required under Section 724.114;
 - e. a copy of the general inspection schedule prepared in accordance with Section 724.115(b) (included the specific inspection schedule for the hazardous waste unit(s) to be permitted).
 - f. a copy of the contingency plan that meets the requirements of Section 724, Subpart D;
 - g. a description of precautions to prevent accidental ignition or reaction of ignitable, reactive or incompatible waste to demonstrate compliance with Section 724.117;
 - h. description of traffic patterns, estimated volumes, control lanes, stacking lanes, load bearing capacity, and traffic control signals;
 - j. an outline of both the introductory and continuing training programs for personnel involved in hazardous waste management that meets the requirements of Section 724.116;
 - k. a copy of the closure and post-closure plan that is developed in accordance with the requirements of Section 724.212, 218, and 297;
 - l. the most recent closure cost estimate for the facility prepared in accordance with Section 724.242;
 - m. a copy of the documentation required to demonstrate financial assurance under Section 724.243;
 - n. the most recent post-closure cost estimate for the facility prepared in accordance with Section 724.244;

- o. a copy of the documentation required to demonstrate financial assurance under Section 724.245;
 - p. a copy of the documentation which shows compliance with liability requirements under Section 724.247; and
 - q. a topographic map in a scale of 1 in equal to 200 feet, that shows a distance of 1000 feet around the facility with the following: contour lines; map scale and date; 100-yr flood plain area; surface water and intermittent streams; surrounding land use; a wind rose; orientation of the map; legal boundaries of the facility; access control; injection and withdrawal wells both on and off-site; buildings; barriers for drainage or flood control; and location of hazardous waste management units.
- Location information of the Part B application must contain the following information:
 - a. location of any active or inactive shaft or tunneled mine below the facility;
 - b. location of any active faults in the earth's crust within 2 miles of the facility boundary;
 - c. location of existing private wells or existing sources of a public water supply within 100 feet of any disposal unit;
 - d. location of the corporate boundaries of any municipalities within one and one-half miles of the facility boundary;
 - e. documentation showing approval of municipalities if such approval is required;
 - f. identification of whether the facility is located within a 100-year floodplain (provide NFIP map, or map with calculations);
 - g. description of the 100-year floodplain factors (e.g., wave action) which must be considered in designing, constructing, operating or maintaining the facility to withstand washout; and
 - h. various engineering analysis to be performed in accordance with the requirements of Section 703.184 (d) (if facility is located in 100-year floodplain).
 - Groundwater Monitoring information must be addressed in the Part B application and include the following items:
 - a. identification of the uppermost aquifer and aquifers hydraulically interconnected beneath the facility property including, groundwater flow rate and direction, and the basis for making the determination;

- b. in the topographic map required above, the proposed point of compliance as identified in Section 724.195 and proposed groundwater monitoring wells required in Section 724.197 must be shown;
- c. detailed plans and engineering report describing the proposed groundwater monitoring system to be implemented to meet the requirements of Section 274.197.
- d. a description of the groundwater monitoring program that addresses the requirements for detection monitoring under Section 274.198 that will include a proposed list of indicator parameters, waste constituents, or reaction products that can provide a reliable indication of the presence of hazardous constituents in the groundwater;
- e. procedures to calculate background values for each proposed monitoring parameter or constituent; and
- f. a description of the proposed sampling and analysis, and statistical comparison procedures to be utilized in evaluating groundwater monitoring data.

- Exposure information must be included in the Part B application for the disposal of hazardous waste in the landfill, and must include the following information :
 - a. reasonably foreseeable potential releases from both normal operations and accidents at the unit, including releases associated with transportation to and from the unit;
 - b. the potential pathways of human exposure to hazardous wastes or constituents through releases described above; and
 - c. the potential magnitude and nature of the human exposure resulting from such releases.

- Identification of Solid Waste Management Units (SWMUs) must be included in the Part B application, and must address the following:
 - a. the location of all SWMUs on the topographic map described above;
 - b. designation of the type of unit (e.g., tank, surface impoundment, etc...);
 - c. general description and structural description of the SWMUs;

- d. the operation date of when these SWMUs will begin operation; and
- e. specification of all wastes that will be managed at the SWMUs.

- Specific information on the units that will be permitted must be included in the Part B application. For this document, specific information requirements will be addressed for landfills and tanks, since these units have the highest probability for requiring a hazardous waste permit for the proposed facility.

Specific Information for Tank(s): The following information must be included in the Part B application for the permitting of a hazardous waste tank:

- a. a written assessment of the structural integrity and suitability for handling hazardous waste in the tank system, including certification of a registered independent professional engineer as required in Section 724.291 and 292;
- b. dimensions and capacity of each tank;
- c. description of feed system, safety cutoff, bypass systems and pressure controls;
- d. a diagram of the piping, instrumentation, and process flow for each tank system;
- e. a description of materials and equipment used to provide external corrosion protection meeting the requirements of Section 724.292(a)(3)(B), as follows:
 - corrosion-resistant materials of construction such as special alloys, fiberglass reinforced plastic, etc.,
 - corrosion-resistant coating with cathodic protection, or
 - electrical isolation devices such as insulating joints, flanges, etc;
- f. a detailed description of how the tank system(s) will be installed in compliance with Section 724.292(b), (c), (d), and (e);

- g. detailed plans and description of how the secondary containment system for each tank system is or will be designed, constructed and operated to meet the requirements of 724.293(a), (b), (c), (d), (e), and (f), as follows:
- ° constructed of or lined with a material compatible with the waste(s) to be stored in the tanks system,
 - ° must have sufficient strength and thickness to prevent failure owing to pressure gradients (e.g., static head, external hydrogeological forces), physical contact with the waste to which it is exposed, climatic conditions, and the stress of daily operation,
 - ° placed on a foundation or base capable of providing support to the system, resistance to pressure gradients above and below the system, and capable of preventing failure due to settlement, compression, or uplift,
 - ° provided with a leak-detection system that is designed and operated so that it can detect the presence of any releases of hazardous waste in the secondary containment system within 24 hours from the time the release first occurred,
 - ° sloped or otherwise designed or operated to drain and remove liquids resulting from leaks, spills, or precipitation,
 - ° an external liner must be capable of containing 100 percent of the capacity of the largest tank within the secondary containment system and prevent **run-on** or infiltration of precipitation into the secondary containment system unless the system has excess capacity to contain precipitation resulting from a 25-year, 24-hour rainfall event,
 - ° the external liner must be free of cracks or gaps, and must completely surround the tanks and cover the surrounding earth likely to come into contact with the waste being released from the tank,
 - ° the vault system must be capable of containing 100 percent of the capacity of the largest tank within the secondary containment

- system and prevent **run-on** or infiltration of precipitation into the containment system unless the system has excess capacity to contain precipitation from a 25-year, 24-hour rainfall event,
- the vault system must be constructed with chemical-resistant water stops in place at all joints (if any),
 - the vault system must be provided with an impermeable interior coating or lining that is compatible with the stored waste and will prevent the migration of any waste released into the containment system,
 - the vault system must be provided with a means to protect against the formation of and ignition of vapors within the vault (only applicable if the waste meets definition of ignitable or reactive characteristic hazardous waste),
 - the vault system must be provided with an exterior moisture barrier to prevent migration of moisture into the vault if the vault is subject to hydraulic pressures, and
 - all ancillary equipment associated with the tank must be provided with secondary containment (e.g., trench, jacketing, double-walled pipe) unless it is exempted under Section 724.293(f);
- h. description of control and practices to prevent spills and overflows, as required under Section 724.294(b); and
- i. for tank systems in which ignitable, reactive or incompatible wastes are to be stored or treated, a description of how operating procedures, the tank system, and facility design will achieve compliance with the requirements of Section 724.298 and 724.299.

Specific Information for Landfill(s): The following types of information must be included in the Part B application for the permitting of a hazardous waste landfill:

- a. a list of the hazardous wastes placed or to be placed in each landfill or landfill cell;
- b. detailed plans and an engineering report describing how the

- landfill will be designed, constructed, operated and maintained to comply with the requirements of Section 724.401 (e.g., the liner system and leachate collection system; control of run-on and run-off; management of collection and holding facilities; control of wind dispersal of particulate matter);
- c. the liner system and leachate collection and removal system must be designed to be in compliance with the minimum technological requirement (MTR), as follows:
- the system must consist of a two-liner, two-leachate collection system;
 - the lower liner (secondary) must, at a minimum, be constructed of clay (3 feet minimum) or other material with a permeability of no more than 1×10^{-7} cm/sec.
 - one leachate collection (detection) system will be placed immediately above the secondary liner and will be designed to detect (in a timer manner), collect, and remove liquids and leaks occurring from the top (primary) liner;
 - the primary liner will be placed above the leachate collection system (should have the same permeability as the secondary liner); and
 - a primary leachate collection system will be placed on top of the primary liner and will be designed to quickly collect and remove leachate which percolate through the landfilled waste materials.
- d. a description of how each landfill, including the liner and cover system will be inspected in order to meet the requirements of Section 724.403(a) and (b);
- e. detailed plans and engineering report that will be incorporated into the closure plan, will describe the final cover which will be applied to each landfill or landfill cell at closure to meet the requirements of Section 724.410(a), as follows:
- provide long-term minimization of migration of liquids through the landfill;
 - function with minimal maintenance;
 - promote drainage and minimize erosion or abrasion of the cover;
 - accommodate settling and subsidence so that the cover's integrity is maintained; and
 - have a permeability less than or equal to the permeability of the bottom liner;
- f. a description of how each landfill will be maintained and monitored after closure in accordance with Section 724.410(b) will be incorporated in the post-closure plan; and

- g. if bulk or noncontainrized liquid wastes or waste containing free liquids is to be landfilled, an explanation of how Section 724.414 will be complied with.
3. **Land Disposal Restriction Requirement:** Due to the recent finalization of the land disposal restriction for all existing hazardous wastes (effective May 8, 1990); hazardous wastes may not be placed into the landfill unless they have met specific treatment standards that have been established for each waste. Wastes that may be generated at the proposed facility (e.g., sulfate byproduct, and filter cake, salts) that meet the definition of a characteristic hazardous waste would have to meet treatment standards before being landfilled. Although extensions to the effective date of treatment standards for specific hazardous wastes have been granted by EPA, by the time the proposed facility is constructed and waste disposal operation begin, all land disposal treatment standards will most likely be in effect including the standard for the newly identified toxic characteristic (TC) hazardous waste (effective September 25, 1990). The land disposal restriction for each type of hazardous waste that has a potential to be generated at the proposed facility is discussed in the following sections.

Characteristically Corrosive Hazardous Waste, EPA Waste No. D002: The land disposal restriction treatment standards for hazardous waste that exhibits the characteristics of corrosivity became effective of August 8, 1990. The treatment standards for this type of hazardous waste were broken into three waste types and is presented in the following table.

Corrosive Waste Type D002BDAT Treatment Standard

Acid Category (e.g., $\text{pH} \leq 2.0$) Deactivation (DEACT) to remove characteristic of corrosivity (e.g., treat waste to make $\text{pH} > 2.0$).

Corrosive Waste Type D002BDAT Treatment Standard

Alkaline Category (e.g., $\text{pH} \geq 12.5$) DEACT to remove the characteristic of corrosivity (e.g., treat waste to make $\text{pH} < 12.5$).

Other Corrosives (e.g., steel corrosives) DEACT to remove the corrosive characteristic.

Toxicity Characteristic (TC) Hazardous Waste: The toxicity characteristic (TC) rule became effective on September 25, 1990,

and expands the existing EP-toxicity characteristic constituents (8 metals and 6 pesticides) by adding an additional 25 compounds. The regulation also requires a different procedure for determining toxicity characteristics; from the old EP-toxicity test to the Toxicity Characteristic Leaching Procedure (TCLP). All wastes that will be generated at the proposed facility must be evaluated under this new TC criteria. In terms of the applicability of the land disposal restrictions to the TC hazardous waste, EPA has determined that until such time treatment standards are developed, wastes that solely exhibit the TC criteria are not presently prohibited from land disposal. Although, at the present time, EPA has not proposed treatment standards for these types of hazardous wastes, it is highly possible that most of the TC constituents will have their respective treatment standards set at the hazardous waste concentration level (e.g., for Arsenic, the TC concentration level based on the TCLP is 5.0 mg/l). As an important note, the rainfall leachate that will be generated from the proposed hazardous waste landfill should be examined under the TC criteria. If this criteria is met, then the leachate pond may become subject to permitting.

- Land Disposal Restriction Effect on Permitting Requirements Under RCRA: Since the treatment standards for the TC hazardous wastes have not yet been established, the effects that the land disposal restrictions will have on the permitting requirements for the proposed site cannot be determined.

If a facility was to manage only the **corrosive** hazardous waste on-site (e.g., treatment, storage, and/or disposal), compliance with the land disposal treatment standards will have the following effect on the permitting requirements.

- a. Since the land disposal restriction treatment standards requires that the waste(s) be treated to remove the corrosive characteristics, the waste, once treated, will no longer be considered a hazardous waste. Subsequently, the landfill that will receive this treated waste will no longer be classified as a hazardous waste management unit, and will not require a hazardous waste permit.
- b. The on-site treatment of the corrosive hazardous waste will not require a hazardous waste permit because it is exempted under Section 724.101(f)(6) and 720.110 of the Illinois regulations (this exemption is only applicable if the elementary neutralization unit

- meets the definition of a tank, tank system, container, transport vehicle, or vessel).
- c. The storage of the corrosive hazardous waste prior to treatment may require a hazardous waste permit. However, if the corrosive hazardous waste is stored in tanks and/or containers for a period of less than 90 days prior to treatment and disposal, the storage units would be exempt from permitting.

3.2.3.4. Water Pollution Control Regulations

For this Coal Liquefaction facility, the Water Management Plan was developed for permitting purposes based on segregation and discharge of storm water run-off. The process wastewater is treated in order to obtain by-products such as ammonia and phenols.

National Pollutant Discharge Elimination System (NPDES)

The Environmental Protection Agency (EPA) prohibits any discharge to public waters without a permit, and imposes stringent pollution control requirements on all discharges, whether existing or new. An applicant who intends to make any discharge to navigable waters (under the definitions, almost any water is considered navigable) must apply for and receive a NPDES permit which will set forth the parameters and conditions allowed for the discharges.

These NPDES permits are issued by the EPA, except where a state has received authority from the EPA to administer their own NPDES permit system. Before a NPDES permit will be issued, the state in which the discharge originates must certify to the EPA that all discharges will comply with the applicable effluent limitations.

EPA regulations require new dischargers to apply for a permit 180 days before commencing operations. However, abatement requirements may not be finalized until the permit application is approved. Therefore, the company should apply much earlier (during the design stage preferably) than the 180 days in order to determine the extent of abatement equipment which may be required of them in their permits. Figure 3-17 illustrates the timing necessary to obtain a NPDES Wastewater Discharge Permit.

The wastewater permitting for the State of Illinois is administered by the Illinois EPA, which has been authorized under the federal Clean Water Act to issue NPDES permits in lieu of the USEPA, although the USEPA may review permit applications for major projects. In addition to the permit forms used by the USEPA, the Illinois EPA also requires a construction permit prior to the construction of wastewater collection systems and treatment works. In general practice, both the NPDES and the Illinois construction permit applications are submitted simultaneously for processing convenience. The Illinois construction permit application will require the submittal of

construction permit applications are submitted simultaneously for processing convenience. The Illinois construction permit application will require the submittal of plans and specifications for the sewer and wastewater treatment systems.

The following sections describe items which must be addressed in a NPDES permit application.

Effluent Guidelines and Standards

EPA has issued standards for numerous industrial categories, defining the levels of pollution control required for new plants. At this time, no effluent standards have been developed specifically for coal liquefaction facilities. Therefore, limits associated with specific processes in the regulations have been applied to similar processes at the proposed coal liquefaction facility. Discussions with the Illinois EPA will be conducted prior to the preparation of the permit application to determine the accepted method of applying the effluent guidelines. The New Source Performance Standards (NSPS) and Pretreatment Standards for New Sources (PSNS) apply to plants if construction commences after the standards have been promulgated or proposed. Plants discharging wastes into municipal systems do not require permits, but may be subject to the user charges and pretreatment standards. The standards relevant to a coal liquefaction facility are summarized in the following sections.

Part 414 - Organic Chemicals, Plastics, and Synthetic Fibers; Subpart F - Commodity Organic Chemicals and Subpart G - Bulk Organic Chemicals

For the proposed coal liquefaction facility, this subpart would apply to the wastewater discharges resulting from the manufacture of organic chemicals. This would include wastewater discharges from Plants 2, and 4 thru 8-1 at the proposed facility. The following standards of this Subpart would apply.

New Source Performance Standards - Any new source subject to this Subpart must not exceed the quantity (mass) determined by multiplying the wastewater flow times the following concentrations:

- BOD5 : 80 mg/L maximum for any one day, and 30 mg/L maximum for a monthly average.
- TSS : 149 mg/L maximum for any one day, and 46 mg/L maximum for a monthly average.
- pH : within a range of 6.0-9.0 at all times.

Figure 3-17

Timing for Wastewater Discharge Permits (1)

(1) This figure illustrates the typical timing requirements as indicated in the regulations and confirmed through conversations with the Illinois EPA. Individual permits may require more or less than that indicated above depending on the complexity of the source(s) to be permitted.

Also included under NSPS are the standards detailed for the Pretreatment Standards for New Sources (PSNS) as follows.

Pretreatment Standards for New Sources - Any new point source subject to this Subpart must achieve discharges not exceeding the quantity (mass) determined by multiplying the wastewater flow times the following concentrations:

- Acenaphthene, Naphthalene, and Phenanthrene: 47 $\mu\text{g/L}$ maximum for any one day, and 19 $\mu\text{g/L}$ maximum for a monthly average (standards are for each pollutant).

Part 419 - Petroleum Refinery Point Source Category; Subpart B - Cracking Subcategory

This Subpart applies to all wastewater discharges from any facility that produces petroleum products by use of topping or cracking. For the proposed coal liquefaction facility, this Subpart would apply to the hydrotreatment operations contained in Plants 4 through 7.

Any new source subject to this Subpart must achieve the New Source Performance Standards (NSPS) specified in Table 3-23. The standards in Table 3-21 are to be multiplied by the size and process factors contained in the regulations to calculate the maximum for any one day and maximum averages of daily values for 30 consecutive days.

Any new source subject to this Subpart which introduces pollutants into a publicly owned treatment works (POTW) must comply with 40 CFR Part 403 and the following Pretreatment Standards for New Sources (PSNS).

- Oil and grease: 100 mg/L maximum for any one day
- Ammonia (as N): 100 mg/L maximum for any one day; where the discharge to the POTW consists solely of sour waters, the owner or operator has the option of complying with this limit or the daily maximum mass limitation for ammonia set forth in the NSPS listed in Table 3-21.

Table 3-21

**SUBPART B - CRACKING SUBCATEGORY
NSPS EFFLUENT LIMITATIONS
(LBS/1000 BBL FEEDSTOCK)**

EFFLUENT CHARACTERISTIC	MAXIMUM FOR ANY ONE DAY	AVERAGE OF DAILY VALUES FOR 30 CONSECUTIVE DAYS SHALL NOT EXCEED
BOD5	5.8	3.1
TSS	4	2.5
COD (note 1)	41.5	21
Oil and Grease	1.7	0.93
Phenolic Compounds	0.042	0.02
Ammonia (as N)	6.6	3
Sulfide	0.037	0.017
Total Chromium	0.084	0.049
Hexavalent Chromium	0.0072	0.0032
pH	note 2	note 2

Note 1. In any case in which the applicant can demonstrate that the chloride ion concentration in the effluent exceeds 1000 mg/L (1000 ppm), the permitting authority may substitute TOC as a parameter in lieu of COD.

2. Within the range of 6.0-9.0 at all times.

Part 420 - Iron and Steel Manufacturing Point Source Category; Subpart A - Cokemaking Subcategory

Any new source subject to this Subpart which introduces pollutants into a publicly owned treatment works (POTW) must comply with 40 CFR Part 403 and achieve the following Pretreatment Standards for New Sources (for the proposed coal liquefaction facility, this Subpart would apply to the coking operations in Plant 8-1).

- Ammonia (as N): 0.0645 lb/1000 lb product maximum for any one day, and 0.0322 lb/1000 lb product average of daily values for 30 consecutive days.
- Cyanide: 0.0172 lb/1000 lb product maximum for any one day, and 0.00859 lb/1000 lb product average of daily values for 30 consecutive days.
- Phenols: 0.0430 lb/1000 lb product maximum for any one day, and 0.0215 lb/1000 lb product average of daily values for 30 consecutive days.

Part 423 - Steam Electric Power Generating Point Source Category

For the proposed coal liquefaction facility, this Subpart would apply to Plant 31 (Steam and Power Generation Plant). Any new source subject to this Subpart must achieve the following New Source Performance Standards.

- The pH of all discharges, except once through cooling water, shall be within the range of 6.0-9.0.
- There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.
- Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10-year, 24-hour rainfall event shall not be subject to the following limitations: TSS limitation for any time not to exceed 50 mg/L.

Part 434 - Coal Mining Point Source Category; Subpart B - Coal Preparation Plants

The following New Source Performance Standards shall apply to discharges from new source coal preparation plants and their associated areas, if such discharges normally exhibit a pH of less than 6.0 prior to treatment.

- Total Iron: 6.0 mg/L maximum for any one day, and 3.0 mg/L average of daily values for 30 consecutive days.
- Total Manganese: 4.0 mg/L maximum for any one day, and 2.0 mg/L average of daily values for 30 consecutive days.
- TSS: 70 mg/L maximum for any one day, and 35 mg/L average of daily values for 30 consecutive days.
- pH: 6.0-9.0 at all times.

If such discharges normally exhibit a pH equal to or greater than 6.0 prior to treatment, then the total manganese standard listed above is not applicable.

Illinois Water Quality Standards and Limitations

The Illinois EPA water quality effluent standards and limitations are identical to those promulgated by the USEPA.

External Sources of Water

The Phase Zero Water Management Plan is based on the total reuse of waters and wastewaters until all water has either evaporated, been chemically consumed, or taken to landfill as surface moisture on solid waste materials. This approach reduces the need for freshwater make-up to an absolute minimum and, under normal operating conditions, eliminates any wastewater discharge. There will be occasional short-term discharges when conditions are abnormal, such as during plant start-up or shut-down, when the cooling towers are not operating at full design capacity, or during periods of heavy rainfall exceeding the design when excess storm run-off will be allowed to overflow. These occasional short-term discharges of excess water will come from large storage ponds. Although the overflowing water will not be pure rain water, its level of contamination is expected to be very low. During detailed design, provisions should be made to ensure that the overflowing water will be the least contaminated of the ponds' contents. Overflow pipes will be located far from inlet pipes, in deep quiescent portions of the pond to facilitate settling of any settleables, and baffled to keep floatables from escaping.

The main external sources of water for the project will most likely be storm run-off and moisture imported with the run-of-mine coal. These sources, the water they furnish, and the disposition of these waters are discussed individually in the following sections.

Storm Water Run-off

Outfalls that discharge storm water associated with industrial activities must be permitted. Those outfalls that discharge storm water not associated with industrial activity do not require permitting unless the storm water is from a municipal separate storm sewer system serving a population greater than 100,000. Non-storm waters are prohibited from entering storm sewers and must have individual NPDES construction permits prior to the commencement of construction. In the past, the NPDES permits addressed discharges of water without much concern for storm water run-off. The storm water regulations require that a more detailed assessment of industrial and non-industrial storm water run-off be included in the NPDES permit application.

Storm water run-off is segregated into three categories:

- Uncontaminated run-off
- Coal storage pile run-off
- Contaminated and oily run-off

Uncontaminated run-off is that which is not expected to come into contact with any contaminants. Included are areas located on plant lands separate from the plant's industrial activities, such as parking lots and administrative and employee buildings. Large parking lots, however, due to their impervious nature, may generate large amounts of oil, grease, and heavy metals which may have adverse impacts on receiving waters. Permits may be required for specific storm water discharges by the Director who has authority to designate storm water discharges, such as those from parking lots, as significant contributors of pollutants or a contributor to a water quality violation.

Run-off from coal storage piles and surrounding areas will be collected and conveyed in a separate drainage system and routed to a surge pond. This stream is expected to be acidic and to contain variable levels of suspended and dissolved solids. The coarse solids will settle out in the pond. The finer solids will be removed in a clarifier-softener followed by media filtration. In addition, the pH will be adjusted and some of the hardness will be reduced. The cleaned, pH-adjusted effluent will be routed to the utility water storage pond to be blended with uncontaminated run-off.

Operators of storm water discharges associated with industrial activity which require permits shall meet the following permitting requirements:

- discharges to privately or Federally owned storm water conveyance systems (conveyance that is not a municipal separate storm system) are required to be covered by an individual permit.
- individual permits for storm water discharges associated with industrial activities are required to meet all of the provisions of Sections 402 and 301 of the Clean Water Act. These sections require the control for the discharge of pollutants to utilize the Best Available Technology (BAT). These requirements include meeting technology-based and, where necessary, water quality-based requirements.
- specific monitoring and sampling procedures are outlined in the regulations. Monitoring and sampling shall occur during both storm and non-storm conditions.
- proper forms, as specified in the regulations, must also be completed and submitted as part of the permit application.
- permit applicants for storm water discharges associated with industrial activities must certify that all of the outfalls covered in the permit application have been tested for non-storm water discharges which are not covered by a NPDES permit.
- applicants must also submit known information regarding the history of significant spills at the facility. This information is necessary to aid in the determination of which drainage areas are likely to generate storm water discharges associated with industrial activity, evaluate pollutants of concern, and to develop appropriate permit conditions. A significant spill is one that releases oil or hazardous substances in excess of the reportable quantity for that material.

Construction operations that result in the disturbance of one acre or more of total land area, except for operations that are for single family residential projects that result in the disturbance of less than five acres total land area, are included in the regulatory definition of storm water discharges associated with industrial activity.

Specific permit application requirements are necessary for construction activities, including narrative descriptions of:

- the nature of the construction activity
- the total area of the site and the area of the site that is expected to undergo excavation during the life of the permit
- proposed measures to control pollutants in storm water discharges during and after construction

- an estimate of the run-off coefficient of the site and the increase in impervious area after the construction addressed in the permit application is completed, a description of the nature of fill material and existing data describing the soil or the quality of the discharge
- the name of the receiving water

Surge Attenuation

Because storm water run-off results in variable and, at times, very large flow rates that can easily overload and upset treatment facilities, it is necessary to regulate these flow rates. This is done by use of a surge attenuation pond. At the inlet to the API separator, flows of contaminated water in excess of separator capacity are diverted automatically to the surge pond. After flow subsides below a design level, the settled contents of the surge pond are pumped back into the inlet of the separator at rates which are a function of the level in the pond: the higher the level, the greater the pumping rate.

3.2.3.5. TOXIC SUBSTANCES CONTROL ACT

The Toxic Substances Control Act (TSCA) provides the authority for the Environmental Protection Agency to secure information on all new and existing chemical substances and to control any of these substances determined to cause unreasonable risk to the public health or environment.

Section 8 of the Act requires chemical manufacturers and, in some cases, processors to report production and exposure-related data on approximately 2,300 chemicals to the EPA. Specifically, Section 8 (e) states:

Any person who manufactures, processes, or distributes in commerce a chemical substance or mixture and who obtains information which reasonably supports the conclusion that such substance or mixture presents a substantial risk of injury to health or the environment, shall immediately inform the Administrator of such information unless such person has actual knowledge that the Administrator has been adequately informed of such information.

The list of chemicals subject to these regulations is found in 40 CFR 712.18. This list is periodically updated in the Federal Register. These regulations would apply to the hydrocarbon products from the coal liquefaction facility, specifically naphtha, light distillate, heavy distillate, and gas oil.

Under Section 5 of the Act, any person who intends to manufacture a new chemical substance for commercial purposes must submit notice to the EPA at least 90 days before he commences manufacture. Section 3 (9) defines a "new chemical substance" as any chemical substance which is not included on the list, or "inventory", of existing chemical substances compiled by EPA under Section 8. The inventory was published in the Federal Register on May 15, 1979.

Section 5 (d) (1) of the Act defines the contents of a premanufacture notice (PMN). It requires the manufacturer to report certain information described in Section 8 (a) (z), e.g., chemical identity, uses, and exposure data. In addition, Section 5 (d) (1) requires the submission of test data, in the possession of the person submitting the notice, which are related to the effects on health or the environment from the manufacture, processing, distribution in commerce, use, and disposal of the chemical substance.

3.2.3.6 OCCUPATIONAL SAFETY AND HEALTH ACT (OSHA)

The Occupational Safety and Health Act (OSHA) intends to assure safe and healthful working conditions by authorizing enforcement of the standards developed under the Act, by assisting and encouraging the States in their efforts to assure safe and healthful working conditions and by providing for research, information, education, and training in the field of occupational safety and health. The Occupational Safety and Health Act created the Occupational Safety and Health Administration and charged the agency with the regulatory responsibility to protect workers from hazards of the workplace. The Act also created the National Institute for Occupational Safety and Health (NIOSH), which has among its responsibilities the duty to make recommendations for the OSHA regulatory standards.

Both safety and health regulations have been promulgated by OSHA under the Occupational Safety and Health Act. Safety regulations include handling and labeling requirements and safety precautions (such as protective clothing or equipment). Health regulations are exemplified by employee health record requirements, and the setting of contaminant exposure limits and maximum contaminant levels for workplace air.

Recommendations for regulations are made to OSHA by NIOSH, the scientific advisory body of OSHA and other recognized standards-setting organizations, including the American Conference of Governmental and Industrial Hygienists and the American National Standards Institute.

Recommended Contaminant Limits for Workplace Air

Recommendations for contaminant limits in workplace air are made by the National Institute of Occupational Safety and Health, the American Conference of Governmental and Industrial Hygienists, and the American National Standards Institute.

NIOSH is the sister research body of OSHA, and its responsibilities include developing criteria for setting occupational standards. This information is generally developed on either a substance-by-substance basis or a process-specific basis. Results of the NIOSH literature investigations are published in criteria documents. Preparation of a criteria document addressing a single chemical contaminant or industry requires about 45 weeks. Approximately 24 criteria documents are produced in a year by NIOSH.

NIOSH also prepares documents addressing health and safety guidelines for various occupations. An example of one of these is a document entitled "Recommended Health and Safety Guidelines for Coal Gasification Pilot Plants." This document addresses the various coal gasification processes and attempts to identify the associated potential health hazards. On the basis of identified hazards, guidelines for worker protection are prescribed in terms of engineering controls, work practice, workplace monitoring, medical surveillance, and personal protection. Table 3-22 lists those compounds known to be present in coal liquefaction processes for which occupational standards have been established.

3.2.3.7 Noise Regulations and Design Implications

Illinois Community Noise Regulations

In Illinois, regulation of noise in the community or on the property line of an industrial facility is regulated by the State of Illinois. It is possible, but unlikely, that a local community would also have community noise regulations. The State regulations have three basic provisions, as follows:

- Limits on noise levels in octave (frequency) bands
- Prohibition on tones
- Limits on impulsive noises
- A complaint resolution procedure, based largely on avoiding a nuisance.

Upon identification of candidate site(s), the specific limits which are controlling with respect to plant design and equipment requirements can be determined.

Table 3-22

EXPOSURE LIMITS FOR COMPOUNDS FOUND IN
COAL LIQUEFACTION PLANTS (a)

COMPOUND	WHERE FOUND	TLV-TWA	TLV-STEL
		mg/m3 (ppm)	mg/m3 (ppm)
Acetic Acid	Gas Stream	25(10)	37(15)
Acetone	Laboratory	1780(750)	2380(1000)
Ammonia	Gas Stream	17(25)	24(35)
Aniline (skin)	Gas Stream	7.6(2)	(b)
Antimony	Trace Element in Coal	0.5(b)	(b)
Arsenic	Trace Element in Coal	0.2(b)	(b)
Benzene	Laboratory Gas	32(10)	(b)
Beryllium	Trace Element in Coal	0.002(b)	(b)
1,3-Butadiene	Gas Stream	22(b)	(b)
Cadmium fume dust	Trace Element in Coal	0.05(b,c)	(b)
Carbon dioxide	Gas Stream	9,000(5,000)	54,000(30,000)
Carbon disulfide	Gas Stream	31(10)	(b)
Carbon monoxide	Gas Stream	57(50)	458(400)
Carbon tetrachloride	Laboratory	31(5)	(b)
Chromium (soluble & metal)	Trace Element in Coal	0.5(b)	(b)
Coal dust (> 5% SiO ₂)	Coal Preparation Area	2.4(b)	(b)
Coal dust (< 5% SiO ₂)	Coal Preparation Area	10(b)	(b)
Coal tar pitch volatiles	Gas Stream	0.2(b)	(b)
Cresol (skin)	Gas Stream	0.2(b)	(b)
Ethyl mercaptan	Gas Stream	1.3(0.5)	(b)
Hydrogen chloride	Gas Stream	7.5(5) (d)	(b)
Hydrogen sulfide	Gas Stream	14(10)	21(15)
Lead and lead compounds	Trace Element in Coal	0.15(b)	(b)
Manganese	Trace Element in Coal	5(b)	(b)
Mercury	Trace Element in Coal	0.05(b)	(b)
Methyl ethyl ketone	Laboratory	590(200)	885(300)
Methyl mercaptan	Gas Stream	0.98(0.5)	(b)
Naphtha (coal tar)	Gas Stream	(b,e)(100)	(b)
Naphthalene	Gas Stream	52(10)	79(15)
Nickel carbonyl	Methanation	0.12(0.05)(c)	(b)
Nickel (soluble and metal)	Trace Element in Coal	1(b,c)	(b)
Phenol (skin)	Gas and Effluent Stream	19(5)	(b)
Propane	Gas Stream	(b,e)(1,000)	(b)
Pyridine	Gas Stream	16(5)	(b)
Selenium compounds	Trace Element in Coal	0.2(b)	(b)
Silica dust (total)	Trace Element in Coal	10(b)	(b)
Silica dust (respirable)	Trace Element in Coal	0.05(b)	(b)
Styrene (skin)	Gas Stream	213(50)	426(100)
Sulfur dioxide	Thermal Oxidizer	5.2(2)	13(5)
Toluene	Slurry Oil, Gas Stream	377(100)	565(150)
Vanadium	Trace Element in Coal	0.05(b)	(b)
Xylene (V2O5 dust and fume)	Gas Stream	434(100)	651(150)

(a) From American Conference of Governmental and Industrial Hygienists, "Threshold Limit Values and Biological Exposure Indices for 1989-1990."

(b) Value no available or adopted.

(c) Value recommended for change.

(d) Ceiling or not-to-be-exceeded value.

(e) From Sax, N. Irving and Richard J. Lewis, Sr., "Dangerous Properties of Industrial Material."

Noise Limits in Octave Bands

The specific octave band limits during the nighttime for noise from an industrial facility, such as a coal liquefaction plant, are based on land use and are detailed in Table 3-23. The limits in Table 3-23 are in octave bands; the approximate A-weighted equivalent is given for reference only. These limits are taken as an hourly equivalent noise level (Leq). The Leq is a constant A-weighted sound pressure level that has the same energy as the actual fluctuating level. There are corresponding limits during the daytime, but the nighttime limits are expected to apply because of 24-hour operation of the plant. Measurements are to be made no closer than 25 feet from a noise source.

Land Use A is for libraries, prisons, schools, and for any dwellings or places where people sleep. Land Use B is for commercial establishments, including communications facilities, stores (wholesale and retail), financial services, real estate services, personal and professional services, military bases, most government services, amusement parks, resorts, and churches.

Limits on Impulsive Sound

The following noise limits apply to impulsive sounds emanating from an industrial facility, such as a coal liquefaction plant. These limits describe the allowable A-weighted sound pressure levels (in dBA) emitted from an industrial facility to a receiver on:

Class A Land:

Daytime: 56 dBA

Nighttime: 46 dBA

Class B Land: 61 dBA

Nighttime is defined in the regulations as 10:00 pm to 7:00 am. The State of Illinois defines impulsive sound as "either a single pressure peak or a single burst (multiple peaks) for a duration of usually less than one second." This implies a very fast rise and decay time for sound. Dropping pipe, slamming a car door, blasting, or a drop hammer forge are examples of impulsive sounds.

Prohibition on Tones

Prominent discrete tones are prohibited. A tone exists if the arithmetic average of the sound pressure levels in the two adjacent 1/3 octave bands exceeds the level in the 1/3 octave band by more than the following:

Table 3-23

NIGHTTIME NOISE LIMITS IN OCTAVE BANDS

OCTAVE BAND CENTER FREQUENCY (HERTZ)	ALLOWABLE SOUND PRESSURE LEVELS (IN dB) EMITTED FROM AN INDUSTRIAL FACILITY TO A RECEIVER ON:	
	CLASS A LAND	CLASS B LAND
31.5	69	80
63	67	79
125	62	74
250	54	69
500	47	63
1000	41	57
2000	36	52
4000	32	48
8000	32	45
Approximate Equivalent A- weighted Level (dBA)	55	66

- 5 dB for 1/3 octave bands with center frequencies between 500 and 10,000 Hertz (Hz)
- 8 dB for 1/3 octave bands with center frequencies between 160 and 400 Hz
- 10 dB for 1/3 octave bands with center frequencies between 25 and 125 Hz.

In addition, the sound pressure level in the 1/3 octave band in question must exceed each adjacent 1/3 octave band.

Verification Measurements

Measurements used to determine compliance with these regulations are taken downwind. Since atmospheric conditions are more favorable to propagation of sound downwind, sound pressure levels will typically be higher downwind. However, the limits should be assumed to apply in all directions, because the wind will eventually blow in all directions. In all cases, these limits apply no closer than 25 feet from a noise source. The regulations include a provision for correcting measured levels for background noise levels (noise from other nearby and far-away sources that are continuing). Measurements to verify compliance are expected to be cumbersome, because most sound level meters measure only one frequency at a time, need to measure each frequency for a minimum of one hour, need to measure downwind, and the need to measure nominally steady state noises as well as tones and impulsive noises.

Exceptions and Enforcement

The regulations include exceptions, including emergency warning devices, construction equipment, and unregulated safety relief valves. However, safety valves that lift too often could be considered a nuisance. The noise limits would presumably apply to construction equipment used as part of operating the plant.

The State of Illinois relies mostly on complaints and usually does not attempt to enforce its regulations. Violating a provision of the regulations can be used to help demonstrate that a nuisance exists. It should be assumed that all Illinois regulations must be met on the property line of the site and at all locations in the nearby community. Generally, the State seems to interpret its noise regulations in a "reasonable" manner.

Annoyance and Community Reaction

If people are annoyed, they can file a complaint. The complaint resolution procedure includes a hearing before the Illinois Pollution Control Board. If the Board determines that a nuisance has been created by the noise, then abatement can be ordered. Meeting all of the noise limits and prohibitions is not sufficient to avoid annoyance of nearby residents and complaints. Most complaints heard by the Board are based on subjective evaluation and not on specific noise measurements.

Regulation of Transportation Noise

The State has noise limits and requirements for motor vehicles and the U.S. Department of Transportation has limits for railroad vehicles and operations. Vehicular traffic entering and leaving the site are excluded from the noise limits. However, in some cases, transportation noise might be considered to contribute to a nuisance.

Occupational Noise Regulations

The following sections describe the OSHA noise exposure regulations related to a coal liquefaction facility.

Hearing Conservation Program

A hearing conservation program is required by OSHA (46 CFR 4078) for each employee whose TWA equals or exceeds 85 dBA. The TWA is the average sound pressure level to which an employee is subjected to during a day. An employee who is exposed to 85 dBA for eight hours will have a TWA of 85 dBA. The regulations describe how the TWA and noise doses can be computed for employees, such as most maintenance workers in a coal liquefaction plant, exposed to varying noise levels. A hearing conservation program must include both an audiometric testing program and use of hearing protectors in cases where hearing loss is detected.

Hearing Loss Claims

Employees who suffer hearing loss may file for compensation from the employer. More and more employees are receiving compensation for hearing loss, even though some hearing loss may be due to age and some may be caused by exposure to noise outside of the work place. Monetary awards can be sizeable. A hearing conservation program to identify new workers who already have hearing loss helps limit awards for hearing loss.

Noise Criteria in Normally Quiet Areas

Noise levels in normally quiet areas of the plant must be sufficiently low so that communication (speech and telephone) can be easily maintained. Adequate communication can typically be maintained and undue annoyance avoided if the noise levels listed in Table 3-24 are maintained in normally quiet areas.

Potential Effects on the Site Selection and Layout

Community noise regulations and the need to avoid creating a noise nuisance are expected to affect the selection of the site, the size of the site, the layout of the site, and provisions for transporting materials from the site. Mining activities, the coal liquefaction plant, and transportation of products off of the site are expected to have an impact on noise.

Site Selection

Site selection is likely to be impacted by noise considerations. Noise criteria for sites with noise sensitive neighbors are likely to be more stringent and, hence, more noise control is likely to be required. Not only is the presence of noise sensitive neighbors likely to have an adverse effect, but the existing transportation on or adjacent to the site is likely to reduce the impact of transportation noise. While traffic entering or leaving the site is exempted from the noise limits and restrictions, transportation noise should be considered in site selection. The following are generally favorable methods to reduce the impact of noise on the environmental assessment, planning, design, and operation of the coal liquefaction plant:

- Larger sites
- Further from noise sensitive receptors, including Land Use A
- Absence of important historical, recreational, or cultural sites
- Nearby availability of existing transportation
- Property lines further from mining activities
- Topography where the coal liquefaction plant can be located away from the property line and away from the tops of hills
- Absence of noise sensitive receptors that overlook the site.

3.2.3.8 FEDERAL AVIATION ADMINISTRATION (FAA) POLICIES

The following FAA policies influence the layout, design, and proximity of new plants relative to nearby airports.

Table 3-24

**NOISE CRITERIA IN
NORMALLY QUIET AREAS**

SPACE	TYPICAL A-WEIGHTED NOISE LEVELS (dBA)	TYPICAL NC CRITERIA
Control Rooms	50-60	45-55
Laboratories	40-50	35-45
Private Offices	40-50	30-40
Large Offices	45-55	35-45
General Secretarial Areas	45-55	40-50
Lunch Rooms	50-60	45-55
Large Conference Rooms	35-45	25-35
Small Conference Rooms	40-50	30-40

Good Engineering Practice (GEP) Stack Heights

When a building or buildings interrupt wind flow, an area of turbulence called building downwash is created. Pollutants being emitted from a fairly low level (i.e. a roof vent or even a short stack) can be caught in this turbulence, affecting the dispersion of the pollutants.

The effects of building downwash can be significantly reduced or even eliminated by designing stacks at good engineering practice (GEP) heights. The GEP stack height is calculated by the following equation:

$$\text{GEP} = H_b + 1.5 L$$

Where,

H_b = height of the building

L = lesser of the height and the projected width of the building

In dispersion modeling demonstrations, credit is not given for actual stack heights above GEP stack height.

Proximity to Airports

As part of the preliminary site assessment and environmental impact statement, the FAA and nearby airports should be contacted in order to ascertain whether or not the building and stack configurations proposed for the coal liquefaction facility will in any way impact or affect local air traffic or operations at nearby airports.

SAFETY PLANNING

Hazards Analysis

A hazards analysis is a necessary step in comprehensive emergency planning for a community. Comprehensive planning depends upon a clear understanding of what hazards exist and what risk they pose for various members of the community. A hazards analysis is a 3-step decision-making process used to identify the potential hazards facing a community with respect to the accidental releases of extremely hazardous substances (EHSs).

The hazards analysis is designed to consider all potential acute health hazards within the planning district and to identify which hazards are of high priority and should be addressed in the emergency response planning process. The emergency response planning covered under Title III of the Superfund Amendments and Reauthorization Act (SARA) must address all EHSs that are reported to the State Emergency Response Commission (SERC), but other substances including EHSs below their threshold

planning quantity (TPQ) may also be included (see Section 10.2). A brief overview of the three components of a hazards analysis is presented below.

Hazards Identification

Hazards identification typically provides specific information on situations that have the potential for causing injury to life or damage to property and the environment due to a hazardous materials spill or release. A hazards identification includes information about:

- chemical identities
- the location of facilities that use, produce, process, or store hazardous materials
- the type of design of chemical container or vessel
- the quantity of material that could be involved in an airborne release
- the nature of the hazard (e.g., airborne toxic vapors, fire, explosion, handling conditions) most likely to accompany hazardous materials spills or releases.

Vulnerability Analysis

A vulnerability analysis identifies areas in the community that may be affected or exposed, individuals in the community who may be subject to injury or death from certain specific hazardous materials, and what facilities, property, or environment may be susceptible to damage should a hazardous materials release occur. A comprehensive vulnerability analysis provides information on:

- the extent of the vulnerable zones (i.e., an estimation of the area that may be affected in a significant way as a result of a spill or release of a known quantity of a specific chemical under defined conditions)
- the population, in terms of numbers, density, and types of individuals (e.g., facility employees, neighborhood residents, people in hospitals, schools, prisons, day care centers) that could be within a vulnerable zone
- the private and public property that may be damaged, including essential support systems (e.g., water, food, power, communication, medical) and transportation facilities
- the environment that may be affected, and the impact of a release on sensitive natural areas and endangered species.

Risk Analysis

A risk analysis is an assessment by the community of the probability of an accidental release of a hazardous material and the actual consequences that might occur, based on the estimated vulnerable zones. The risk analysis provides an estimation of:

- the probability of an accidental release based on the history of current conditions and controls at the facility
- the severity of consequences of human injury that may occur (acute, delayed, and/or chronic health effects), the number of possible injuries and deaths, and the associated high-risk groups
- the severity of consequences on critical facilities such as fire and police stations, hospitals, and communication centers
- the severity of consequences of damage to property
- the severity of damage to the environment

Superfund Amendments and Reauthorization Act (SARA) Title III Community Emergency Planning and Right-to-Know Act

On October 17, 1986, SARA was promulgated into law. Title III of SARA contains numerous requirements for federal, state, and local governments, as well as private industry, in the areas of emergency planning, community right-to-know, hazardous emissions reporting, and emergency notification. These requirements build upon the original Chemical Emergency Preparedness Program (CEPP), numerous existing state and local programs aimed at community right-to-know and preparedness.

The objectives of Title III are to improve local chemical emergency response capabilities and to provide citizens and local governments access to information about chemicals in their localities. Title III addresses planning by:

- identifying the EHSs that trigger the planning process
- requiring facilities to identify themselves if they have quantities of EHSs exceeding the TPQs
- requiring the establishment of a state and local planning structure and process
- requiring facilities to make information available to local planners
- specifying the minimum contents of local emergency plans

Title III required EPA to publish a list of EHSs and TPQs for each substance triggering the planning process. EPA fulfilled this requirement in a rule published on April 22, 1987 (Federal Register, Vol. 52, No. 77, pp. 13378-13410). The list of EHSs included the 402 chemicals found in the CEPP Interim Guidance List of Acutely Toxic Chemicals and four additional chemicals added as a result of new information. Four chemicals have been removed from the list and 36 others are proposed for delisting as they do not meet the acute lethality criteria (see the above-referenced Federal Register for the list chemicals triggering the planning process).

ILLINOIS EPA CONTACTS

The persons listed below are those from whom information or assistance was obtained with respect to the coal liquefaction study. Other staff members at these agencies should also be able to offer assistance.

Air Permits

Dan Punzak or Chris Roman
Illinois EPA
Division of Air Pollution Control
2200 Churchill Rd
PO Box 19276
Springfield, Illinois 62794-9276
(217) 782-7326

Wastewater Permits

Sandy Braun
Illinois EPA
Division of Water Pollution Control
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Springfield, Illinois 62794-9276
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Solid and Hazardous Waste

Chris Liebman (Solid Waste)
Amy Dragovich (Hazardous Waste)
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Land Pollution Control Division
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(217) 782-6762

3.3 TASK IV

Task IV concerns the development of mathematical algorithms and models for equipment sizing, scale-up, costing, and train duplication for incorporation into the Task V ASPEN Simulation program. The task is being done in parallel with Task V.

3.3.1 Mathematical Modeling

Algorithms for capital costs, multiple train requirements and spare plants continued to be developed and incorporated into the block models as they were developed during this reporting period. Block model algorithms for capital costs, multiple trains and spare plants have been completed for:

Plant 1	Coal Cleaning and Preparation (jig cleaning) Alternate Case 1 (Heavy Media Separation) Alternate Case 2 (Spherical Agglomeration)
Plant 2	Coal Liquefaction
Plant 3	Gas Plant
Plant 4	Naphtha Hydrotreater
Plant 5	Gas Oil Hydrotreater
Plant 6	Hydrogen Recovery and Purification Plant
Plant 8.1	ROSE-SR Critical Solvent Deashing Unit
Plant 9	Hydrogen Production (Coal Gasification)
Plant 9-01	Hydrogen Production by Steam Reforming of Natural Gas
Plant 10	Air Separation Plant
Plant 11	Sulfur Plant

The basic form of these algorithms was described in a December 17, 1990 letter from Sam N. Habash to Swenam Lee which transmitted preliminary documentation for Plants 1, 2, 10 and 11.

Capital cost equations for the major equipment items in Plant 2 will be completed during the next reporting period, since the major equipment items have not been identified.

3.4 TASK V

Task V concerns the development of the ASPEN process simulation model of the baseline design. The model will produce complete heat and material balances, elemental balances around each plant and the entire process complex, a major equipment list and outline specifications for Plant 2, utility requirements, capital cost for all plants, and a discounted cash flow economic model for the total complex. The model will be suitable for studying technology advances and options in a case study approach. The model will not include optimization capabilities.

3.4.1 Coal Cleaning and Preparation Plant

A Fortran user block model, report writer and documentation for the base case model of Plant 1 (jig cleaning) was completed during the last (September-December) reporting period. During this period, Fortran user block models, report writers and documentation were completed for two additional Plant 1 options.

These options are Alternate Case 1 (Heavy Media Separation) and Alternate Case 2 (Spherical Agglomeration). Material balances, capital and utility estimates for each option are represented. The user will have the flexibility to choose one of the three coal cleaning options in order to evaluate its impact on the entire complex.

3.4.2 Coal Liquefaction

A simplified Fortran user block model and report writer for a combined model of Plant 2 (Coal Liquefaction) and Plant 8 (ROSE-SR) and Plant 6 (Hydrogen Purification) were completed. This model (Plant 268) is being used for the initial simulation of the entire complex. It will be split apart into separate models for each plant as modeling progresses.

Later in the reporting period, as more detailed information became available, an improved elemental balanced yields model was developed for Plant 2, the coal liquefaction plant. This reactor yields model was developed based on the HRI report for Plant 2. This model was incorporated into the Plant 268 model. Two additional yield models were also developed, one for use with the kinetic model, and a first reactor yields model for use with the alternate vent gas separation case.

Development of a steady-state kinetic model for the two-stage coal liquefaction reactor system continued throughout the reporting period. A spreadsheet version of the model has been developed for predicting Wilsonville operations. A commercial size prediction model is being developed, which will later be incorporated into a Fortran sub-block for the coal liquefaction reactors.

During the next reporting period a detailed ASPEN simulation of the entire Plant 2 complex will be completed.

3.4.3 Gas Plant

As reported in the last quarterly report, a preliminary model, report writer and documentation for Plant 3 (the gas plant), have been completed. This model is based on a compression, expansion and fractionation scheme. However, the Bechtel design has evolved to be a different scheme which uses a lean oil absorber.

Sufficient details for the lean oil absorber scheme were not available during this reporting period to update the gas plant model. We expect that during the next reporting period a complete flow scheme and material balance will be available to update the simulation model gas plant.

3.4.4 Naphtha Hydrotreater

The Fortran block model and report writer for Plant 4, the naphtha hydrotreater, was developed during this reporting period. This elementally balanced model predicts the product properties as a function of the degree of desulfurization, denitrogenation and oxygen removal. Documentation of this model will be completed during the next reporting period.

3.4.5 Gas Oil Hydrotreater

The Fortran user block model and report writer for Plant 5, the gas oil hydrotreater, was developed during this reporting period. This model uses the same basic logic as the Plant 4 model. Documentation of this model will be completed during the next reporting period.

3.4.6 Hydrogen Recovery and Purification Plant

For modeling purposes, Plant 6 was split into two sub-plants; Plant 6.1 which recovers hydrogen from the high pressure off-gas from the coal liquefaction plant by membrane permeation, and Plant 6.2 which recovers hydrogen by pressure swing absorption. Fortran user block models and report writer for both sections of Plant 6 were developed during this reporting period. Documentation of these models will be completed during the next reporting period.

3.4.7 ROSE-SR Critical Solvent Deashing Unit

The Fortran user block model and report writer were developed for Plant 8.1, the ROSE-SR critical solvent deashing unit. This block model is based upon licensor information received by Bechtel from Kerr-McGee Corporation. Since this is a proprietary process, it is being modeled on a "black-box" basis. However, the user will be able to modify the base case conditions to study the effect of varying the amount of hydrocarbons leaving the ash concentrate stream. Documentation will be completed during the next reporting period.

3.4.8 Hydrogen Production by Coal Gasification

The Fortran user block model, report writer and preliminary documentation were completed for Plant 9, Hydrogen Production by Coal Gasification, during the previous reporting period. It was described in the September-December Quarterly report.

3.4.9 Hydrogen Production by Steam Reforming

The Fortran user block model, report writer and preliminary documentation were completed for Plant 9.1, Hydrogen Production by Steam Reforming of Natural Gas, during the previous reporting period. It was described in the September-December Quarterly report.

3.4.10 Air Separation Plant

The Fortran user block model, report writer and preliminary documentation were completed for Plant 10, the Air Separation, was previously completed. It was described in the May-August Quarterly report.

3.2.11 Sulfur Plant

The Fortran users block model, report writer and documentation were completed for Plant 11, the Sulfur Plant, was previously completed. It was described in the September-December Quarterly report.

3.4.12 Elemental Balance Capability and Unit Cost Model Subcontract

Amoco is subcontracting to Simulation Sciences Inc. the development of a general elemental balance capability and a generalized unit cost model for the ASPEN/SP program.

Simulation Sciences initiated work on these tasks during March. Basic programming on the capital cost portion has been completed, however, the report writer still needs to be written. This needs to be interfaced with and attached to ASPEN/SP. There was no work done on the elemental balance subcontract during this reporting period.

Simulation Sciences work on these subcontract tasks is expected to be completed during the next reporting period.

3.4.13 Utilities Plant

Logic for Plant 31, the Utilities Plant, has been developed and implemented in three separate Fortran subroutines in a stand-alone program. These subroutines will be the heart of the Fortran user block model for the utilities plant.

3.4.14 Capital Cost Reporting

Development of the portion of the output report summarizing plant capital cost and utilities consumption has begun. Fortran programming has been completed on the section which produces the short summary tables for the entire complex.

4. KEY PERSONNEL STAFFING REPORT

Key Personnel staffing report for this reporting period (December 24, 1990 through March 17, 1991) as required by DOE/PETC is included in Table 4-1 shown below.

**TABLE 4-1
KEY PERSONNEL STAFFING REPORT**

Duration of Quarter		From December 24, 1990 to March 17, 1991
<u>Name of Key Person</u>	<u>Function</u>	<u>% Time Spent*</u>
<u>Rechtel:</u>		
S. N. Habash	Project Manager	72
S. N. Poddar	Technical/Project Coordinator	100
T. J. Reynolds	Project Secretary	75
R. F. Earhart	Process Manager	41
H. F. Zaras	Support Facil. Manager	63
<u>Amoco:</u>		
A. B. Schachtschneider	Project Manager	10
S. J. Kramer	Principal Investigator	77
Arun Basu	Principal Investigator	43

* (Number of hours spent/total available working hours for December 24, 1990 through March 17, 1991) x 100.

END

**DATE
FILMED
9 / 22 / 92**