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Conceptual Design Study of a Coal Gasification Combined-Cycle Powerplant for Industrial Cogeneration

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CONCEPTUAL DESIGN STUDY

OF A COAL GASIFICATION COMBINED CYCLE POWERPLANT FOR INDUSTRIAL COGENERATION

The enclosed final report, NASA Technical Memorandum 81687, presents the results of a six-month effort conducted by the Davy McKee Corporation under NASA Contract NAS3-22105-AE.

The technical feasibility, environmental characteristics, and economics of a coal gasification combined-cycle cogeneration powerplant was examined for the NASA Lewis Research Center in response to its energy needs and to national policy aimed at decreasing dependence on oil and natural gas. The powerplant would provide the steam heating and baseload electrical requirements of the Center while serving as a prototype for industrial cogeneration and a modular building block for utility applications.

The study included screening of candidate gasification, sulfur removal, and power conversion components; definition of a reference system; quantification of plant emissions and waste streams; estimates of capital and operating costs; and a procurement and construction schedule. On the basis of the results the proposed powerplant appears to be technically feasible and environmentally superior and has the potential to be economically attractive at maturity. The powerplant can use high-sulfur Eastern coal while generating the lowest possible amount of solid waste and surpassing airborne emission standards by an order of magnitude thus allowing siting in urban areas close to electrical and steam users. The cogeneration aspect of the design provides for up to twice the coal utilization efficiency of conventional steam-electric powerplants. In addition, the modularity of the design minimizes on-site fabrication thereby reducing construction times significantly. Finally, we believe that powerplants of this type can be built with essentially current technology and can have broad application to both industrial sites and utilities for new and retrofit applications.

We appreciate your interest in this project and encourage your comments.

Harvey S. Bloomfield

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Project Manager

Enclosure

Summary

A coal gasification combined-cycle cogeneration powerplant project has been evaluated for the NASA Lewis Research Center in response to its energy needs and to National legislation aimed at decreasing dependence on oil and natural gas as boiler fuels. The powerplant would be sited at the Lewis facility in Cleveland, Ohio, and would provide both the Lewis steam heating and baseload electricity needs by using high-sulfur Eastern U.S. coal in an environmentally attractive manner. In addition, the plant would serve as an industrial prototype and a modular building block for utility applications.

This report presents the results of a contracted study (NAS3-22105-AE) by the Davy McKee Corporation to establish a reference system configuration, candidate process and power conversion components, waste disposal facilities, and materials handling and other equipment; to develop a conceptual plant design; to assess the technical and environmental feasibility of the project; to provide an implementation schedule; and to estimate capital and operating costs and manpower requirements for the plant.

The resulting plant design is based on the simultaneous production of up to 90 000 pounds of low-pressure steam per hour and a net electric power of about 16 megawatts. The steam will be generated by gasifying about 200 tons of coal per day in a pressurized, fluidized-bed gasifier and burning the resulting low-Btu gas in a combined-cycle cogeneration powerplant. The cogenerated electricity will be produced by a double-ended generator connected to both the gas and steam turbines. Electrical generation in excess of demand can be exported to the local utility grid.

The fuel gas produced by the gasifier contains particulates, which are removed by a combination of hot and cold cyclones and a venturi scrubber, and hydrogen sulfide, which is removed and converted to elemental sulfur cake in a Holmes-Stretford unit. Sulfur and gasifier ash constitute the bulk of the solid waste stream, which is estimated at 50 tons per day maximum. The gaseous waste stream from the heat-recovery steam generator stack is estimated to contain less than 0.1 pound per million Btu of sulfur oxides (SO_x) and 10 parts per million of oxides of nitrogen (NO_x)—both well below Environmental Protection Agency (EPA) requirements of 1.2 lb/10^6 Btu SO_x and 75 ppm NO_x.

On the basis of the study results the proposed powerplant is technically and environmentally feasible. Although it will be a "first of its kind" plant, many of the key components are conventional designs fully proven in commercial applications, and no insurmountable problems are anticipated. The principal technical challenges lie in gasifier operation and the integration and control of process streams to achieve high reliability and efficiency. The total project is estimated to require 42 months (24 months for construction) and to have a capital cost of $58 million based on third-quarter 1980 price levels. This includes field indirect costs, design, construction, management, and architect-engineer services but excludes escalation, insurance, taxes, royalties, licenses, commissions, fencing, cost of land, cost of capital, permits, and startup costs. Some of this total cost is associated with additional system demonstration requirements, backup capabilities, and increased operational flexibility as requested by NASA.

Total annual operating cost for the plant, estimated on the basis of third-quarter 1980 prices and excluding any indirect costs or capital charges, was estimated to be $4 136 000. The plant is assumed to operate 330 days per year. Total net annual output will be

Steam (125 psi, 430° F), Btu .... 385×10^9
Electricity, Btu (kWh) .... 444×10^9 (130×10^6)

Introduction

Until a generation ago stationary sources of power and heat – whether utility, industrial, residential, or otherwise – generally relied on coal as their fuel. This practice continued until the 1950's, when plentiful supplies of low-cost oil and natural gas led to widespread displacement of coal. New power and heat plants were constructed, and many existing plants converted, to use these cleaner, more easily handled fuels. Conversions were commonplace by the 1960's, with the trend accelerated by the Nation's increasing environmental concerns. The process continued into the first years of the past decade. But the OPEC oil embargo of 1973 made us startlingly aware of a growing vulnerability: our dependence on increasingly insecure and expensive foreign supplies of petroleum. For this reason the United States has been challenged to find a suitable way to return to reliance on coal as a predominant fuel for power and heat. This is particularly so because America's known coal reserves are greater than those of any other nation in the world. Yet, revival of coal usage must be carried out in a manner consistent with both the spirit and the letter of justifiable environmental concerns. This is especially true for the eastern half of the country, including Ohio, where high-sulfur coal is the predominant variety.

The NASA Lewis Research Center presents a typical example of current fuel usage in power and heat generation. Natural gas is used to fire boilers at the Center in order to provide steam heat for use in laboratories and other facilities. Electric power is purchased from the Cleveland Electric Illuminating Company (CEI).

As a step toward dealing with America's future energy needs, Federal energy policy has directed all Government buildings and installations to conserve natural gas and oil and, wherever practical, to convert to coal in an environmentally acceptable manner. This study addresses a powerplant that would enable NASA Lewis to meet these requirements and at the same time undertake demonstration of technology that could substantially accelerate the use of high-sulfur coal in an environmentally attractive manner. Under consideration is a new kind of electric powerplant that will turn "dirty" coal into a clean-burning industrial fuel gas and use waste heat from the process to generate steam for heating buildings. In effect, air pollution will be minimal and the energy yield per unit of coal will be approximately doubled in comparison with the conventional approach of electric power generation alone.

The study reported herein was performed by the Davy McKee Corporation for Lewis to assess the technical, environmental, and economic factors involved in a coal gasification–cogeneration approach. The design objectives of the study were to identify applicable gasifiers, gas cleanup systems, power conversion components, waste disposal facilities, and materials handling equipment; to select particular equipment for a reference conceptual, integrated coal gasification–cogeneration powerplant design; and to develop estimates of capital and operating costs and an engineering and construction schedule for a plant of this design.

Project Goals

The Coal Gasifier Combined-Cycle Cogeneration (COCOGEN) Powerplant Project has been initiated to assess the feasibility of providing the NASA Lewis Research Center with an alternative-energy powerplant that can meet the Center's steam heating and baseload electric power requirements. The goal of the project is to design, construct, and characterize the operation of a COCOGEN powerplant at the Lewis site in Cleveland, Ohio. The proposed powerplant can have significant near-term National and regional impact if it is constructed on an expedited basis. National benefits of this project include (1) the establishment of a viable option for industrial cogeneration with coal, (2) a major step toward the acceptance of a utility integrated-gasifier, combined-cycle powerplant, and (3) the potential for development of a new environmental benchmark for coal-fired powerplants. The project can achieve significant regional impact through the expanded use of Eastern and Midwestern U.S. coals.

Operation of the powerplant will characterize the integrated-gasifier, combined-cycle concept for utility powerplant applications and serve as a demonstration of the environmentally acceptable use of coal for industrial and commercial cogeneration applications including Federal facilities and laboratories.

Powerplant Objectives

The COCOGEN powerplant proposed will combine coal gasification, combined-cycle power generation, and cogeneration of heat and electricity in a single facility. The overall concept is shown in figure 1,

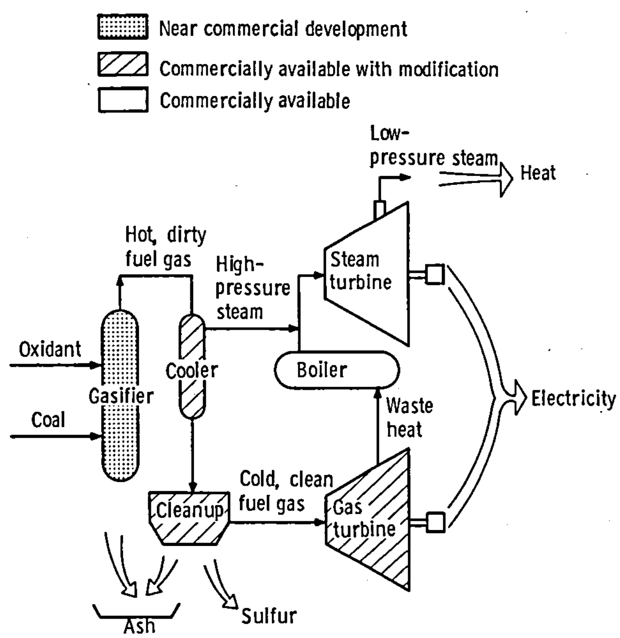


Figure 1. - Coal gasifier cogeneration powerplant concept.

which illustrates the arrangement and development status of key powerplant components. A major objective of the powerplant design is to minimize development risk through the use of current technology in commercially available components. The code used in figure 1 indicates the technological status of each selected component. The gasifier is considered to be near commercial development; the fuel gas cooler, gas cleanup system, and gas turbine are commercially available but require some modification; and the heat-recovery steam boiler and extraction steam turbine are commercially available items. System integration and control are in themselves considered to be developmental.

The environmental objectives of the COCOGEN powerplant are to meet or better all emissions standards for solid, liquid, and gaseous waste products while using high-sulfur coal. These waste streams include gasifier bottom ash, elemental sulfur cake, fuel gas combustion products (NO_x and SO_x), particulate (coal dust), and waste water runoff from the coal pile.

The performance objective of the powerplant is to provide the Lewis steam heating and baseload electrical requirements with a design that uses less energy than a conventional coal-fired steam plant in combination with conventional electric power generation.

Powerplant Requirements

The conceptual design of the COCOGEN powerplant was based on meeting the following broad set of general design criteria and the specific Lewis steam heating and electrical loads:

(1) The powerplant should be able to use a variety of U.S. coals, including Ohio No. 9, without pretreatment.

(2) Powerplant emissions shall meet, or better, all existing EPA standards for solid, liquid, and gaseous waste streams.

(3) Solid and liquid waste streams shall be suitable for direct sanitary landfill.

(4) Powerplant equipment should be state of the art and commercially available without extensive modification.

(5) Two gasifier modules shall be used to demonstrate parallel operation for multiple-unit applications.

(6) The gas cooler (heat exchanger) shall be limited to modest steam conditions in order to reduce development risk.

(7) The powerplant shall use less energy than a conventional coal-fired steam plant in combination with conventional electric power generation.

The specific Lewis requirements, based on typical steam and electrical load demand data, are shown in figures 2 and 3, respectively. In general, Lewis steam demand is characterized by a seasonal variation and follows ambient temperature (degree-days). The electrical demand is characterized by nighttime research loads of up to 200 megawatts, daytime research intermediate loads of up to 40 megawatts, and an institutional baseload of about 8 megawatts.

The primary function of the powerplant is to provide the Lewis heating requirement of 125-psia, 430° F saturated steam. A maximum winter steam rate of 90 000 lb/hr and a summer steam rate of 26 000 lb/hr were specified for the powerplant.

The overall specification for electricity output was set to be greater than 8 megawatts in order to meet baseload requirements. A closer definition of the electricity output specification was obtained from a more detailed analysis of the Lewis electrical load profile. This was accomplished by integrating the daily load profile to generate the typical annual Lewis load-duration curve shown in figure 4, which indicates the fraction of time the electrical load is

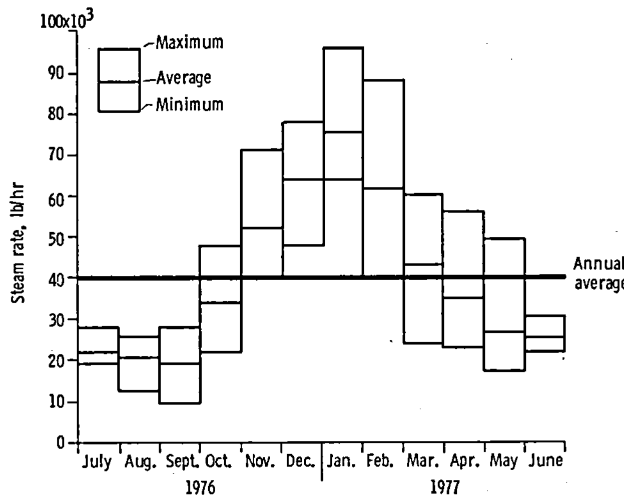


Figure 2. - NASA Lewis Research Center typical monthly steam demand.

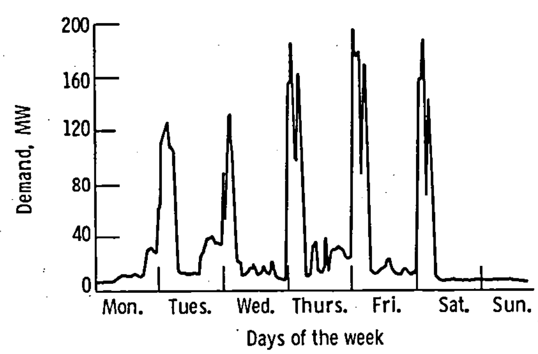


Figure 3. - NASA Lewis Research Center typical daily electric demand (August 1979).

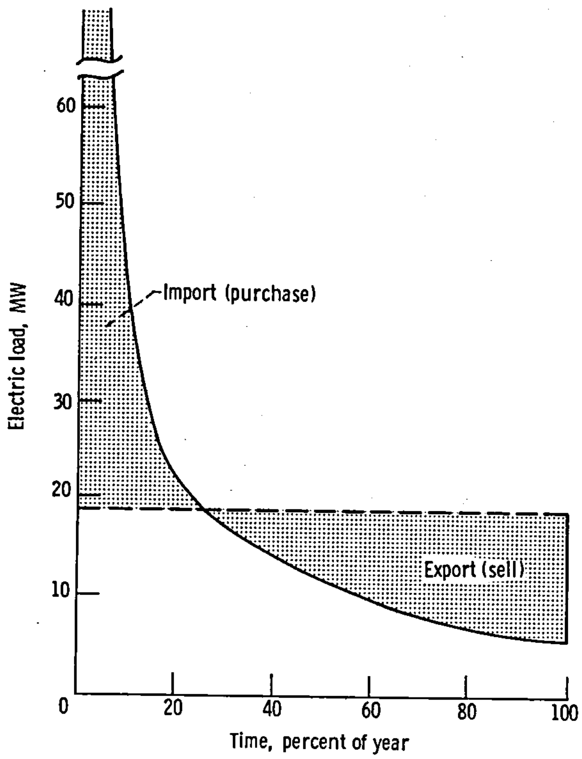


Figure 4. - NASA Lewis Research Center annual electric load duration curve.

higher than a particular value. As shown in figure 4 a capacity of about 19 megawatts will produce approximately equal areas of energy above and below its value; however, as can be seen from figure 3 power would be both imported and exported nearly every day of normal Lewis operation.

Conceptual Design Summary

The COCOGEN facility has been designed to produce up to 90 000 pounds of steam per hour at 125 psia and 430° F for space heating. This is accomplished by gasifying up to 238 tons of Ohio No. 9 coal per day in either or both of two parallel air-blown, fluidized-bed gasifiers, burning the resulting low-Btu gas in a gas turbogenerator, and recovering the heat in the exhaust to generate superheated (750° F, 615 psia) steam to power an extraction steam turbogenerator.

Additional high-pressure steam is produced by cooling the fuel gas stream exiting the gasifier from 1850° F to 400° F. This steam is combined with that produced by cooling the gas turbine exhaust from 1000° F to 270° F. The combined flow passes through an extraction steam turbine, where low-pressure steam for space heating is extracted.

Coal is delivered to the site by 25-ton trucks and stored in an open coal pile. It is retrieved by a system of enclosed conveyors, crushed, weighed, and fed to the feed surge bin. A pressurized lockhopper system injects the coal into the gasifier. In the gasifier the carbon is partially consumed by steam gasification and combustion and the remaining ash is continuously withdrawn through the bottom of the gasifier and transported to a silo for short-term storage.

The fuel gas produced by the gasifier contains particulates and hydrogen sulfide (H_2S). The solid material is removed by a combination of hot and cold cyclones and a venturi scrubber. The H_2S is converted to elemental sulfur cake in a direct-conversion Stretford unit. The sulfur and gasifier ash constitute the bulk of the solid waste stream, estimated at 50 tons per day maximum. The gaseous waste stream from the heat-recovery steam generator stack contains less than 1 ppm SO_x and 10 ppm NO_x.

Byproduct electricity is produced by a generator connected to both the gas turbine and the steam turbine. The net electric power available (16 MW) can be used by Lewis and the excess exported to the utility grid, depending on electrical load requirements at any particular time.

The plant design includes cooling water facilities, boiler feed water and condensate treatment, an auxiliary boiler, coal pile drainage water and plant waste water treatment, liquid-nitrogen storage and evaporation, and a flare system. A detailed design description including engineering drawings is given in appendix B. A simplified schematic of the COCOGEN powerplant is shown in figure 5. This figure includes all major components and subsystems with temperatures and pressures given at key locations. An isometric view of the powerplant layout at the NASA Lewis site is shown in figure 6.

Reference System

To provide a basis for technical and economic evaluation, a reference system consisting of specific components was selected. Details of candidate components examined and the evaluation criteria used are given in appendix A.

Evaluation and selection of the gasifier and the sulfur removal system were given major emphasis. Thirty-three gasifiers were evaluated against 17 selection criteria, and five gasifier types were identified as acceptable. Three categories of sulfur (acid gas) removal systems representing 11 process types were evaluated against five selection criteria, and three processes were identified as acceptable.

Evaluation and selection of energy conversion equipment were primarily focused on gas

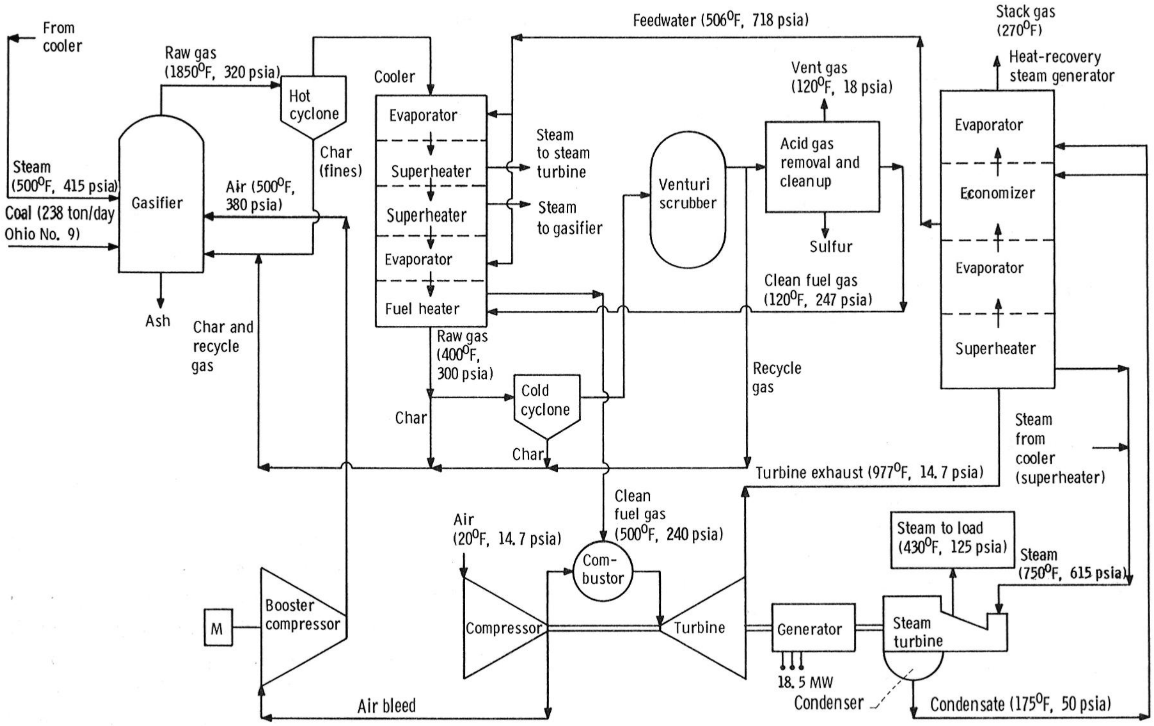


Figure 5. - COCOGEN simplified schematic diagram (winter condition).

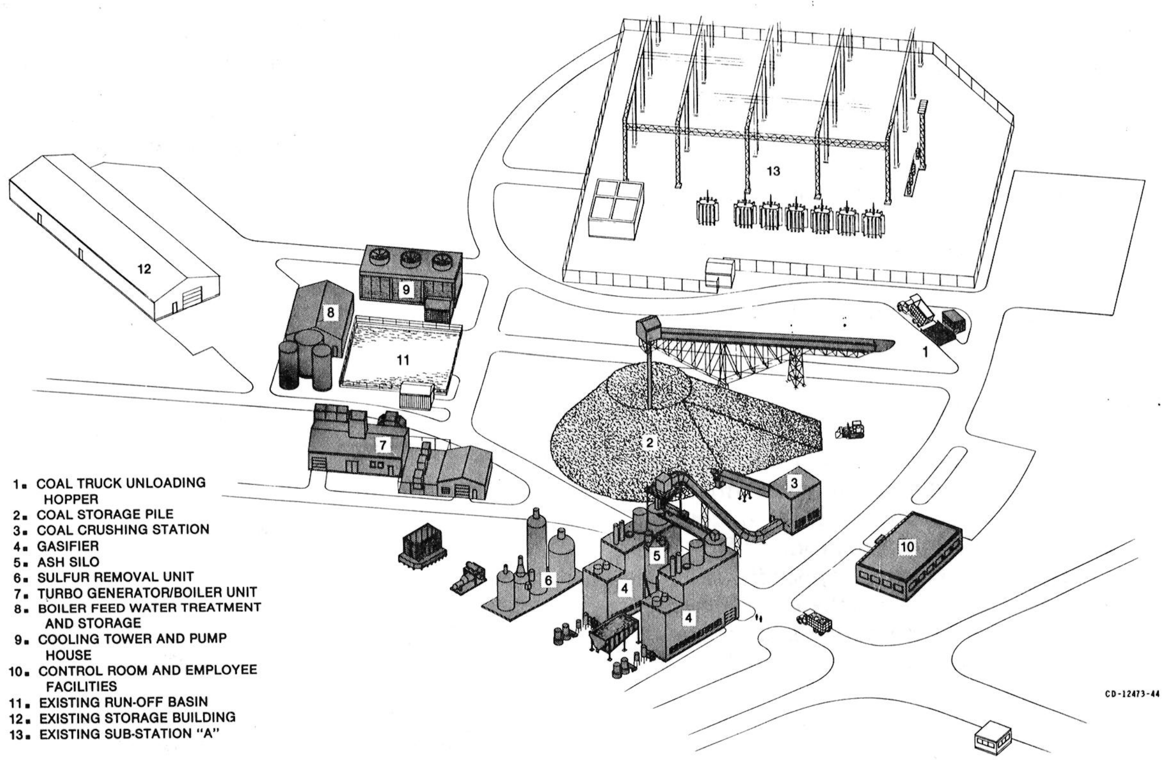


Figure 6. - Coal gasifier cogeneration powerplant.

turbomachinery because of the importance of the low-Btu gas combustion required of this component. A survey of nine gas turbine manufacturers resulted in the identification of three specific models that met evaluation criteria.

An extensive system analysis was conducted to determine the integrated performance and design characteristics of the acceptable components. The specific reference system components, shown in table I, are representative of a feasible (not optimized) system and were selected to provide realistic estimates of system performance, environmental impact, and costs.

Reference System Performance

The reference system components, shown in table I, were integrated into a complete powerplant conceptual design, and system performance was determined for both a summer and winter design point. Actual plant performance will vary between these two design point extremes.

Powerplant performance is shown in table II. Included in the performance summary is coal utilization efficiency, which is defined as the total plant electrical and thermal output energy divided by the energy (heating value) of the coal input. The COCOGEN powerplant efficiency is compared with the efficiency of other competing powerplant types in figure 7. The comparison includes large-scale conventional Rankine-cycle steam powerplants (with flue gas desulfurization) and large-scale gasifier combined-cycle powerplants. Thus the overall efficiency advantages of cogeneration, for an industrial, small-scale COCOGEN powerplant, are significant.

Details of powerplant performance, including mass and heat balances and power and heat distribution, are given in appendix B, tables XII to XV.

Reference System Emissions

The environmental characteristics of the reference system design were assessed and compared with those of conventional coal-fired powerplants. A detailed evaluation of emissions and waste products from the COCOGEN powerplant is given in appendix B. This section of the report summarizes the environmental impact of the reference system design and includes a comparison with conventional coal-fired utility powerplants.

The type and quantity of emissions and waste products from the COCOGEN reference system design are illustrated in figure 8. A nominal throughput of 200 tons per day of Ohio No. 9 coal results in the emission of ash and carbon from the gasifier bottom

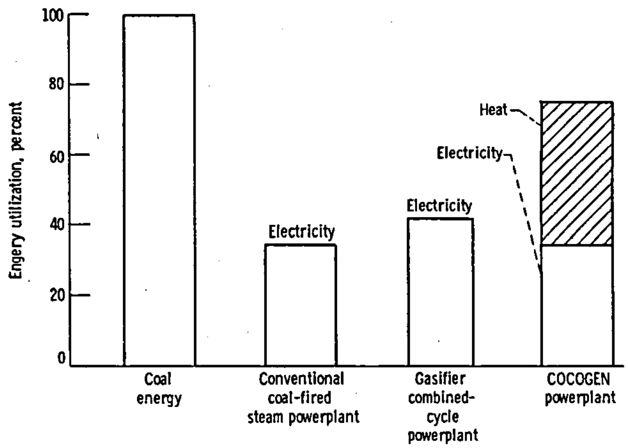
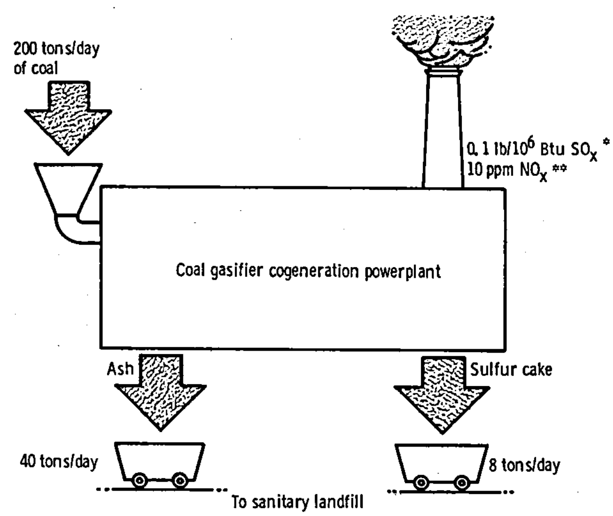


Figure 7. - Comparison of energy utilization efficiency.

(38 tons per day) and from the venturi scrubber (2 tons per day); sulfur cake from the Holmes-Stretford process (8 tons per day for a 4-percent-sulfur coal); and SO_x and NO_x from the heat-recovery steam generator stack (<0.1 lb/10^6 Btu SO_x and <10 ppm NO_x). The sulfur and ash solid wastes should be suitable for sanitary landfill disposal either as separate or combined streams.

Emissions to the air, specifically SO_x and NO_x, are a factor of 10 below current environmental standards and may represent a new environmental benchmark for the use of high-sulfur coal. Figure 9 compares the relative quantity of emissions from a COCOGEN powerplant with those from a conventional direct-coal-fired steam powerplant (with scrubbers) of equivalent output. Total COCOGEN powerplant emissions are about 60 percent (by weight) of those



*EPA standard: 1.2 lb/10^6 Btu for coal-fired plant
**EPA standard: 75 ppm for gas turbines

Figure 8. - NASA Lewis COCOGEN powerplant environmental impact.

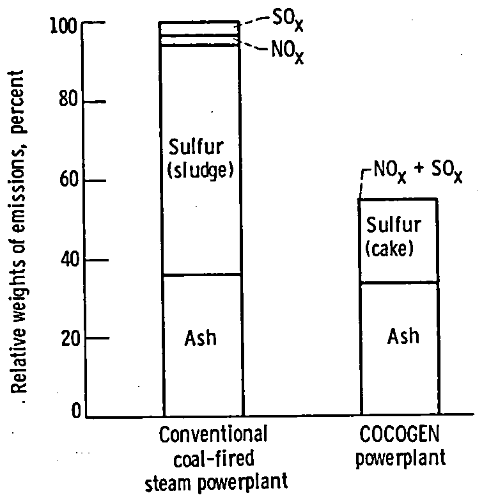


Figure 9. - Comparison of powerplant emissions.

from the conventional powerplant. In addition, the COCOGEN elemental sulfur cake product is more easily handled than the sludge generated by conventional wet-flue-gas desulfurization methods.

Powerplant Implementation Schedule

A schedule for engineering, procurement, and construction of the COCOGEN powerplant was developed and is shown in figure 10. The bar chart schedule shows the estimated durations for all activities based on the assumption that a single engineering construction company would have total project responsibility. The total duration from contract award to startup is 42 months.

The 16-month duration for engineering is based on an engineering man-hour estimate and typical durations for design engineering activities. An average manpower loading of 30 to 35 man-hours, with a peak of 55 to 60 man-hours at the eighth month, was assumed.

Procurement duration estimates were based on vendor delivery information for the reference system. For the activities between the inquiry stage and placement of purchase orders, the following durations (in weeks) were used:

Bid period 4
Commercial and technical analysis 3
Client approval 3
Purchase order placed 1

The critical long-duration items are the fabrication and delivery of the sulfur removal unit and the power generation unit.

Construction duration was estimated at 26 months, with field opening 16 months after contract award. An average manpower loading of 90 to 100 man-hours with a 150 to 160 man-hour peak at 60 percent of construction completion was assumed.

Cost Estimates

The capital and operating costs for the COCOGEN powerplant are based on estimates for design, construction, and operation typical of a first-of-a-kind powerplant. In particular, contingencies are included in engineering design man-hours, vendor quotes for major hardware packages requiring modification from "off the shelf," and operating manpower and maintenance requirements.

Capital cost estimates are based on third-quarter 1980 dollars and are accurate to ±20 percent. Operating cost estimates are based on third-quarter 1980 dollar costs for materials and manpower.

Capital Costs

The total direct cost of the reference system design is estimated to be $51 270 000. This includes vendor quotes for the coal gasifier package, the sulfur removal package, and the power generation package, as well as detailed estimates for the coal-handling area, gasifier and powerplant auxiliaries, and site development and supporting facilities. The components included in each of the aforementioned categories are listed in table III. The total indirect cost of the reference system design is estimated at $7 030 000. This includes $2 250 000 field indirect cost for construction management and $4 780 000 for professional design and integration services. All capital costs and exclusions are summarized in table IV.

Operating Costs

Operating cost estimates for the reference system design were based on meeting the Lewis steam demand with a powerplant on-stream availability of 90 percent (330 days/yr) and standby gas-fired boiler operation of 10 percent (35 days/yr). The assumption of steady-state operation at rated load results in the maximum (conservative) variable cost estimates shown in table V. Labor cost estimates were based on first-of-a-kind powerplant operation—resulting in maximum (conservative) estimates of manpower requirements. The estimated labor requirements for a three-shift operation are given in table VI. The estimated direct annual operating cost of $4 136 090 provides for the generation of 385×10^9 Btu of steam and 130×10^6 kilowatt-hours of electricity.

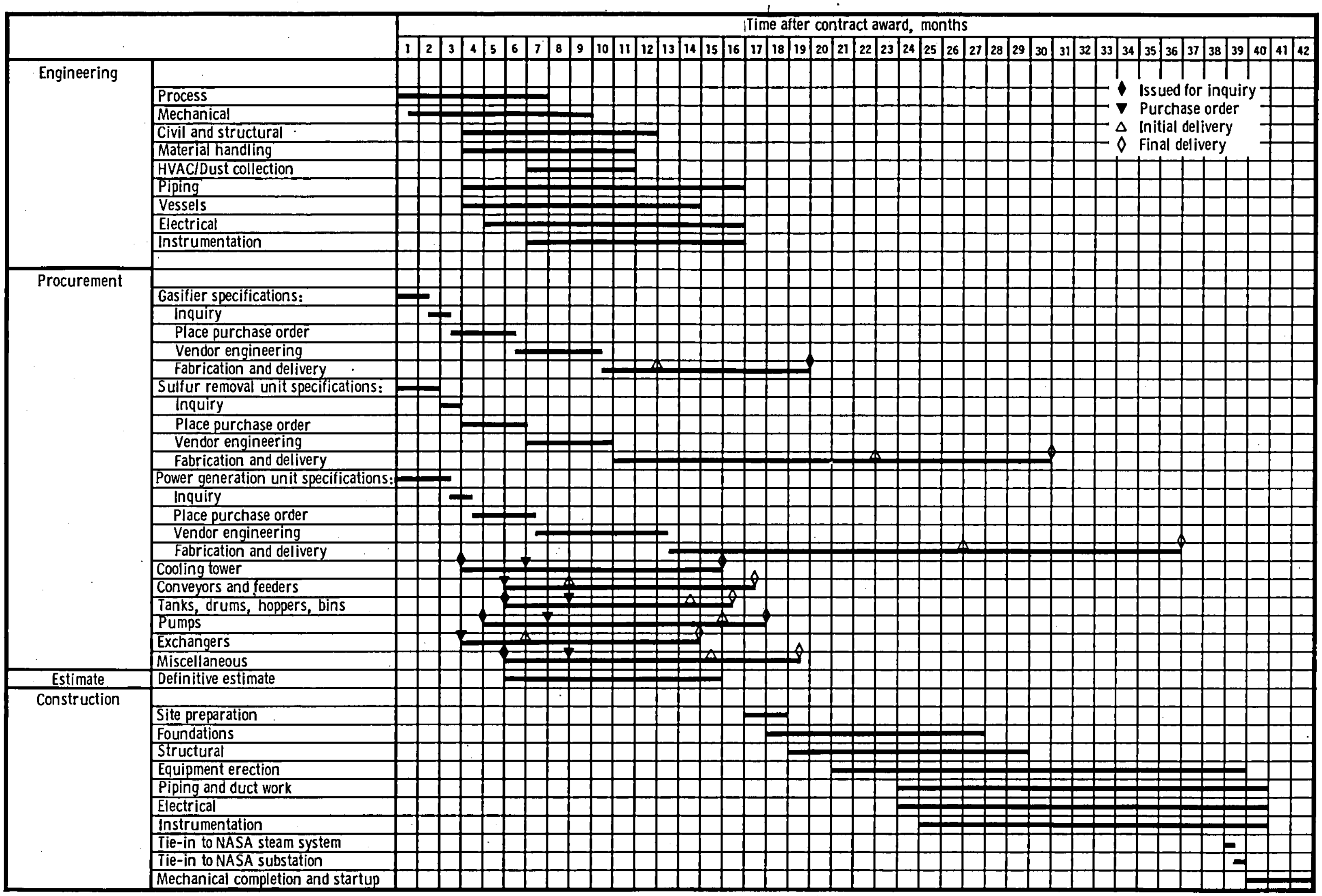


Figure 10. - Powerplant implementation schedule.

Conclusions

On the basis of the conceptual design developed in this study, it was concluded that a coal gasifier cogeneration combined-cycle powerplant is feasible for the NASA Lewis Research Center site in Cleveland, Ohio. Screening and evaluation of candidate gasifiers, sulfur removal processes, and power conversion hardware led to the identification of a reference system for this feasibility study. This system was used as the basis for assessing performance, emissions, and capital and operating costs.

The powerplant will use high-sulfur Eastern coal in an environmentally superior manner while providing twice the coal utilization efficiency of conventional electric powerplants. In addition, it can be built with essentially current technology and can have broad application to both industrial sites and utilities for new and retrofit applications. The proposed NASA Lewis Research Center site in Cleveland, Ohio—located between a major airport and a metropolitan park—was found to be acceptable. No environmental barriers are foreseen.

The conceptual design powerplant generates about 16 megawatts of electricity while providing the Center's steam heating load of 26 000 to 90 000 pounds per hour from a coal throughput of 205 to 238 tons per day of Ohio No. 9. Overall coal utilization efficiency will vary from 44.4 percent (summer) to 71.4 percent (winter). Solid waste streams of up to 40 tons of ash and 8 tons of sulfur per day are expected to be suitable for sanitary landfill. Emissions to the air will be an order of magnitude below current Federal standards with sulfur and nitrogen oxide levels of 0.1 lb/10^6 Btu and 10 ppm, respectively.

The total direct capital cost for powerplant procurement and construction was conservatively estimated at $51.27 million (1980 dollars). Indirect capital costs of $7.03 million (1980 dollars) include design and construction management. Operating costs were estimated at $4.14 million (1980 dollars) annually.

Appendix A

Component Evaluation and Reference System Selection

Gasifiers

Classification

Coal gasification involves the reaction of coal with air or oxygen and steam to yield a gaseous product suitable for use as a source of energy or as a raw material for the synthesis of other materials. An important advantage of coal gasification over the direct combustion of coal is greater ease in the removal of unwanted chemical species, such as sulfur. Past experience has shown that it is generally less expensive to remove sulfur from a gaseous fuel prior to combustion than it is to remove it from combusted gaseous products.

Existing coal gasifier designs can be classified into four categories:

(1) Fixed-bed gasifiers
(2) Fluidized-bed gasifiers
(3) Entrained-flow gasifiers
(4) Miscellaneous gasifiers

Fixed-bed gasifiers. – Coal is normally fed by gravity into the top of fixed-bed gasifiers. The coal forms a bed that moves slowly downward through the gasifier as air or oxygen and steam flow countercurrently upward. The bed consists of several distinct zones: a drying and devolatilization zone at the top, a gasification zone, a combustion zone, and an ash or slag zone near the bottom. Advantages of fixed-bed gasifiers over other gasifier types include low solids carryover into the product gas, good gas-to-solid contact resulting in good carbon conversion, and inherent safety because of the large fuel inventory within the gasifier itself. Disadvantages of fixed-bed gasifiers are their inability to handle highly swelling and caking coals, limitations as to the percentage of fines they can accept, and a relatively low gas production rate per gasifier cross-sectional area. Fixed-bed gasifiers are operated at lower temperatures than other gasifiers, and thus tars and oils generated in the product gas require a removal step.

Fluidized-bed gasifiers. – Fluidized-bed gasifiers are characterized by a bed of coal in the fluidized condition. Each coal particle is separately suspended by the flow of air or oxygen and steam from the bottom of the gasifier. No grates are required and, because fluidized-bed particles remain in continuous motion, no external mechanical agitation is needed, thus simplifying operation and maintenance. Solids and gases mix well, resulting in excellent solid-gas contact. Fluidized-bed gasifiers generally have a wide operating range, produce a tar- and oil-free product gas, can tolerate any particle size, possess a high degree of process reliability, and have a high capacity per cross-sectional area. They generally are considered one of the easiest to control and the safest gasifier types because of the large carbon inventory in the bed.

Entrained-flow gasifiers. – Coal is fed into entrained-flow gasifiers as finely ground particles suspended or entrained in the oxidant stream. Entrained-flow gasifiers are operated at very high temperatures, and coal particles react with the oxidants as they are carried into the gasifier. Because reactions are rapid, entrained-flow gasifiers generally have high capacities. Additional advantages of entrained-flow gasifiers are their ability to use any coal type and their production of a tar- and oil-free gas. Disadvantages include the requirement to pulverize the coal beforehand, the special materials and construction required to handle the high temperatures, and less inherent safety than the other gasifier categories because of the faster response times required.

Miscellaneous gasifiers. – The miscellaneous category of gasifiers includes those that do not fit clearly into the fixed-bed, fluidized-bed, or entrained-flow categories. Gasifiers in this category are currently experimental in nature and many employ a second medium—such as a molten salt, iron, or slag bath—to enhance gasification.

Evaluation and Selection

Gasifiers were evaluated for the Lewis COCOGEN facility by comparing the characteristics of available gasifier designs with the gasifier characteristics desired. The desired characteristics were based on a set of specific criteria that were developed jointly by NASA and Davy McKee. These criteria in order of decreasing importance are as follows:

(1) The gasifier must be able to use any U.S. coal (including Ohio).

(2) The stage of development must be at least near commercialization.

(3) Gasifier sizes (capacities) available must meet NASA needs.

(4) Pressurization up to 400 psia is required.

(5) Reliability and safety must be verifiable.
(6) The amount of tars and oils produced must be negligible.
(7) The ability of handle fines is required.
(8) Waste product must be environmentally acceptable.
(9) Coal conversion efficiency must exceed 85 percent.
(10) Turndown ability without significant performance loss is required.
(11) The method of feeding coal must be compatible with the NASA Lewis site.
(12) Product gases must be cleanable by commercial processes.
(13) Maximum height cannot exceed 80 feet.
(14) No special or costly coal preparation or pretreatment can be required.
(15) Cost estimate and delivery schedule must be provided by the vendor.
(16) Vendor cooperation and design assistance is required.
(17) Both air and oxygen operation is desirable.

Thirty-three different gasifiers were considered. These gasifiers are listed in table VII according to generic type—fixed bed, fluidized bed, entrained flow, and miscellaneous.

Candidate gasifiers were evaluated against the selection criteria through a combination of literature search, vendor contacts, and site visits. These results are shown in table VIII, which evaluates all candidate gasifiers against the five most important criteria. A checkmark indicates that a particular gasifer meets a particular criterion; an X indicates that it does not. A single X eliminated a gasifier from further consideration.

Five gasifiers were judged initially acceptable for the proposed plant. They are (not necessarily in order of preference):
(1) Fixed bed—British Gas Corp.
(2) Fluidized bed—U-Gas and Westinghouse
(3) Entrained flow—Babcock & Wilcox and Texaco

A detailed system analysis for each of the five gasifiers was conducted to evaluate their characteristics and requirements when operated in an integrated COCOGEN system. Overall system performance and mass and energy balances were estimated for each gasifier for the following specific cases:

Coal type	Ohio No. 9, Illinois No. 6
Coal throughput, tons per day	200–800
Oxidant, percent oxygen	21 (air), 60, 80
Pressure, psi	100–360

Results of preliminary system analyses showed that the pressurized, fluidized-bed gasifiers (Westinghouse and U-Gas) appear to be particularly attractive for the Lewis application. The Westinghouse gasifier was selected as the reference for the conceptual design on the basis of successfully meeting all evaluation criteria.

Gas Treatment and Cleanup

The product gases generated in most gasifiers contain high levels of dust and impurities as well as undesirable chemical species. For the COCOGEN application the product fuel gas must be extremely clean and essentially free of large ash particles, metallic elements such as vanadium and sodium, and sulfur. These impurities will adversely affect the life of gas turbine blades and, in addition, contribute to air pollution.

Particulate removal. – Fluidized-bed gasifiers produce a raw gas product carrying carbon-containing particles. These particles must be removed prior to combustion. Typically the dust or ash loading of the gas leaving fluidized-bed gasifiers is about 35 to 40 grains per standard cubic foot of dry gas, with an average particle size of about 0.3 millimeter.

Acid gas removal. – Much of the sulfur present in coal leaves the gasifier as so-called acid gases, H_2S and COS. Typically over 90 percent of the sulfur is in the form of H_2S. The product gas must be treated to remove these sulfur compounds in order to meet environmental standards for sulfur oxides, which are formed during combustion in the gas turbine.

Conventional coal-burning powerplants are restricted by the EPA as to the amount of these compounds they can emit into the atmosphere. At this time no regulations exist for permissible amounts of sulfur in exhaust gases from gasified coal processes. It is expected, however, that when regulations are established, they will be equivalent to those relating to powerplants that burn coal directly.

Classification—Acid Gas Removal

Except for coals with very low sulfur levels, below about 0.1 percent, fuel gases produced by gasification will probably require an acid gas removal step to reduce the sulfur content. Many different processes to extract the acid gas species from fuel gases have been developed, and most are available commercially today. In general, these processes fall into three categories:
(1) Chemical-solvent processes
(2) Physical-solvent processes
(3) Direct-conversion process

For processes in the first two categories an additional step (a Claus plant) is required to recover sulfur as a final product. The direct-conversion process eliminates this requirement because H_2S is oxidized directly to elemental sulfur.

Chemical-solvent processes. – These processes are characterized by relatively high heats of solution and are not sensitive to operating pressure. The concentration levels of the absorbents, however, are important since they determine the circulation rates and subsequent regeneration heat requirements, which are generally high.

Physical-solvent processes. – These processes have low heats of solution, and the solubilities of the acid gases depend on their partial pressures. At pressures below 200 psia little absorption occurs unless the acid gas concentration in the fuel gas is high or the absorption is done at very low temperatures, below $-70°$ F. The energy required for regeneration for physical solvent processes is much less than that for chemical-solvent processes.

Direct-conversion process. – This process is characterized by oxidation-reduction reactions. The H_2S in the fuel gas is absorbed in an alkaline solution containing oxidizing agents in a short-residence-time contact unit, usually a venturi contactor. The resulting solution is then oxidized by air and the sulfide is oxidized to elemental sulfur. The sulfur product is then separated by froth flotation without any heat addition.

Evaluation and Selection

Two principal criteria are important in the selection of a particulate removal system. First, the system must reduce the quantity and size of particulates appearing in the product gas to make the gas suitable for combustion in a gas turbine. Second, the system must have a proven record of high performance and low maintenance.

The following criteria were established for the selection of a suitable acid gas removal process:

(1) The process must accommodate a 100-percent range of sulfur contents in the product gas (typically from 0.47 to 1.0 mole percent H_2S).

(2) The process must accommodate a wide range of gas pressure and be particularly effective above 200 psi.

(3) The process should remove a minimum of carbon dioxide from the product gas.

(4) The process should be commercially proven and should not add detrimental impurities to the product gas.

Particulate removal. – The dust removal system selected for the reference design consists of two initial hot cyclones treating the gas exiting the gasifier followed by a third cold cyclone and a wet venturi scrubber. The exhaust gas coming from the scrubber will have a dust loading of less than 0.001 grain per standard cubic foot of dry gas. This level is within the acceptable dust loading for typical moving machinery parts. In addition, the particulate loading in the final gas is likely to decrease even further as the gas exiting the venturi is cooled. Condensate forms during this cooling and carries additional particles with it. The condensate is separated from the product gas in a knockout drum. The product gas is cooled to about 120° F before being sent to the desulfurization unit for H_2S removal.

Acid gas removal. – Most chemical-solvent processes were found to have high affinity for CO_2 and to remove a large percentage of the CO_2 that is present. If large amounts of CO_2 are present, the ability to remove sulfur suffers and the resulting product gas may retain as much as 600 ppm sulfides. Certain solvents, such as Alkazid DIK, however, can reduce the sulfides to 50 ppm and provide an H_2S stream gas suitable for further processing in a Claus (tail gas) plant. Of the chemical-solvent processes studied, the Alkazid-Claus is acceptable for the Lewis application.

An advantage of physical-solvent processes is that the vapor pressures of most physical solvents are low and thus carryover of the solvent into the product gas is very low. Carbon-steel construction is common with physical solvent processes. A major disadvantage that physical-solvent processes share with chemical-solvent processes is that many result in $H_2S:CO_2$ ratios in the waste gas stream that are too low to allow economical processing of the gas in a Claus plant. The Selexol, Rectisol, and Alkazid processes are exceptions. Of the physical-solvent processes studied, the Selexol-Claus is acceptable. This process selectively removes H_2S down to the 5 ppm level while also removing about 15 percent of the CO_2 present in the product gas. The minimum operating pressure for a Selexol unit is about 200 psi.

The Stretford direct-conversion process was examined, and Peabody's Holmes-Stretford system was selected for evaluation. This process is unique in that it is not influenced by total gas pressure or by the sulfur level of the product gas. It can be operated at all pressures and with any concentration of H_2S. It requires no tail-gas plant because, as mentioned earlier, elemental sulfur is produced and removed directly, with a resulting sulfur level of the product gas as low as 5 ppm. The Holmes-Stretford process, however, does not remove COS nor will it be economical for gases containing CO_2 when the CO_2 partial pressure exceeds 20 psia. These factors are not considerations for the Lewis application because of the small COS concentration and a CO_2 partial pressure less than 20 psia.

The three processes, Alkazid or Selexol in combination with a Claus plant and Holmes-Stretford, were then compared. Although it was judged that any of these three processes could be used, the Holmes-Stretford process met all the selection criteria at the lowest cost and was therefore used in the reference design.

Power Generation

Components

Combined-cycle powerplants typically consist of three basic components: (1) a gas turbine generator set, (2) a waste-heat-recovery boiler, and (3) a steam turbine generator set. Fuel is combusted in the gas turbine to generate electric power. The exhaust gas from the gas turbine is passed through the waste-heat-recovery boiler, where steam is produced either with or without supplemental fuel combustion. Steam from the waste-heat-recovery boiler is sent to a steam turbine, which generates additional electricity.

A variety of packaged combined-cycle power generating systems are offered by manufacturers. However, because of the special needs for low-pressure steam extraction to provide heating (cogeneration) and the capability to burn low-Btu fuel gas, an assembly of individual components was selected for the Lewis application.

Evaluation and Selection

Selection criteria were developed for power generation equipment. Candidate equipment was evaluated and compared, and one set of components was selected for use in the conceptual plant design on the basis of these criteria. Important selection criteria included the following:

General configuration. – The power generation system shall use commercially available state-of-the-art components to the maximum extent possible and shall include a gas (combustion) turbine, heat-recovery steam generator, and extraction steam turbine. The gas turbine combustor must have the capability to fire low-Btu gas and additionally must be able to supply pressurized air bleed (to a system-integrated coal gasifier) without causing a compressor-turbine mismatch. The steam turbine shall operate at modest steam conditions (to minimize development risk in the gas cooler) and shall include provision for steam extraction at 125 psia for heating and 50 psia for water treatment.

Steam requirements. – The steam turbine must generate up to 90 000 pounds of steam per hour during winter months and about 26 000 pounds per hour at other times. The steam should be generated by using, in part, condensate returning from the existing Lewis facility.

Electric power requirements. – The electric power output shall meet Lewis baseload demand levels of 8 megawatts.

Operation. – The selected electric power and steam generation components should provide high performance and reliable operation over the range and mode of steam demand. The preferred mode of operation is to run the gas turbine at design (baseload) conditions and let the extraction rate of the steam turbine fluctuate with seasonal demand. In addition, the gas turbine must be capable of dual fuel operation, using both low-Btu and natural gas fuels.

A survey of major power generation manufacturers was conducted. The availability of both heat-recovery steam generators and extraction steam turbines was found to be good. The availability of small state-of-the-art gas turbine equipment was more restricted. Three machines were identified as being appropriate for this application. The characteristics of these gas turbines are shown in table IX. Of the three suitable gas turbines the Westinghouse CW182 machine was used in the conceptual design reference system together with a model M25 extraction steam turbine.

Appendix B
Conceptual Plant Design

Design Basis

Steam and power generation. – The design basis for the steam produced by the powerplant was derived from data provided by NASA for a typical 12-month period. From these data two hourly steam production rates were selected for performing detailed heat and material balance calculations. One rate (designated "winter case") is 90 000 pounds of steam per hour and corresponds approximately to the maximum consumption recorded. The second rate selected for design calculations (designated "summer case") is 26 000 pounds of steam per hour. This rate actually represents a range of operations throughout the year and includes spring, summer, and fall conditions.

The varying steam load will be accommodated by the Westinghouse M25 two-stage extraction steam turbine running in combination with a modified Westinghouse CW182 low-Btu, gas-fired turbine. Steam for heating is extracted at 125 psia, and deaerator steam is extracted at 50 psia.

The design basis for the electric power generated by the reference gas turbine-steam turbine set will be 18.9 megawatts gross (summer) and 18.5 megawatts gross (winter). Gas turbine gross outputs will vary between 11.5 and 14.4 megawatts, and steam turbine gross outputs between 7.4 and 4.1 megawatts, respectively.

Coal storage and handling—ash collection. – Washed coal is delivered to the site by trucks of approximately 25-ton capacity. An open coal pile is provided based on three days "live" storage capacity and 15 days "dead" storage capacity. The coal feed system is designed to supply up to 200 tons of coal per day simultaneously to each of the two gasifier trains. The product from the roll crusher (and feed to the gasifier) is minus 1/4 inch, with fines not exceeding 10 percent of minus 100 mesh. Ash is collected from both gasifier trains in a storage silo designed to contain about three days production.

Gasification. – Two duplicate Westinghouse air-blown, pressurized, fluidized-bed gasifier modules are provided to demonstrate parallel operation. The gasifier modules include feedbins, lockhoppers, cyclones, raw gas coolers (steam generators), steam drums, pumps, a recycle gas compressor, piping, and instruments. Each gasifier has a maximum design capacity of 200 tons per day of Ohio No. 9 coal. The two modules can be operated together or singly. For example, each gasifier may operate at about 60 percent capacity since the downstream equipment is sized for a throughput of 240 tons of coal per day. The analysis of Ohio No. 9 coal as used in this study is shown in table X.

Sulfur removal and recovery. – The design specification for the Holmes-Stretford sulfur removal unit is based on processing 238 tons per day (19 810 lb/hr) of Ohio No. 9 coal with a sulfur content of 5 percent. This represents a maximum-sulfur case for the winter design condition.

The resulting specification for the fuel gas to the Holmes-Stretford unit is given in table XI along with a minimum-sulfur design operating case equivalent to 205 tons per day (17 065 lb/hr) of Ohio No. 9 coal with 2.4 percent sulfur content. The product gas from the Holmes-Stretford unit was specified to have a maximum H_2S concentration of 5 ppm by volume and sodium plus potassium levels and vanadium levels each less than 0.1 ppm (by weight).

Soils data. – A review of test boring data for an area adjacent to the proposed plant site indicates that the soil is suitable for the construction without piling.

Boiler feed water and condensate. – Boiler feed water is treated by reverse osmosis based on 2 percent blowdown to produce 615-psia, 750° F steam. Condensate is returned from the existing heating system and treated prior to reuse.

Nitrogen. – Nitrogen is required in the gasification plant for startup, to pressurize vessels, and to purge instruments. A liquid-nitrogen storage and vaporization system can be rented for this purpose. The new facility equipment will include a booster compressor to raise the vaporized nitrogen to the gasifier operating pressure.

Cooling water. – The plant will have a cooling water facility including a cooling tower, circulating pumps, and cooling water treatment.

Electricity. – The plant electrical system will be connected to the existing substation adjacent to the site. It is designed to draw power from the substation or to feed power to the utility company grid. A 300-kilowatt standby diesel generator is provided to furnish power to an auxiliary package boiler, to the gas turbine auxiliaries, and for emergency lighting and instrument power.

Steam. – Four levels of steam are produced in the plant: 615-psia, 750° F steam for the steam turbine, 427-psia, 502° F steam for the gasifier, 125-psia, 430° F steam for heating, and 50-psia, 298° F steam for the deaerator.

Fire protection. – The existing Lewis fire station will service the plant. The fire waterline will be extended to the plant site as required, and a sprinkler system will be provided in the coal-handling area.

Reliability. – Two further provisions have been included in the plant design to insure that Lewis loads can be met at all times. First, the gas turbine is specified to burn natural gas, which permits the production of steam and electric power during gasifier train outages. Second, a natural-gas-fired auxiliary boiler is provided to produce 100 000 pounds of steam per hour completely independently of the operation of the gasification and power generation sections of the plant. In addition, total duplication of pumps has been provided throughout the plant.

Site Considerations

A presently vacant potential site for the facility is located at the southeast corner of the NASA Lewis Research Center. This site was evaluated and judged to be acceptable for the following reasons:

(1) The proposed site is on NASA property, under NASA control.

(2) It is level and relatively clear.

(3) The site includes an existing coal pile area and drainage water collection basin that can be used with the new facility.

(4) It is accessible for coal delivery and ash removal by trucks using an existing road adjacent to the main Lewis complex. Thus the required truck traffic will cause minimal disturbance to routine activities.

(5) It is adjacent to an existing electrical substation and about 1000 feet from a main steam distribution line, which facilitates tie-ins to the power and steam systems.

(6) It is large enough to accommodate the powerplant without overcrowding.

The only restriction applicable to the site is its proximity to Cleveland Hopkins International Airport. An exclusion line for possible future expansion of the airport runs adjacent to the site but does not interfere with it. The exclusion includes a height limitation of approximately 80 feet at the proposed site. Since the process equipment selected for the reference system will not exceed 80 feet in height, this limitation presents no difficulties.

Coal pile drainage. – The Rainfall Frequency Atlas of the U.S. Weather Bureau gives the 10-year, 24-hour storm for Cleveland as 3.3 inches. The resulting required runoff volume, based on the area of the coal pile and a coefficient of imperviousness of 0.8 for the coal, is 102 500 gallons. The proposed treatment system will collect and treat the runoff water to give an effluent with less than 50 milligrams per liter of suspended solids and a pH of 6 to 8. The runoff water will be collected in the existing 150 000-gallon basin. After lime and polymer addition for neutralization and to agglomerate the solids, the effluent water can be discharged to the existing creek adjacent to the site.

Climatic data. – The following climatic data for the Cleveland area were used in the conceptual design: summer design temperature, 80° F; winter design temperature, 20° F.

Coal handling system. – The design of the facility is based on the delivery of coal by trucks of approximately 25-ton capacity. Coal can be delivered economically from southern Ohio in about 3 hours on interstate highways.

Coal trucks can proceed from the main highway adjacent to the Center (Ohio Rt. 17) along Hangar Access Road without going through the facility itself. Solid waste materials can be removed by truck in the same manner. Costs have been included to upgrade and extend Hangar Access Road to accommodate this increased truck traffic.

Design Description

The COCOGEN powerplant design is shown in detail in the process flow diagrams for each plant subsystem at the end of this appendix.

Coal Receiving and Storage

The washed coal is dumped into the truck hopper (BN–101) and conveyed by the belt feeder (FE–101) and a transport conveyor (CO–101) to the storage pile. Conveyor CO–101 is sized to deliver 100 tons per hour. A dust suppression system (DC–101) applies a wetting compound to the coal in the unloading area at critical points in order to inhibit dust formation. A suspended magnet (SM–101) removes tramp metal from the coal moving on conveyor CO–101.

The coal is transferred from the transport conveyor to the loading spout (DC–103), which distributes it evenly to the drawdown hopper (FE–102). This hopper and the free-flowing coal above it constitute a 600-ton "live" storage capacity equivalent to about 3 days coal consumption at normal operating levels. The surrounding coal storage of 3300-ton capacity provides an additional 15 days of "dead" storage reserve. The coal from the dead storage pile is moved into the drawdown hopper by a bulldozer or front-end loader.

The coal is retrieved from the coal pile by the vibrating feeder (FE–103) and a transport conveyor (CO–102). Conveyor CO–102 is sized for a maximum rate of over 400 tons per day so that it can simultaneously supply coal to each gasifier train at its design operating capacity. Metal detectors (MD–101) automatically stop the conveyors if metallics are detected on the belt, thereby protecting the downstream crusher (CR-101).

A belt scale (BS-101) meters the total coal feed rate to the crusher. The crusher is designed to process 400 tons of coal per day, reducing it from 2 inches × 0 to 1/4 inch × 0 with fines not exceeding 10 percent of minus 100 mesh.

The crushed coal is moved to the gasifier area by the flexible-wall, fast-rise transport conveyor (CO-103) at a maximum rate of 400 tons per day. A belt conveyor (FE-104) and a transport conveyor (CO-104) feed coal at 200 tons per day to one of the two gasification modules by means of a belt scale (BS-102). Coal not directed to the first module automatically overflows to the second module. The result is that up to 200 tons per day can be fed to either gasification module simultaneously.

At the transfer points and areas of turbulence, dust collectors (CD-102, 104, 105), which include bag houses, are provided to capture and recycle fines.

Coal Gasification and Waste Heat Recovery

The gasification-heat recovery equipment is comprised of two duplicate trains or modules. One train is designated by 200-series tag numbers and the other by 400-series tag numbers, with the understanding that the description of 200-series tag numbers that follows also applies to the train of duplicate equipment. The Westinghouse gasification unit is designed for a gasifier operating pressure of 320 psia and requires coal, air, and steam.

Coal from the coal feed surge bin (BN-201) is fed by gravity to the lockhopper feed system (BN-202). It is brought to gasifier pressure by pressurizing it with nitrogen and then passed on to the pressurized coal hopper (BN-203). The lockhopper feed system operates on a cyclic basis consisting of coal feeding, pressurization with nitrogen, pressurized coal passing to hopper BN-203, and depressurization.

Coal from hopper BN-203 is fed to the gasifier (R-201) pneumatically by a mixture of steam and air through rotary valves at the bottom of hopper BN-203. In the gasifier the coal is heated by its own heat of combustion to high temperature in a recirculating fluidized bed. At these conditions the coal goes through a devolatilization reaction to form char, which consists essentially of carbon and ash. Part of the char formed during the devolatilization reaction is partially combusted to generate the heat required to drive the gasification reaction. The remainder of the char reacts with steam to form low-Btu fuel gas. At a temperature above 1900° F the ash present in the char becomes sticky and forms spherical agglomerates that defluidize and are removed continuously from the bottom of the bed. The ash, cooled by the incoming coal-steam-air mixture, is collected in batch fashion in the ash lockhoppers (BN-204) below the gasifier. From the lockhoppers the ash is conveyed by the char transfer conveyors to the ash silo (BN-501). These processes of devolatization, combustion, gasification, and ash agglomeration take place simultaneously.

Because of the required fluidization velocity the exit gas from the gasifier carries some particles. The particles are separated from the 1850° to 1950° F gas by the primary cyclone (CY-201) and the secondary cyclone (CY-202) operating in series. The solids from the primary and secondary cyclones are collected in the primary- and secondary-cyclone discharge bins (BN-205 and BN-206). From these bins they are reinjected into the gasifier through a lockhopper system consisting of the fines-receiving lockhopper (BN-207), the fines-pressurizing lockhopper (BN-208), and the fines-feed lockhopper (BN-209).

The sensible heat in the hot gas leaving the secondary cyclone (CY-202) is used in the waste-heat-recovery train, which consists of a series of heat exchangers (high-pressure steam generator, H-201; high-pressure steam superheater, H-202; low-pressure steam generator-superheater, H-203; and fuel gas heater, H-204). These produce 610-psig, 750° F superheated steam and 400-psig, 510° F gasifier reaction steam and preheat the fuel gas stream. High-pressure steam drum (D-201) and low-pressure steam drum (D-202) feed the boilers through recirculating pumps (high-pressure steam generator feed pump, P-201; and low-pressure steam generator feed pump, P-202). Raw-gas-cooler fines-receiving bins (BN-210 and BN-211) collect char particles from the heat exchangers for reinjection to the gasifier.

The fuel gas exiting the heat exchanger train is cooled to 400° F. It passes to the cold cyclone (CY-203) for further particulate removal before continuing to the venturi scrubber (S-201). Any char removed by cyclone CY-203 is collected in the cold cyclone fines-receiving bin (BN-212) and reinjected in the gasifier.

Gas Cleanup and Recycling

The final particulate removal to a level acceptable for gas turbine operation is achieved by using the venturi scrubber (S-201). The gas enters the scrubber at 400° F and is cooled to about 256° F, and particulates are removed to a level of 1 grain per 1000 standard cubic feet. To minimize water requirements, the venturi scrubber water is cooled in the slurry interchanger (E-204) and the slurry cooler (E-205). The water is recirculated after the particulate is removed in the settler (T-502). This settler serves both gasification trains.

The gas leaving the venturi scrubber is further cooled to 120° F in the product gas condenser (E-203), and water is separated out in the condensate drum (D-203). From here it is sent to the Holmes-Stretford desulfurization unit (SYS-2501). Part of the process condensate collected in drum D-203 is returned to the venturi scrubber (S-201) as makeup water, and the remainder is sent to the steam generation system.

Part of the cooled gas from drum D-203 is used to pneumatically convey the particulate collected in the hot cyclones, the waste-heat-recovery train, and the cold cyclone to the gasifier. The recycled gas is compressed to 360 psig by the recycle gas compressor (C-201).

Sulfur Removal and Recovery

The reference sulfur removal and recovery system for the conceptual design is the Peabody Holmes-Stretford process unit (SYS-2501). The design basis for the unit is a maximum H_2S feed gas concentration of 1.0 percent by volume, corresponding to 12 standard tons of sulfur per day. Normal H_2S feed gas concentration is 0.47 percent by volume, corresponding to 4.75 standard tons of sulfur per day. Process data for both cases are given in the process flow diagrams at the end of this appendix. The particulate-free, cool gas (combined streams from the two gasification trains) containing 0.47 percent by volume of H_2S (design concentration; the maximum concentration is 0.99 percent) is sent to the unit at 265 psig and 120° F. The H_2S is directly oxidized to elemental sulfur, and the desulfurized fuel gas produced has a maximum H_2S content of 5 ppmv by volume.

Holmes-Stretford process chemistry. – In the Holmes-Stretford process, hydrogen sulfide is removed from an acid gas by intimate contact with an alkaline solution containing a vanadium salt along with anthraquinone-disulfonic acid (ADA) in an absorber. The wash liquor consists of a solution of sodium carbonate and sodium bicarbonate whose proportions are determined by the absolute partial pressure of carbon dioxide above the solution and by the total sodium content of these two salts. The pH value of the wash solution is influenced by all cations and anions dissolved. The vanadium in solution is solely in its pentavalent form and the latter oxidizes the hydrosulfide ion to elemental sulfur:

$$2V^{5+} + HS^{-} = 2V^{4+} + S + H^{+}$$

The stoichiometry of this equation clearly shows that the molarity of vanadium in a Holmes-Stretford solution must be twice that of the hydrosulfide it is required to neutralize.

In normally constituted wash liquor and in the absence of a sequestering agent, the quadrivalent vanadium is insoluble. If a plant is run with a stoichiometric deficiency of vanadium and/or a deficiency of sequestering agent, vanadium is precipitated from the solution and lost from the process.

After the hydrosulfide oxidation stage the wash liquor contains sulfur particles. Before it is recirculated to the hydrogen sulfide absorption step, air is bubbled through the solution. This serves two purposes:

(1) The bubbles of air attach themselves to the sulfur particles, causing them to rise and float as a froth, which is removed and dewatered.

(2) The quadrivalent vanadium is reoxidized with the aid of an oxygen carrier.

In the reversible cycle, anthraquinone/semianthraquinone (a salt of the 2:7-disulfonic acid) is employed as an oxygen carrier from the air in the production of the quinone form and/or hydrogen peroxide. Either oxidant restores the quadrivalent vanadium to the pentavalent state, itself being reduced to the semiquinone or water. The rate of oxidation rises with increasing pH (increasing hydroxyl-ion concentration). The pH of the wash liquor increases with the sum of sodium carbonate and bicarbonate concentrations. Because quinone acts as an oxygen carrier in a cyclic manner, its concentration is not related to the vanadium molarity. The lower limit of quinone concentration is fixed by the required oxidative rate; its upper limit is determined by the solubility of the semiquinone in the wash liquor. The oxidized forms of vanadium and the quinone are returned to the gas absorber.

The structure of the anthraquinone molecule insures that all four of the positions occupied by hydrogen in the hydroquinone molecule have been occupied by radicals inactive to hydrogen peroxide. This yields a quinone with an indefinite life.

The massive side rings sterically hinder the activity of the hydroxyl groups. The mechanism of the reaction between oxygen and the hydroquinone form is speculative but, by analogy with the commercial process in which beta-ethoxyanthraquinone is used to manufacture hydrogen peroxide, the latter compound is assumed to be the primary product.

Holmes-Stretford unit description. – The fuel gas is scrubbed in an absorption tower (F010) with an alkaline Holmes-Stretford liquor containing pentavalent vanadate as the principal oxidant. The dissolved hydrogen sulfide is converted in a single step to elemental sulfur, which remains in suspension in the liquor. A hold tank in the lower section of the tower gives the liquor the necessary residence time to complete the reaction, while the vanadate is reduced to its quadrivalent form. The reduced liquor (containing the elemental sulfur) is fed from the absorption tower to an oxidizer (G010) as a low-concentration slurry. Here air is blown through the liquor, the vanadium is restored to its pentavalent form, and the sulfur is separated by flotation as a thick froth on the surface of the liquid. This froth is skimmed off the oxidizer, filtered, and washed to produce a wet cake of sulfur. The clear underflow consisting of oxidized Holmes-Stretford liquor is recycled to the absorption tower.

The inlet acid gas flows through the absorption tower (F010), which consists of a venturi contactor and a mist-extractor tower. Oxidized Holmes-Stretford liquor enters the absorber and reacts with hydrogen-sulfide in the gas. The vanadate is reduced to the vanadium form. The reduced Holmes-Stretford liquor flows to the hold tank at the bottom of the tower for the reaction to be completed.

Next the reduced Holmes-Stretford liquor is sent through a flash drum (G060) to the oxidizer unit for reconversion to the oxidized form. The gas released in drum G060 is combined with the oxidizer vent stream and sent to the flare if required. In the oxidizer, unit air separates the sulfur from the liquor by a process of flotation, and it also simultaneously oxidizes the Holmes-Stretford liquor to the vanadate form for reuse in the absorption tower. Compressed air for the oxidizer is provided by an air blower (K010). About 600 standard cubic feet per minute of vent gas is exhausted from the oxidizer through an exhaust fan (K020). Since this stream has a small quantity of combustibles, it is combined with the vent gas from drum G060 for disposal.

The oxidized and clarified Holmes-Stretford liquor flows by gravity from the oxidizer to a pump tower (G030), which serves as a reservoir of Holmes-Stretford liquor for the system. Holmes-Stretford liquor from the pump tower is recycled back to the absorption tower.

The sulfur froth from the top of the oxidizer (G010) overflows to an agitated slurry tank (G020). A slurry pump (J020) transfers the sulfur slurry from the slurry tank to a proprietary sulfur-recovery system (N010). Sulfur is discharged from this system as a wet cake containing approximately 50 percent solids by weight.

Water is generated by the chemical reactions involved in the process. This water must be removed so that the Holmes-Stretford liquor is not diluted. For this purpose a side stream from the main liquor loop is fed to an evaporator (E020) to dispose of the excess water.

A small chemical makeup tank (G040) is provided for the initial filling of the liquor circuit and for the routine addition of chemicals consumed. The chemicals are charged manually, and either process water or Holmes-Stretford liquor from the pump tank (G030) can be used to dissolve the chemicals. To maintain a stable circulating-liquor temperature, a heater (E010) is installed in the main liquor circuit to compensate for seasonal temperature variations.

The gas leaving the Holmes-Stretford unit next enters the proprietary particulate-free treatment section. There the gas leaving the Holmes-Stretford unit is treated for complete removal of any mist or particulate carryover of the Holmes-Stretford solution. The treated gas from the particulate-free unit is expected to contain less than 0.1 part per million (by weight) of either sodium plus potassium or vanadium. The fuel gas stream is discharged from the Holmes-Stretford unit through a final knockout drum (G050).

Power Generation

The desulfurized fuel gas is first preheated to 274° F in the clean fuel gas heater (E-501) by circulating hot water at 506° F. It is then further heated in the gasification waste-heat-recovery unit fuel gas heater (H-204) to 500° F before it enters the gas turbine unit (SYS-2502-A). This unit consists of a compressor, a combustor, and a gas turbine with connection to a double-ended generator. The other end of the generator is connected to a double-extraction steam turbine (SYS-2502-B).

To adapt the conventional gas turbomachinery to low-Btu gas combustion, some compressor air must be bled from the system. The bleed air, which is about 12 weight percent of the total air inlet to the compressor, is required for the gasification reaction. Before going to the gasifier the air (20 psia, 601° F) is cooled in a series of exchangers (air-air interchanger, E-502; condensate heater, E-503; and bleed air trim cooler, E-504) and then compressed to 380 psia by a booster compressor (C-501). The hot combustion gases from the gas turbine at 970° to 1015° F are exhausted to a heat-recovery steam generator (SYS-2502-B).

Steam Condensate and Boiler Feed Water

The heat-recovery steam generator (HRSG) and the steam turbine are included in the SYS-2502-B package. The HRSG includes evaporators (H-501 and H-503), an economizer (H-502), a superheater (H-504), and a vent stack. The gas turbine exhaust is cooled to 270° F in this unit. Steam at 615 psia and superheated to 750° F is produced in H-503 and H-504 for power generation by the steam turbine. In addition to generating superheated steam the gas turbine exhaust has sufficient sensible heat to generate hot water at 506° F for process requirements and low-pressure steam. The hot water produced in H-502 is then used as boiler feed water for steam generation in the gasifier waste-heat-recovery exchangers (H-203 and H-403), as boiler feed water for producing additional superheated steam for the steam turbine in the gasifier waste-heat-recovery exchangers (H-202 and H-402), and as hot water for fuel gas preheating to 274° F in E-501. The low-pressure steam produced in H-501 is used in the deaerator (D-501).

The double-extraction steam turbine (SYS-2502-B) generates a electrical maximum of 7.4 megawatts at the summer design point and a maximum of 90 000 lb/hr of steam at the winter design point. Both summer and winter steam rates are supplied at 125-psia pressure. A second extraction point, at 50 psia, produces 5200 pounds of steam per hour for the deaerator (D-501).

The steam turbine condensate and the return condensate from the Center are treated in a condensate polishing unit (SYS-2504) and stored in the condensate storage tank (TK-503). The condensate is pumped from storage through E-503, where it is heated to 174° F before being sent to the deaerator (D-501).

The deaerator operates at a temperature of 240° F. The total boiler feed water requirement ranges from 105 000 to 113 000 pounds per hour for the two design steam production conditions. The noncondensibles from the deaerator are vented to the atmosphere. The expected steam vent included with the noncondensibles is assumed to be 0.6 weight percent of the boiler feed water requirement.

Makeup water to the deaerator is supplied by the raw water treatment package (reverse osmosis unit), which treats the incoming water from the existing city waterline. A raw water storage tank (TK-501) and a treated-water storage tank (TK-502) are provided.

Support Facilities

Cooling water and waste water treatment. – The plant blowdowns from steam generation units (D-201, D-401, D-202, D-402, and D-502) are let down at 125 and 50 psig through high- and low-pressure blowdown drums (D-503 and D-504). The liquid from D-504 is cooled in blowdown cooler (E-505) and sent to waste water treatment.

The waste water treatment consists of a neutralization system package (SYS-2510), a settling tank (TK-505), a sludge tank (TK-506), and a filter press (FL-502). This unit treats the following:

(1) Char sludge from the gasification settler (T-502)

(2) Process condensates from the venturi scrubbing section

(3) Cooling tower blowdown liquor from sand filter (FL-501)

(4) Blowdown from steam generation units

The treated water from the waste water treatment unit is returned to the cooling tower. The filter process cake is mainly gasification char containing 50 percent water.

The plant cooling water (5898 and 2600 gallons per minute, equivalent to summer and winter steam production cases) is cooled from 115° F to 85° F in the offsite cooling tower (CT-501). The estimated evaporation and drift losses are about 3 percent of the circulation rate.

The makeup water requirement for the cooling tower and Holmes-Stretford unit is supplied from the raw water storage tank (TK-501). The raw water is, in fact, city water supplied to Lewis and therefore does not require treatment. The total plant makeup raw water is about 190 and 87 gallons per minute for the two design cases.

Nitrogen and flare systems. – Nitrogen is required in the gasification plant for startup, lockhopper pressurization, and instrument purging. Requirements have been generously estimated at 12 tons per day. The nitrogen evaporator and storage package (SYS-205) includes liquid-nitrogen storage and vaporizer. A compressor is provided to boost the nitrogen to 500-psig delivery pressure.

A flare is included in the plant design to provide for emergency release of the fuel gas. A smokeless ground flare is specified to prevent any interference to the adjacent airport from an elevated flare. It is sized for a duty of 101×10^6 Btu/hr.

Auxiliary boiler. – A 100 000-lb/hr, gas-fired, 200-psig steam boiler is provided to meet the maximum Lewis heating load totally independent of the powerplant. This boiler will provide a reliable steam source for the Center's heating load and permit decommissioning of the existing boilers. The auxiliary boiler as now specified does not provide superheated steam for power generation.

Coal pile water runoff treatment. – The layout for the facility locates the new coal pile at the site of a previous coal pile. The adjacent 150 000-gallon runoff water collection basin will accommodate the new coal pile design water runoff of 102 500 gallons. From this basin the water is pumped to a floculation tank (TK-504). The water is neutralized and fines are agglomerated in this tank by the addition of lime and polymer. The agglomerated fines are recycled to the coal pile, and the clarified water is discharged.

Design Summary

Summary mass and heat balances based on the process flow sheets are shown in tables XII and XIII, respectively. Plant power and thermal distribution are summarized in tables XIV and XV, respectively. The plant chemical and utility requirements are shown in table XVI.

Other engineering drawings including overall plan and section views, elevations, process flow sheets, and a single-line electrical diagram are given at the end of this appendix.

Emissions and Waste Products

Effluents from the COCOGEN powerplant include air, liquid, and solid waste streams. Both the types and quantities of the waste streams have been estimated from the current process design information and are summarized as follows:

(1) Solid waste material resembles the ash typical of a conventional coal-fired installation. The bottom ash from the gasifier is generally inert and impervious to leaching.

(2) The highly efficient gas treatment processes result in emissions of sulfur dioxide, nitrogen oxide, and particulates that are well below current standards.

(3) The gasification system produces no oil or tar condensates; therefore waste water problems are reduced to treating conventional blowdown and runoff streams.

Emissions to Air

The storage and handling of coal represent a potential source of air pollution from dust formation. However, the coal preparation area includes provisions to minimize this problem. A dust suppression system is provided at the truck-unloading station and at the belt feeder under the truck-unloading hopper. The transport conveyors are enclosed. Three separate dust collectors, including bag filters, are provided with pickup points at all locations where dust is likely to be formed. The fines are returned to the main coal stream and used in the coal gasification along with the main crushed-coal stream. Although the coal pile is open, it can be coated and sealed against dusting.

Particulates from the gasifier are collected in cyclones and recycled to the gasifier. The gasifier bottom ash is transported pneumatically to a storage silo. This system also includes a cyclone bag filter dust collector. The ash is discharged from the silo to trucks through a rotary ash conditioner that suppresses dust formation during loading and subsequent hauling. The particulate emission from the coal and ash handling and storage operations is estimated to be less than 1 lb/hr.

No major gaseous effluents are expected from the gasification area. The nitrogen used in the coal feed lockhopper system is frequently vented to the atmosphere during the depressurization of the lockhoppers. This vent stream, containing coal dust, can be sent through bag filters, if required, before it is vented to the atmosphere. The absorbed gases in the Holmes-Stretford process circulating solution (from the absorption tower) are desorbed in the flash drum and oxidizer. The maximum flow of this vented gas stream is calculated to be 6378 standard cubic feet per minute. Since it contains minor amounts of CO, H_2, and CH_4, it can be directed to the flare for disposal if required. There is no sulfur associated with this stream.

The main vent stream to the atmosphere is the heat-recovery steam generator stack gas, which is the gas turbine exhaust stream. The expected composition of this stream is given by stream 25 shown in the waste-heat recovery and off-site facilities process flow diagrams. It contains 1 ppm SO_x and less than 10 ppm NO_x.

The deaerator and cooling tower units emit a maximum of 185 gallon of water vapor to the atmosphere per minute. The possibility for air pollution caused by the cooling tower results from leaks in exchangers that handle gases from the gasification area. The gaseous contaminants can enter the atmosphere from evaporation losses. The only technique for preventing such pollution is continuous monitoring of appropriate cooling water streams and provision of facilities for immediate removal of the offending exchanger from the system. Spare equipment is provided to allow for such action. Because chromate treatment for cooling tower blowdown is not used, the possibility of chromate carryover in the evaporated water is eliminated.

Solid and Liquid Effluents

These waste streams are from three sources: the gasifier bottom ash, the Holmes-Stretford sulfur removal unit, and waste water treatment sludge. It is expected that these materials will be removed from the plant by truck and transported to an appropriate landfill site.

The gasifier bottom waste material is withdrawn from the ash storage silo and consists mainly of agglomerated ash. This ash is spherical in shape and formed by a mechanism of "internal pooling" of mineral species. Leaching tests conducted by Westinghouse have shown that it is inert and resistant to leaching of mineral components, making it suitable for nonacidic landfill disposal. The composition of the gasifier waste is about 83 percent ash, 17 percent carbon, and less than 1/2 percent sulfur.

There is one solid effluent (and no liquid effluent) from the Holmes-Stretford sulfur removal unit. It is a wet cake containing 50 percent sulfur and 50 percent interstitial solution and dissolved salts such as the Holmes-Stretford mix—soda ash, sodium thiosulfate, and sodium sulfate. This wet cake can be mixed with the gasifier ash for disposal or may be disposed of separately.

Some trace contaminants such as hydrogen cyanide, mercury, selenium, and arsenic may be carried with the fuel gas from the gasifier. The Holmes-Stretford liquor is an excellent absorbent for HCN. It is converted into innocuous thiocyanate from the reaction of sodium hydrosulfide with HCN. The sodium thiocyanate formed is a highly soluble compound that leaves with the wet cake and is easily bio-oxidized in the landfill. Trace metals are also partially captured in the Holmes-Stretford liquor and are precipitated either as carbonates or hydroxides that also leave with the wet sulfur cake.

A solid or sludge waste stream is produced by the waste water treatment facility. This facility processes the following:

(1) Gasification solids from the venturi scrubber containing 20 percent solids (carbon and ash) and 80 percent water

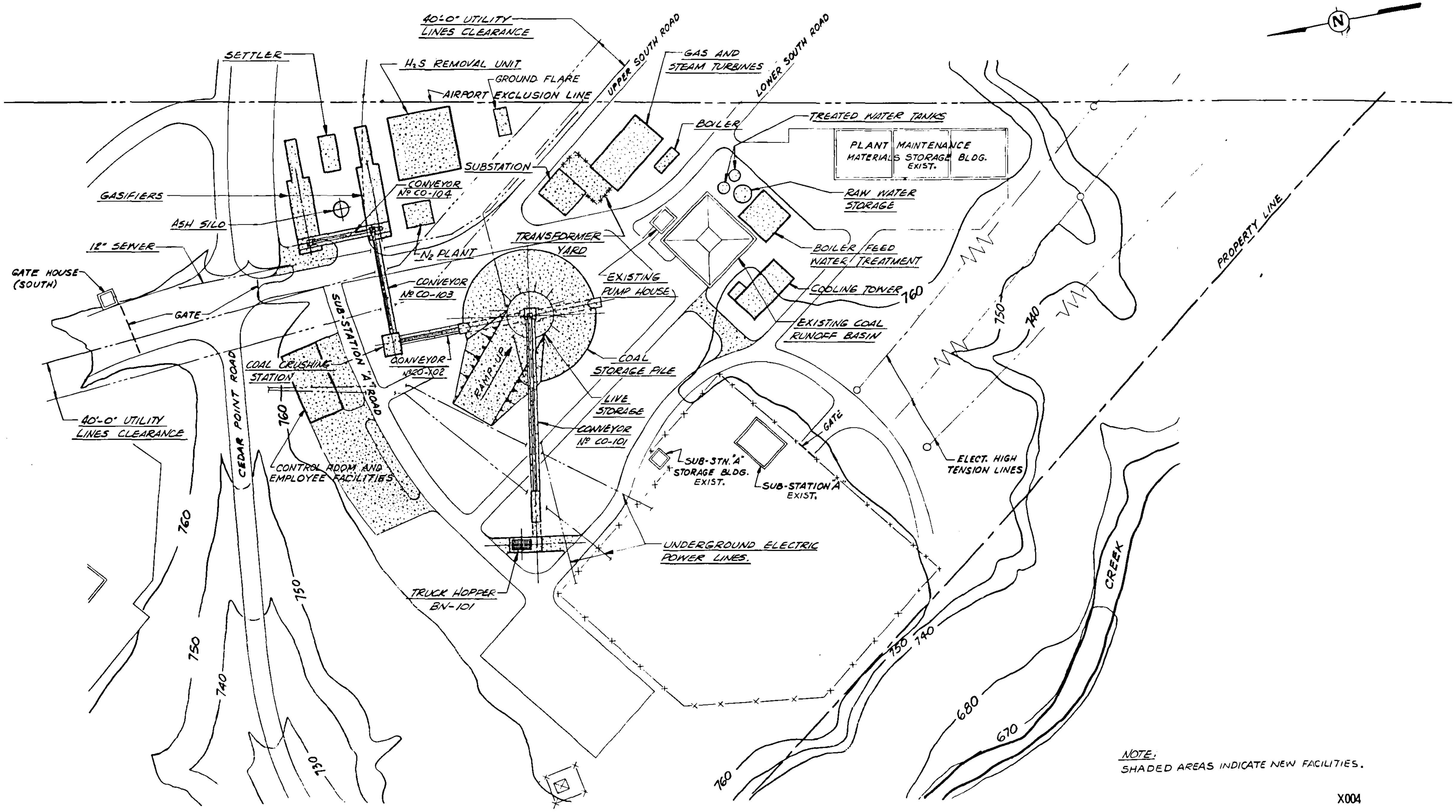
(2) Cooling tower blowdown

(3) Steam generation blowdown

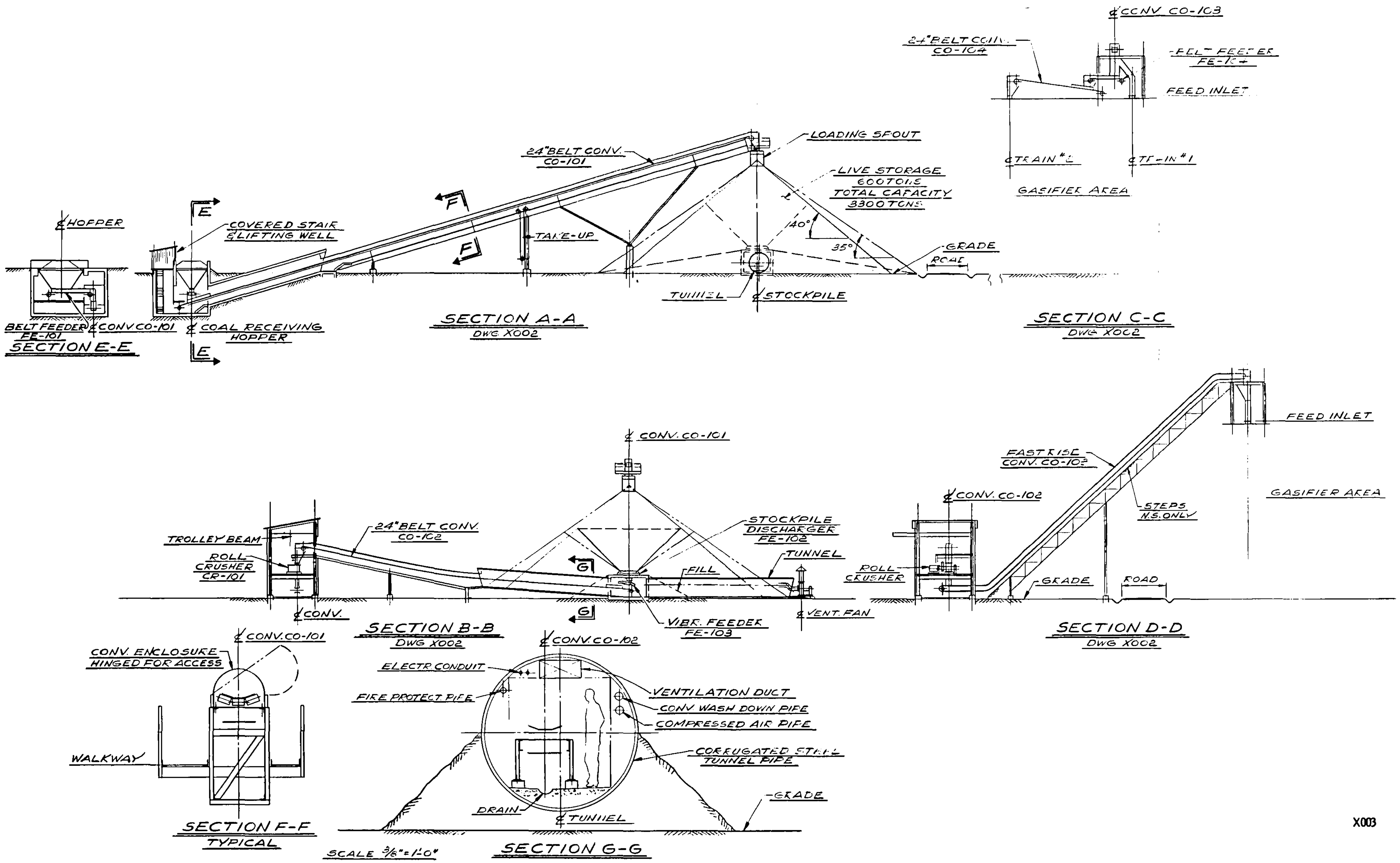
(4) Gasifier process condensate

These streams are sent to the neutralization system and then filter pressed for final solid disposal. The liquid effluents form a part of the makeup water for cooling tower losses.

The filter pressed cake contains mainly carbon and ash particles and is disposed of as 50 percent solids in the wet form. Because of the nature of the gasification process used for this plant, no oils, tars, or higher hydrocarbons are formed during the gasification. Furthermore, because the gasifier operating temperature is approximately 1900° F, formation of formic acid is negligible. Hence no special biological treatment unit is needed in the waste water treatment system. The expected sludge composition and rate are given by stream 29 in the process flow diagrams. The water in the cake should not contain any material other than that inherent in the raw (city) water source.



Plan of COCOGEN powerplant



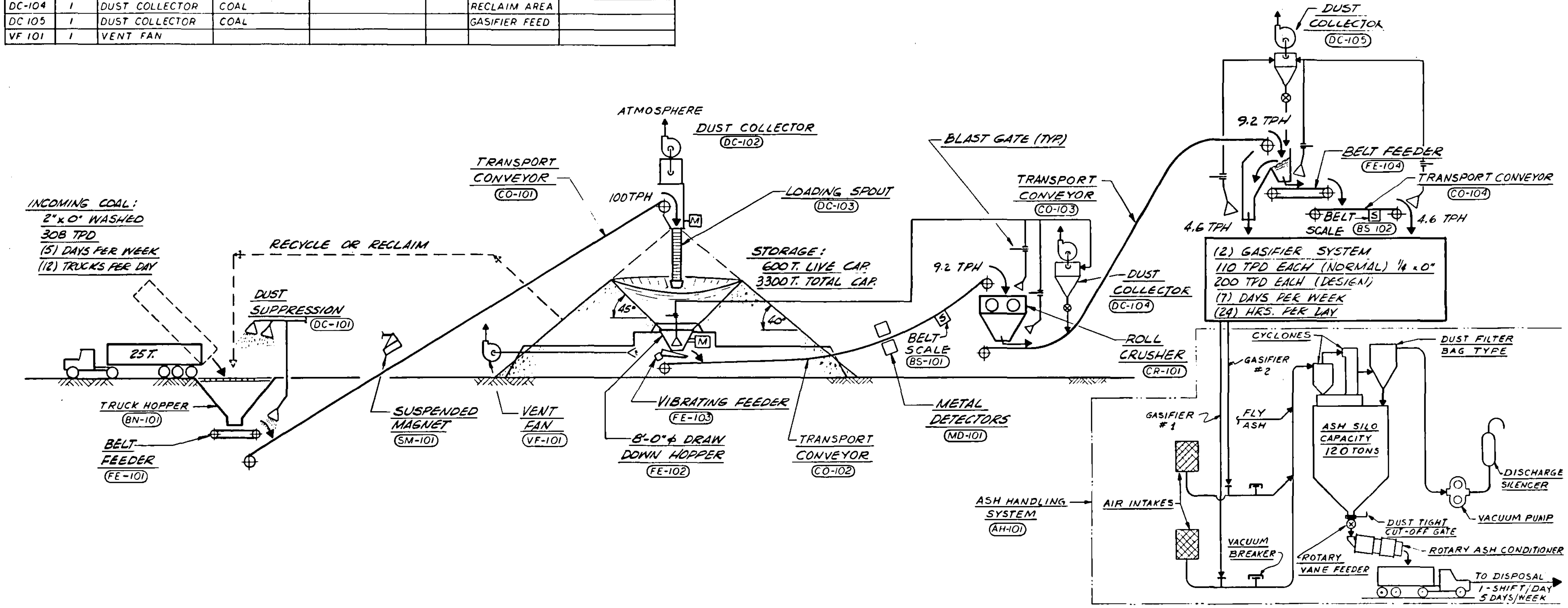
Sectional arrangement of coal-handling area

EQUIPMENT SCHEDULE

ITEM Nº	Nº REQ'D.	DESCRIPTION	MATERIAL HANDLED	SIZE & FLOW	EST. H.P.	LOCATION	REMARKS
FE-101	1	BELT FEEDER	COAL	24"-100NTPH	3	RECEIVING HOPPER	
FE-102	1	DRAW DOWN HOPPER	COAL	8'-0"DIA.-17NTPH	4	STORAGE PILE	
FE-103	1	VIBRATING FEEDER	COAL	18"X30"-17NTPH	1/4	STORAGE PILE	MECHANICAL
FE-104	1	BELT FEEDER	COAL	24"-8.5NTPH ⓘ	1/2	CONV. CO-103	
SM-101	1	SUSPENDED MAGNET	FERROUS PIECES		—	CONV. CO-101	PERMANENT MAGNET
MD-101	1	METAL DETECTOR			—	CONV. CO-102	
CR-101	1	CRUSHER	COAL	17 NTPH	60	CRUSHING STA.	
BS-101	1	BELT SCALE			—	CONV. CO-102	
BS-102	1	BELT SCALE			-	CONV. CO-104	
DC-101	1	DUST SUPPRESSION				TRUCK HOPPER	
DC-102	1	DUST COLLECTOR				STORAGE AREA	
AH-101	1	ASH HANDLING SYSTEM	ASH			GASIFIER	
BN-101	1	TRUCK HOPPER	COAL				
DC-103	1	LOADING SPOUT	COAL	100 NTPH		STORAGE PILE	
DC-104	1	DUST COLLECTOR	COAL			RECLAIM AREA	
DC 105	1	DUST COLLECTOR	COAL			GASIFIER FEED	
VF 101	1	VENT FAN					

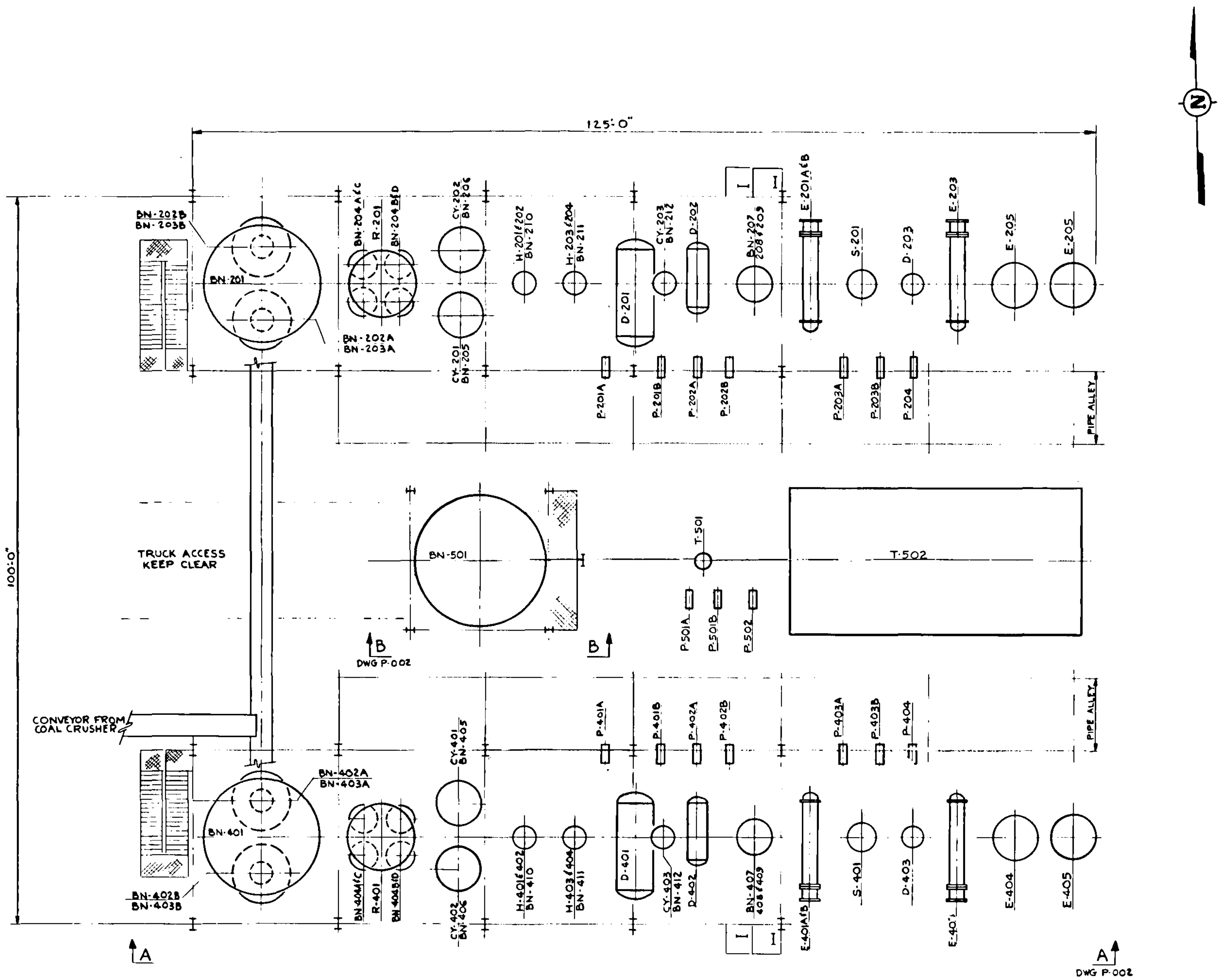
CONVEYOR SCHEDULE

CONV. Nº	MATERIAL	Nº REQ'D.	MAT'L. LBS/FT³	FLOW NTPH	DESIGN NTPH	BELT WIDTH	BELT SPEED	LENGHT FT.	RISE FT	RISE ANGLE	CALC. H.P	MOTOR H.P	TAKE-UP	REMARKS
CO-101	COAL	1	45	100	100	24	250	250	75.5	16°+	14.52	20	GRAVITY	
CO 102	COAL	1	45	9.2	17	24	250	150	20.0	12°	5.04	10	GRAVITY	
CO 103	COAL	1	45	9.2	17	—	—	140	100.0	45°	—	15	—	FAST RISE DESIGN
CO 104	COAL	1	45	4.6	8.5 ⓘ	24	200	39	5.5	8°	2.74	5	MECHANICAL	



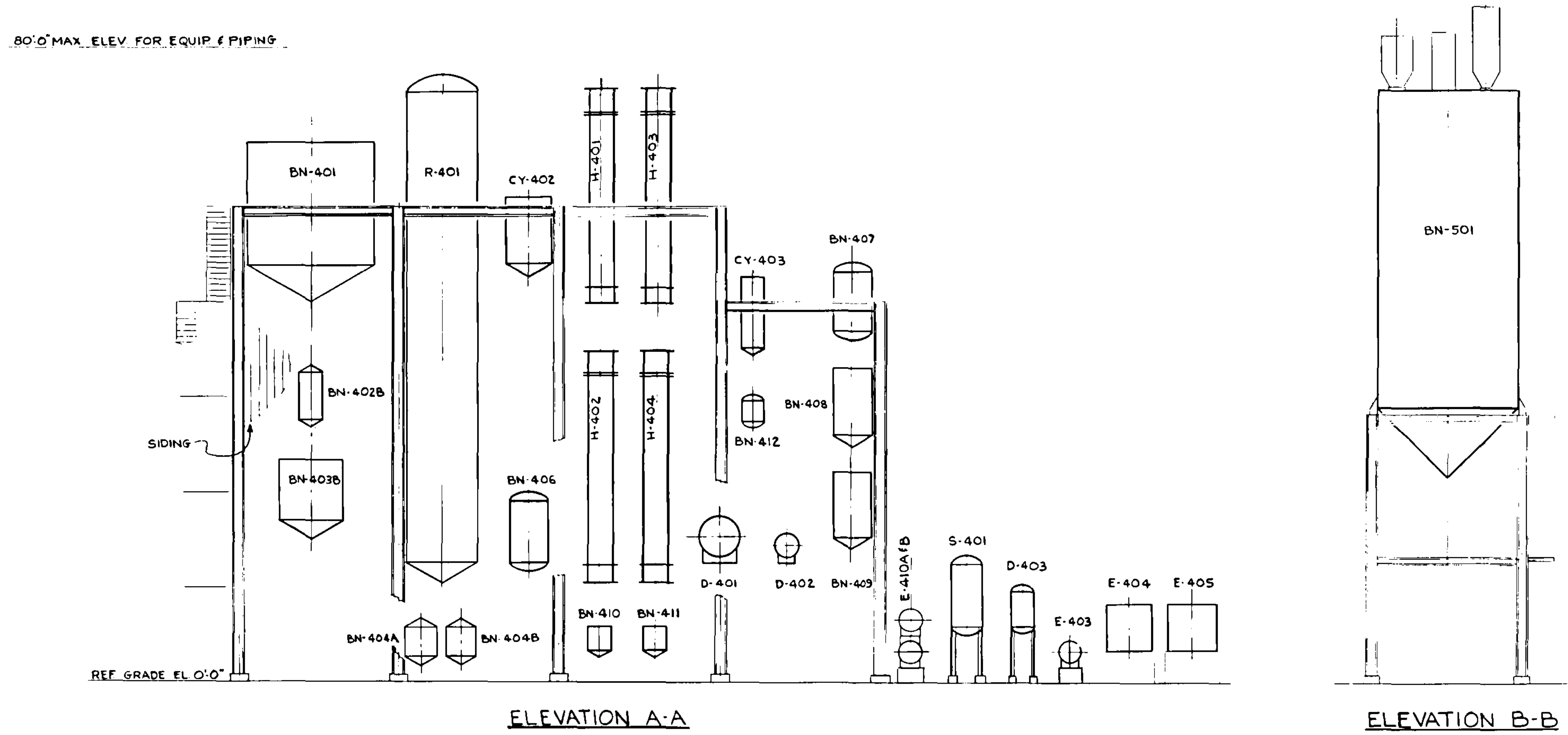
F-10101

Material flow diagram of coal-handling area



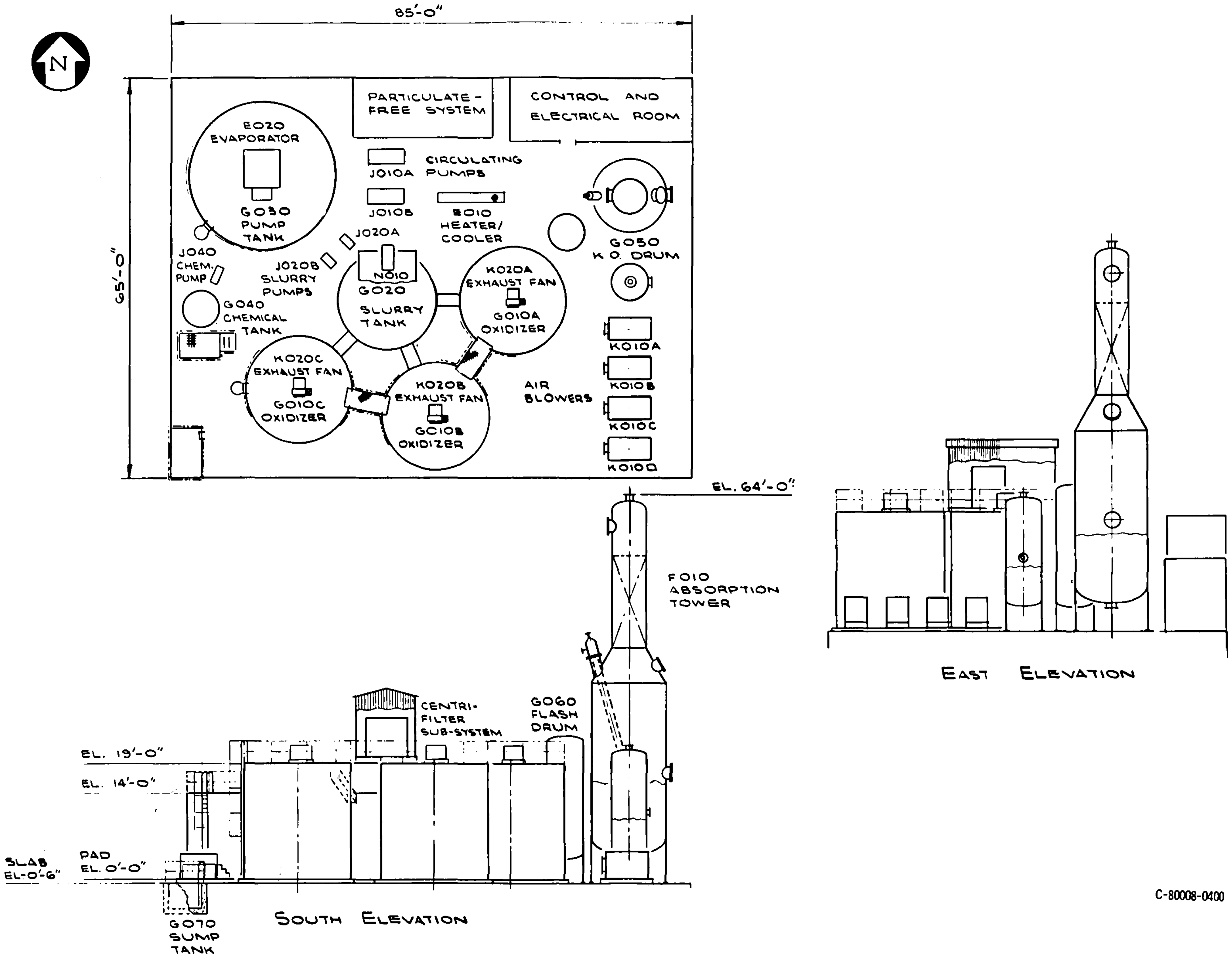
P-001

Plan of coal gasification area



P-002

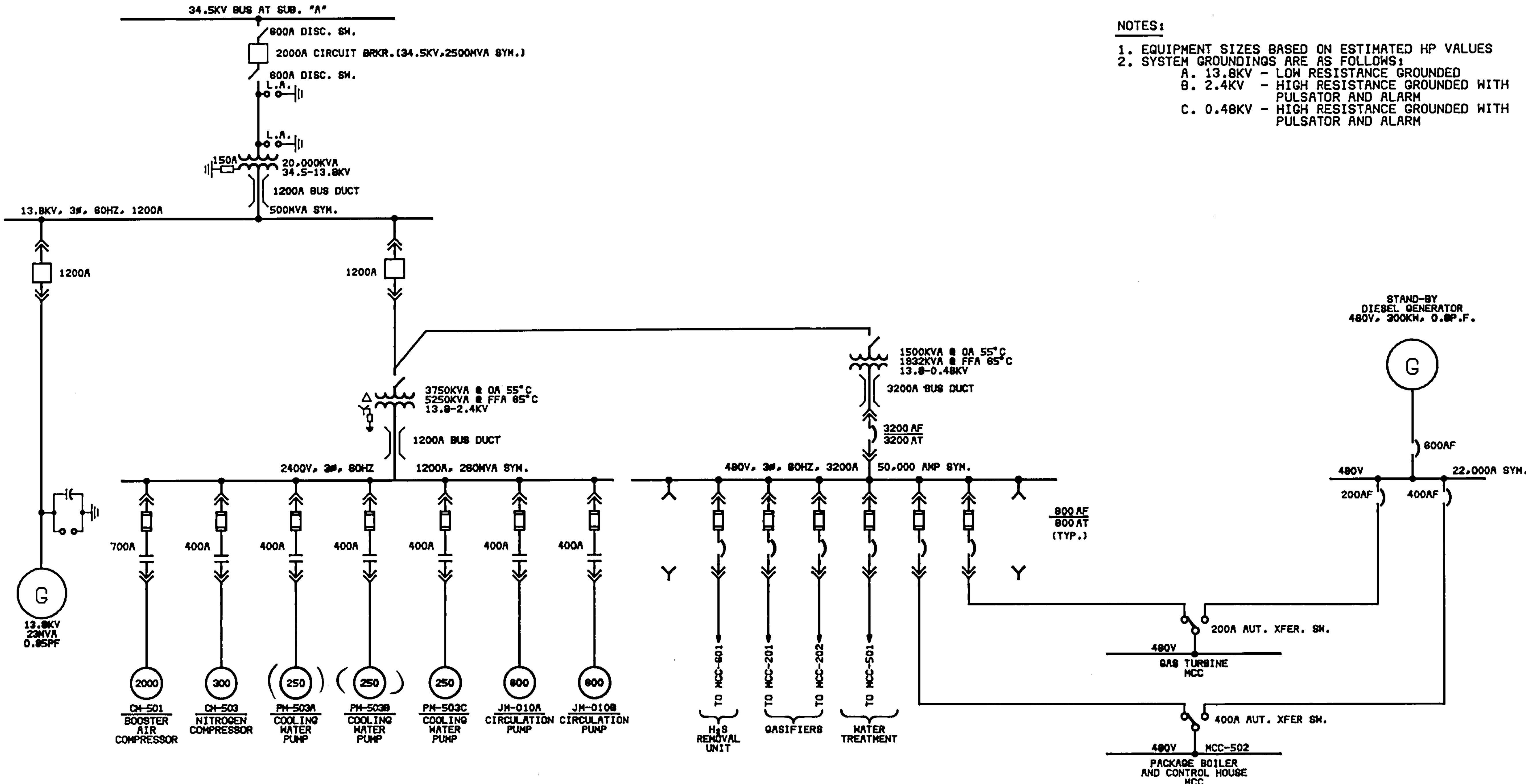
Elevation of coal gasification area



General arrangement of Holmes-Stretford system

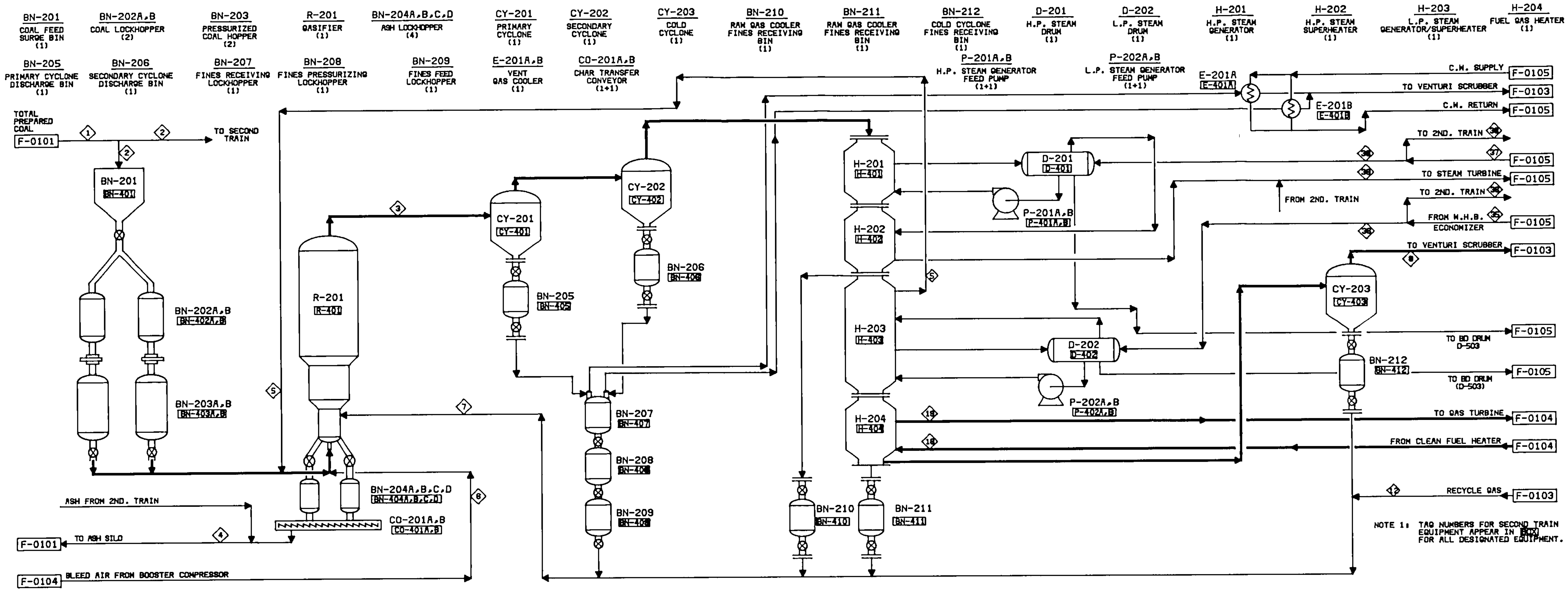
NOTES:

1. EQUIPMENT SIZES BASED ON ESTIMATED HP VALUES
2. SYSTEM GROUNDINGS ARE AS FOLLOWS:
   A. 13.8KV - LOW RESISTANCE GROUNDED
   B. 2.4KV - HIGH RESISTANCE GROUNDED WITH PULSATOR AND ALARM
   C. 0.48KV - HIGH RESISTANCE GROUNDED WITH PULSATOR AND ALARM



Single-line electrical diagram of COCOGEN powerplant

N-0001

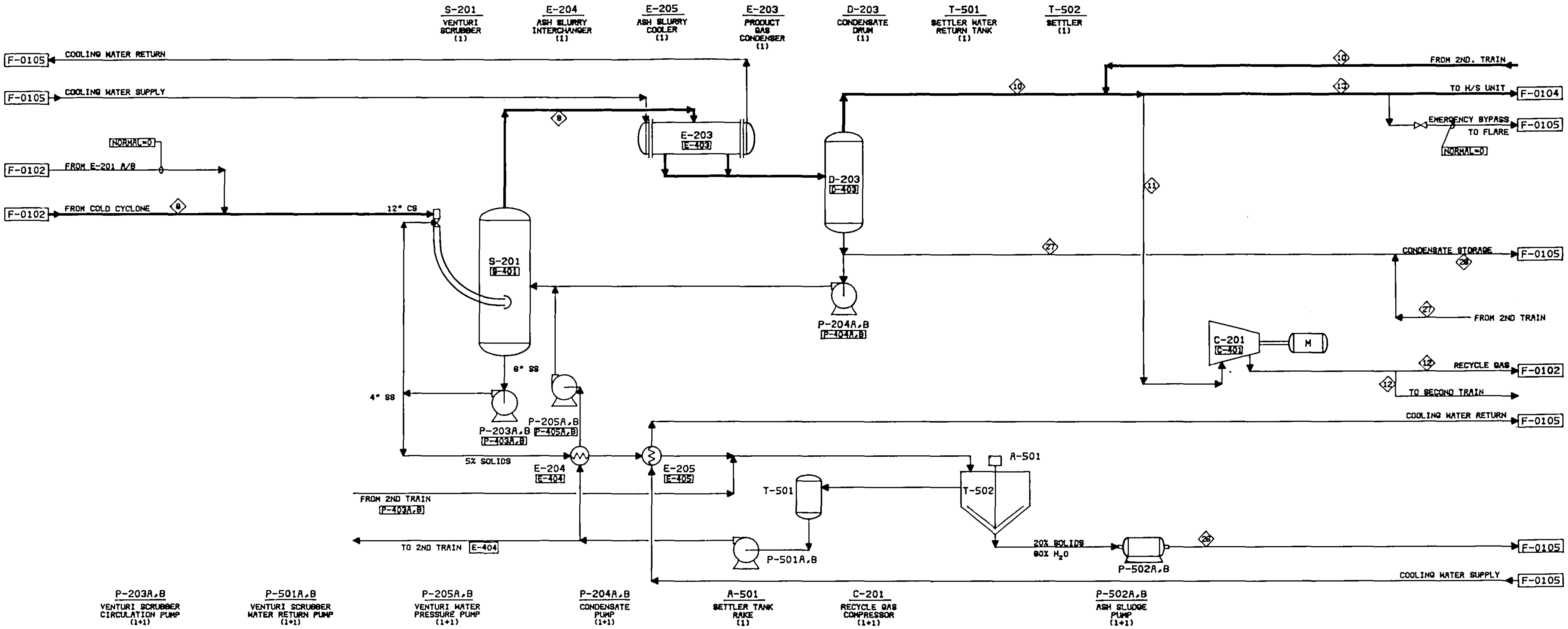


STREAM NUMBER		1		2		3		4		5		6		7		8	
DESCRIPTION		TOTAL PROCESS COAL		PROCESS COAL PER TRAIN		RAW GAS PER TRAIN		TOTAL GASIFIER BOTTOM ASH		REACTION STEAM PER TRAIN		REACTION AIR PER TRAIN		RECYCLE GAS AND FLY ASH PER TRAIN		GAS TO VENTURI SCRUBBER PER TRAIN	
PHASE		S		S		S+G		S		G		G		G+S		S+G	
COMPONENT	MOL. WT.	LB/HR	WT %	LB/HR	WT %	MOL/HR	VOL %	LB/HR	WT %	LB/HR	WT %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %
CARBON	12.011	11058	64.80		64.80			514	16.82								
HYDROGEN	2.018	741	4.34		4.34	184.06	12.97							13.85	13.58	184.06	12.97
OXYGEN	32.000	1329	7.79		7.79							185.28	21.00				
NITROGEN	28.014	222	1.30		1.30	754.63	50.43					697.01	79.00	53.68	52.53	754.63	50.43
SULFUR	32.060	413	2.42		2.42			10	0.32								
CHLORINE	- -																
ASH	- -	2684	15.73		15.73			2532	82.86								
WATER	18.016	618	3.62		3.62	69.93	4.67			2133	100.00			0.68	0.65	69.93	4.67
CARBON MONOXIDE	28.011					368.85	24.63							26.22	25.66	368.85	24.63
CARBON DIOXIDE	44.011					73.87	4.94							5.24	5.13	73.87	4.94
METHANE	16.043					28.62	1.91							2.04	2.00	28.62	1.91
HYDROGEN SULFIDE	34.076					6.74	0.45							0.48	0.47	6.74	0.45
CARBONYL SULFIDE	60.071					NA	-							NA		NA	
FLY ASH						(2730LB/HR)	-							(2638LB/HR)		(92LB/HR)	
TOTAL		17065	100.00	8533	100.00	1496.50	100.00	3058	100.00	2133	100.00	882.29	100.00	102.17	100.00	1496.50	100.00
TOTAL GAS FLOW, MOL/HR.	(DRY)					1426.57						882.29		101.51		1426.57	
WATER (V)/DRY GAS	(VOL/VOL)					0.049						-		0.0065		0.049	
TOTAL (WET) FLOW, LB/HR.		17065		8533		39788		3056		2133		25455		5184		37150	
PRESSURE-PSIA						320				415		380		375		300	
TEMPERATURE-°F						1850		200		500		500				400	
VOL. FLOW RATE-SCFM(DRY)						9023								842		9022	
HHV BTU/LB		11590															
HHV BTU/SCF DRY GAS																	

STREAM NUMBER	12		18		19		35		36		37		38		39	
DESCRIPTION	RECYCLE GAS PER TRAIN		S-FREE FUEL GAS PER TRAIN		FUEL GAS TO TURBINE PER TRAIN		450 PSI BFW TOTAL		450 PSI BFW PER TRAIN		720 PSI BFW TOTAL		720 PSI BFW PER TRAIN		615 PSI SUPERHEATED STEAM TOTAL	
PHASE	G		G		G		L		L		L		L		G	
COMPONENT	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON																
HYDROGEN	13.85	13.51	178.41	13.50	178.41	13.50										
OXYGEN																
NITROGEN	53.68	52.56	700.85	53.04	700.85	53.04										
SULFUR																
CHLORINE																
ASH																
WATER	0.68	0.64	8.955	0.68	8.955	0.68	4352	100.00	2178	100.00	31968	100.00	15984	100.00	31342	100.00
CARBON MONOXIDE	26.22	25.68	339.005	25.65	339.005	25.65										
CARBON DIOXIDE	5.24	5.15	67.945	5.14	67.945	5.14										
METHANE	2.04	1.98	26.315	1.99	26.315	1.98										
HYDROGEN SULFIDE	0.48	0.47	0.005	5 PPM	0.005	5 PPM										
CARBONYL SULFIDE	NA															
FLY ASH	-															
TOTAL	102.17	100.00	1321.585	100.00	1321.585	100.00	4352	100.00	2176	100.00	31968	100.00	15984	100.00	31342	100.00
TOTAL GAS FLOW, MOL/HR. (DRY)	101.51		1312.63		1312.63											
WATER (V)/DRY GAS (VOL/VOL)	0.0065		0.0068		0.0068											
TOTAL (WET) FLOW, LB/HR.	2556		33068		33068		4352		2176		31968		15984		31342	
PRESSURE-PSIA	375		245		240		457		457		720		725		615	
TEMPERATURE-°F			274		500		458		458		506		506		750	
VOL. FLOW RATE-SCFM(DRY)	642		8302		8302											
HHV BTU/LB																
HHV BTU/SCF DRY GAS																

F-0102

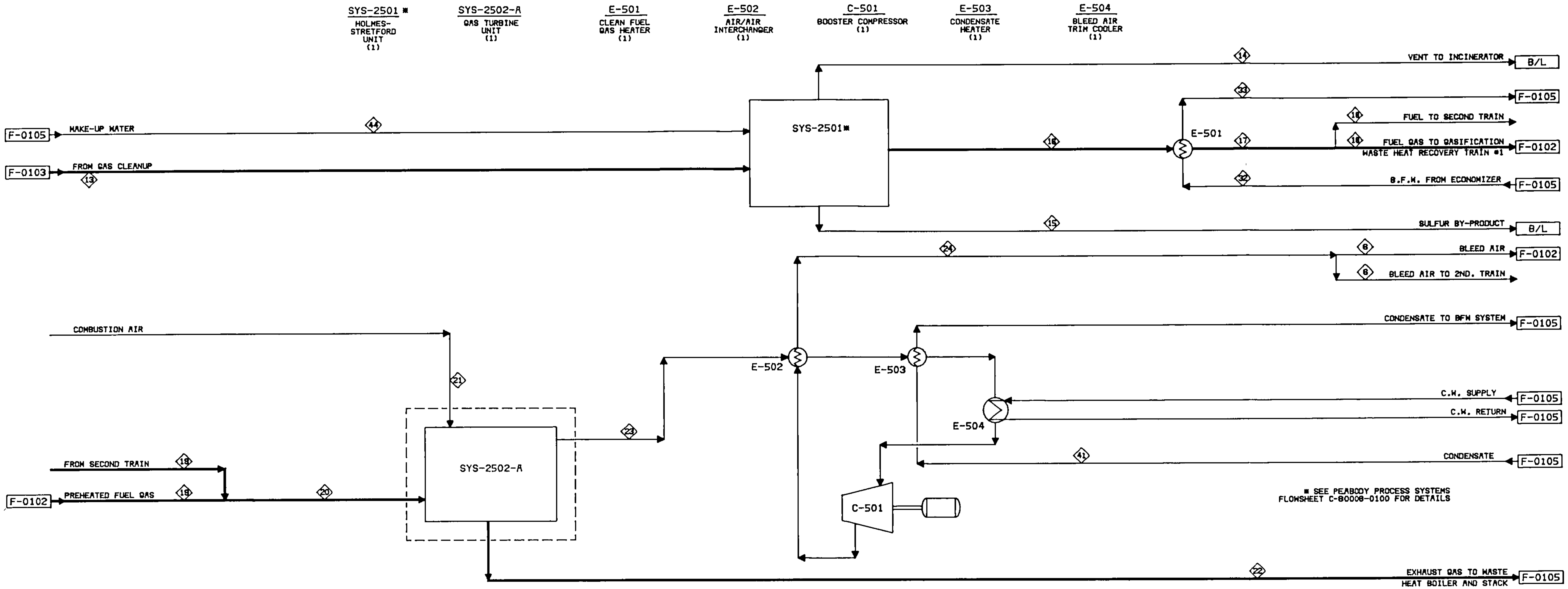
Process flow diagram of coal gasification and waste-heat recovery facilities - summer case



STREAM NUMBER		6		8		10		11		12		13		26		27		28			
DESCRIPTION		GAS TO VENTURI SCRUBBER PER TRAIN		VENTURI OUTLET GAS PER TRAIN		PARTICULATE FREE GAS PER TRAIN		TOTAL RECYCLE GAS TO COMPRESSOR		RECYCLE GAS PER TRAIN		TOTAL GAS TO H/S UNIT		TOTAL CHAR SLUDGE		PROCESS CONDENSATE PER TRAIN		TOTAL PROCESS CONDENSATE			
PHASE		G+S		G		G		G		G		G		S+L		L		L			
COMPONENT	MOL WT.	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	LB/HR	WT%	LB/HR	WT%	LB/HR	WT%		
CARBON	12.011													32	3.48						
HYDROGEN	2.016	184.06	12.97	184.06	11.94	184.06	13.51	27.70	13.51	13.85	13.51	360.42	13.51								
OXYGEN	32.000																				
NITROGEN	28.014	754.63	50.43	754.63	46.42	754.83	52.56	107.36	52.56	53.68	52.56	1401.80	52.56								
SULFUR	32.060																				
CHLORIDE	- -																				
ASH	- -													152	16.52						
WATER	18.018	69.83	4.67	199.25	12.26	9.18	0.64	1.32	0.64	0.66	0.64	17.04	0.64	736	80.00	727	100.00	1454	100.00		
CARBON MONOXIDE	28.011	368.85	24.63	368.65	22.67	368.65	25.68	52.44	25.68	26.22	25.68	684.86	25.68								
CARBON DIOXIDE	44.011	73.87	4.84	73.87	4.54	73.87	5.15	10.48	5.15	5.24	5.15	137.26	5.15								
METHANE	16.043	28.62	1.91	28.62	1.76	28.62	1.99	4.08	1.89	2.04	1.89	53.16	1.89								
HYDROGEN SULFIDE	34.076	6.74	0.45	6.74	0.41	6.74	0.47	0.96	0.47	0.48	0.47	12.52	0.47								
CARBONYL SULFIDE	60.071	NA		NA		NA		NA	NA	NA		NA									
FLY ASH (LB/HR)		(92)																			
TOTAL		1496.50	100.00	1625.82	100.00	1435.75	100.00	204.34	100.00	102.17	100.00	2667.16	100.00	920	100.00	727	100.00	1454	100.00		
TOTAL GAS FLOW,MOL/HR.	(DRY)	1426.57		1426.57		1426.57		203.02		101.51		2650.12									
WATER (V)/DRY GAS	(VOL/VOL)	0.048		0.1397		0.0064		0.0064		0.0064		0.0064									
TOTAL (WET) FLOW,LB/HR.		37150		39385		35861		5112		2556		66910		920		727		1454			
PRESSURE-PSIA		300		270		265		265		375		265		50		265		265			
TEMPERATURE-°F		400		288		120		120				120		100		120		120			
VOL. FLOW RATE-SCFM(DRY)		9022		9022		9022		1284		642		16760									
HHV BTU/LB																					
HHV BTU/SCF DRY GAS																					

F-0103

Process flow diagram of gas cleanup and recycling facilities - summer case



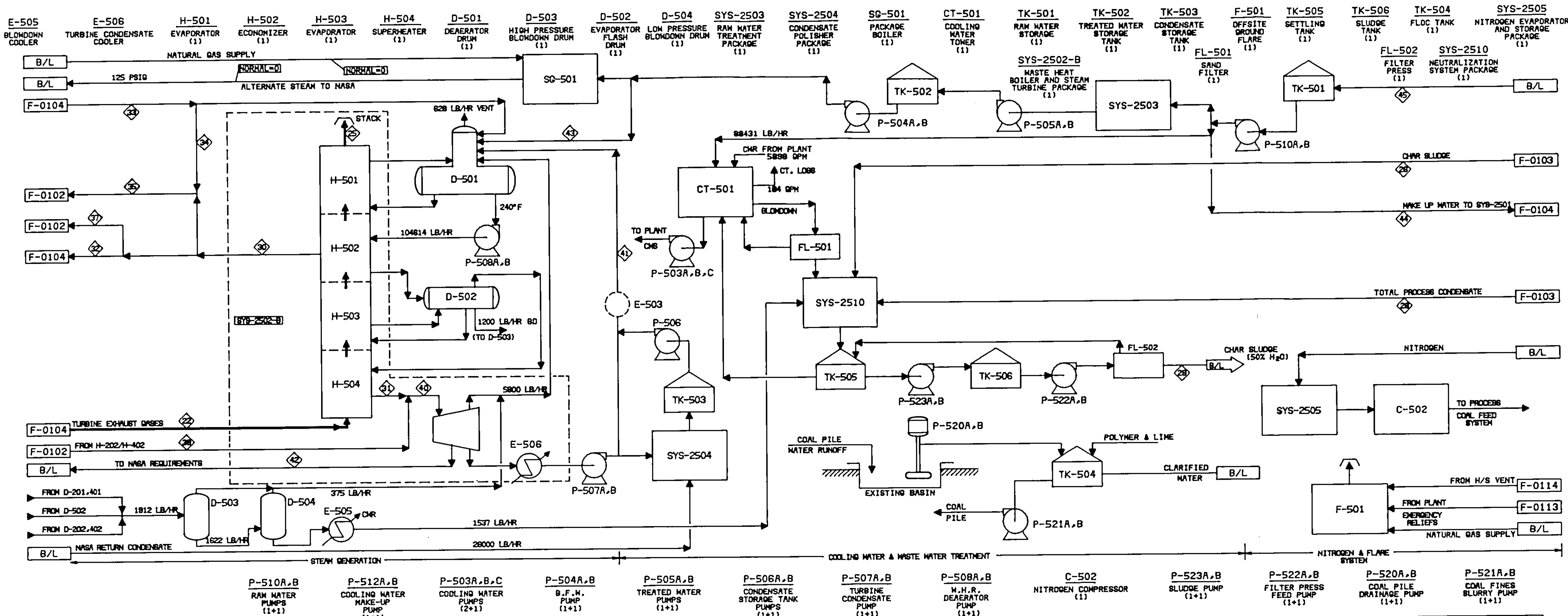
STREAM NUMBER		6		13		14		15		16	
DESCRIPTION		COMPRESSED BLEED AIR TO EACH GASIFIER		TOTAL GAS TO HOLMES-STRETFORD UNIT		HOLMES-STRETFORD UNIT VENT GASES		SULFUR BY PRODUCT TOTAL		S-FREE CLEAN GAS	
PHASE				G		G		S		G	
COMPONENT	MOL WT.	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %			MOL/HR	VOL %
CARBON	12.011										
HYDROGEN	2.016			380.42	13.51	3.80	28.41			356.82	13.50
OXYGEN	32.000	185.28	21.00								
NITROGEN	28.014	697.01	79.00	1401.90	52.59					1401.90	53.04
SULFUR	32.060							401	80.00		
CHLORIDE	- -										
ASH	- -										
WATER	18.016			17.04	0.64	1.29	9.39	100	20.00	17.91	0.68
CARBON MONOXIDE	28.011			684.86	25.69	6.95	50.29			678.01	25.65
CARBON DIOXIDE	44.011			137.28	5.15	1.37	10.05			135.89	5.14
METHANE	16.043			53.16	1.99	0.53	3.89			52.63	1.99
HYDROGEN SULFIDE	34.078			12.52	0.47					0.01	5 PPM
CARBONYL SULFIDE	60.071			NA						NA	
SULFUR DIOXIDE											
FLY ASH											
TOTAL		882.29	100.00	2687.18	100.00	13.63	100.00	501	100.00	2643.17	100.00
TOTAL GAS FLOW,MOL/HR.	(DRY)	882.29		2650.12		12.35				2625.26	
WATER (V)/DRY GAS	(VOL/VOL)	-		0.0064		0.1036					
TOTAL (WET) FLOW,LB/HR.		25455.00		88810.00		281.00		501.00		66132.00	
PRESSURE-PSIA		380.00		285.00		15.00				250.00	
TEMPERATURE-°F		500.00		120.00		20.00		120.00		120.00	
VOL. FLOW RATE-SCFM(DRY)		5580.00		18780.00		78.00				18604.00	
HHV BTU/LB											
HHV BTU/SCF DRY GAS				147.70		287(AIR FREE BASIS)				147.60	

STREAM NUMBER		17		18		19		20		21	
DESCRIPTION		S-FREE CLEAN GAS		S-FREE TO PREHEATING PER TRAIN		PREHEATED S-FREE GAS PER TRAIN		TOTAL GAS TO GAS TURBINE		COMBUSTION AIR	
PHASE		G		G		G		G		G	
COMPONENT	MOL WT.	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %
CARBON	12.011										
HYDROGEN	2.016	356.82	13.50	178.410	13.50	178.410	13.50	356.82	13.50		
OXYGEN	32.000									3095.05	21.00
NITROGEN	28.014	1401.90	53.04	700-950	53.04	700-950	53.04	1401.90	53.04	11643.30	79.00
SULFUR	32.060										
CHLORIDE	- -										
ASH	- -										
WATER	18.016	17.91	0.68	8.955	0.68	8.955	0.68	17.91	0.68		
CARBON MONOXIDE	28.011	678.01	25.65	339.005	25.65	339.005	25.65	678.01	25.65		
CARBON DIOXIDE	44.011	135.89	5.14	67.945	5.14	67.945	5.14	135.89	5.14		
METHANE	16.043	52.63	1.99	26.315	1.99	26.315	1.99	52.63	1.99		
HYDROGEN SULFIDE	34.078	0.01	5 PPM	0.005	5 PPM	0.005	5 PPM	0.01	5 PPM		
CARBONYL SULFIDE	60.071										
SULFUR DIOXIDE											
FLY ASH											
TOTAL		2643.17	100.00	1321.585	100.00	1321.585	100.00	2643.17	100.00	14738.35	100.00
TOTAL GAS FLOW,MOL/HR.	(DRY)	2625.26		1312.63		1312.63		2625.26		14738.35	
WATER (V)/DRY GAS	(VOL/VOL)	0.0068		0.0068		0.0068		0.0068		-	
TOTAL (WET) FLOW,LB/HR.		66132.00		33066.00		33066.00		66132.00		425217.00	
PRESSURE-PSIA		247.00		247.00		240.00		240.00		ATM	
TEMPERATURE-°F		274.00		274.00		500.00		500.00		80.00	
VOL. FLOW RATE-SCFM(DRY)		18604.00		9302.00		9302.00		18604.00		93218.00	
HHV BTU/LB											
HHV BTU/SCF DRY GAS		147.60		147.60		147.60		147.60			

STREAM NUMBER		22		23		24		32		33		41		44	
DESCRIPTION		GAS TURBINE EXHAUST		BLEED AIR		TOTAL COMPRESSED BLEED AIR		HOT WATER TO FUEL GAS HEATER		HOT WATER RETURN FROM FUEL GAS HEATER		TOTAL RETURN CONDENSATE		MAKE-UP WATER	
PHASE		G		G		G		L		L		L		L	
COMPONENT	MOL WT.	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON	12.011														
HYDROGEN	2.016														
OXYGEN	32.000	2101.81	13.92	370.56	21.00	370.56	21.00								
NITROGEN	28.014	11651.18	77.16	1394.02	79.00	1394.02	79.00								
SULFUR	32.060														
CHLORIDE	- -														
ASH	- -														
WATER	18.016	480.00	3.18					7724	100.00	7724	100.00	86117	100.00	139	100.00
CARBON MONOXIDE	28.011														
CARBON DIOXIDE	44.011	866.53	5.74												
METHANE	16.043														
HYDROGEN SULFIDE	34.078	0.01	1 PPM												
CARBONYL SULFIDE	60.071														
SULFUR DIOXIDE															
FLY ASH															
TOTAL		15099.53	100.00	1764.58	100.00	1764.58	100.00	7724	100.00	7724	100.00	86117	100.00	139	100.00
TOTAL GAS FLOW,MOL/HR.	(DRY)	14619.53		1764.58		1764.58									
WATER (V)/DRY GAS	(VOL/VOL)	0.0328		-		-									
TOTAL (WET) FLOW,LB/HR.		440439.00		50910.00		50910.00		7724		7724		86117		139	
PRESSURE-PSIA		14.65		120.00		380.00		730		710		50		50	
TEMPERATURE-°F		1013.00		801.00		500.00		506		150		125		120	
VOL. FLOW RATE-SCFM(DRY)		92468.00		11160.00		11160.00									
HHV BTU/LB															
HHV BTU/SCF DRY GAS															

F-0104

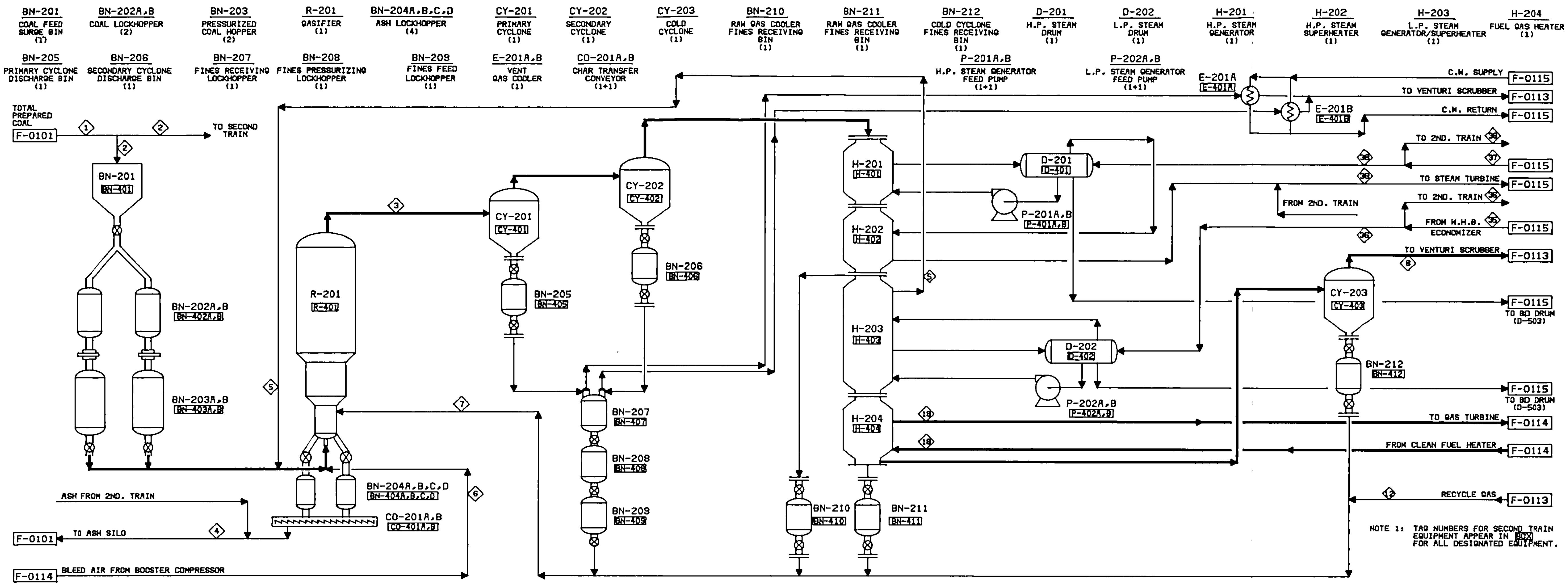
Process flow diagram of desulfurization and power generation facilities



STREAM NUMBER		22		25		26		28		29		30		31		32		33		34		35		37		38		40		41		42		43		45	
DESCRIPTION		GAS TURBINE EXHAUST		BOILER STACK GAS TO VENT		CHAR SLUDGE		TOTAL PROCESS CONDENSATE		CHAR SLUDGE DISPOSAL		TOTAL HOT WATER TO PROCESS		SUPER HEATED STEAM TO STEAM TURBINE		HOT WATER TO FUEL GAS HEATER		HOT WATER RETURN FROM FUEL GAS HEATER		MAKEUP WATER FOR TOTAL REACTION STEAM		WATER FOR REACTION STEAM TO H-203,403		WATER FOR STEAM TO H-201,401		SUPER HEATED STEAM TO TURBINE		TOTAL SUPER HEATED STEAM TO TURBINE		TOTAL RETURN CONDENSATE		STEAM TO NASA USAGES		MAKEUP WATER TO DEAERATOR		TOTAL PLANT MAKEUP WATER	
PHASE		G		G		S + L		L		S		L		G		L		L		L		L		L		G		G		L		L		L		L	
COMPONENT	MOL. WT.	MOL/HR	VOL %	MOL/HR	VOL %	LB/HR	VOL %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON	12.011					32	3.48			32	8.70																										
HYDROGEN	2.016																																				
OXYGEN	32.000	2101.81	13.82	2101.81	13.82																																
NITROGEN	28.014	11851.18	77.18	11851.18	77.18																																
SULFUR	32.060																																				
CHLORIDE	- -																																				
ASH	- -					152	16.52			152	41.30																										
WATER	18.016	480.00	3.18	480.00	3.18	736	80.00	1454	100.00	184	50.00	43414	100.00	80000	100.00	7724	100.00	7724	100.00	830	100.00	4352	100.00	31888	100.00	31342	100.00	81342	100.00	86117	100.00	26000	100.00	8431	100.00	85001	100.00
CARBON MONOXIDE	28.011																																				
CARBON DIOXIDE	44.011	886.53	5.74	886.53	5.74																																
METHANE	16.043																																				
HYDROGEN SULFIDE	34.076																																				
CARBONYL SULFIDE	60.071																																				
SULFUR DIOXIDE	64.06	0.01	1 PPM	0.01	1 PPM																																
FLY ASH																																					
TOTAL		15088.53	100.00	15088.53	100.00	820	100.00	1454	100.00	388	100.00	43414	100.00	80000	100.00	7724	100.00	7724	100.00	830	100.00	4352	100.00	31888	100.00	31342	100.00	81342	100.00	86117	100.00	28000	100.00	8431	100.00	85001	100.00
TOTAL GAS FLOW, MOL/HR.	(DRY)	14619.53		14619.53																																	
WATER (V)/DRY GAS	(VOL/VOL)	0.0328		0.0328		-		-																													
TOTAL (WET) FLOW, LB/HR.		440438		440438		820		1454		388		43414		80000		7724		7724		830		4352		31888		31342		81342		86117		28000		8431		85001	
PRESSURE-PSIA		14.65		14.65		50		285		-		718		815		718		710		710		457		718		815		815		50		125		50		50	
TEMPERATURE-°F		1013		270		100		120		100		506		750		508		150		150		458		506		750		750		175		430		80		80	
VOL. FLOW RATE-SCFM(DRY)		92486		92486																																	
HHV BTU/LB																																					
HHV BTU/SCF DRY GAS																																					

F-0105

Process flow diagram of waste-heat recovery and off-site facilities - summer case

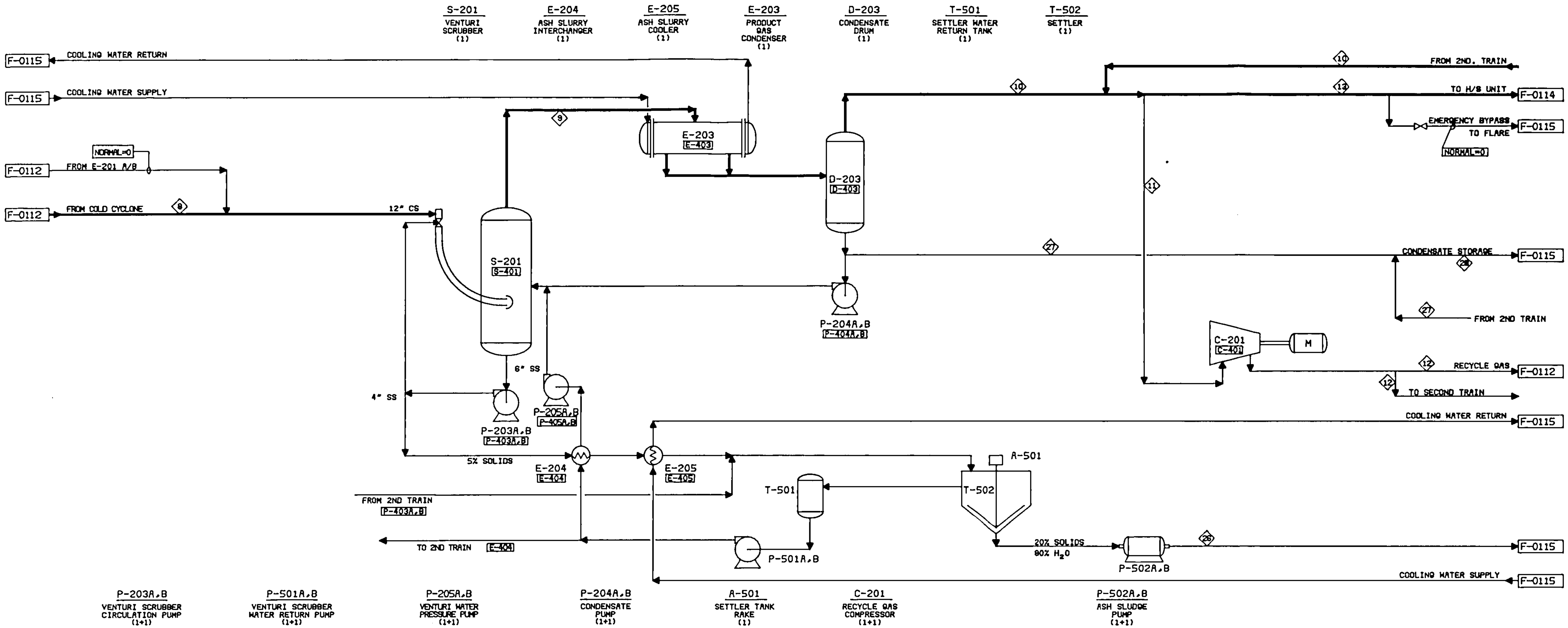


STREAM NUMBER		1		2		3		4		5		6		7		8	
DESCRIPTION		TOTAL PROCESS COAL		PROCESS COAL PER TRAIN		HOT RAW GAS PER TRAIN		TOTAL GASIFIER BOTTOM ASH		REACTION STEAM PER TRAIN		REACTION AIR PER TRAIN		RECYCLE GAS PLUS CHAR PER TRAIN		GAS TO SCRUBBER PER TRAIN	
PHASE		S		S		G+S		S		G		G		G+S		G+S	
COMPONENT	MOL WT.	LB/HR	WT %	LB/HR	WT %	MOL/HR	VOL %	LB/HR	WT %	LB/HR	WT %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %
CARBON	12.011	12837	64.80	6418	64.80			597	16.82								
HYDROGEN	2.016	860	4.34	430	4.34	225.27	12.97							16.08	13.51	225.27	12.97
OXYGEN	32.000	1543	7.79	772	7.79							215.08	21.00				
NITROGEN	28.014	258	1.30	129	1.30	875.99	50.43					809.11	79.00	62.31	52.56	875.99	50.43
SULFUR	32.060	479	2.42	239	2.42			12	0.32								
CHLORINE	- -																
ASH	- -	3116	15.73	1558	15.73			2939	82.86								
WATER	18.016	717	3.62	359	3.62	81.17	4.67			2476	100.00			0.77	0.64	81.17	4.67
CARBON MONOXIDE	28.011					427.94	24.63							30.43	25.68	427.94	24.63
CARBON DIOXIDE	44.011					85.75	4.94							6.09	5.15	85.75	4.94
METHANE	16.043					33.23	1.91							2.38	1.99	33.23	1.91
HYDROGEN SULFIDE	34.076					7.83	0.45							0.55	0.47	7.83	0.45
CARBONYL SULFIDE	60.071																
FLY ASH	(LB/HR)					(3169)								(3062)		(107)	
TOTAL		19810	100.00	9905	100.00	1737.18	100.00	3547	100.00	2476	100.00	1024.18	100.00	118.61	100.00	1737.18	100.00
TOTAL GAS FLOW,MOL/HR,	(DRY)					1656.01								117.84		1656.01	
WATER (V)/DRY GAS	(VOL/VOL)																
TOTAL (WET) FLOW,LB/HR.		19810		9905		46187		3547		2476		29549		6030		43125	
PRESSURE-PSIA						320				415		380		375		300	
TEMPERATURE-°F						1850				500		500				400	
VOL. FLOW RATE-SCFM(DRY)																	
HHV BTU/LB		11590		11590													
HHV BTU/SCF DRY GAS																	

STREAM NUMBER	12		18		19		35		36		37		38		39	
DESCRIPTION	RECYCLE GAS PER TRAIN		S-FREE FUEL GAS PER TRAIN		FUEL GAS TO TURBINE PER TRAIN		TOTAL 450 PSIA BFW FROM ECONOMIZER		450 PSIA BFW FROM ECONOMIZER PER TRAIN		TOTAL 720 PSIA BFW FROM ECONOMIZER		720 PSIA BFW FROM ECONOMIZER PER TRAIN		615 PSIA TURBINE STEAM PER TRAIN	
PHASE	G		G		G		L		L		L		L		G	
COMPONENT	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON																
HYDROGEN	16.08	13.51	207.10	13.50	207.10	13.50										
OXYGEN																
NITROGEN	62.31	52.56	813.68	53.04	813.68	53.04										
SULFUR																
CHLORINE																
ASH																
WATER	0.76	0.64	10.39	0.68	10.39	0.68	5052	100.00	2526	100.00	37120	100.00	18560	100.00	36392	100.00
CARBON MONOXIDE	30.43	25.68	393.53	25.65	393.53	25.65										
CARBON DIOXIDE	6.09	5.15	78.87	5.14	78.87	5.14										
METHANE	2.38	1.99	30.54	1.99	30.54	1.99										
HYDROGEN SULFIDE	0.56	0.47	0.01	5 PPM	0.01	5 PPM										
CARBONYL SULFIDE																
FLY ASH (LB/HR)																
TOTAL	118.61	100.00	1534.12	100.00	1534.12	100.00	5052	100.00	2526	100.00	37120	100.00	18560	100.00	36392	100.00
TOTAL GAS FLOW,MOL/HR, (DRY)	117.84		1523.73		1523.73											
WATER (V)/DRY GAS (VOL/VOL)																
TOTAL (WET) FLOW,LB/HR.	2968		38384		38384		5052		2526		37120		18560		36392	
PRESSURE-PSIA	375		247		240		457		457		725		725		815	
TEMPERATURE-°F			120		500		458		458		506		506		750	
VOL. FLOW RATE-SCFM(DRY)																
HHV BTU/LB																
HHV BTU/SCF DRY GAS																

Process flow diagram of coal gasification and waste-heat recovery facilities - winter case

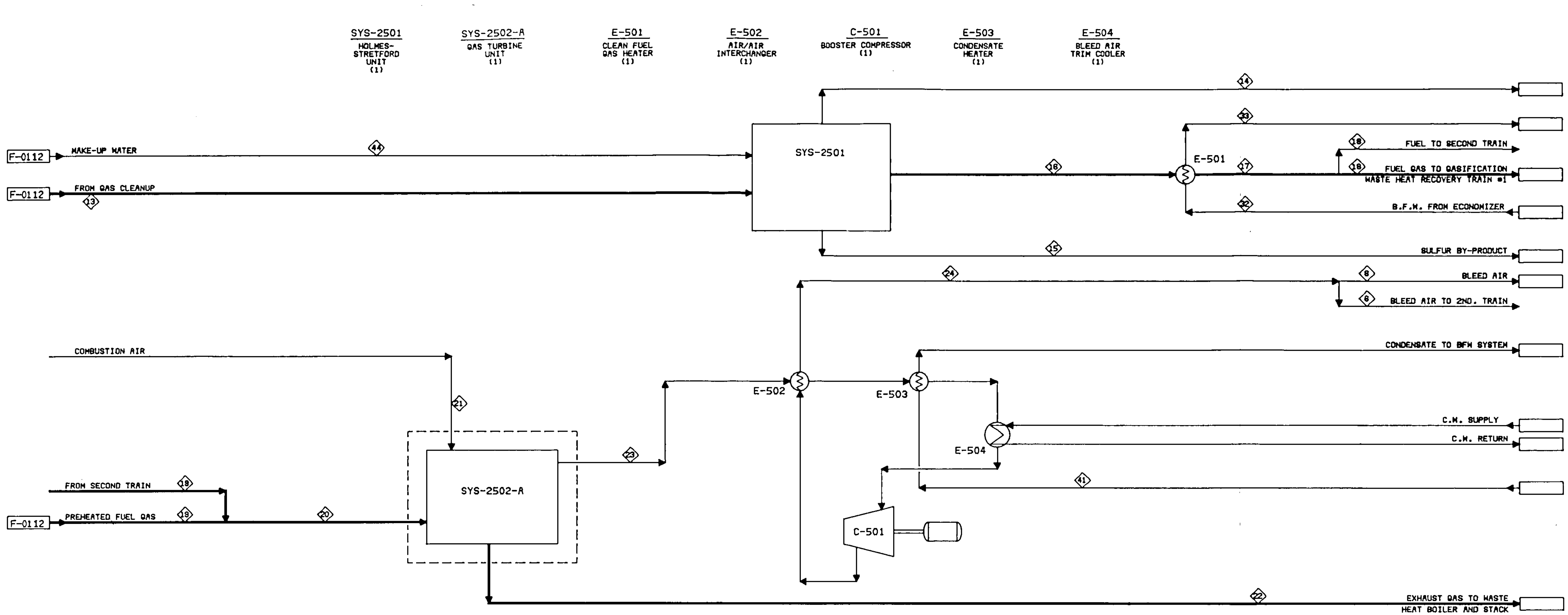
F-0112



STREAM NUMBER		8		9		10		11		12		13		26		27		28	
DESCRIPTION		GAS TO SCRUBBER PER TRAIN		VENTURI OUTLET GAS PER TRAIN		PARTICULATE FREE GAS PER TRAIN		TOTAL RECYCLE GAS TO COMPRESSOR		RECYCLE GAS PER TRAIN		TOTAL GAS TO H/S UNIT		TOTAL CHAR SLUDGE		PROCESS CONDENSATE PER TRAIN		TOTAL PROCESS CONDENSATE	
PHASE		G		G		G		G		G		G		S+L		L		L	
COMPONENT	MOL. WT.	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	MOL/HR	VOL%	LB/HR	WT%	LB/HR	WT%	LB/HR	WT%
CARBON	12.011													37	3.48				
HYDROGEN	2.016	225.27	12.97	225.27	11.94	225.27	13.51	32.17	13.51	16.08	13.51	418.37	13.51						
OXYGEN	32.000																		
NITROGEN	28.014	875.98	50.43	875.99	46.42	875.99	52.56	124.61	52.56	62.31	52.56	1627.37	52.56						
SULFUR	32.060																		
CHLORIDE	- -																		
ASH	- -													177	16.52				
WATER	18.016	81.17	4.67	231.40	12.26	10.65	0.64	1.53	0.64	0.76	0.64	19.78	0.64	858	80.00	842	100.00	1684	100.00
CARBON MONOXIDE	28.011	427.94	24.63	427.94	22.67	427.94	25.68	60.86	25.68	30.43	25.68	795.01	25.68						
CARBON DIOXIDE	44.011	85.75	4.94	85.75	4.54	85.75	5.15	12.18	5.15	6.09	5.15	159.33	5.15						
METHANE	16.043	33.23	1.91	33.23	1.76	33.23	1.89	4.75	1.89	2.38	1.89	61.70	1.89						
HYDROGEN SULFIDE	34.076	7.83	0.45	7.83	0.41	7.83	0.47	1.11	0.47	0.58	0.47	14.55	0.47						
CARBONYL SULFIDE	60.071																		
FLY ASH	(LB/HR)	(107)		-		-													
TOTAL		1737.18	100.00	1887.41	100.00	1666.68	100.00	237.21	100.00	118.61	100.00	3096.11	100.00	1070	100.00	842	100.00	1684	100.00
TOTAL GAS FLOW, MOL/HR.	(DRY)	1656.01		1656.01		1656.01		235.68		117.84		3076.33							
WATER (V)/DRY GAS	(VOL/VOL)																		
TOTAL (WET) FLOW, LB/HR.		43125		45528		41745		5935		2968		77555		1070		842		1684	
PRESSURE-PSIA		300		270		285		285		375		285		50		285		285	
TEMPERATURE-°F		400		258		120		120		188		120		100		120		120	
VOL. FLOW RATE-SCFM (DRY)																			
HHV BTU/LB																			
HHV BTU/SCF DRY GAS																			

F-0113

Process flow diagram of gas cleanup and recycling facilities - winter case



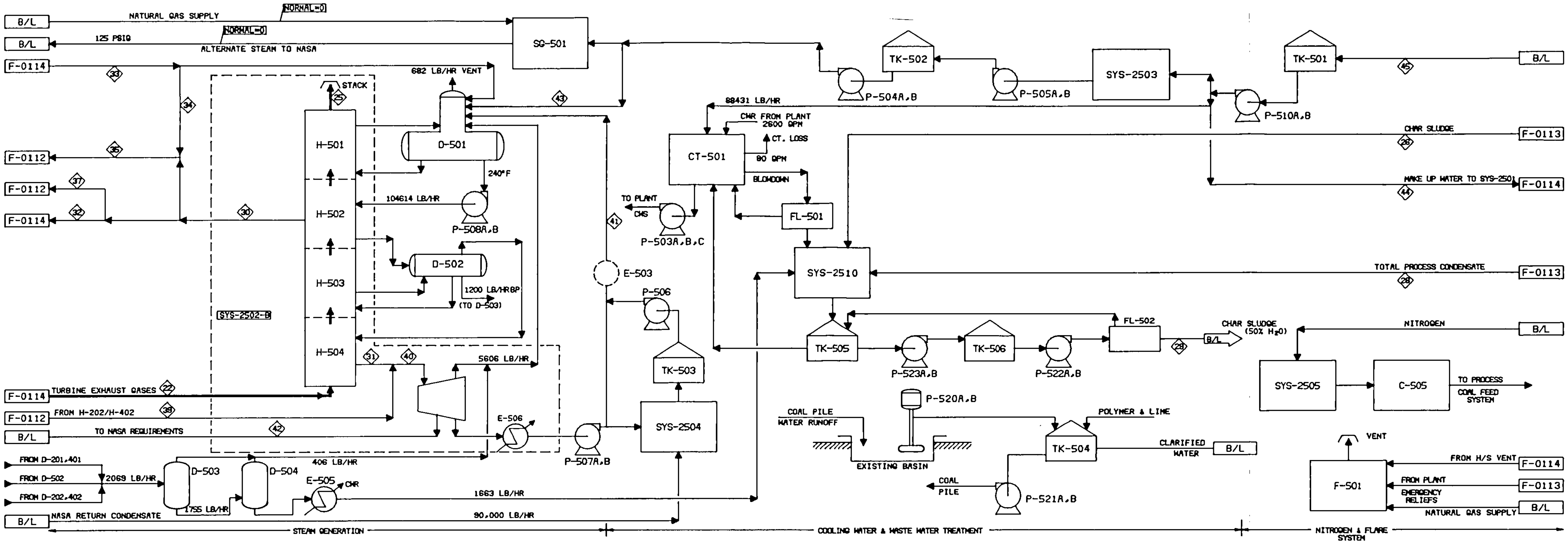
STREAM NUMBER		6		13		14		15		16		17	
DESCRIPTION		BLEED AIR PER TRAIN		TOTAL GAS TO HOLMES/STRETFORD		HOLMES/STRETFORD VENT GASES		SULFUR BY PRODUCT		TOTAL S-FREE GAS		TOTAL S-FREE GAS TO PREHEATING	
PHASE		G		G		G		L		G		G	
COMPONENT	MOL WT.	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	LB/HR	WT %	MOL/HR	VOL %	MOL/HR	VOL %
CARBON	12.011												
HYDROGEN	2.016			418.37	13.51	4.18	26.41			414.19	13.50	414.19	13.50
OXYGEN	32.000	215.08	21.00										
NITROGEN	28.014	808.11	79.00	1627.37	52.56					1627.37	53.04	1627.37	53.04
SULFUR	32.060							466	80.00				
CHLORIDE	- -												
ASH	- -												
WATER	18.018									20.79	0.68	20.78	0.68
CARBON MONOXIDE	28.011			19.78	0.64	1.48	9.38	116	20.00	787.06	25.65	787.06	25.65
CARBON DIOXIDE	44.011			795.01	25.68	7.95	50.26			157.74	5.14	157.74	5.14
METHANE	16.043			159.33	5.15	1.59	10.05			61.08	1.88	61.08	1.99
HYDROGEN SULFIDE	34.076			61.70	1.88	0.62	3.89			0.02	5 PPM	0.02	5 PPM
CARBONYL SULFIDE	60.071			14.55	0.47	-	-						
SULFUR DIOXIDE	64.06												
FLY ASH													
TOTAL		1024.19	100.00	3096.11	100.00	15.82	100.00	582	100.00	3068.25	100.00	3068.25	100.00
TOTAL GAS FLOW,MOL/HR.	(DRY)			3076.33		14.34				3047.46		3047.46	
WATER (V)/DRY GAS	(VOL/VOL)												
TOTAL (WET) FLOW,LB/HR.		29549		77555		338		582		76768		76768	
PRESSURE-PSIA		380		265		18				250		247	
TEMPERATURE-°F		500		120		120		100		120		274	
VOL. FLOW RATE-SCFM(DRY)													
HHV BTU/LB													
HHV BTU/SCF DRY GAS													

STREAM NUMBER		18		19		20		21		22		23		24	
DESCRIPTION		S-FREE GAS TO PREHEATING PER TRAIN		PREHEATED S-FREE GAS PER TRAIN		TOTAL PREHEATED S-FREE GAS		COMBUSTION AIR		GAS TURBINE EXHAUST		BLEED AIR		TOTAL COMPRESSED BLEED AIR	
PHASE		G		G		G		G		G		G		G	
COMPONENT	MOL WT.	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %	MOL/HR	VOL %
CARBON	12.011														
HYDROGEN	2.016	207.10	13.50	207.10	13.50	414.19	13.50								
OXYGEN	32.000							3486.61	21.00	2333.62	13.71	430.16	21.00	430.16	21.00
NITROGEN	28.014	813.68	53.04	813.68	53.04	1627.37	53.04	13116.31	79.00	13125.46	77.11	1618.22	79.00	1618.22	79.00
SULFUR	32.060														
CHLORIDE	- -														
ASH	- -														
WATER	18.018	10.39	0.88	10.39	0.68	20.79	0.68			557.17	3.27				
CARBON MONOXIDE	28.011	393.53	25.65	393.53	25.65	787.06	25.65								
CARBON DIOXIDE	44.011	78.87	5.14	78.87	5.14	157.74	5.14			1005.88	5.91				
METHANE	16.043	30.54	1.98	30.54	1.99	61.08	1.88								
HYDROGEN SULFIDE	34.076	0.01	5 PPM	0.01	5 PPM	0.02	5 PPM								
CARBONYL SULFIDE	60.071														
SULFUR DIOXIDE	64.06									0.02	1 PPM				
FLY ASH															
TOTAL		1534.12	100.00	1534.12	100.00	3068.25	100.00	16602.92	100.00	17022.15	100.00	2048.38	100.00	2048.38	100.00
TOTAL GAS FLOW,MOL/HR.	(DRY)	1523.73		1523.73		3047.46		16602.92		16464.99		2048.38		2048.38	
WATER (V)/DRY GAS	(VOL/VOL)														
TOTAL (WET) FLOW,LB/HR.		38384		38384		76768		479012		496682		59098		59098	
PRESSURE-PSIA		247		240		240		ATM		14.65		120		380	
TEMPERATURE-°F		274		500		500		AMB		1013		810		500	
VOL. FLOW RATE-SCFM(DRY)															
HHV BTU/LB															
HHV BTU/SCF DRY GAS															

STREAM NUMBER				32		33		41		44	
DESCRIPTION				BFW TO FUEL GAS HEATER		BFW RETURN FROM FUEL GAS HEATER		TOTAL RETURN CONDENSATE		MAKE-UP WATER TO HOLMES & STRETFORD	
PHASE				L		L		L		L	
COMPONENT	MOL WT.			LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON	12.011										
HYDROGEN	2.016										
OXYGEN	32.000										
NITROGEN	28.014										
SULFUR	32.060										
CHLORIDE	- -										
ASH	- -										
WATER	18.018			8969	100.00	8969	100.00	83246	100.00	161	100.00
CARBON MONOXIDE	28.011										
CARBON DIOXIDE	44.011										
METHANE	16.043										
HYDROGEN SULFIDE	34.076										
CARBONYL SULFIDE	60.071										
SULFUR DIOXIDE	64.06										
FLY ASH											
TOTAL				8969	100.00	8969	100.00	93246	100.00	161	100.00
TOTAL GAS FLOW,MOL/HR.	(DRY)										
WATER (V)/DRY GAS	(VOL/VOL)										
TOTAL (WET) FLOW,LB/HR.				8969		8969		83246		161	
PRESSURE-PSIA				730		730		50		50	
TEMPERATURE-°F				506		506		125		60	
VOL. FLOW RATE-SCFM(DRY)											
HHV BTU/LB											
HHV BTU/SCF DRY GAS											

F-0114

Process flow diagram of desulfurization and power generation facilities - winter case



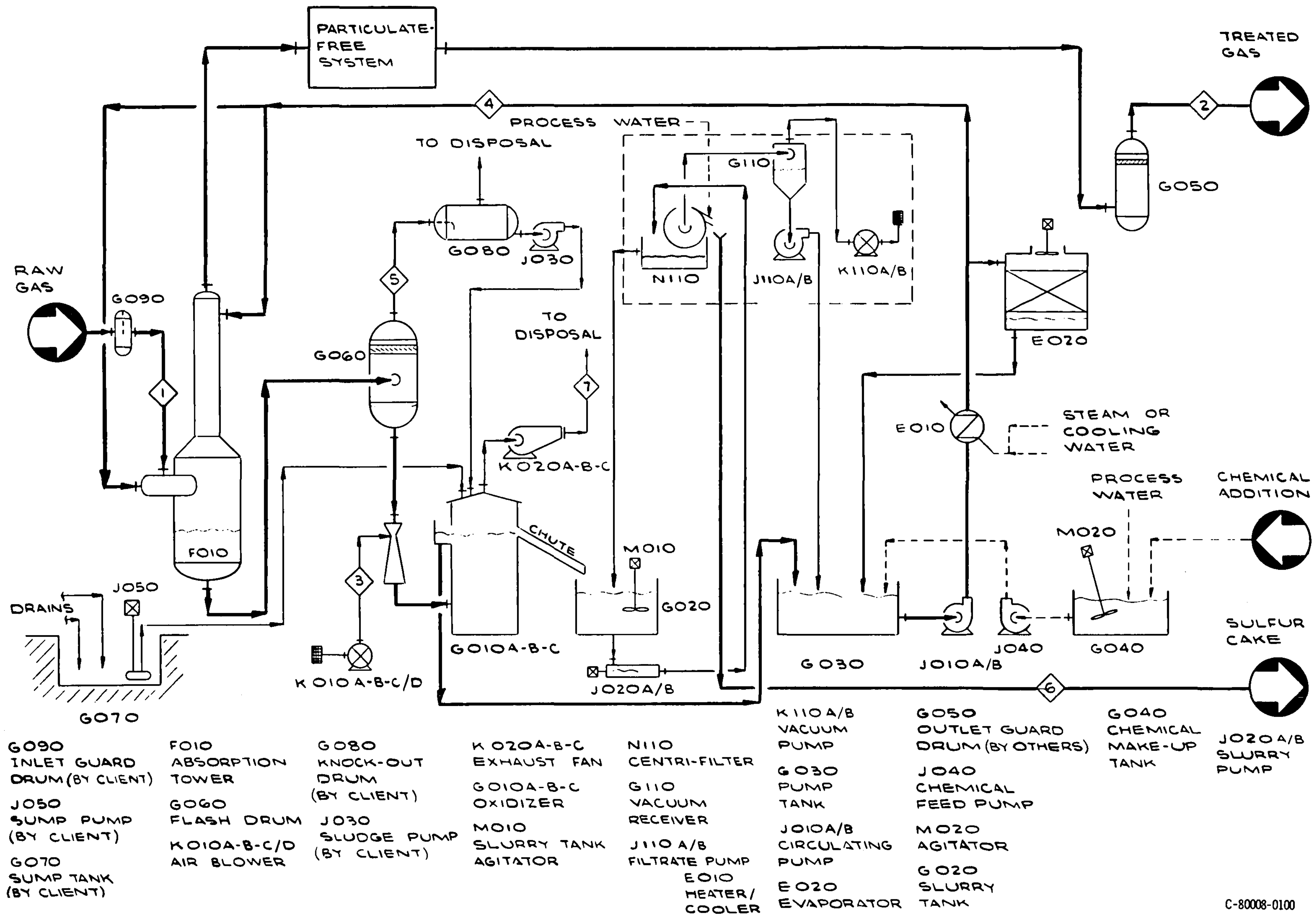
STREAM NUMBER		22		25		26		28		29		30	
DESCRIPTION		GAS TURBINE EXHAUST		BOILER STACK GAS TO VENT		CHAR SLUDGE		TOTAL PROCESS CONDENSATE		CHAR SLUDGE DISPOSAL		TOTAL HOT WATER TO PROCESS	
PHASE		G		G		S + L		L		S		L	
COMPONENT	MOL. WT.	MOL/HR	VOL. %	MOL/HR	VOL. %	LB/HR	VOL. %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON	12.011					37	3.48			37	8.65		
HYDROGEN	2.016												
OXYGEN	32.000	2333.62	13.71	2333.62	13.71								
NITROGEN	28.014	13125.46	77.11	13125.46	77.11								
SULFUR	32.060												
CHLORIDE	- -												
ASH	- -					177	16.52			177	41.35		
WATER	18.016	557.17	3.27	557.17	3.27	856	80.00	1684	100.00	214	50.00	50410	100.00
CARBON MONOXIDE	28.011												
CARBON DIOXIDE	44.011	1005.88	5.91	1005.88	5.91								
METHANE	16.043												
HYDROGEN SULFIDE	34.076												
CARBONYL SULFIDE	60.071												
SULFUR DIOXIDE	64.06	0.02	1 PPM	0.02	1 PPM								
FLY ASH													
TOTAL		17022.16	100.00	17022.16	100.00	1070	100.00	1684	100.00	428	100.00	50410	100.00
TOTAL GAS FLOW,MOL/HR,	(DRY)	16464.98		16464.99									
WATER (V)/DRY GAS	(VOL/VOL)	0.0338		0.0338									
TOTAL (WET) FLOW,LB/HR.		486682		486682		1070		1684		428		50410	
PRESSURE-PSIA		14.65		14.65		50		285				718	
TEMPERATURE-°F		877		977		100		120		100		506	
VOL. FLOW RATE-SCFM(DRY)		104138		104138									
HHV BTU/LB													
HHV BTU/SCF DRY GAS													

STREAM NUMBER	31		32		33		34		35		37	
DESCRIPTION	SUPER HEATED STEAM TO STEAM TURBINE		HOT WATER TO FUEL GAS HEATER		HOT WATER RETURN FROM FUEL GAS HEATER		MAKEUP WATER FOR TOTAL REACTION STEAM		WATER FOR REACTION STEAM TO H-203,403		WATER FOR STEAM TO H-201,401	
PHASE	G		L		L		L		L		L	
COMPONENT	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON												
HYDROGEN												
OXYGEN												
NITROGEN												
SULFUR												
CHLORIDE												
ASH												
WATER	62054	100.00	8869	100.00	8869	100.00	731	100.00	5052	100.00	37120	100.00
CARBON MONOXIDE												
CARBON DIOXIDE												
METHANE												
HYDROGEN SULFIDE												
CARBONYL SULFIDE												
SULFUR DIOXIDE												
FLY ASH												
TOTAL	62054	100.00	8869	100.00	8969	100.00	731	100.00	5052	100.00	37120	100.00
TOTAL GAS FLOW,MOL/HR, (DRY)												
WATER (V)/DRY GAS (VOL/VOL)												
TOTAL (WET) FLOW,LB/HR.	62054		8869		8869		731		5052		37120	
PRESSURE-PSIA	815		718		710		710		457		718	
TEMPERATURE-°F	750		506		150		150		458		506	
VOL. FLOW RATE-SCFM(DRY)												
HHV BTU/LB												
HHV BTU/SCF DRY GAS												

STREAM NUMBER	38		40		41		42		43		45	
DESCRIPTION	SUPER HEATED STEAM TO TURBINE		TOTAL SUPER HEATED STEAM TO TURBINE		TOTAL RETURN CONDENSATE		STEAM TO NASA USAGES		MAKEUP WATER TO DEAERATOR		TOTAL PLANT MAKEUP WATER	
PHASE	G		G		L		L		L		L	
COMPONENT	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %	LB/HR	WT %
CARBON												
HYDROGEN												
OXYGEN												
NITROGEN												
SULFUR												
CHLORIDE												
ASH												
WATER	36382	100.00	88446	100.00	83246	100.00	80000	100.00	7297	100.00	43437	100.00
CARBON MONOXIDE												
CARBON DIOXIDE												
METHANE												
HYDROGEN SULFIDE												
CARBONYL SULFIDE												
SULFUR DIOXIDE												
FLY ASH												
TOTAL	36382	100.00	88446	100.00	83246	100.00	80000	100.00	7297	100.00	43437	100.00
TOTAL GAS FLOW,MOL/HR, (DRY)												
WATER (V)/DRY GAS (VOL/VOL)												
TOTAL (WET) FLOW,LB/HR.	36382		88446		83246		80000		7297		43437	
PRESSURE-PSIA	815		815		50		125		50		50	
TEMPERATURE-°F	750		750		175		430		80		80	
VOL. FLOW RATE-SCFM(DRY)												
HHV BTU/LB												
HHV BTU/SCF DRY GAS												

F-0115

Process flow diagram of waste-heat recovery and off-site facilities - winter case



12 Standard tons per day sulfur

Flow	Stream						
	Feed gas ⟨1⟩	Treated gas ⟨2⟩	Air to oxidizer ⟨3⟩	Liquor to absorber ⟨4⟩	Degassing ⟨5⟩	Wet sulfur cake ⟨6⟩	Ventilation air ⟨7⟩
Gas, scfm	20 595	20 115	---	---	378	(a)	---
HS liquor, gal/min	---	(b)	---	2010	---	---	---
Air, scfm	---	---	2400	---	---	---	6000
H_2S	1.0% max.	5 ppm	---	---	---	---	---
Pressure, psig	250	240	12.5	280	20	---	Ambient
Temperature, °F	120	96	260	95	95	---	95

[a]Sulfur, 1000 lb/hr; water, 940 lb/hr; dissolved salts, 60 lb/hr; vanadium, 130 ppm (wt.).

[b]Vanadium, 0.1 ppm (wt.); Na plus K, 0.1 ppm (wt.).

4.75 Standard tons per day sulfur

Flow	Stream						
	Feed gas ⟨1⟩	Treated gas ⟨2⟩	Air to oxidizer ⟨3⟩	Liquor to absorber ⟨4⟩	Degassing ⟨5⟩	Wet sulfur cake ⟨6⟩	Ventilation air ⟨7⟩
Gas, scfm	17 165	16 787	---	---	378	(c)	---
HS liquor, gal/min	---	(d)	---	2010	---	---	---
Air, scfm	---	---	2400	---	---	---	6000
H_2S	0.47%	5 ppm	---	---	---	---	---
Pressure, psig	250	240	12.5	280	20	---	Ambient
Temperature, °F	120	95	260	94	94	---	94

[c]Sulfur, 396 lb/hr; water, 367 lb/hr; dissolved salts, 29 lb/hr; vanadium, 130 ppm (wt.).

[d]Vanadium, 0.1 ppm (wt.); Na plus K, 0.1 ppm (wt.).

Process flow diagram of Holmes-Stretford system

TABLE I. - COCOGEN POWERPLANT

REFERENCE SYSTEM

COMPONENTS

Component	Description
Gasifier	DOE-Westinghouse pressurized fluidized bed (low-Btu gas, air blown)
Particulate removal	Primary and secondary hot cyclones, cold cyclone, and venturi scrubber
Sulfur removal	Peabody Holmes-Stretford direct-conversion process
Gas turbine	Westinghouse CW182
Steam turbine	Westinghouse M25

TABLE II. - COCOGEN POWERPLANT

PERFORMANCE SUMMARY

	Summer	Winter
Ambient temperature, ^{o}F	80	20
Steam production at 125 psia, lb/hr	26 000	90 000
Coal throughput (Ohio No. 9), ton/day	205	238
Total power generation (gross), MW	18.9	18.5
Gas turbine power output (gross), MW	11.5	14.4
Steam turbine power output (gross), MW	7.4	4.1
Powerplant consumption, MW	2.4	2.5
Total power generation (net), MW	16.5	16.0
Coal utilization efficiency, percent	44.5	71.4
Annual steam production, Btu	385×10^{9}	
Annual electric generation, MWhr	130×10^{3}	

TABLE III. - COCOGEN POWERPLANT COMPONENTS

Category	Components
Coal handling	Coal truck unloading hopper Conveyors Coal storage pile equipment Crusher
Coal gasifier	Surge feedbins Lockhoppers Gasifiers (two) Raw gas coolers Cyclones Heat exchangers Recycle compressors
Sulfur removal unit	Tanks Towers Exchangers Vessels Filters
Power generation package	Gas turbine Steam turbine Generator Heat-recovery steam generator
Gasifier and powerplant auxiliaries	Scrubbers Cyclones Coolers Pumps Water treatment Cooling tower Package steam boiler Foundations Structures Piping Controls
Site development and supporting facilities	Waste treatment systems Site development Control building Offsite road

TABLE IV. - COCOGEN POWERPLANT CAPITAL

COST ESTIMATE

[Based on third-quarter 1980 price levels.]

	Cost, dollars
Coal-handling area	2 620 000
Coal gasifier package	19 900 000
Sulfur removal unit package	4 600 000
Power generation package	13 530 000
Gasifier and powerplant auxiliaries	8 620 000
Site development and supporting facilities	2 000 000
Total direct cost	51 270 000
Field indirect cost and construction management	2 250 000
Professional services	4 780 000
Total plant cost	[a]58 300 000

[a]Exclusions: escalation; insurance; taxes; coal-hauling trucks; royalties, licenses, and commissions; fencing; cost of land; cost of capital; permits; and startup costs.

TABLE V. - COCOGEN POWERPLANT ANNUAL

OPERATING COST ESTIMATE

	Unit cost, dollars	Cost, dollars
Coal, per ton	38.75	2 685 380
Natural gas, per 1000 cubic feet	3.20	108 680
Water, per 1000 cubic feet	1.80	19 220
Nitrogen, per ton	60.00	237 600
Soda ash, per lb	.05	7 310
Special chemicals, per lb	5.00	33 000
Waste disposal, per ton	6.00	89 100
Operating supplies	(a)	57 800
Maintenance material	(b)	200 000
Total variable costs		3 438 090
Operating labor and supervision	------	442 000
Maintenance labor	------	240 000
Laboratory service	------	16 000
Total semivariable costs		698 000
Total cost		4 136 090

[a]Assumed to be 10 percent of operating labor costs.
[b]Assumed to be 3.5 percent of plant cost.

TABLE VI. - COCOGEN ANNUAL LABOR

COST ESTIMATE

	Shift			Total
	1	2	3	
Supervisor	0	1	0	1.0
Operator - powerplant	1	1	1	[a]4.2
Operator - control room	1	1	1	4.2
Operator - relief	1	1	1	4.2
Laborer	0	1	0	1.0
Shift maintenance	0	2	0	2.4
Total	3	7	3	17.0

[a]4.2 Employees provide coverage for 21 shifts per week.

TABLE VII. - CANDIDATE GASIFIERS

Gasifier type	Candidates
Fixed bed	Wellman Riley Morgan Wilputte Chapman Two Stage (Woodall-Duckham, IFE, Stoic, Pullman) Lurgi British Gas Corp. MERC (now METC) GEGAS
Fluidized bed	Winkler Westinghouse IGT U-Gas COGAS CO_2 acceptor BCR Battelle-Carbide Hygas Synthane Hydrane
Entrained flow	Koppers-Totzek Texaco Shell-Koppers Combustion Engineering Babcock & Wilcox Bigas Foster-Wheeler
Miscellaneous	Otto-Rummel Kellogg ATGAS/PATGAS TRW Rockwell Bell

TABLE VIII. - GASIFIER EVALUATION SUMMARY

Gasifier	Criterion (a)			
	1	2	3	4
Fixed bed				
British Gas Corp.	√	√	√	√
All others	X			
Fluidized bed:				
Westinghouse	√	√	√	√
IGT U-Gas	√	√	√	√
Winkler	X			
All others		X		
Entrained flow:				
Texaco	√	√	√	√
Babcock & Wilcox	√	√	√	√
Koppers-Totzek				X
Shell-Koppers			X	
Combustion Engineering				X
All others		X		
Miscellaneous (all)		X		

[a]Criteria:

1 - Ability to use any U.S. coal.

2 - Near commercial stage of development

3 - Gasifier sizes available to meet NASA needs

4 - Pressurization up to 400 psia required

TABLE IX. - GAS TURBINE SUMMARY

Manufacturer	Model	Nominal output, MW	Inlet temperature, ^{o}F	Exhaust temperature, ^{o}F	Compressor pressure ratio
Westinghouse Canada, Ltd	CW182	14.4	1850	977	8
Solar Turbines International	MARS	8.9	2000	900	16
General Electric GT Division	LM2500	20.1	2140	940	18

TABLE X. - ANALYSIS OF OHIO NO. 9

COAL

[Higher heating value (HHV), 11 590 Btu/lb (as received).]

Ultimate analysis	Content, wt%
Carbon	64.8
Hydrogen	4.34
Oxygen	7.79
Sulfur	2.42
Nitrogen	1.30
Ash	15.73
Water	3.62
Total	100.00

TABLE XI. - SPECIFICATION OF FUEL

GAS TO HOLMES-STRETFORD UNIT

Species	Content, mol percent	
	Minimum	Maximum
CO	25.68	25.54
CO_2	5.15	5.12
H_2	13.51	13.44
CH_4	1.99	1.98
N_2	52.56	52.29
H_2S	.47	.99
H_2O	.64	.64
Total	100.00	100.00
Flow rate, mol/hr	2681.2	3217.0
(scfm)	(16 958.0)	(20 350.0)
Sulfur content, ton/day	4.9	12.3
Pressure, psia	265	
Temperature, ^{o}F	120	

TABLE XII. - OVERALL MASS BALANCE FOR

COCOGEN POWERPLANT

Stream	Description	Summer	Winter
--	Ambient air temperature, ^{o}F	80	20
	Input, lb/hr		
1	Process coal	17 065	19 810
21	Air to gas turbine system	425 217	479 012
45	Total plant makeup water	95 001	43 437
	Total input	537 283	542 259
	Output, lb/hr		
4	Gasifier bottom ash	3 056	3 547
14	Holmes-Stretford unit vent gases	291	338
15	Sulfur byproduct	501	582
25	Stack gas	440 439	496 682
29	Char sludge	368	428
--	Cooling tower evaporation and dry losses	92 000	40 000
--	Deaerator losses	628	682
	Total output	537 283	542 259

TABLE XIII. - OVERALL HEAT BALANCE FOR COCOGEN POWERPLANT

[Basis, 60° F H_2O (liquid).]

Stream	Description	Summer	Winter
1	Ambient air temperature, $^{\circ}F$	80	20
	Input, Btu/hr		
1	Process coal	197.78×10^{6}	229.60×10^{6}
21	Air to gas turbine system	2.09	----------
45	Total plant makeup water	1.90	----------
--	Condensate from NASA at 250° F	4.94	17.10
	Total input	206.69×10^{6}	246.70×10^{6}
	Output, Btu/hr		
4	Carbon in gasifier bottom ash (higher heating value (HHV))	7.24×10^{6}	8.40×10^{6}
14	Holmes-Stretford unit vent gases (HHV)	1.34	1.55
15	Sulfur byproduct (HHV)	1.49	1.73
25	Stack gas sensible heat	32.01	36.10
29	Char sludge carbon (HHV)	0.45	0.52
42	Steam export to NASA needs	31.56	109.25
--	Heat to cooling water		
	Process cooling	24.79	28.78
	Turbine condensate cooling	48.93	2.64
--	Deaerator loss	0.71	0.77
--	Net power product	56.36	54.75
--	Unaccounted losses	1.81	2.21
	Total output	206.69×10^{6}	246.70×10^{6}

TABLE XIV. - ELECTRIC POWER DISTRIBUTION

FOR COCOGEN POWERPLANT

Component	Summer	Winter
Ambient-temperature air, ^{o}F	80	20
Total plant power generation, MW		
Gas turbine	11.495	14.430
Steam turbine	7.407	4.074
Total generated	18.902	18.504
Plant power consumption, MW		
Booster air compression	1.320	1.369
Recycle gas compression	0.112	0.131
Desulfurization	0.261	0.336
Cooling water pumps	0.224	0.224
Cooling tower	0.112	0.112
Boiler feed water pumps	0.093	0.093
Coal handling	0.075	0.075
Miscellaneous	0.190	0.190
Total consumed	2.387	2.462
Net power available	16.515	16.042

TABLE XV. - THERMAL DISTRIBUTION FOR

COCOGEN POWERPLANT

Component	Summer	Winter
Heat input, Btu/hr		
Coal	197.78×10^{6}	229.60×10^{6}
Air to gas turbine system	2.09	----------
Plant makeup water	1.90	----------
Condensate return from NASA	4.94	17.10
Total heat input	206.69×10^{6}	246.70×10^{6}
Net output, Btu/hr		
Power	56.36×10^{6}	54.75×10^{6}
Steam	31.56	109.25
Total net output	87.92×10^{6}	164.00×10^{6}

TABLE XVI. - CHEMICAL AND UTILITY

REQUIREMENTS FOR COGOGEN

POWERPLANT

Chemical requirements	
Zinc phosphate, lb/hr	452
Polymeric dispersant, lb/hr	150
Biocidic, lb/hr	76
H_2SO_4, lb/hr	1661
Holmes-Stetford chemical mix, lb/hr	0.8
Soda ash, lb/hr	18.5
Utility requirements	
Water, gal/min	[a]190
Nitrogen, ton/day	12
Natural gas, ft^3/min	[b]674

[a]Based on 26 000 lb steam/hr for heating load.

[b]Based on 35 days/yr steam production from natural gas.

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4. Title and Subtitle CONCEPTUAL DESIGN STUDY OF A COAL GASIFICATION COMBINED-CYCLE POWERPLANT FOR INDUSTRIAL COGENERATION		5. Report Date March 1981
		6. Performing Organization Code 778-46-12
7. Author(s) Harvey S. Bloomfield, S. G. Nelson, H. F. Straight, T. K. Subramaniam, and R. G. Winklepleck		8. Performing Organization Report No. E-723
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9. Performing Organization Name and Address National Aeronautics and Space Administration Lewis Research Center Cleveland, Ohio 44135		11. Contract or Grant No.
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15. Supplementary Notes

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16. Abstract

The feasibility of a coal gasification combined-cycle cogeneration powerplant was examined for the NASA Lewis Research Center in response to its energy needs and to National policy aimed at decreasing dependence on oil and natural gas. The powerplant would provide the steam heating and baseload electrical requirements of the Center while serving as a prototype for industrial cogeneration and a modular building block for utility applications. A conceptual design study by the Davy McKee Corp. was conducted under NASA Contract NAS3-22105-AE to assess technical feasibility, environmental characteristics, and economics. The study included screening of candidate gasification, sulfur removal, and power conversion components; definition of a reference system; quantification of plant emissions and waste streams; estimates of capital and operating costs; and a procurement and construction schedule. On the basis of the results the proposed powerplant is technically feasible and environmentally superior and has the potential to be economically attractive at maturity.

17. Key Words (Suggested by Author(s))	18. Distribution Statement
Coal; Gasification; Cogeneration; Combined cycle; Low-Btu gas	Unclassified - unlimited STAR Category 44

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