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Development of standardized air-blown coal gasifier/gas turbine concepts for future electric power systems — Source link

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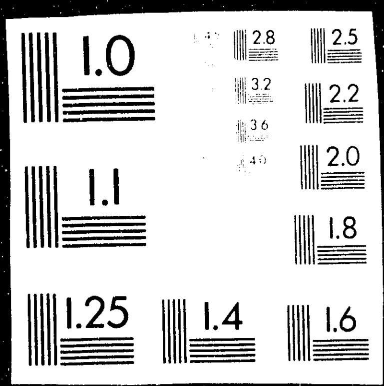

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DEVELOPMENT OF STANDARDIZED AIR-BLOWN COAL GASIFIER/GAS TURBINE CONCEPTS FOR FUTURE ELECTRIC POWER SYSTEMS

Volume 1

Final Report

By
R. S. Sadowski
M. J. Brown
J. C. Hester
J. T. Harriz
G. J. Ritz

February 1991

Work Performed Under Contract No. AC21-89MC26291

For
U.S. Department of Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
CRS Sirrine, Inc.
Greenville, South Carolina

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February 1991

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Executive Summary:

The objective of this study is to develop standardized air blown fixed bed gasification hot gas cleanup integrated gasifier combined cycle (IGCC) systems.

The standardized IGCC gasifier system is to be compatible with three sizes of coal plants, 50 MW(e), 100 MW(e), and 200 MW(e). It is to be operated so as to produce hot raw gas intended for hot gas cleanup and direct combustion in a gas turbine without quenching.

The data reviewed was developed principally by the Department of Energy's Morgantown Energy Technology Center (METC), General Electric (GE), the Lurgi Corporation, Westinghouse, Asea Brown Boveri, Thermoflow. and British Gas Corporation, and the Electric Power Research Institute (EPRI). The data generated was developed principally by C.R.S.Sirrine, Inc. utilizing the GTPro and Mesa combustion turbine and steam cycle performance programs, North Carolina State University, and Physical Sciences Incorporated.

Historical information reveals that maximum coal inputs (hence raw gas outputs) to fixed bed systems vary significantly due to wide ranges in coal reactivity, caking and ash fusion characteristics. Gasification outputs appear to be reduced to less than 50% of rated capacity when operating on highly caking and low fusion coals. Gas compositions vary with coal composition as would be expected. However gas composition also varies greatly based upon steam use rates which are governed by ash fusion temperatures and in some cases grate cooling requirements.

In attempting to understand fixed bed performance several gasifier concepts currently at, or near commercially developed, were evaluated. Available gasifier options considered include entrained bed, fixed bed slagging gasifiers, fixed bed non-slagging gasifiers, and a steam fluidized bed gasifier. These were evaluated against desired IGCC criteria with the result that no available gasifier completely meets all the criteria. The Lurgi Mark IV fixed bed non-slagging bed gasifier comes closest to meeting all of the governing criteria.

Gas turbine compressor surge is a potential limiting factor in power output and efficiency when applied to the steam cooled air-blown fixed-bed coal gasification IGCC system. Water injection for gasifier temperature control reduces this concern.

Although historical information reveals that maximum coal inputs (hence raw gas outputs) to fixed bed systems vary significantly due to wide ranges in coal reactivity, caking and ash fusion characteristics, the selection of standardized modular components assumes the successful near term development of air-blown fixed bed gasifiers capable of operation without capacity reduction due to coal quality changes over the range of US coals contemplated.

It has been determined that the formation of stickey tars and asphaltines during the devolitization process is the main cause of subsequent agglomeration leading to channeling, reduced coal/air/steam reactions, and hence output capacity reductions. Two approaches to dealing with this problem are postulated herein. The first provides for a mechanical means of breaking up agglomerates as and once they have formed. The other is aimed at preventing the inception of agglomeration.

The results of this study indicate that although the anticipated first system costs will be relatively high, the assumption of pre-engineered standardized and modularized systems for Commercial Gasification IGCC Applications (CGIA) systems results in an "Nth unit" total facility cost of under $1,000/kwn in sizes larger than 200 MWe. The resultant ten year levellized cost of electricity (COE) reflected the low CGIA standardized plant cost advantage.

This study also identified existing coal fired utility power plants as near term candidates for standardized CGIA application. While many consider conventional flue gas scrubbers as the economical solution to the emissions concerns of large coal fired utilities, such systems are expensive and adversely affect power plant efficiency by consuming significant quantities of power which would have otherwise been available to the grid. In effect, while reducing stack emissions, scrubbers return reduced plant electricity output for their significant expense. Retrofitting and repowering existing coal fired power plants with CGIA results in much lower emissions than currently available commercial scrubber systems plus very substantial increased power output for the same coal input for which the facility has already been designed.

There is solid justification for the consideration of the addition of CGIA systems to existing coal fired utility plants. The majority of the most costly of the capital cost items of the power plant already exist. These include coal receiving/handling/storage/reclaim, water sourcing/purification/treatment/disposal, electricity generation/conditioning/distribution, and the most costly of all, the boiler island itself. Unlike other repowering strategies which require replacement of the boiler island, this study presents a way to simply add on the IGCC system to the existing coal plant with minimum modification to the existing infrastructure. The result is an approximate 20% increase in power output while reducing the plant's stack gas emissions by in excess of 99% for SO2, 95% for NOx, 99+% for particulates, and 25% for CO2.

A survey, in the form of a questionnaire, was also conducted at the 1990 Cogeneration and Independent Power Production Congress held in Boston, Massachusetts. The majority of the survey respondents had utilized coal in the past (63%) and present (50%), and a greater majority (75%) expected to be burning some coal in the future. While most (75%) believe coal is presently environmentally safe to burn, all (100%) believe coal will be environmentally safe to burn by the year 2000. Most (63%) do not expect to burn more coal annually in the next ten years.

The average expected turnkey capital cost for an IGCC coal fired plant was $1340/kWn. Additionally, the largest group (although all were minority preferences - 23%) would prefer to purchase their coal combustion and emissions control equipment from Babcock & Wilcox.

Two thirds would prefer to license coal combustion and emissions control technology from the Electric Power Research Institute (EPRI). In this case, they would expect to then select their own equipment supplier who would furnish the equipment under an EPRI license.

When given a choice of environmental, efficiency, and cost factors, the respondents' were primarily cost conscious, particularly with "cost of electricity". The environment was of secondary importance, and efficiency third. The vast majority (88%) would buy a coal fired facility if (question 8) its cost of electricity was 5¢/kwh, plant cost was $1,000/kwn, FERC efficiency was 38% (or utility cycle efficiency was 41%), it had 99% sulfur removal, its NOx emissions were 0.1 lb/MBtu, and it produced elemental sulfur as a marketable waste product.

The business and financial communities require firm guarantees of unit performance, the proof of which must be borne out under the scrutiny of their own independent "due diligence" engineering reviews. Therefore, although the "N'th" unit will be financeable, the initial units which will be required to demonstrate satisfactory performance must be innovatively developed and financed.

The standardized IGCC gasifier system is to be compatible with three sizes of coal plants, 50 MW(e), 100 MW(e), and 200 MW(e). It is to be operated so as to produce hot raw gas intended for hot gas cleanup and direct combustion in a gas turbine without quenching the gas.

The data reviewed was developed from the principal investigator's experience in the development of stoker, pulverized and fluidized coal combustion systems in the cogeneration and independent power production (IPP) industries. In addition, information developed by the Department of Energy's Morgantown Energy Technology Center (METC), CRS Sirrine, Inc., and that of a number of cogeneration and independent power production developers have been subjectively evaluated in the development of this study.

The "Commercialization Plan" contemplated for this emerging product to serve a burgeoning power production market was developed with the recognition that first unit implementation looms as the greatest threat to timely introduction of this concept for widespread use in the cogeneration, independent power production, and utility industries. It includes an unorthodox approach to licensing via the Electric Power Research Industry (EPRI) or a similar independent organization capable of unbiased evaluation and sanctioning of desirable technological concepts for faster implementation of the CGIA technology scheme in the earliest possible timeframe. Process guarantees are expected from the system developer while hardware and performance guarantees are from sub-system equipment manufacturers.

It is also sensitive to the ongoing developmental efforts by others such as those under the DOE's Clean Coal Technologies program. Such heroic efforts to demonstrate full scale novel clean coal utilization technologies should be lauded and supported in every conceivable way.

In the spirit of working along a slightly different path from the norm, this plan for commercialization takes some seemingly widely divergent (however necessary) routes to expidite the process of development, demonstration, and bringing the concept to an industry that would like to immediately implement it if it could be considered technologically proven and thus financeable.

Since additional development of a fixed bed gasifier is currently needed before the economic goals of this study can be realized, it is believed that the cogeneration, independent power production, and utility industries will not endorse it until such time that the improved gasifier is demonstrated. Therefore, this study proposes the retrofitting/repowering of either an existing coal fired utility facility which is perhaps nearing retirement, or a similar cogen/IPP facility as the fastest route to achieve commercial status. An existing coal fired facility is appropriate because it presumably already contains most of the infrastructure necessary to support a coal gasification endeavor.

Once commercial status is reached, it is proposed that an independent utility industry representative organization evaluate the demonstrated CGIA retrofitted plant, and using its own criteria, agrees to sanction the technology (assuming it is acceptable). The developer of the CGIA technology would then merely license the technology to the utility industry through the third party (EPRI or equal). In this manner, any utility user could select the builder of the plant who would license it through the industry representative from the CGIA developer. Therefore, if utility A prefers vendor AA to build the plant perhaps because vendor AA previously had built the existing facility, vendor AA would pay a license fee through EPRI to the CGIA developer (similar to the way Lurgi licenses their gasifiers). The value of this scenario is its ability to immediately implement the CGIA concept simultaneously to all users through all qualified vendors. This maximizes CGIA utilization. Since the CGIA developer would provide process guarantees and equipment manufacturers the hardware and performance guarantees, the third party licensing authority would provide only their sanction of the technology (no guarantee liability).

Coal gasification processes are even more difficult to classify and categorize than coal combustion processes because it seems more schemes are contemplated for gasification than for combustion. Some gasification systems contemplated might begin with fixed beds and lump coal, then graduate to crushed coal which allows a range from slug flow to fast elutriative systems to be plausible. Finally, pulverized coal systems typically with molten slag tapping rounds out this array of processes under consideration.

For purposes of this report, the various types of coal gasification schemes have been divided into three classes: entrained, fluidized and fixed bed types.

Consideration was given to the attributes of the various gasifier types consistent with how well each type is perceived to be capable of handling each of a significant number of potential constraints. The summary table following rates the gasifier types from the perspective of the specific boundaries of this contract (ie. Air Blown, Hot Gas Cleanup, FSI=8, all US Coals, AFR Reducing 1900F to 2700F+, Run of Mine Coal Size, Pressure to 600 psia).

Experience with fixed beds and the MBG fluid bed operating on **caking coals** has not been encouraging. Allowing for the development of a stirrer mechanism and longer residence time in the MBG raised our rating in this category to "fair". Both the entrained beds and PyGas were rated "excellent" since both feed crushed or pulverized coal in a manner which averts the adverse consequences of agglomeration due to caking of highly swelling coals.

Since the Lurgi gasifier has a long history of succerssfully dealing with all but the lowest coal **ash fusion range** characteristics by carefully controlling bed temperature, it received a "good" rating in this category. Since PyGas also overtly controls bed temperature while also preventing agglomeration (unlike other fixed bed gasifiers), it received an "excellent" rating. Entrained beds received a "poor" rating since historcally, air blown pulverized coal fired utility boilers have demonstrated the inability to maintain molten ash taps for the majority of coals in the USA. Fluid Beds also received a "poor" rating, but for just the opposite reason to entrained beds. It is known that low fusion temperature coals suffer from agglomeration and subsequent clinkering in fluid bed combustors in an oxidizing atmosphere. Adding to this the lowering of the fusion temperature of most US coals in a reducing atmosphere results in added concern.

Tar production is a valid concern for caking coals in fixed beds resulting in only a "fair" rating. A "poor" rating was averted only by virtue of the hope that some fixed bed gasifiers might effectively recycle tars back to the gasifier "hot zone". Since PyGas does force the products of pyrolysis through the "hot zone" it received an "excellent" rating. Since entrained beds operate at high enough temperatures to crack any forming tars, they also received an "excellent" rating. Fluid beds operate at the lowest temperature of any of the gasifier types which adversely affects their ability to crack tar. According to MBG, their fluid bed requires twenty seconds to crack tars formed by caking coals. Since other fluid bed advocates believe that tars can be cracked at the 1600 F operating temperature (given sufficient residence time) it was felt that a rating of "good" was justified.

The hotter the gasification process, the greater the potential for **volatilized alkali** production. Therefore the entrained bed types rated "poor" in this category. Fluid beds also rated "poor" even though they produce considerably less volatilized alkali than entrained beds because of the tight restrictions placed on these trace metals by turbine considerations. This is compounded by the high fines carryover of fluid beds and the likelihood that sub-micron fines will evade collection devices and carry condensed alkali to the turbine where it can re-volatilize and condense on turbine blades. Fixed beds rated "good" since most of the alkali volatilized becomes condensed carrying over fines at the low temperatures associated with fixed bed gasifiers. PyGas rated "excellent" because it forces any volatilized alkali to pass through the ash bed as endothermic reaction cooling causes alkali condensation onto the exiting ash. In addition, ash constituents known to promote alkali removal exist in sufficient quantities in many coal ashes to effectively catalyze the process in the PyGas case.

Entrained beds rated "poor" on **air blown limitations** strictly due to the previously identified air blown pulverized coal fired utility experience of limited coal tapability characteristics. This limitation would not exist for oxygen blown entrained beds (oxygen blown is preferred by most entrained bed gasifier protagonists) due to the considerably higher operating temperatures attendant with oxygen gasification. Fixed beds were rated "good" because of sufficient past known operating experience of air blown systems. Both the fluid bed and PyGas types were rated "excellent". Fluid beds because of their past operational successes when air blown in oxidizing atmospheres, and PyGas because of its past successful experience with air blown pyrolyzers, and since it provides for such careful control of its process temperature when air blown.

Fixed beds were rated "fair" with respect to **surge margin limitations** because a significant amount of operating data required high enough steam flows for bed cooling to exceed gas turbine compressor surge margin limitations. The remaining three gasifier types were all rated "excellent" since they all are capable of minimizing the amount of steam fed to the gasifier.

Fines carry over from the gasifier is the first of the less significant potential constraints of gasifiers. In this regard, both the fixed and fluid beds were judged "poor" because fluid beds have inherently high fines carryover and many fixed beds feed coal very near to where product gas exits enhancing carry over potential. The entrained beds were rated "excellent" due to their unique molten ash particulate removam mechanism. PyGas was also rated "excellent" since coal fines must traverse through a torturous path where they tend to accumulate and exit with the ash rather than make the low velocity sweeping turn to exit with the coal gas.

Entrained beds produce very high **exit temperature** which earned them a "poor" rating as the hot gas cleanup unit (HGCU) ideally requires approximately 1200 degrees F gasifier exit temperatures. Cooling the coal gas with water spray potentially produces too much water vapor for the gas turbine, and cooling via heat exchangers shifts energy recovery toward the Rankine and away from the preferred Brayton thermodynamic cycle. Fixed beds produce lower than optimal exit temperatures especially for high moisture coals such as sub bituminous coals and lignites. For this reason, they were also rated "poor". Fluid beds were judged "fair" because at 1600 F less cooling is required to reach the optimum exit temperature. PyGas was rated "excellent" owing to its ability to control its exit temperature to produce the optimum temperature for the HGCU inlet.

Entrained beds rated "excellent" for **carbon utilization** as they have demonstrated very low carbon content in the quenched bottom ash. Fluid beds rated "poor" because it is known that they require additional ash combustion in a separate burner to consume the high carbon remaining within their residual ash fraction. Fixed beds rated "good" since they have a reasonably good experience record of ash carbon minimization under optimized operating conditions. PyGas also rated "excellent" because it operates with similar residence times to fixed bed gasifiers while exposing much more coal surface area in the form of porous pyrolyzed char to promote carbon utilization. In addition, PyGas provides for a carbon burnout zone just above the grate similar to other fixed bed gasifiers.

Thermal-phoresis potential is greatest for the fixed bed gasifier type which consequently rated "poor" in this category because of low exit temperatures combined with uncracked volatilized tar in its product gas. Fluidized beds rated "good" because although their operating temperature and geometry tends to indicate at least some probability of tar escape with the product gas, they may develop long enough residence times to crack the tar as postulated by the MBG gasifier. The entrained bed and PyGas rated "excellent" here since they both operate at sufficiently high temperatures to crack any tars and keep exit piping sufficiently hot.

Both the entrained and fluid bed gasifiers rated "good" for **ammonia and cyanide** production minimization because although they both produce the nitrogen bearing compounds, their ability to minimize water content will likely keep such generation to a reasonable minimum. Fixed beds rated "poor" due to their past history of relatively high production rates of these nitrogenous compounds particularly when higher steam flows are required. Since PyGas minimizes steam introduction into the gasification process, it minimizes ammonia and cyanide generation.

Even though the batching process is a negative feature, fixed bed gasifiers were judged "excellent" for **pressure containment** entirely due to Lurgi's past successes at up to

600 psia operating pressures. The other types of gasifiers were all rated "good" because they have yet to consistently demonstrate up to 600 psia containment. The other types do have the ability to improve upon the fixed bed batch feeding concept, because they are inherently continuous feed processes which can be operated in an oxidizing (pneumatic feed) mode at relatively low coal feed temperatures.

Since most fluid and fixed bed gasifiers introduce coal via lock hoppers adjacent to the gasification vessel hot raw gas enters the lock hopper each time coal is fed into the gasifiers. This then requires a sophisticated and relatively expensive purge system to insure the hot raw gas does not leak into the raw coal feed system. This earned both a "poor" rating in the category of **coal feed system losses**. Both entrained and PyGas coal feeds are continuous and are pressurized far upstream of the gasifier vessels where no hot raw gasses can accumulate. This alleviates their systems from coal gas related losses, hence they are both rated "excellent" in this category.

Gasification **capacity** is logically a function of operating temperature which tends to hasten the required reactions. Therefore, entrained bed gasifier types are rated "excellent", while fluidized bed types are rated "poor" since their's has the lowest peak operating temperature. Although they operate at approximately 2300 F peak temperatures, fixed bed gasifiers are only rated "fair" because they gasify lump sized coal which is somewhat slow to react. PyGas rates "good" because it operates at the temperature and residence time of a fixed bed gasifier and the coal size gradation of a fluid bed while exposing much more coal surface area in the form of porous pyrolyzed char to promote carbon utilization.

Since entrained bed gasifiers must maintain very hot molten conditions to tap their slag formations, they are likely to have only "fair" **turndown** capability. Since fluid bed gasifiers are limited by fluidization velocities, they too rate only "fair" in turndown capability. Fixed bed gasifiers have historically been capable of reasonably "good" turndown of in excess of 2 to 1. Similarly, PyGas is expected to function much like a fixed bed gasifier from a turndown standpoint. Since its pyrolyzer section has been demonstrated to be capable of operating in excess of 5 to 1 turndown, it was also rated "good" in that category.

An item unrated in the summary table, but a very important issue is efficiency. IGCC systems which maximize the Brayton thermodynamic cycle, and those in combination with Rankine thermodynamic cycles which minimize stack oxygen will tout the highest efficiency. Hot gas cleanup units (HGCU) for sulfur capture also minimize system heat loss without concern for low temperature corrosion attendant with cold gas sulfur recovery systems which currently advertise heat recovery. Current fast developing sulfur removal and recovery schemes like zinc ferrite, zinc titanite, and copper based hot gas cleanup systems are expected to be an integral part of the low cost IGCC system contemplated herein.

Summary Table

Gasifier Attributes

Gasifier Type	Entrained Bed (Slag Tap)	Fluidized Bed (Dry Ash)	Fixed Bed (Dry Ash)	Pyrolysis Gasification (PyGas) (Dry Ash)
Potential Constraints				
(* Denotes Major Area of Impact)				
*Caking Coals	E	F	F	E
*Ash Fusion Range (Reducing)	P	P	G	E
*Tar Production	E	G	F	E
*Volatilized Alkali	P	P	G	E
*Air Blown Limitations	P	E	G	E
*Surge Margin Limitations	E	E	F	E
Fines Carry-over	E	P	P	E
Exit Temperature	P	F	P	E
Carbon Utilization	E	P	G	E
Thermal-Phoresis	E	G	P	E
Ammonia & Cyanide Production	G	G	P	E
Pressure Containment	G	G	E	G
Coal Feed System Losses	E	P	P	E
Capacity	E	P	F	G
Turndown	F	F	G	G

Key: E - Excellent
G - Good
F - Fair
P - Poor

The above judgements were made on the basis of the entire range of coal characteristics established for consideration in this project.

Summary Table

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Status of Low BTU Gasification Systems for a Standardized IGCC Gasifier

Section 1

January, 1991

Work Performed Under Contract No. DE-AC21-89MC26291

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

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1.1 Summary

This section includes the assimilation of empirical data and industry experience describing fixed bed gasifiers as a basis for assessing the status of such gasifiers in IGCC systems.

The standardized IGCC gasifier module is to be compatible with three sizes of coal plants, 50 MW(e), 100 MW(e), and 200 MW(e). It is to be operated so as to produce hot raw gas intended for hot gas cleanup and direct combustion in a gas turbine without quenching the gas.

Historical information reveals that maximum coal inputs (hence raw gas outputs) to fixed bed systems vary significantly due to wide ranges in coal reactivity, caking and ash fusion characteristics. Gasification outputs appear to be reduced to less than 50% of rated capacity when operating on highly caking and low fusion coals. Gas compositions vary with coal composition as would be expected. However, gas composition also varies greatly based upon steam use rates which are governed by ash fusion temperatures and in some cases, grate cooling requirements.

In attempting to understand fixed bed gasifier performance, several gasifier concepts currently at, or near commercially developed, were evaluated. Available gasifier options considered include entrained bed, fixed bed slagging gasifiers, fixed bed non-slagging gasifiers, and a steam fluidized bed gasifier. These were evaluated against desired IGCC criteria with the result that no available gasifier completely meets all the criteria. The Lurgi Mark IV fixed bed non-slagging bed gasifier comes closest to meeting all of the governing criteria.

The typical scope of supply and historical roles of various suppliers with respect to the fixed bed gasifier are also reviewed in this section of the report.

1.2 Gasifier Concepts Overview

The criteria against which each candidate gasifier was measured is as follows:

- Operates as an Air Blown Gasifier
- Operates on Caking Coals
- Operates on Widely Varying Ash Fusion Ranges
- Operates with Run of Mine Coal (High Fines Content)
- Operates at 600 psia
- Minimizes Tar Production
- Minimizes Volatilized Alkali Production
- Minimizes Ammonia Production
- Maximizes Heating Value at 1200 deg F Exit Temperature

In order to better understand the effects of various parameters upon gasifier performance, an overview of various gasifiers which were subjectively judged "near commercial" for the application under consideration was conducted. The results of that overview are as presented in the following sections.

1.2.1 Overview Descriptions of Candidate Gasifiers

1.2.1.1 Lurgi Fixed Bed

Lurgi has significant experience as shown in Table 1 (commercial since 1936), mostly with oxygen blown gasifiers on non-caking coals. The gasifier device (in various diameters) is a single stage mature mechanical design applicable to a limited coal range. It is generally acknowledged that the design requires a stirrer to effectively utilize caking coals. In addition, coal fines [1] (less than 3.2 mm, 0.125 inches) beyond approximately 10% generally cannot be tolerated in the feed; therefore, fines must be separated from the coal feed and either briquetted or fired elsewhere. Tars which are produced must either be removed or their condensation planned for following the gasifier exit.

Table 1

FIXED-BED GASIFICATION COMMERCIALLY PROVEN

O LURGI GASIFIERS (Based on O2 Operation):

MARK IV 650 T/D 4 METER DIAMETER
MARK V 1000 T/D 5 METER DIAMETER

O SASOL I - 16 MARK IV GASIFIERS FOR OVER 30 YEARS

O MARK V GASIFIER INSTALLED AT SASOL I - 1979

O SASOL II - 36 MARK IV GASIFIERS - 1979
O SASOL II - 40 MARK IV GASIFIERS - 1982

O SASOL III - TWIN TO SASOL II PLANT - 1982

O GREAT PLAINS GASIFICATION PLANT - 14 MARK IV

O SASOL GASIFIERS - 2 YEAR MAINTENANCE SCHEDULE WITH 3-AND 6-MONTH INSPECTIONS

1.2.1.2 British Gas/Lurgi (BGL)

The BGL approach to solve the above-referenced Lurgi limitations is to inject coal fines and tar through lower bed tuyeres and to operate as a slagging gasifier. In the late 1970's a six (6) ft diameter oxygen blown slagging gasifier was tested on Pittsburgh #8 coal with 25% fines without adverse effects on gas quality.

One distinct advantage of all slagging gasifiers is their benign bottom ash. Concurrently, this slagging approach results in nearly 100% carbon utilization. Preheated air is required to 1,000F to maintain a slag pool.

Indications are that BGL has experience with the Lurgi stirrer [2], and that they successfully gasified Pittsburgh #8, Ohio #9, and British coals of equivalent strong caking tendencies with the stirrer. BGL claims to be able to start up from an empty state to full gas production in 4 hours. The device is a single stage mature mechanical design for a wide coal range up to FSI=8 and 25% fines (below 1/4 inch) provided a deep bed stirrer is incorporated.

1.2.1.3 Lurgi Fluidized Bed

The Lurgi fluidized bed coal gasifier [3] is the result of Lurgi's desire to handle a wide variety of coals. As a higher exhaust temperature fluidized bed, it is likely to produce significant volatilized alkali. Lurgi's current focus is toward this unit as opposed to the fixed bed configuration based upon its ability to handle a wider range of coals and coal fines.

1.2.1.4 Dow

Dow startup occurred in April, 1987 for a 2,200 TPD entrained bed two-stage oxygen blown gasifier [4]. The initial stage is a slagging gasifier which utilizes a ground coal slurry and operates at 2,400F. The second stage admits additional coal slurry to boost the heating value of the gas to approximately 200 BTU/cu.ft.

This gasifier is NOT AIR BLOWN. All of Dow's experience has been based on oxygen. Private indicators are that the Dow technology may be approaching near commercial basis for air blowing, but only as a licensed product with no process guarantees.

In the Dow demonstration unit, they have provided a 100% standby gasifier, and report a plant availability of 50% overall. Their most recent availability is 80% over a three month period.

1.2.1.5 Shell Coal Gasification (SCG)

The Shell coal gasifier [5] is NOT A FIXED BED type. In addition, it is NOT AIR BLOWN; however, it is a commercial system.

Shell appears unprepared to guarantee or even offer their gasifier on a commercial basis [5] until their Netherlands demonstration project is complete. Their oxygen blown 2000 TPD 250 MW Netherlands facility will begin operation at the end of 1993.

In their system pulverized coal is dried to 2% moisture, pressurized to 430 psig, and fed into the lower part of an empty vessel with oxygen and steam. The entrained-bed flame temperature reaches 3,000F, but the outlet from the gasifier is normally 2,700F. The bottom ash is removed as slag. Fly ash is removed downstream of heat recovery in dry form.

1.2.1.6 Texaco

The Texaco coal gasifier [6] is NOT A FIXED BED type. In addition, it is NOT AIR BLOWN; however, it is a commercial system. Based upon this review, it does not appear that significant test experience exists in an air blown mode.

1.2.1.7 MBG Coal Gasification

The MANGHH coal gasifier [7] is NEITHER A FIXED BED NOR AIR BLOWN. However, as it reportedly is a near commercial device which is to be furnished on a guaranteed performance basis, it shall be included in any overview and pursued as a candidate CRS Sirrine Engineers, Inc. gasifier.

It is anticipated that this device will operate on all US bituminous and sub-bituminous coals regardless of caking properties, and regardless of fines content since the coal feed is in pulverized form. Therefore it has the potential for much wider applicability than currently commercial fixed bed air blown gasifiers.

Its product gas, at 312 BTU/scf (51%H_2, 11% CH_4), may not require any significant combustor modifications to be acceptable to current gas turbine combustion systems.

Because it operates at 1500F, tar condensation is not likely to be an issue, therefore it may solve three major fixed bed gasifier limitations, (i.e., caking coals, fines, and tar).

1.2.2 Process Descriptions of Candidate Gasifiers

1.2.2.1 Lurgi Fixed Bed

The process consists of high pressure coal gasification in a gravitating bed by injection of steam plus air (or steam plus oxygen) with countercurrent gas/solid flow. Sized coal (1 1/2 inch x 1/4 inch) is fed through a lock hopper arrangement into the top of the gasifier. The resulting low BTU gas (100-180 BTU/std cu ft) is normally water quenched to avoid tar, oils, phenols, ammonia, and particulate contamination of the combustible produced gas (Table 2).

Table 2
LURGI GASIFIER CHARACTERISTICS

- Gasifier dimensions:
  - 2.5 to 3.8 m (8.3 to 12.4 ft) in diameter
  - 2.1 to 3.0 m (7 to 10 ft) coal bed depth
  - 5.8 m (19 ft) approximate overall height of coal gasifier itself
  - 12.5 m (41 ft) height flange to flange including coal and ash locks

- Bed type and gas flow: gravitating bed; continuous countercurrent gas flow; lateral gas outlet near the top of the gasifier.

- Heat transfer and cooling mechanism: Direct gas/solid heat transfer; water jacket provides gasifier cooling.

- Coal feeding mechanism: Intermittent, pressurized lock hopper at the top of the gasifier which dumps the coal onto a rotating, water-cooled coal distributor.

- Gasification media introduction: Continuous injection of steam plus air or oxygen at the bottom of the coal bed through a slotted ash extraction grate.

- Ash removal mechanism: Rotating, slotted grate at the bottom of the coal bed; refractory lined, pressurized lock hopper collects the ash and dumps it intermittently.

- Turndown to approximately 50% acheivable.

- **Special Features:**
  - Direct quench gas scrubber and cooler which knocks out particulates, tars, oils, phenols and ammonia is attached to the gasifier at the gas outlet.
  - Gasifier water jacket supplies approximately 10 percent of the required gasification steam.
  - Rotating distributor provides uniform coal bed depth.
  - Tar injection nozzle at the top of the gasifier permits recycle of by-product tar which also helps to reduce coal fines carryover in the product gas (optional feature).
  - Rotating, optional water cooled coal bed agitator aids the gasification of strongly caking coals.

In the air blown mode, the device is output limited by volume and velocity increase over oxygen blown operation. Preheating of the inlet air to assure gasifier exiting temperature in excess of tar condensation temperatures is limited by the materials of construction of the grate and grate drive.

This design may produce excessive fines carryover and experience clinkering from interstitial fines plugging during devolatilization when caking coals exceed 10% fines. The expected performance of the gasifier air blown on caking coals is directly related to the Lurgi stirring mechanism capabilities to deal with clinker formation. It is known that the Lurgi stirrer was successfully tested (per DOE) on moderately caking coals at SASOL in a 12 ft diameter gasifier. In general, however, Lurgi requires pre-heating to condition highly caking coals. This is unattractive owing to the added complexity of the system.

Typical Lurgi performance characteristics when air blown at 300 - 450 psi are as follows (8,10):

Input:
Low Caking Coal Flow = 21 tph typ (10-26.5 Range)
High Caking Coal Flow = 13.8 tph typ (6.4-16. 4 Range)
Steam Flow = 14 tph typ (0.6-1.5 t/t coal)
Air Flow = 44 tph typ (1.3-3.7 t/t coal)
Outputs:
Proportional to diam sq & sq rt of opn press
Gas Quality = 150 BTU/scf (100-180 BTU/scf)
Gas Flow = 79 tph typ (3.75 t gas/t coal per METC)
Gas Flow = 47 MMscfd
H2S = 0.78 tph typ
Tar = 6 tph typ
Ash = 5 tph typ
Ammonia (NH3) = 4000-9000 ppmv (METC)
Volatilized Sodium (NaCl) = 0.028-0.035 ppmv
Volatilized Potassium (KCl) = 0.13-0.16 ppmv
Temperature - 955 F typ
Ash Carryover = 0.96 tph typ (3.7%)

Areas of Technical Concern Include:

- Coal Fines: Must be removed
- Caking Coals: Some stirrer experience; little mfg confidence
- Tar Production: Expect about 5%, maintain above condensation temp
- Ammonia Production: Approximately 0.5% producing NO_X at 3000ppm
- Volatilized Alkali: Little expected @ 1000°F-1100°F exit temp
- Carbon Utilization: Expect 3-10% carbon carryover
- Coal Input per Unit: Limited by coal properties to 6-26 tph.

It is understood that the Lurgi fixed bed gasifier pressurized lock hopper arrangement has an associated thermal loss from gasifier hot gas product venting. Such venting is necessitated by the admittance of hot raw gas product during the coal feed sequence. This hot raw gas is at operating pressure and hence must be vented before the coal bunker side valve is opened to atmosphere. Depending upon where and how the gas is vented, it can be a significant loss to the process.

1.2.2.2 British Gas/Lurgi (BGL)

The British Gas Lurgi (BGL) oxygen blown system was estimated by EPRI to cost 22% less than Lurgi in 1976 [3]. The BGL design utilizes highly preheated oxygen consistent with tap port temperatures which will both maintain molten slag and assure all recycled organic species are burned to extinction, thereby eliminating concerns over sulfur bearing oil and tar compounds. Since BGL is a slagging type gasifier, it is claimed to be capable of handling all US coals.

The BGL design provides for very high operating temperatures in the slag tap (and hence char burning) area which increases its output capacity. The negative aspect of this feature may be a greater propensity for volatilized sodium leaving the gasifier. The quenched slag is easily handled and "environmentally benign" per DOE.

The BGL gasifier unit has a good history of feeding a coal fines/water slurry directly into the grate tuyere area without output degradation.

Typical BGL results for their 71/2 ft dia.unit are as follows:

- Various Coals Including Pittsburgh, #8 Coal, 1 1/4 in x 1/8 in size, FSI 7.5
- Rated Coal Input = 21 tph (Equiv Coal Input @ 12.63 ft ID=60 TPH)
- Maximum Achieved Unit Power Output = 27 MW (Equiv. Unit Pwr Out = 75 MW)
- Steam/Oxygen =0.6 - 0.9 t/t coal
- Steam Consumption =0.3 - 0.5 t/t coal
- Oxygen Comsumption =0.5 - 0.6 t/t coal
- Output Gas = 298 - 357 BTU/scf
- Water Quenched Ash

Areas of Technical Concern for the BGL unit are as follows:

- May freeze tap port on high fusion coal when air blown
- Coal fines carryover: must be collected and reinjected into hot zone
- Caking Coals: Only short term O_2 blown experience
- Est. Volatilized Sodium (NaCl) = 0.028-0.035 ppmv (perhaps higher)
- Est. Volatilized Potassium (KCl) = 0.13-0.16 ppmv (perhaps higher)

1.2.2.3 Lurgi Fluidized Bed

Lurgi CFB gasification units can be air or oxygen operated. Like the fixed bed processes the CFB can be operated at atmospheric or elevated pressures. The latter is, however, still in the demonstration phase and is available on limited commercial terms.

The advantages associated with the CFB gasifier are as follows:

- Intensive mixing of gas and solids
- High heat and mass transfer rates
- High gasification reaction rates (i.e. high specific throughput)
- Uniform temperature through the reactor (no hot spots)
- Zero tar and oil production
- Insitu desulfurization by limestone addition

The gasification unit comprises the cylindrical, refractory lined reactor and the cyclone for the recycling of solids.

Feed material enters the reactor by means of a screw feeder, located at the reactor's base. Preheated gasification agent is injected into the reactor bottom.

For coals it is sufficient in most cases to crush it to about minus 6 mm.

Expected CFB performance is as follows:

- Coal Throughput = 51 TPH (O2 Blown) @ 13 ft dia & 300 psig
- Gas Quality = 117 BTU/scf (typ air blown)

Areas of Technical Concern for the CFB gasifier are as follows:

- Coal Fines: Not a problem
- Caking Coals: Not a problem
- Tar Production: Not a problem
- Ammonia Production [3]: 8 - 20000 ppmv > Significant NOx Likely on Coal
- Volatilized Sodium [8] (NaCl) = 0.8-23 ppmv
- Volatilized Potassium [8] (KCl) = 2-12 ppmv
- Carbon Loss [3]: High; 65% carbon in dust is also significantly high

1.2.2.4 Dow Gasifier

The Dow gasifier is an oxygen blown entrained bed concept originally developed by Dow to produce synthetic gas for subsequent chemical processing. The system was, according to Dow discussion, optimized to utilize lignite as the source of gaseous chemical feedstocks.

The Dow unit is sized for a nominal coal input of 95 tons per hour. The areas of technical significance for this unit are as follows:

- Coal fines: Compatible since primary fuel is crushed to less than 1/8 inch.
- Caking coals: Compatible since the fuel stream is a ground coal slurry (process not yet demonstrated on highly caking coals)
- Tar Production: Minimal due to high exhaust temps
- Ammonia Production: Minimal due to high exhaust temps
- Volatilized Alkali: Significant due to high temperatures
- Carbon Utilization: Excellent due to recycle and slagging operation

1.2.2.5 Shell Gasifier

The Shell gasifier represents one of the most commercially advanced coal gasifiers and is therefore discussed in greater detail here. According to published information, the Shell Coal Gasification Process (SCGP), is a clean and efficient process for converting coal into fuel gas. It is based on a dry feed, entrained-bed, high-pressure, high temperature slagging design. The process can handle a wide variety of coals, ranging from bituminous to lignite, in an environmentally acceptable way and produces a high purity medium-BTU gas.

Much of the equipment and the expertise required to operate the equipment in the process is widely utilized in other applications both within the utility industry and the petroleum refining/petrochemical industries. Examples include coal receiving, milling and drying, and dry pneumatic coal conveying systems which are very much related to existing utility central station generating facilities. The gasification process is not unlike that of utility coal Cyclone (B&W) and wet bottom Turbofurnace (Riley) applications in that coal is consumed at high temperature and its inorganic fraction is removed from the furnace in molten slag form. Acid gas removal and recovery using the Sulfinol system may be likened to existing petrochemical acid recovery and production processes such as Claus or Stretford, except that apparently Sulfinol is a physical/chemical solvent absorption system unlike Stretford which is a direct oxidation system.

The coal receiving and handling facilities utilized in an SCGP plant are conventional and similar to those already being utilized in many existing coal fired boiler installations. Unloading hoppers, vibrating feeders, conveyors, stackers, and reclaimers well proven at existing coal burning facilities can be readily employed in the SCGP plant.

The coal milling drying unit includes a conventional bowl mill, identical to those used in a pulverized coal boiler. This mill grinds the coal to a specification of 90 wt% less than 88 microns with a maximum of 5 wt% less than 5 microns. As the coal is being ground, it is simultaneously dried to 5 wt% moisture content, utilizing a steam heated inert gas stream that carries the evaporated water from the system as it sweeps the pulverized coal through an internal classifier to collection in a baghouse. By-product nitrogen from the air separation plant is used as makeup inert gas for the drying operation. The dried and milled coal is delivered to the gasifier feed system using a pneumatic conveying system.

A 95% (volume) oxygen stream is supplied by an air separation plant and compressed for delivery to the gasification plant.

Nitrogen from the air separation unit is compressed to provide low pressure and high pressure nitrogen for use in the gasification plant, for makeup inert gas to coal milling and drying, and for transporting coal in the feed system.

Milled and dried coal from the coal milling and drying area is pneumatically transported to the coal pressurization and feeding system. This system consists of a receiving vessel, two lockhoppers, and a feed hopper. The receiving vessel separates the coal from its nitrogen transport medium and then transfers the coal to one of the two lockhoppers. These two lockhoppers are operated on a time cycle such that one is filled and pressurized while the other is emptied and depressurized. Once a lockhopper has been charged with coal from the receiving vessel, it is then pressurized with nitrogen and its contents discharged into the feed hopper. Pressurized coal is continuously withdrawn from the feed hopper and pneumatically conveyed with nitrogen to the gasifier's coal burners.

The nitrogen which is separated from the incoming coal in the receiving vessel is recycled to the milling and drying system through bag filters located in the receiving vessel.

Lockhoppers are widely utilized in materials handling applications. They have proven to be a safe and reliable method for transferring solids under pressure.

In the gasifier, pressurized coal, oxygen and, if necessary, steam enter the pressure vessel through opposed burners. The gasifier consists of an outer pressure vessel and an inner, water-cooled membrane wall. The gasifier wall temperature is controlled by circulating water through the membrane wall to generate saturated steam for subsequent superheating in the syngas cooler. The membrane wall encloses the gasification zone from which two outlets are provided. One opening at the bottom of the gasifier is used for the removal of slag. The other opening allows hot raw gas to exit from the top of the gasifier.

Most of the mineral content of the feed coal leaves the gasification zone in the form of molten slag. The high gasifier temperature (up to 3000°F) ensures that the molten slag flows freely down the membrane wall into a water-filled compartment at the bottom of the gasifier. Flux may be added to the coal feed to promote the necessary slag flow out of the bottom of the gasifier if the ash viscosity of a particular coal would not generate the proper slag flow from the gasifier. As the molten slag contacts the water bath, the slag solidifies into dense, glassy granules. These slag granules fall into a collecting vessel located beneath the slag bath and are transferred to a pair of lockhoppers which operate on a timed cycle to receive the slag. After a lockhopper is filled, the slag is washed with clean makeup water to remove entrained gas and any surface impurities. After washing, the lockhopper is depressurized and the slag is fed to a dewatering bin. This bin is equipped with an inclined screw to lift the settled solids off the bottom of the vessel and deposit them on a conveyor belt for delivery to intermediate storage.

The hot raw product gas leaving the gasification zone is quenched with cooled, recycle product gas to convert any entrained molten slag to a hardened solid material called flyslag prior to entering the syngas cooler.The syngas cooler recovers high-level heat from the quenched raw gas by generating superheated high-pressure steam. The syngas cooler includes superheat, evaporative, and economizer sections.The gasifier and syngas cooler included in the SCGP plant are similar to the water wall boilers which are widely used in other utility processes.

The bulk of the flyslag contained in the raw gas leaving the syngas cooler is removed from the gas using commercially demonstrated equipment such as bag filters or cyclones. The remainder of the solids is washed out in a series of scrubbers (9) and separators. The gas leaving the scrubbers has solids content of 1 mg/m3 and a temperature of 40 degrees C. If not recycled, the flyslag leaving the process is pneumatically conveyed to one of two flyslag lockhoppers. After a lockhopper is filled, the flyslag is purged with high pressure nitrogen to remove any entrained raw gas. After purging, the lockhopper is depressurized and the flyslag is pneumatically conveyed to a silo for intermediate storage. All vent gases from the flyslag lockhoppers and the storage silo are filtered of particulates during discharge.

The gas leaving the bag filters is further purified by passing through a wet particulate removal unit where any residual flyslag is removed to a level of less than 1 ppm. This wet scrubbing system also removes other minor contaminants such as soluble alkali salts. Makeup water is continually added to the wet particulate removal unit to control the concentration of contaminants in the blowdown stream. The contaminated water is sent to the sour water stripping unit to recover the contaminants.

The washed raw gas from the wet particulate removal unit is routed to a catalytic hydrolyzer to convert the minor nitrogen contaminant (hydrogen cyanide) to ammonia, and carbonyl sulfide (COS) to hydrogen sulfide. The gas is heated before entering the hydrolyzer to the appropriate conversion temperature using medium pressure steam. Gas leaving the hydrolyzer is cooled by heat exchange with process makeup water, product gas, boiler feedwater, and/or cooling water.

The last treatment the medium BTU gas receives before it is delivered to the power block is contact with an aqueous MDEA (methyl diethanolamine) solvent to remove hydrogen sulfide in an acid gas absorber. In this absorber, the hydrogen sulfide in the raw fuel gas is absorbed by countercurrent contact with the MDEA solution. Clean medium BTU gas containing about 100 ppmv hydrogen sulfide plus carbonyl sulfide leaves the absorber. This sulfur level is well below that required by current air emission standards for combustion of the fuel gas in the combustion turbines.

A typical composition of the clean medium BTU gas now ready for delivery to the combustion turbines is shown on Table 3.

Table 3
Shell Gasifier Output Composition

Component	Percent Volume
H_2	32
CO	62
CO_2	1
H_2S	26 ppm
COS	77 ppm
NH_3	2 ppm
CH_4	0.03
N_2	4
Ar	0.50
H_2O	0.20
LHV, BTU/lb	5,465
LHV, BTU/scf	288

1.2.2.6 Texaco Gasifiers

One of the most widely utilized coal gasification concepts is the oxygen blown Texaco process. As with the Shell concept presented previously, this widespread acceptance gives it a certain "near commercial" credence which justifies a more thorough review.

The Texaco process is an entrained bed oxygen blown system capable of burning a wide variety of coal sizes and types. This process includes a pulverized coal/water slurry which is introduced at 600 psig into the top of a refractory lined vessel using a specially designed burner. It is mixed with oxygen to produce a partial combustion gas at 2,300 - 2,800°F temperatures. Medium BTU gas results and the ash is removed as molten slag from a slag tap port in the bottom of the radiant cooler below the gasifier reactor vessel.

The hot coal gas and slag from the gasifier reactor discharge into the radiant cooler below which generates 1,600 psig saturated steam. The slag drops into a water pool at the bottom of the radiant cooler and is removed through a lock hopper system. The process proceeds into a convection cooler where more 1,600 psig saturated steam is generated.

The technical issues associated with the Texaco gasifiers are as follows:

- Coal Fines: Good compatibility, but some fines may carry over and be recycled back into the gasifier.
- Caking Coals: Compatible
- Tar Production: Free of tars and phenols
- Volatilized Sodium (NaCl) = 8-46 ppmv
- Volatilized Potassium (KCl) = 4-1000 ppmv
- Carbon Utilization: Excellent
- Coal Input per Unit: 42 tph (15 TPH @ Ube)

Characteristics of the Texaco process are as shown in Table 4.

Table 4
Texaco Gasifier Characteristics

Characteristic	Advantage	Limitation
Experience	Commercial design available and development program exists on second-generation processes.	Less developed than fixed bed
Complexity	No moving parts and has simpler geometry than fluid bed. Water jackets add to system complexity.	Critical design areas include combustor nozzles and heat recovery in presence of molten slag.
Capacity	Highest capacity per unit volume	
Inventory (coal)		Smallest inventory of four generic classes: requires advanced control techniques to ensure safe reliable operation.
Feed Coal		
Type	Any coal may be used without pretreatment.	
Handling	No fines are rejected.	Pulverizing and drying of surface moisture are required. Potential erosion due to gas-solid streams.
Product Gas	Free of tars and phenols.	Ash, char, and sensible heat in gas must be recovered, which reduces efficiency.
Ash Removal	Produces inert slagged ash with low carbon content; fines carried over can be recycle to gasifier.	Higher thermal loss in ash.
Temperature		Highest temperature of four classes (1) causes thermal losses, (2) requires better materials of construction, and (3) requires greater use of oxygen or preheated air which results in higher CO_2 content in product gas.
Operating Range		Process has the least operating range and is limited by need to maintain slagging conditions without degrading refractories.

With regard to operating experience, Cool Water, the best known of the Texaco gasifiers, is one of four full-scale Texaco Coal Gasification plants in commercial operation today.

In a second Texaco project, Tennessee Eastman, a subsidiary of Eastman Kodak, has operated a 900 TPD gasifier at Kingsport, Tennessee since 1983, producing methanol and acetic anhydride. That unit has an onstream factor of greater than 90 percent.

In a third project, Ube Ammonica Industry Co., Inc. owns and operates a 1,650 TPD Texaco gasification plant in Japan for ammonia production. The facility began operations 1984 and has been onstream over 90 percent of the time since startup. Ube has run on petroleum coke and has gasified a variety of coals, including some from South Africa, Australia, and Canada.

The fourth project is Synthesegas Anlage Ruhr (SAR). In the summer of 1986, an 800 TPD gasification plant began operations at the SAR plant in Oberhausen, West Germany. SAR produces syngas as a feedstock to make several organic chemicals. Worldwide, over 90 plants have used Texaco gasification to make syngas from various petroleum feedstocks. Many of the key process components in these plants, such as sulfur removal and recovery equipment, are used routinely in oil refineries and other industries.

1.2.2.7 MBG Coal Gasification

The process consists of high pressure coal gasification in a FLUIDIZED bed by injection of steam plus heat from an indirect in-bed heat exchanger. Run of mine coal (3 inch x 0 inch) is pulverized and then fed through a pressure raising arrangement into the top of the gasifier. The resulting low BTU gas is normally water quenched to increase the heating value (to 312 BTU/std cu ft) and to remove ammonia, cyanide, and particulate contamination.

STEAM blown, the device is output limited by volume and velocity increase which tend to carry over pulverized coal in all but the lowest superficial velocities in fluid bed operation. Preheating of the inlet heat exchange medium (helium in one case, and hydrogen regenerator in another) to assure gasifier exiting temperature in excess of tar condensation temperatures is limited by the materials of construction of the heat exchanger.

There is some concern that this design may produce excessive fines carryover and large levels of volatilized alkali.

The expected performance of the steam blown gasifier on caking coals is expected to be unaffected by caking properties since the coal is pulverized, and the bed is fluidized. Although MANGHH has acknowledged having a pilot plant with some 26,600 hours of operation (33% of which was on caking coals), the system is not available for commercial supply.

Anticipated gasifier performance is as follows:

Input:

Coal Flow = 15 tph typ
Superheated Fluidizing Steam > 1000°F
Operating Pressure = 21 bar
Operating Temperature = 1500F (1490-1526F) (810-830C)

Output:

Gas Quality = 312 BTU/scf
Tar = Likely to be an issue
Ash = Recycling necessary
Ammonia - Unknown status
Volatilized Sodium - Expected to be high
Temperature - 1500F typ
Ash Carryover = Known to require recycle

Areas of Technical Concern are as follows:

- Coal Fines: Carryover may be a problem
- Caking Coals: Compatible
- Tar Production: May be a problem @ 1500F
- Ammonia Production: Unknown
- Volatilized Alkali: High levels; requires subsequent quench
- Carbon Utilization: Estimated @ 95%
- Others
    - Helium media heat exchanger will have materials of construction concerns @ 1500F. This may be acceptable if replacement intervals & cost are reasonable.
    - Undetected failure of in-bed exchanger may cause catastrophic heat release.

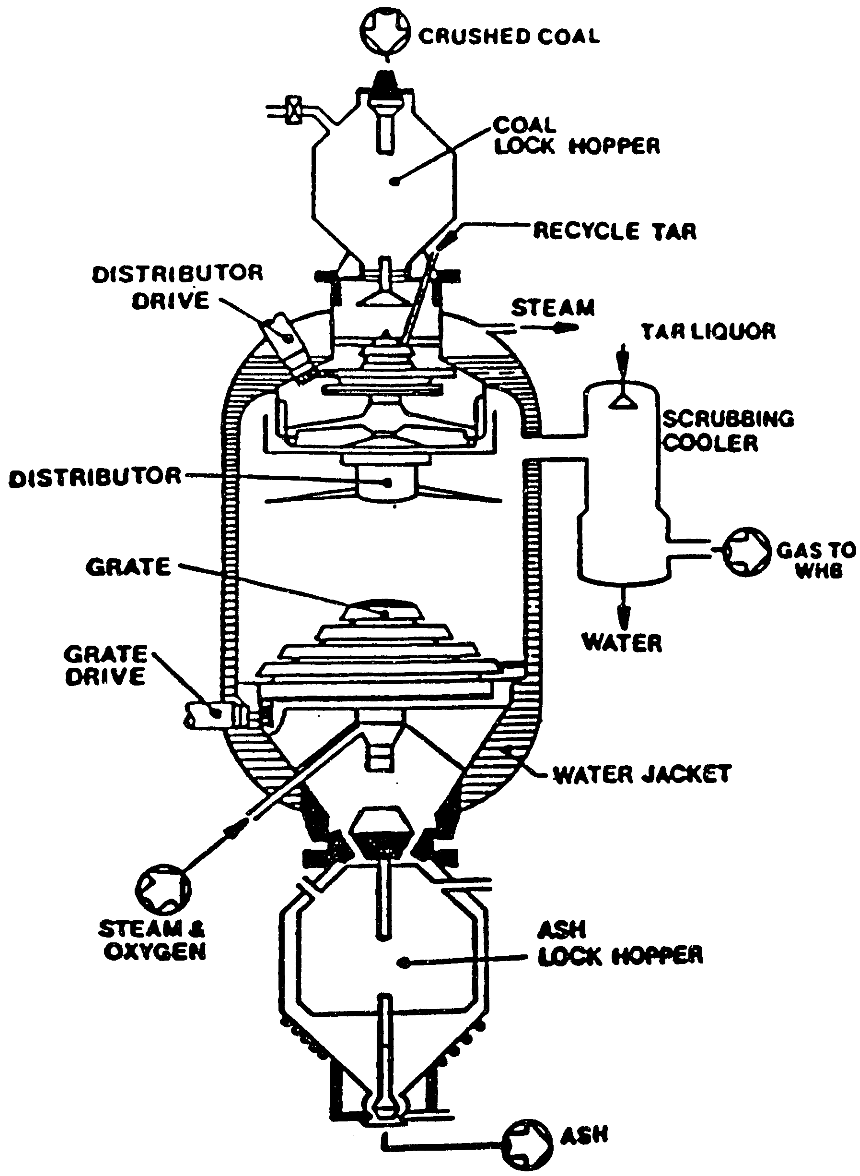
1.3. Estimated System Performance

1.3.1 Performance Discussion

Publically available empirical information was used to generate predicted Lurgi Mark IV fixed bed air blown configuration gas generation rates and gas compositions.

A general synopsis of the Lurgi system was recently developed by METC (Notestein) and is repeated here to establish a basis for subsequent performance comments.

According to METC, with the use of the fixed bed gasifier, there has historically been a problem relative to the use of feedstock coal with a "large" fines fraction (defined as the portion of the coal which is less than 0.25 inch in size). With the conventional Lurgi design, this concern arises for two reasons. First, the water quench liquid based gas cleanup system is susceptible to reduced performance, plugging, etc. as a result of excessive dust/fines being carried over in the raw product gas and depositing in the scrubbing liquor. Secondly, the design of the top of the gasifier does little to reduce the propensity for solids carryover (Figure 1) since the top of the coal bed is essentially at the elevation of the cup shaped pan immediately above the "distributor" blades. The blades turn through the upper portions of the coal bed probably within a few feet of the top of the bed (to maintain porosity of the devolatilization zone and break up any forming agglomerates). The raw gas outlet is very near the top of the coal bed and represents a localized port in a region where a significant portion of the gasifier cross section is unavailable for gas flow (due to blockage by the coal feed and distribution machinery). It is consequently probable that, over at least some portion of the bed surface, local gas velocities are actually accelerating as the raw gas leaves the coal bed, passes through the overbed region, and reaches the gasifier outlet to the scrubbing cooler.



Lurgi pressurized gasifier. (Figure used with permission from Amundson and Arri, 1978.)

Figure 1

Nowacki, Perry ed. Coal Gasification Processes. Noyes Data Corp.; Park Ridge, New Jersey; 1981.

As a result, any fines which are picked up by the gas leaving the bed are quite likely to remain entrained with the gas, at least until it enters the scrubbing cooler. This problem has been addressed by Lurgi with two basic approaches; [1] make the coal "sticky" so individual fines are attached to larger non-entrainable lumps and [2] cover the fines quickly so there is a more tortuous pathway to be followed before the "average fine" can exit the coal bed.

An example of the first approach is the use of "recycle tar" which is ejected onto the coal in the distributor to serve as a dust suppressant. Similarly, tests have shown that a higher fraction of fines can be tolerated with "tarry" coals, such as Pittsburgh #8, which become "sticky" as they warm in the top of the gasifier.

One of the most sophisticated embodiments of the second approach is found in Lurgi's U.S. Patent No. 4,405,340. When coal or any solid is dumped in a pile, it will assume a natural angle of repose characteristic of the particular solid material and will also become segregated with the preponderance of larger particles falling to the outside of the pile and the smaller, or fine, particles residing in the middle of the pile; i.e., the motions inherent in the piling process encourage the fines to be located near the centerline of the distributor and the larger particles on the periphery. This patent allows the size segregation to take place within the distributor and positions coal outlet chutes such that "predominantly fine" coal, is laid on top of the bed and immediately overlain by "predominantly coarse" coal exiting from a second distributor discharge chute (as the distributor pan rotates). This is a relatively recent patent (1983) and the degree to which this design has proven to be beneficial is not presently known.

From a gas perspective, the grate design of the Lurgi gasifier tends to emphasize uniform gas distribution and relies primarily on the amount of steam utilized and the chemistry of the coal char/ash to preclude excessive clinker formation. While hardfacing of grate surfaces is done, this appears to mitigate wear and there are no features to overtly deal with clinkers. As alluded to above, if the bed temperature distribution is as designed, the stirrer will reduce the formation of agglomerates in the upper portions of the bed (incipient clinkers) and the steam will suppress lower bed temperatures enough to preclude the formation of significant clinkers. Under these conditions there is no need to deal with clinkers; however, this grate design is not very forgiving should clinkering occur.

Beyond this issue of fines (and a separated one of caking coals), it is an acknowledged fact that a Lurgi gasifier will produce a low BTU gas that can be used in a gas turbine. The remaining issues are primarily economic in nature, i.e., the means to dispose of the "dust" caught by the cyclone, and the cost of acquiring and installing the gasifier hardware. Table 5 provides a summary of Pro/Con statements relative to this design.

Table 5
Dry Bottom Lurgi Concept

PRO	CON
1. Huge general experience base.	1. Little experience with air blowing, and none with "non-quenched" operation.
2. Capable of using all U.S. coals. (w/modifications as discussed later)	2. Grate not tolerant of "rocks".
3. Very coal specific capability to accept up to 35 percent of the feed as fines.	3. Top bed stirring only.
	4. Large steam usage.
4, Commercially availability.	5. Tars and fines in product gas.
	6. Internal/central feed system raises over bed gas velocities and complicates stirrer.

1.3.2 Performance Parameters

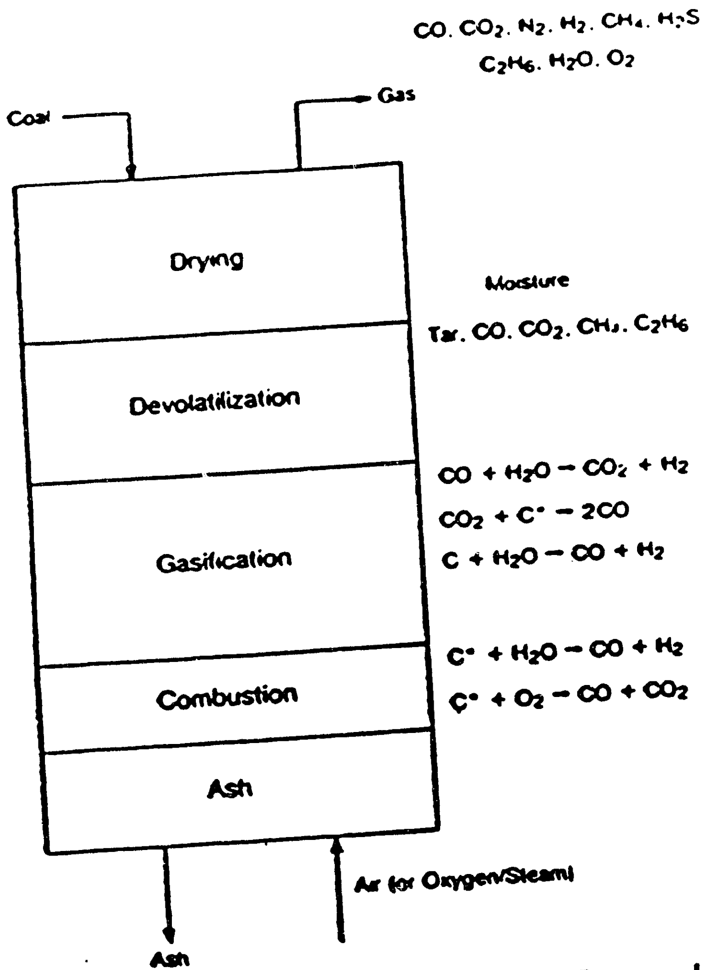
In the performance of a fixed bed gasifier, the output of the device is a function of:

1) The characteristics of the coal being supplied.
2) The relative quantities of air and steam contained in the blast.
3) The operating pressure.

As shown in Figure 2, the gasifier is roughly divided into "zones" which accomplish the following:

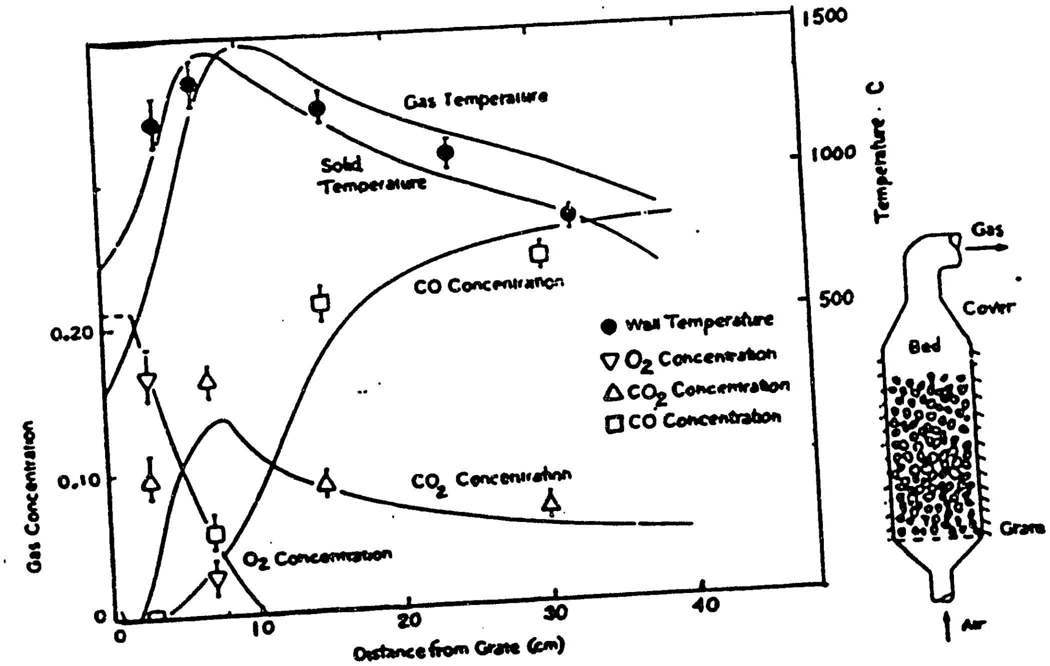
- A drying, tar producing zone at the top of the gasifier.
- A devolatilization zone producing light organic compounds.
- A gasification zone producing the primary gasifier fuel components, CO and H_2.
- A combustion zone producing the heat necessary to drive the reactions in the zones above.
- A bottom ash cooling zone which preheats the incoming air and steam.

Typical gas compositions and temperatures at various locations in a fixed bed gasifier (air blown) are shown in Figure 3, while Figure 4 connotes various operating parameters in a Lurgi gasifier.



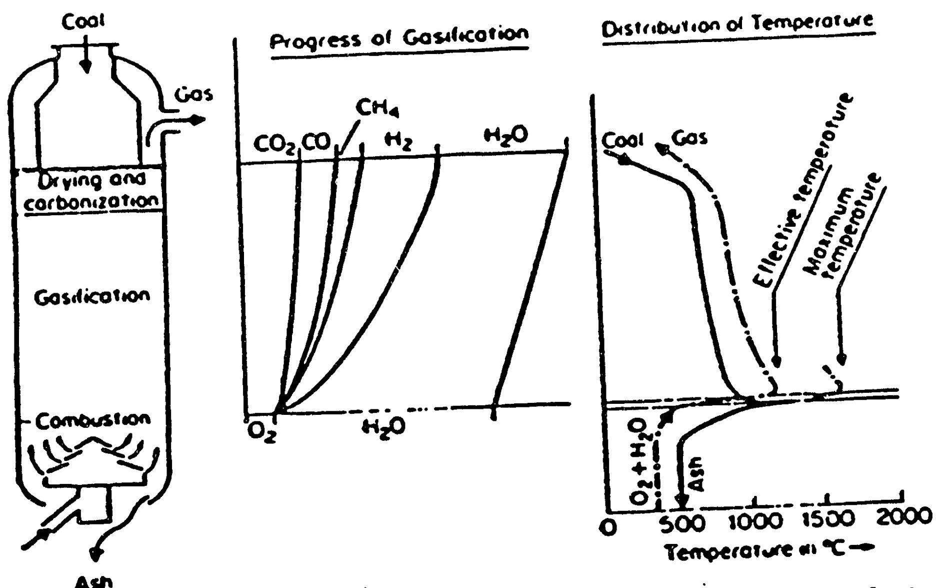
Chemical reactions occurring in a fixed-bed gasifier. (Figure used with permission from DeSai and Wen, 1978, under support by U.S. Dept. of Energy, Morgantown Energy Technology Center, Morgantown, WV)

Figure 2



Comparison of measured and predicted temperature and concentration profiles throughout a fixed-bed gasifier. (Figure used with permission from Barriga and Essenhigh, 1979)

Figure 3



Lurgi pressure gasifier and its operating properties during coal gasification.

Figure 4

The performance of the Lurgi gasifier is, as stated previously, determined by the coal characteristics and the air and steam quantities involved. From a simplified analysis, these factors manifest themselves as follows:

a) The coal provides the carbon and hydrogen for the resultant CO, CxHy, and H_2 in the resulting gas.
b) The coal provides the carbon and hydrogen required in the combustion which elevates the reactants to the desired temperature level.
c) The air quantity provides the oxygen required by the combustion (b above) and the CO in the gases.
d) The steam quantity provides the tempering effects on bed temperature to maintain levels below ash fusion temperatures.

Utilizing these performance indicators yields the range of input/output parameters as shown in Table 6.

Table 6
Estimated Lurgi Air Blown Characteristics

1. Gas Outlet Temperature: 700 to 1100°F
2. Gasifier Pressure: 300 to 465 psia
3. Solids Residence Time: Approximately 1 hour
4. Coal Feed Rate: 100 to 400 lb/hr-ft2
5. Coal Sizing: Up to 1.5 to 2.0 inches with up to 10% less than 0.125 inches
6. Steam Input: Approximately 0.5 to 0.6 lb per lb of coal.
7. Air Input: 1.3 to 2.0 lb per lb of coal
8. Gas Production: 13 to 67 scf per lb coal

Using the Mark IV dimensions of 12.4 feet in diameter and 10-12 feet of active coal depth, the solids bed moves downward at approximately 0.2 feet per minute, and the coal input is approximately 6 to 24 tons per hour. At 12,000 BTU/lbm HHV, the gas production would be approximately 1.5 to 5.5mm BTU per hour.

Tables 7 thru 12 show the performance of air-blown, fixed-bed gasifiers as presented in various published reports.

In addition to these published data, METC has generated data on fixed bed gasifier output which indicates that output is related to absolute pressure to the 0.5 power. Figure 5 illustrates the results of this pressure effect.

As a general overview of the status of air-blown, fixed-bed gasifiers, Table 13 summarizes much of the available data while Figure 6 illustrates the results.

A key element in the performance of the standardized IGCC gasifier is the expected alkali metal output. Figures 7 and 8 illustrate those expected performance parameters based upon available data.

1.4. Issues Affecting Gasifier Performance

Based upon a review of available information as presented in Sections 1 thru 3 of this report, it is anticipated that the parameters listed in the following paragraphs will affect air-blown, fixed-bed gasifier performance. The exact effects of each of the parameters will require empirical determination; however, each of them has been identified as significant to IGCC gasifier performance.

1.4.1 Free Swelling Index (FSI)

This index will likely have the greatest single influence upon gasifier coal throughput (gas output). The literature indicates about a four to one range of output over the free swelling index (FSI) range of zero (0) to eight (8). Clearly, if a standard IGCC gasifier is to be applicable to all U.S. coals up to a FSI of eight (8), this influence must be recognized, planned, and designed.

TABLE 7

GE DATA FOR FIXED-BED GASIFIER PERFORMANCE

	1 Baseline	2 Low Steam	3 High Steam	4 Alternate Stirrer	5 Half Flow	6 High Blast
Test Run	33-1	34-2	34-1	33-2	33-2	34-2
Raw Coal, lbm/hr	1858	1616	1627	1821	893	1848
Coal Moisture, %	9.0	8.6	7.5	9.0	8.2	8.5
Dry Coal, lbm/hr	1691	1467	1504	1650	820	1691
Dry Fines Carryover, %	4	2.3	3.4	2.0	1.4	1.3
Hot Gas T. °F	1084	1080	1150	1046	948	1109
Quench Exit T. °F	342	330	365	342	336	340
Raw Gas, lbm/hr	6306	6409	3261	6480		
Gas Composition, Vol. % Dry						
H_2	20.9	17.1	21.6	20.4	19.9	21.5
CO	16.5	24.6	9.8	18.3	16.4	18.5
CO_2	12.4	6.4	17.1	11.4	12.9	11.5
N_2	45.0	47.4	46.1	44.6	44.7	43.4
CH_4	4.2	3.8	4.5	4.3	5.2	4.3
H_2S	.3	.3	.3	.3	.3	.3
Gas Heating Value, BTU/sft^3	163	171	146	168	168	171
Gas Water Content, Vol. %	18.4	10.3	27.4	17	15.8	19.4
Tar Yield Wt % Dry Coal	3.1	2.9	4.7	3.2		
Carbon Efficiency, %	84	95	87	88	90	89
Cold Gas Efficiency, %	73	84	73	78	79	80
Enthalpy Conversion Effic. %	66	78	62	70	71	71
Steam Utilization %	57	73	42	61	65	50

TABLE 8

TYPICAL LURGI PERFORMANCE DATA FOR AIR-BLOWN OPERATION

Coal HHV, Btu/lb	Subituminous 12,700
Air, scf/scf of crude gas	0.51
Steam (excluding jacket steam) lb/scf of crude gas	0.012
Air/Coal ratio, lb/lb	2.3 to 2.7
Steam/Coal Ratio, lb/lb	1 to 1.5
Crude gas, scf/1000 lb daf coal	62,223
Tar, oil, naphtha, lb/1000 daf coal	72
Gas analysis (dry and sulfur-free crude gas),	%
CO_2	14.0
CO	15.8
H_2	25.0
CH_4	5.0
C_nH_m	0.2
N_2	40.0

°Volatile matter = 32.0%, Fischer tar = 4%
+Caking, volatile matter = 39.0-45.0%

Table 9

Performance Characteristics of Moving-Bed Gasifiers

Gasifier	Lurgi	GEGAS-D	MERC
Diameter (ft)	12	3	3.5
Height (ft)	N/A	N/A	6.5
Gasifying capacity (lb/hr ft^2)		200	100-200
Pressure lpsi (gauge)	300-450	200-300	15-225
		Pittsburgh	Arkwright
Coal composition			
C	57.12	67.42	75.92
H	3.93	4.98	5.70
O	8.27	7.39	4.92
N	0.83	1.35	1.38
S	4.45	3.82	2.71
Ash	13.3	15.02	8.25
Moisture	12.1	2.53	1.12
Air Coal (lb/lb)	-	2.63	2.5-3.67
Oxygen/coal (lb/lb)	-	-	-
Steam (lb/lb)		0.45	0.5-0.74
Gas composition (mol%)			
CO	14.54	23.8	16.0-23.0
CO_2	16.22	6.7	7.0-12.0
N_2	42.85	49.2	48.0-55.0
H_2	22.36	17.0	13.0-17.0
CH_4	3.88	3.2	2.0-3.5
C_2H_6	-	-	0.3
C_2H_4	-	-	-
H_2S	-	-	0.3-0.6
O_2	-	-	0.1
Heating value of gas (BTU/SCF)	158	160	100.0-180.0

Nowacki, Perry ed. Coal Gasification Processes. Noyes Data Corp.; Park Ridge, New Jersey; 1981.

Table 10
Process Data and Gas Produced for the Lurgi Gasifier

	EPRI Study Illinois No. 6
Feed Coal	
Ash%	9.6
Moisture %	4.2
Size, inches	1/4 - 1 1/2
HHV, Btu/lb	12,235
Ton/day/gasifier	625
Gasifiers	
Inner diameter, ft	-
Number	16*
Stirred	Yes
Water-cooled grate	-
Gasifying medium	Air-steam
Oxygen, tpd	-
Oxygen, tpd of coal	-
Air, tpd	1,390
Air, ton/ton of coal	2.22
Steam, tpd	892
Steam, ton/ton of coal	1.43
Product gas	
HHV, Btu/scf	179
MMscfd/gasifier	47
Exit temperature, °F	955
Raw gas, mol %	
CO	16.52
H_2	23.76
CH_4	3.94
C_nH_m	0.10
$H_2S + COS$	0.75
$N_2 + Ar$	41.49
CO_2	13.44
HHV, Btu/scf	

Nowacki, Perry ed. Coal Gasification Processes. Noyes Data Corp.; Park Ridge, New Jersey; 1981

Table 11

INPUT STREAMS

• Coal: (Stream No. 1)	
- Type:	New Mexico Subbituminous C
- Size:	2.0 to 44.4
(in)	(0.08 to 1.75)
- Rate: g/sec-m^2	337
(lb/hr-ft^2)	(248)
- Composition:	
Volatile matter	31.0%
Moisture	16.4%
Ash	17.8%
Sulfur (dry basis)	0.63%
- HHV: J/kg	2.03 x 10^7
(Btu/lb)	(8838)
- Swelling number:	2
- Caking index:	0
• Steam: (Stream No. 2)	0.965 kg/kg DAF coal
• Oxygen: (Stream No. 3)	NA
• Air: (Stream No. 3)	1.99 kg/kg DAF coal

GAS OUTPUT

• Gasifier pressure:	2.07 MPa (300 psia)
• Steam /air (kg/kg):	0.485
• Gas outlet temperature:	Data not available
• Gas production rate: Nm3/kg coal	3.10
(scf/lb coal)	(52.5)

Cavanaugh. E.C., et al. Environmental Assessment Data Base for Low/Medium-Btu Gasification Technology, Vol II. Radian Corp., Austin, Texas: Nov 1977 (EPA/600/7-77/125B)

Table 12

Gas Composition and Heating Value for Typical Air Blown, Low-Btu Gasifiers

Gas Component	Fixed Beds: Single-Stage	Fixed Beds: Two-Stage	Fixed Beds: Pressurized Single-Stage	Fluidized Beds
H2	15.7	16.0	21.8	13.2
CO	25.4	29.8	14.8	21.5
CO2	4.7	3.3	14.8	7.0
CH4	3.2	2.9	6.1	0.5
C2+	-	-	-	-
N2	50.5	47.3	41.7	57.7
Other	0.5	0.7	0.8	0.1
Heating value, Btu/scf	164	176	180	117

Nowacki, Perry ed. Coal Gasification Processes. Noyes Data Corp.; Park Ridge, New Jersey; 1981.

Figure 5

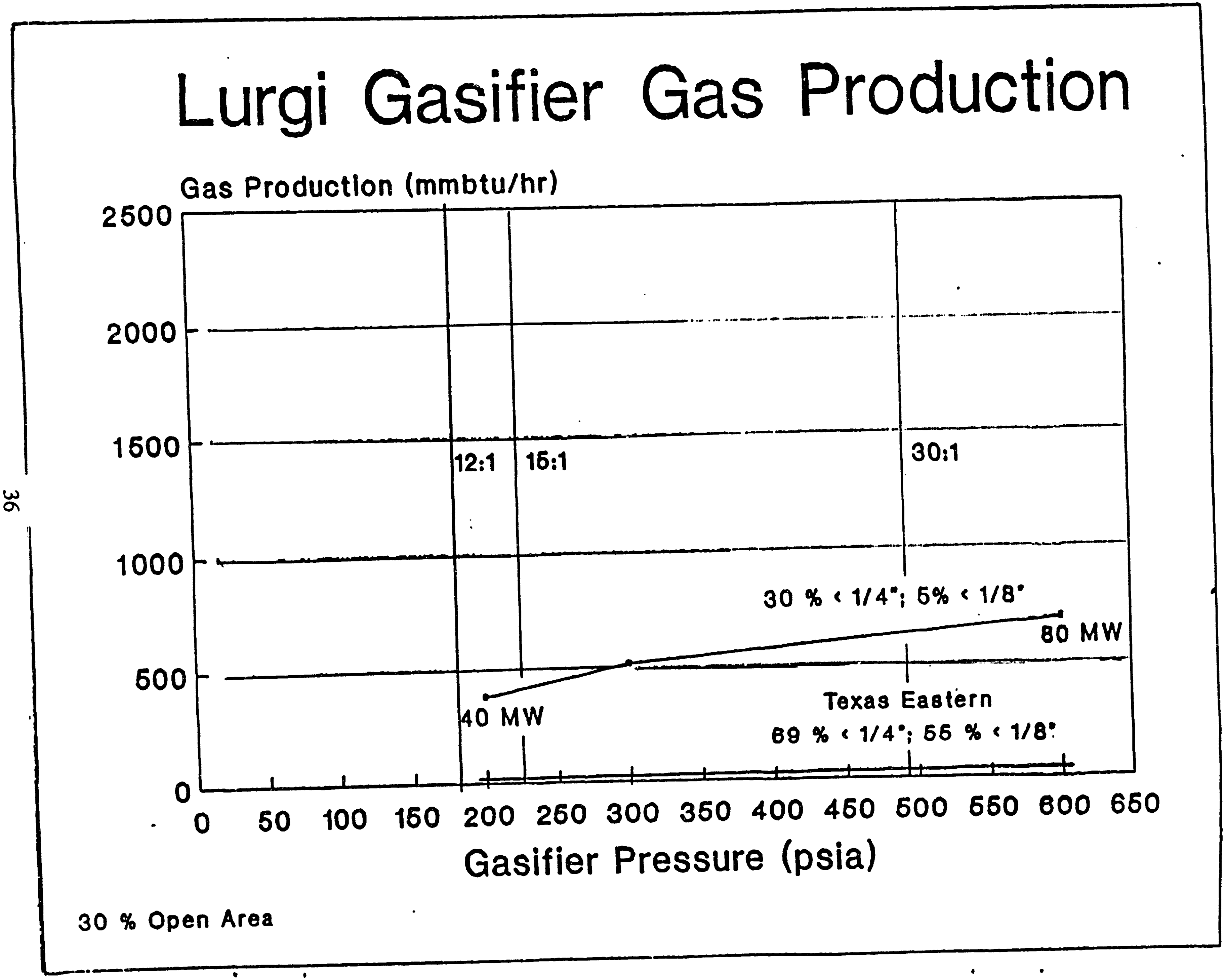

Lurgi Gasifier Gas Production
Gas Production (mmbtu/hr)
2500
2000
1500
1000
500
0
12:1
15:1
30:1
30 % < 1/4"; 5% < 1/8"
80 MW
40 MW
Texas Eastern
69 % < 1/4"; 55 % < 1/8"
0
50
100
150
200
250
300
350
400
450
500
550
600
650
Gasifier Pressure (psia)
30 % Open Area

Table 13
Normalized Fixed Bed Gasifier Output Performance

In each case, the actual or expected gasifier coal throughput was normalized to a 12.63 ft diameter equivalent output for a Lurgi Mark IV Gasifier using proportional area and square root ratio of operating pressure

Reference	Actual Observed Coal Throughput (tph)	Actual Observed Operating Press (psia)	Actual Gasifier Bed Area (sq ft)	Sq Root of Operating Pressure	Proportional Output Equiv for 12.63 ft dia (tph)	Sq Root Equiv Output @ 14.7 psia (tph)	Sq Root Equiv Output @ 200 psia (tph)	Sq Root Equiv Output @ 300 psia (tph)	Sq Root Equiv Output @ 450 psia (tph)
Equivalent Pressure (psia)						15	200	300	450
(1) GEGAS-D (Table 1)	0.96	200.0	9.62	12.63	12.5	3.8	12.5	15.4	18.9
(1) GEGAS-D (Table 1)	0.96	300.0	9.62	17.30	12.5	2.8	10.2	12.5	15.4
(11) MERC (Table-1)	0.48	15.0	9.62	3.87	6.3	6.2	22.8	28.0	34.3
(11) MERC (Table-1)	0.96	225.0	9.62	15.00	12.5	3.2	11.8	14.5	17.7
(1)Wellman-Galusha (T-1)	0.19	15.0	50.28	3.87	0.5	0.5	1.7	2.1	2.6
(1)Wellman-Galusha (T-1)	2.49	15.0	50.28	3.87	6.2	6.1	22.6	27.7	34.0
(10)EPRI Study (Table-2)	26	400	201	20	16.2	3.1	11.4	14.0	17.2
(11) MERC (Table 26)	0.61	104.70	9.62	9.49	7.9	3.2	11.8	14.5	17.7
(11) MERC (Table 26)	0.55	90.70	9.62	9.52	7.1	2.9	10.6	13.0	15.9
(11) MERC (Table 26)	0.46	37.70	9.62	6.14	6.0	3.8	13.8	17.0	20.8
(11) MERC (Table 26)	0.62	155.70	9.62	12.48	8.1	2.5	9.1	11.2	13.7
(11) MERC (Table 26)	0.69	140.70	9.62	11.86	8.9	2.9	10.6	13.0	16.0
(11) MERC (Table 26)	0.70	153.70	9.62	12.40	9.1	2.8	10.4	12.7	15.6
(11) MERC (Table 26)	0.61	104.70	9.62	10.23	7.9	3.0	10.9	13.4	16.4
(12) Riley	1.50	15.00	86.62	3.87	2.2	2.1	7.9	9.7	11.9
(12,13) Riley	3.50	15.00	86.62	3.87	5.1	5.0	18.5	22.6	27.8

Empirical Gasifier Output Prediction

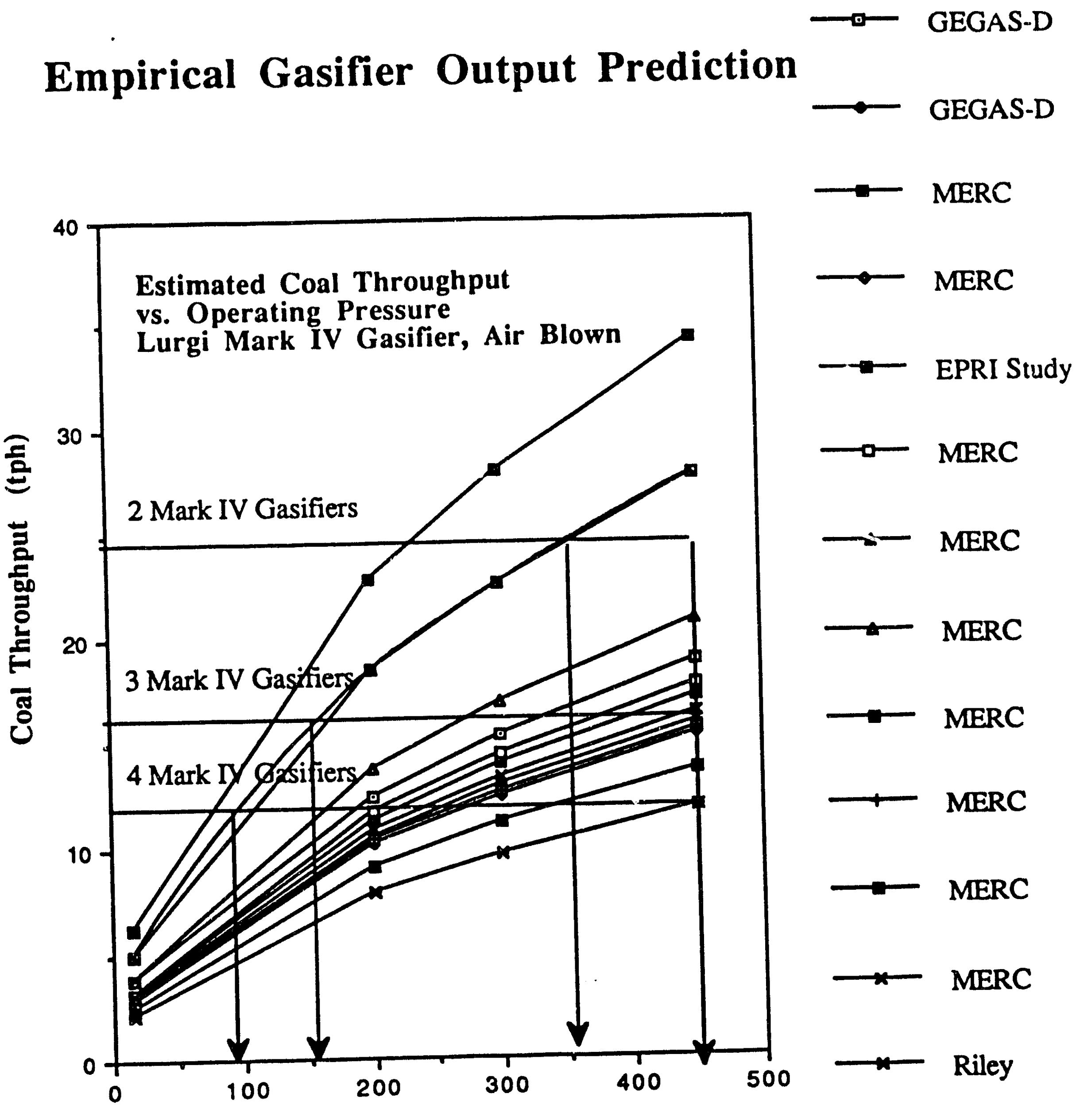


Figure 6

Actual Volatilized NaCl (PPMV) (Ref. 14)
AFO
Anticipated Gasification Temperatures
(Maximum Allowable for Gas Turbines < 0.1 ppm)

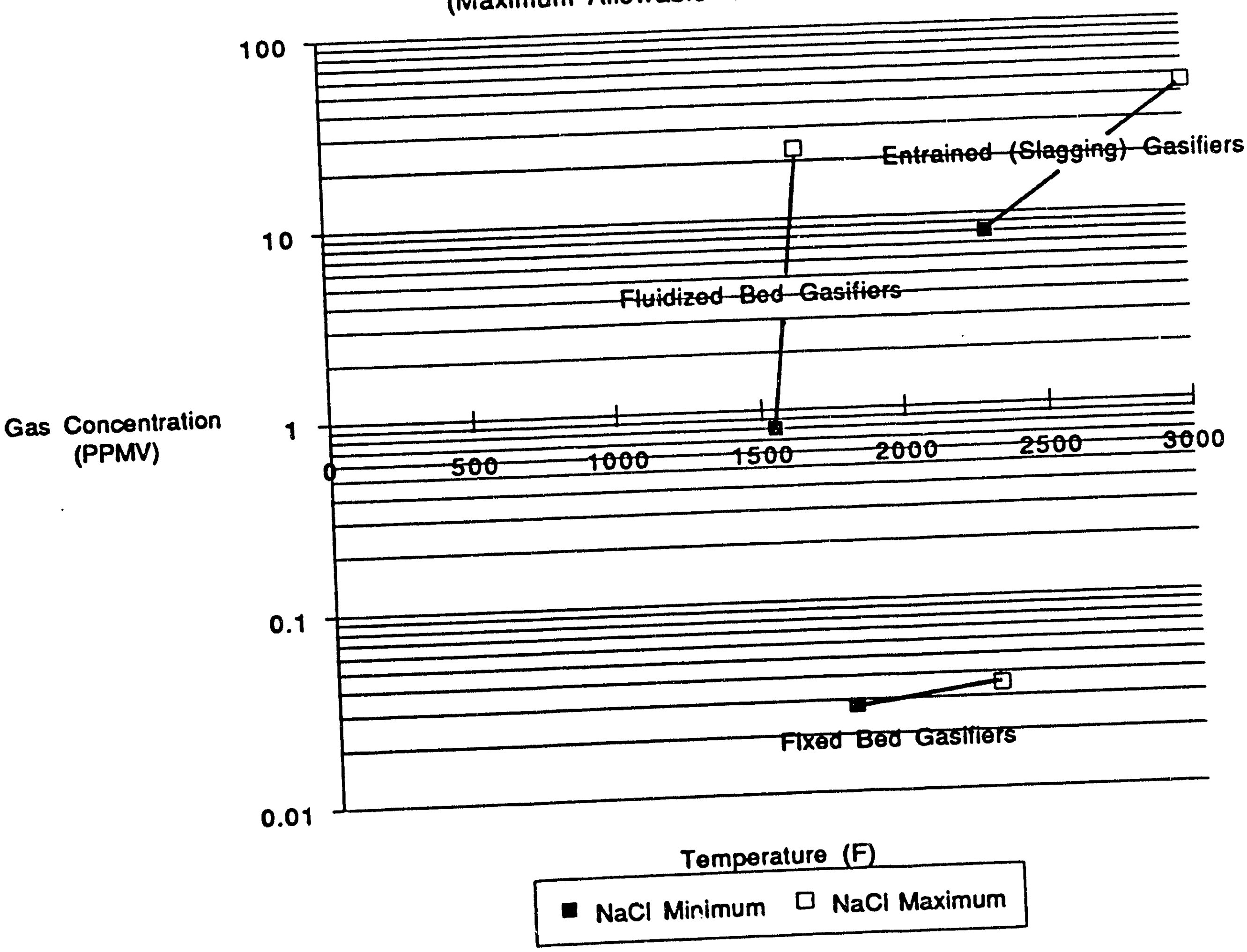
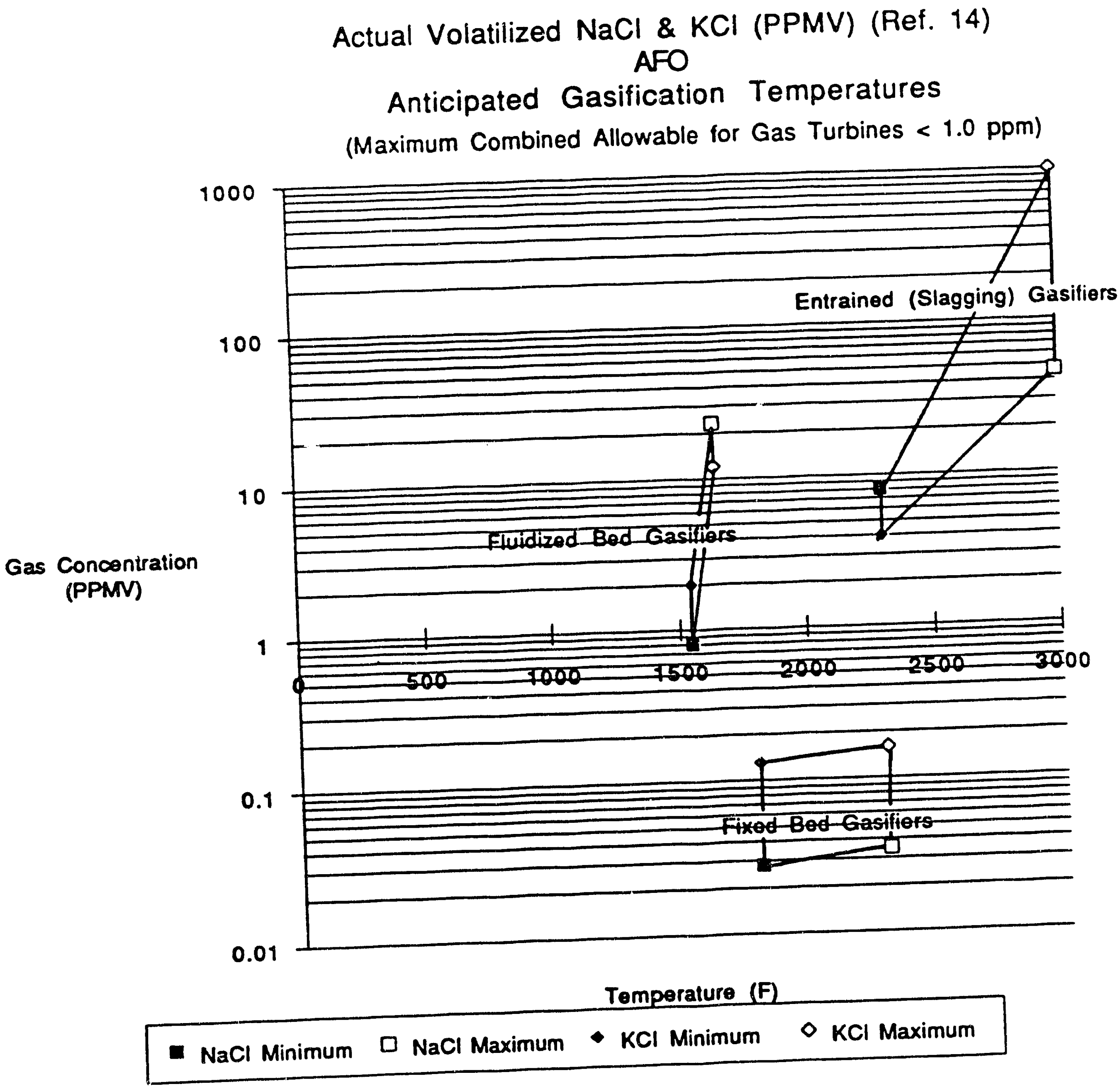


Figure 7



Actual Volatilized NaCl & KCl (PPMV) (Ref. 14)
AFO
Anticipated Gasification Temperatures
(Maximum Combined Allowable for Gas Turbines < 1.0 ppm)
1000
100
10
1
0.1
0.01
Gas Concentration
(PPMV)
0
500
1000
1500
2000
2500
3000
Entrained (Slagging) Gasifiers
Fluidized Bed Gasifiers
Fixed Bed Gasifiers
Temperature (F)
NaCl Minimum
NaCl Maximum
KCl Minimum
KCl Maximum

Figure 8

1.4.2 Ash Fusion Temperatures

Ash fusion temperature affects the amount of steam that must be added to the gasifier to maintain the ash below its softening temperature. The lower the ash fusion temperature, the more steam that is required to prevent clinker formation.

1.4.3 Ammonia & Cyanide Production

All fixed bed gasifiers are likely to produce some ammonia and cyanide. A relatively large fraction of this "fuel bound nitrogen" is likely to become NOx when the gas is combusted in the gas turbine. There appears to be little that can be done in the gasifier to mitigate fuel bound nitrogen production, and therefore down stream NOx reduction and removal strategies (e.g. staged combustion or SCR) are expected to be necessary and employed.

1.4.4 Volatilized Alkali Production

From available data, it appears that the hotter the gasification process, the greater the volatilized alkali production. Slagging entrained bed gasifiers produce about three orders of magnitude more sodium and potassium than gas turbine manufacturers consider acceptable. Fluid bed gasifiers produce about two orders of magnitude more than is acceptable. Only fixed bed non-slagging gasifiers appear capable of maintaining sufficiently low volatilized alkali levels for direct hot gas utilization gas turbines without post gasifier treatment of the alkali vapors.

1.4.5 Tar Production

Tar production can be minimized by various operational techniques, however some tar should always be expected from a fixed bed gasifier. Several gasifier suppliers have reduced tar production by readmitting volatiles produced gas back through the char bed region.

1.4.6 Thermal-phoresis

It is known that when gasifier exit temperatures are maintained well above the tar condensation range such that the tars and heavy oils tend to crack, resulting coke has an affinity for accumulating on any and all duct surfaces, irrespective of duct refractory temperatures. The term "thermal-phoresis" has been used to describe this phenomenon. Historically, the best way to deal with it is to minimized the extent of any ductwork between the gasifier outlet and the hot gas cleanup unit (HGCU). Other obvious treatments such as soot blowers may have deleterious affects on the HGCU process.

1.4.7 Ash Carbon Content

Ideally, gasification should proceed with near complete utilization of the carbonaceous fraction of the coal. During upset conditions, such as gas channeling, significant quantities of unburned carbon may occur. Such channeling is often the result of agglomeration caused clinkering and is typically associated with high free swelling coal properties. This negatively affects both process efficiency and ash disposal. Ash disposal cost is affected by its carbon content. Since coal ash, which contains less than 5% unburned carbon, can usually be stabilized, a reasonable goal for the standard IGCC gasifier is to maintain less than 5% carbon in the bottom ash.

1.4.8 Pressure Containment

It is anticipated that the standard IGCC gasifier will be operated at various pressures depending primarily upon output required and coal characteristics. Pressure drop across the gasifier in addition to the attendant pressure losses of the systems downstream of the gasifier (tar & particulate removal, desulfurization/regeneration, etc.), culminate in the need for a booster compressor (or similar device) which allows the gasifier to operate at significantly greater pressures than that of the gas turbine. This presents a formidable need to adequately seal all gasifier penetrations against a hot, high pressure environment. Several gasifier suppliers have met this challenge to pressures in the 350 psig range (SASOL Lurgi - 400 psig; Shell - 450 psig; Texaco - 600 psig). The remaining question is one of maintainability of the hardware involved.

1.4.9 Coal Feed System Losses

It is well known that any pressurized lock hopper arrangement has an associated thermal loss from gasifier hot gas product venting. Such venting is necessitated by the admittance of hot raw gas product during the coal feed sequence. This hot raw gas is at operating pressure and hence must be vented before the coal bunker slide valve is opened to atmosphere. Depending upon where and how the gas is vented, it can be significant loss to the process.

1.4.10 Coal Sizing

Most fixed bed coal gasifiers specify very tightly controlled feed gradation. It is unlikely that any fixed bed coal gasifier commercially available today will guarantee acceptable performance with significant fines content in the coal feedstock. Clearly, this shortcoming must be addressed either by alternative utilization of fines, or gasifier design changes intended to accommodate run of mine coals. None exist today.

1.4.11 Turndown

The range of gasifier operation from steady state full load to "banked" or "standby" pulsed condition, introduces a myriad of interdependant process phenomena which serve to complicate the whole issue of "turndown". Gasifier conditions, such as the relative position of the drying, devolatization, gasification, combustion, and ash burnout zones, are likely to be affected by externally forced operational changes to the gasification process.

1.5. Gasifier Installation and Agreements

Of concern to the operation of an air-blown, fixed-bed gasifier are the following non-technical issues:

- Typical plant problem areas
- Plant operating characteristics
- Personnel levels and capability requirements
- Plant economics
- Lurgi role & deliverables including services provided by license
- Cost basis

The available definitive literature is very sparse with respect to these areas in that most presentations of gas plant data are for the entire plant and do not treat the gasifier as a defined entity. However, Table 14 does show the gasification, quench, and shift conversion applicable to SNG applications (the typical Lurgi scope of supply) as resulting in 23% of Plant capital costs. Previous CRSS discussions with Lurgi indicate that such a scope for 2 (two) Mark IV gasifiers equates to approximately $80 million dollars. Based upon CRSS personnel experience with Lurgi systems, this yields Mark IV estimated costs of approximately $15 million each. Others CRSS discussions with Lurgi recently have yielded similar budgetary estimates.

With regard to Lurgi scope of supply questions, recent CRSS discussions with Lurgi (March 1990) have established the following:

- Lurgi does not manufacture any equipment.
- Technology use for a specific installation is the license one receives from Lurgi.
- Lurgi performance guarantees are coal specific but are complete with respect to output, composition, efficiency, and cost.
- Lurgi will quote, on a limited basis, a reduced scope from that involving coal gas cleanup to include only gasifier output at the effluent flange.
- Lurgi will accommodate mildly caking coals (FSI approximately 3-4) in the fixed bed design utilizing a deep bed stirrer.

With respect to plant operating personnel and plant operating characteristics, discussions with Coastal Coal management relative to the Mark IV facilities in the US indicates minimal problems were experienced (after shakedown) at the Great Plains facility. Further discussion with these operating personnel will be held after finalization of Lurgi secrecy agreements.

Table 14
Estimated Coal Gasification Capital Costs

ALLOCATION OF PRODUCT PRICE
Single product (SNG), no allocation necessary

UNIT OPERATION CONTRIBUTION TO COMPOSITE PRODUCT PRICE (CAPITAL INVESTMENT EFFECTS ONLY)

UNIT OPERATION		%
Coal Storage		1.7
Coal Preparation		3.1
Coal Feed	}	
Gasification	}	
Raw Gas Quench	}	23.0
Shift Conversion	}	
Acid Gas Removal		14.1
Methanation		7.0
Sour Water Treatment		2.3
Sulfur Recovery		6.5
Solids Disposal		0.4
Steam And Utility Systems		21.4
Plant Water		2.6
Oxygen Plant		7.8
General Facilities		10.0
		100.0

OTHER INFORMATION

ANNUAL COSTS		$MM/yr
Catalysts and Chemicals		10.77
Water (60c/Mgal)		0.69
Labor		31.80
Administration and Overhead		19.08
Supplies		16.21
Local Taxes and Insurance		35.65
GROSS ANNUAL COSTS		114.20
BY-PRODUCTS		
Sulfer ($26/to)	0.82	
NH ($165/ton)	7.61	
Oil, Naphtha, Tar	43.79	
Fines ($0.41/MMBtu)	13.32	(65.54)
NET ANNUAL COSTS		48.66

Reference

Factored Estimates for Western Coal Commerical Concepts, C.F. Braun, FE-2240-5, October 1976.

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(3) Herbert, P.K. et al, "Lurgi's CFB Gasification Technology for Combined Cycle Power Generation (Part I) and Gas Production from Biomass (Part II)", Eighth Annual EPRI Conference on Coal Gasification, Proceedings August, 1989, Palo Alto, California

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(5) Personal communication with Mr. Chuck Howser, Shell Chemical Corp., April, 1990

(6) Tetsuei Sueyama, et al, "Four-Year Operating Experience With Texaco Coal Gasification Process In Ube Ammonia", Eighth Annual EPRI Conference on Coal Gasification, Proceedings August, 1989, Palo Alto, California

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Preliminary Assessment of Optimum Combinations of Combustion Turbine and Gasifier/HGCU Hardware

Section 2

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2.1. Summary

The objective of the study covered by Contract DE-AC21-89MC26291 is to develop an integrated gasification combined cycle (IGCC) for electric power generation. This IGCC system will incorporate an air-blown, fixed-bed gasifier and a hot gas clean up (HGCU) unit.

This section addresses:

1) Performance data of currently available gas turbines,

2) Advantages/disadvantages of candidate gas turbines matched with gasifier/HGCU module, and

3) Performance characteristics of near term commercially available (by the year 2000 AD) gas turbines with an air-blown, fixed-bed gasifier/HGCU module.

The standardized IGCC system is to be compatible with three sizes of coal fueled plants: 50 MW(e), 100 MW(e), and 200 MW(e). The gasifier will produce a hot raw gas for hot gas clean up and direct combustion in a gas turbine.

The data reviewed has been developed principally by the Department of Energy's Morgantown Energy Technology Center (METC), General Electric, Westinghouse, Asea Brown Boveri, the Lurgi Corporation, and Thermoflow.

Gas turbine compressor surge is a potential limiting factor in power output and efficiency when applied to the steam cooled air-blown, fixed-bed coal gasification IGCC system. Water injection for gasifier temperature control reduces this concern.

2.2. Gas Turbine Selection

2.2.1 Overview Descriptions of Candidate Gas Turbines

Table 1 is a list of commercially available gas turbines as compiled by Maher Elmasri, author of GTPro. [1] This table cites ISO (59 F, 60% Relative Humidity) no-loss performance for gas turbines fired on methane. Gas turbines that could be integrated into a 50 MW, 100 MW, or 200 MW IGCC system were selected from Table I based on the size (power output) of the gas turbine and the manufacturers experience with burning low-Btu fuels. (see Table 2)

Gas turbines must be selected to complement nominal 50 MW(e), 100 MW(e), and 200 MW(e) plant designs. The gas turbine power contribution to each size plant must be established to begin the selection process. General Electric has done extensive research with combined cycle systems and has determined that for a standard combined cycle plant with an unfired heat recovery steam generator and a gas turbine fired with natural gas, the gas turbine will provide approximately two-thirds of the total power. [2]

Three principal manufacturers, General Electric, Westinghouse, and Asea Brown Boveri, are participating in IGCC projects. General Electric's experience is with the Texaco Gasification Process that is being used in the Cool Water IGCC plant in Daggett, California. Westinghouse has provided the gas turbines for the Dow Gasification Process used in an IGCC power plant in Plaquemine, Louisiana. Asea Brown Boveri is working in conjunction with Shell Oil Company to develop an IGCC power plant in the Netherlands. All of the commercial experience to date has been with oxygen-blown gasifiers. An oxygen-blown gasifier produces raw gas with a lower heating value of approximately 300 Btu/scf. From an air-blown gasifier, the raw gas has a lower heating value of approximately 140 Btu/scf. Although few commercial applications utilize fuels with heating values below 100 Btu/scf, laboratory tests have indicated that stable combustion can be maintained with lower heating values down to 80 Btu/scf. [3]

The following areas must be addressed in order to burn a low-Btu fuel.

Table 1

Nominal ISO No Loss performance on CH4 — Revised: 02-21-1990

Model	Shafts No.	Speed RPM	Press. PR	Output kWe	H.R. Btu/kWh	Efficiency %LHV
G.E. 5371PA	1	5100	10.2	26840	11690	29.2
G.E. 6541B	1	5100	11.8	38920	10790	31.6
G.E. 7111EA	1	3600	12.4	84620	10360	32.9
G.E. 7191F	1	3600	13.7	151340	9650	35.4
G.E. LM500	2	7000	14.5	3860	11540	29.6
LM/TG1600	3	7000	21.7	13520	9510	35.9
LM/TG2500PE	2	3600	18.4	22190	9420	36.2
LM/TG2500PH	2	3600	16.4	19700	9630	35.4
LM/TG5000PD	3	3600	25.5	33350	9390	36.3
LM5000ST80	3	3600	33.0	46300	8170	41.8
LM5000ST120	3	3600	33.0	51500	7885	43.3
LM/TG5000PC	3	3600	25.3	33760	9400	36.3
UTC FT4C-3F	3	3600	14.0	29810	10960	31.1
Sol Saturn	1	22120	6.7	1080	14785	23.1
Sol Centaur	1	14950	9.3	3880	12300	27.7
Sol Mars	2	8568	15.7	8840	10976	31.1
Jupitr/GT35	3	3600	2.0	16360	10650	32.0
Alsn 501KB5	1	14250	9.3	3725	12450	27.4
Alisn 570KA	2	11500	12.0	4610	12250	27.9
Alisn 571KA	2	11500	12.7	5590	10650	32.0
CW 251 B10	1	5420	14.2	42300	10600	32.2
W 501 D5	1	3600	14.2	106800	10100	33.8
ABB GT 8	1	6300	16.3	46950	10830	31.5
ABB GT 11N	1	3600	12.4	81600	10715	31.8
KWU V84.2	1	3600	10.6	103400	10250	33.3
ABB GT 10	2	7700	13.6	21800	10420	32.7
RRSpeySK15	3	5220	18.5	11630	10530	32.4
Avon/Cooper	2	5500	9.0	14600	12000	28.4
RB211/Coopr	3	4800	20.0	25250	9600	35.5
Drsr DC990	2	7200	12.5	4210	11830	28.8
Rstn TB5000	2	7950	7.0	3830	13500	25.3
Rstn Torndo	1	11085	12.0	6215	11390	30.0
Mtsb MF111A	1	9660	12.8	12850	11150	30.6
Mtsb MF111B	1	6990	14.6	14850	10950	31.2
NvPgn PGT10	2	7900	14.0	9980	10500	32.5
Mtsui SB60	2	5680	12.1	12650	11460	29.8
G.E. 9161E	1	3000	12.2	118800	10220	33.4
G.E. 9161F	1	3000	13.7	217900	9650	35.4
MW 701D(5)	1	3000	13.8	133750	9980	34.2
ABB GT 13D2	1	3000	12.5	100500	10640	32.1
ABB GT 13E	1	3000	14.1	148000	9855	34.6
KWU V94.2	1	3000	10.7	150300	10210	33.4
UTC FT8	3	3600	20.0	25420	8920	38.3
MW501F	1	3600	14.2	152300	9800	34.8
KWU V64.3	1	5600	15.8	55000	10060	33.9
CW 251 B12	1	5400	14.8	47700	10420	32.7

Table 2

Model	Speed RPM	Press. PR	Output kWe	H.R. Btu/kWh	Efficiency % LHV
50 MW Cycle Available Turbines					
LM/TG5000PD	3600	25.5	33350	9390	36.3
LM/TG5000PC	3600	25.3	33760	9400	36.3
100 MW Cycle Available Turbines					
GE 7111EA	3600	12.4	84620	10360	32.9
W 501 D5	3600	14.2	106800	10100	33.8
ABB GT 11N	3600	12.4	81600	10715	31.8
200 MW Cycle Available Turbines					
GE 7191F	3600	13.7	151340	9650	35.4
MW501F	3600	14.2	152300	9800	34.8

2.2.1.1 NOx Formation

The IGCC power plant will incorporate a fixed-bed, air-blown gasifier. The Lurgi Mark IV gasifier produces 4000-9000ppmv of NH3 in raw gas. [4] Ammonia in the gaseous state is very unstable and will reduce to harmless N2 in a reducing (oxygen deficient) environment, or partially to NOx in an oxidizing (oxygen rich) environment. Conventional gas turbine combustors operate in an oxidizing environment which results in 30-70% conversion of ammonia to NOx. This would exceed emission control limits of 0.1 lb/million Btu which is the anticipated permissible level required by the year 2000 AD. NOx formation can be controlled by staged combustion. In the primary zone of staged combustion, a portion of the total air necessary for combustion is supplied to the fuel. This reducing environment promotes the formation of N2 rather than NOx. After the oxygen content of the primary zone is consumed, the products of incomplete combustion are mixed with additional air to complete the combustion process. This process reduces unstable ammonia to stable N2 before sufficient oxygen is present to form NOx. [5]

2.2.1.2 Trace Metal Contaminants

Trace metal contaminant levels in the hot-section components lead to corrosion, poor performance, and unscheduled maintenance. Specific contaminants that must be controlled are sodium and potassium. To prevent rapid deterioration of gas turbine components, strict limits are placed on these contaminants. Table 3 shows the limits placed on the gas turbines manufactured by the selected vendors.

Table 3

	General Electric	Westinghouse	Asea Brown Boveri
Sodium plus Potassium (ppm by weight)	0.150	0.134	0.050

To reach these levels, fines must be separated from the gas fuel stream prior to entry into the combustor section of the gas turbine. In addition to corrosion in the hot-gas components, high level of contaminants can cause hot-gas control valves to bind as experienced in the Cool Water Project. [6]

2.2.1.3 Fuel Handling System

The high temperature (1000 F+) of raw gas entering the gas turbine will necessitate development of special fuel control valves. Previous project experience with IGCC systems have all entailed cooling the gas after exiting the gasifier. In these cases, the temperature of the fuel entering the gas turbine combustor rarely exceeded 400 F. Thermal stress, erosion, and sticking are potential problems that must be addressed. Although current gas turbine control valves cannot handle high temperature gases, control valves will be well within state-of-the-art design within the schedule of commercial availability of this IGCC project.

2.2.1.4 Fuel Injectors

Modifications must be made to the fuel injectors to prevent excessive combustion wall temperatures. The main combustibles of the synthetic gas are CO and H2. These two constituents have flame speeds 1.7 and 9.25 times faster than methane, respectively. These higher flame speeds greatly increase combustor wall temperatures. Flame speeds can be reduced by increasing the diameter of the gas injector openings. Optimization is required to determine the best orifice diameter to support stable combustion while minimizing combustor wall temperatures and control valve pressure differential. [7]

In addition to orifice diameter, the angle of the injector openings has an effect on combustion wall temperature. Excessive angles of injection will cause the gas to come close enough to the combustion wall to substantially increase metal temperatures.

2.2.1.5 Compressor Surge

With the low heating value of the coal derived gas, large mass and volume fuel flow rates are needed to supply the required heat input. Supplying this large quantity of fuel to a standard turbine cycle increases turbine expander mass flow, requiring an increase in combustion/expander inlet pressure. Compressor discharge pressure would have to rise to meet the increased combustor pressure. The compressor will accommodate increased discharge pressure at a decreased mass flow rate. There is a limit to the increased discharge pressure/decreased mass flow control range called surge. At this point, pulsations will occur within the compressor that will cause mechanical damage.

To avoid surge and maintain the combustor/expander at close to design pressures and mass flow rates, compressed air can be bled off the compressor discharge This bleed air can be supplied to the fixed-bed gasifier. Surge within the compressor can be avoided if the mass flow through the expansion section is kept lower than 1.085 times the compressor mass flow for heavy-duty gas turbines and lower than 1.07 times the compressor mass flow for aero-derivative gas turbines. [8],[9]

2.2.2 Cycle Description

Coal is supplied to a fixed-bed gasifier. The gasifying medium is air with a cooling medium injected into the gasifier to prevent the overheating of the grate and control peak combustion zone temperatures. Air used for gasification is extracted from the gas turbine at the compressor discharge. A boost compressor, placed between the compressor discharge and gasifier, will be used to overcome all pressure losses associated with the gasification process and to provide the needed fuel inlet pressure to the combustor. Raw gas exiting the gasifier contains H2S/COS and particulates that must be removed before combustion in the gas turbine. Cyclones will be used to reduce particulates levels. A zinc ferrite desulfurization system (HGCU) is used to clean the gas to 10 ppmv levels of H2S/COS. [10] The desulfurization unit consists of an absorber and regeneration vessel. Regeneration produces a SO2 stream. This SO2 stream is passed through a sulfur recovery process (SRP) to make sulfuric acid, liquid SO2, or elemental sulfur. Clean gas leaving the zinc ferrite system is combusted in a gas turbine. The exhaust gas from the gas turbine passes through a heat recovery steam generator (HRSG) to produce steam for a steam turbine. (See Figure 1)

Table 4 shows the equipment needed for the three sizes of facilities.

Table 4

	50 MW	100 MW	200 MW
Gasifiers	2	3	5
HGCU Systems	1	2	4
SRP Units	2	2	2
Gas Turbines	1	1	1
Steam Turbines	1	1	1
HRSG	1	1	1

2.3. Estimated Gas Turbine Performance

2.3.1 Characteristics of Fuel Supplied

The coal used for gasification is Illinois No. 6. Air and steam inputs to the gasifier were assumed to be 2.12 and 0.836 lb per lb of coal, respectively. Table 5 shows the coal analysis and gas produced in the fixed-bed gasifier.

GAS TURBINE COMBINED CYCLE INTEGRATED WITH AIR BLOWN FIXED BED GASIFIER

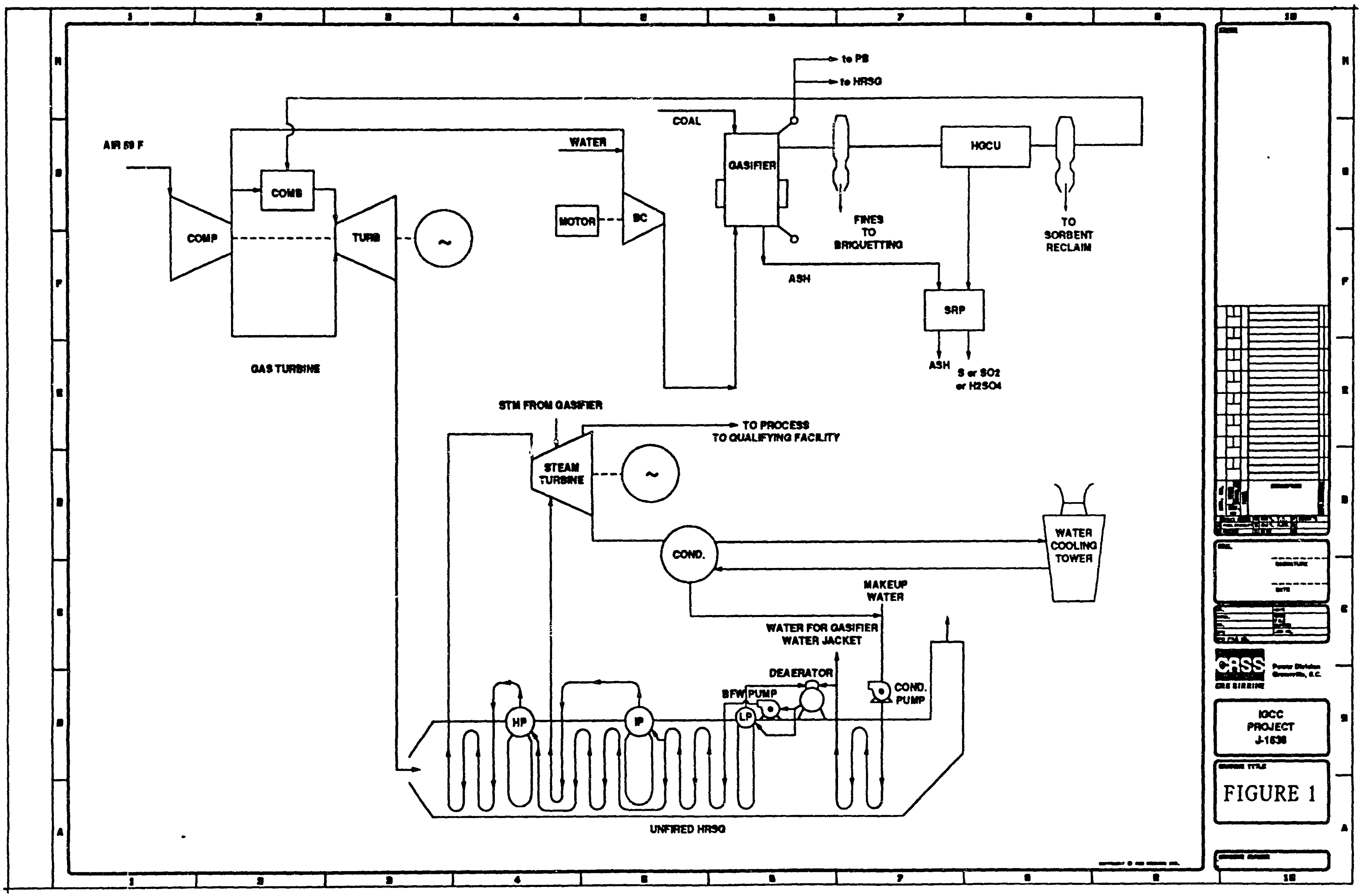

Figure 1

Table 5

Illinois No. 6 Coal		Low-Btu Fuel	
Constituents	Wt. %	Constituents	Mol. %
C	57.47	CO	13.93
H	3.68	H_2	20.03
O	5.84	CH_4	3.33
N	0.90	CnHm	0.08
S	4.04	H_2S+COS	0.63
Cl_2	0.09	N_2+Ar	38.51
H_2O	12.00	CO_2	11.34
ASH	15.98	H_2O	12.15
HHV = 12,235 Btu/lbm		HHV/LHV = 2538 / 2221 Btu/lbm (HHV/LHV = 154 / 134 Btu/scf) (above heating values exclude sensible heat)	

Raw gas exits the gasifier at approximately 955 F. Passing through the zinc ferrite desulfurization system, sulfur is removed to about 10ppm H2S/COS and the temperature of the gas is raised to 1020 F. The gas entering the gas turbine combustor, including sensible heat, has a lower heating value of 2496 Btu/lbm (151 Btu/scf).

2.3.2 Confidence in GTPro Through Westinghouse Comparison

The GTPro computer program was used to estimate system performance of all gas turbines selected. Confidence in GTPro's analysis was established by comparing predicted performance data received from Westinghouse against data computed by GTPro. Westinghouse evaluated three cases; the W 501 D5 gas turbine fueled by a low-Btu fuel at 20 F, 59 F, and 90 F. Table 6 lists performance of the W 501 D5 gas turbine predicted by Westinghouse for all three cases along with the computed results by GTPro (the low Btu fuel is shown at the bottom of the table). Maximum variance between the Westinghouse and GTPro evaluations is 2.7%, with a typical variance of 1.5%. Predicted performance has not been verified by gas turbine manufacturers [11].

TABLE 6

GAS TURBINE - WESTINGHOUSE 501-D5
ALTITUDE - 0 ft
INLET LOSS - 4" H2O EXHAUST LOSS - 12" H2O
FUEL - LOW-BTU GAS

WESTINGHOUSE PREDICTED PERFORMANCE

	CASE 1	CASE 2	CASE 3
AMB. TEMP	20 F	59 F	90 F
LOAD	BASE	BASE	BASE
INJ FLUID	-	-	-
INJ FLOW	0	0	0
COMP BLEED	85.35 LB/S	79 LB/S	73.22 LB/S
NET POWER	127918 KW	112110 KW	98940 KW
HEAT RATE (LHV)	10406 BTU/KWHR	10749 BTU/KWHR	11183 BTU/KWHR
FUEL FLOW	133.67 LB/S	121 LB/S	111.1 LB/S
EXHAUST FLOW	902 LB/S	832 LB/S	770 LB/S
EXHAUST TEMP	968 F	986 F	1008 F

GTPro CALCULATED PERFORMANCE

	CASE 1	CASE 2	CASE 3
AMB. TEMP	20 F	59 F	90 F
LOAD	BASE	BASE	BASE
INJ FLUID	-	-	-
INJ FLOW	0	0	0
COMP BLEED	85.30 LB/S	79 LB/S	73.26 LB/S
NET POWER	128809 KW	112023 KW	100099 KW
HEAT RATE (LHV)	10264 BTU/KWHR	10602 BTU/KWHR	10881 BTU/KWHR
FUEL FLOW	135 LB/S	121 LB/S	111 LB/S
EXHAUST FLOW	904 LB/S	833 LB/S	774 LB/S
EXHAUST TEMP	972 F	988 F	1001 F

VARIANCE

	CASE 1	CASE 2	CASE 3
NET POWER	0.70%	0.08%	1.17%
HEAT RATE (LHV)	1.36%	1.37%	2.70%
FUEL FLOW	1.00%	0.00%	0.09%
EXHAUST FLOW	0.22%	0.12%	0.52%
EXHAUST TEMP	0.41%	0.20%	0.69%

LOW-BTU GAS COMPOSITION - CO2 = 11.4% (VOL), CO = 12.9%, H2 = 1.4%, H2O = 18.4%, N2 = 32.66%, CH4 = 4.08%, CnHm = 0.16%
LHV (77 F) = 2350 BTU/LB
Fuel supplied at 1100 F.

2.3.3 50 MW Cycle

Table 7 displays GTPro predicted performance for the GE LM/TG5000PC gas turbine fired on the fuel specified in Section 3.1. Ambient conditions at sea level are varied from 20 F to 90 F. Aero-derivative engines use highly loaded compressors with small operating margins. With the increase in mass flow through the expansion section, the compressor quickly reaches its surge limit and the turbine inlet temperature must be reduced. This control function reduces fuel consumption, which reduces expander mass flow and required compressor discharge/combustor pressure.

2.3.4 100 MW Cycle

Table 8 displays GTPro predicted performance for the selected gas turbines for this cycle. By bleeding air from the compressor, all three turbines can burn the low-Btu fuel without derating the turbine inlet temperature or approaching the surge limit of the compressor. The W 501 D5 is slightly more efficient than the GE and ABB gas turbines. However, the exhaust temperature for the GE gas turbine is 17 degrees F higher than the W 501 D5 and 26 degrees F higher than the ABB GT 11N at ISO conditions. This will cause the steam cycle efficiency to be the highest for the GE gas turbine. Therefore, combined cycle efficiency for both the Westinghouse and GE systems will be comparable, while the ABB combined cycle system will have the lowest efficiency.

2.3.5 200 MW Cycle

Table 9 displays GTPro predicted performance results for the GE 7191 F and the MW 501 F gas turbines. Both turbines can successfully operate on the low-Btu fuel by bleeding air from the compressor. The General Electric gas turbine is slightly more efficient than the Mitsubishi-Westinghouse gas turbine. Again, General Electric's exhaust temperature is 10 degrees F higher at ISO conditions which will increase combined cycle efficiency.

TABLE 7 - 50 MW CYCLE

GAS TURBINE - GENERAL ELECTRIC LM/TG5000PC
ALTITUDE - 0 ft FUEL - LOW-BTU GAS
INLET LOSS - 4" H2O EXHAUST LOSS - 12" H2O

AMB. TEMP	20 F	59 F	90 F
REL. HUMIDITY	60 %	60 %	60 %
INLET FLOW	310.0 lb/s	267.0 lb/s	234.0 lb/s
AIR BLEED	25.9 lb/s	22.3 lb/s	19.5 lb/s
FUEL FLOW	46.2 lb/s	39.9 lb/s	34.8 lb/s
TURBINE INLET TEMP	2166 F	2186 F	2181 F
EXHAUST FLOW	330.0 lb/s	285.0 lb/s	250.0 lb/s
EXHAUST TEMP	801 F	849 F	885 F
POWER GENERATED	44312 KW	36576 KW	30489 KW
Heat Rate HHV (1)	10558 Btu/KWhr	11047 Btu/KWhr	11559 Btu/KWhr
Efficiency HHV (1)	32.32 %	30.89 %	29.52 %
Coal Flow	12.2 lb/s	10.5 lb/s	9.2 lb/s
Heat Rate HHV (2)	12124 Btu/KWhr	12685 Btu/KWhr	13273 Btu/KWhr
Efficiency HHV (2)	28.14 %	26.90 %	25.71 %

(1) Based on cleaned fuel gas heating value
(2) Based on coal heating value

TABLE 8a - 100 MW CYCLE

GAS TURBINE - GENERAL ELECTRIC GE 7111 EA
ALTITUDE - 0 ft FUEL - LOW-BTU GAS
INLET LOSS - 4" H2O EXHAUST LOSS - 12" H2O

AMB. TEMP	20 F	59 F	90 F
REL. HUMIDITY	60 %	60 %	60 %
INLET FLOW	695.0 lb/s	641.0 lb/s	595.0 lb/s
AIR BLEED	66.6 lb/s	60.3 lb/s	55.8 lb/s
FUEL FLOW	120.0 lb/s	108.0 lb/s	99.7 lb/s
EXHAUST FLOW	748.0 lb/s	688.0 lb/s	639.0 lb/s
EXHAUST TEMP	977 F	1001 F	1018 F
POWER GENERATED	102844 KW	89954 KW	81879 KW
Heat Rate HHV (1)	11816 Btu/KWhr	12158 Btu/KWhr	12331 Btu/KWhr
Efficiency HHV (1)	28.88 %	28.06 %	27.67 %
Coal Flow	31.7 lb/s	28.5 lb/s	26.3 lb/s
Heat Rate HHV (2)	13568 Btu/KWhr	13961 Btu/KWhr	14159 Btu/KWhr
Efficiency HHV (2)	25.15 %	24.44 %	24.10 %

(1) Based on cleaned fuel gas heating value
(2) Based on coal heating value

TABLE 8b - 100 MW CYCLE

GAS TURBINE - WESTINGHOUSE 501-D5
ALTITUDE - 0 ft FUEL - LOW-BTU GAS
INLET LOSS - 4" H2O EXHAUST LOSS - 12" H2O

AMB. TEMP	20 F	59 F	90 F
REL. HUMIDITY	60 %	60 %	60 %
INLET FLOW	855.0 lb/s	791.0 lb/s	737.0 lb/s
AIR BLEED	83.3 lb/s	75.0 lb/s	68.8 lb/s
FUEL FLOW	149.0 lb/s	134.0 lb/s	123.0 lb/s
EXHAUST FLOW	920.0 lb/s	850.0 lb/s	791.0 lb/s
EXHAUST TEMP	969 F	985 F	998 F
POWER GENERATED	131307 KW	114726 KW	103144 KW
Heat Rate HHV (1)	11491 Btu/KWhr	11828 Btu/KWhr	12076 Btu/KWhr
Efficiency HHV (1)	29.69 %	28.85 %	28.26 %
Coal Flow	39.3 lb/s	35.4 lb/s	32.5 lb/s
Heat Rate HHV (2)	13195 Btu/KWhr	13582 Btu/KWhr	13867 Btu/KWhr
Efficiency HHV (2)	25.86 %	25.12 %	24.61 %

(1) Based on cleaned fuel gas heating value
(2) Based on coal heating value

TABLE 8c - 100 MW CYCLE

GAS TURBINE - ASEA BROWN BOVERI GT 11N
ALTITUDE - 0 ft FUEL - LOW-BTU GAS
INLET LOSS - 4" H2O EXHAUST LOSS - 12" H2O

AMB. TEMP	20 F	59 F	90 F
REL. HUMIDITY	60 %	60 %	60 %
INLET FLOW	719.0 lb/s	678.0 lb/s	637.0 lb/s
AIR BLEED	66.0 lb/s	60.3 lb/s	56.0 lb/s
FUEL FLOW	118.0 lb/s	108.0 lb/s	99.8 lb/s
EXHAUST FLOW	770.0 lb/s	726.0 lb/s	681.0 lb/s
EXHAUST TEMP	964 F	976 F	993 F
POWER GENERATED	97551 KW	86460 KW	77704 KW
Heat Rate HHV (1)	12250 Btu/KWhr	12650 Btu/KWhr	13006 Btu/KWhr
Efficiency HHV (1)	27.86 %	26.97 %	26.23 %
Coal Flow	31.2 lb/s	28.5 lb/s	26.4 lb/s
Heat Rate HHV (2)	14066 Btu/KWhr	14525 Btu/KWhr	14935 Btu/KWhr
Efficiency HHV (2)	24.26 %	23.49 %	22.85 %

(1) Based on cleaned fuel gas heating value
(2) Based on coal heating value

2.4. Issues Affecting Turbine Performance

2.4.1 Coal Quality

The Free Swelling Index and ash fusion characteristics of the coal vary the raw gas quantity from the gasifier. Therefore, once a gasifier has been selected to process a selected coal, variations in the coal might reduce the gas output. This will result in reduced power production.

2.4.2 Gasifier Cooling

Steam is injected into the gasifier to cool the grate and control peak combustion zone temperatures. However, as the amount of steam is increased, the heating value of the exiting gas decreases by dilution. This results in large quantities of fuel needed for combustion in the gas turbine. The compressor will reach the surge limit with excessive amounts of steam injection into the gasifier.

Alternative methods of cooling the gasifier grate and limiting peak gasifier combustion zone temperature to avoid ash melting are being developed. One such method is the use of atomized water spray between the turbine compressor bleed and the booster compressor. Such a scheme serves to cool the gasifier air bleed stream by water evaporation (in lieu of an intercooler). Ultimately, this also serves to cool the gasifier grate and lower peak gasification temperature with minimum addition of mass to the low Btu gas stream. Using water instead of steam increases the heating value of the fuel, leaving the gasifier by approximately 20%. Therefore, fuel flow requirements for the gas turbine will decrease and compressor surge avoided.

TABLE 9a - 200 MW CYCLE

GAS TURBINE - GENERAL ELECTRIC GE 7191 F
ALTITUDE - 0 ft   FUEL - LOW-BTU GAS
INLET LOSS - 4" H2O   EXHAUST LOSS - 12" H2O

AMB. TEMP	20 F	59 F	90 F
REL. HUMIDITY	60 %	60 %	60 %
INLET FLOW	987.0 lb/s	921.0 lb/s	859.0 lb/s
AIR BLEED	110.8 lb/s	102.0 lb/s	95.0 lb/s
FUEL FLOW	198.0 lb/s	183.0 lb/s	170.0 lb/s
EXHAUST FLOW	1074.0 lb/s	1002.0 lb/s	935.0 lb/s
EXHAUST TEMP	1073 F	1102 F	1129 F
POWER GENERATED	180379 KW	161714 KW	147509 KW
Heat Rate HHV (1)	11116 Btu/KWhr	11460 Btu/KWhr	11671 Btu/KWhr
Efficiency HHV (1)	30.70 %	29.78 %	29.24 %
Coal Flow	52.3 lb/s	48.3 lb/s	44.9 lb/s
Heat Rate HHV (2)	12764 Btu/KWhr	13159 Btu/KWhr	13402 Btu/KWhr
Efficiency HHV (2)	26.73 %	25.93 %	25.46 %

(1) Based on cleaned fuel gas heating value
(2) Based on coal heating value

TABLE 9b - 200 MW CYCLE

GAS TURBINE - MITSUBISHI-WESTINGHOUSE 501-F
ALTITUDE - 0 ft   FUEL - LOW-BTU GAS
INLET LOSS - 4" H2O   EXHAUST LOSS - 12" H2O

AMB. TEMP	20 F	59 F	90 F
REL. HUMIDITY	60 %	60 %	60 %
INLET FLOW	1016.0 lb/s	941.0 lb/s	876.0 lb/s
AIR BLEED	117.1 lb/s	105.7 lb/s	97.4 lb/s
FUEL FLOW	208.0 lb/s	188.0 lb/s	174.0 lb/s
EXHAUST FLOW	1107.0 lb/s	1023.0 lb/s	953.0 lb/s
EXHAUST TEMP	1075 F	1092 F	1108 F
POWER GENERATED	188682 KW	166235 KW	150272 KW
Heat Rate HHV (1)	11164 Btu/KWhr	11453 Btu/KWhr	11726 Btu/KWhr
Efficiency HHV (1)	30.57 %	29.79 %	29.10 %
Coal Flow	54.9 lb/s	49.6 lb/s	45.9 lb/s
Heat Rate HHV (2)	12819 Btu/KWhr	13151 Btu/KWhr	13465 Btu/KWhr
Efficiency HHV (2)	26.60 %	25.95 %	25.34 %

(1) Based on cleaned fuel gas heating value
(2) Based on coal heating value

2.4.3 Gas Turbine Compressor Surge

Surge occurs when compressor discharge pressure rises and discharge flow is reduced beyond the design margin. Compressor discharge pressure is related to combustor/expander mass flow rates. This establishes an upper limit on fuel gas flow.

Efforts to minimize fuel mass flow (water injection versus steam injection to gasifier) will reduce surge control requirements.

2.4.4 Combustion Turbine Inlet Temperatures

Latest advancements in metallurgy and air cooling techniques have allowed turbine inlet temperatures to rise to 2300 F. Single crystal casting techniques and new cobalt-based alloys point toward higher firing temperatures in the future. An increase of 100 F in firing temperature relates to a 10 to 13% increase in power output and 2 to 4% improvement in simple cycle efficiency. [11]

It may be difficult to reach these higher turbine inlet temperatures with an existing aero-derivative gas turbine burning low-Btu fuel. The increased mass flow through the expansion section of the turbine causes shaft speeds and pressures to rise quickly in multi-shaft machines. As a result, turbine inlet temperatures may have to be decreased to control overall gas turbine performance.

2.4.5 Fuel Inlet Pressure

Some manufacturer's requirements indicate a need for a pressure drop across the fuel control valve of up to 75 psi. The operating pressure of the gasifier will be increased over the compressor discharge pressure by the amount needed to overcome system pressure losses and pressure drops across the fuel valves. Minimization of fuel valve pressure losses decreases gasification pressure and therefore, air booster compressor power consumption.

2.4.6 Volatilized Alkali

There exists significant concern (Appendix B) as to the fate of volatilized alkali between the coal gasifier and the turbine combustor. If significant fractions of alkali reach the turbine combustor and form sodium sulfate, premature turbine expander blade corrosion may be expected.

2.4.7 NOx Emissions

The combination of rich/lean combustion at the turbine combustor combined with selective catalytic reduction (SCR) is believed to be sufficient to achieve the goal of 0.1 lb/MBtu NOx emission rate.

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Gasifier Design Modifications Required to Accommodate High Free Swelling Coals

Section 3

January 1991

Work Performed Under Contract No. DE-AC21-89MC26291

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
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3.1. Summary

This specific section is intended to evaluate advantages/disadvantages of candidate coal gasifiers matched with combustion turbine/HGCU modules. It also provides for the development and expected performance characteristics of selected advanced coal gasification machines as required to accommodate program objectives. Included is the assimilation of empirical data and industry experience describing optimized combinations of air-blown Fixed Bed Gasifier/HGCU/Combustion Turbine combinations.

The data reviewed was developed from the principal investigator's experience in the design, construction, and operation of air-blown, fixed-bed coal gasifier, stoker, pulverized and fluidized coal combustion systems. In addition, data developed by the Department of Energy's Morgantown Energy Technology Center (METC), General Electric (GE), the Lurgi Corporation, GT Pro and MESA Computer Programs was utilized in the assessment of the status of air-blown, fixed-bed coal gasifiers as applied to standardized IGCC systems.

Although historical information reveals that maximum coal inputs (hence raw gas outputs) to fixed bed systems vary significantly due to wide ranges in coal reactivity, caking and ash fusion characteristics, the selection of standardized modular components assumes the successful near term development of air-blown, fixed-bed gasifiers capable of operation without capacity reduction due to coal quality changes over the range of US coals contemplated.

It has been determined that the formation of stickey tars and asphaltines during the devolitization process is the main cause of subsequent agglomeration leading to channeling, reduced coal/air/steam reactions, and hence output capacity reductions. Two approaches to dealing with this problem are postulated herein. The first provides for a mechanical means of breaking up agglomerates as and once they have formed. The other is aimed at preventing the inception of agglomeration.

3.2. Coal Gasifier Selections

3.2.1 Overview Descriptions of Candidate Coal Gasifiers

In order to better understand the effects of various parameters upon coal gasifier performance, an overview of selected available coal gasifiers [1][2] was conducted (Table 1). The results of that overview are presented in the following sections.

Table 1
Generic Gasifier Features

Gasifier	Features
Air-blown, Fixed-bed, Dry-ash Bottom	
Lurgi	300 psi Operating Experience Mature Mechanical Design Commercially Available
Riley Morgan	Air-blown Experience on US Coals Water Cooled Stirrer Experience
Wellman Galusha	Mature Mechanical Design
Woodall-Duckham	Two Stage Mature Mechanical Design
Kohlegas Nordrhein	Internal Recycle of Top Gas
GE	Air-blown Experience on US Coals
METC	Air-blown Experience on US Coals Water Cooled Stirrer Experience High Pressure Operating Experience Grate Accomodates Clinkers
Air-blown, Fixed-bed & Entrained-bed, Slagging Bottom	
British Gas Lurgi	Capable of Handling Fines Produces Benign Ash
Voest-Alpine Gasification Reactor	Capable of Handling Fines Produces Benign Ash
National Coal Board	Capable of Handling Fines Produces Benign Ash
Py-Gas Coal Gasifier at Full Capacity	Accepts High Free Swelling Coals Accepts Coal Fines Cracks Tars Condenses Volatilized Alkali Eliminates Coal Feed Lock Hopper Losses

The concept of modular standardized plants results in the anticipation of the utilization of either the proper number of Lurgi or METC air-blown fixed bed coal gasifiers sized for the specific coal characteristic analysis under consideration (Figure 1), or the anticipation of an alternate air-blown, fixed-bed coal gasifier capable of operating without capacity limitations over the entire range of coal characteristics contemplated within this study. Four hot gas cleanup unit (HGCU) absorber modules and a four HGCU regenerator modules sized for shop fabrication and truck delivery (approximately 13 ft. diameter) are anticipated to be of sufficient capacity for the 200 MW nominal plant capacity (Figure 2). Two direct sulfur dioxide recovery process (DSO2RP) packed column vessels, steaming tower and drying tower in series including heat exchangers for sulfur dioxide condensation are anticipated to be sufficient for 99+% sulfur removal.

3.2.1.1 Air-blown, Fixed-bed, Dry-ash Bottom

Several air-blown, fixed bed, dry ash bottom gasifier candidates were considered. These include Lurgi, Riley Morgan, Wellman Galusha, Woodall Duckham/GI, Kohlegas Nordrhein (KGN), GE, and METC. These coal gasification devices are mature mechanical designs applicable to limited capacity outputs [3]. The Lurgi (Figure 3) and METC (Figure 4) designs come closest to meeting the operational constraints imposed by the IGCC concepts of this study. Both are high operating pressure designs which have acknowledged limited air-blown experience, but which have been demonstrated on a wide variety of US coals. The Lurgi gasifier output is suspect on high free swelling coals [3][4][5], while the METC gasifier requires scaleup of at least 15 to 1 on coal throughput to be considered for cogeneration applications. Its ability to gasify high free swelling coals is contingent on its internal stirrer mechanism's ability to break up clinkers into manageable sizes and to control channeling during the agglomeration process.

3.2.1.2 Air-blown, Fixed & Entrained-bed, Slagging Bottom

Several air-blown fixed and entrained bed, slagging bottom-ash gasifier candidates were considered. These include British Gas Lurgi (BGL), Voest-Alpine Gasification Reactor, National Coal Board (NCB-CURL) fixed bed reactors, and Texaco, Shell, and Dow entrained bed reactors.. These coal gasification devices are also mature mechanical designs applicable to a limited coal inorganic fraction characteristic range

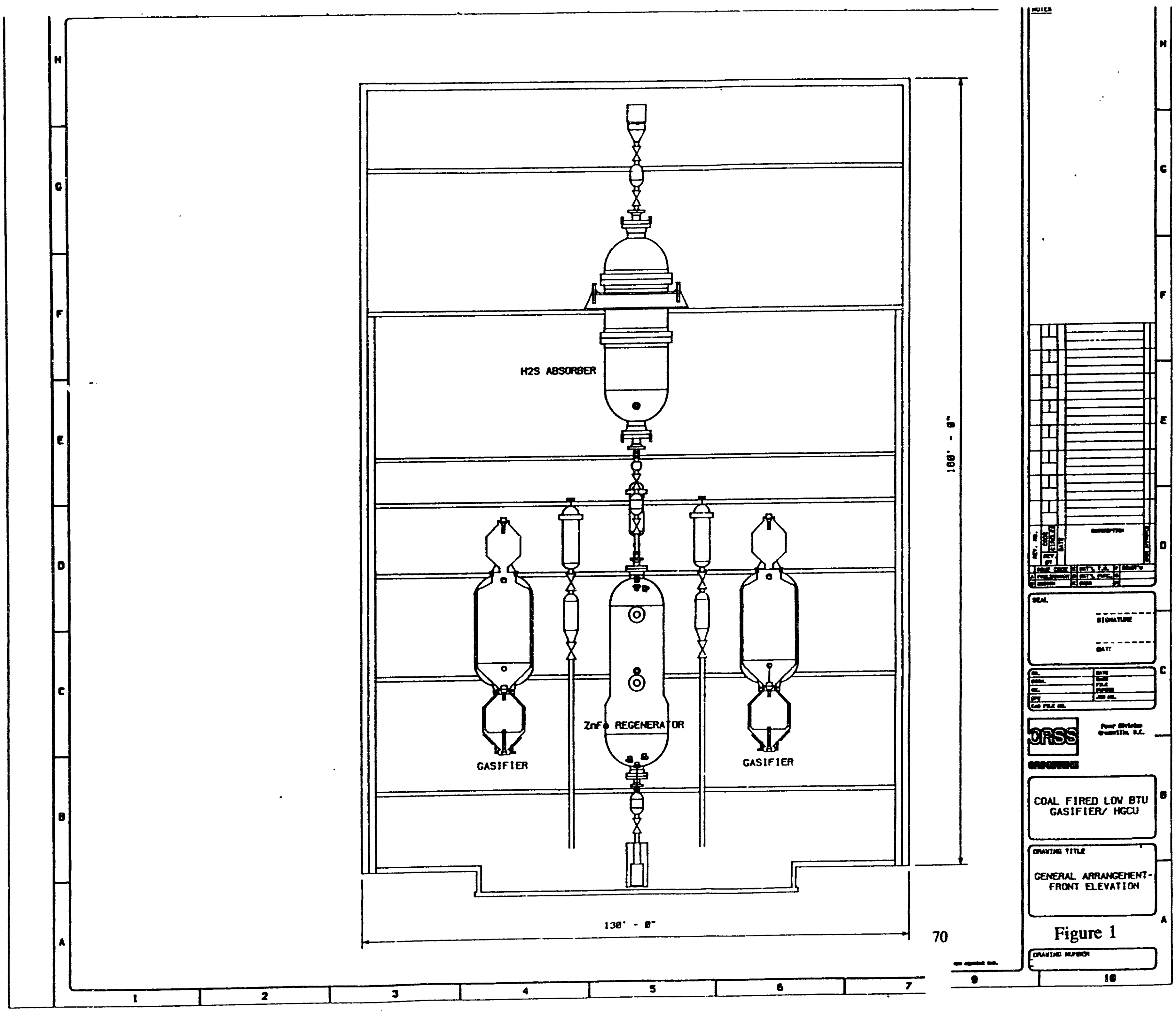
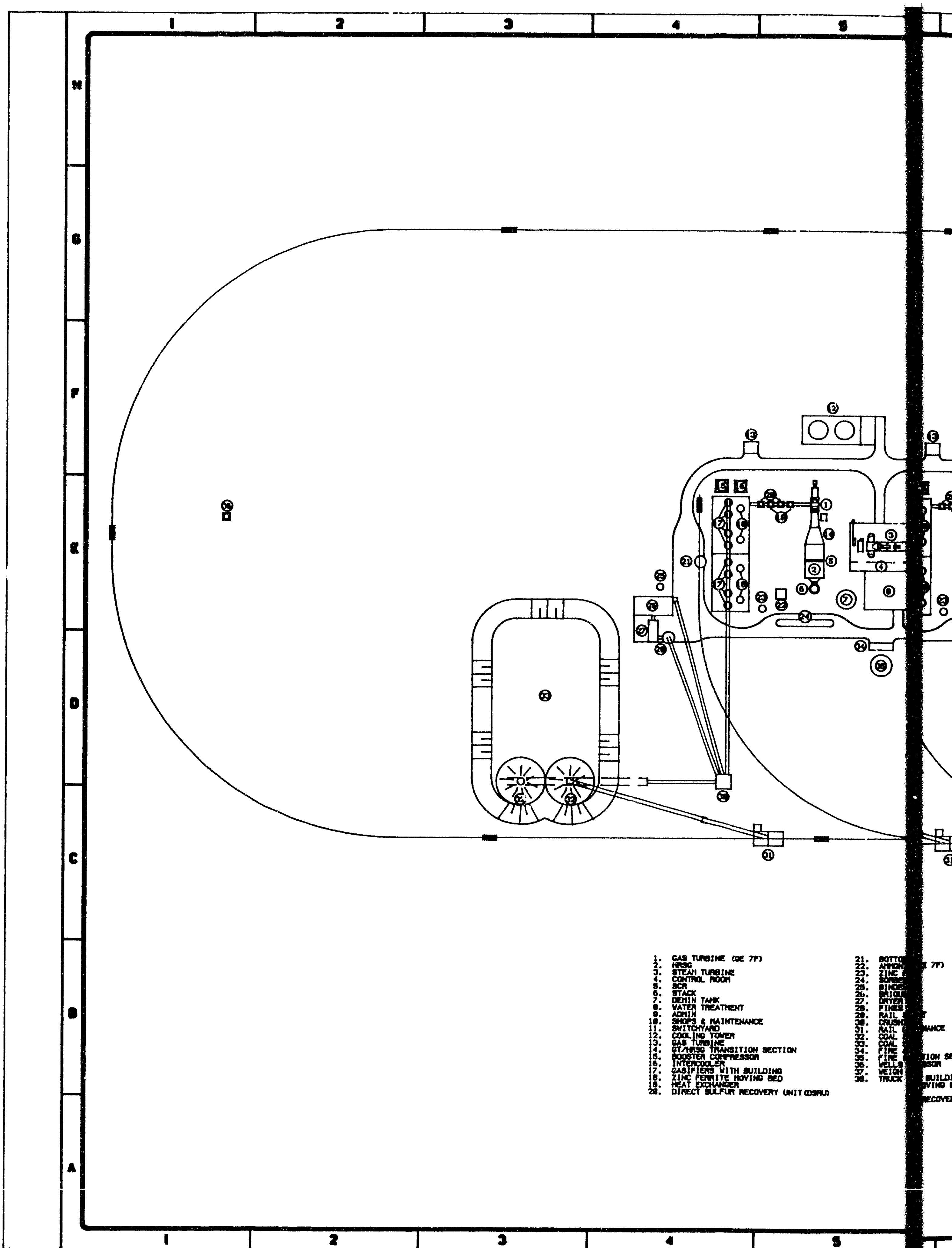
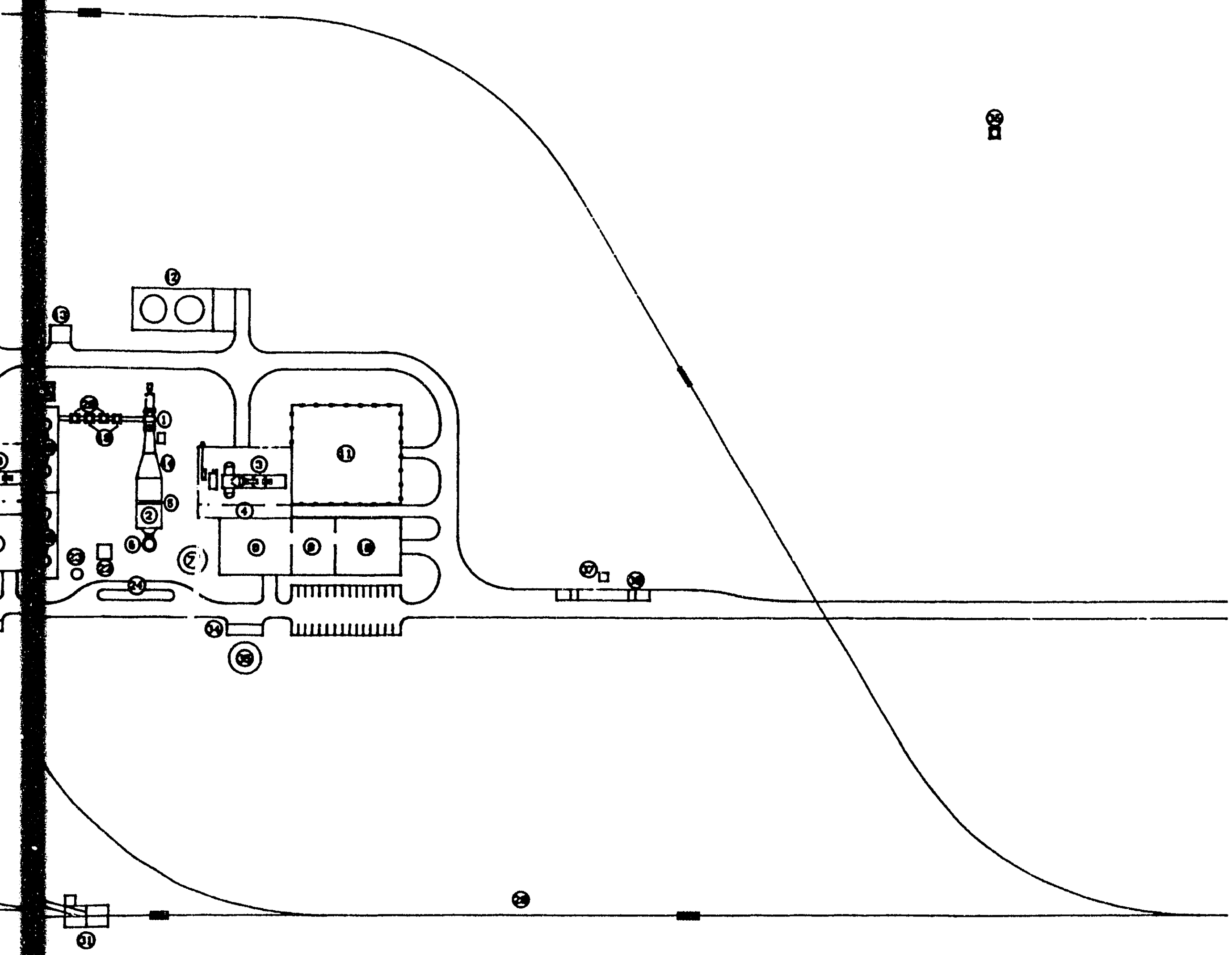

H2S ABSORBER
ZnFe REGENERATOR
GASIFIER
GASIFIER
180' - 0"
130' - 0"
SIGNATURE
COAL FIRED LOW BTU GASIFIER/ HGCU
DRAWING TITLE
GENERAL ARRANGEMENT-FRONT ELEVATION

Figure 1


1. GAS TURBINE (GE 7F)
2. HRSG
3. STEAM TURBINE
4. CONTROL ROOM
5. SCR
6. STACK
7. DEMIN TANK
8. WATER TREATMENT
9. ADMIN
10. SHOPS & MAINTENANCE
11. SWITCHYARD
12. COOLING TOWER
13. GAS TURBINE
14. GT/HRSG TRANSITION SECTION
15. BOOSTER COMPRESSOR
16. INTERCOOLER
17. GASIFIERS WITH BUILDING
18. ZINC FERRITE MOVING BED
19. HEAT EXCHANGER
20. DIRECT SULFUR RECOVERY UNIT (DSRU)
21. BOTTO
22. AMMON
23. ZINC
24. SORBE
25. BINDE
26. BRIQU
27. DRYER
28. FINES
29. RAIL
30. CRUSH
31. RAIL
32. COAL
33. COAL
34. FIRE
35. FIRE
36. WELLS
37. WEIGH
38. TRUCK



21. BOTTOM ASH SILO
22. AMMONIA
23. ZINC FERRITE RECOVERY
24. SORBENT RECOVERY
25. BINDER TANK
26. BRIQUET BLDG.
27. DRYER
28. FINES SILO
29. RAIL SYSTEM
30. CRUSHING/SCREENING TOWER
31. RAIL UNLOADING
32. COAL STORAGE (LIVE)
33. COAL STORAGE (DEAD)
34. FIRE & RAW WATER PUMP HOUSE
35. FIRE & RAW WATER TANK
36. WELLS
37. WEIGH STATION
38. TRUCK SCALE

0' 120' 240' 360'

NOTES

SEAL

SIGNATURE

DATE

CRSS

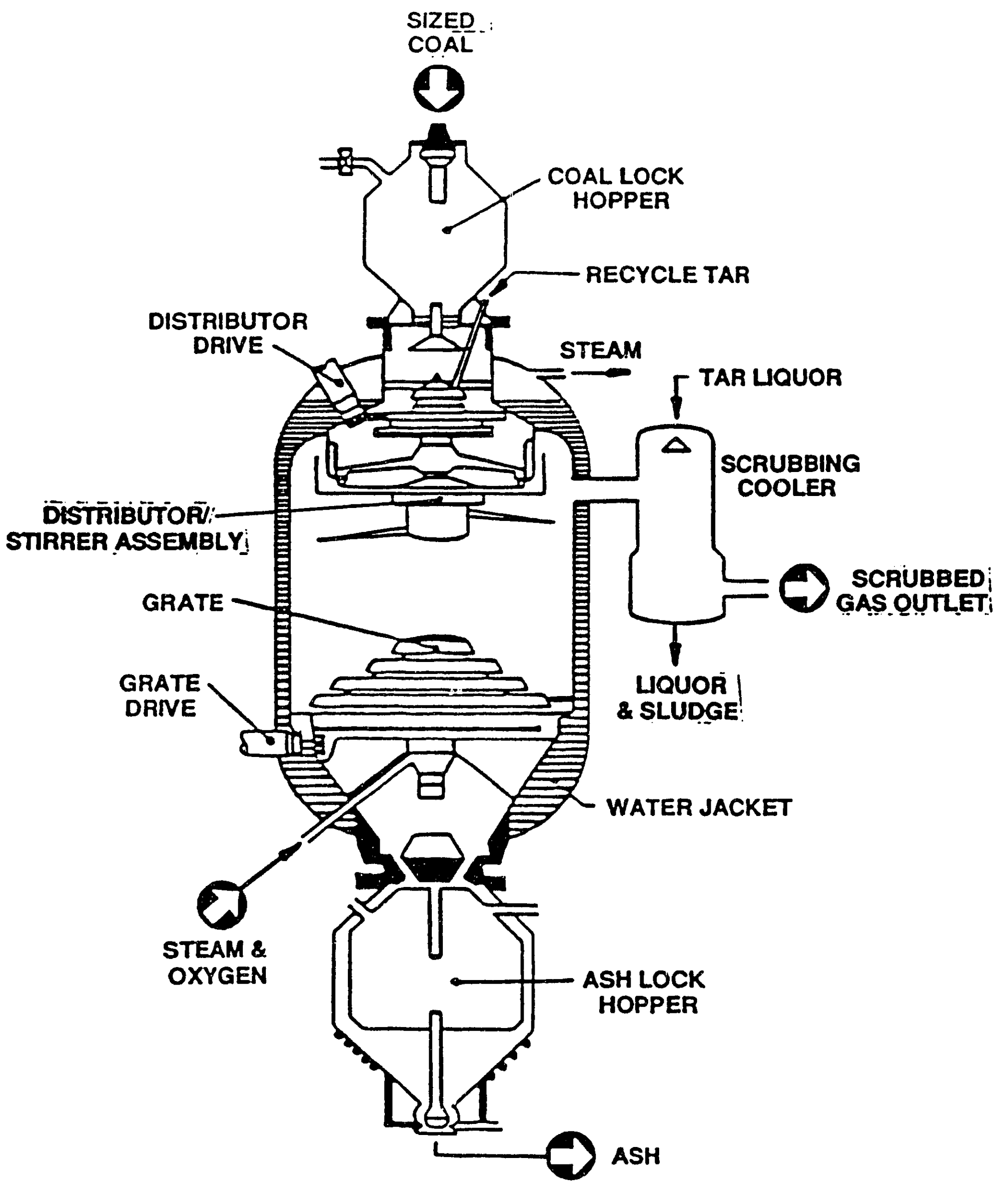
DEVELOPMENT OF STANDARDIZED AIR-BLOWN COAL GASIFIER/ GAS TURBINE CONCEPTS

DRAWING TITLE

PLOT PLAN
220 MW PLANT

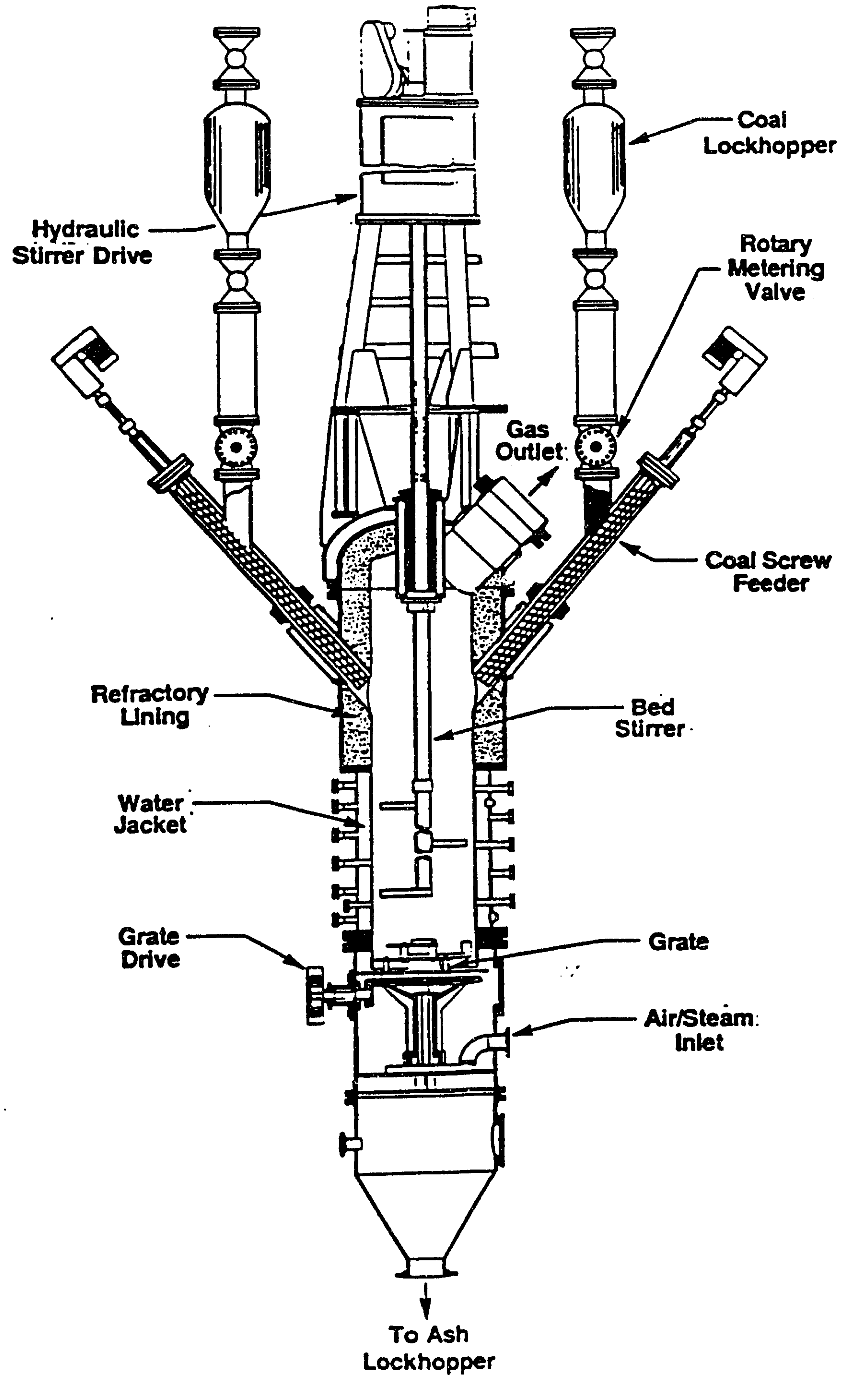
Figure 2

DRAWING NUMBER



Lurgi Pressure Gasifier

Figure 3



Sectional View of Current METC Fixed-Bed Gasifier

Figure 4

when air-blown. The anticipated draw back of these candidates stems from the historical limits of similar applications of utility sized slagging pulverized coal fired boilers designed for molten ash tapping removal. Both the B&W Cyclone and the Riley Wet Bottom Turbo Furnace (Figure 5) designs saw very limited application [6] due to the limited availability of coals in the USA whose ash fusion temperature ranges and theoretical T-250 poise viscosity characteristics were low enough to avoid molten slag tapping difficulties. In many cases fluxing agents had to be introduced into the firing chamber of these utility applications to maintain molten slag conditions and avoid freezing of the slag prior to tapping.

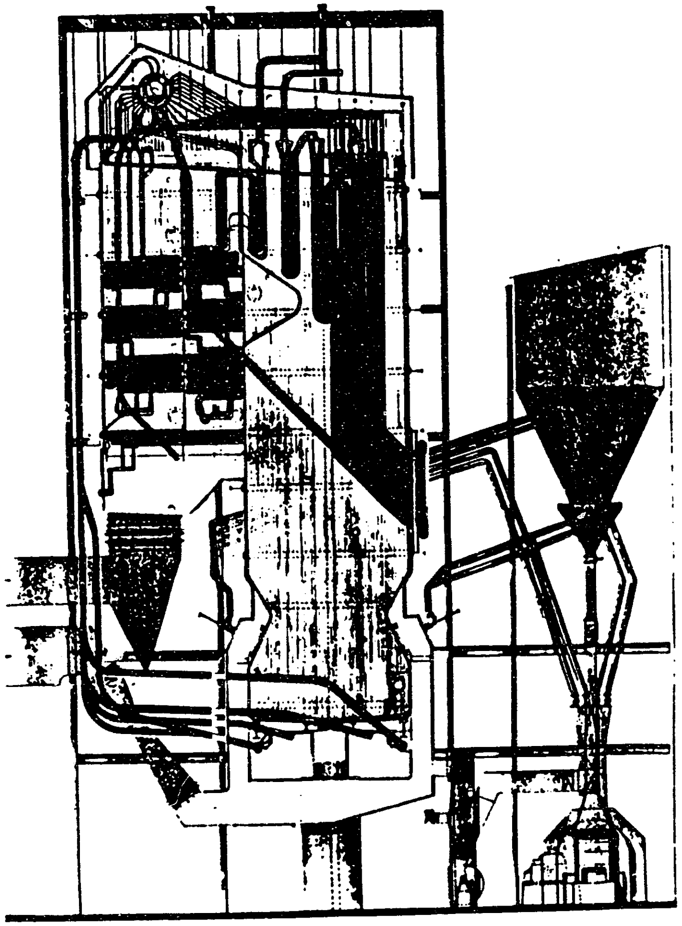
A second concern in the consideration of molten bottom gasifiers is the expectation of considerably greater volatilized alkali [7][8] generation due to their comparatively higher gasification operating temperatures. Data reviewed (Figure 6) shows as much as three orders of magnitude greater amounts of volatilized alkali is associated with these higher operating temperature processes than for the lower operating temperature fixed-bed, dry-bottom gasifiers.

For these reasons, this study will not give further consideration to the entrained or fixed bed slagging type of gasifier.

3.2.1.3 Py-Gas Coal Gasifier

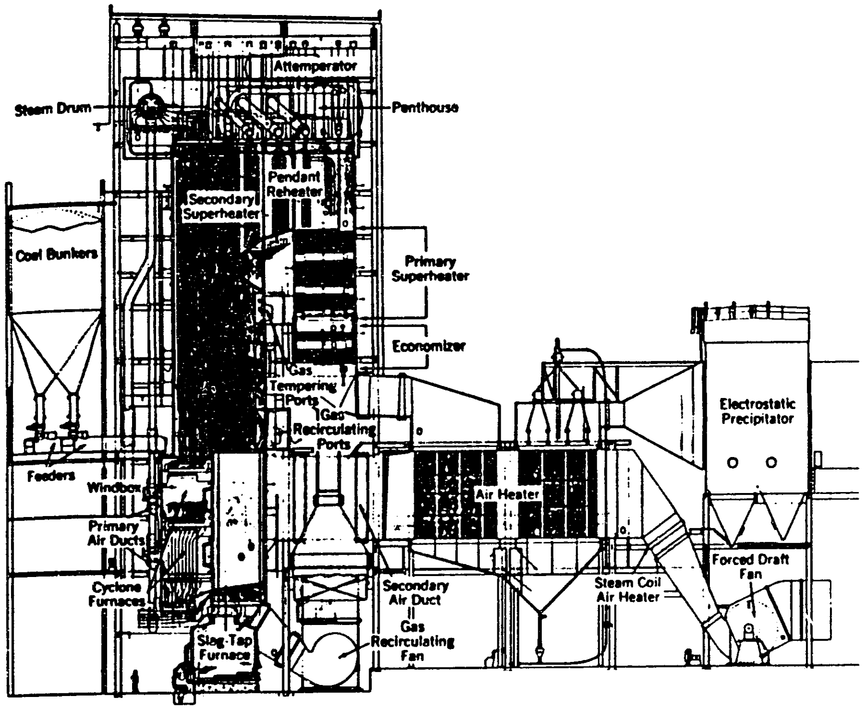
Consistent with the objectives of this study, a new concept in coal gasification design is presented herein. While the approach anticipated in paragraph 3.1 above deals with agglomeration and clinkering (which lead to channeling and capacity curtailment) after the fact, the approach of the PyGas (Figure 7) concept is to avoid (by design) the conditions within the gasifier which promote or initiate agglomeration and clinkering.

Typical Utility Type Pulverized Coal Fired Slag Tap Boilers



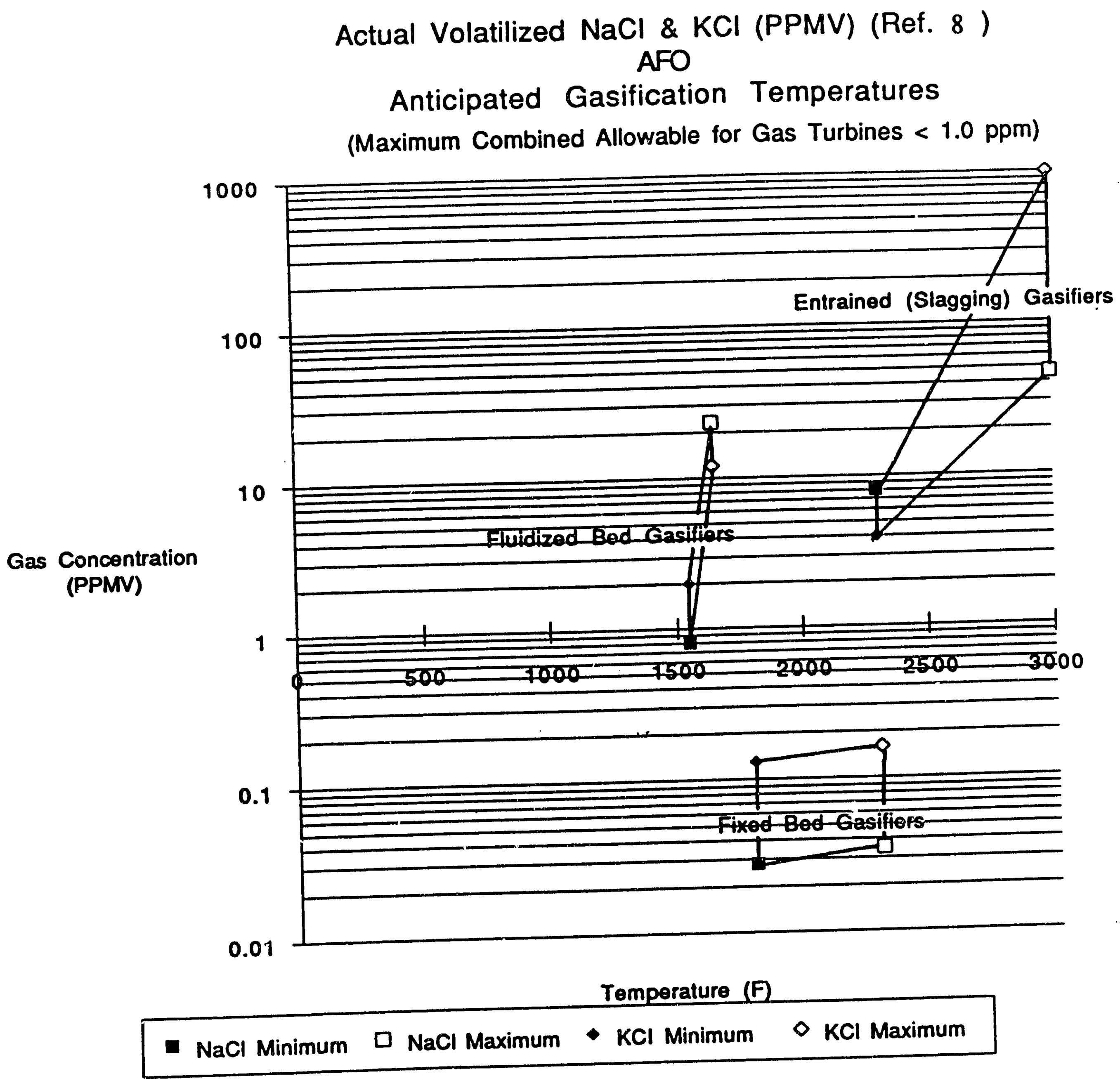
Above is a wet bottom type Turbo Furnace at a large southern utility. This unit produces 3,136,000 pounds of steam per hour at a pressure of 2875 psig and a temperature of 1000/1000F, firing pulverized coal.

Steam/Fossil-fuel boilers for electric utilities



Radiant boiler with Cyclone Furnaces.

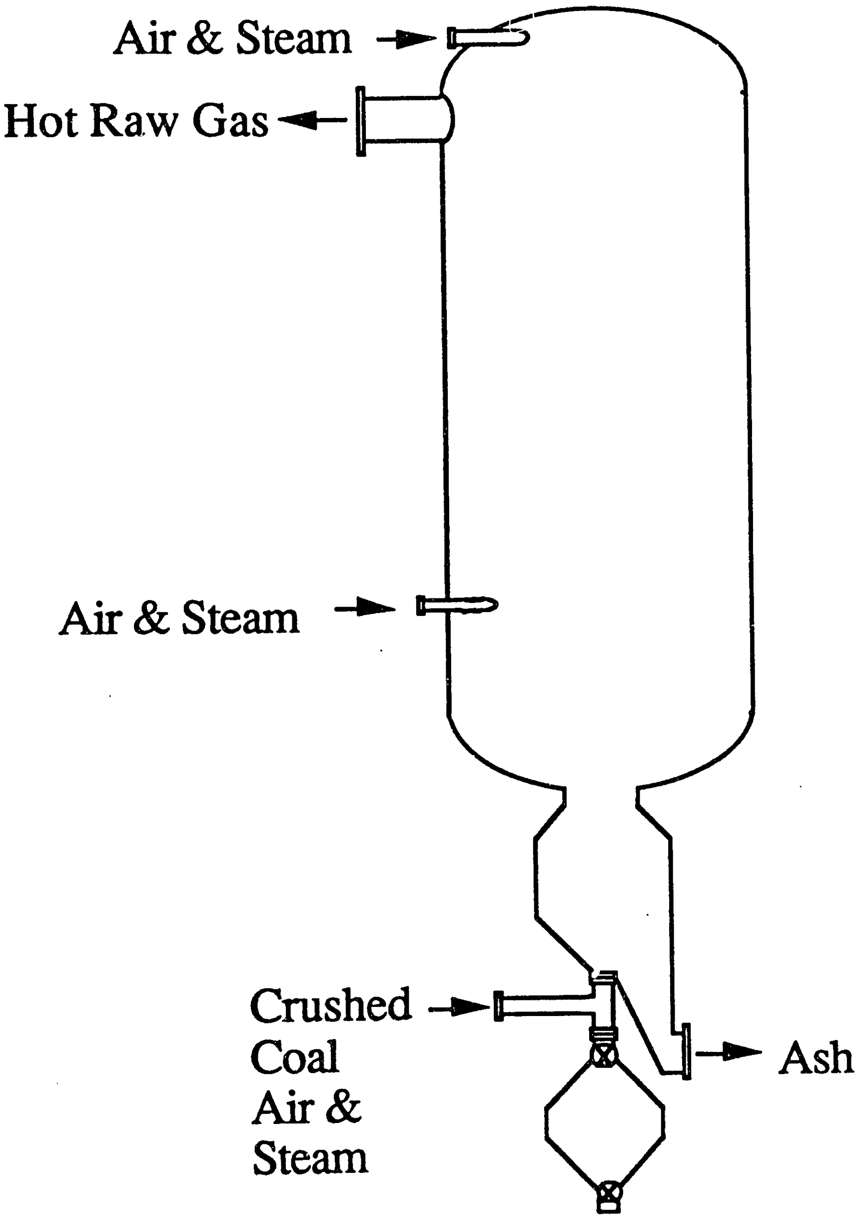
Figure 5



Actual Volatilized NaCl & KCl (PPMV) (Ref. 8)
AFO
Anticipated Gasification Temperatures
(Maximum Combined Allowable for Gas Turbines < 1.0 ppm)
1000
100
10
1
0.1
0.01
Gas Concentration (PPMV)
0
500
1000
1500
2000
2500
3000
Entrained (Slagging) Gasifiers
Fluidized Bed Gasifiers
Fixed Bed Gasifiers
Temperature (F)
NaCl Minimum
NaCl Maximum
KCl Minimum
KCl Maximum

Figure 6

The PyGas Producer



Major Features

1. Consumes Run of Mine Coal
2. Accepts Caking Coals
3. Cracks Tars
4. Consumes Fuel Moisture
5. Minimizes Volatilized Alkali Carryover
6. Continuous Coal Feed (No Lock Hopper Losses)
7. Dry Ash Removal
8. High Carbon Utilization
9. Air Blown
10. Produces Very Hot Raw Gas (Ideal for Hot Gas Cleanup)

Figure 7

3.2.2. Detailed Descriptions of Candidate Coal Gasifiers

The following coal gasifiers were selected for more detailed consideration since they are all anticipated to be commercially available within the timeframe of consideration of this report (ten years). It is not the intent of this study to preclude other manufacturers from such consideration, or to imply that these represent the only such advanced coal gasifiers which may be available.

3.2.2.1 Lurgi Mark IV

The Lurgi Mark IV gasifier is approximately 41 ft in height and 12.63 ft ID (4 meters) in diameter [1][2]. It has successfully operated at pressures in the 300 psi to 450 psi range which is consistent with the requirements of this application. Although it has primarily operated on low free swelling coals and with oxygen, it is believed that it can operate successfully air-blown and (with the application of a stirrer mechanism) on higher free swelling index coals. However, experience with the operation of a full sized atmospheric air-blown coal gasifier indicates that a stirrer mechanism cannot prevent the agglomeration phenomenon from occuring, and in some cases makes channeling even worse, thereby severely curtailing gasification output. Therefore, even with a stirrer mechanism, the Lurgi Mark IV will likely be very greatly derated when operating on US coals with free swelling indexes as high as 8. The maturity of the Lurgi Mark IV design establishes it as commercially available and financeable today. While this is a plus for this design, it also means that the normally desireable competitive market condition does not currently exist. This in turn is likely to result in higher premiums for the commercial product until such time that a more competitive environment develops.

3.2.2.2 Scaled-up METC Gasifier

One alternative gasifier candidate which could be developed, creating a more competitive environment, is the METC design [9]. This device has successful test facility sized operating experience on a wide variety of US coals. It could readily be upsized to a 13 foot ID full sized shop fabricated truck shippable vessel suitable for application to IGCC systems as defined within the scope of this project. It is likely to perform as well or better than the present day Lurgi Mark IV gasifier since it has a well developed stirrer and grate capable of crushing small clinkers. It is also likely to be limited in capacity [10] when applied to coals with free swelling indexes of 8 (FSI=8); however, if cost competitive, it could conceivably meet the economics hurdles of this study.

3.2.2.3 Py-Gas Coal Gasifier

Within the context of this study, the Py-Gas coal gasifier is a coal pyrolyzer contained within an air-blown, fixed-bed, dry bottom coal gasifier vessel. The purpose of the pyrolysis section of the device is to devolatilize the coal feed stream passing rapidly through the agglomeration zone [5][10][11] before the remaining ash/char enters the gasification section of the vessel. In this way, the whole phenomenon of agglomeration is avoided. Since agglomeration (most pronounced with high free swelling eastern high volatile bituminous coals) is a precursor to clinkering and channeling, the device will not suffer from capacity curtailment resulting from agglomeration (Figure 8).

The use of pneumatically conveyed crushed coal (typically 1/4 inch by 0), as the feed to the pyrolysis chamber [12][13][14][15], eliminates all concern and the costly complexity of lump coal lock hopper arrangements and their associated venting schemes.

The use of crushed coal feedstock [12][13][14][15] also enhances the use of "run of mine" coal without the added cost and complexity of a briquetting plant required by lump coal gasifier designs, further enhancing the cost competitiveness of such a coal gasifier device.

Greater gasification capacity results from the use of smaller sized coal which can react more readily than lump coal due to its greater gas-to-coal surface reaction area.

The pyrolyzer exit to gasifier entrance provides for the introduction of cocurrent air and steam flow with the char to be gasified. This, in turn, provides better temperature control of the fixed gasification bed, and results in the cracking of tars formed during the devolatization process as the cocurrent streams pass down through the hottest region of the gasifier prior to exiting the vessel.

An Experimental Illustration of Devolatilization & Agglomeration

(Ref. 5)

"We have found it useful to observe this process in a simple laboratory test. The devolatilization of a small number of particles can be studied in a simple retort under simulated gasifier exit conditions. Both the gaseous environment and temperature exiting in the upper regions in the fuel bed are recreated in the retort. The results of such a test on an eastern bituminous coal with a free swelling index of 4 1/2 and a non-swelling northern plains lignite is illustrated in Figure 8.

In each test three pieces of sized fuel (1" X 3/4") were inserted into an oven preheated to a desired control temperature. The coal particles were made to touch each other and a blended producer gas mixture was fed into the oven chamber. The object of the experiment was to simulate the heating rate experienced by large coal feed particles falling onto a gasifier fuel bed. After devolatilization was complete the char particles were removed, weighed and then tested for strength in a drop shatter test.

It can be seen in Figure 8 that the swelling for each group of bituminous coal particles was not the same. Less swelling and less surface flow appears to have occurred as the temperature was increased. At high heating rates a steep temperature gradient is produced throughout the large coal particle. Under these conditions the outer layer of the particle exists in a plastic and liquid state for only a very short period. An outer semi-coke shell is formed before a deep plastic layer develops. This shell is strong enough to restrict further expansion of the particle. At lower particle heating rates temperature gradients are much less steep. In the experiment described by Figure 8 a large agglomerated mass was formed at a temperature of 750°F. The structure of this swollen char mass was exceptionally weak and had the fragility of a Christmas Tree ornament.

Unlike bituminous coal the lignite particles did not noticeably change in volume when heated nor did they fuse with adjacent particles. The particles appeared to exhibit a distinct laminar structure with splintering occurring along the bedding planes.

The effect of temperature and heating rate on the strength of lignite char was found to be directly opposite to that for bituminous char. The amount of lignite char breakage in a drop shatter test was found to increase with higher retort temperatures while the amount of bituminous char breakage decreased."

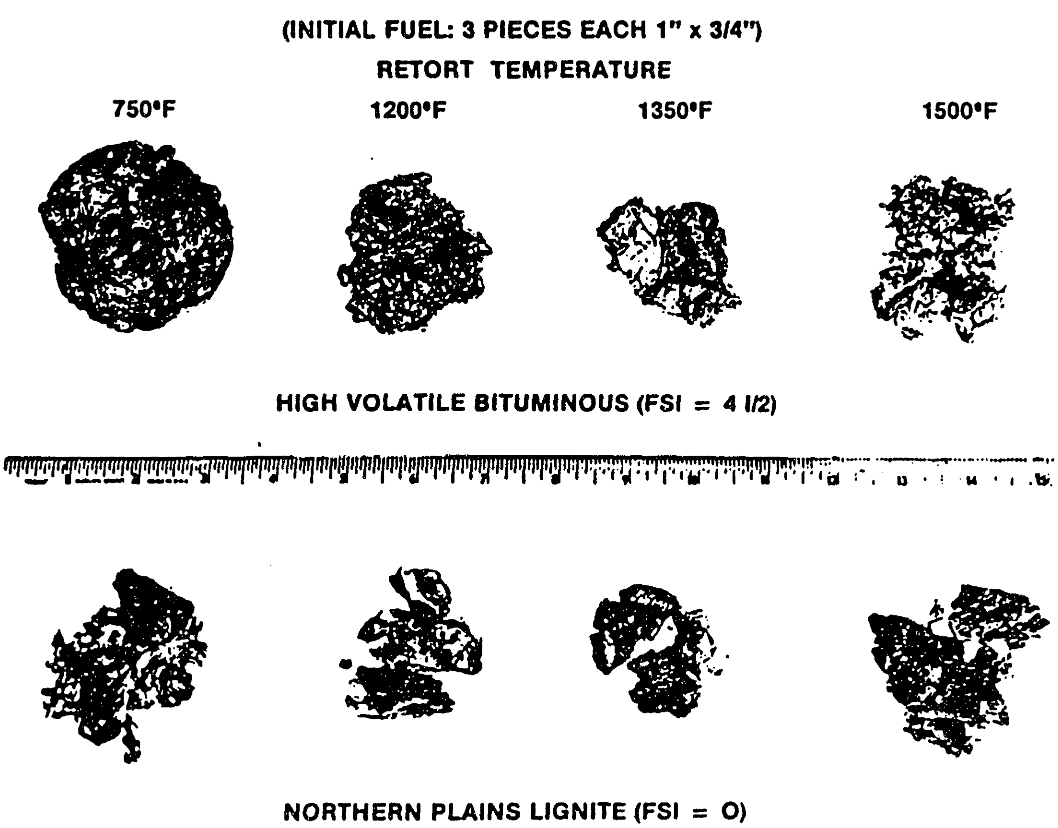


Figure 8

Since the gas is forced to pass through the ash cooling region of the gasifier, any volatilized alkali generated in the combustion zone will be cooled and passed through the ash bed resulting in their removal prior to exiting the gasifier. This gasifier configuration also lends itself to aluminosilicate sorbent volatilized alkali removal strategies.

3.3. Estimated System Performance

3.3.1 Performance Discussion

During the compilation of capacity data, publically available empirical information was used to generate predicted system performance. Very wide ranges of gasification unit throughput appear throughout the literature [3][4][5]. The performance of an air-blown fixed bed coal gasifier is the direct result of the coal quality and characteristics utilized in a given gasifier.

3.3.2 Performance Parameters

In the performance of a coal gasifier, the output of the device is a function of:

3.3.2.1 The characteristics of the coal being supplied to the gasifier.

3.3.2.2 The relative quantities of air and steam fed to the coal gasifier.

3.4. Issues Affecting System Performance

Based upon a review of available information as presented in Sections 1 thru 3 of this report, it is anticipated that the parameters listed in the following paragraphs will affect air-blown, fixed-bed gasifier performance. At present, the exact effects of each of the parameters will require experimental determination; however, each of them has been identified as significant to IGCC coal gasifier performance.

3.4.1 Coal Free Swelling Index (FSI)

This index will likely have the greatest single influence on gasifier coal throughput (gas output). The literature indicates about a four to one range of output over the free swelling index (FSI) range of zero (0) to eight (8). Clearly, if a standard IGCC gasifier to be applicable to all U.S. coals up to a FSI of eight (8), this influence must be recognized, planned, and designed.

3.4.2 Coal Ash Fusion Temperature Characteristics

Ash fusion temperature affects the amount of steam which must be added to the gasifier to maintain the ash below its softening temperature [2]. The lower the ash fusion temperature, the more steam that is required to prevent clinker formation.

3.4.3 Gasifier Steam to Coal Ratio

Steam is introduced into the coal gasifier to both cool the grate and to control the peak combustion zone temperatures below the coal's inorganic fraction melting point. The Lurgi Mark IV steam-to-coal ratio typically ranges from 0.6 to 1.7. Concern has been expressed that at high steam flows to the gasifier, the coal derived low Btu gas mass flow to the combustion turbine can exceed turbine compressor surge margin limitations. This problem has caused CRS Sirrine Engineers, Inc. to focus attention on ways to minimize steam flow to the gasifier in an effort to avoid such turbine compressor surge margin limitations. One potential remedy under consideration is the utilization of water in lieu of steam for cooling the gasifier. Such a concept would take advantage of the evaporative process of water to provide equivalent cooling at much lower moisture flow levels. A potential secondary benefit might also be derived from the location of water injection into the gasifier air stream. If introduced between the turbine compressor and the booster compressor, the evaporative process can be utilized to reduce the temperature and volume of the air to the booster compressor saving on booster compressor power consumption. Perhaps more importantly, it averts the materials challenge and high cost attendant with high compressor inlet temperatures. In this way, the equipment, complexity, and cost of intercooling are also minimized.

3.4.4 Coal Sizing

Most fixed bed coal gasifiers specify very tightly controlled coal feed gradation. It is unlikely that any fixed bed coal gasifier commercially available today will guarantee acceptable performance with significant fines content in the coal feedstock, particularly for caking coals. Clearly, this shortcoming must be addressed either by alternative utilization of fines, or gasifier design changes intended to accommodate run of mine coals. The PyGas coal gasifier design addresses this inherent gasifier problem.

3.4.5 Tar Production

Tar production can be minimized by various operational techniques, however some tar should always be expected from a fixed-bed gasifier. Several gasifier suppliers have reduced tar production by readmitting volatiles produced gas back through the char bed region. The PyGas coal gasifier design addresses this inherent gasifier problem by forcing the tars produced in the volatilization process to pass through the peak gasifier temperature zone where they are cracked.

3.4.6 Volatilized Alkali Production

From available data (Figure 6), it appears that the hotter the gasification process, the greater the volatilized alkali production. Slagging entrained bed gasifiers produce about three orders of magnitude more sodium and potassium than gas turbine manufacturers consider acceptable. Fluid bed gasifiers produce about two orders of magnitude more than is acceptable. Only fixed-bed, nonslagging gasifiers appear capable of maintaining sufficiently low volatilized alkali levels for direct hot gas utilization gas turbines without post gasifier treatment of the alkali vapors.

3.4.7 Thermal-phoresis

It is known that when gasifier exit temperatures are maintained well above the tar condensation range, the tars and heavy oils tend to crack. The resulting coke has an affinity for accumulating on any and all duct surfaces irrespective of duct refractory temperatures. The term "thermal-phoresis" has been used to describe this phenomenon. Historically, the best way to deal with it is to minimize the extent of any ductwork between the gasifier outlet and the hot gas cleanup unit (HGCU). Other obvious treatments such as soot blowers may have deleterious affects on the HGCU process.

3.4.8 Coal Feed Lock Hopper Batch Feeding vs. Continuous Pneumatic Feed

Typically, pressurized lock hopper arrangements which are located near the gasifier have an associated thermal loss from gasifier hot gas product venting. Such venting is necessitated by the admittance of hot raw gas product during the coal feed sequence. This hot raw gas is at operating pressure and hence must be vented before the coal bunker side valve is opened to atmosphere. Depending upon where and how the gas is vented, it can be a significant loss from the process.

The use of pneumatically conveyed crushed coal (typically 1/4 inch by 0) as the feed to the pyrolysis chamber of the PyGas gasifier, eliminates all concern and the costly complexity of lump coal lock hopper arrangements and their associated venting schemes.

3.4.9 Gasifier Air-to-Coal Ratio

The air-to-coal ratio to the gasifier is set by the gasification reaction requirements to consume the coal and produce low Btu gas therefrom. Typically for the Lurgi Mark IV gasifier, this ratio ranges from 1.3 to 1.9. For coals requiring air flows on the higher end of the range, care must be exercised in the admission of steam (again perhaps via the use of water) to the gasifier so as not to exceed combustion turbine surge ratio limitations.

3.4.10 Ammonia & Cyanide Production

All fixed bed gasifiers are likely to produce some ammonia and cyanide. A relatively large fraction of this "fuel bound nitrogen" is likely to become NOx when the gas is combusted in the gas turbine. There appears to be little that can be done in the gasifier to mitigate fuel bound nitrogen production. Therefore, to achieve NOx emission levels of 0.1 lb/MBtu , down stream NOx reduction and removal strategies (e.g. staged combustion , NOx reburning, ammonia injection, and SCR) are expected to be necessary and employed.

3.4.11 Ash Carbon Content

Ideally, gasification should proceed with near complete utilization of the carbonaceous fraction of the coal. During upset conditions such as gas channeling due to clinkering caused typically by high free swelling coal properties, significant quantities of unburned carbon may occur. This negatively affects both process efficiency and ash disposal since ash disposal cost is affected by its carbon content. Since coal ash which contains less than 5% unburned carbon can be stabilized, a reasonable goal for the standard IGCC gasifier is to maintain less than 5% carbon in the bottom ash.

3.4.12 Pressure Containment

It is anticipated that the standard IGCC gasifier will be operated at various pressures depending primarily on output required and coal characteristics. Pressure drop across the gasifier in addition to the attendant pressure losses of the systems downstream of the gasifier (tar and particulate removal, desulfurization/ regeneration, etc.) will culminate in the need for a booster compressor (or similar device) which allows the gasifier to operate at significantly greater pressures that the gas turbine. This presents a formidable need to adequately seal all gasifier penetrations against a hot, high pressure environment. Several gasifier suppliers have met this challenge to pressures in the 350-450 psig range. The remaining question is one of maintainability of the hardware involved.

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Design & Performance of Standardized Fixed Bed Air Blown Gasifier IGCC Systems

Section 4

January 1991

Work Performed Under Contract No. DE-AC21-89MC26291

For
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4.1. Summary

This specific section is intended to evaluate advantages/disadvantages of candidate coal gasifiers matched with combustion turbine/HGCU modules. It also provides for the development and expected performance characteristics of selected advanced coal gasification machines as required to accommodate program objectives. Included is the assimilation of empirical data and industry experience describing optimized combinations of air-blown Fixed Bed Gasifier/HGCU/Combustion Turbine combinations.

Information developed by the Department of Energy's Morgantown Energy Technology Center (METC), CRS Sirrine Engineers, Inc., and that of a number of cogeneration and independent power production developers have been objectively and subjectively evaluated in the development of this study.

The results indicate that although the anticipated first system costs will be relatively high, the assumption of pre-engineered standardized and modularized systems for Commercial Gasification IGCC Application (CGIA) systems results in an "Nth unit" total facility cost of under $1,000/kwn in sizes larger than 200 MWe. The resultant ten year levellized cost of electricity (COE) reflected the low CGIA standardized plant cost advantage.

Several issues relating to cost barriers to achieving the economic goals set for the study were broached. The first was to avert combustion turbine output limitations caused by encroachment on compressor surge margin limitations due to high low Btu coal gas mass flows to the turbine combustor. It was noted that the steam flow to the gasifier for grate cooling and gasifier peak combustion temperature limit control was the basic cause of excessive fuel related mass flow to the combustion turbine. The approach of replacement of gasifier steam flow with spray water flow upstream of the booster compressor was found to serve two worthwhile purposes. It allowed the combustion turbine to operate at full output by reducing the net fuel mass flow to within turbine manufacturer surge margin limits. It also reduced the turbine compressor outlet temperatures to tolerable limits to the booster compressor without the need for intercooling, thereby saving on both intercooling and booster compressor costs.

Another issue dealt with by this study was the cost/benefit of several basic sulfur recovery strategies downstream of the hot gas cleanup unit (HGCU). It was determined that the most costly strategy would be elemental sulfur recovery, followed by sulfuric acid production, and finally direct sulfur dioxide recovery. The one potential exception to this order might be elemental sulfur recovery via the ReSox process. The potential advantage of this method of elemental sulfur recovery may be the utilization of the (otherwise lost) carbon from the gasifier ash to reduce the SO2 stream to elemental sulfur in the reductor vessel. There appears to be sufficient carbon loss in the gasifier ash to meet the carbon combustion requirement for the burning of free O2 and reduction of SO2 in the HGCU SO2 bleed stream. The strategy of SO2 recovery by condensation and pumping to liquid SO2 tanks appears to be both lowest in capital cost, and highest in byproduct sales value. This is apparently due to the broader market spectrum for SO2 than either of the other two forms of sulfur recovery.

The study also identified rich/lean 50% NO reduction during combustion at the turbine in addition to ammonia injection with SCR reduction of 80% in the HRSG as a required combined NOx control strategy for achieving the study goal of 0.1 lb/MBtu emission limitations. This method of NOx control was the result of the consideration of 40% of the coal gasification generated ammonia to NO conversion at the combustor. The notion that coal gasification with water injection at the booster compressor as noted above will result in less ammonia generation was not considered since such low moisture gasification levels have not yet been widely demonstrated. Some testing has been done at low steam injection flows. Based upon the apparent relationship of ammonia generation with increased steam injection to the gasifier suggests significant ammonia generation control may be possible with reduced gasifier moisture levels. The extent to which lowered ammonia levels may alter the ammonia to NO percent conversion has not been addressed herein.

The consideration of a supplemental low Btu coal gas fired HRSG as an alternative NOx control strategy to ammonia injection and SCR by NO reburning was reviewed. The consideration was the tradeoff between the additional first cost of the supplementally fired HRSG vs. the considerably higher continuing operating cost associated with ammonia and potential catalyst contamination and required replacement intervals. No clear direction evolved from the level of depth of this study's effort in this area, and it remains an issue for future consideration.

This study also identified existing coal fired utility power plants as near term candidates for standardized CGIA application. While many consider conventional flue gas scrubbers as the economical solution to the emissions concerns of large coal fired utilities, such systems are expensive and adversely affect power plant efficiency by consuming significant quantities of power which would have otherwise been available to the grid. In effect, while reducing stack emissions, scrubbers return reduced plant electricity output for their significant expense. Retrofitting and repowering existing coal fired power plants with CGIA results in much lower emissions than currently available commercial scrubber systems plus very substantial increased power output for the same coal input for which the facility has already been designed.

There is solid justification for the consideration of the addition of CGIA systems to existing coal fired utility plants. The majority of the most costly of the capital cost items of the power plant already exist. These include coal receiving/handling/storage/reclaim, water sourcing/purification/treatment/disposal, electricity generation/conditioning/distribution, and the most costly of all, the boiler island itself. Unlike other repowering strategies which require replacement of the boiler island, this study presents a way to simply add on the IGCC system to the existing coal plant with minimum modification to the existing infrastructure. The result is an approximate 20% increase in power output while reducing the plant's stack gas emissions by well in excess of 90% for SO2, NOx, and particulates.

4.2. Integration & Matching of Commercial Gasification IGCC Applications

The initial efforts of combining the various systems which comprise the Commercial Gasification IGCC Applications (CGIA) (Figure 1) revolved around establishing an engineering level mass and energy balance [1][2][3] sufficient to identify the processes involved (Table 1a - d). Appendix C includes reasonably complete mass and energy balances for the nominal 50 MWe, 100 MWe, 200 MWe, and utility retrofit/repower cases. Several combinations of inputted coal analyses with actual

Combined Gasifier IGCC Application (CGIA)

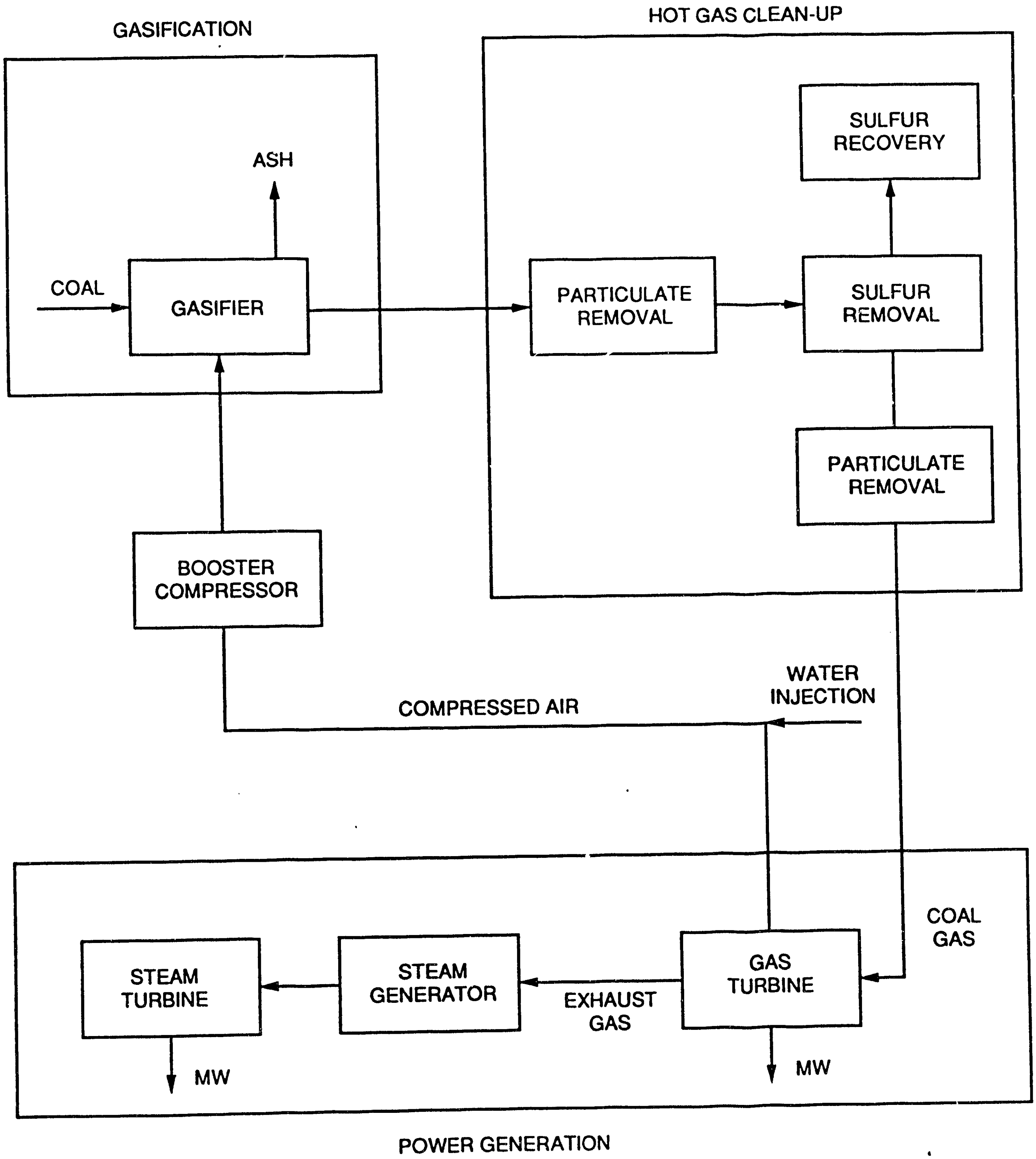


Figure 1

	A	B	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	Table 1a - Standardized IGCC Gasifier Utility Application												Reference Coal -		Illinois #6	
2	Mass & Energy Balance				GE 7111 EA			Plant	Full Load				Predicted Gasifier Output			
3	Stream No.		1		2		3		4				5		6	Unco
4	Identification		AR Coal		Coal Fines		Sized Coal		Comp Air @	2.41 A/C			Water @	0.26	Ash	Carb
5	From		Illinois #6		Sizer @	30 %	Combined Streams		Aux Compr &/or Booster Compr				Cooling Water	H2O/	Gasifier	2.69
6	To		Sizer		Briquetting		Gasifier		Gasifier.				Gasifier	Coal	Ash Silo	
7	Gas	Mol Wt	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	lb/mol	wt %	mol %	lb/hr		lb/hr	wt %
8																
9	CO	28.010							0	0.00	0.00	0.00				
10	H2	2.016							0	0.00	0.00	0.00				
11	CO2	44.010							111	0.01	0.05	0.03				
12	H2O	18.015							1,485	0.18	0.64	1.02	25,205			
13	CH4	16.042							0	0.00	0.00	0.00				
14	C2H6	30.068							0	0.00	0.00	0.00				
15	H2S	34.076							0	0.00	0.00	0.00				
16	COS	60.070							0	0.00	0.00	0.00				
17	N2	28.013							175,286	21.65	75.03	77.28				
18	Ar	39.948							3,049	0.38	1.31	0.95				
19	HCl	36.461							0	0.00	0.00	0.00				
20	HCN	27.026							0	0.00	0.00	0.00				
21	NH3	17.030							0	0.00	0.00	0.00				
22	CS2	76.131							0	0.00	0.00	0.00				
23	SO2	64.059							0	0.00	0.00	0.00				
24	NO	30.006							0	0.00	0.00	0.00				
25	O2	31.999							53,684	6.63	22.98	20.72				
26	NaCl	58.497							0	0.00	0.00	0.00				
27	KCl	74.596							0	0.00	0.00	0.00				
28	Total Gas (lb/hr)								233,635	28.86	100.00	100.00	25,205			
29																
30	Volumetric Flow Rates (STP 14.7 psia, 59F)															
31	(acfm)								4,377							
32	(scfm)								51,121							
33																
34	Heat (BTU/lb)												1332			
35	Cp (BTU/lb F)								0.251						0.260	
36	HHV (BTU/lb)		10,776		10,776		10,776		0						0	
37	LHV (BTU/lb)		10,239		10,239		10,260		0						0	
38	Sensible Heat above															
39	59 F Btu/lb steam		0		0		0		135						154	
40	Latent Heat of															
41	Water Btu/lb steam								7						0	
42																
43	Chemical Heat		992.61		297.78		1034.51		0.00						22.73	
44	(LHV) MBtu/hr															
45	Sensible Heat		0.00		0.00		0.00		31.58						1.73	
46	above 59 F MBtu/hr															
47	Latent Heat		52.05		15.62		52.05		1.54						0.00	
48	of Water MBtu/hr															
49	TotalHeat(MBtu/hr)		1044.67		313.40		1086.56		33.12				33.57		24.46	
50			Number of Gasifiers for 85% Plant Availability @90% Gasifier Availability,										350	psia & 17 tph (typical) G		
51																
52	C	12.011	58,273	60.11%	17,482	60.11%	61,282	60.7[illegible]%		30					1,568	13.
53	H	1.008	4,043	4.17%	1,213	4.17%	4,043	4.01%		165			2,801			
54	O	16.000	7,339	7.57%	2,202	7.57%	7,339	7.28%		55,085			22,405			
55	N	14.007	1,144	1.18%	343	1.18%	1,144	1.13%		175,286			25,205	Total		
56	S	32.060	2,792	2.88%	838	2.88%	2,792	2.77%		230,566	Total				0	0.
57	CL2	35.500	0	0.00%	0	0.00%	0	0.00%								
58	H2O	18.016	13,669	14.10%	4,101	14.10%	13,669	13.56%								
59	ZnFe2O4															
60	ZnS															
61	FeS															
62	Fe2O3															
63	ZnO															
64	ASH		9,694	10.00%	2,908	10.00%	10,563	10.48%							9,694	86.
65	Total Solids		96,944	100.01%	29,083	100.01%	100,831	100.00%							11,262	10
66	Total Flow (pph)		96,944 *		29,083		100,831		233,635				25,205		11,262	
67																
68	Total Flow (pps)		26.93		8.08		28.01		64.90				7.00		3.13	
69	Pressure (psia)		14.7		14.7		14.7		350 *				350 *		14.7	
70	Temperature (F)		59		59		59		598 *				598 *		650	

N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
erence Coal -		Illinois #6								J-1538		DE-AC21-89MC26291				1
dicted Gasifier Output				10/16/90				Revision 7								2
5		6	Uncomb	7		8		9				10		55 scf/lb of coal		3
Water @	0.26	Ash	Carbon	Fines (Char)		Tar		Dust(per RTI dia)		Miscellaneous		Hot Gas with Tars				4
Cooling Water	H_2O/	Gasifier	2.69%	Gasifier @	4.00%	Gasifier @	6.00%	Final Cyclone		Gasifier Heat		Gasifier	N_2 in coal			5
Gasifier	Coal	Ash Silo		Briquetting		HGCU		Reclaim		Losses		HGCU	to NH_3 Conv		90.1%	6
lb/hr		lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %			lb/hr	lb/mol	wt %	mol %	7
																8
												90,473	6.39	26.26	22.82	9
												4,070	0.29	1.18	14.26	10
												40,487	2.86	11.75	6.50	11
25,205												17,590	1.24	5.11	6.90	12
												7,392	0.52	2.15	3.26	13
												1,466	0.10	0.43	0.34	14
												2,543	0.18	0.74	0.53	15
												748	0.05	0.22	0.09	16
												175,399	12.39	50.91	44.24	17
												3,068	0.22	0.89	0.54	18
												0	0.00	0.00	0.00	19
												119	0.01	0.03	0.03	20
												1,176	0.08	0.34	0.49	21
												0	0.00	0.00	0.00	22
												0	0.00	0.00	0.00	23
												0	0.00	0.00	0.00	24
												0	0.00	0.00	0.00	25
												0	0.00	0.00	0.00	26
												0	0.00	0.00	0.00	27
25,205												344,532	24.34	100.00	100.00	28
																29
												344,532				30
												15,447				31
												89,400				32
																33
1332																34
		0.260		0.260		0.26		0.260				0.329				35
		0		10,936		17,329		0				2,588.8				36
		0		10,936		16,571		0				2,375.0				37
																38
		154		276		276		323				349				39
																40
		0		0		749		0				214				41
																42
		22.73		42.41		96.39		0.00				818.25				43
																44
		1.73		1.07		1.60		0.16		60.7 Water/steam		120.13				45
										jacket						46
		0.00		0.00		4.36		0.00		14.1 Traversing		73.69	Gas HHV=	189	Btu/scf	47
										Stirrer			Estimated=	544	Btu/lb	48
33.57		24.46		43.48		102.35		0.16		74.8 Total		1012.07	Calculated=	548	Btu/lb	49
350	psia & 17 tph (typical) Coal each:				4.0			Unit Output (MWn)		122.3 MWn			BulkGas=	3.97%	H_2O	50
													Calc Comb Temp (F)	2045		51
		1,568	13.92	3,009	77.60%	5,119	88.00%					56,736	56,735	0.00%		52
2,801				0	0.00%	465	8.00%					8,527	8,527	0.00%		53
22,405				0	0.00%	116	2.00%					96,979	96,979	0.00%		54
25,205	Total			0	0.00%	58	1.00%					176,430	176,429	0.00%		55
		0	0.00	0	0.00%	58	1.00%					2,792	2,793	-0.02%		56
				0	0.00%						Sub-Totals	341,463	341,464	0.00%		57
				0	0.00%							Sum of	Sum of Gas	Mass		58
								440	9			Streams	Constituents	Unbalance		59
								10	2			balance check				60
								29	6			Cycle Efficiency(g) = 43.37%				61
								0	0			Cycle Efficiency (n) = 39.94%				62
								10	2							63
		9,694	86.08	869	22.40%			0	0							64
		11,262	100	3,878	100.00%	5,817	100.00%	489	100							65
25,205		11,262		3,878		5,817		489				344,532				66
																67
7.00		3.13		1.08		1.62		0.14				95.70				68
350 •		14.7		350 •		350 •		259				259				69
598 •		650		1120		1120		1300				1120				70

	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS
1	Table 1b - Standardized IGCC Gasifier Utility Application											Reference Coal -			Illinois
2	Mass & Energy Balance			GE 7111 EA			Plant					Predicted Gasifier Output			
3	Stream No.		11				12				13	14			
4	Identification		Air				Bleed Air				Bleed Air				
5	From		Atmosphere				Compressor				for	Compressor Discharge			
6	To		Gas Turbine Compressor				Booster Compressor Cooler				Coolant	Compressor			
7	Gas	Mol Wt	lb/hr	lb/mol	wt %	mol %	lb/hr	lb/mol	wt %	mol %	lb/hr	Combustor lb/hr	lb/mol	wt %	mol %
8															
9	CO	28.010	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
10	H2	2.016	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
11	CO2	44.010	1,092	0.01	0.05	0.03	111	0.01	0.05	0.03	84	898	0.01	0.05	0.03
12	H2O	18.015	14,663	0.18	0.64	1.02	1,485	0.18	0.64	1.02	1,127	12,051	0.18	0.64	1.02
13	CH4	16.042	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
14	C2H6	30.068	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
15	H2S	34.076	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
16	COS	60.070	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
17	N2	28.013	1,730,316	21.65	75.03	77.28	175,286	21.65	75.03	77.28	132,966	1,422,064	21.65	75.03	77.28
18	Ar	39.948	30,293	0.38	1.31	0.95	3,069	0.38	1.31	0.95	2,328	24,896	0.38	1.31	0.95
19	HCl	36.461	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
20	HCN	27.026	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
21	NH3	17.030	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
22	CS2	76.131	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
23	SO2	64.059	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
24	NO	30.006	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
25	O2	31.999	529,940	6.63	22.98	20.72	53,684	6.63	22.98	20.72	40,723	435,532	6.63	22.98	20.72
26	NaCl	58.497	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
27	KCl	74.596	0	0.00	0.00	0.00	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
28	Total Gas (lb/hr)		2,306,304	28.86	100.00	100.00	233,635	28.86	100.00	100.00	177,228	1,895,441	28.86	100.00	100.00
29															
30	Volumetric Flow Rates (STP 14.7 psia, 59F)														
31	(scfm)		504,631				8,979					72,843			
32	(acfm)		504,631				51,121				39,056	414,732			
33															
34	hgAdiabHeat(BTU/lb)														
35	Cp (BTU/lb F)		0.240				0.254					0.254			
36	HHV (BTU/lb)		0.0				0.0					0.0			
37	LHV (BTU/lb)		0.0				0.0					0.0			
38	Sensible Heat														
39	above 59 F Btu/lb		0				158					158			
40	Latent Heat														
41	of Water Btu/lb		7				7					7			
42															
43	Chemical Heat		0.00				0.00					0.00			
44	(LHV) MBtu/hr														
45	Sensible Heat		0.00				36.85					298.93			
46	above 59 F MBtu/hr														
47	Latent Heat		15.25				1.54					12.53			
48	of Water MBtu/hr														
49	TotalHeat(MBtu/hr)		15.25				38.39					311.46			
50												Parasitic Load		10.48 MWg	
51															
52	C	12.011		298				30			23		245	245	0.00%
53	H	1.008		1,629				165			125		1,339	1,339	0.00%
54	O	16.000		543,768				55,085			41,786		446,897	446,897	0.00%
55	N	14.007		1,730,316				175,286			132,966		1,422,064	1,422,064	0.00%
56	S	32.060		0				0			0		0	0	0.00%
57	CL2	35.500		2,276,011	sub-totals			230,566	sub-totals		174,900	sub-totals	1,870,545	1,870,545	0.00%
58	H2O	18.016												balance check	
59	ZnFe2O4														
60	ZnS														
61	FeS														
62	Fe2O3														
63	ZnO														
64	ASH														
65	Total Solids														
66	Total Flow (pph)		2,306,304				233,635				177,228	1,895,441			
67															
68	Total Flow (pps)		640.64 •				64.90			•	49.23	526.51			
69	Pressure (psia)		14.7 •				184 •					184			
70	Temperature (F)		59 •				681 •					681			

	AQ	AR	AS	AT	AU	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG
·ence Coal -		Illinois #6								J-1538			DE-AC21-89MC26291				1
·cted Gasifier Output							Revision 7									10/16/90	2
	14				15			16						17			3
	Compressor Discharge				Fuel		%H2S	Inlet Gas		Thrml NO (ppmvd)		25	Exhaust Gas				4
	Compressor				HGCU		Removed	GT Combustor		*Rich/Lean Red. F		85%	Gas Turbine				5
	Combustor				GT Combustor		99.0%	GT Expander									6
	lb/mol	wt %	mol %	lb/hr	mol/hr	wt %	mol %	lb/hr	lb/mol	mols	wt %	mol%	lb/hr	mols/hr	wt %	mol%	7
																	8
0	0.00	0.00	0.00	90,473	3,230	26.38	22.84	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	9
0	0.00	0.00	0.00	4,020	1,994	1.17	14.10	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	10
8	0.01	0.05	0.03	40,487	920	11.80	6.51	208,384	2.70	0.0021	9.31	6.13	208,468	4736.82	8.63	5.68	11
1	0.18	0.64	1.02	19,365	1,075	5.65	7.60	88,787	1.15	0.00	3.97	6.38	89,913	4991.03	3.72	5.98	12
0	0.00	0.00	0.00	7,392	461	2.16	3.26	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	13
0	0.00	0.00	0.00	1,466	49	0.43	0.34	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	14
0	0.00	0.00	0.00	25	1	0.01	0.01	6	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	15
0	0.00	0.00	0.00	7	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	16
4	21.65	75.03	77.28	175,399	6,261	51.14	44.28	1,598,280	20.69	0.0255	71.40	73.84	1,731,246	61801.53	71.67	74.10	17
6	0.38	1.31	0.95	3,068	77	0.89	0.54	27,965	0.36	0.00	1.25	0.91	30,293	758.30	1.25	0.91	18
0	0.00	0.00	0.00	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	19
0	0.00	0.00	0.00	119	4	0.03	0.03	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	20
0	0.00	0.00	0.00	1,176	69	3.34	0.49	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	21
0	0.00	0.00	0.00	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	22
0	0.00	0.00	0.00	0	0	0.00	0.00	56	0.0007	0.0000	0.0025	0.0011	56	0.87	0.00	0.00	23
0	0.00	0.00	0.00	0	0	0.00	0.00	456	0.0059	0.0000	0.0204	0.0197	456	15.19	0.02	0.02	24
2	6.63	22.98	20.72	0	0	0.00	0.00	314,516	4.07	0.0044	14.05	12.72	355,239	11101.56	14.71	13.31	25
0	0.00	0.00	0.00	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	26
0	0.00	0.00	0.00	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	27
1	28.86	100.00	100.00	342,998	14,141	100.00	100.00	2,238,439	28.97	0.0345	100.00	100.00	2,415,667	83405.30	100.00	100.00	28
								2,238,442 bal ck					2,415,670	bal ck			29
																	30
3				16,012				193,591					1,438,278				31
2				89,281				487,816					526,595				32
																	33
																	34
4				0.334				0.278					0.267				35
0				2,548.9				0.0					0.0				36
0				2,330.0				0.0					0				37
																	38
3				375				546					251				39
																	40
7				219				41					39				41
																	42
0				799.20				0.00					0.00				43
																	44
3				128.46				1222.06					607.31				45
																	46
3				75.06				92.34					93.51				47
																	48
6				1002.71				1314.40	1314.17 bal chk				700.82				49
·asitic Load		10.48 MWg			Combustion Turbine Output			84.385 MWg					1.05 Turbine Compressor Surge Margin				50
																	51
	245	245	0.00%		56,587			56,832	56,832	0.00%			56,855	56,855	0.00%		52
	1,339	1,339	0.00%		8,526			9,865	9,865	0.00%			9,990	9,990	0.00%		53
	446,897	446,897	0.00%		98,360			545,257	545,260	0.00%			587,045	587,045	0.00%		54
	1,422,064	1,422,064	0.00%		176,429			1,598,493	1,598,493	0.00%			1,731,459	1,731,459	0.00%		55
	0	0	0.00%		28			28	28	0.10%			28	28	0.00%		56
	1,870,545	1,870,545	0.00%		339,930	sub-total		2,210,475	2,210,477	0.00%	sub-total		2,385,377	2,385,377	0.00%	sub-total	57
		balance check								balance check					balance check		58
																	59
																	60
																	61
																	62
																	63
																	64
																	65
				342,998				2,238,439					2,115,667				66
																	67
1				95.28				621.79					671.02				68
1				259				177 *					15.13				69
1				1180				2,020 *					999 *				70

	BH	BI	BJ	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT
1	Table 1c - Standardized IGCC Gasifier Utility Application									Reference Coal -		Illinois #6	J-153
2	Mass & Energy Balance				GE 7111 EA			Predicted Gasifier Output					Revi
3	Stream No.			18			19	Thrml NO (ppmvd)		25	20	21	22
4	Identification			Fuel for Supplementary Firing			Flue Gas		SCR Red F	80 %	Superheated Steam	Low Pressure Steam	Make Up W
5	From			Gasifier			HRSG		R/L Red F	85 %	HRSG	HRSG	WaterTrea
6	To			HRSG			Stack		NOx Reburn F	0 %	Steam Turbine	Steam Turbine	HRSG
7	Gas	Mol Wt	lb/hr	lb/mol	wt %	mol %	lb/hr	mols/hr	wt %	mol %	lb/hr	lb/hr	lb/hr
8													
9	CO	28.010	0	6.39	26.26	22.82	0	0.00	0.00	0.00			
10	H2	2.016	0	0.29	1.18	14.26	0	0.00	0.00	0.00			
11	CO2	44.010	0	2.86	11.75	6.50	208,468	4736.82	8.63	5.68			
12	H2O	18.015	0	1.24	5.11	6.90	89,913	4991.03	3.72	5.98			
13	CH4	16.042	0	0.52	2.15	3.26	0	0.00	0.00	0.00			
14	C2H6	30.068	0	0.10	0.43	0.34	0	0.00	0.00	0.00			
15	H2S	34.076	0	0.18	0.74	0.53	0	0.00	0.00	0.00			
16	COS	60.070	0	0.05	0.22	0.09	0	0.00	0.00	0.00			
17	N2	28.013	0	12.39	50.91	44.24	1,731,246	61801.53	71.68	74.11			
18	Ar	39.948	0	0.22	0.89	0.54	30,293	758.30	1.25	0.91			
19	HCl	36.461	0	0.00	0.00	0.00	0	0.00	0.00	0.00			
20	HCN	27.026	0	0.01	0.03	0.03	0	0.00	0.00	0.00			
21	NH3	17.030	0	0.08	0.34	0.49	0	0.00	0.00	0.00			
22	CS2	76.131	0	0.00	0.00	0.00	0	0.00	0.00	0.00	Stack Emissions (lb/MBtu)		
23	SO2	64.059	0	0.00	0.00	0.00	56	0.87	0.00	0.00	0.053		
24	NO	30.006	0	0.00	0.00	0.00	91	3.04	0.00	0.00	0.09		
25	O2	31.999	0	0.00	0.00	0.00	355,239	11101.56	14.71	13.31			
26	NaCl	58.497	0	0.00	0.00	0.00	0	0.00	0.00	0.00			
27	KCl	74.596	0	0.00	0.00	0.00	0	0.00	0.00	0.00			
28	Total Gas (lb/hr)		0	24.34	100.00	100.00	2,415,305	83393.15	100.00	100.00			
29							2,415,305	bal chk					
30	Volumetric Flow Rates (STP 14.7 psia, 59F)												
31	(acfm)		0				723,328						
32	(scfm)		0				526,518						
33													
34	Heat (BTU/lb)										1459.5	1237.9	
35	Cp (BTU/lb F)		0.334				0.248						
36	HHV (BTU/lb)		2548.9				0.0						
37	LHV (BTU/lb)		2330.0				0						
38	Sensible Heat above												
39	59 F Btu/lb steam		0				48						
40	Latent Heat of												
41	Water Btu/lb steam		0				39						
42													
43	Chemical Heat		0.00				0.00						
44	(LHV) MBtu/hr												
45	Sensible Heat		0.00				116.02						
46	above 59 F MBtu/hr												
47	Latent Heat		0.00				93.51						
48	of Water MBtu/hr												
49	TotalHeat(MBtu/hr)		0.00				209.53				412.72	58.87	
50												HRSG Turbine Output	48.4
51													
52	C	12.011		0			56,855	56,855	0.00%				
53	H	1.008		0			9,990	9,990	0.00%				
54	O	16.000		0			586,851	586,851	0.00%				
55	N	14.007		0			1,731,289	1,731,289	0.00%				
56	S	32.060		0			28	28	0.00%				
57	CL2	35.500		0	sub-total		2,385,013	2,385,013	0.00%	sub-total			
58	H2O	18.016											
59	ZnFe2O4												
60	ZnS												
61	FeS												
62	Fe2O3												
63	ZnO												
64	ASH												
65	Total Solids												
66	Total Flow (pph)		0				2,415,667				282,780	47,556	
67													
68	Total Flow (pps)		0 •				671.02				78.55	13.21	
69	Pressure (psia)		259				14.7				1265	115	
70	Temperature (F)		1180				251 •				935	423	

BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW
r Utility Application				Reference Coal -		Illinois #6	J-1538	DE-AC21-89MC26291		1
I EA		Predicted Gasifier Output					Revision 7		10/16/90	2
	19	Thrml NO (ppmvd)		25	20	21	22	23	24	3
	Flue Gas		SCR Red F	80 %	Superheated Steam	Low Pressure Steam	Make Up Water	Sat. Steam	Process Stm	4
	HRSG		R/L Red F	85 %	HRSG	HRSG	WaterTreatment	Gasifier	Stm Turbine	5
	Stack		NOx Reburn F	0 %	Steam Turbine	Steam Turbine	HRSG	Steam Turbine	Process Facility	6
mol %	lb/hr	mols/hr	wt %	mol %	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	7
22.82	0	0.00	0.00	0.00						8
14.26	0	0.00	0.00	0.00						9
6.50	208,468	4736.82	8.63	5.68						10
6.90	89,913	4991.03	3.72	5.98						11
3.26	0	0.00	0.00	0.00						12
0.34	0	0.00	0.00	0.00						13
0.53	0	0.00	0.00	0.00						14
0.09	0	0.00	0.00	0.00						15
44.24	1,731,246	61801.53	71.68	74.11						16
0.54	30,293	758.30	1.25	0.91						17
0.00	0	0.00	0.00	0.00						18
0.03	0	0.00	0.00	0.00						19
0.49	0	0.00	0.00	0.00						20
0.00	0	0.00	0.00	0.00	Stack Emissions (lb/MBtu)					21
0.00	56	0.87	0.00	0.00	0.053					22
0.00	91	3.04	0.00	0.00	0.09					23
0.00	355,239	11101.56	14.71	13.31						24
0.00	0	0.00	0.00	0.00						25
0.00	0	0.00	0.00	0.00						26
100.00	2,415,305	83393.15	100.00	100.00						27
	2,415,305	bal chk								28
										29
	723,328									30
	526,518									31
										32
										33
	0.248				1459.5	1237.9	48	1204		34
	0.0									35
	0									36
										37
	48									38
										39
	39									40
										41
	0.00									42
										43
	116.02									44
										45
	93.51									46
										47
	209.53									48
					412.72	98.87	1.53	60.69		49
						HRSG Turbine Output	48.4	MW_g		50
										51
	56,855	56,855	0.00%							52
	9,990	9,990	0.00%							53
	586,851	586,851	0.00%							54
	1,731,289	1,731,289	0.00%							55
	28	28	0.00%							56
	2,385,013	2,385,013	0.00%	sub-total						57
										58
										59
										60
										61
										62
										63
										64
										65
	2,415,667				282,780	47,556	31,811	59,730	0	66
										67
	671.02				78.55	13.21	8.84	16.59	0.00	68
	14.7				1265	115	15	350	250	69
	253 •				935	423	80	432	420	70

	BX	BY	BZ	CA	CB	CC	CD	CE	CF	CG	CH	CI	
1	Table 1d - Standardized IGCC Gasifier Utility Application									Reference Coal - Illinois #6			
2	Mass & Energy Balance				GE 7111 EA				Predicted Gasifier Output				
3	Stream No.		25		26					27		27a	
4	Identification		Regen Recycle Loop		Conc SO2 Bleed					Elemental Sulfur		Elemental Sulfur	Su
5	From		Recycle Blower		Regen Loop					Redox Process		DSRP	SO2
6	To		Regenerator		SRP					Marketable Byproduct		Marketable Byproduct	Market
7	Gas	Mol Wt	lb/hr	wt%	lb/hr	lbs/mol	mols/hr	wt%	mol%	lb/hr	wt%	lb/hr	
8													
9	CO	28.010			0	0.00	0.00	0.00	0.00				
10	H2	2.016			0	0.00	0.00	0.00	0.00				
11	CO2	44.010	141	0.05	12	0.02	0.27	0.05	0.04				
12	H2O	18.015	1,756	0.62	146	0.20	8.12	0.62	1.11				
13	CH4	16.042			0	0.00	0.00	0.00	0.00				
14	C2H6	30.068			0	0.00	0.00	0.00	0.00				
15	H2S	34.076			0	0.00	0.00	0.00	0.00				
16	COS	60.070			0	0.00	0.00	0.00	0.00				
17	N2	28.013	212,397	74.87	17,700	24.10	631.84	74.87	86.02				
18	Ar	39.948	0	0.00	0	0.00	0.00	0.00	0.00				
19	HCl	36.461			0	0.00	0.00	0.00	0.00				
20	HCN	27.026			0	0.00	0.00	0.00	0.00				
21	NH3	17.030			0	0.00	0.00	0.00	0.00				
22	CS2	76.131			0	0.00	0.00	0.00	0.00				
23	SO2	64.059	66,311	23.37	5,526	7.52	86.26	23.37	11.74				
24	NO	30.006			0	0.00	0.00	0.00	0.00				
25	O2	31.999	3,081	1.09	257	0.35	8.02	1.09	1.09				
26	NaCl	58.457			0	0.00	0.00	0.00	0.00				
27	KCl	74.596			0	0.00	0.00	0.00	0.00				
28	Total Gas (lb/hr)		283,686	100.00	23,640	32.19	735	100.00	100.00				
29													
30	Volumetric Flow Rates		(STP 14.7 psia, 59 F)										
31	(acfm)		9,972		786								
32	(scfm)		55,650		4,637								
33													
34	Heat (BTU/lb)												
35	Cp (BTU/lb F)		0.240		0.240					0.000		0.000	
36	HHV (BTU/lb)												
37	LHV (BTU/lb)												
38	Sensible Heat above												
39	59 F Btu/lb steam												
40	Latent Heat of												
41	Water Btu/lb steam												
42													
43	Chemical Heat									11.00		11.00	
44	(LHV) MBtu/hr												
45	Sensible Heat		91.30		7.04					0.00		0.00	
46	above 59 F MBtu/hr												
47	Latent Heat		1.86		0.15					0.00		0.00	
48	of Water MBtu/hr												
49	TotalHeat(MBtu/hr)		93.13		7.19					11.00		11.00	
50													
51													
52	C	12.011											
53	H	1.008											
54	O	16.000											
55	N	14.007											
56	S	32.060								2,763		2,763	
57	CL2	35.500											
58	H2O	18.016											
59	ZnFe2O4												
60	ZnS												
61	FeS												
62	Fe2O3												
63	ZnO												
64	ASH				0.00			0					
65	Total Solids												
66	Total Flow (pph)		283,686		23,640					2,763		2,763	
67													
68	Total Flow (pps)		78.80		6.57					0.77		0.77	
69	Pressure (psia)		294		294					15		15	
70	Temperature (F)		1400		1300					284		190	

CA	CB	CC	CD	CE	CF	CG	CH	CI	CJ	CK	CL	CM
CC Gasifier Utility Application						Reference Coal - Illinois #6			J-1538	DE-AC21-89MC26291		1
	GE 7111 EA				Predicted Gasifier Output				Revision	7	10/16/90	2
	26					27		27a	27b	28		3
oop	Conc SO2 Bleed					Elemental Sulfur		Elemental Sulfur	Sulfur Dioxide	Ash		4
	Regen Loop					Resox Process		DSRP	SO2 Recovery Unit	SO2 Reductor		5
	SRP					Marketable Byproduct		Marketable Byproduct	Marketable Byproduct	Disposal		6
wt%	lb/hr	lbs/mol	mols/hr	wt %	mol %	lb/hr	wt %	lb/hr	lb/hr	lb/hr	wt %	7
												8
	0	0.00	0.00	0.00	0.00							9
	0	0.00	0.00	0.00	0.00							10
0.05	12	0.02	0.27	0.05	0.04							11
0.62	146	0.20	8.12	0.62	1.11							12
	0	0.00	0.00	0.00	0.00							13
	0	0.00	0.00	0.00	0.00							14
	0	0.00	0.00	0.00	0.00							15
	0	0.00	0.00	0.00	0.00							16
74.87	17,700	24.10	631.84	74.87	86.02							17
0.00	0	0.00	0.00	0.00	0.00							18
	0	0.00	0.00	0.00	0.00							19
	0	0.00	0.00	0.00	0.00							20
	0	0.00	0.00	0.00	0.00							21
	0	0.00	0.00	0.00	0.00							22
23.37	5,526	7.52	86.26	23.37	11.74							23
	0	0.00	0.00	0.00	0.00							24
1.09	257	0.35	8.02	1.09	1.09							25
	0	0.00	0.00	0.00	0.00							26
	0	0.00	0.00	0.00	0.00							27
100.00	23,640	32.19	735	100.00	100.00							28
												29
F)												30
	786											31
	4,637											32
												33
												34
	0.240					0.000		0.000	0.000			35
												36
												37
												38
										154	0	39
												40
												41
												42
						11.00		11.00	11.00	3.97	0	43
												44
	7.04					0.00		0.00	0.00	0.00	0	45
												46
	0.15					0.00		0.00	0.00	0.00	0	47
												48
	7.19					11.00		11.00	11.00	3.97	0.4	49
												50
												51
										274	3	52
												53
												54
												55
						2,768		2,763	2,768			56
												57
												58
												59
												60
												61
												62
												63
	0.00			0						9,694	97	64
										9,968	100	65
	23,640					2,763		2,763	5,526	9,968	100	66
												67
	6.57					0.77		0.77	1.53	2.77		68
	294					15		15	100	15		69
	1300					284		190	59	284		70

and predicted coal gasifier outputs were studied to get an idea of ranges and constraints to be expected when changing coals.

Once satisfied that the mass and energy balances were reasonably accurate, the empirical relationships developed by others (Figure 2) with actual coal gasifier operating experience [4] of the type of gasifier selected were superimposed into the balances (both Microsoft Excel & Lotus were used to build the spreadsheets) which appear in Appendix C.

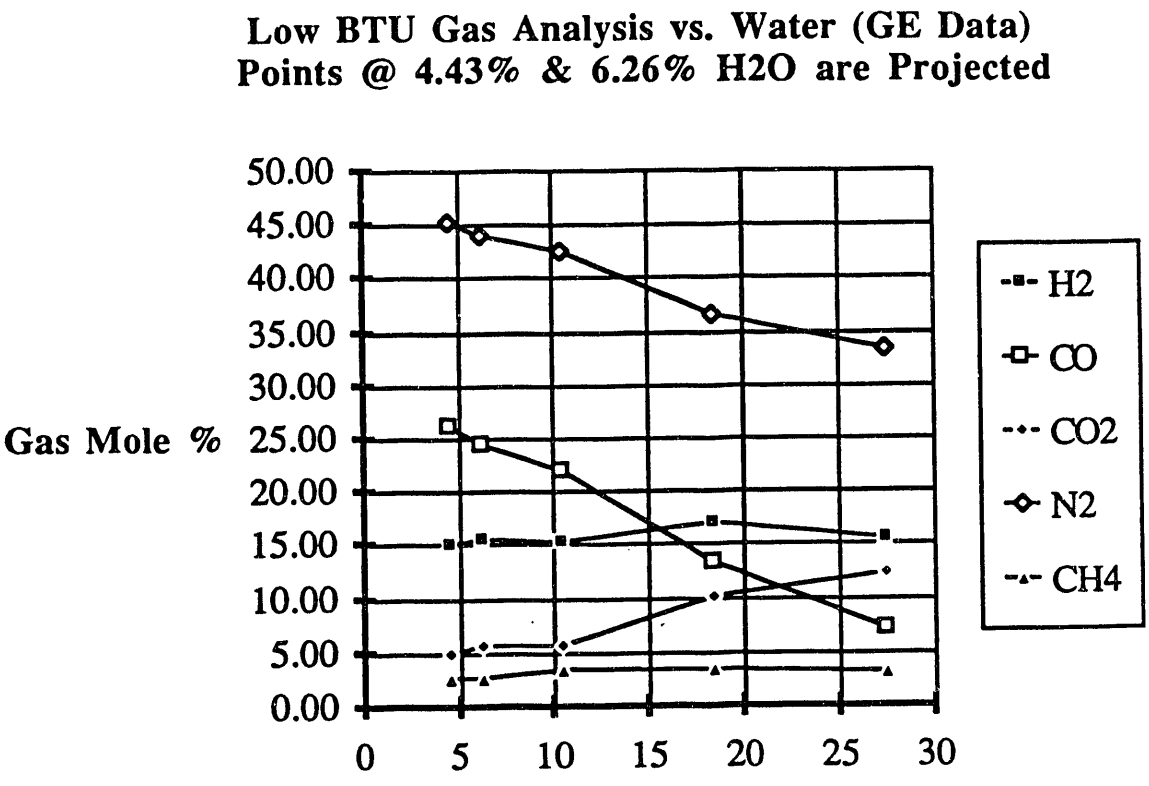


Figure 2

Gasifier sizing consistent with an expected 85% plant availability (Table 2) criterion was utilized. Assuming no alternate fuel backup (such as natural gas to fire the combustion turbines when necessary), and an individual gasification/HGCU modular island availability of 90%, each unit must be sized for 150% design capacity to achieve a total plant availability of 85%. Table 3 serves to identify the loss of overall plant availability when the number of gasification/HGCU modules is reduced to two. For the larger plants which require eight truck shippable gasification modules, the same statistical probability analysis (Table 4) shows the individual module design overcapacity can be reduced to 15% to 20% while the total plant availability increases to 88%. The effect of capacity factor (or availability) on cost of electricity (COE) is as shown on Figure 3. It should be noted that while the actual anticipated module availability is arguable since none have yet been built, this availability analysis serves to show the added value which multiple modular parallel path systems brings to any total facility. This very same logic has been utilized by the utility industry for many years with respect to the numbers of identical modularized coal pulverization

Table 2. 4 Unit Availability Analysis

NERC GADS Stat Summary Rpt 10 Yr Avg 100-199 MW Sized Facilities

4 Parallel Units w/ Natural Gas Backup Sized for % Capacity of 0 %

PROJECT: J-1538-120MWPlantSize (DE-AC-89MC26291) DATE: 4/16/90

* means input required	
One Year = 8760 Hours	
*Planned Outage Days Annually (Unforced Outage Time)	21
Hours Annually Available @ 100% (discounting planned outages)	8,256
*Balance of Plant % Historical Availability (Other Than Boiler Island)	95
*Assumed Availability (Presumed Historical) of Turbines & HRSG	95
Hours Annually Available (Discounting Planned Outages,BOP,Turbines & HRSG UnAvailability)	7,451
*Anticipated (or Required) Individual Gasifier Isl'd Avail %	90
*Total Output of System (MW)	120
*Design Capacity of Each Parallel GasifierIsland System(%)	150
Probability That 4 of 4 Trains Will Be Operating =	65.61%
Probability That 3 of 4 Trains Will Be Operating =	29.16%
Probability That 2 of 4 Trains Will Be Operating =	4.86%
Probability That 1 of 4 Trains Will Be Operating =	0.36%
Probability That 0 of 4 Trains Will Be Operating =	0.01%
Total =	100%

Probability %	Output MW	Max In Service hrs/yr	Capability %	Units #	Total MWH Annually
65.61%	120	7451.04	100	4/4	586,635
29.16%	120	7451.04	150	3/4+ngbu	293,318
4.86%	120	7451.04	150	2/4+ngbu	32,591
0.36%	120	7451.04	150	1/4+ngbu	1,207
0.01%	120	7451.04	150	0/4+ngbu	0
100%	120	7451.04		Total	913,751

Maximum Possible (100% Availability) Power @ 8760 Hours Annually	1,051,200
Maximum Possible Power Annually (Discounting Plnd Out'gs,BOP,Tbns&HRSG Unavail)	894,125
*% Natural Gas Backup Unit(ngbu) Capacity =	0 %
*% Natural Gas Backup Unit(ngbu) Availability =	99%
Natural Gas Backup Capacity (MW) =	0
%of Max Possible (of100%Avail)Annual Power Generated (Incl Gasif UnAvail)	85.06%

Table 3. 2 Unit Availability Analysis
NERC GADS Stat Summary Rpt 10 Yr Avg 100-199 MW Sized Facilities
3 Parallel Units w/Natural Gas Backup Sized for % Capacity of 0 %
PROJECT: J-1538-120MWPlantSize(DE-AC89MC26291) DATE: 4/16/90

*** means input required**	
One Year = 8760 Hours	
***Planned Outage Days Annually (Unforced Outage Time)**	21
Hours Annually Available @ 100% (discounting planned outages)	8,256
***Balance of Plant % Historical Availability (Other Than Boiler Island)**	95
***Assumed Availability (Presumed Historical) of Turbines & HRSG**	95
Hours Annually Available (Discounting Planned Outages,BOP,Turbines & HRSG UnAvailability)	7,451
***Anticipated (or Required) Individual Gasifier Isl'd Avail %**	90
***Total Output of System (MW)**	120
***Design Capacity of Each Parallel Blr Island System (%)**	150

Probability That 3 of 3 Trains Will Be Operating = 72.90%
Probability That 2 of 3 Trains Will Be Operating = 24.30%
Probability That 1 of 3 Trains Will Be Operating = 2.70%
Probability That 0 of 3 Trains Will Be Operating = 0.10%
Total = 100%

Probability %	Output MW	In Service hrs/yr	Capability %	Units #	Total MWH Annually
72.90%	120	7451.04	100	3/3	651,817
24.30%	120	7451.04	150	2/3+ngbu	217,272
2.70%	120	7451.04	150	1/3+ngbu	12,071
0.10%	120	7451.04	150	0/3+ngbu	0
100%	120	7451.04		Total	881,160

Maximum Possible (100% Availability) Power @ 8760 Hours Annually	1,051,200
Maximum Possible Power Annually (Discounting Plnd Out'gs,BOP,Tbns&HRSG Unavail)	894,125
***%Natural Gas BackupUnit(ngbu)Capacity = 0 %**	
*% Natural Gas Backup Unit(ngbu) Availability = 99%	
Natural Gas Backup Capacity (MW) = 0	
%of Max Possible (of100%Avail)Annual Power Generated (Incl Gasif UnAvail)	83.82%

Table 4. 8 Unit Availability Analysis

NERC GADS Stat Summary Rpt 10 Yr Avg 100-199 MW Sized Facilities

8 Parallel Units w/ Gas Backup Blr Sizd for % Cap of	0
PROJECT: J-1538-120MWPlantSize(DE-AC-89MC26291) **DATE:**	4/16/90
*** means input required**	
One Year = 8760 Hours	
***Planned Outage Days Annually (Unforced Outage Time)**	21
Hours Annually Available @ 100% (discounting planned outages)	8,256
***Balance of Plant % Avail (Other Than Boiler Island)**	94
Hours Annually Available (Disc Bal of Plt Avail & Plnd Outages)	7,745
***Anticipated (or Required) Individual Blr Island Avail %**	90.00
***Total Output of System (MW)**	120
***Design Capacity of Each Parallel Blr Island System (%)**	150
Probability That 8 of 8 Trains Will Be Operating (%)	43.05
Probability That 7 of 8 Trains Will Be Operating (%)	38.26
Probability That 6 of 8 Trains Will Be Operating (%)	14.88
Probability That 5 of 8 Trains Will Be Operating (%)	3.07
Probability That 4 of 8 Trains Will Be Operating (%)	0.68
Probability That 3 of 8 Trains Will Be Operating (%)	0.04
Probability That 2 of 8 Trains Will Be Operating (%)	0.00
Probability That 1 of 8 Trains Will Be Operating (%)	0.00
Probability That 0 of 8 Trains Will Be Operating (%)	0.00
Total (%)	100

Probability %	**Output MW**	**In Service hrs/yr**	**Capability %**	**Units #**		**Total Annually MWH**
43.05	120	7745	100	8/8		400,074
38.26	120	7745	150	7/8		463,854
14.88	120	7745	150	6/8		155,584
3.07	120	7745	150	5/8		26,754
0.68	120	7745	150	4/8		4,756
0.04	120	7745	150	3/8		198
0.00	120	7745	150	2/8		8
0.00	120	7745	150	1/8		0
0.00	120	7745	150	0/8		0
99.98	120	95			Total	1,051,228

Max Possible (100% Availability) Power @ 8760 Hours Annually	1,051,200
Max Possible Pwr Annually (Disc Bal of Plt Unavail & Plnd Outages)	929,394
***% Gas Boiler Capacity**	0
*% Gas Boiler Availability	95
Gas Boiler Capacity (#/hr)	0
% of Max Possible (100% Avail) Annual Pwr Generated	88

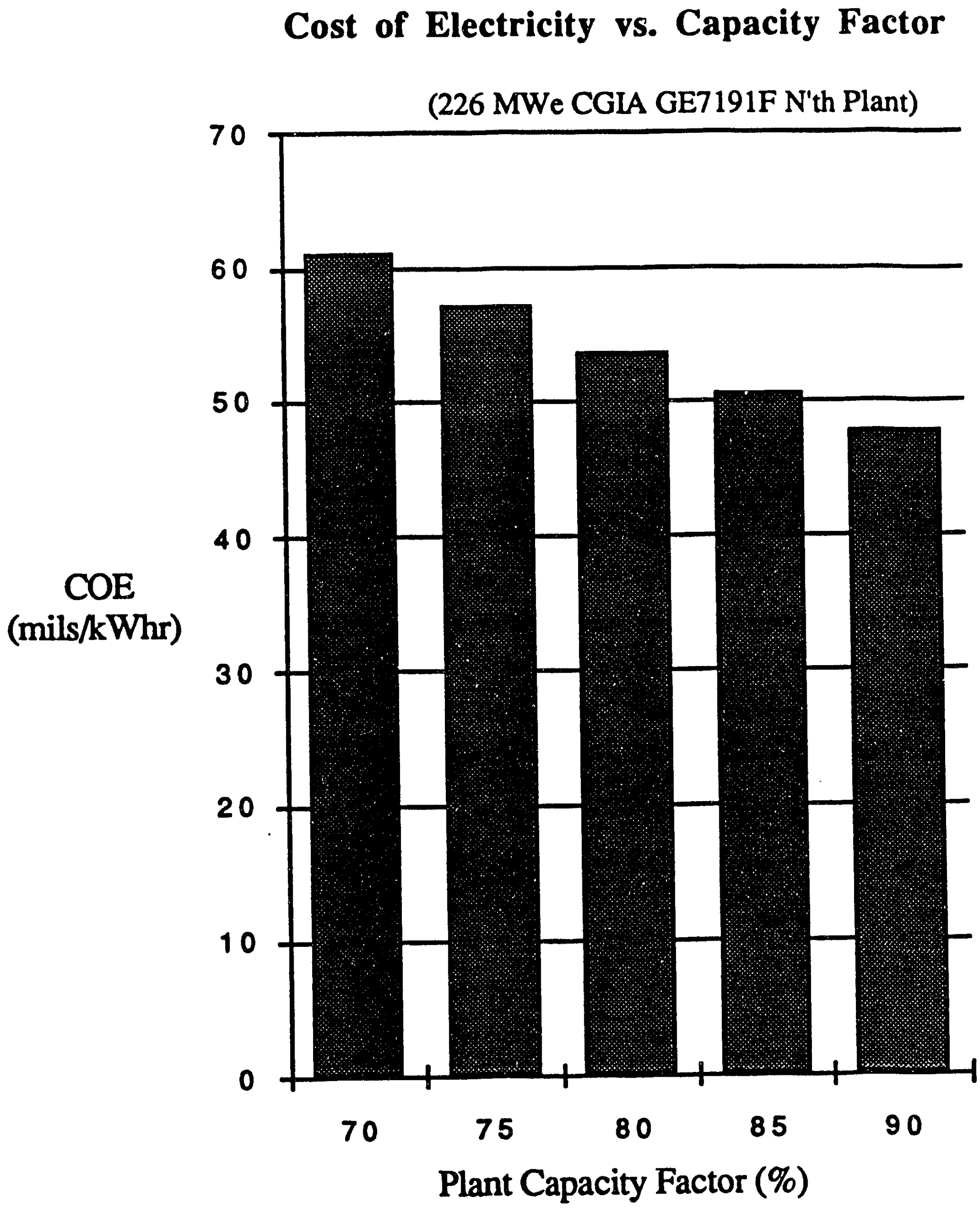


Figure 3

systems selected in shop fabricated truck shippable modules. Their employment of multiple individually oversized pulverizers was done in order to accommodate the well known low availability of pulverizers due to high part wear of grinding elements, and consequent down time. The fruits of their wisdom is readily identifiable in NERC GADS [5] statistical data which shows the forced outage rates and total plant unavailability due to pulverizers is almost zero. Based on previous industry experience and projections of new gasifier concepts expected to adequately deal with the adverse consequences of caking and low ash fusion coals, the typical coal throughput of a 14 foot diameter fixed-bed, air-blown gasifier operating at 300-450 psi (Figure 4) was subjectively (and somewhat arbitrarily) set at 17 tons per hour. This figure is consistent with Lurgi expectations for Illinois No. 6 coal.

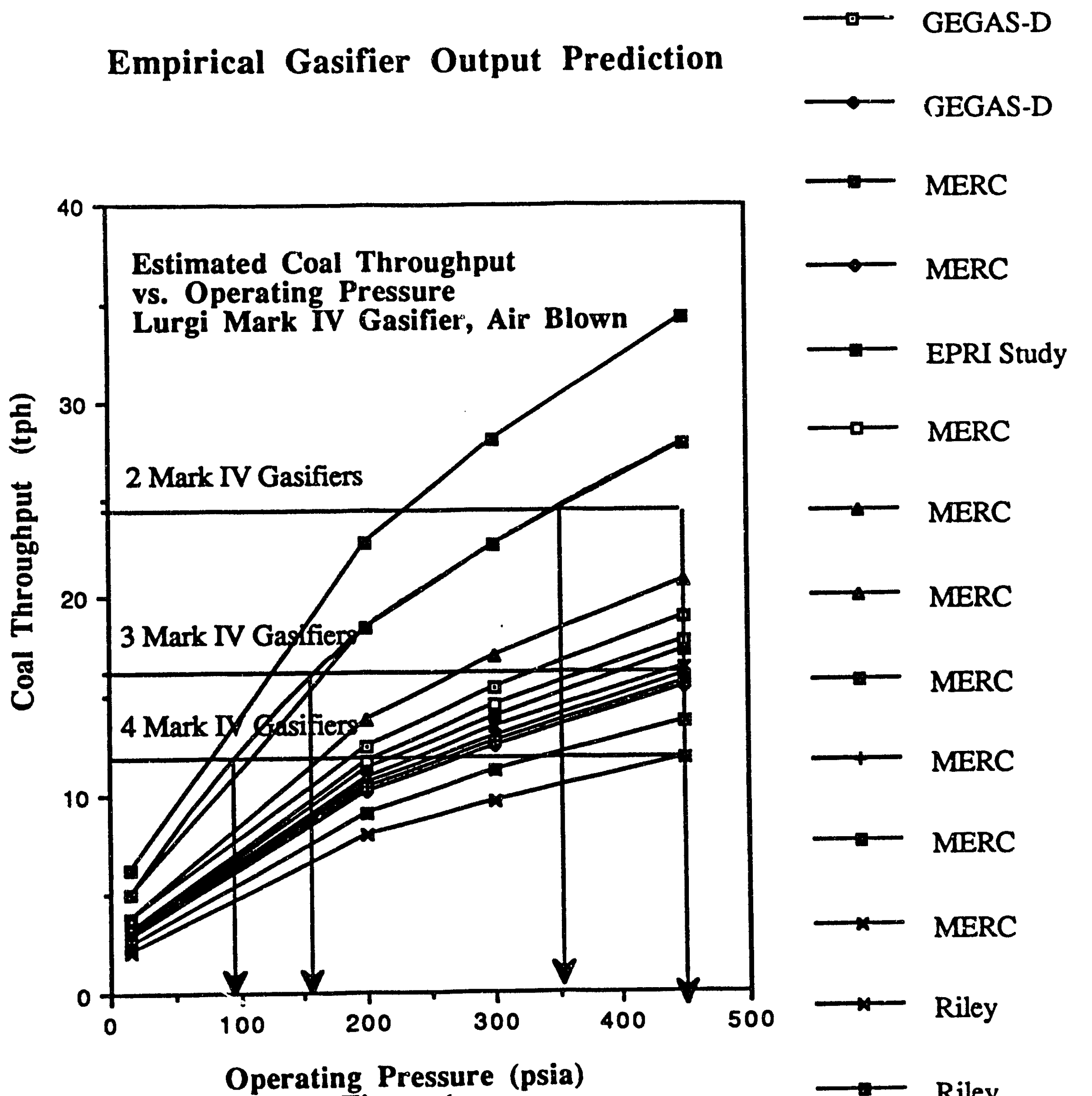


Figure 4

It was determined that it made logical sense to select available combustion turbines which when combined with an unfired heat recovery steam generator/turbine set

(Brayton plus Rankine cycles) would produce power outputs close to the three plant sizes selected for the study. Thus, the three nominal sizes became approximately 45 MWn, 120 MWn, and 227 MWn, when utilizing GE LM/TG5000PC, ABB GT 11 N, and MW 501 F combustion turbines respectively.

Initial cost assessments [6][8][9][10] indicated that the smallest plant size was going to be uneconomical due to the relatively high equipment and development costs with respect to power output. It should be noted, however, that the smallest plant also potentially had the highest efficiency. The GE LM/TG 5000 PC which was selected for the 50 MWe case was then reconsidered as a fully Steam Injected Gas Turbine (STIG) configuration. In this mode it was initially expected that the lower cost of eliminating the steam turbine and higher power output would improve its overall cost effectiveness. It was found that due to the high mass flows of the low BTU coal gas to the turbine combustor, the machine was steam input (hence power output) limited by surge margin limitations of its manufacturer. This was especially true when high steam flows to the gasifier were needed. This limitation prompted the consideration of the use of water to the booster compressor inlet in lieu of steam to the gasifier. The net effect of either is to control inlet gas temperatures, grate temperatures, gasification peak combustion zone temperatures; however, less H2O is needed to effect the same inlet gas cooling when water spray is used due to its heat of evaporation.

The cumulative results of the study revealed that the plant cost goal of $1,000 /kW (or less) for the N'th unit can be met at CGIA unit capacities greater than 200 MWe as shown in Figure 5.

The specific results of the analysis for the plant sizes given consideration follow for each nominal size. In addition, a scheme selected for application to existing coal fired utility plants with a low BTU coal gas fired conversion of the coal boiler resulting in a plant efficiency in excess of 40% follows.

4.2.1 50 MW Size for Co-generation & IPP

The GE/LM/TG5000PC aeroderivative turbine was initially studied for application as a cogeneration and Independent Power Production (IPP) CGIA candidate. Later, owing to the economic unattractiveness of it as a STAG type unit, its use as a STIG unit was considered.

Air-Blown Fixed Bed IGCC Plant Costs

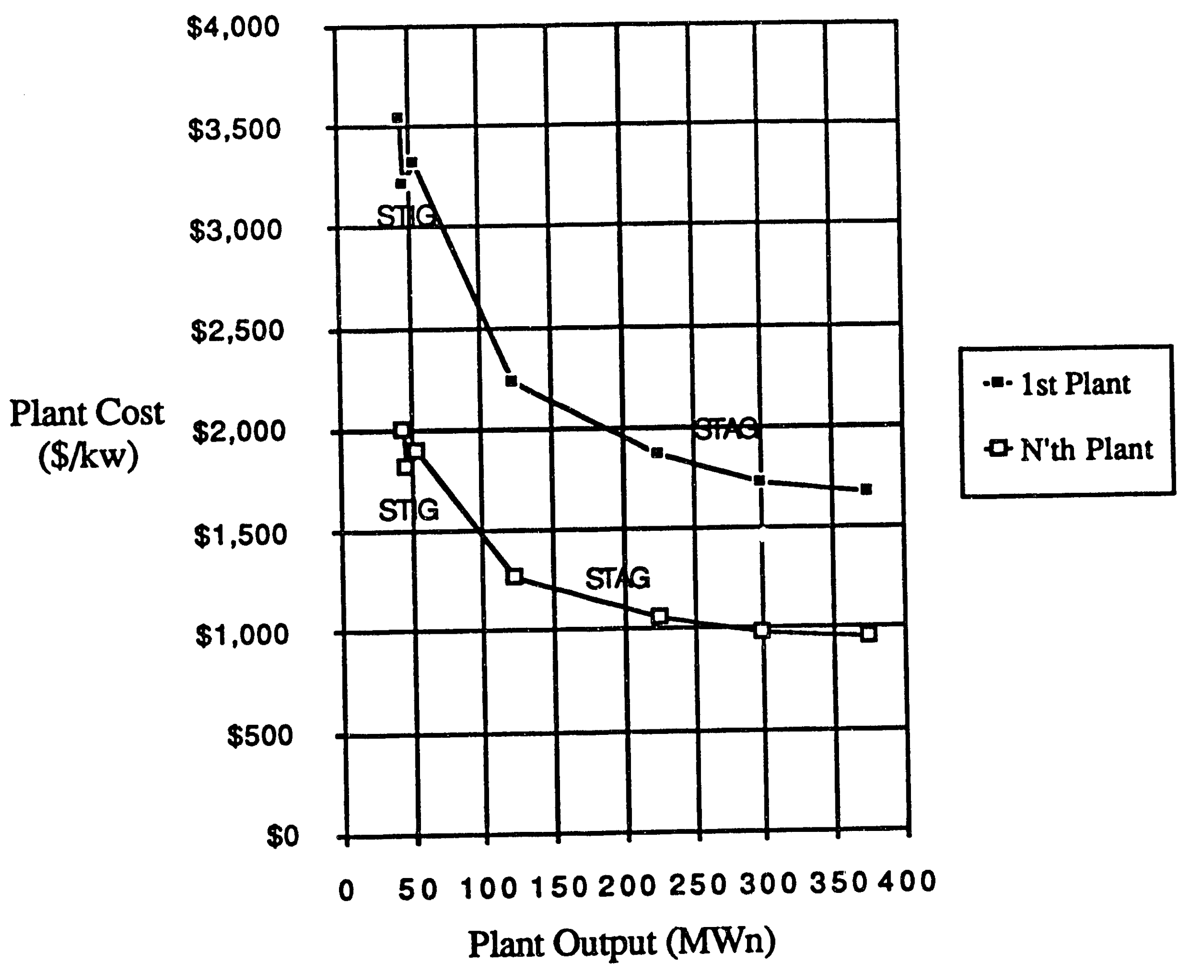
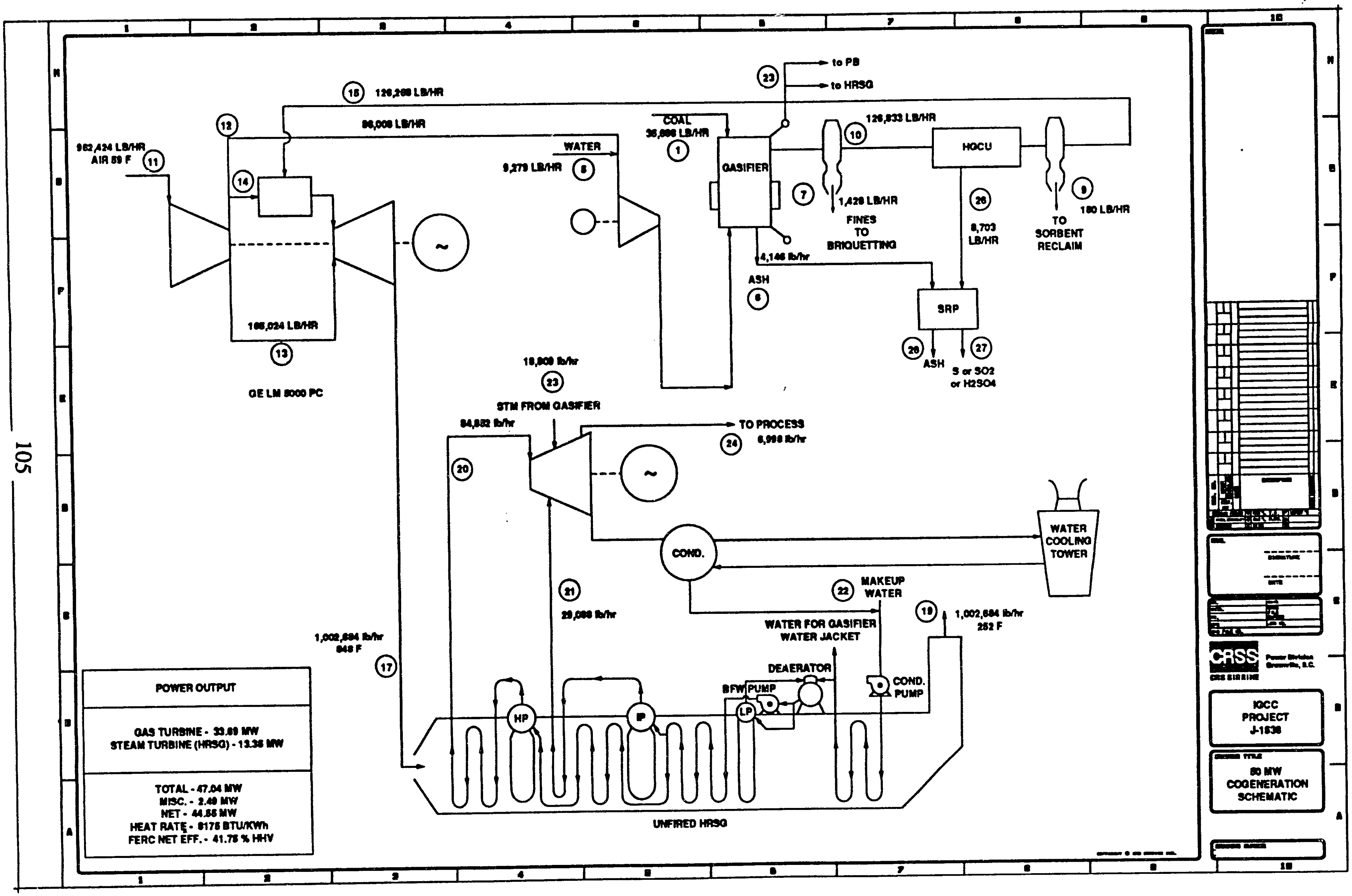


Figure 5

4.2.1.1 STAG

The schematic shown in Figure 6 reflects a basic CGIA concept applied to a cogeneration (cogen) or independent power production (IPP) facility. It utilizes a GE LM/TG5000PC aeroderivative combustion turbine with an unfired heat



POWER OUTPUT
GAS TURBINE - 33.69 MW
STEAM TURBINE (HRSG) - 13.38 MW
TOTAL - 47.04 MW
MISC. - 2.40 MW
NET - 44.66 MW
HEAT RATE - 8176 BTU/KWh
FERC NET EFF. - 41.75 % HHV
GE LM 6000 PC
962,424 LB/HR
AIR 59 F
166,024 LB/HR
126,268 LB/HR
96,008 LB/HR
WATER
9,279 LB/HR
COAL
36,666 LB/HR
GASIFIER
ASH
4,146 lb/hr
to PB
to HRSG
126,833 LB/HR
1,429 LB/HR
FINES
TO
BRIQUETTING
HGCU
8,703
LB/HR
SRP
ASH
S or SO2
or H2SO4
180 LB/HR
TO
SORBENT
RECLAIM
18,809 lb/hr
STM FROM GASIFIER
84,852 lb/hr
TO PROCESS
6,998 lb/hr
COND.
WATER
COOLING
TOWER
29,098 lb/hr
MAKEUP
WATER
WATER FOR GASIFIER
WATER JACKET
DEAERATOR
BFW PUMP
COND.
PUMP
1,002,684 lb/hr
252 F
1,002,684 lb/hr
848 F
HP
IP
LP
UNFIRED HRSG
CRSS
CRS SIRRINE
IGCC
PROJECT
J-1538
50 MW
COGENERATION
SCHEMATIC

Figure 6

recovery steam generator (HRSG). To meet the year 2000 goal of 0.1 lb/MBtu NOx emissions, ammonia injection/selective catalytic reduction (SCR) is deemed necessary. Since CGIA employs a zinc ferrite (ZnFe) hot gas cleanup unit (HGCU), the SO2 emission limit goal of 0.1 lb/MBtu can be met with 99.5% desulfurization which is consistent with removal efficiencies of current HGCU designs. By the year 2000, such impediments as sulfur bearing tars, and sulfur regeneration/recovery efficiency losses are judged to have been overcome by improved gasifier and HGCU designs.

The nominal 50 MWe plant generates a net output to the grid of 45 MWe. A plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) (Figure 7) from approximately 9¢/kWh to 12¢/kWh. Clearly, this result is uneconomical.

Its initial facility total costs are estimated at $159-million (Table 5a). Even applying N'th plant reduction factors [7] which lowered its anticipated costs to $97-million failed to reduce its costs sufficiently for serious consideration.

A detailed cost analysis appears in Table 5a -5f. The costs were initially estimated for a conventional natural gas-fired combined cycle facility. The added costs of coal gasification were then added to the cogen plant costs. Sources of capital, terms, return rates expected, and ultimate costs of money were determined from costs typical of many small entrepreneurial co-gen & IPP developers (Table 6). Owner's costs were also included in order to generate ultimate costs of electricity (COE).

A 40% cost reduction factor was taken for the "Nth" plant to adequately reflect the total effects of modularization, standardization, and replication. Justification comes from having identified such companies as Cogentrix who was able to produce a very low cost (approximately 40% plant reduction) coal fired power plant using "low tech" and mature technology (stokers).

Plant Cost Sensitivity GE-LM/TG5000PC
45 MWe CGIA, N'th Plant

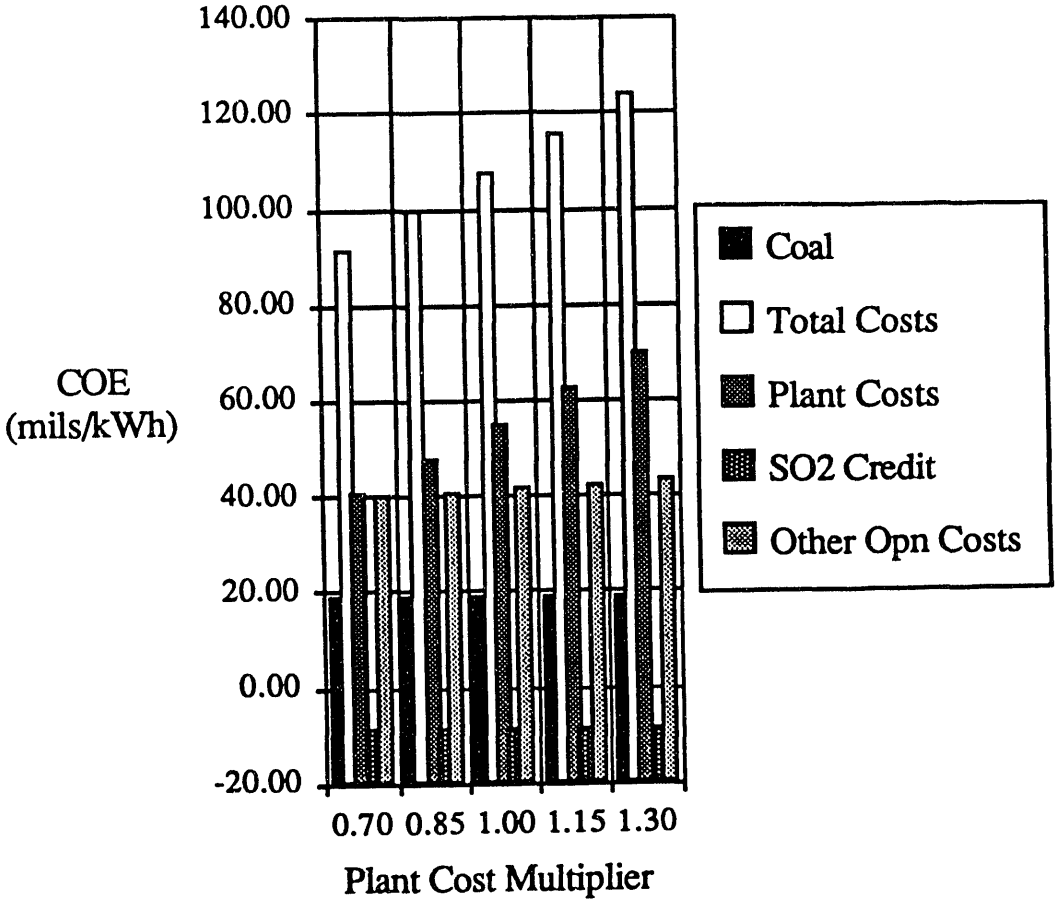


Figure 7

Table 5 a

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) LM/TG5000PC Project No. J-1538
Date: Feb-91 by: RSS
Plant Size Studied (MWg) 47.04 (MWn) 45
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 2,157 ($/KWn) 2,255

System Description: 1-Stage Dry Bottom Fixed Bed Coal Gasifiers, ZnFe Moving Bed (GE type)
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)

Number Trains & Section Description	Total Flow & Units	1st Plant SectionCost, ($)	N-th Plant Section Cost, ($)	N-th Learning Reduct (%)	N-th Plant Cost ($/kwn)
1 ea, Coal Handling	7200TPD	4,895,156	4,895,156	0	109
1 ea, Briquetting System	2400 TPD	3,207,625	2,566,100	20	57
2 ea, Gasification & Ash	36 - lb/sec	17,213,738	13,770,990	20	306
1 ea, Hot Gas Cleanup System (GE type)	36 - lb/sec	8,635,578	5,181,347	40	115
1 ea, Gas Turbine	LM/TG5000PC	19,828,125	15,862,500	20	353
1 ea, HRSG, (Includes CO Catalyst & SCR)	24 - lb/sec	7,883,016	7,883,016	0	175
1 ea, Steam Turbine	14 MWe	6,024,688	6,024,688	0	134
1 ea, Booster Compressor	25 - lb/sec	900,000	900,000	0	20
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)	2 K - lb/hr	4,387,500	2,632,500	40	59
Sub-total		72,975,426	59,716,297		1,327
BalanceofPlant(% sub-t w/out proc conting)	37%	26,878,255	16,126,953	40	358
TOTAL PROCESS CAPITAL		99,853,681	75,843,250		1,685
Fully Standardized Designed N'th Plant			59,912,209	40	1,331
Engineering (Only)	9%				
Engineering (Contractor's) Fees (Incl Proj&ConstMgt, Testing/Startup, Design/Build Contr Fees, but NOT Opn, Data Col & Rptg, Admin, Dspsn) (%ofTotal Process Capital)	22%	22,347,433	13,408,460	40	298
Project Contingency (%ofTotal Process Capital)	13%	12,980,979	7,788,587	40	173
TOTAL PLANT INVESTMENT		135,182,093	81,109,256		1,802
Allowance for Funds During Construction, (AFDC)	13%	12,755,000	7,653,000		170
WorkCap,Taxes,Royal,Devel,Permits,Legal, Fuel Inven, Spare Parts, Underwriter Costs	10%	10,372,271	7,900,963		176
Land(HistoricalSiteCostsforCo-generation) Acreage @ $8,500 per Acre = 49	0.3%	418,000	418,000		9
TOTAL CAPITAL REQUIREMENT		158,727,364	97,081,219		2,157

Table 5 b

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) LM/TG5000PC Project No. J-1538

Date: 2/8/91 by: RSS

Plant Size Studied (MWg) 47.04 (MWn) 45

TypicalGasFiredTurnkeyConstrCost($/KWg) 1,178 ($/KWn) 1,231

	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
COGEN SYSTEM GROUP INCLUDING STRD CONTROLS, ELECTRICAL, BLDG, CIVIL, STRUCT, ARCHETEC, MECHAN					
Gas Turbine/Gen Syst(Incl Cogen Plt I&C)	$11,406,250				
Steam Turbine/Generator System	$4,634,375				
StartUp&BackupFuel(NatGas)PrepSystem	$571,250				
Condenser & Vacuum Systems	$529,375				
TURBINE ISLAND	$17,141,250	$5,130,379	$22,271,629	495	18
Aux Blr for Startup/Emerg PwrGen (Optional)	$0	$0	$0		
HtRecovSteamGenerator(w/COCatyl&SCR)	$5,828,125	$2,124,977	$7,953,102		
HRSG Ductwork & Stack (Incl)					
BOILER ISLAND	$5,828,125	$2,054,891	$7,883,016	175	6
Cooling Tower					
Evaporative Makeup,Circ Water,&AuxSys					
SUB TOT COOL'G TWR SYST	$763,125	$268,278	$1,031,403	23	0.8
Raw Water Well, Pumps,Fire Prot System					
Demineralizer, Treatment & Storage					
Treated Water Pumping & Control					
CondensateRet,WaterChem,Filtr,StorTanks					
Chem Treat & Cooling Systems					
Feed Water Heaters&Deaerator					
FEEDWATER & WATER TREATMENT SYST	$1,936,563	$634,543	$2,571,106	57	2
Generation Plant Electrical System (Incl)					
Sub Station,X-fmrs,Switchyard (Incl)					
and Balance of Plant Electrical	$3,993,750				
Power Transmission Lines	$220,000	$880,000			
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$4,213,750	$2,855,106	$7,068,856	157	6
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions Monitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$1,956,250	$595,538	$2,551,788	57	2.1
BUILDINGS (Contr Rm,Lav,HVAC,CompAir)	$662,500	$320,601	$983,101		
PAINTING/INSUL/LAGG'G/SCAFFOLDING	$150,000	$45,664	$195,664		
COGENERATION SYST SUB TOTAL	$32,651,563	$11,905,000	$44,556,563	990	36
ADD. DESIGN ENGINEERING@8%	$3,564,525		$3,564,525		
ADD. PROJECT MANAGEMENT@3%	$891,131		$891,131		
ADD. CONSTRUCTION MGT@3%		$1,336,697	$1,336,697		
ADD. TEST'G @1% (2% test&strtup)	$445,566		$445,566		
ADD. START UP COSTS @1%	$445,566		$445,566		
ADD. DES/BUILD CONTR'S FEE@7%	$1,782,263		$1,782,263		
SUB TOT INDIRECT COSTS	$7,129,051	$1,336,697	$8,465,748	188	7
SUB TOTAL COGENERATION TURNKEY CONSTRUCTION COST	$39,780,614	$13,241,697	$53,022,311	1,178	43

Table 5 c

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) LM/TG5000PC Project No. J-1538

Date: Feb-91 by: RSS

Plant Size Studied (MWg) 47 (MWn) 45

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 2,157 ($/KWn) 2,255

COAL GASIFICATION ADDERS	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
Coal Rail Spur					
Coal Receiving, Storage & Handling System					
Coal Fines Briquetting System	$3,435,938	$1,459,219	$4,895,156	109	4
Mobile Equip(2-B'dozers,Fr Loader,LiftTrk)					
SUB TOTAL COAL FACILITIES	$5,869,250	$2,233,531	$8,102,781	180	7
COMBUSTOR MOD. for COAL GAS FIRING	$1,250,000	$937,500	$2,187,500	49	2
AIR HANDLING FLOW MODULE	$2,250,000	$562,500	$2,812,500	63	2
BOOSTER COMPRESSOR&INTERCOOLER	$750,000	$150,000	$900,000	20	1
ADDITIONAL PROCESS WATER SYSTEM	$375,000	$114,161	$489,161	11	0.4
HighPressureAir&GasDuctwork&Cyclones,					
Coal Feed & Lock Hopper Systems (Incl)					
Gasifiers (Lurgi Mark IV Comparable)					
Ash Handling Lock Hopper System (Incl)					
Grate, Leveller, & Stirrer Drives (Incl)					
GASIFIER ISLAND	$11,360,995	$5,426,930	$16,787,925	373	14
HOT GAS CLEANUP UNIT(GE ZNFeSyst)	$4,773,750	$3,283,613	$8,057,363	179	7
ZnFe Outlet Gas Cyclones & Ductwork					
Regeneration Compressor & Heat Exch					
SO2 Recovery Plant	$2,939,625	$1,447,875	$4,387,500	98	4
SulfurCondensateHandling,Storage&Loadout,					
Catalyst Conveying & Loadout (Incl)					
ZincFerriteSorbentConveying&Storage(Incl)					
FLUE GAS CLEANUP SYSTEM AUXILIARIES	$450,544	$127,671	$578,215	13	0
Bottom Ash Handling System					
Ash Storage Silo & Outloading System (Incl)					
SUB TOTAL ASH HANDLING SYSTEM	$315,438	$110,375	$425,813	9	0.3
High Pressure Interconnect'g Piping					
Interconnecting Coal/Sorb System Piping					
Additional Fire Protection Pumps/Piping					
Additional Plant Air Compressors/Piping					
Add'l Instru Air Compressors,Filters/Piping					
SUB TOT ADDITIONAL PIPING SYSTEMS	$824,029	$1,616,486	$2,440,516	54	2
Gasification Syst Excav, Fdns, & Backfill					
Gasification System Roadways/ Parking					
Rail Spur to Cogeneration Plant (1,100 ft)					
Gasification Syst Site Drainage/Leach Field					
SUB TOT ADDITIONAL CIVIL WORK	$561,966	$2,007,753	$2,569,719	57	2
SUB TOT ADDITIONAL BUILDINGS	$812,500	$262,500	$1,075,000	24	1
Generation Plant Electrical System (In Strd CC System)					
Sub Station,X-fmrs,Switchyard (In Strd CC System)					
Gasification System Electrical					
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$920,625	$625,000	$1,545,625	34	1
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions&GasQualityMonitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$1,531,250	$625,000	$2,156,250	48	1.8
ADD.INSUL/LAGG'G/PAINT/SCAFFOLD'G	$203,125	$578,125	$781,250	17	0.6
COAL GASIFIC'N EQUIP ADDERS	$39,611,866	$20,109,020	$55,297,118	1,229	45

Table 5 d

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)		LM/TG5000PC	Project No. J-1538		
Date: 2/8/91		by: RSS			Per Cent
Plant Size Studied (MWg) 47		(MWn) 45			ofConst$
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 2,157		($/KWn) 2,255		($/KWn)	(%)
	Equipment	Installation	Total		
ADD. DESIGN ENGINEERING@8%	$4,423,769				
ADD. PROJECT MANAGEMENT@3%	$1,658,914				
ADD. CONSTRUCTION MGT@3%					
ADD. TEST'G @1% (2% test&strtup)	$552,971				
ADD. START UP COSTS @1%	$552,971				
ADD. DES/BUILD CONTR'S FEE@7%	$3,870,798				
SUB TOT ADDIT. INDIRECT COSTS	$11,059,423	$2,822,262	$13,881,685	308	11
SUB TOT COAL GASIFICATION TURNKEY CONSTRUCTION COST	**$90,451,903**	**$36,172,979**	**$122,201,114**	2,716	100

Table 5 e

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)	LM/TG5000PC			
Date: 2/8/91	by: RSS			
Plant Size Studied (MWg) 47	(MWn) 45			
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 2,157	($/KWn) 2,255		($/KWn)	
		Total		
OWNERS COSTS				
Site		$418,000	9	
Development		$661,740	15	
Working Capital		$1,622,000	36	
Permits		$1,267,364	28	
Legal Fees		$70,897	2	
Taxes & Royalties		$1,217,000	27	
Fuel Inventory		$572,000	13	
Spare Parts		$1,445,000	32	
Interest During Construction		$12,755,000	283	
Underwriters' Costs		$3,516,270	78	
CONTINGENCY & RISK (@ % OF TOTAL PROCESS CAPITAL STATED BELOW)	12.88%	$12,980,979	288	
SUB TOTAL OWNERS COST		$36,526,250	812	
INSTALLED PROJECT TOTAL		**$158,727,364**	**3,527**	**N/A**

Table 5 f

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)		LM/TG5000PC	Project No. J-1538
Date:	Feb-91	by: RSS	
Plant Size Studied (MWg)	47.04	(MWn) 45	
"N"th Coal Fired Turnkey Constr Cost ($/KWg)	2,157	($/KWn) 2,255	
MWn	44.55		
	Calculated 10 Yr Levelized Operating Costs (mils/kwh)		
Coal Plus Oil/Gas for Strt/Emrg	19.00		
ZnFe,NOx,CO,DSRP Catalysts	5.97		
Residue Disposal	0.77		
Operating Labor+O&M Guar Premium+G&A	19.83		
Insurance & Local Taxes	5.94		
Maintenance & Equip Reserves	8.39		
Util.&OperatingConsumables(NoAuxPwrIncl)	0.83		
Other (Miscellaneous)	0.24		
SO2 Recovery Plant	-8.29		
TOTAL OPERATING COSTS	52.68		
PLANT COST INCL CONTINGENCIES	62.88		
TOTAL COST OF ELECTRICITY (COE)	115.56		

Table 6

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)				*Steam Sale Agreement of			3.39	$/1000 lb		
*MAIN CHANGES OR CONDITIONS: Coal Fuel										
(* Means Input Value) Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Year Number	1	2	3	4	5	6	7	8	9	10
Debt Cover Ratio (opn inc/pri.dbt)	1.730	1.935	2.164	2.417	2.704	3.134	3.497	3.902	4.350	4.853
***FG&E 1988 RFP Avd'd Costs (¢/kwh)**	**6.24**	**6.82**	**7.46**	**8.16**	**8.94**	**9.8**	**10.75**	**11.8**	**12.95**	**14.23**
*Pwr Wheeling Charge (mils/KWH)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Net Power Rate (¢/KWH)	6.240	6.820	7.460	8.160	8.940	9.800	10.750	11.800	12.950	14.230
NPV of Pwr Rate Selected	63.024		% of Avoided Costs			50.29		NPV of Avoided Costs Non-Lev		
Ending Balance of pri dbt($-mil)	200.699	194.987	188.527	181.221	172.958	163.613	153.044	141.090	127.571	112.281
Int'st Paymnt on pri dbt($-mil/yr)	25.488	24.826	24.078	23.232	22.275	21.193	19.969	18.584	17.019	15.248
Principle Payment ($-million/yr)	5.050	5.712	6.460	7.306	8.263	9.345	10.569	11.954	13.519	15.290
Total Prim'ry Debt Pymnt($mil/yr)	30.538	30.538	30.538	30.538	30.538	30.538	30.538	30.538	30.538	30.538

FIXED OR INITIAL VALUES: ELECTRICAL OUTPUT			
***Net Output (mw)**	**214.00**		
*Coal Plant Availability (%)	80.0		
Effective hrs/yr incl Oil/Gas Opn	7008		
Annual Avg Steam Sold (lb/hr)	31,925	MBtu/hr	33.202
Electr Prod'n for Sale, (M-KWH/yr)	1,500		
*Combustion Efficiency (%)	95		
COAL CONSUMPTION		FERC Efficiency	
*Firing Rate (MBTU/hour)	1,738	44.1	
Coal Consumpt'n (MMBTU/year)	12.821		
*Coal HHV (1000 BTU/lb)	12.235		
Coal Consumption (1000 tons/year)	524		
Coal Cost at Source (Mine) (¢/MBTU)	106.3		
*Coal Cost FOB Mine ($/ton)	26.00		
Inflat, Coal FOB Mine1st 5 yrs (%/yr)	5		
*Coal Transportation Cost ($/ton)	13.10		
Deliv & Unld Coal Cost (1000$/year)	20,488		
ZnFe, NOx,CO,&DSRP CATALYST CONSUMPTION			
*SO2 Removal Efficiency (%)	99		
*Sulfur in Coal (%, by weight)	4.00		
*ZnFe Sorbent Purity (percent)	100		
*DSRP, CO & NOx Catalyst Cost (1000$/yr)	3,000	GE Data	
*HGCU ZnFe Cost($/ton)	5,202	4,280	
Annual ZnFe Use (1000 ton/year)	0.6	0.4	
Sorbent & Catalyst Costs (1000$/year)	6,121	1,712	
RESIDUE DISPOSAL			
*Ash Content (percent)	16		
*Ash Generation (1000 ton/year)	98.0		
Total Solid Waste (1000 ton/year)	98.0		
*Solid Waste Disposal Cost ($/ton)	10.31		
Solid Waste Disposal Cost ($1000/yr)	1,010		
OTHER FIRST YEAR EXPENSES			
*Number of Plant Personnel	36		
*Labor Rate ($1000/man-year)	73.4		
Labor Cost ($1000/year)	2,642		
O & M Guaran Prem ($1000/year)	624		
*Property Tax ($1000/year)	2,793		
Maint. Supplies ($1000/yr)	4,837		
Util (incl Water) &Oprtg Suppls ($1000/yr)	591		
Equipment Reserve ($1000/yr)	594		
G&A ($l000/yr)	214		
Miscellaneous ($l000/year)	107		

Miscellaneous Payment Not Appropriate
Subtotal: Fuel, Sorbent, Solid Waste ($-mil/yr)
Total Expenses ($-mil/yr)
Insurance @ 0.5% ($1000/year)
Total Insured Expenses ($-mil/yr)

CONSTRUCTION COSTS
Plt Constr ($-mil)
Interconnect Cost Estimate (Included in Plt Const Estim) ($-mil)
Total Constr ($-mil)(depr)

OWNERS' COSTS
*Site Purchase ($-million)
*Construction Period (months)
Construction Interest Rate (%/yr)
Construction Interest ($-mil)(depr)
*Working Capital, (% of construction cost)
Working Capital ($-million)
*Fuel Invent (% of a yr's use for 37 days supply)
Fuel Inventory ($-million)
*Spare Parts (% of equipment cost)
Spare Parts ($-million)
*Recov of Devel$ Incl Permits,Legal ($-mil)(depr)
Total Owners Cost ($-million)
Financing Fees (@ 3%)(depr)
Turnkey Cost (n'th Plant)Including Contingency, Risk &1st Year Taxe

PRIMARY (SENIOR) DEBT-permanent financing
*Min Debt Coverage Ratio Yrs 1-3 (opn inc/pri debt)
Quarterly Debt Payment ($-mil)
Interest Rate on Primary Debt (%/yr)
Primary Loan ($-million)

EQUITY -permanent financing
Outside Equity (Subordinated Debt), (% of turnkey costs)
Outside Equity (Subordinated Debt) Investment ($-million)
Owner's Equity Investment ($-mil) @ 5%
Levelized Annual Outside Equity (Subordinated Debt) Cash Payment
Levelized Annual Owner's Equity Cash Expectations ,($-mil/yr)

DEBT PLUS EQUITY
Total Debt Payments (Primary & Subordinated) ($-mil/yr)
Total Cost of Money (%/yr of turnkey cost)
Effective Interest (Proportioned @Primary Rate & Equity Return Rate

l of		3.39	$/1000 lb		*DATE: Jun 18, '90			*RUN NO.		4					
					Coal Price $/ton		3.64		*Steam Sale to User			223.727	MMlb/yr	*by:	R.S.S.
97	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	AVG
i	7	8	9	10	11	12	13	14	15	16	17	18	19	20	20 yrs
34	3.497	3.902	4.350	4.853	5.417	6.041	6.734	7.515	8.384						4.318
.8	**10.75**	**11.8**	**12.95**	**14.23**	**15.65**	**17.21**	**18.93**	**20.85**	**22.97**	25.32	27.92	**30.81**	**34**	**37.54**	35.770
00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00	10.750	11.800	12.950	14.230	15.650	17.210	18.930	20.850	22.970	25.320	27.920	30.810	34.000	37.540	17.418
29		NPV of Avoided Costs Non-Levellized					125.330								
613	153.044	141.090	127.571	112.281	94.988	75.430	53.311	28.294	0.000	0.000	0.000	0.000	0.000	0.000	120.523
193	19.969	18.584	17.019	15.248	13.245	10.980	8.419	5.521	2.244	0.000	0.000	0.000	0.000	0.000	16.821
45	10.569	11.954	13.519	15.290	17.293	19.558	22.119	25.017	28.294	0.000	0.000	0.000	0.000	0.000	13.717
538	30.538	30.538	30.538	30.538	30.538	30.538	30.538	30.538	30.538	0.000	0.000	0.000	0.000	0.000	30.538

: Not Appropriate	0.000
Solid Waste ($-mil/yr)	27.6190
r)	56.701
00/year)	931
($-mil/yr)	57.6320
OSTS	
	186.177
ate (Included in Plt Const Estim) ($-mil)	0.000
r)	186.177
n)	2.006
onths)	24
ite (%/yr)	12.5
-mil)(depr)	29.279
construction cost)	2.00
on)	3.724
use for 37 days supply)	12.7
i)	2.602
pment cost)	2.00
	3.373
ermits,Legal ($-mil)(depr)	2.000
illion)	42.984
)(depr)	7.72851
i)Including Contingency, Risk &1st Year Taxes ($-million)	257.617
DEBT-permanent financing	
tio Yrs 1-3 (opn inc/pri debt)	1.73
t ($-mil)	7.63454
y Debt (%/yr)	12.5
.)	205.749
it financing	
nated Debt), (% of turnkey costs)	15.13
nated Debt) Investment ($-million)	38.977
ent ($-mil) @ 5%	12.881
le Equity (Subordinated Debt) Cash Payments ,($-mil/yr)	7.655
r's Equity Cash Expectations ,($-mil/yr)	2.530
Y	
rimary & Subordinated) ($-mil/yr)	38.193
/yr of turnkey cost)	14.83
rtioned @Primary Rate & Equity Return Rate) (%)	12.71

FIXED CONDITIONS IN THE PROGRAM		
Term of Debt Service (yrs).		15
Term of Power Contract (yrs)		20
Depreciation Period (years)		20
FINANCIAL INPUTS: RATES, ETC.		
*Power Rate Discount %	N/A	0.0
*Property Tax Rate	N/A	0
*Discount Rate - proj NPV (%/yr)		12.0
Inflation Rates		
*General		5.0
*Coal at Mine (years 1-5)		5.0
*Coal at Mine (years 6-25)		8.0
*Transportation Cost		5.0
*Power Rate		4.0
*Pwr Rate	N/A	0.0
Interest Rates		
*Construction Loan		12.5
*Primary Debt		12.5
* Equity After Tax Rate of Return	N/A	18.0
Tax Rates (Combined Federal & State)		
*Corporate		38.0
*Investor's		38.0
Depreciable Amt. (% of x-key $)		91
***Year of Initial Operation**		**1992**
Auxiliary Gas/Oil Pwr Blr Considerations		
*1st yr Cost of Coal ($/MBTU)		1.76
Cost of #2 Oil (¢/gal)		96.1
* % of Operation on Oil/Gas		2.00
Incr $ Oil/Gas for Strt/Emrg (mil$/yr)		0
Current Delivered Coal Cost ($/MBTU)		1.60
Annual Operating Hours on Oil/Gas		140
Availability(% of Max MW Generatn)		80
CCGT Eq Cost of Fuel ($/MBTU)		2.15
(Includes Coal,Sorbent,& Waste Disposal)		
FERC Efficiency (%)		44.1
Net Power Output Cycle Efficiency (%)		42.0
Water Costs (¢/1000 Gal)		75
Process Make-up Water (1000 Gal/Yr)		128,375
Cooling Twr Make-up Water (1000 Gal/Yr)		487,196
Elemental Sulfur Credit ($/Ton)		105
Sulfur Credit 1st Year (1000$/Yr)		2,201
Sulfuric Acid Credit ($/Ton)		86
Sulfuric Acid Credit 1st Year (1000$/Yr)		5,520
Sulfuric Acid Advantage over Elemental Sulfur		2.50795
Sulfur Dioxide Credit ($/Ton)(FOB AL)		230
Sulfur Dioxide Credit 1st Year (1000$/Yr)		9,642
Sulfuric Acid Advantage over Elemental Sulfur		4.38074

4.2.1.2 STIG

The schematic shown in Figure 8 reflects a basic CGIA concept applied as a STIG unit to a cogeneration (Cogen) or independent power production (IPP) facility. It utilizes a GE LM 5000 ST 120 aeroderivative combustion turbine with an unfired heat recovery steam generator (HRSG), however, it does not employ a steam turbine/generator. Its HRSG generated steam is partially injected into the combustion turbine (to its compressor surge margin limits) increasing its output, and the balance of steam generated is available for process use.

To meet the year 2000 goal of 0.1 lb/MBtu NOx emissions, ammonia injection/selective catalytic reduction (SCR) is deemed necessary.

Since CGIA employs a zinc ferrite (ZnFe) hot gas cleanup unit (HGCU), the SO2 emission limit goal of 0.1 lb/MBtu can be met with 99.5% desulfurization which is consistent with removal efficiencies of current HGCU designs. By the year 2000, such impediments as sulfur bearing tars, and sulfur regeneration/recovery efficiency losses are judged to have been overcome by improved gasifier designs and HGCU's.

The nominal 50 MWe plant generates a net output to the grid of 47 MWe. A plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) (Figure 9) from approximately 8¢/kWh to 11¢/kWh. Clearly, this result is also uneconomical almost irrespective of the value of the process steam.

Its initial facility total costs are estimated at $136-million (Table 7a). Even applying N'th plant reduction factors (7) which lowered its anticipated costs to $83-million failed to reduce its costs sufficiently for serious consideration.

A detailed cost analysis appears in Tables 7b-7f. The costs were initially estimated for a conventional natural gas-fired combined cycle facility. The added costs of coal gasification were then added to the co-gen plant costs. Sources of capital, terms, return rates expected, and ultimate costs of money were determined from costs typical of many small entrepreneurial cogen & IPP developers (Table 6). Owner's costs were also included in order to generate ultimate costs of electricity (COE).

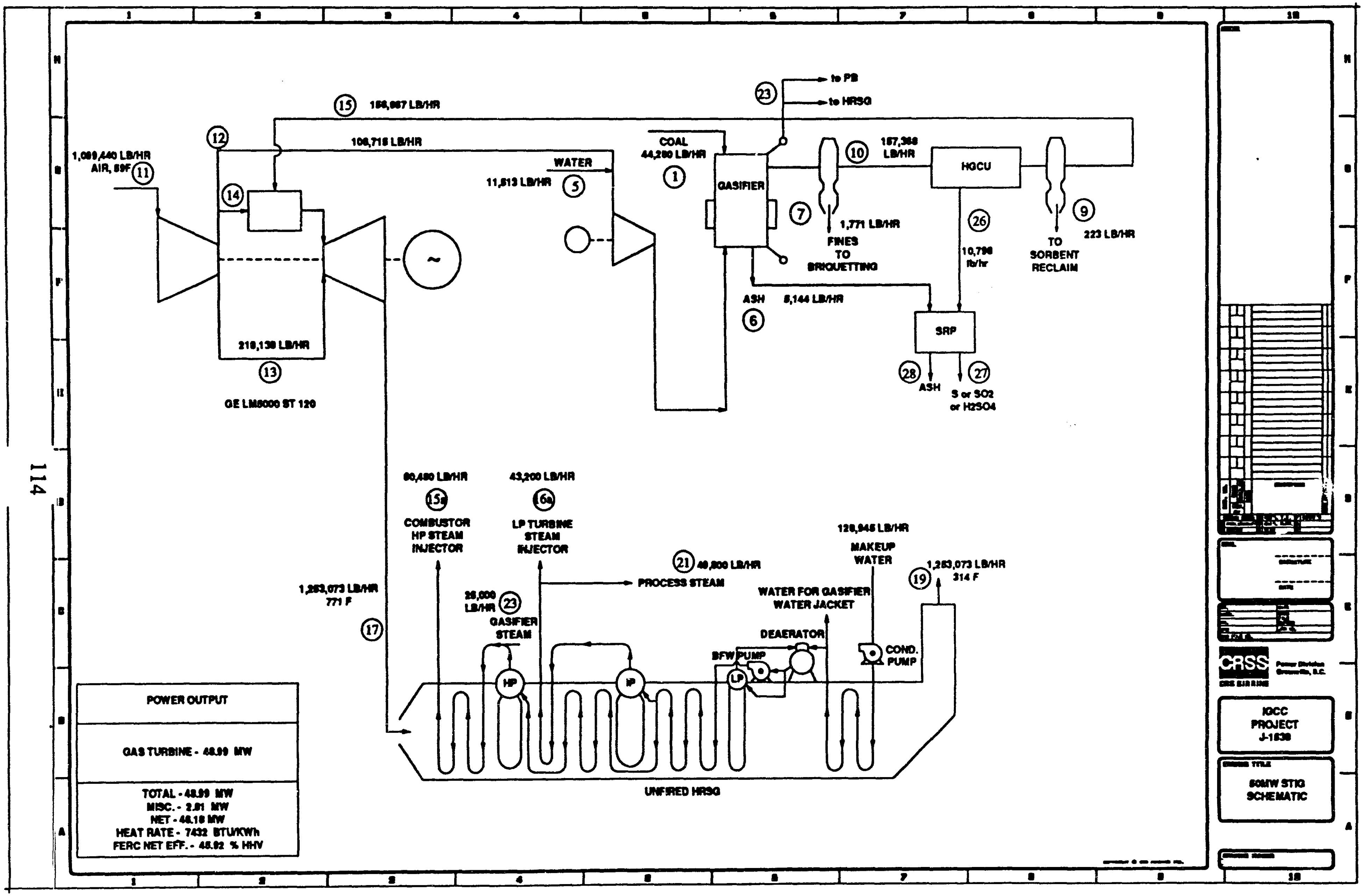

1,089,440 LB/HR
AIR, 59F
11
12
14
15
158,667 LB/HR
106,716 LB/HR
WATER
11,613 LB/HR
5
COAL
44,280 LB/HR
1
GASIFIER
7
23
to PB
to HRSG
10
157,368 LB/HR
HGCU
9
1,771 LB/HR
FINES TO BRIQUETTING
26
10,796 lb/hr
TO SORBENT RECLAIM
223 LB/HR
ASH
5,144 LB/HR
6
SRP
28
ASH
27
S or SO2 or H2SO4
218,139 LB/HR
13
GE LM6000 ST 120
60,480 LB/HR
15a
COMBUSTOR HP STEAM INJECTOR
43,200 LB/HR
16a
LP TURBINE STEAM INJECTOR
21
40,800 LB/HR
PROCESS STEAM
128,946 LB/HR
MAKEUP WATER
1,263,073 LB/HR
314 F
19
1,263,073 LB/HR
771 F
17
26,000 LB/HR
23
GASIFIER STEAM
WATER FOR GASIFIER WATER JACKET
DEAERATOR
COND. PUMP
BFW PUMP
LP
HP
UNFIRED HRSG
POWER OUTPUT
GAS TURBINE - 48.99 MW
TOTAL - 48.99 MW
MISC. - 2.81 MW
NET - 46.18 MW
HEAT RATE - 7432 BTU/KWh
FERC NET EFF. - 45.92 % HHV
CRSS
IGCC PROJECT J-1630
50MW STIG SCHEMATIC

Figure 8

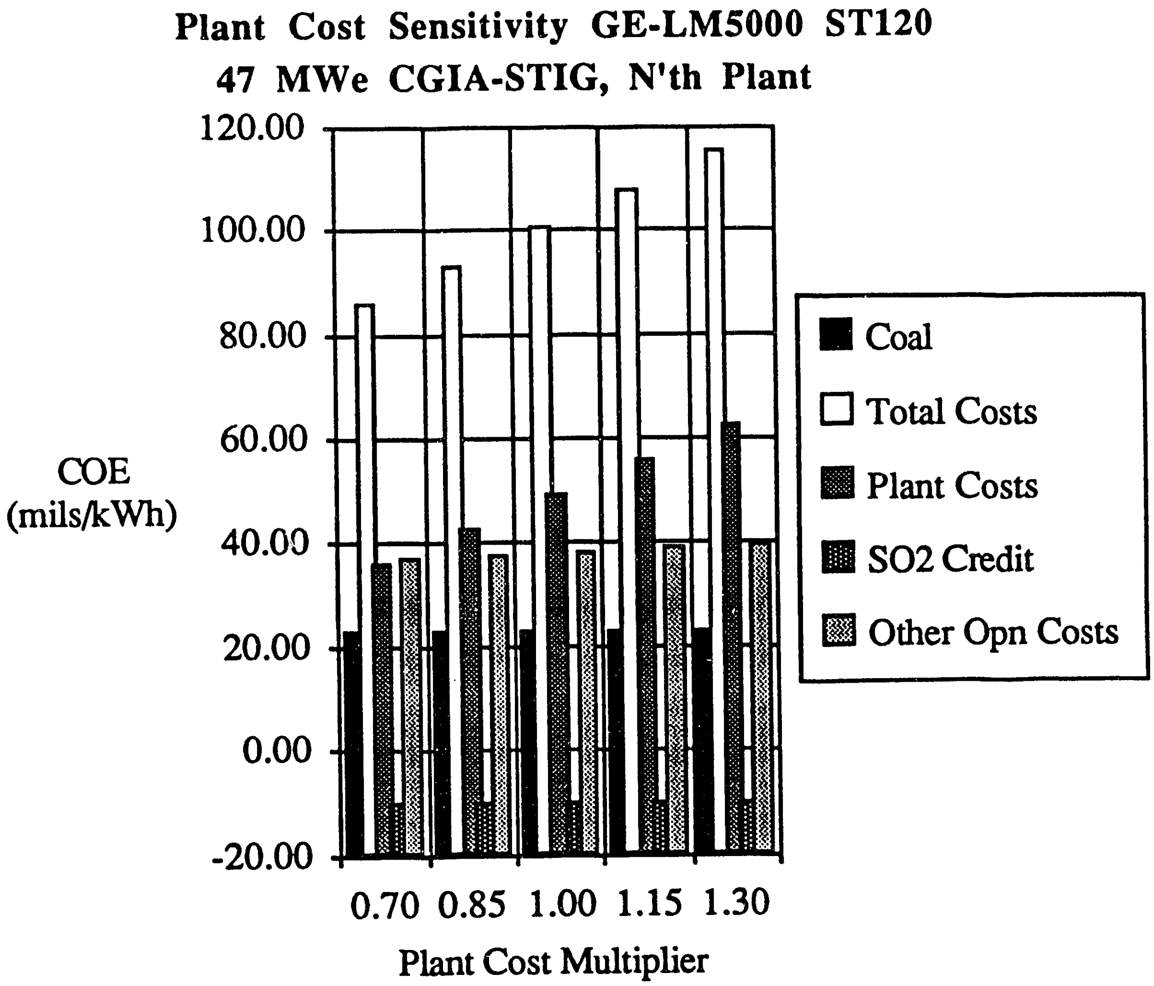

Plant Cost Sensitivity GE-LM5000 ST120
47 MWe CGIA-STIG, N'th Plant
COE
(mils/kWh)
120.00
100.00
80.00
60.00
40.00
20.00
0.00
-20.00
0.70 0.85 1.00 1.15 1.30
Plant Cost Multiplier
Coal
Total Costs
Plant Costs
SO2 Credit
Other Opn Costs

Figure 9

Table 7 a

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) LM 5000 ST120 Project No. J-1538
Date: Feb-91 by: RSS
Plant Size Studied (MWg) 49 (MWn) 46
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,702 ($/KWn) 1,813

System Description: 1-Stage Dry Bottom Fixed Bed Coal Gasifiers, ZnFe Moving Bed (GE type)
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)

Number Trains & Section Description	Total Flow & Units	1st Plant SectionCost, ($)	N-th Plant Section Cost, ($)	N-th Learning Reduct (%)	N-th Plant Cost ($/kwn)
1 ea, Coal Handling	7200TPD	4,934,318	4,934,318	0	107
1 ea, Briquetting System	2400 TPD	3,233,286	2,586,629	20	56
2 ea, Gasification & Ash	45 - lb/sec	16,659,559	13,327,647	20	290
1 ea, Hot Gas Cleanup System (GE type)	45 - lb/sec	6,066,722	3,640,033	40	79
1 ea, Gas Turbine	LM 5000 ST120	24,090,418	19,272,334	20	419
1 ea, HRSG, (Includes CO Catalyst & SCR)	17/29 - lb/sec	4,352,681	4,352,681	0	95
1 ea, Steam Turbine	0	0	0	0	0
1 ea, Booster Compressor	30 - lb/sec	2,356,200	2,356,200	0	51
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)	2.5 K - lb/hr	3,823,458	2,294,075	40	50
Sub-total		65,516,642	52,763,917		1,147
BalanceofPlant(% sub-t w/out proc conting)	30%	19,401,531	11,640,919	40	253
TOTAL PROCESS CAPITAL		84,918,173	64,404,836		1,400
Fully Standardized Designed N'th Plant			50,950,904	40	1,108
Engineering (Only)	9%				
Engineering (Contractor's) Fees (Incl Proj&ConstMgt, Testing/Startup, Design/Build Contr Fees, but NOT Opn, Data Col & Rptg, Admin, Dspsn) (%ofTotal Process Capital)	23%	19,565,709	11,739,425	40	255
Project Contingency (%ofTotal Process Capital)	13%	11,039,362	6,623,618	40	144
TOTAL PLANT INVESTMENT		115,523,244	69,313,947		1,507
Allowance for Funds During Construction, (AFDC)	13%	10,900,000	6,540,000		142
WorkCap,Taxes,Royal,Devel,Permits,Legal, Fuel Inven, Spare Parts, Underwriter Costs	11%	9,215,171	7,101,103		154
Land(HistoricalSiteCostsforCo-generation) Acreage @ $8,500 per Acre = 51	0.4%	433,000	433,000		9
TOTAL CAPITAL REQUIREMENT		136,071,415	83,388,050		1,813

Table 7 b

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)		LM 5000 ST120	Project No. J-1538		
Date: 2/6/91		by: RSS			Per Cent
Plant Size Studied (MWg) 49		(MWn) 46			ofConst$
TypicalGasFiredTurnkeyConstrCost($/KWg) 751		($/KWn) 800		($/KWn)	(%)
	Equipment ($)	Installation ($)	Total ($)		
COGENERATION SYSTEM GROUP INCLUDING STRD CONTROLS, ELECTRICAL, BLDG, CIVIL, STRUCT, ARCHETEC, MECH					
Gas Turbine/Gen Syst(Incl Cogen Plt I&C)	$14,084,937				
Steam Turbine/Generator System	$0				
StartUp&BackupFuel(NatGas)PrepSystem	$752,888				
Condenser & Vacuum Systems	$0				
TURBINE ISLAND	$14,837,825	$3,470,820	$18,308,645	398	18
Aux Blr for Startup/Emerg PwrGen (Optional)	$0	$0	$0		
HtRecovSteamGenerator(w/COCatyl&SCR)	$2,962,500	$678,650	$3,641,150		
HRSG Ductwork & Stack (Incl)					
BOILER ISLAND	$2,962,500	$1,390,181	$4,352,681	95	4
Cooling Tower					
Evaporative Makeup,Circ Water,&AuxSys					
SUB TOT COOL'G TWR SYST	$0	$0	$0	0	0.0
Raw Water Well, Pumps,Fire Prot System					
Demineralizer, Treatment & Storage					
Treated Water Pumping & Control					
CondensateRet,WaterChem,Filtr,StorTanks					
Chem Treat & Cooling Systems					
Feed Water Heaters&Deaerator					
FEEDWATER & WATER TREATMENT SYST	$1,626,648	$429,283	$2,055,931	45	2
Generation Plant Electrical System (Incl)					
Sub Station,X-fmrs,Switchyard (Incl)					
and Balance of Plant Electrical	$1,049,071				
Power Transmission Lines	$726,000	$590,615			
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$1,775,071	$1,926,819	$3,701,890	80	4
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions Monitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$916,210	$402,895	$1,319,105	29	1.3
BUILDINGS (Contr Rm,Lav,HVAC,CompAir)	$811,650	$216,894	$1,028,544		
PAINTING/INSUL/LAGG'G/SCAFFOLDING	$120,960	$30,893	$151,853		
COGENERATION SYST SUB TOTAL	$23,050,864	$7,867,785	$30,918,649	672	30
ADD. DESIGN ENGINEERING@8%	$2,473,492		$2,473,492		
ADD. PROJECT MANAGEMENT@3%	$618,373		$618,373		
ADD. CONSTRUCTION MGT@3%		$927,559	$927,559		
ADD. TEST'G @1% (2% test&strtup)	$309,186		$309,186		
ADD. START UP COSTS @1%	$309,186		$309,186		
ADD. DES/BUILD CONTR'S FEE@7%	$1,236,746		$1,236,746		
SUB TOT INDIRECT COSTS	$4,946,983	$927,559	$5,874,542	128	6
SUB TOTAL COGENERATION TURNKEY CONSTRUCTION COST	$27,997,847	$8,795,344	$36,793,191	800	35

Table 7 c

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) LM 5000 ST120 Project No. J-1538
Date: 2/6/91 by: RSS
Plant Size Studied (MWg) 49 (MWn) 46
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,702 ($/KWn) 1,813

COAL GASIFICATION ADDERS	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
Coal Rail Spur					
Coal Receiving, Storage & Handling System					
Coal Fines Briquetting System	$3,463,425	$1,470,893	$4,934,318	107	5
Mobile Equip(2-B'dozers,Fr Loader,LiftTrk)					
SUB TOTAL COAL FACILITIES	$5,916,204	$2,251,400	$8,167,604	178	8
COMBUSTOR MOD. for COAL GAS FIRING	$2,000,000	$945,000	$2,945,000	64	3
AIR HANDLING FLOW MODULE	$2,268,000	$567,000	$2,835,000	62	3
BOOSTER COMPRESSOR&INTERCOOLER	$2,205,000	$151,200	$2,356,200	51	2
ADDITIONAL PROCESS WATER SYSTEM	$378,000	$115,074	$493,074	11	0.5
HighPressureAir&GasDuctwork&Cyclones,					
Coal Feed & Lock Hopper Systems (Incl)					
Gasifiers (Lurgi Mark IV Comparable)					
Ash Handling Lock Hopper System (Incl)					
Grate, Leveller, & Stirrer Drives (Incl)					
GASIFIER ISLAND	$11,088,796	$5,141,544	$16,230,340	353	16
HOT GAS CLEANUP UNIT(GE ZNFeSyst)	$2,174,000	$3,309,881	$5,483,881	119	5
ZnFe Outlet Gas Cyclones & Ductwork					
Regeneration Compressor & Heat Exch					
SO2 Recovery Plant	$2,364,000	$1,459,458	$3,823,458	83	4
SulfurCondensateHandling,Storage&Loadout,					
Catalyst Conveying & Loadout (Incl)					
ZincFerriteSorbentConveying&Storage(Incl)					
FLUE GAS CLEANUP SYSTEM AUXILIARIES	$454,148	$128,693	$582,841	13	1
Bottom Ash Handling System					
Ash Storage Silo & Outloading System (Incl)					
SUB TOTAL ASH HANDLING SYSTEM	$317,961	$111,258	$429,219	9	0.4
High Pressure Interconnect'g Piping					
Interconnecting Coal/Sorb System Piping					
Additional Fire Protection Pumps/Piping					
Additional Plant Air Compressors/Piping					
Add'l Instru Air Compressors,Filters/Piping					
SUB TOT ADDITIONAL PIPING SYSTEMS	$830,622	$1,629,418	$2,460,040	53	2
Gasification Syst Excav, Fdns, & Backfill					
Gasification System Roadways/ Parking					
Rail Spur to Cogeneration Plant (1,100 ft)					
Gasification Syst Site Drainage/Leach Field					
SUB TOT ADDITIONAL CIVIL WORK	$566,462	$2,023,815	$2,590,277	56	2
SUB TOT ADDITIONAL BUILDINGS	$819,000	$264,600	$1,083,600	24	1
Generation Plant Electrical System (In Strd CC System)					
Sub Station,X-fmrs,Switchyard (In Strd CC System)					
Gasification System Electrical					
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$927,990	$630,000	$1,557,990	34	1
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions&GasQualityMonitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$1,543,500	$630,000	$2,173,500	47	2.1
ADD.INSUL/LAGG'G/PAINT/SCAFFOLD'G	$204,750	$582,750	$787,500	17	0.7
COAL GASIFIC'N EQUIP ADDERS	$38,378,395	$19,941,091	$53,999,524	1,174	52

Table 7 d

"N"th Coal Fired Turnkey Constr Cost ($/KWg) — LM 5000 ST120 — Project No. J-1538

Date: 2/6/91 — by: RSS

Plant Size Studied (MWg) 49 — (MWn) 46

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,702 — ($/KWn) 1,813

	Equipment	Installation	Total	($/KWn)	Per Cent ofConst$ (%)
ADD. DESIGN ENGINEERING@8%	$4,319,962				
ADD. PROJECT MANAGEMENT@3%	$1,619,986				
ADD. CONSTRUCTION MGT@3%					
ADD. TEST'G @1% (2% test&strtup)	$539,995				
ADD. START UP COSTS @1%	$539,995				
ADD. DES/BUILD CONTR'S FEE@7%	$3,779,967				
SUB TOT ADDIT. INDIRECT COSTS	$10,799,905	$2,891,262	$13,691,167	298	13
SUB TOT COAL GASIFICATION TURNKEY CONSTRUCTION COST	$77,176,147	$31,627,697	$104,483,882	2,271	100

Table 7 e

LM 5000 ST120 — Project No. J-1538

Date: 2/6/91 — by: RSS

Plant Size Studied (MWg) 49 — (MWn) 46

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,702 — ($/KWn) 1,813

	Total	($/KWn)	Per Cent ofConst$ (%)
OWNERS COSTS			
Site	$433,000	9	
Development	$661,740	14	
Working Capital	$1,386,000	30	
Permits	$1,267,364	28	
Legal Fees	$70,897	2	
Taxes & Royalties	$1,040,000	23	
Fuel Inventory	$544,000	12	
Spare Parts	$1,229,000	27	
Interest During Construction	$10,900,000	237	
Underwriters' Costs	$3,016,170	66	
CONTINGENCY & RISK (@ % OF TOTAL PROCESS CAPITAL STATED BELOW) 13.18%	$11,039,362	240	
SUB TOTAL OWNERS COST	$31,587,533	687	
INSTALLED PROJECT TOTAL	$136,071,415	2,958	N/A

Table 7 f

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) — LM 5000 ST120 — Project No. J-1538

Date: Feb-91 — by: RSS

Plant Size Studied (MWg) 49 — (MWn) 46.18

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,702 — ($/KWn) 1,813

	Calculcted 10 Yr Levelized Operating Costs (mils/kwh)
Coal Plus Oil/Gas for Strt/Emrg	17.45
ZnFe,NOx,CO,DSRP Catalysts	7.67
Residue Disposal	0.77
Operating Labor+O&M Guar Premium+G&A	19.08
Insurance & Local Taxes	4.90
Maintenance & Equip Reserves	5.62
Util.&OperatingConsumables(NoAuxPwrIncl)	0.79
Other (Miscellaneous)	0.20
SO2 Recovery Plant	-7.60
TOTAL OPERATING COSTS	48.88
PLANT COST INCL CONTINGENCIES	50.94
TOTAL COST OF ELECTRICITY (COE)	99.82

4.2.1.3 Cost Sensitivity

There appears to be little chance of making such a small capacity plant economical (Figure 7). The plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) from approximately 9¢/kWh to 12¢/kWh. Even a switch to a STIG configuration did not improve the plant economics enough (the plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity [COE] [Figure 9] from approximately 8¢/kWh to 11¢/kWh) to warrant serious consideration of such a small plant. Clearly, this result is also uneconomical almost irrespective of the value of the process steam.

4.2.2. 100 MW Size CGIA Concept

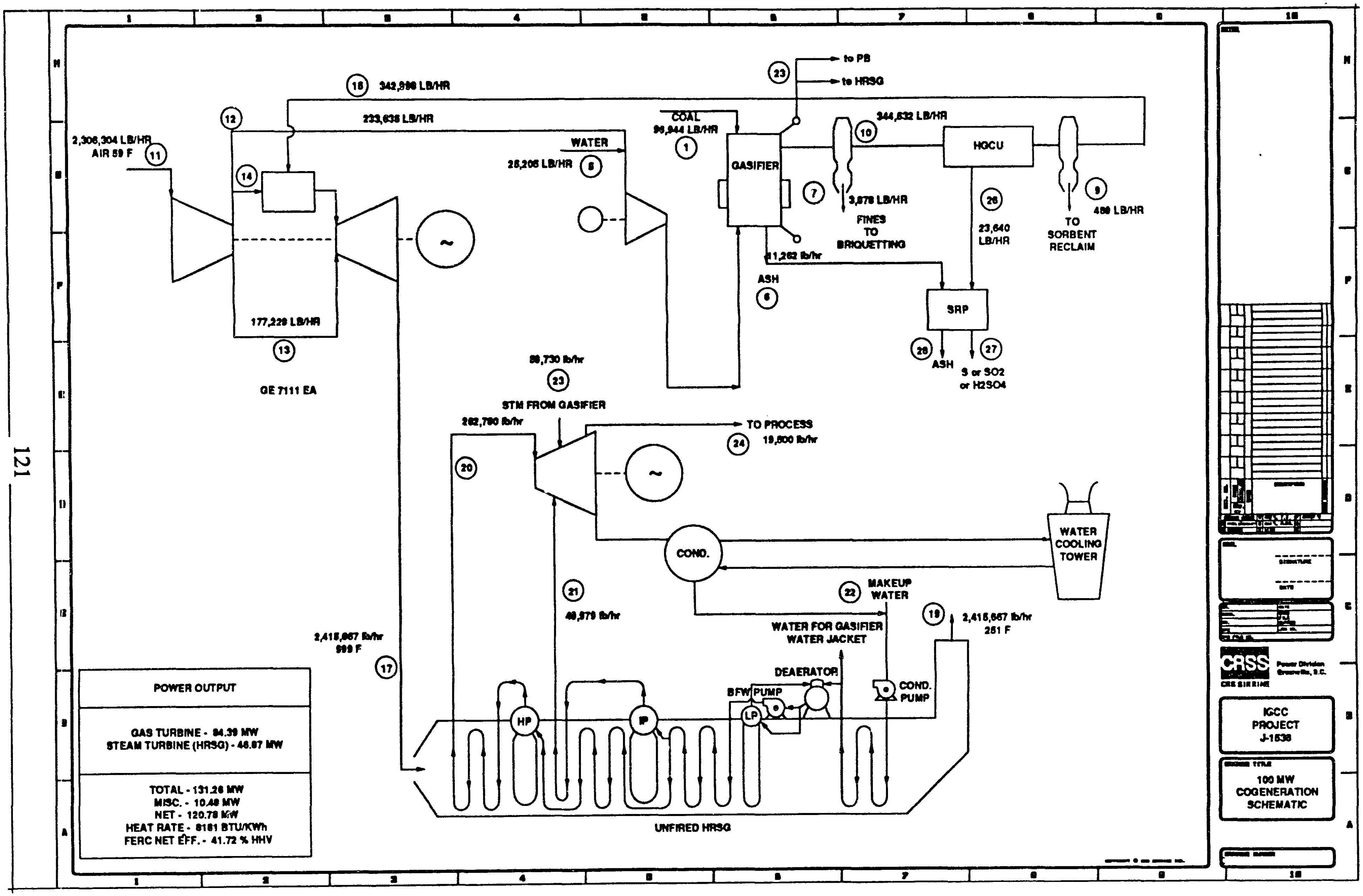
Since it is anticipated that the 100 MWe capacity should be a "building block" modular capacity from which both the cogen/IPP and utility industries can produce CGIA standardized plants, this capacity was studied for both considerations.

4.2.2.1 Cogeneration & IPP Applications

The schematic shown in Figure 10 reflects a basic CGIA concept applied as a STAG unit to a cogeneration (Cogen) or independent power production (IPP) facility. It utilizes a GE 7111EA combustion turbine with an unfired heat recovery steam generator (HRSG), and a steam turbine/generator. Its HRSG generated steam is utilized to generate power with 5% of its thermal output reserved for process use.

To meet the year 2000 goal of 0.1 lb/MBtu NOx emissions, ammonia injection/selective catalytic reduction (SCR) is deemed necessary.

Since CGIA employs a zinc ferrite (ZnFe) hot gas cleanup unit (HGCU), the SO2 emission limit goal of 0.1 lb/MBtu can be met with 99.5% desulfurization which is consistent with removal efficiencies of current HGCU designs. By the year 2000, such impediments as sulfur bearing tars, and sulfur regeneration/recovery efficiency losses are judged to have been overcome by improved gasifier designs and HGCU's.



2,306,304 LB/HR
AIR 59 F
11
12
14
13
177,229 LB/HR
GE 7111 EA
18
342,998 LB/HR
233,638 LB/HR
WATER
25,205 LB/HR
5
COAL
96,944 LB/HR
1
GASIFIER
23
to PB
to HRSG
344,632 LB/HR
10
7
3,878 LB/HR
FINES
TO
BRIQUETTING
11,262 lb/hr
ASH
6
HGCU
26
23,640
LB/HR
9
489 LB/HR
TO
SORBENT
RECLAIM
SRP
28
ASH
27
S or SO2
or H2SO4
98,730 lb/hr
23
STM FROM GASIFIER
262,790 lb/hr
20
TO PROCESS
24
19,500 lb/hr
COND.
WATER
COOLING
TOWER
21
48,979 lb/hr
22
MAKEUP
WATER
WATER FOR GASIFIER
WATER JACKET
19
2,415,667 lb/hr
251 F
2,415,667 lb/hr
999 F
17
DEAERATOR
BFW PUMP
COND.
PUMP
HP
IP
LP
UNFIRED HRSG
POWER OUTPUT
GAS TURBINE - 84.39 MW
STEAM TURBINE (HRSG) - 46.87 MW
TOTAL - 131.26 MW
MISC. - 10.48 MW
NET - 120.78 MW
HEAT RATE - 8181 BTU/KWh
FERC NET EFF. - 41.72 % HHV
CRSS
IGCC
PROJECT
J-1538
100 MW
COGENERATION
SCHEMATIC

Figure 10

The nominal 100 MWe plant generates a net output to the grid of 120-123 MWe. A plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) (Figure 11) from approximately 5¢/kWh to 7¢/kWh. This result would be acceptable for applications in high power cost areas such as the northeast.

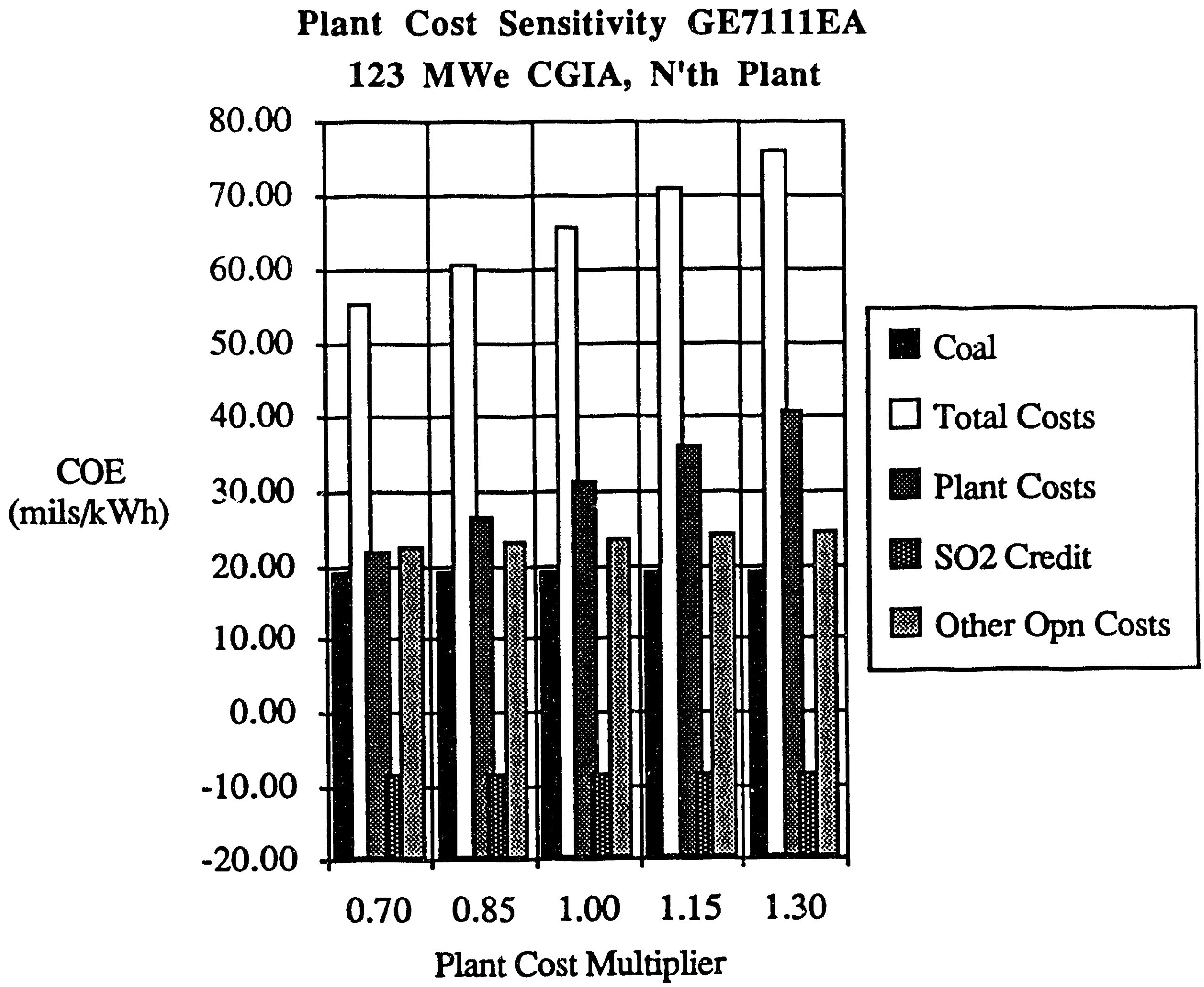
Its initial facility total costs are estimated at $262-million (Table 8). Applying N'th plant reduction factors [7] which lowered its anticipated costs to $160-million reduces its costs sufficiently for serious consideration.

A detailed cost analysis appears in Table 8a - 8f. As in the previous cases, the costs were initially estimated for a conventional natural gas fired combined cycle facility. The added costs of coal gasification were then added to the cogen plant costs. Sources of capital, terms, return rates expected, and ultimate costs of money were determined from costs typical of many small entrepreneurial cogen & IPP developers (Table 6). Owner's costs were also included in order to generate ultimate costs of electricity (COE).

4.2.2.2 Utility Applications

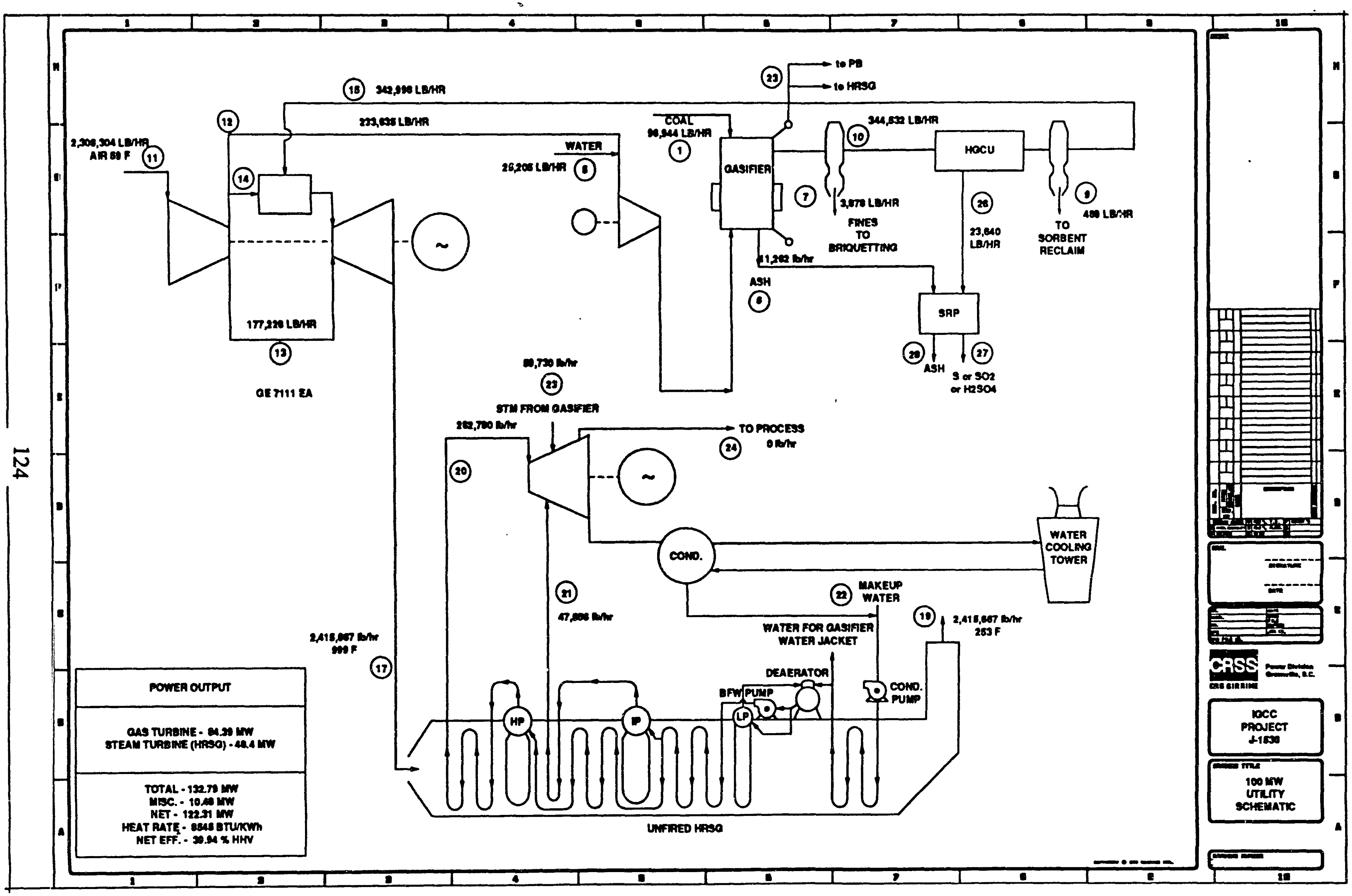
In an effort to determine its applicability to utility industry, the same cycle was reworked (Figure 12) at the same higher pressures and temperatures (relative to the previous 50 MWe case) which are in line with utility practice. In this case there was no process steam included, and all steam generated from the unfired HRSG was utilized to generate power.

The result, as expected, was only a slight increase in power output over the previous case. This was caused by the anticipation of only minimal thermal use (5%) in the cogen/IPP case, and both cases are limited in the Rankine cycle conditions by the low thermal head of the unfired HRSG.



Plant Cost Sensitivity GE7111EA
123 MWe CGIA, N'th Plant
COE (mils/kWh)
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
-10.00
-20.00
0.70
0.85
1.00
1.15
1.30
Plant Cost Multiplier
Coal
Total Costs
Plant Costs
SO2 Credit
Other Opn Costs

Figure 11



2,308,304 LB/HR
AIR 59 F
342,998 LB/HR
223,638 LB/HR
177,228 LB/HR
GE 7111 EA
WATER
26,206 LB/HR
COAL
96,944 LB/HR
GASIFIER
to PB
to HRSG
344,632 LB/HR
HGCU
3,878 LB/HR
FINES
TO
BRIQUETTING
23,640
LB/HR
TO
SORBENT
RECLAIM
408 LB/HR
ASH
SRP
S or SO2
or H2SO4
STM FROM GASIFIER
TO PROCESS
0 lb/hr
COND.
WATER
COOLING
TOWER
MAKEUP
WATER
WATER FOR GASIFIER
WATER JACKET
47,808 lb/hr
2,415,867 lb/hr
253 F
2,415,867 lb/hr
999 F
DEAERATOR
BFW PUMP
COND.
PUMP
HP
IP
LP
UNFIRED HRSG
POWER OUTPUT
GAS TURBINE - 84.39 MW
STEAM TURBINE (HRSG) - 48.4 MW
TOTAL - 132.79 MW
MISC. - 10.48 MW
NET - 122.31 MW
HEAT RATE - 8848 BTU/KWh
NET EFF. - 38.94 % HHV
CRSS
IGCC
PROJECT
J-1536
100 MW
UTILITY
SCHEMATIC

Figure 12

Table 8 a

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE 7111EA Project No. J-1538
Date: Feb-91 by: RSS
Plant Size Studied (MWg) 132.79 (MWn) 122
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,970 ($/KWn) 2,144

System Description: 1-Stage Dry Bottom Fixed Bed Coal Gasifiers, ZnFe Moving Bed (GE type)
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)

Number Trains & Section Description	Total Flow & Units	1st Plant SectionCost, ($)	N-th Plant Section Cost, ($)	N-th Learning Reduct (%)	N-th Plant Cost ($/kwn)
1 ea, Coal Handling	14400TPD	7,910,573	7,910,573	0	65
1 ea, Briquetting System	4800 TPD	5,183,522	4,146,818	20	34
4 ea, Gasification & Ash	98 - lb/sec	33,148,793	26,519,034	20	217
2 ea, Hot Gas Cleanup System (GE type)	98 - lb/sec	13,955,093	8,373,056	40	69
1 ea, Gas Turbine	GE 7111EA	32,042,250	25,633,800	20	210
1 ea, HRSG, (Includes CO Catalyst & SCR)	81 - lb/sec	12,738,954	12,738,954	0	104
1 ea, Steam Turbine	50 MWe	9,735,895	9,735,895	0	80
1 ea, Booster Compressor	66 - lb/sec	1,454,400	1,454,400	0	12
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)	5.4 K - lb/hr	7,090,200	4,254,120	40	35
Sub-total		123,259,680	100,766,650		826
BalanceofPlant(% sub-t w/out proc conting)	35%	42,757,661	25,654,597	40	210
TOTAL PROCESS CAPITAL		166,017,341	126,421,247		1,036
Fully Standardized Designed N'th Plant			99,610,405	40	816
Engineering (Only)	8%				
Engineering (Contractor's) Fees (Incl Proj&ConstMgt, Testing/Startup, Design/Build Contr Fees, but NOT Opn, Data Col & Rptg, Admin, Dspsn) (%ofTotal Process Capital)	21%	35,312,471	21,187,483	40	174
Project Contingency (%ofTotal Process Capital)	13%	21,582,254	12,949,353	40	106
TOTAL PLANT INVESTMENT		222,912,066	133,747,241		1,096
Allowance for Funds During Construction, (AFDC)	13%	21,033,000	12,619,800		103
WorkCap,Taxes,Royal,Devel,Permits,Legal, Fuel Inven, Spare Parts, Underwriter Costs	10%	16,488,701	12,399,621		102
Land(HistoricalSiteCostsforCo-generation) Acreage @ $8,500 per Acre = 135	0.5%	1,147,000	1,147,000		9
TOTAL CAPITAL REQUIREMENT		261,580,767	159,913,662		1,311

Table 8 b

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)		GE 7111EA	Project No. J-1538		
Date: 2/8/91		by: RSS			Per Cent
Plant Size Studied (MWg) 132.79		(MWn) 122			ofConst$
TypicalGasFiredTurnkeyConstrCost($/KWg) 648		($/KWn) 696		($/KWn)	(%)
	Equipment ($)	Installation ($)	Total ($)		
COGEN SYSTEM GROUP INCLUDING STRD CONTROLS, ELECTRICAL, BLDG, CIVIL, STRUCT, ARCHETEC, MECHAN					
Gas Turbine/Gen Syst(Incl Cogen Plt I&C)	$18,432,500				
Steam Turbine/Generator System	$7,489,150				
StartUp&BackupFuel(NatGas)PrepSystem	$923,140				
Condenser & Vacuum Systems	$855,470				
TURBINE ISLAND	$27,700,260	$8,290,693	$35,990,953	295	18
Aux Blr for Startup/Emerg PwrGen (Optional)	$0	$0	$0		
HtRecovSteamGenerator(w/COCatyl&SCR)	$9,418,250	$3,345,799	$12,764,049		
HRSG Ductwork & Stack (Incl)					
BOILER ISLAND	$9,418,250	$3,320,704	$12,738,954	104	6
Cooling Tower					
Evaporative Makeup,Circ Water,&AuxSys					
SUB TOT COOL'G TWR SYST	$1,233,210	$433,536	$1,666,746	14	0.8
Raw Water Well, Pumps,Fire Prot System					
Demineralizer, Treatment & Storage					
Treated Water Pumping & Control					
CondensateRet,WaterChem,Filtr,StorTanks					
Chem Treat & Cooling Systems					
Feed Water Heaters&Deaerator					
FEEDWATER & WATER TREATMENT SYST	$3,129,485	$1,025,422	$4,154,907	34	2
Generation Plant Electrical System (Incl)					
Sub Station,X-fmrs,Switchyard (Incl)					
and Balance of Plant Electrical	$6,453,900				
Power Transmission Lines	$220,000	$880,000			
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$6,673,900	$4,071,771	$10,745,671	88	5
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions Monitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$3,161,300	$962,390	$4,123,690	34	2.1
BUILDINGS (Contr Rm,Lav,HVAC,CompAir)	$1,070,600	$518,092	$1,588,692		
PAINTING/INSUL/LAGG'G/SCAFFOLDING	$242,400	$73,794	$316,194		
COGENERATION SYST SUB TOTAL	$52,629,405	$18,696,402	$71,325,807	585	35
ADD. DESIGN ENGINEERING@8%	$5,706,065		$5,706,065		
ADD. PROJECT MANAGEMENT@3%	$1,426,516		$1,426,516		
ADD. CONSTRUCTION MGT@3%		$2,139,774	$2,139,774		
ADD. TEST'G @1% (2% test&strtup)	$713,258		$713,258		
ADD. START UP COSTS @1%	$713,258		$713,258		
ADD. DES/BUILD CONTR'S FEE@7%	$2,853,032		$2,853,032		
SUB TOT INDIRECT COSTS	$11,412,129	$2,139,774	$13,551,903	111	7
SUB TOTAL COGENERATION TURNKEY CONSTRUCTION COST	$64,041,534	$20,836,176	$84,877,710	696	42

Table 8 c

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)	GE 7111EA		Project No. J-1538		
Date: Feb-91		by: RSS			Per Cent
Plant Size Studied (MWg) 133		(MWn) 122			ofConst$
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,970		($/KWn) 2,144		($/KWn)	(%)
COAL GASIFICATION ADDERS	Equipment ($)	Installation ($)	Total ($)		
Coal Rail Spur					
Coal Receiving, Storage & Handling System					
Coal Fines Briquetting System	$5,552,475	$2,358,098	$7,910,573	65	4
Mobile Equip(2-B'dozers,Fr Loader,LiftTrk)					
SUB TOTAL COAL FACILITIES	$9,484,708	$3,609,387	$13,094,095	107	6
COMBUSTOR MOD. for COAL GAS FIRING	$2,020,000	$1,515,000	$3,535,000	29	2
AIR HANDLING FLOW MODULE	$3,636,000	$909,000	$4,545,000	37	2
BOOSTER COMPRESSOR&INTERCOOLER	$1,212,000	$242,400	$1,454,400	12	1
ADDITIONAL PROCESS WATER SYSTEM	$606,000	$184,484	$790,484	6	0.4
HighPressureAir&GasDuctwork&Cyclones,					
Coal Feed & Lock Hopper Systems (Incl)					
Gasifiers (Lurgi Mark IV Comparable)					
Ash Handling Lock Hopper System (Incl)					
Grate, Leveller, & Stirrer Drives (Incl)					
GASIFIER ISLAND	$22,177,592	$10,283,088	$32,460,680	266	16
HOT GAS CLEANUP UNIT(GE ZNFeSyst)	$7,714,380	$5,306,318	$13,020,698	107	6
ZnFe Outlet Gas Cyclones & Ductwork					
Regeneration Compressor & Heat Exch					
SO2 Recovery Plant	$4,750,434	$2,339,766	$7,090,200	58	4
SulfurCondensateHandling,Storage&Loadout,					
Catalyst Conveying & Loadout (Incl)					
ZincFerriteSorbentConveying&Storage(Incl)					
FLUE GAS CLEANUP SYSTEM AUXILIARIES	$728,079	$206,317	$934,395	8	0
Bottom Ash Handling System					
Ash Storage Silo & Outloading System (Incl)					
SUB TOTAL ASH HANDLING SYSTEM	$509,747	$178,366	$688,113	6	0.4
High Pressure Interconnect'g Piping					
Interconnecting Coal/Sorb System Piping					
Additional Fire Protection Pumps/Piping					
Additional Plant Air Compressors/Piping					
Add'l Instru Air Compressors,Filters/Piping					
SUB TOT ADDITIONAL PIPING SYSTEMS	$1,331,631	$2,612,242	$3,943,873	32	2
Gasification Syst Excav, Fdns, & Backfill					
Gasification System Roadways/ Parking					
Rail Spur to Cogeneration Plant (1,100 ft)					
Gasification Syst Site Drainage/Leach Field					
SUB TOT ADDITIONAL CIVIL WORK	$908,137	$3,244,528	$4,152,666	34	2
SUB TOT ADDITIONAL BUILDINGS	$1,313,000	$424,200	$1,737,200	14	1
Generation Plant Electrical System (In Strd CC System)					
Sub Station,X-fmrs,Switchyard (In Strd CC System)					
Gasification System Electrical					
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$1,487,730	$1,010,000	$2,497,730	20	1
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions&GasQualityMonitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$2,474,500	$1,010,000	$3,484,500	29	1.8
ADD.INSUL/LAGG'G/PAINT/SCAFFOLD'G	$328,250	$934,250	$1,262,500	10	0.6
COAL GASIFIC'N EQUIP ADDERS	$68,257,511	$34,009,346	$94,691,534	776	47

Table 8 d

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) Date: 2/8/91 Plant Size Studied (MWg) 133 "N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,970	GE 7111EA Equipment	by: RSS (MWn) 122 ($/KWn) 2,144 Installation	Project No. J-1538 Total	($/KWn)	Per Cent ofConst$ (%)
ADD. DESIGN ENGINEERING@8%	$7,575,323				
ADD. PROJECT MANAGEMENT@3%	$2,840,746				
ADD. CONSTRUCTION MGT@3%					
ADD. TEST'G @1% (2% test&strtup)	$946,915				
ADD. START UP COSTS @1%	$946,915				
ADD. DES/BUILD CONTR'S FEE@7%	$6,628,407				
SUB TOT ADDIT. INDIRECT COSTS	$18,938,306	$2,822,262	$21,760,568	178	11
SUB TOT COAL GASIFICATION TURNKEY CONSTRUCTION COST	$151,237,351	$57,667,784	$201,329,812	1,650	100

Table 8 e

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) Date: 2/8/91 Plant Size Studied (MWg) 133 "N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,970	GE 7111EA by: RSS (MWn) 122 ($/KWn) 2,144	Total	($/KWn)	
OWNERS COSTS		$1,147,000	9	
Site		$661,740	5	
Development		$2,675,000	22	
Working Capital		$1,267,364	10	
Permits		$70,897	1	
Legal Fees		$2,006,000	16	
Taxes & Royalties		$1,591,000	13	
Fuel Inventory		$2,418,000	20	
Spare Parts		$21,033,000	172	
Interest During Construction		$5,798,700	48	
Underwriters' Costs				
CONTINGENCY & RISK (@ % OF TOTAL PROCESS CAPITAL STATED BELOW)	12.92%	$21,582,254	177	
SUB TOTAL OWNERS COST		$60,250,955	494	
INSTALLED PROJECT TOTAL		$261,580,767	2,144	N/A

Table 8 f

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) — GE 7111EA — Project No. J-1538

Date: Feb-91 — by: RSS

Plant Size Studied (MWg) 132.79 — (MWn) 122

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,970 — ($/KWn) 2,144

MWn 122.31

	Calculated 10 Yr Levelized Operating Costs (mils/kwh)
Coal Plus Oil/Gas for Strt/Emrg	19.26
ZnFe,NOx,CO,DSRP Catalysts	6.80
Residue Disposal	0.77
Operating Labor+O&M Guar Premium+G&A	7.27
Insurance & Local Taxes	3.57
Maintenance & Equip Reserves	4.89
Util.&OperatingConsumables(NoAuxPwrIncl)	0.56
Other (Miscellaneous)	0.11
SO2 Recovery Plant	-8.39
TOTAL OPERATING COSTS	34.84
PLANT COST INCL CONTINGENCIES	33.95
TOTAL COST OF ELECTRICITY (COE)	68.79

4.2.2.3 Cost Sensitivity

There appears to be a reasonable chance of making this 120 MWe capacity plant economical (Figure 11). The plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) from approximately 5.5¢/kWh to 7.5¢/kWh. Clearly, this result is economical in many geographical parts of the US almost irrespective of the value of the process steam which, at 5% thermal, represents only an incidental source of income.

4.2.3. 200 MW Size CGIA Concept

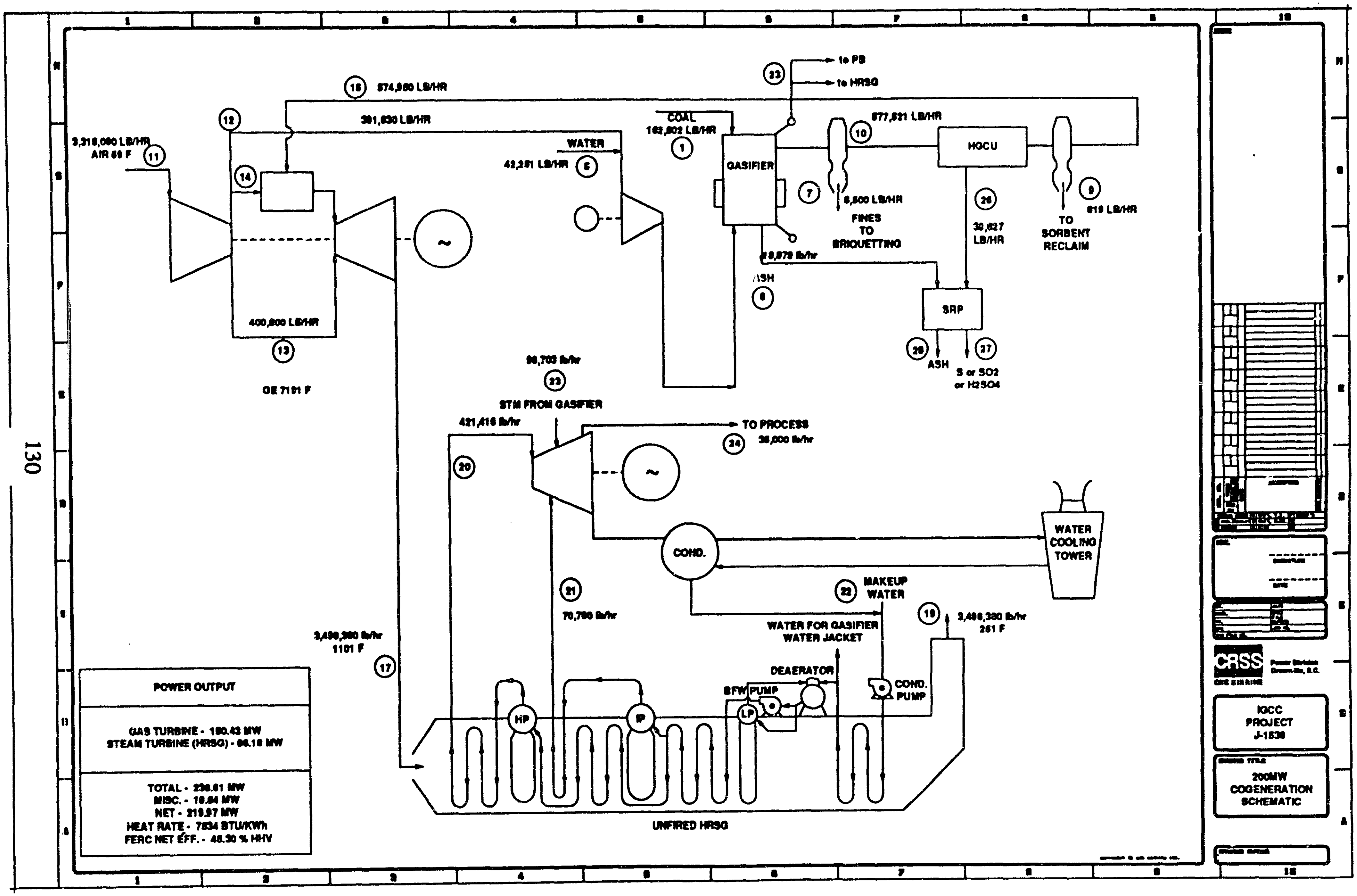
Since it is anticipated that the 200 MWe capacity could also be a "building block" modular capacity from which both the cogen/IPP and utility industries can produce CGIA standardized plants, this capacity was studied for both considerations.

4.2.3.1 Cogeneration & IPP Applications

The schematic shown in Figure 13 reflects a basic CGIA concept applied as a STAG unit to a cogeneration (Cogen) or independent power production (IPP) facility. It utilizes a GE 7191F combustion turbine with an unfired heat recovery steam generator (HRSG), and a steam turbine/generator. Its HRSG generated steam is utilized to generate power with 5% of its thermal output reserved for process thermal use to qualify under Federal Energy Regulatory Commission (FERC) rules.

To meet the year 2000 goal of 0.1 lb/MBtu NOx emissions, ammonia injection/selective catalytic reduction (SCR) is deemed necessary.

Since CGIA employs a zinc ferrite (ZnFe) hot gas cleanup unit (HGCU), the SO2 emission limit goal of 0.1 lb/MBtu can be met with 99.5% desulfurization which is consistent with removal efficiencies of current HGCU designs. By the year 2000, such impediments as sulfur bearing tars, and sulfur regeneration/recovery efficiency losses are judged to have been overcome by improved gasifier designs and HGCU's.



to PB
to HRSG
574,980 LB/HR
391,630 LB/HR
COAL
162,802 LB/HR
577,821 LB/HR
3,316,090 LB/HR
AIR 59 F
WATER
42,281 LB/HR
GASIFIER
HGCU
6,500 LB/HR
FINES
TO
BRIQUETTING
919 LB/HR
TO
SORBENT
RECLAIM
ASH
SRP
S or SO2
or H2SO4
400,800 LB/HR
GE 7101 F
STM FROM GASIFIER
421,416 lb/hr
TO PROCESS
36,000 lb/hr
WATER
COOLING
TOWER
COND.
MAKEUP
WATER
70,786 lb/hr
3,490,380 lb/hr
261 F
WATER FOR GASIFIER
WATER JACKET
3,490,380 lb/hr
1101 F
DEAERATOR
BFW PUMP
COND.
PUMP
HP
IP
LP
UNFIRED HRSG
POWER OUTPUT
GAS TURBINE - 150.43 MW
STEAM TURBINE (HRSG) - 86.18 MW
TOTAL - 236.61 MW
MISC. - 16.64 MW
NET - 219.97 MW
HEAT RATE - 7834 BTU/KWh
FERC NET EFF. - 48.30 % HHV
CRSS
IGCC
PROJECT
J-1530
200MW
COGENERATION
SCHEMATIC

Figure 13

The nominal 200 MWe plant generates a net output to the grid of 223-227 MWe. A plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) (Figure 14) from approximately 4¢/kWh to 6¢/kWh. This result would be acceptable for applications in most areas of the country.

Its initial facility total costs are estimated at $410-million (Table 9a). Applying N'th plant reduction factors [7] which lowered its anticipated costs to $251-million reduces its costs sufficiently for very serious consideration.

A detailed cost analysis appears in Tables 9b - 9f. As in the previous case, the costs were initially estimated for a conventional natural gas fired combined cycle facility. The added costs of coal gasification were then added to the cogen plant costs. Sources of capital, terms, return rates expected, and ultimate costs of money were determined from costs typical of many small entrepreneurial cogen and IPP developers (Table 6). Owner's costs were also included in order to generate ultimate costs of electricity (COE).

4.2.3.2 Utility Applications

In an effort to determine its applicability to utility industry, the same cycle was reworked (Figure 15) at the same higher pressures and temperatures (relative to the previous 50 MWe case) which are in line with utility practice. In this case there was no process steam included, and all steam generated from the unfired HRSG was utilized to generate power.

The result, as expected, was only a slight increase in power output over the previous case. This was caused by the anticipation of only minimal thermal use (5%) in the cogen/IPP case, and both cases are limited in the Rankine cycle conditions by the low thermal head of the unfired HRSG.

The general arrangement drawing for the 50MWe sized plant is shown on Figure 16. Appendices D & E provide details of the plant selected. It is representative of an industrial cogeneration application.

Plant Cost Sensitivity GE7191F
226 MWe CGIA, N'th Plant

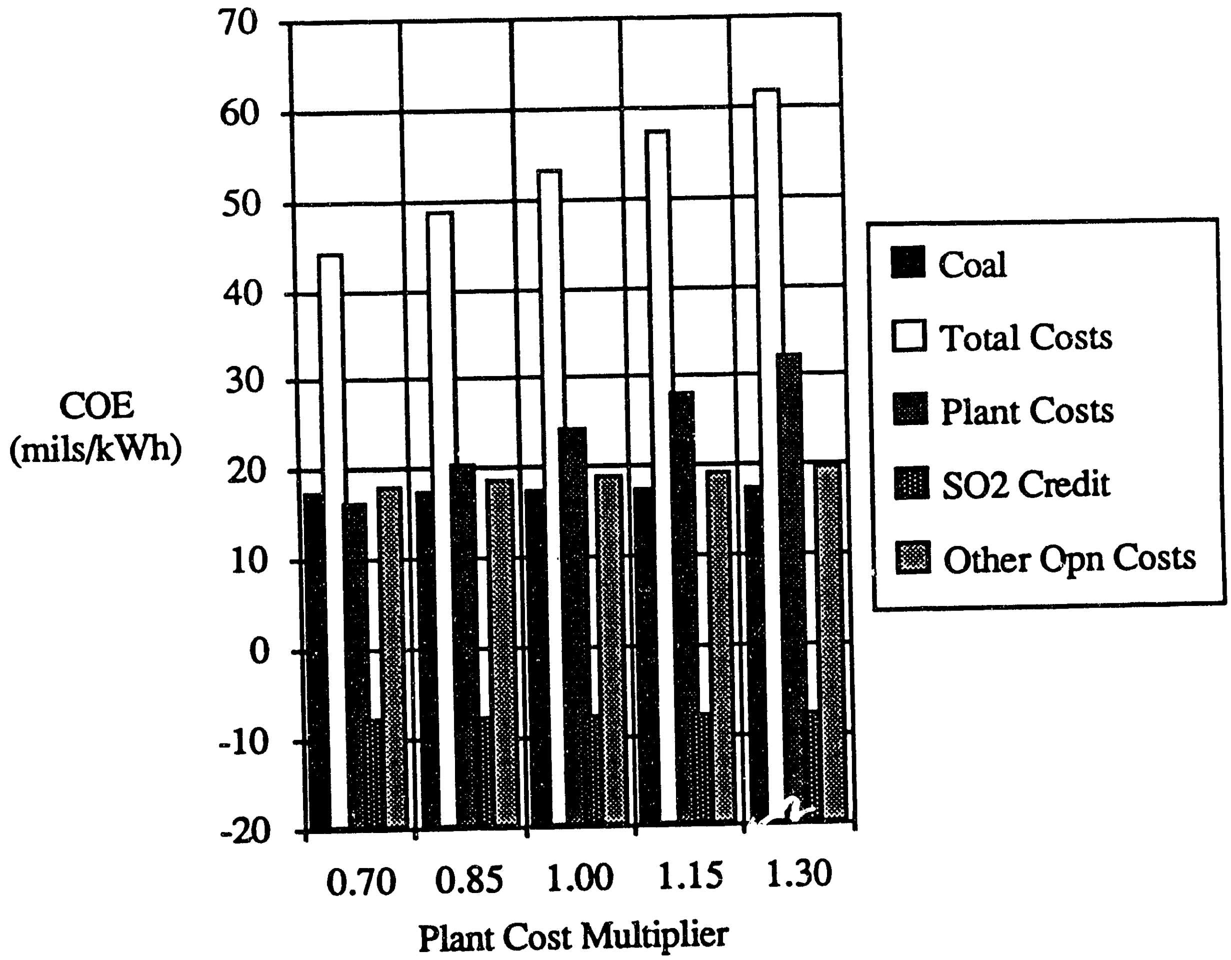


Figure 14

Table 9 a

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538
Date: Feb-91 by: RSS
Plant Size Studied (MWg) 236.61 (MWn) 219
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,734 ($/KWn) 1,873

System Description: 1-Stage Dry Bottom Fixed Bed Coal Gasifiers, ZnFe Moving Bed (GE type)
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)

Number Trains & Section Description	Total Flow & Units	1st Plant SectionCost, ($)	N-th Plant Section Cost, ($)	N-th Learning Reduct (%)	N-th Plant Cost ($/kwn)
1 ea, Coal Handling	28800TPD	11,709,214	11,709,214	0	53
1 ea, Briquetting System	4800 TPD	7,672,639	6,138,111	20	28
8 ea, Gasification & Ash	164 - lb/sec	65,939,904	52,751,923	20	241
4 ea, Hot Gas Cleanup System (GE type)	164 - lb/sec	20,656,301	12,393,781	40	57
1 ea, Gas Turbine	GE7191F	47,428,875	37,943,100	20	173
1 ea, HRSG, (Includes CO Catalyst & SCR)	111 - lb/sec	18,856,175	18,856,175	0	86
1 ea, Steam Turbine	91 MWe	14,411,053	14,411,053	0	66
1 ea, Booster Compressor	111 - lb/sec	2,152,800	2,152,800	0	10
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)	9 K - lb/hr	10,494,900	6,296,940	40	29
Sub-total		199,321,861	162,653,097		743
BalanceofPlant(% sub-t w/out proc conting)	31%	62,761,583	37,656,950	40	172
TOTAL PROCESS CAPITAL		262,083,444	200,310,047		915
Fully Standardized Designed N'th Plant			157,250,066	40	718
Engineering (Only)	8%				
Engineering (Contractor's) Fees (Incl Proj&ConstMgt, Testing/Startup, Design/Build Contr Fees, but NOT Opn, Data Col & Rptg, Admin, Dspsn) (%ofTotal Process Capital)	21%	54,188,469	32,513,081	40	148
Project Contingency (%ofTotal Process Capital)	13%	34,070,848	20,442,509	40	93
TOTAL PLANT INVESTMENT		350,342,761	210,205,656		960
Allowance for Funds During Construction, (AFDC)	13%	33,057,000	19,834,200		91
WorkCap,Taxes,Royal,Devel,Permits,Legal, Fuel Inven, Spare Parts, Underwriter Costs	9%	24,877,711	18,445,027		84
Land(HistoricalSiteCostsforCo-generation) Acreage @ $8,500 per Acre = 243	0.6%	2,062,000	2,062,000		9
TOTAL CAPITAL REQUIREMENT		410,339,472	250,546,883		1,144

Table 9 b

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: 2/8/91 by: RSS

Plant Size Studied (MWg) 236.61 (MWn) 219

TypicalGasFiredTurnkeyConstrCost($/KWg) 530 ($/KWn) 571

	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
COGEN SYSTEM GROUP INCLUDING STRD CONTROLS, ELECTRICAL, BLDG, CIVIL, STRUCT, ARCHETEC, MECHAN					
Gas Turbine/Gen Syst(Incl Cogen Plt I&C)	$27,283,750				
Steam Turbine/Generator System	$11,085,425				
StartUp&BackupFuel(NatGas)PrepSystem	$1,366,430				
Condenser & Vacuum Systems	$1,266,265				
TURBINE ISLAND	$41,001,870	$12,271,867	$53,273,737	243	17
Aux Blr for Startup/Emerg PwrGen (Optional)	$0	$0	$0		
HtRecovSteamGenerator(w/COCatyl&SCR)	$13,940,875	$4,883,445	$18,824,320		
HRSG Ductwork & Stack (Incl)					
BOILER ISLAND	$13,940,875	$4,915,300	$18,856,175	86	6
Cooling Tower					
Evaporative Makeup,Circ Water,&AuxSys					
SUB TOT COOL'G TWR SYST	$1,825,395	$641,720	$2,467,115	11	0.8
Raw Water Well, Pumps,Fire Prot System					
Demineralizer, Treatment & Storage					
Treated Water Pumping & Control					
CondensateRet,WaterChem,Filtr,StorTanks					
Chem Treat & Cooling Systems					
Feed Water Heaters&Deaerator					
FEEDWATER & WATER TREATMENT SYST	$4,632,258	$1,517,827	$6,150,085	28	2
Generation Plant Electrical System (Incl)					
Sub Station,X-fmrs,Switchyard (Incl)					
and Balance of Plant Electrical	$9,553,050				
Power Transmission Lines	$220,000	$880,000			
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$9,773,050	$5,604,453	$15,377,503	70	5
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions Monitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$4,679,350	$1,424,527	$6,103,877	28	1.9
BUILDINGS (Contr Rm,Lav,HVAC,CompAir)	$1,584,700	$766,878	$2,351,578		
PAINTING/INSUL/LAGG'G/SCAFFOLDING	$358,800	$109,229	$468,029		
COGENERATION SYST SUB TOTAL	$77,796,298	$27,251,801	$105,048,099	480	33
ADD. DESIGN ENGINEERING@8%	$8,403,848		$8,403,848		
ADD. PROJECT MANAGEMENT@3%	$2,100,962		$2,100,962		
ADD. CONSTRUCTION MGT@3%		$3,151,443	$3,151,443		
ADD. TEST'G @1% (2% test&strtup)	$1,050,481		$1,050,481		
ADD. START UP COSTS @1%	$1,050,481		$1,050,481		
ADD. DES/BUILD CONTR'S FEE@7%	$4,201,924		$4,201,924		
SUB TOT INDIRECT COSTS	$16,807,696	$3,151,443	$19,959,139	91	6
SUB TOTAL COGENERATION TURNKEY CONSTRUCTION COST	$94,603,994	$30,403,244	$125,007,238	571	40

Table 9 c

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: Feb-91 by: RSS

Plant Size Studied (MWg) 237 (MWn) 219

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,734 ($/KWn) 1,873

COAL GASIFICATION ADDERS	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
Coal Rail Spur					
Coal Receiving, Storage & Handling System					
Coal Fines Briquetting System	$8,218,763	$3,490,451	$11,709,214	53	4
Mobile Equip(2-B'dozers,Fr Loader,LiftTrk)					
SUB TOTAL COAL FACILITIES	$14,039,246	$5,342,607	$19,381,853	89	6
COMBUSTOR MOD. for COAL GAS FIRING	$2,990,000	$2,242,500	$5,232,500	24	2
AIR HANDLING FLOW MODULE	$5,382,000	$1,345,500	$6,727,500	31	2
BOOSTER COMPRESSOR&INTERCOOLER	$1,794,000	$358,800	$2,152,800	10	1
ADDITIONAL PROCESS WATER SYSTEM	$897,000	$273,072	$1,170,072	5	0.3
HighPressureAir&GasDuctwork&Cyclones,					
Coal Feed & Lock Hopper Systems (Incl)					
Gasifiers (Lurgi Mark IV Comparable)					
Ash Handling Lock Hopper System (Incl)					
Grate, Leveller, & Stirrer Drives (Incl)					
GASIFIER ISLAND	$44,355,184	$20,566,176	$64,921,360	296	20
HOT GAS CLEANUP UNIT(GE ZNFeSyst)	$11,418,810	$7,854,401	$19,273,211	88	6
ZnFe Outlet Gas Cyclones & Ductwork					
Regeneration Compressor & Heat Exch					
SO2 Recovery Plant	$7,031,583	$3,463,317	$10,494,900	48	3
SulfurCondensateHandling,Storage&Loadout,					
Catalyst Conveying & Loadout (Incl)					
ZincFerriteSorbentConveying&Storage(Incl)					
FLUE GAS CLEANUP SYSTEM AUXILIARIES	$1,077,701	$305,390	$1,383,090	6	0
Bottom Ash Handling System					
Ash Storage Silo & Outloading System (Incl)					
SUB TOTAL ASH HANDLING SYSTEM	$754,527	$264,017	$1,018,544	5	0.3
High Pressure Interconnect'g Piping					
Interconnecting Coal/Sorb System Piping					
Additional Fire Protection Pumps/Piping					
Additional Plant Air Compressors/Piping					
Add'l Instru Air Compressors,Filters/Piping					
SUB TOT ADDITIONAL PIPING SYSTEMS	$1,971,078	$3,866,635	$5,837,713	27	2
Gasification Syst Excav, Fdns, & Backfill					
Gasification System Roadways/ Parking					
Rail Spur to Cogeneration Plant (1,100 ft)					
Gasification Syst Site Drainage/Leach Field					
SUB TOT ADDITIONAL CIVIL WORK	$1,344,223	$4,802,544	$6,146,767	28	2
SUB TOT ADDITIONAL BUILDINGS	$1,943,500	$627,900	$2,571,400	12	1
Generation Plant Electrical System (In Strd CC System)					
Sub Station,X-fmrs,Switchyard (In Strd CC System)					
Gasification System Electrical					
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$2,202,135	$1,495,000	$3,697,135	17	1
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions&GasQualityMonitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$3,662,750	$1,495,000	$5,157,750	24	1.7
ADD.INSUL/LAGG'G/PAINT/SCAFFOLD'G	$485,875	$1,382,875	$1,868,750	9	0.6
COAL GASIFIC'N EQUIP ADDERS	$113,912,440	$55,685,734	$157,035,345	717	50

Table 9 d

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538
Date: 2/8/91 by: RSS
Plant Size Studied (MWg) 237 (MWn) 219
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,734 ($/KWn) 1,873

	Equipment	Installation	Total	($/KWn)	Per Cent ofConst$ (%)
ADD. DESIGN ENGINEERING@8%	$12,562,828				
ADD. PROJECT MANAGEMENT@3%	$4,711,060				
ADD. CONSTRUCTION MGT@3%					
ADD. TEST'G @1% (2% test&strtup)	$1,570,353				
ADD. START UP COSTS @1%	$1,570,353				
ADD. DES/BUILD CONTR'S FEE@7%	$10,992,474				
SUB TOT ADDIT. INDIRECT COSTS	$31,407,068	$2,822,262	$34,229,330	156	11
SUB TOT COAL GASIFICATION TURNKEY CONSTRUCTION COST	$239,923,502	$88,911,240	$316,271,913	1,444	100

Table 9 e

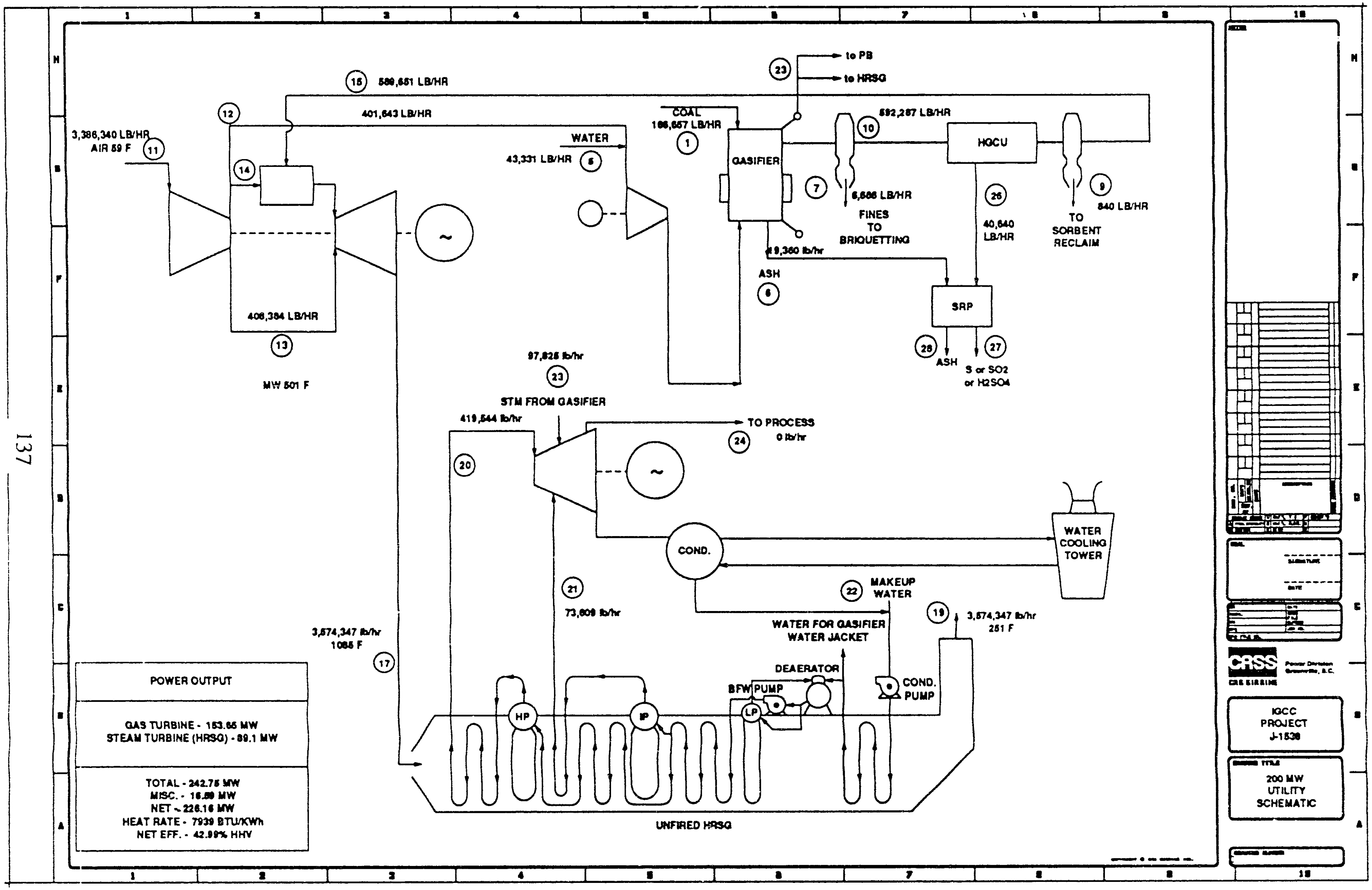
IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F
Date: 2/8/91 by: RSS
Plant Size Studied (MWg) 237 (MWn) 219
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,734 ($/KWn) 1,873

	Total	($/KWn)	
OWNERS COSTS			
Site	$2,062,000	9	
Development	$661,740	3	
Working Capital	$4,204,000	19	
Permits	$1,267,364	6	
Legal Fees	$70,897	0	
Taxes & Royalties	$3,153,000	14	
Fuel Inventory	$2,592,000	12	
Spare Parts	$3,834,000	18	
Interest During Construction	$33,057,000	151	
Underwriters' Costs	$9,094,710	42	
CONTINGENCY & RISK (@ % OF TOTAL PROCESS CAPITAL STATED BELOW) 13.02%	$34,070,848	156	
SUB TOTAL OWNERS COST	$94,067,559	430	
INSTALLED PROJECT TOTAL	$410,339,472	1,874	N/A

Table 9 f

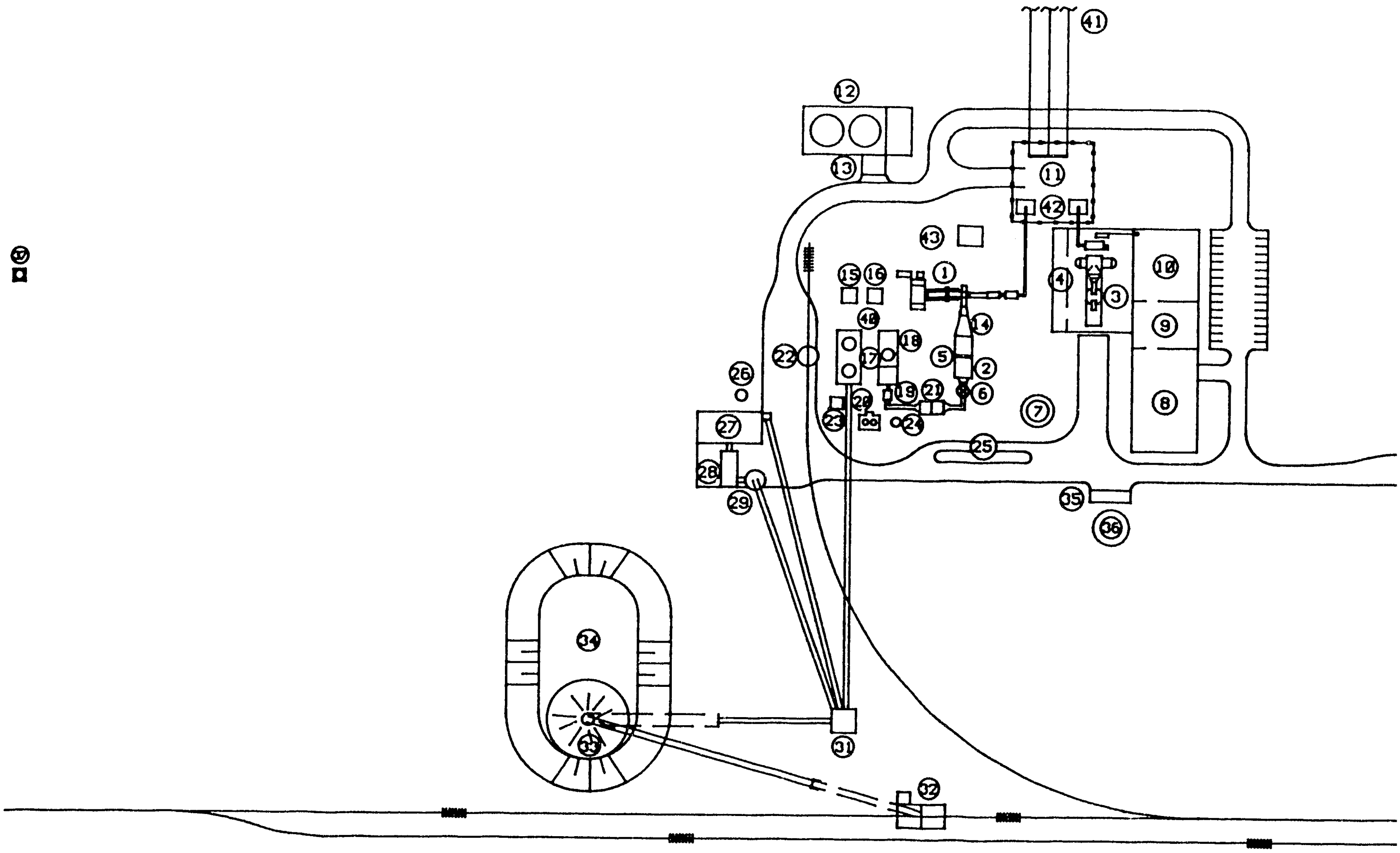
IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538
Date: Feb-91 by: RSS
Plant Size Studied (MWg) 236.61 (MWn) 219
"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,734 ($/KWn) 1,873
MWn 219.97

	Calculated 10 Yr Levelized Operating Costs (mils/kwh)
Coal Plus Oil/Gas for Strt/Emrg	17.44
ZnFe,NOx,CO,DSRP Catalysts	6.50
Residue Disposal	0.77
Operating Labor+O&M Guar Premium+G&A	4.08
Insurance & Local Taxes	3.12
Maintenance & Equip Reserves	4.01
Util.&OperatingConsumables(NoAuxPwrIncl)	0.46
Other (Miscellaneous)	0.08
SO2 Recovery Plant	-7.60
TOTAL OPERATING COSTS	28.86
PLANT COST INCL CONTINGENCIES	27.91
TOTAL COST OF ELECTRICITY (COE)	56.77

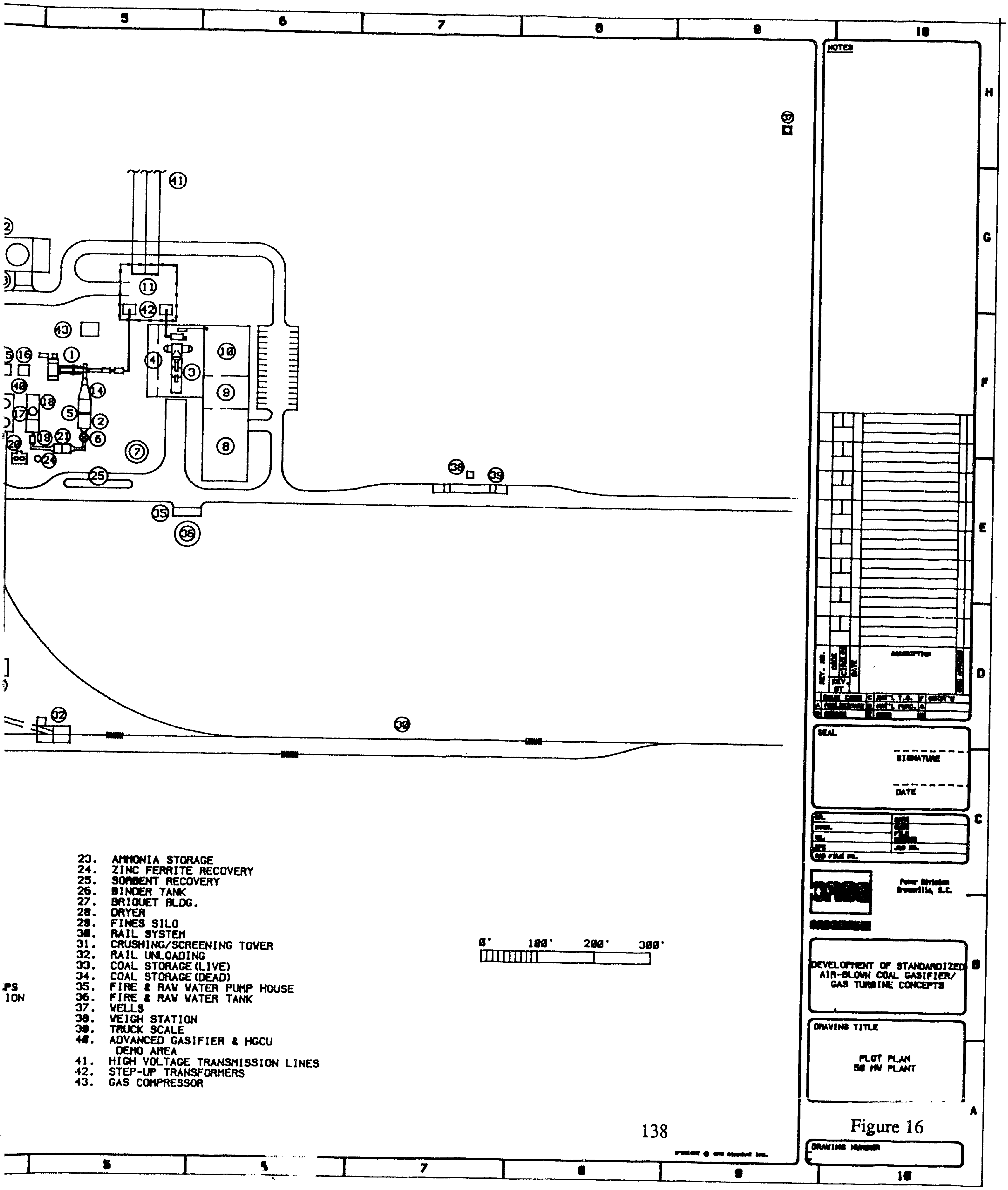


to PB
to HRSG
589,651 LB/HR
401,643 LB/HR
3,386,340 LB/HR
AIR 59 F
WATER
43,331 LB/HR
COAL
186,657 LB/HR
GASIFIER
592,287 LB/HR
HGCU
6,686 LB/HR
FINES
TO
BRIQUETTING
40,640
LB/HR
TO
SORBENT
RECLAIM
840 LB/HR
19,360 lb/hr
ASH
SRP
ASH
S or SO2
or H2SO4
406,384 LB/HR
MW 501 F
97,825 lb/hr
STM FROM GASIFIER
419,544 lb/hr
TO PROCESS
0 lb/hr
COND.
WATER
COOLING
TOWER
MAKEUP
WATER
73,609 lb/hr
3,574,347 lb/hr
1065 F
WATER FOR GASIFIER
WATER JACKET
3,574,347 lb/hr
251 F
DEAERATOR
BFW PUMP
COND.
PUMP
HP
IP
LP
UNFIRED HRSG
POWER OUTPUT
GAS TURBINE - 153.65 MW
STEAM TURBINE (HRSG) - 89.1 MW
TOTAL - 242.75 MW
MISC. - 16.59 MW
NET - 226.16 MW
HEAT RATE - 7939 BTU/KWh
NET EFF. - 42.99% HHV
CRSS
IGCC
PROJECT
J-1536
200 MW
UTILITY
SCHEMATIC

Figure 15



1. GAS TURBINE
2. HRSG
3. STEAM TURBINE
4. CONTROL ROOM
5. SCR
6. STACK
7. DEMIN TANK
8. WATER TREATMENT
9. ADMIN
10. SHOPS & MAINTENANCE
11. SWITCHYARD
12. COOLING TOWER
13. COOLING TOWER CIRC. PUMPS
14. GT/HRSG TRANSITION SECTION
15. BOOSTER COMPRESSOR
16. INTERCOOLER
17. GASIFIERS WITH BLDG.
18. HGCU
19. HEAT EXCHANGER
20. SORBENT SUPPLY SYSTEM
21. BAGHOUSE
22. BOTTOM ASH SILO
23. AMMONIA STORAGE
24. ZINC FERRITE RECOVERY
25. SORBENT RECOVERY
26. BINDER TANK
27. BRIQUET BLDG.
28. DRYER
29. FINES SILO
30. RAIL SYSTEM
31. CRUSHING/SCREENING TOWER
32. RAIL UNLOADING
33. COAL STORAGE (LIVE)
34. COAL STORAGE (DEAD)
35. FIRE & RAW WATER PUMP HOUSE
36. FIRE & RAW WATER TANK
37. WELLS
38. WEIGH STATION
39. TRUCK SCALE
40. ADVANCED GASIFIER & HGCU DEMO AREA
41. HIGH VOLTAGE TRANSMISSION LINES
42. STEP-UP TRANSFORMERS
43. GAS COMPRESSOR



23. AMMONIA STORAGE
24. ZINC FERRITE RECOVERY
25. SORBENT RECOVERY
26. BINDER TANK
27. BRIQUET BLDG.
28. DRYER
29. FINES SILO
30. RAIL SYSTEM
31. CRUSHING/SCREENING TOWER
32. RAIL UNLOADING
33. COAL STORAGE (LIVE)
34. COAL STORAGE (DEAD)
35. FIRE & RAW WATER PUMP HOUSE
36. FIRE & RAW WATER TANK
37. WELLS
38. WEIGH STATION
39. TRUCK SCALE
40. ADVANCED GASIFIER & HGCU DEMO AREA
41. HIGH VOLTAGE TRANSMISSION LINES
42. STEP-UP TRANSFORMERS
43. GAS COMPRESSOR
0' 100' 200' 300'
NOTES
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Greenville, S.C.
DEVELOPMENT OF STANDARDIZED AIR-BLOWN COAL GASIFIER/ GAS TURBINE CONCEPTS
DRAWING TITLE
PLOT PLAN
50 MW PLANT
DRAWING NUMBER

Figure 16

General arrangement drawing Figure 17 for the 100 MWe sized facility provides for greater materials handling capabilities typical of an independent power producer (IPP) application.

Figure 18 shows the 200 MWe sized plant. It provides for 100 car unit train capability. Such a plant is typical of utility practice, although, at 30 days supply, less fuel "dead storage" has been anticipated than utilities normally consider typical (90 days). This plant might be considered an IPP/Utility hybrid since it incorporates some features typical of both plant types. For example, a utility coal handling system is utilized, but cogeneration financial factors were used in its COE determination.

Standardized Gasifier/HGCU module front and side elevations are shown on Figures 19 and 20. A single module is sufficient for the 50 MW plant size. The 100 MW plant size requires two (2) such modules. The 200 MW module includes four (4) modules, and the 500 MW coal fired DOE reference plant needs six (6) modules for retrofit/repowering.

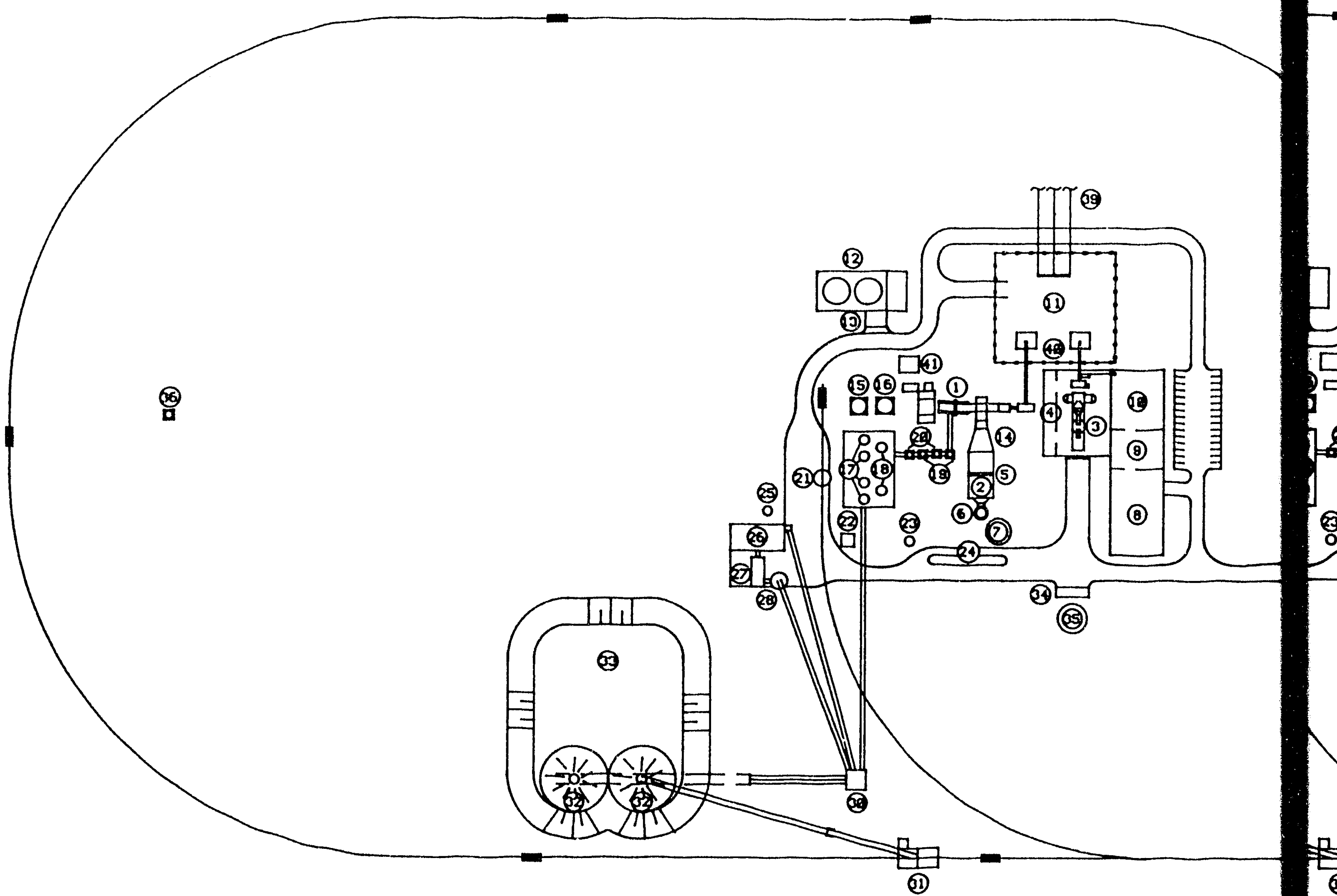
4.2.3.3. Retrofit/Repowering of Coal Fired Utility Plant

Three factors weigh heavily in the consideration of utilities as logical implementors of CGIA technology:

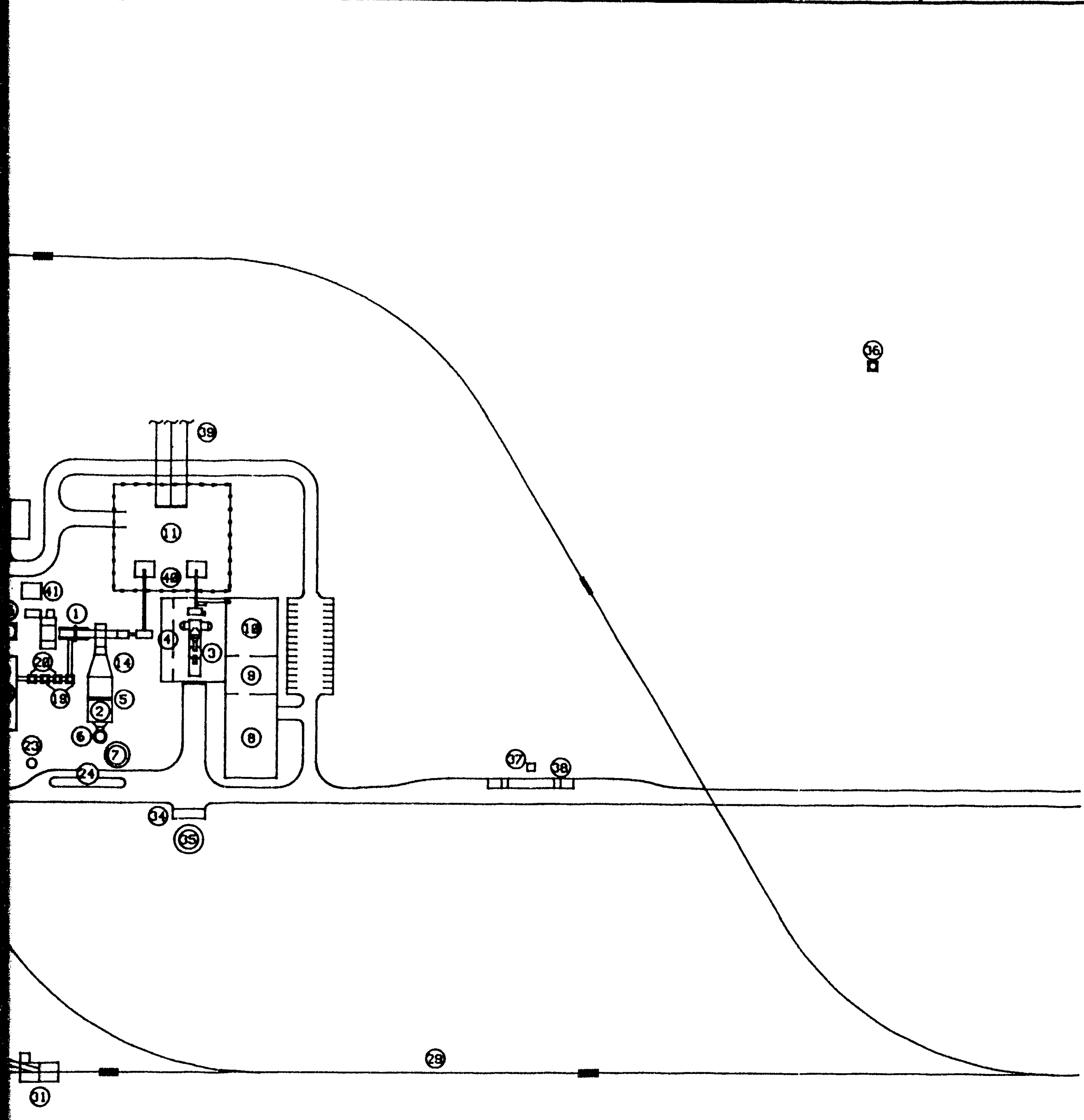
- Cogenerators and Independent Power Producers (IPP's) are not likely to to be interested in CGIA due to its high costs in the smaller size ranges of interest to them.

- Utilities are currently mandated [11] to reduce emissions from their largest coal fired power plants. They will evaluate all available technological solutions, and will find the added MWe output from CGIA an attractive alternative to IPP's for their load growth needs.

- Although the "N'th" CGIA plant is cost effective, the high cost of the, 1st plant must be mitigated by such considerations as the utilization of existing coal plants which already have most of the equipment needed in place. Old



1. GAS TURBINE (GE 7F)
2. HRSG
3. STEAM TURBINE
4. CONTROL ROOM
5. SCR
6. STACK
7. DEMIN TANK
8. WATER TREATMENT
9. ADMIN
10. SHOPS & MAINTENANCE
11. SWITCHYARD
12. COOLING TOWER
13. COOLING TOWER CIRC. PUMPS
14. GT/HRSG TRANSITION SECTION
15. BOOSTER COMPRESSOR
16. INTERCOOLER
17. GASIFIERS WITH BUILDING
18. ZINC FERRITE MOVING BED
19. HEAT EXCHANGER
20. DIRECT SULFUR RECOVERY UNIT (DSRU)
21. BOTTOM ASH SILO
22. AMMONIA INJECTION SYSTEM
23. ZINC FERRITE RECOVERY
24. SORBENT RECOVERY
25. BINDER TANK
26. BRIQUET BLDG.
27. COAL DRYER
28. COAL FINES SILO
29. RAIL SYSTEM
30. CRUSHING/SCREENING TOWER
31. RAIL UNLOADING BLDG (BOT DU
32. COAL STORAGE (LIVE)
33. COAL STORAGE (DEAD)
34. FIRE & RAW WATER PUMP HOUSE
35. FIRE & RAW WATER TANK
36. WELLS
37. WEIGH STATION
38. TRUCK SCALE
39. HIGH VOLTAGE TRANSMISSION LI
40. STEP-UP TRANSFORMERS
41. GAS COMPRESSOR



21. BOTTOM ASH SILO
22. AMMONIA INJECTION SYSTEM
23. ZINC FERRITE RECOVERY
24. SORBENT RECOVERY
25. BINDER TANK
26. BRIQUET BLDG.
27. COAL DRYER
28. COAL FINES SILO
29. RAIL SYSTEM
30. CRUSHING/SCREENING TOWER
31. RAIL UNLOADING BLDG (BOT DUMP HOP)
32. COAL STORAGE (LIVE)
33. COAL STORAGE (DEAD)
34. FIRE & RAW WATER PUMP HOUSE
35. FIRE & RAW WATER TANK
36. WELLS
37. WEIGH STATION
38. TRUCK SCALE
39. HIGH VOLTAGE TRANSMISSION LINES
40. STEP-UP TRANSFORMERS
41. GAS COMPRESSOR

0' 120' 240' 360'

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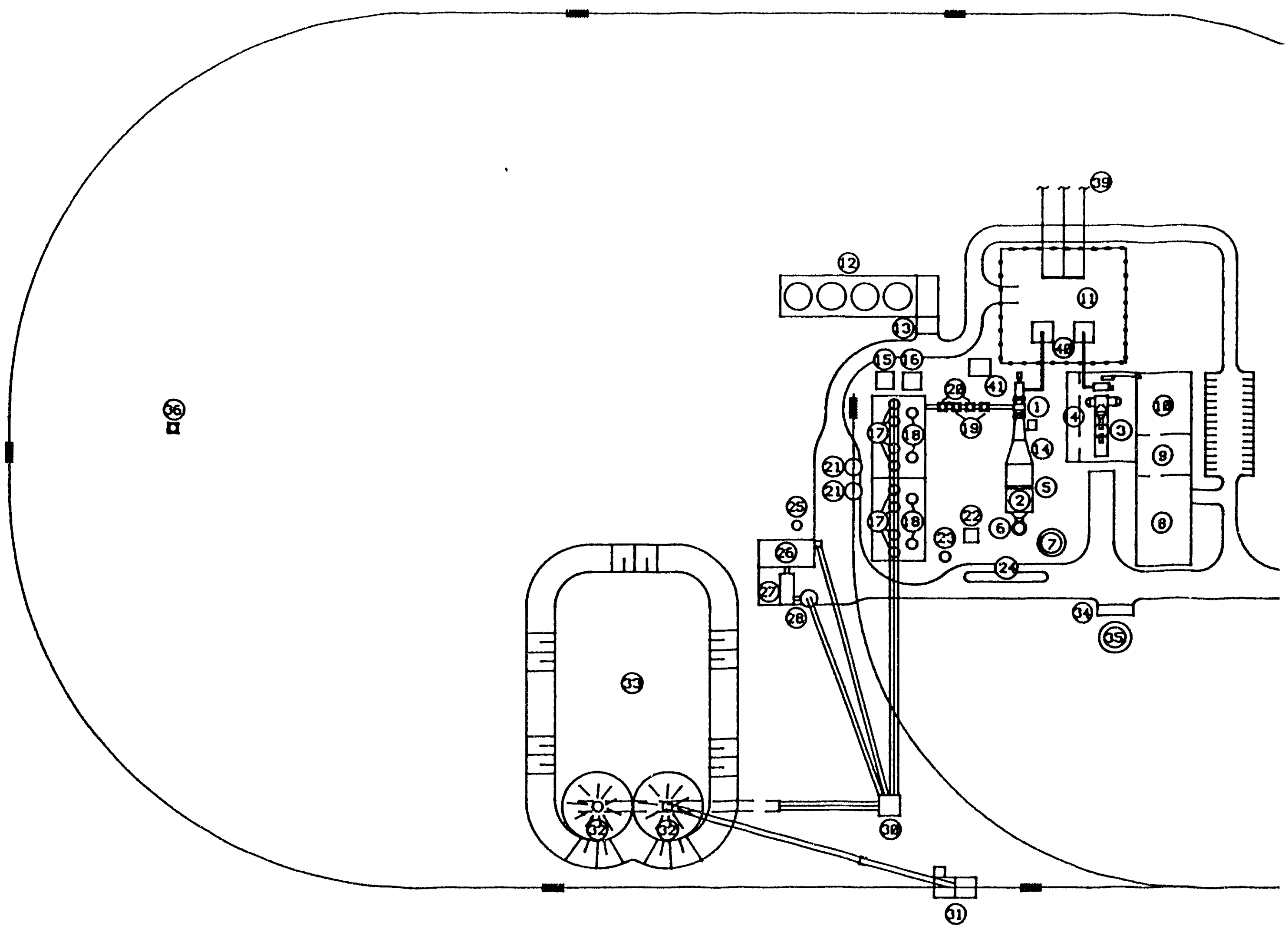
DEVELOPMENT OF STANDARDIZED AIR-BLOWN COAL GASIFIER/ GAS TURBINE CONCEPTS

DRAWING TITLE

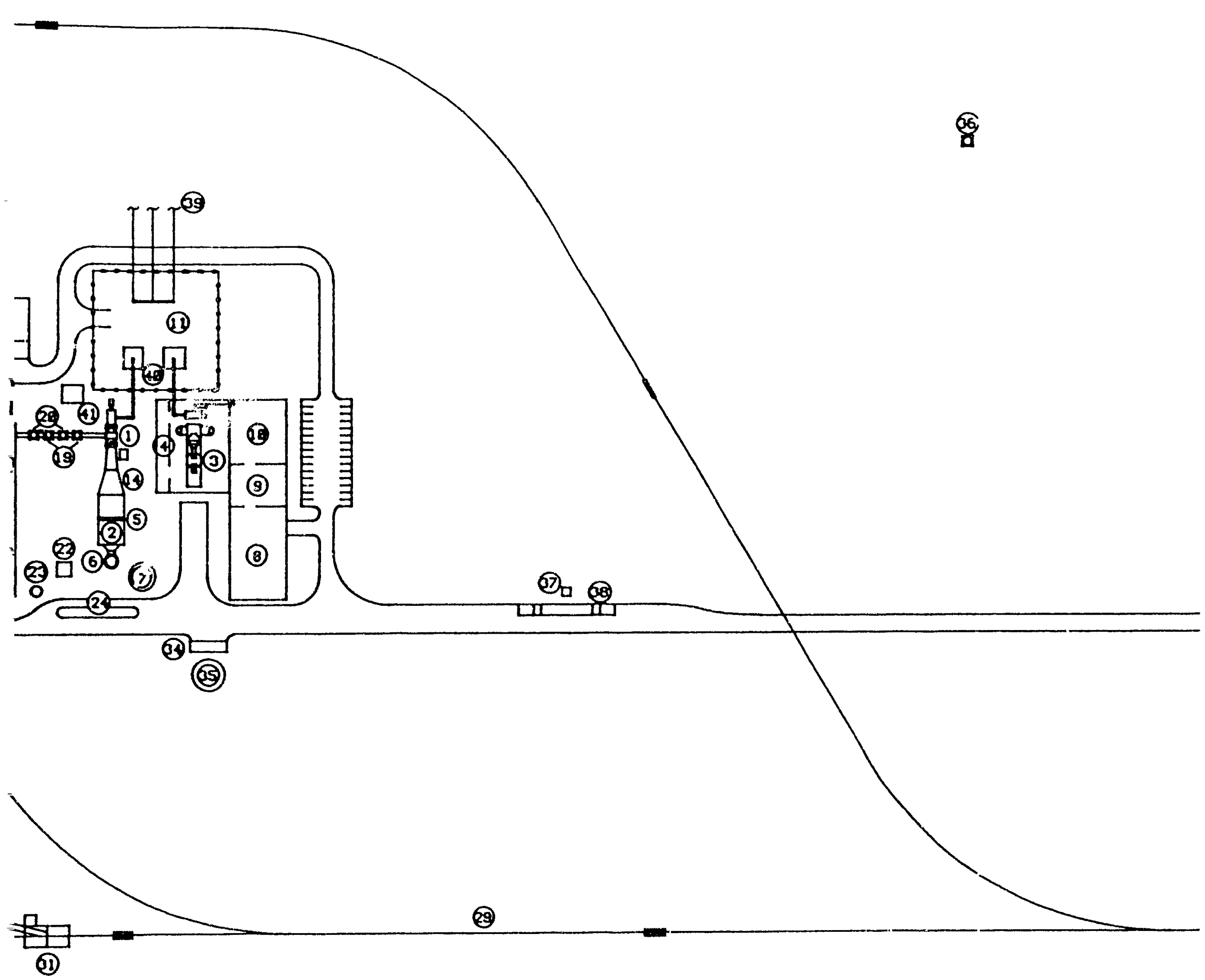
PLOT PLAN
100 MW PLANT

Figure 17

DRAWING NUMBER



1. GAS TURBINE (GE 7F)
2. HRSG
3. STEAM TURBINE
4. CONTROL ROOM
5. SCR
6. STACK
7. DEMIN TANK
8. WATER TREATMENT
9. ADMIN
10. SHOPS & MAINTENANCE
11. SWITCHYARD
12. COOLING TOWER
13. COOLING TOWER CIRC. PUMP
14. GT/HRSG TRANSITION SECTION
15. BOOSTER COMPRESSOR
16. INTERCOOLER
17. GASIFIERS WITH BUILDING
18. ZINC FERRITE MOVING BED
19. HEAT EXCHANGER
20. DIRECT SULFUR RECOVERY UNIT (DSRU)
21. BOTTOM ASH SILO
22. AMMONIA INJECTION SYST
23. ZINC FERRITE RECOVERY
24. SORBENT RECOVERY
25. BINDER TANK
26. BRIQUET BLDG.
27. COAL DRYER
28. COAL FINES SILO
29. RAIL SYSTEM
30. CRUSHING/SCREENING TOW
31. RAIL UNLOADING BLDG (B
32. COAL STORAGE (LIVE)
33. COAL STORAGE (DEAD)
34. FIRE & RAW WATER PUMP
35. FIRE & RAW WATER TANK
36. WELLS
37. WEIGH STATION
38. TRUCK SCALE
39. HIGH VOLTAGE TRANSMISS
40. STEP-UP TRANSFORMERS
41. GAS COMPRESSOR



21. BOTTOM ASH SILO
22. AMMONIA INJECTION SYSTEM
23. ZINC FERRITE RECOVERY
24. SORBENT RECOVERY
25. BINDER TANK
26. BRIQUET BLDG.
27. COAL DRYER
28. COAL FINES SILO
29. RAIL SYSTEM
30. CRUSHING/SCREENING TOWER
31. RAIL UNLOADING BLDG (BOT DUMP HOP)
32. COAL STORAGE (LIVE)
33. COAL STORAGE (DEAD)
34. FIRE & RAW WATER PUMP HOUSE
35. FIRE & RAW WATER TANK
36. WELLS
37. WEIGH STATION
38. TRUCK SCALE
39. HIGH VOLTAGE TRANSMISSION LINE
40. STEP-UP TRANSFORMERS
41. GAS COMPRESSOR

0' 120' 240' 360'

NOTES

REV. NO. | CODE | CIRCLE | DATE | REV. BY | DESCRIPTION

ISSUE CODE					
A	PRELIMINARY	C	MAT'L T.O.	F	CONST'N
B	DESIGN	D	MAT'L PURC.	G	
		E	BIDS	H	

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SIGNATURE

DATE

DR.	DATE
DSGN.	CADD FILE NUMBER
CK.	
OPE	JOB NO.
CAD FILE NO.	

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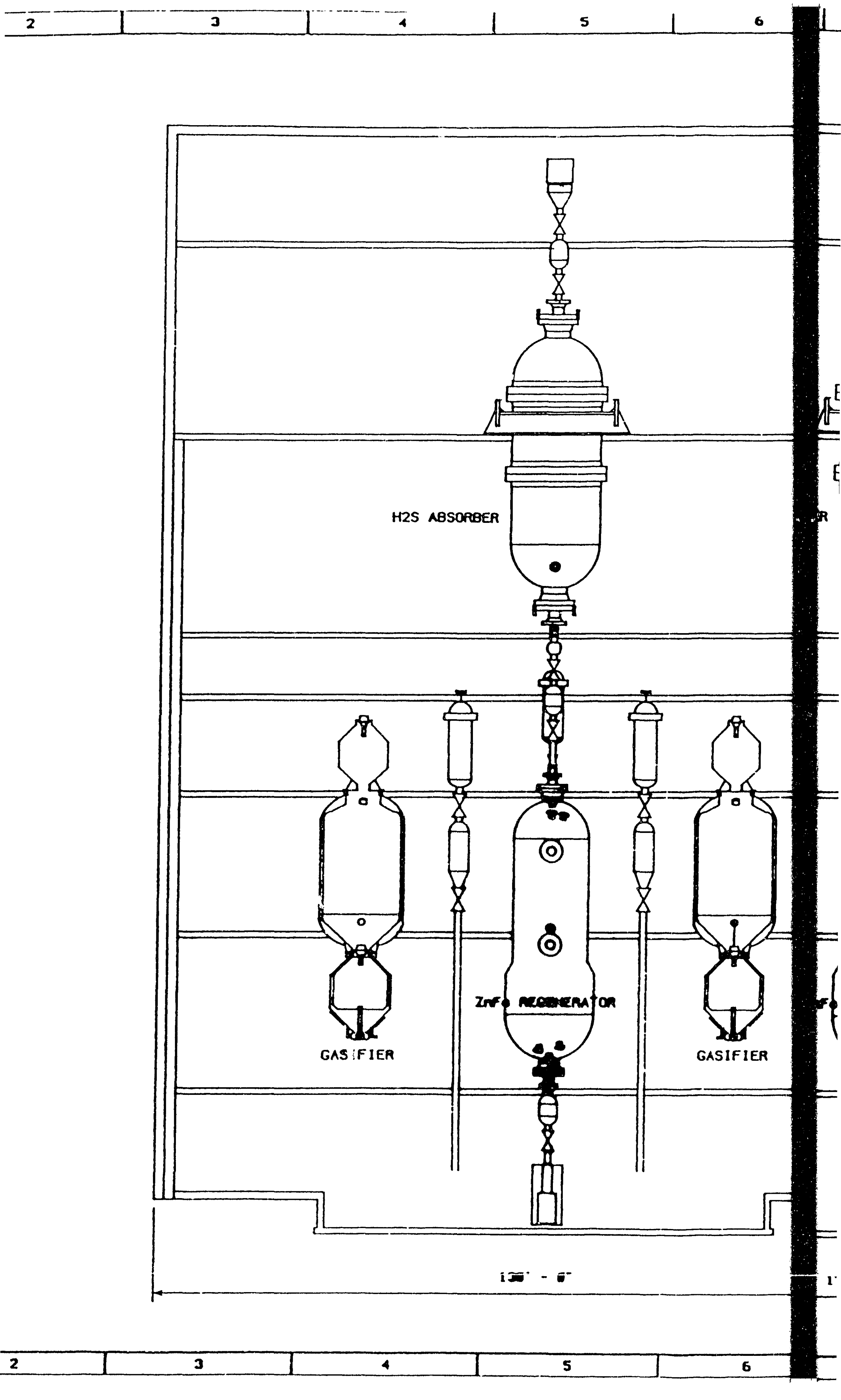
DEVELOPMENT OF STANDARDIZED AIR-BLOWN COAL GASIFIER/ GAS TURBINE CONCEPTS

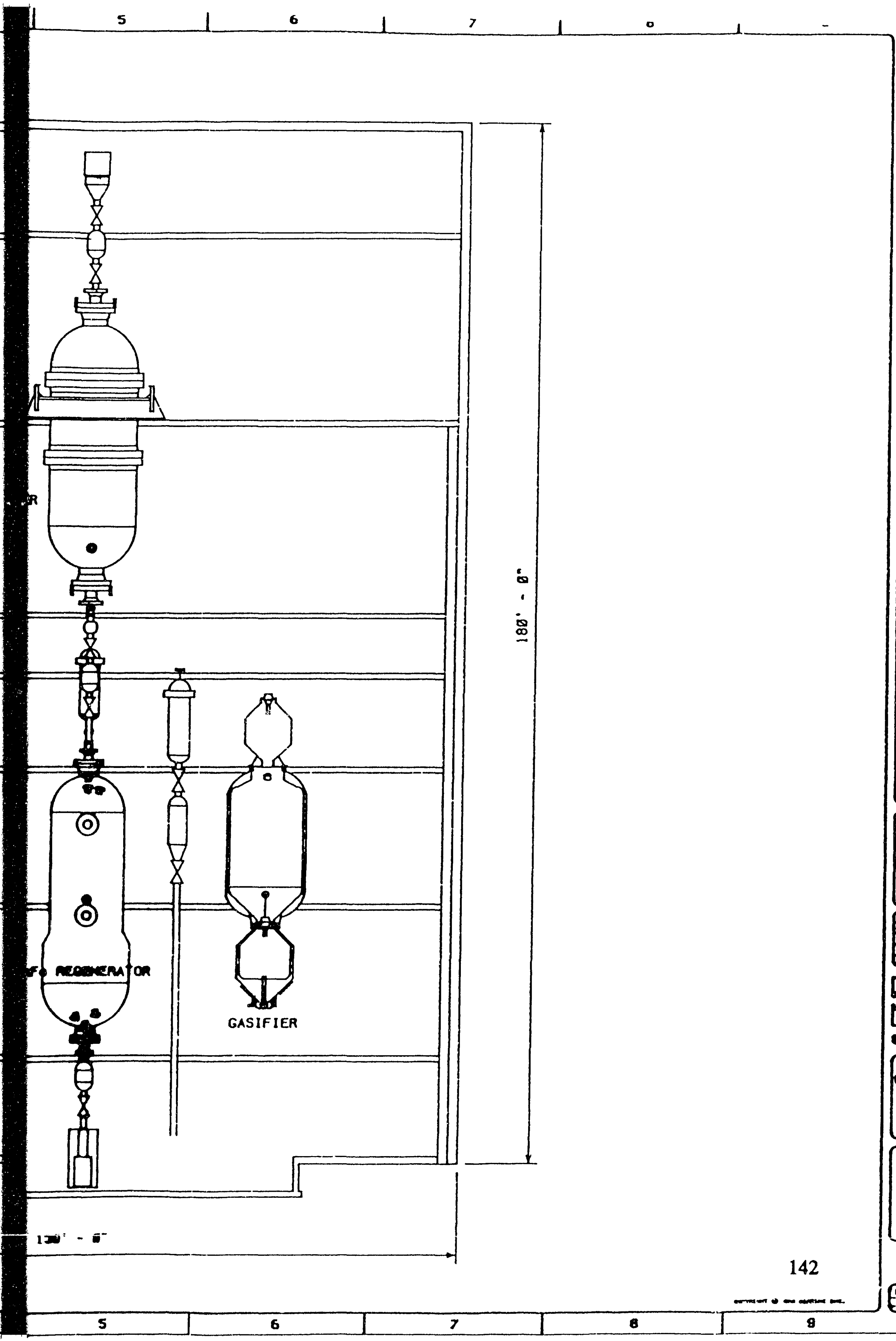
DRAWING TITLE

PLOT PLAN
200 MW PLANT

Figure 18

DRAWING NUMBER


H2S ABSORBER
ZnFe REGENERATOR
GASIFIER
GASIFIER



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DATE

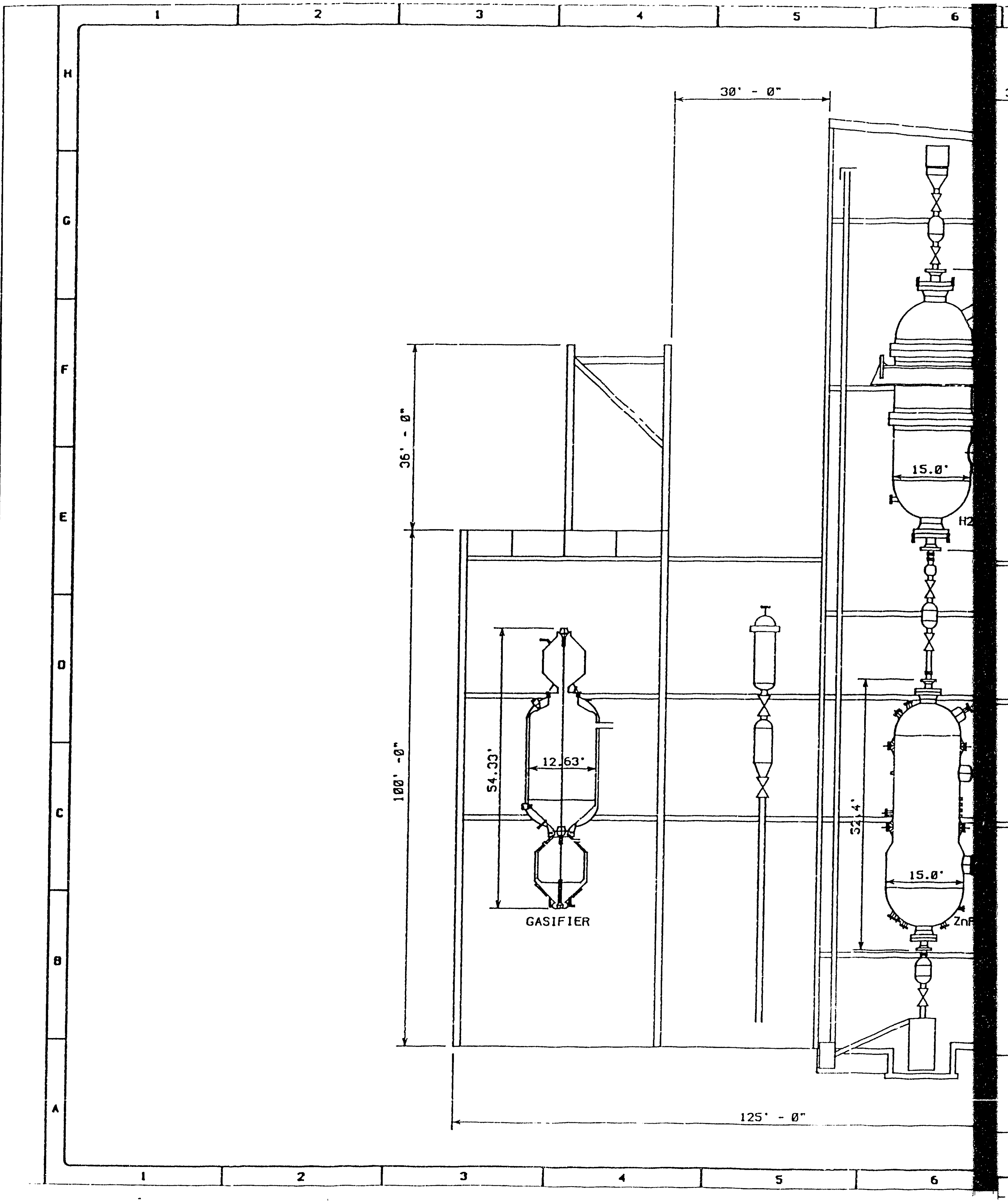
COAL FIRED LOW BTU GASIFIER/HGCU MODULE

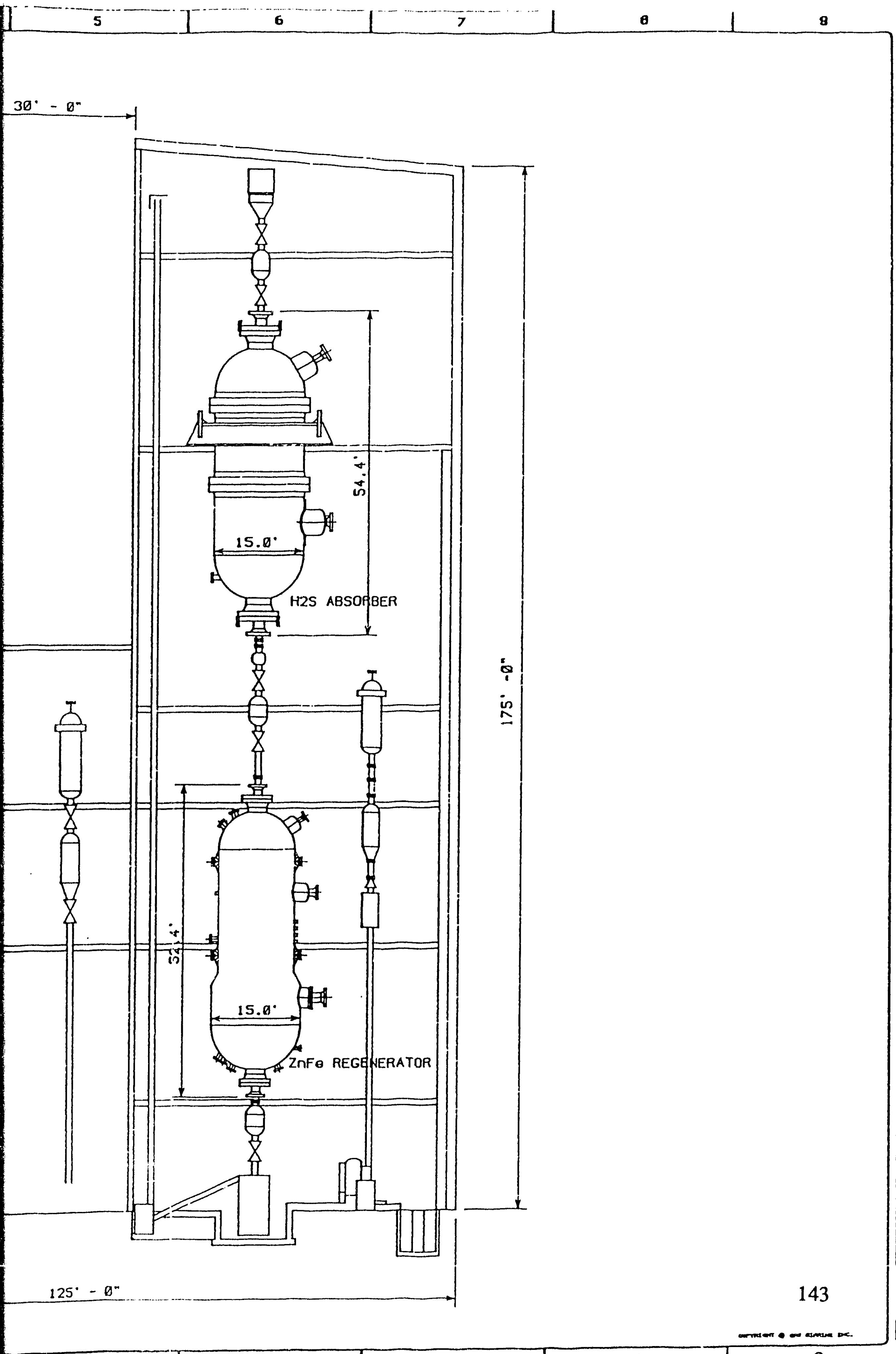
DRAWING TITLE

GENERAL ARRANGEMENT- FRONT ELEVATION

Figure 19

DRAWING NUMBER


30' - 0"
36' - 0"
100' -0"
54.33'
12.63'
GASIFIER
15.0'
52.4'
15.0'
125' - 0"



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COAL FIRED LOW BTU GASIFIER/HGCU MODULE

DRAWING TITLE

GENERAL ARRANGEMENT-SIDE ELEVATION

Figure 20

DRAWING NUMBER

inefficient coal plants due to be retired represent excellent retrofit/repowering candidates, because CGIA improves their cycle efficiency by 20% or more.

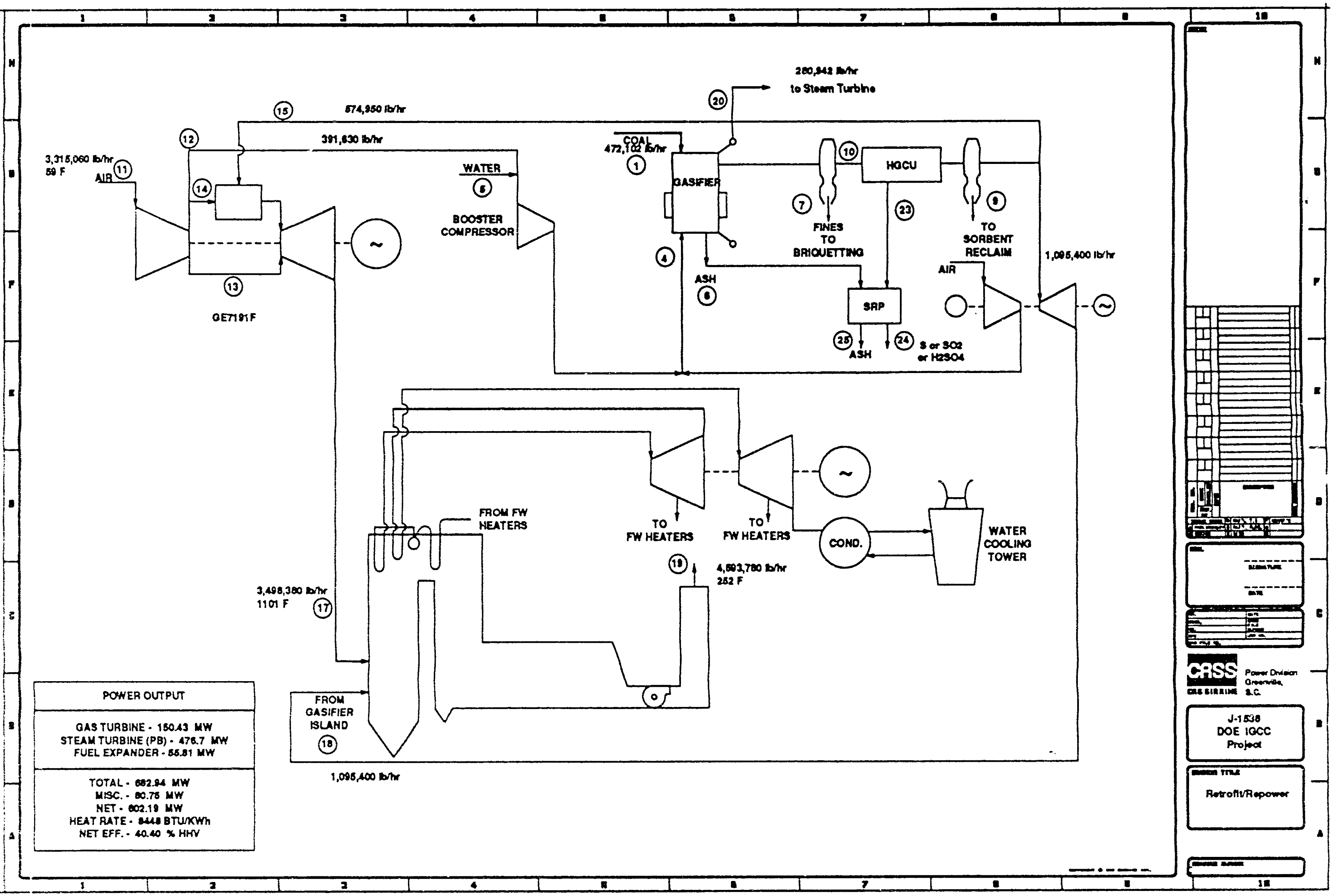
To effectively evaluate a retrofit/repower strategy as applied to a coal fired utility power plant, a 150 MWe class combustion turbine combined cycle plant was utilized to retrofit the DOE 500 MWe coal fired reference plant using CGIA technology (Figure 21). This arrangement (Figure 22) simultaneously accomplished several important technical triumphs:

- It combined a very efficient Rankine cycle @ 2400 psig/1005/1005 reheat, with a very efficient Brayton cycle @ 2300 F combustion temperature resulting in a combined cycle efficiency well in excess of 40% net based on coal higher heating value [12].

- Consistent with this study's objective of achieving NOx emission values of less than 0.1 lb/MBtu, it provided for the firing of low BTU coal gas in the existing coal boiler as a positive NOx control strategy using staged firing NOx reburn techniques [13].

- It reduced the oxygen content in the turbine exhaust gas to a minimum through firing supplemental low Btu gas in the existing boiler which served to maximize cycle efficiency by lowering the dry stack gas losses [14].

- Given an existing coal fired power plant with its inherent limitations, and then adding coal gasifiers and an external combustion turbine which consumes and converts a considerable per cent of the available energy, results are less than full load firing with the existing coal boiler. This should be looked upon as an inherent advantage since it alleviates the operating conditions of the existing (and sometimes overstressed at full load) coal boiler.


280,942 lb/hr
to Steam Turbine
574,950 lb/hr
391,630 lb/hr
3,315,060 lb/hr
59 F
AIR
WATER
BOOSTER
COMPRESSOR
COAL
472,102 lb/hr
GASIFIER
HGCU
FINES
TO
BRIQUETTING
TO
SORBENT
RECLAIM
1,095,400 lb/hr
AIR
ASH
SRP
ASH
S or SO2
or H2SO4
GE7191F
FROM FW
HEATERS
TO
FW HEATERS
TO
FW HEATERS
COND.
WATER
COOLING
TOWER
3,498,380 lb/hr
1101 F
4,593,780 lb/hr
252 F
FROM
GASIFIER
ISLAND
1,095,400 lb/hr
POWER OUTPUT
GAS TURBINE - 150.43 MW
STEAM TURBINE (PB) - 476.7 MW
FUEL EXPANDER - 55.81 MW
TOTAL - 682.94 MW
MISC. - 80.75 MW
NET - 602.19 MW
HEAT RATE - 8448 BTU/KWh
NET EFF. - 40.40 % HHV
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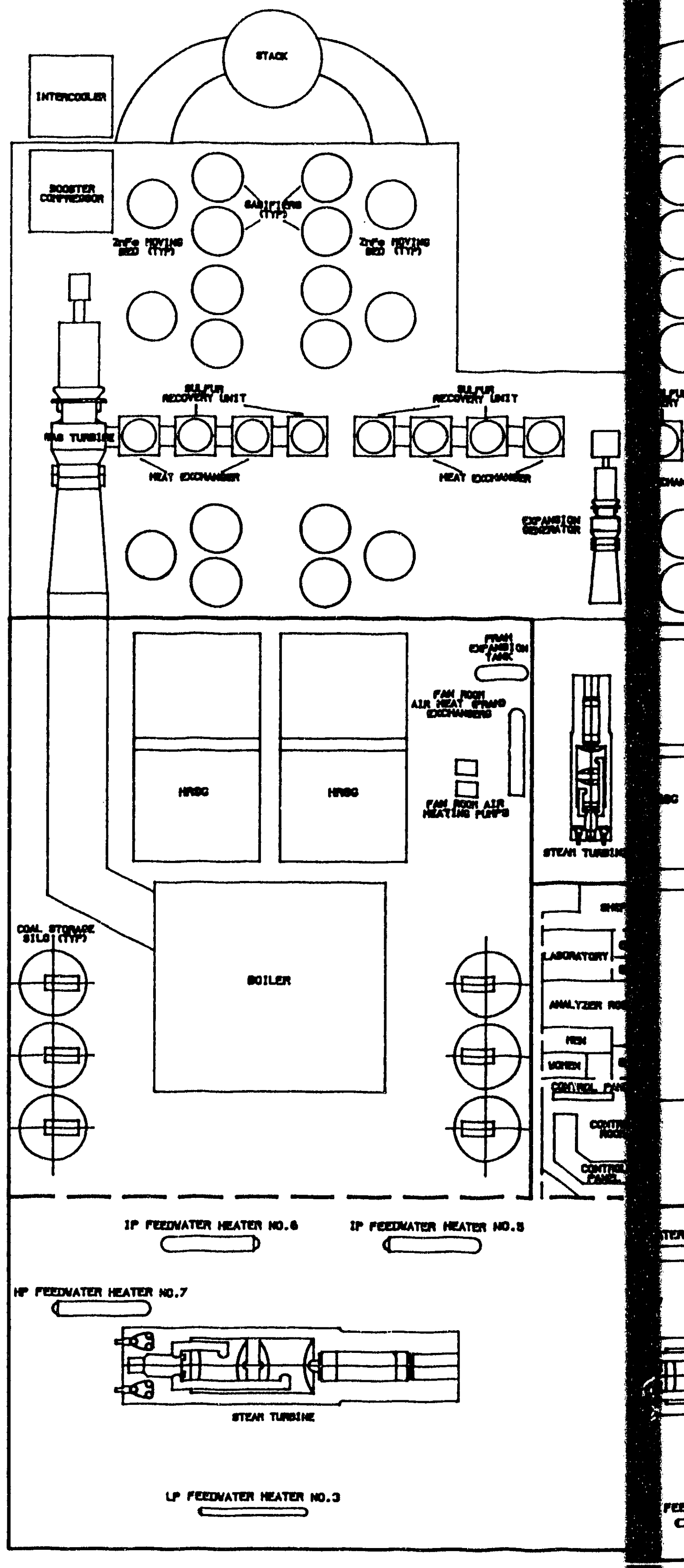
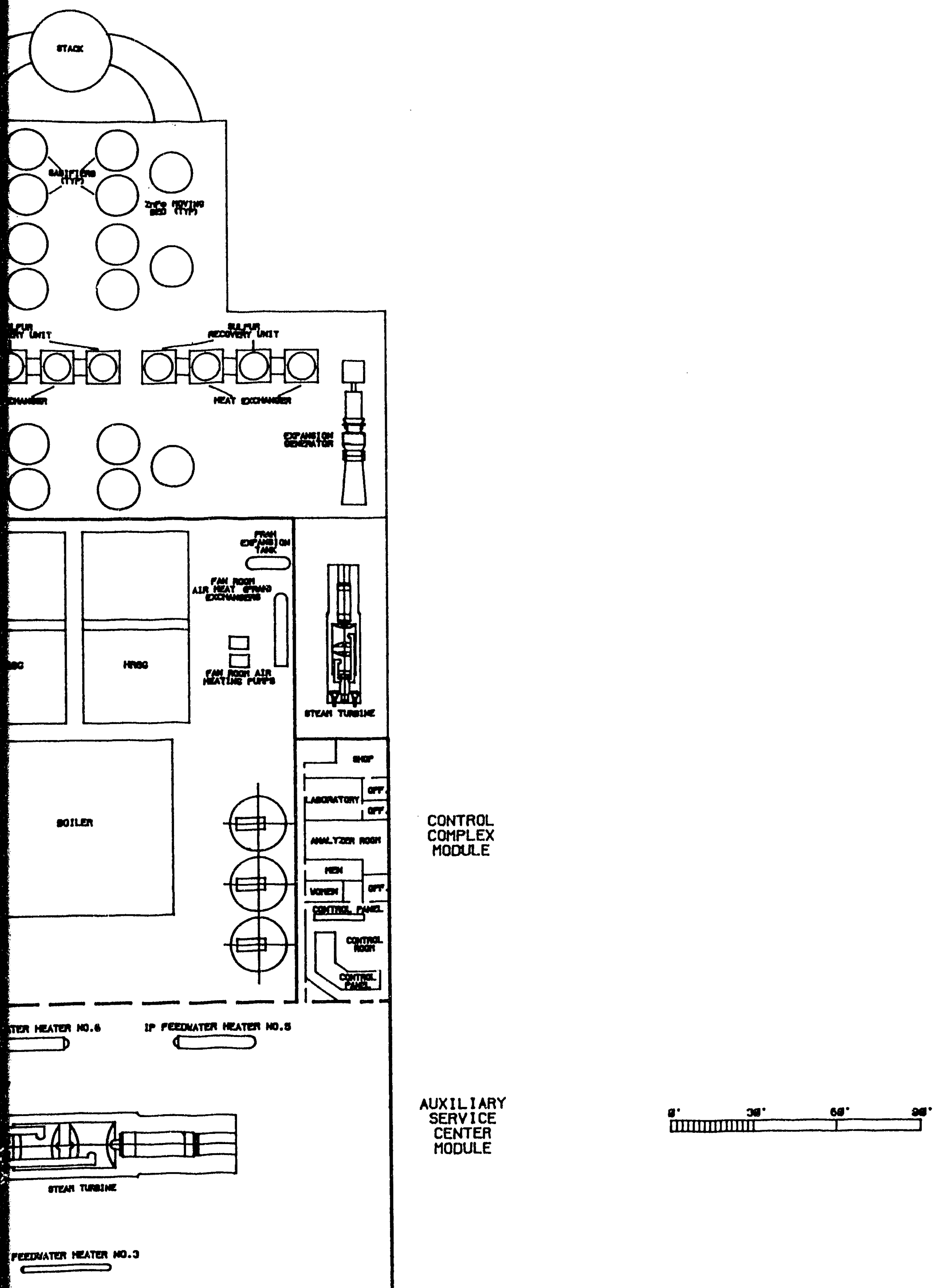
J-1536
DOE IGCC
Project
Retrofit/Repower

Figure 21



BOILER MODULE

TURBINE GENERATOR MODULE



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SEAL

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DATE

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Greenville, S.C.

REFERENCE PLANT ARRANGEMENT PLAN OPERATING AND FEEDER FLOOR

DRAWING TITLE

500 MW RETROFIT/REPOWERING WITH IGCC

Figure 22

DRAWING NUMBER

- The anticipated high furnace exit gas temperature (FEGT) when switching from pulverized coal to low Btu coal gas fuel is overcome by firing the existing coal boiler at a reduced capacity [15]. In this manner, any existing boiler's FEGT can be matched such that boiler performance can be maintained at close to original design conditions. To recover from the impact of expected reduced furnace absorptivity, a conventional unfired heat recovery steam generator section replaces the original air heater (or furnace water wall platens may be added).

- Since turbine exhaust gas provides considerable sensible heat to the low Btu gas fired converted coal boiler in addition to slightly more than the necessary oxygen for combustion in the converted coal boiler, the existing (presumably regenerative) air heater is replaced with an unfired heat recovery steam generator (HRSG) to reduce the boiler exiting flue gas temperature to an acceptable stack exit temperature of 250 to 290 F. A separate steam loop and small low pressure steam turbine/generator is added (as in the case of any combined cycle plant) due to the likelihood that the utility plant will have many feed water heaters in existence such that its feed water temperature will likely exceed 500 F precluding its use as a cooling medium for the boiler exit gas.

A comparison of the CGIA scheme (Table 10a - 10f) with retrofit wet limestone scrubbers [16] reveals that the "N'th" CGIA plant is less costly to install than the wet scrubber system on an evaluated basis. Such considerations as the comparative cost of the wet scrubber retrofit, a capacity credit for the additional MWe produced with the more efficient CGIA system, and an additional capacity credit for the additional parasitic power load attendant with the wet scrubber system all combined to favor the CGIA approach.

The operating costs (Table 10b) reveals that the itemized per kwhr cost of the wet scrubber is automatically increased by 3% since it uses up 3% of the plant's input energy in parasitic power draw. In addition, the CGIA scheme has a lower fuel cost per kwhr consistent with its greater efficiency than the original coal fired power plant. The wet scrubber also suffers from the cost of limestone sorbent , higher water consumption, and waste disposal. The CGIA is substantially credited with

Table 10a

Retro/Rpwr CGIA Plant Costing, (DE-AC21-89MC26291) GE7191F Proj. No. J-1538

Date:	1/28/91	by:	RSS	Per Cent ofConst$
Original Plant Size (MWg)	536	(MWn) 510		
Repowered Plant Size (MWg)	683	(MWn) 602	($/KWn)	(%)

System Description: 1-Stage Dry Bottom Fixed Bed Coal Gasifiers (10-units), ZnFe (GE type), (5-units), SO2 Recovery Plant

RETROFIT/REPOWERING OF EXISTING UTILITY COAL FIRED POWERPLANT

Number Trains & Section Description	Total Flow & Units	1st Plant SectionCost, ($)	N-th Plant Section Cost, ($)	N-th Learning Reduct (%)	N-th Plant Cost ($/kwn)
1 ea, Coal Handling	3000 TPH	0	0	0	0
1 ea, Briquetting System		0	0	20	0
16 ea, Gasification & Ash	131 - lb/sec	86,007,497	68,805,998	20	135
8 ea, Hot Gas Cleanup System (GE type)	466 - lb/sec	39,629,965	23,777,979	40	47
1 ea, Gas Turbine	GE7191F	58,832,000	47,065,600	20	92
1 ea, HRSG, (Includes CO Catalyst & SCR)	1274 - lb/sec	21,554,374	21,554,374	0	42
1 ea, Steam Turbine		0	0	0	0
8 ea, Booster & Auxiliary Compressor	316 - lb/sec	14,731,200	14,731,200	0	29
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)	1,382 K - lb/hr	23,938,200	14,362,920	40	28
Demolition of Existing Equipment		14,105,439	14,105,439		
Sub-total		258,798,675	204,403,510		401
BalanceofPlant(% sub-t w/out proc conting)	15%	39,192,642	23,515,585	40	46
TOTAL PROCESS CAPITAL		297,991,317	227,919,095		447
Fully Standardized Designed N'th Plant			178,794,790	40	351
Engineering (Only)	9%				
Engineering (Contractor's) Fees (Incl Proj&ConstMgt, Testing/Startup, Design/Build Contr Fees, but NOT Opn, Data Col & Rptg, Admin, Dspsn) (%ofTotal Process Capital)	22%	65,143,948	39,086,369	40	77
Project Contingency (%ofTotal Process Capital)	13%	38,738,871	23,243,323	40	46
TOTAL PLANT INVESTMENT		401,874,136	**241,124,482**		473
Allowance for Funds During Construction, (AFDC)	13%	37,920,000	37,920,000		74
WorkCap,Taxes,Royal,Devel,Permits,Legal, Fuel Inven, Spare Parts, Underwriter Costs	8%	24,963,260	24,963,260		49
Land(HistoricalSiteCostsforCo-generation) Acreage @ $8,500 per Acre = 0	0.0%	0	0		0
TOTAL CGIA CAPITAL REQUIREMENT		464,757,396	304,007,742		596
LESS CAPITAL COST of SCRUBBERS w/LOW NOX BURNERS & SNCR (Source: J.A. Werhane, W. DePriest, & D.G. Sloat, Oct., 1990)		173,400,000	173,400,000		340
LESS CREDIT FOR ADDITIONAL CAPACITY of 107 MWe (Increased Capacity + Scrubber Parasitic Power)		171,200,000	171,200,000		1,600
EQUIV CGIA vs SCRUBBER RETROFIT CAPITAL REQUIREMENT		120,157,396	-40,592,258		-80

Table 10b

Retro/Rpwr CGIA Plant Costing, (DE-AC21-89MC26291)			GE7191F Proj. No.	J-1538
Date:	1/28/91	by:	RSS	Per Cent
Original Plant Size (MWg)	536	(MWn) 510		ofConst$
Repowered Plant Size (MWg)	683	(MWn) 602	($/KWn)	(%)
	CGIA Calculated 10 Yr Lev'l Oprtg Costs (mils/kwh)	Scrubbers Calculated 10 Yr Lev'l Operating Costs (mils/kwh)		
MWn	602	495	@3% Plant Input Scrubber Pwr	
Coal Plus Oil/Gas for Strt/Emrg	18.65	22.90	delta Effic & Pwr Incl	
ZnFe,NOx,CO,SRP Catalysts	4.42	4.69	L'stn,NOx,CO Cat	
Residue Disposal	0.77	2.82	delta Pwr Incl	
Operating Labor+G&A	2.04	2.10	delta Pwr Incl	
Insurance & Taxes	3.48	4.07	delta Pwr Incl	
Maintenance & Equip Reserves	3.15	3.68	delta Pwr Incl	
Util.&OperatingConsumables(NoAuxPwrIncl)	0.48	0.51	H2O Use@3GPM/MW hr	
Other (Miscellaneous)	0.07	0.07		
Liquid Sulfur Dioxide Recovery Credit	-8.13	0.00		
TOTAL OPERATING COSTS	24.93	40.84		
PLANT COST INCL CONTINGENCIES	30.77	17.55		
TOTAL COST OF ELECTRICITY (COE)	55.7	58.39		

Table 10c

Retro/Rpwr CGIA Plant Costing, (DE-AC21-89MC26291) GE7191F Proj. No. J-1538

Date: 1/28/91 by: RSS

Original Plant Size (MWg)	536	(MWn) 510			Per Cent ofConst$
Repowered Plant Size (MWg)	683	(MWn) 602		($/KWn)	(%)
	Equipment ($)	Installation ($)	Total ($)		
COGENERATION SYSTEM GROUP INCLUDING STRD CONTROLS, ELECTRICAL, BLDG, CIVIL, STRUCT, ARCHETEC, MECHAN					
Gas Turbine/Gen Syst(Incl Blr Fuel Exp Tbn)	$35,840,000				
Steam Turbine/Generator System	$0				
StartUp&BackupFuel(NatGas)PrepSystem	$0				
Condenser & Vacuum Systems	$0				
TURBINE ISLAND	$35,840,000	$10,226,333	$46,066,333	204	13
Aux Blr for Startup/Emerg PwrGen (Optional)	$0	$0	$0		
HtRecovSteamGenerator(w/COCatyl&SCR)	$10,800,000	$3,287,827	$14,087,827		
HRSG Ductwork & Stack (Incl)					
BOILER ISLAND	$16,524,000	$5,030,374	$21,554,374	95	6
Cooling Tower					
Evaporative Makeup,Circ Water,&AuxSys					
SUB TOT COOL'G TWR SYST	$0	$0	$0	0	0.0
Raw Water Well, Pumps,Fire Prot System					
Demineralizer, Treatment & Storage					
Treated Water Pumping & Control					
CondensateRet,WaterChem,Filtr,StorTanks					
Chem Treat & Cooling Systems					
Feed Water Heaters&Deaerator					
FEEDWATER & WATER TREATMENT SYST	$0	$0	$0	0	0
Generation Plant Electrical System (Incl)					
Sub Station,X-fmrs,Switchyard (Incl)					
and Balance of Plant Electrical	$6,390,000				
Power Transmission Lines	$0				
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$9,776,700	$2,976,304	$12,753,004	56	3
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions Monitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$4,788,900	$1,457,877	$6,246,777	28	1.7
BUILDINGS (Contr Rm,Lav,HVAC,CompAir)	$0	$0	$0		
PAINTING/INSUL/LAGG'G/SCAFFOLDING	$367,200	$111,786	$478,986		
COGENERATION SYST SUB TOTAL	**$65,048,715**	**$19,802,675**	**$84,851,390**	**375**	**23**
DESIGN ENGINEERING @ 8% of syst cost	$6,788,111		$6,788,111		
PROJECT MANAGEMENT @ 2% of syst cost	$1,697,028		$1,697,028		
CONSTRUCTION MANAGEMENT @3% of syst cost		$2,545,542	$2,545,542		
TESTING@1%of syst cost(test&strt-up sum typ2%)	$848,514		$848,514		
START UP COSTS @1% of syst cost	$848,514		$848,514		
DESIGN/BUILD CONTRACTOR'S FEE @4% of syst cos	$3,394,056		$3,394,056		
SUB TOT INDIRECT COSTS	**$13,576,223**	**$2,545,542**	**$16,121,765**	**71**	**4**
SUB TOTAL COGENERATION TURNKEY CONSTRUCTION COST	**$78,624,938**	**$22,348,217**	**$100,973,155**	**447**	**28**

Table 10d

Retro/Rpwr CGIA Plant Costing, (DE-AC21-89MC26291) GE7191F Proj. No. J-1538

Date: 1/28/91 by: RSS

Original Plant Size (MWg) 536 (MWn) 510

Repowered Plant Size (MWg) 683 (MWn) 602

COAL GASIFICATION ADDERS	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
Coal Rail Spur					
Coal Receiving, Storage & Handling System					
Coal Fines Briquetting System	$0	$0	$0	0	0
Mobile Equip(2-B'dozers,Fr Loader,LiftTrk)					
SUB TOTAL COAL FACILITIES	$0	$0	$0	0	0
COMBUSTOR MOD. for COAL GAS FIRING	$3,060,000	$2,295,000	$5,355,000	24	1
AIR HANDLING FLOW MODULE	$5,508,000	$1,377,000	$6,885,000	30	2
BOOSTER COMPRESSOR&INTERCOOLER	$12,276,000	$2,455,200	$14,731,200	65	4
ADDITIONAL PROCESS WATER SYSTEM	$0	$0	$0	0	0.0
HighPressureAir&GasDuctwork&Cyclones,					
Coal Feed & Lock Hopper Systems (Incl)					
Gasifiers (Lurgi Mark IV Comparable)					
Ash Handling Lock Hopper System (Incl)					
Grate, Leveller, & Stirrer Drives (Incl)					
GASIFIER ISLAND	$57,025,216	$27,239,856	$84,265,072	373	23
HOT GAS CLEANUP UNIT(GE ZNFeSyst)	$20,808,782	$13,713,922	$34,522,704	153	10
ZnFe Outlet Gas Cyclones & Ductwork					
Regeneration Compressor & Heat Exch					
SO2 Recovery Plant	$16,038,594	$7,899,606	$23,938,200	106	7
SulfurCondensateHandling,Storage&Loadout,					
Catalyst Conveying & Loadout (Incl)					
ZincFerriteSorbentConveying&Storage(Incl)					
FLUE GAS CLEANUP SYSTEM AUXILIARIES	$3,687,250	$1,044,862	$5,107,261	23	1
Bottom Ash Handling System					
Ash Storage Silo & Outloading System (Incl)					
SUB TOTAL ASH HANDLING SYSTEM	$1,290,770	$451,655	$1,742,425	8	0.5
High Pressure Interconnect'g Piping					
Interconnecting Coal/Sorb System Piping					
Additional Fire Protection Pumps/Piping					
Additional Plant Air Compressors/Piping					
Add'l Instru Air Compressors,Filters/Piping					
SUB TOT ADDITIONAL PIPING SYSTEMS	$4,294,264	$8,349,061	$12,643,325	56	3
Gasification Syst Excav, Fdns, & Backfill					
Gasification System Roadways/ Parking					
Rail Spur to Cogeneration Plant (1,100 ft)					
Gasification Syst Site Drainage/Leach Field					
SUB TOT ADDITIONAL CIVIL WORK	$2,301,750	$9,207,000	$11,508,750	51	3
SUB TOT ADDITIONAL BUILDINGS	$1,108,250	$358,050	$1,466,300	6	0
Generation Plant Electrical System (In Strd CC System)					
Sub Station,X-fmrs,Switchyard (In Strd CC System)					
Gasification System Electrical					
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$2,253,690	$1,530,000	$3,783,690	17	1
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions&GasQualityMonitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$3,748,500	$1,530,000	$5,278,500	23	1.4
ADD.INSUL/LAGG'G/PAINT/SCAFFOLD'G	$497,250	$1,415,250	$1,912,500	8	0.5
COAL GASIFIC'N EQUIP ADDERS	$150,949,510	$78,866,462	$213,139,927	943	59

Table 10e

Retro/Rpwr CGIA Plant Costing, (DE-AC21-89MC26291)

Date: 1/28/91

Original Plant Size (MWg) 536

Repowered Plant Size (MWg) 683

GE7191F by: (MWn) 510 (MWn) 602

J-1538 Proj. No. J-1538

	Equipment	Installation	RSS Total	($/KWn)	Per Cent ofConst$ (%)
ADDITIONAL DESIGN ENGINEERING @ 8%	$17,051,194				
ADDITIONAL PROJECT MANAGEMENT @ 3%	$6,394,198				
ADDITIONAL CONSTRUCTION MANAGEMENT@ 3%		$6,394,198	$6,394,198		
ADDITIONAL TESTING @1% (2% test&strtup)	$2,131,399				
ADDITIONAL START UP COSTS @1%	$2,131,399				
ADD. DESIGN/BUILD CONTRACTOR'S FEE @7%	$14,919,795				
SUB TOT ADDIT. INDIRECT COSTS	$42,627,985	$6,394,198	$49,022,183	217	14
SUB TOT COAL GASIFICATION TURNKEY CONSTRUCTION COST	$272,202,433	$107,608,877	$363,135,265	1,607	100

Table 10f

Retro/Rpwr CGIA Plant Costing, (DE-AC21-89MC26291)

Date: 1/28/91

Original Plant Size (MWg) 536

Repowered Plant Size (MWg) 683

GE7191F by: (MWn) 510 (MWn) 602

Proj. No. J-1538

	RSS Total	($/KWn)	Per Cent ofConst$ (%)
OWNERS COSTS			
Site	$0	0	
Development	$0	0	
Working Capital	$4,822,000	21	
Permits	$1,897,899	8	
Legal Fees	$102,101	0	
Taxes & Royalties	$3,617,000	16	
Fuel Inventory	$0	0	
Spare Parts	$4,320,000	19	
Interest During Construction	$37,920,000	168	
Underwriters' Costs	$10,204,260	45	
CONTINGENCY & RISK (@ % OF TOTAL PROCESS CAPITAL STATED BELOW) 13.48%	$38,738,871	171	
SUB TOTAL OWNERS COST	$101,622,131	450	
INSTALLED PROJECT TOTAL	$464,757,396	2,056	N/A

its sulfuric acid byproduct. Secondary benefits of the CGIA system include a reduction in total water utilization of the original coal fired plant in contrast to a significant increase in water consumption for the wet scrubber scenario. In addition, the condenser/cooling tower capacity is sufficient to accommodate the flow from the additional low pressure steam turbine.

4.2.3.4 Cost Sensitivity

There appears to be an excellent chance of making this 575 MWe net capacity plant economical (Figure 23). The plant cost estimate sensitivity analysis for the N'th plant revealed costs of electricity (COE) from approximately 4¢/kWh to 6¢/kWh. Clearly, this result is an economical alternative to wet scrubbers for retrofitting and repowering existing coal fired utility power plants.

Plant costs (Figure 24), and cost of electricity (COE) (Figure 25) reflect the lowest anticipated cost system. These figures reflect a PyGas (or equivalent METC scaled-up gasifier) installation.

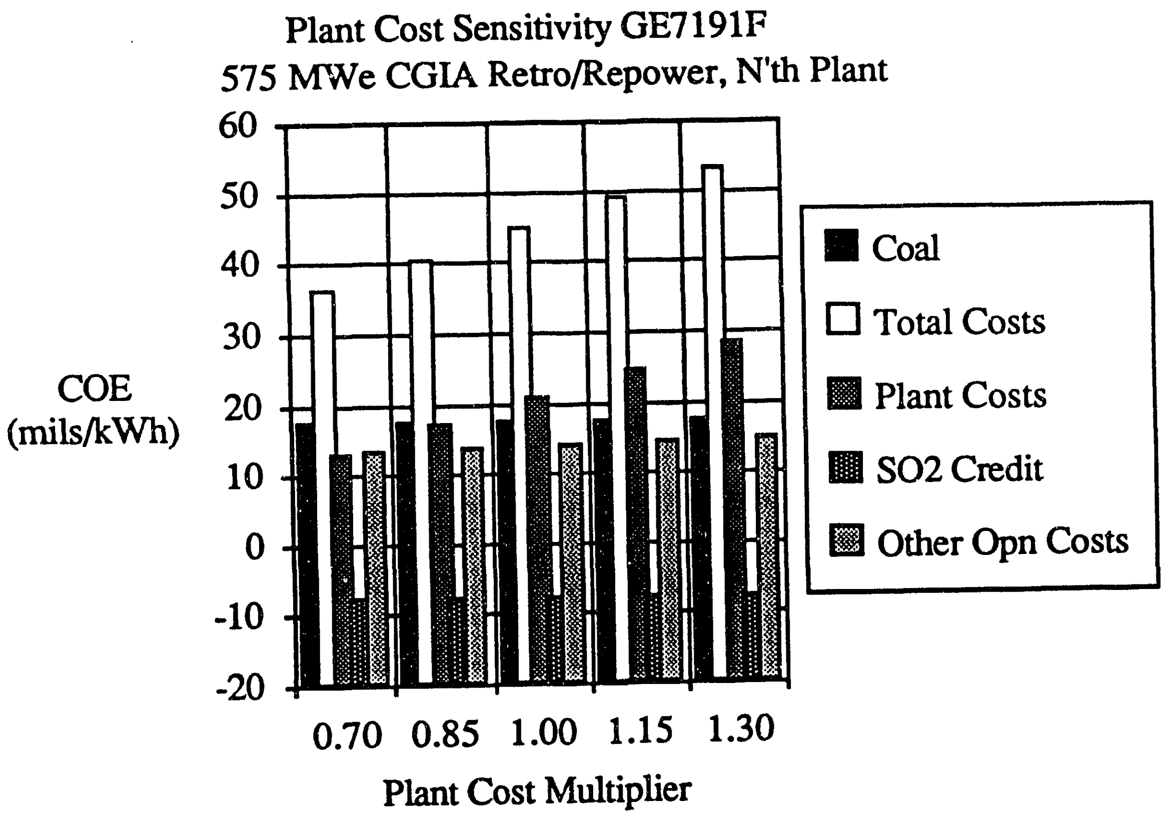
Plant Cost Sensitivity GE7191F
575 MWe CGIA Retro/Repower, N'th Plant
60
50
40
30
20
10
0
-10
-20
COE
(mils/kWh)
Coal
Total Costs
Plant Costs
SO2 Credit
Other Opn Costs
0.70
0.85
1.00
1.15
1.30
Plant Cost Multiplier

Figure 23

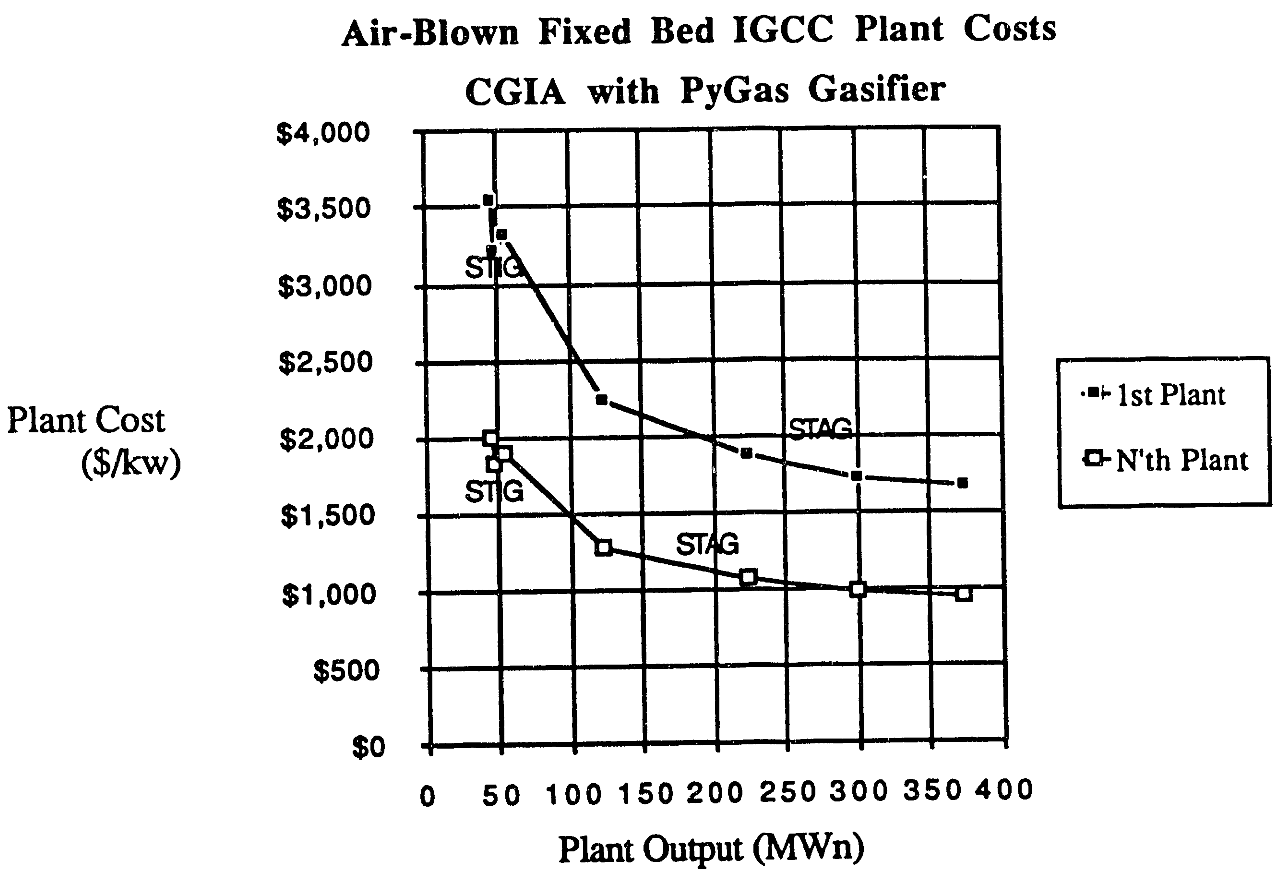
Air-Blown Fixed Bed IGCC Plant Costs
CGIA with PyGas Gasifier
Plant Cost
($/kw)
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
STIG
STAG
STIG
STAG
0
50
100
150
200
250
300
350
400
Plant Output (MWn)
1st Plant
N'th Plant

Figure 24

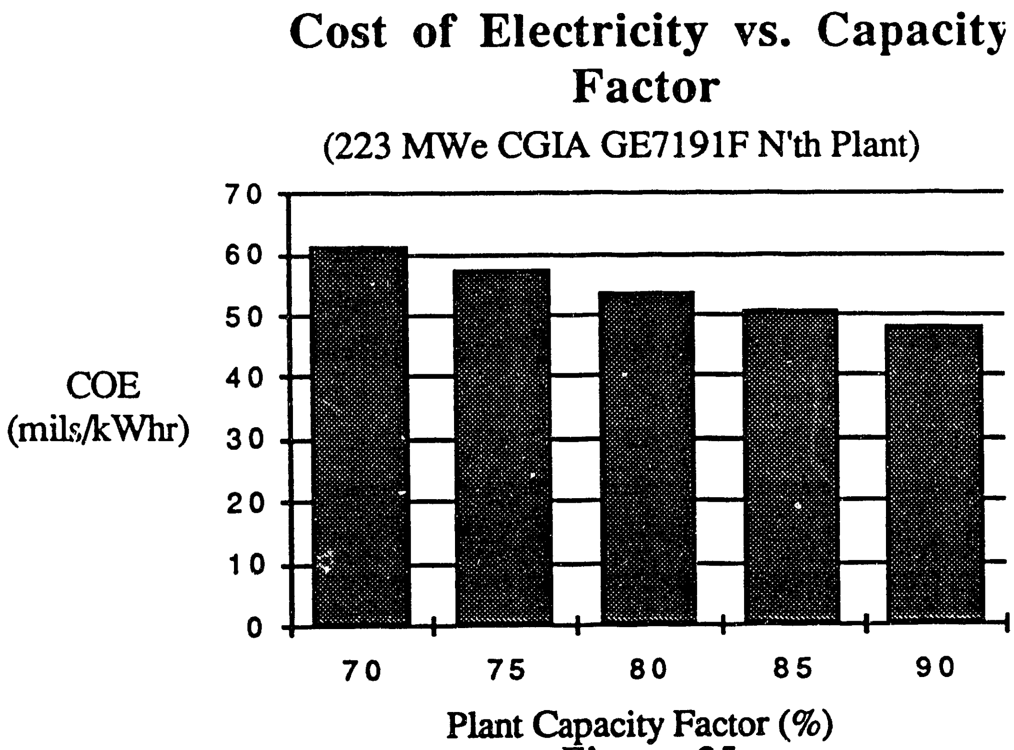

Figure 25

4.3. Standardized Module Design & Performance

This study involved the use of both the GT-Pro [15] and MESA [16] computer programs for the determination of combustion turbine and steam boiler/turbine performance. An in-house program to identify mass and energy balances resulting from the previously mentioned programs was developed to specifically study the interrelationship of the many CGIA subsystems using both Lotus and Microsoft Excel on PC's. Several such balances appear in Appendix C. Although the study concentrated on coal gasifier relationships with the HGCU and power island, several other systems were included and considered. These include the coal briquetting plant, booster compressor , sulfur recovery processes, and various materials collection and storage points.

From a performance standpoint, only subtile differences appear between the products of the combustion turbine manufacturers with higher combustion temperatures producing slightly higher overall plant efficiencies. All arrangements studied were capable of overall plant efficiencies in excess of 39% based on higher heating value of the coal and net power output after parasitic losses (Table 11).

The more heat utilized as thermal process load, the greater the overall plant efficiency consistent with the original intent of the PURPA laws, and FERC rules.

Table 11
Auxiliary Power Losses (@ 122.2 MWe)

Coal Handling & Gasification	559
Briquetting/Binder	397
Regen Air Compressor	780
Recirc Gas Fan	86
H2SO4 Plant	408
Booster Compressor	3,344
Transformer	723
Power Cycle & Miscellaneous	4,186
Total, kW	10,482

Since coal as a fuel source contains less hydrogen than natural gas, it potentially can produce slightly greater overall efficiencies due to there being less moisture formed stack gas losses [14].

This study utilized existing coal gasifier test data results when determining the thermal output from the gasification process. The data utilized was generated from very small gasifiers relative to those which will be utilized on full scale applications. To account for the expected gain in the larger sized from lowered radiation losses and losses to the gasifier water jacket, this study assumed that the difference between the calculated gasifier thermal output, and the actual test data output went into gasifier water jacket steam generation. It, therefore, utilized such available heat as a source of steam generated power output.

4.3.1. Performance of the 50 MW Size for Co-generation & IPP

4.3.1.1 STAG

The selected nominal 50 MWe plant typically generates 34 MWe from the combustion turbine, 13 MWe from the steam turbine, and 5% thermal process steam. Its overall Federal Regulatory Energy Commission (FERC) efficiency was 41.75%.

Other system information appears in the following table:

Table 12
50 MWE CGIA PLANT

Coal Feed Rate	35,688 lb.hr
Air to Coal Ratio	2.41
Water Spray to Coal Ratio	0.26
Unfired HRSG/Steam Turbine Conditions	
Flow Rate	23.6lb/sec
Pressure	865 psig
Temperature	800 F
Process Steam Conditions	
Flow Rate	1.94 lb/sec
Pressure	250 psia
Temperature	420 F
Combustion Turbine Output	33.69 MWe
Steam Turbine Output	13.4 MWe
Overall Efficiency (FERC if Appropriate)	41.75%

4.3.1.2 STIG

The selected nominal 50 MWe plant typically generates 49 MWe from the combustion turbine, and the balance is thermal process steam. Its overall FERC efficiency was 45.92%, even though it had a relatively high stack gas temperature of 314 degrees F.

Other system information appears in the following table:

Table 13
50 MWE CGIA STIG PLANT

Coal Feed Rate	44,280 lb.hr
Air to Coal Ratio	2.41
Water Spray to Coal Ratio	0.26
Unfired HRSG/Steam Conditions (Dual Pressure)	
Flow Rate	16.8/25.83 lb/sec
Pressure	600/250 psig
Temperature	650/450 F
Process Steam Conditions	
Flow Rate	13.8 lb/sec
Pressure	250 psig
Temperature	450 F
Combustion Turbine Output	49.0 MWe
Overall Efficiency (FERC if Appropriate)	45.92%

4.3.2. Performance of the 100 MW Sized CGIA Plant

4.3.2.1 Cogeneration & IPP Applications

The selected nominal 100 MWe plant typically generates 81-85 MWe from the combustion turbine, 46-49MWe from the steam turbine, and 5% thermal process steam. Its overall FERC efficiency was 41.05%-41.72%.

Other system information appears in the following table:

Table 14
100 MWE CGIA PLANT

	GE 7111EA	ABB GT 11 N
Coal Feed Rate	96,944 lb.hr	96,707 lb.hr
Air to Coal Ratio	2.41	2.41
Water Spray to Coal Ratio	0.26	0.26
Unfired HRSG/Steam Turbine Conditions		
Flow Rate	78.55 lb/sec	77.52 lb/sec
Pressure	1265 psig	1265 psig
Temperature	935 F	935 F
Process Steam Conditions		
Flow Rate	5.42 lb/sec	5.33 lb/sec
Pressure	250psig	250psig
Temperature	420 F	420 F
Combustion Turbine Output	84.4 MWe	81.1 MWe
Steam Turbine Output	46.9 MWe	47.8 MWe
Overall Efficiency (FERC if Appropriate)	41.72%	41.05%

4.3.2.2 Utility Applications

The selected nominal 100 MWe plant typically generates 81-85 MWe from the combustion turbine, and 48-50MWe from the steam turbine. Its overall efficiency was 39.31%-39.94%.

Other system information appears in the following table:

Table 15
100 MWE CGIA PLANT

	GE 7111EA	ABB 11 N
Coal Feed Rate	96,944 lb.hr	96,707 lb.hr
Air to Coal Ratio	2.41	2.41
Water Spray to Coal Ratio	0.26	0.26
Unfired HRSG/Steam Turbine Conditions		
Flow Rate	78.55 lb/sec	77.52 lb/sec
Pressure	1265 psig	1265 psig
Temperature	935 F	935 F
Combustion Turbine Output	84.4 MWe	81.1 MWe
Steam Turbine Output	48.4 MWe	49.3 MWe
Overall Efficiency (Net, HHV Basis)	39.94%	39.31%

4.3.3. Performance of the 200 MW Sized CGIA Plant

4.3.3.1 Cogeneration & IPP Applications

The selected nominal 200 MWe plant typically generates 150-154 MWe from the combustion turbine, 86-87 MWe from the steam turbine, and 5% thermal process steam. Its overall FERC efficiency was 44.83%-45.3%.

Other system information appears in the following table:

Table 16
200 MWE CGIA PLANT

	GE 7191F	MW501F
Coal Feed Rate	162,502 lb.hr	166,657 lb.hr
Air to Coal Ratio	2.41	2.41
Water Spray to Coal Ratio	0.26	0.26
Unfired HRSG/Steam Turbine Conditions		
Flow Rate	117 lb/sec	116.5 lb/sec
Pressure	1465 psig	1465 psig
Temperature	1000 F/1000 F	1000 F/1000 F
Combustion Turbine Output	150.4 MWe	153.6 We
Steam Turbine Output	86.2 MWe	86.0 MWe
Overall Efficiency (FERC if Appropriate)	45.30%	44.83%

4.3.3.2 Utility Applications

The selected nominal 200 MWe plant typically generates 150-154 MWe from the combustion turbine, 89-90 MWe from the steam turbine. Its overall efficiency was 43.0%-43.47%.

Other system information appears in the following table:

Table 17
200 MWE CGIA PLANT

	GE 7191F	MW501F
Coal Feed Rate	162,502 lb.hr	166,657 lb.hr
Air to Coal Ratio	2.41	2.41
Water Spray to Coal Ratio	0.26	0.26
Unfired HRSG/Steam Turbine Conditions		
Flow Rate	117 lb/sec	116.5 lb/sec
Pressure	1465 psig	1465 psig
Temperature	1000 F/1000 F	1000 F/1000 F
Combustion Turbine Output	150.4 MWe	153.6 We
Steam Turbine Output	89.3 MWe	89.1 MWe
Overall Efficiency (FERC if Appropriate)	43.47%	43.0%

4.4. Financial Inputs

4.4.1. Cogeneration and Independent Power Production

Considerable effort was placed upon generating input assumptions consistent with typical cogeneration and independent power production project development scenarios. A project pro-forma was developed as a means of checking for reasonableness of inputs based upon the principal investigator's experience with the requirements for relatively small co-generation and IPP plants developed by very small entrepreneurial companies which lack the financial strength of many larger more substantial developers. Therefore, the assumptions utilized within this study should be somewhat on the conservative side with respect to its estimates for the cost of "money". The following assumptions were incorporated into this study:

4.5. Owner's Cost Factors

4.5.1.	Construction Period	24 Months
4.5.1.	Site (Incl Rights of Way)	$8,500/Acre
4.5.2.	Working Capital (of Construction Cost)	2%
4.5.3.	Development Recovery (of Construction Cost) (Incl permits,licenses,legal,consultants, due diligence)	$2-mil
4.5.4.	Fuel Inventory (30 Days Dead, 7 Days Live Storage)	37 Days
4.5.5.	Financing Fees	3%
4.5.6.	Spare Parts (Initial)	2%

4.6. Economic Inputs (Major Only)

4.6.1.	General Inflation	5%
4.6.2.	Coal @ Mine (Years 1-5)	5%
4.6.3.	Coal @ Mine (Years 6-20)	8%
4.6.4.	Coal Transportation	5%
4.6.5.	Discount Rate	12%
4.6.6.	Interest During Construction	12.5%
4.6.7.	Interest on Primary Debt	12.5%
4.6.8.	Equity After Tax Rate of Return (ATROR)	18%
4.6.9.	Corporate & Investor's Tax Rates	34%
4.6.10.	Property Tax Rates	2%
4.6.11.	Coal Fuel	$1.6/MBtu
4.6.12.	Natural Gas Fuel	$3.0/MBtu
4.6.13.	Catalysts	4 mils/kwh
4.6.14.	Disposal	$10.31/ton
4.6.15.	Operation (Fully Burdened)	$73,400/man-year
4.6.16.	Insurance	1/2%
4.6.17.	Cost of Capital	
	1. Debt Coverage Ratio (Min)(Opn Inc/Pri Debt)	1.73
	2. Subordinated Debt	15%
	3. Owner's Equity	5%
4.6.18.	Term of Debt Service	15 Years
4.6.19.	Term of Power Contract	20 Years
4.6.20.	Depreciation Period	20 Years
4.6.21.	Depreciation Amount (% of X-key)	88%
4.6.22	Capacity Factor	80%
4.6.23.	Water	75¢/1000 gal
4.6.24.	Startup & Auxiliary Fuel Usage	2%
4.6.25.	Elemental Sulfur Credit	$105/Ton
4.6.26.	Sulfuric Acid Credit	$86/Ton
4.6.27.	Liquid Sulfur Dioxide Credit	$230/Ton

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14. "Steam Generation from Turbine Exhaust Gas", by R.R. Leonard et al, Riley Stoker Corp., National Power Conference, Cincinnati, Ohio, September 24, 1963

15. "Diagnosis of Thermal and Fluid Dynamic Performance of a Boiler", by F. W. Bauer et al. Stone & Webster Engineering Corporation, Technical Paper Series, 1989

16. "SO2 and NOx Retrofit Control Technologies Handbook", EPRI, Palo Alto, CA., October, 1985

17. GTPro is a Proprietary Program of Thermoflow, Inc., Waltham, Massachusetts

18. MESA is a Proprietary Program of The MESA Company, The Woodlands, Texas

Assessment of Standardized Fixed-Bed, Air-Blown Gasifier IGCC Market Acceptance

Section 5

January 1991

Work Performed Under Contract No. DE-AC21-89MC26291

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
CRS SIRRINE, INC.
Power Division
P.O. Box 5456
1041 East Butler Road
Greenville, South Carolina 29606-5456

5.1. Summary

This specific section is intended to evaluate advantages/disadvantages of candidate coal gasifiers matched with combustion turbine/HGCU modules. It also provides for the development and expected performance characteristics of selected advanced coal gasification systems. Included is the assimilation of empirical data and industry experience describing optimized combinations of air-blown, Fixed Bed Gasifier/HGCU/Combustion Turbine combinations.

A survey, in the form of a questionnaire, was also conducted at the 1990 Cogeneration and Independent Power Production Congress held in Boston, Massachusetts. The majority of the survey respondents had utilized coal in the past (63%) and present (50%), and a greater majority (75%) expected to be burning some coal in the future. While most (75%) believe coal is presently environmentally safe to burn, all (100%) believe coal will be environmentally safe to burn by the year 2000. Most (63%) do not expect to burn more coal annually in the next ten years.

The average expected turnkey capital cost for an IGCC coal fired plant from the survey was $1340/kWn. Additionally, the largest group (although all were minority preferences - 23%) would prefer to purchase their coal combustion and emissions control equipment from Babcock & Wilcox.

Two thirds would prefer to license coal combustion and emissions control technology from the Electric Power Research Institute (EPRI). In this case, they would expect to then select their own equipment supplier who would furnish the equipment under an EPRI license.

When given a choice of environmental, efficiency, and cost factors, the respondents' were primarily cost conscious, particularly with "cost of electricity". The environment was of secondary importance, and efficiency third. The vast majority (88%) would buy a coal fired facility if (question 8) its cost of electricity was 5¢/kwh, plant cost was $1,000/kwn, FERC efficiency was 38% (or utility cycle efficiency was 41%), it had 99% sulfur removal, its NOx emissions were 0.1 lb/MBtu, and it produced elemental sulfur as a marketable waste product.

The business and financial communities require firm guarantees of unit performance, the proof of which must be borne out under the scrutiny of their own independent "due diligence" engineering reviews. Therefore, although the "N'th" unit will be financeable, the initial units which will be required to demonstrate satisfactory performance must be innovatively developed and financed.

Results IS COAL IN OUR FUTURE Results

This questionnaire will be utilized with complete source confidentiality on U.S. Department of Energy Contract DE-AC21-89 MC 262. The results of the survey were as indicated.

PLEASE CIRCLE ONE

1. Have you (your company) in the past, do you currently, and do you plan to utilize coal as a primary fuel in the near future?

past yes	currently yes	future yes	no
63%	50%	75%	12%

2. Do you believe coal is currently environmentally safe to burn?

yes	no
75%	25%

3. Do you believe coal technology will be forthcoming which will make coal combustion environmentally acceptable by the year 2000 ?

yes	no
100%	0%

4. Do you expect your company will burn more coal annually in the next ten years?

yes	no
37%	63%

5. At what turnkey capital cost ($/kw) would your company utilize coal fuel today?

(Average Result) 1340 $/kw (net)

6. Who would you prefer to purchase the major coal combustion and emissions control equipment from ?

Babcock & Wilcox	23%	Westinghouse	8%
Combustion Engineering	8%	Lurgi	0%
Foster Wheeler	8%	CRS Sirrine	15%
Riley	0%	Dow Chemical	8%
General Electric	15%	Doesn't Matter	8%

7. Would you prefer to license the technology via the Electric Power Research Institute (EPRI), or a similar organization? In this case you would select your own equipment supplier.

EPRI	yes	Similar Organization	yes	No
	67%		17%	16%

8. If a coal fired plant were available today per the following description, would your company buy it?

yes	no
88%	12%

Rank the Following in Order of Importance, 1 thru 6

		Number who selected "Most Important" (1&2)
a.	Facility turnkey capital cost of $1,000/kw	7
b.	FERC efficiency greater than 38% (IPP & Cogen Plants)	4
	Cycle efficiency greater than 41% (Utility Steam Conditions)	8
c.	99% coal sulfur removal effic. (SO_x less than 0.1 lb/MBtu)	9
d.	Elemental sulfur solid waste by-product	4
e.	NO_x emissions less than 0.1 lb/MBtu	6
f.	Total cost of electricity (COE) less than 5 ¢/kwh (levellized)	15

Developments Required to Effect Commercial Gasification IGCC Applications (CGIA) Integration Into the Power Market

Section 6

January 1991

Work Performed Under Contract No. DE-AC21-89MC26291

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
CRS SIRRINE, INC.
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1041 East Butler Road
Greenville, South Carolina 29606-5456

6.1. Summary

This specific section is intended to develop the content required of a "Business Plan" to allow interested parties to implement and pursue the potential IGCC standardized plant market. It is also intended to evaluate advantages/disadvantages of candidate coal gasifiers matched with combustion turbine/HGCU modules to identify barriers to that end. It provides for the development and expected performance characteristics of selected advanced coal gasification machines as required to accommodate program objectives. Included is the assimilation of empirical data and industry experience describing optimized combinations of air blown Fixed Bed Gasifier/HGCU/Combustion Turbine combinations.

The results indicate that although the anticipated first system costs will be relatively high, the assumption of pre-engineered standardized and modularized systems for Commercial Gasification IGCC Applications (CGIA) systems results in an "N'th unit" total facility cost of under $1,000/kwn in sizes larger than 200 MWe. The resultant ten year levellized cost of electricity (COE) reflected the low CGIA standardized plant cost advantage.

This study also identified existing coal fired utility power plants as near term candidates for standardized CGIA application. While many consider conventional flue gas scrubbers as the economical solution to the emissions concerns of large coal fired utilities, such systems are expensive and adversely affect power plant efficiency by consuming significant quantities of power which would have otherwise been available to the grid. In effect, while reducing stack emissions, scrubbers return reduced plant electricity output for their significant expense. Retrofitting and repowering existing coal fired power plants with CGIA results in much lower emissions than currently available commercial scrubber systems plus very substantial increased power output for the same coal input for which the facility has already been designed.

Conventional wisdom would likely suggest that successful commercialization is dependent on the ability of a new product to gain market acceptance. Such market acceptance and subsequent market penetration usually depend on a variety of factors. These typically include a well defined market, clear product definition, a strong marketing plan, and a vendor capable of introducing a new product to the market.

Once market and product are identified, a vendor capable of gaining market acceptance for the product within the power generation community would generally be the logical, although not necessarily the only candidate to carry the product to commercialization. The successful vendor would possess a diverse mixture of knowledge and skills. These would ideally include a thorough working knowledge of and experience in the power generation market. The vendor must be versed in the regulations that govern the utility and independent power producers (IPP) including the Public Utility Holding Company Act (PUHCA), the Public Utilities Regulatory Policy Act (PURPA), and the revised Clean Air Act . In addition, to facilitate rapid commercial acceptance of a new power generation system, the vendor must have established credibility within the power generation community. Organizations that supply capital equipment and/or engineering services to the power generation community are strong candidates for potential vendors with established reputations.

A successful system vendor must also possess the engineering expertise to support project development and product improvement. As operating experience reveals areas for product improvement, the successful vendor must have the technical expertise to make necessary design modifications. These modifications may result in improved technical performance, system reliability, or reduced capital costs.

The successful introduction of a new product often requires a vendor to bid initial products at below cost. This is normally necessary when competing against well established technologies such as pulverized coal fired boilers with flue gas desulfurization. Due to the financial structure and highly competitive nature of IPP projects, a low bidding approach is potentially, although not the only successful way to enter the market. While lowest capital cost is not critical in utility applications, it is often the key criteria in IPP system configuration decisions. Since the rate of return is not regulated for an IPP, lower capital and O&M costs mean higher potential profits.

In order to bid projects at or below cost, a vendor must have a sufficient asset base to subsidize market entry activities. As a result, companies that design and manufacture capital equipment (OEM's) may be strong candidates as potential system vendors. They have the assets and working capital necessary to fund market entry.

A vendor must have the financial strength to offer system guarantees and warranties, or be able to satisfy project financing requirements via some combination of subordinated debt provided by major equipment vendors and process guarantees provided by the commercializing entity. The financial constraints of market entry and the potential liabilities associated with project guarantees and warranties can severely limit the capability of a vendor to penetrate a market. After capturing a few initial projects, the financial exposure associated with them could severely restrict a small developer from obtaining additional project financing. This is particularly true in the highly leveraged joint owner/operator project arrangements commonly seen in the IPP market. Again, an OEM with a strong asset base might be in a better position to continue pursuing new projects. On the other hand, at least some enterprising project developers have successfully leveraged system guarantees and warranties through their major equipment suppliers. Using this scenario, they may actually be better able to spread risk than can an OEM supplier because their approach includes the entire equipment supplier base and not just one supplier.

A key characteristic of the successful vendor will be the ability to aggressively market the system to the user community. While this ability cannot be measured quantitatively when evaluating potential vendors, the company's product history is a reasonable indicator of potential success. Companies that have successfully introduced new capital equipment products in the past are likely to be versed in the aggressive approach often necessary to supplant existing technology.

Finally, a successful vendor must have the capability to fabricate and/or competitively procure the system/components. A successful vendor must be capable of controlling his competitive standing in the marketplace. This is largely dependent on the vendor's ability to control his product costing, hence pricing. A company acting as an assembler of components does not have the ability to control product pricing unless cost effective exclusive price/supply contracts are negotiated with major equipment suppliers. Otherwise, the vendor's pricing and competitiveness are largely controlled by his equipment suppliers. The capability to fabricate major portions of the system or to pursue alternative sources of supply ensures the vendor's ability to control his pricing relative to his competitors.

Because the market potential of this particular product is immense, and since the initial costs of such large complex systems are so high, it is likely that no single OEM will be asset rich enough to be in a position to singularly cover all the financial risk associated with bringing this system to wide commercial implementation.

The "Commercialization Plan" contemplated for this emerging product to serve a burgeoning power production market was developed with the recognition that first unit implementation looms as the greatest threat to timely introduction of this concept for widespread use in the cogeneration, independent power production, and utility industries. It includes an unorthodox approach to licensing via the Electric Power Research Industry (EPRI) or a similar independent organization capable of unbiased evaluation and sanctioning of desirable technological concepts for faster implementation of the CGIA technology scheme in the earliest possible time frame. Process guarantees are expected from the system developer while hardware and performance guarantees are from sub-system equipment manufacturers.

It is also sensitive to the ongoing developmental efforts by others such as those under the DOE's Clean Coal Technologies program. Such heroic efforts to demonstrate full scale novel clean coal utilization technologies should be lauded and supported in every conceivable way.

It is in the spirit of working along a slightly different path that this plan for commercialization takes some seemingly widely divergent (however necessary) routes to expedite the process of development, demonstration, and bringing the concept to an industry that would like to immediately implement it if it could be considered technologically proven and thus financeable.

Since additional development of a fixed-bed gasifier is currently needed before the economic goals of this study can be realized, it is believed that the cogeneration, independent power production, and utility industries will not endorse it until such time that the improved gasifier is demonstrated. Therefore, this study proposes the retrofitting/repowering of either an existing coal fired utility facility which is perhaps nearing retirement, or a similar cogen/IPP facility as the fastest route to achieve commercial status. An existing coal fired facility is appropriate because it presumably already contains most of the infrastructure necessary to support a coal gasification endeavor.

Once commercial status is reached, it is proposed that an independent utility industry representative organization evaluate the demonstrated CGIA retrofitted plant, and using its own criteria, agrees to sanction the technology (assuming it is acceptable). The developer of the CGIA technology would then merely license the technology to the utility industry through the third party (EPRI or equal). In this manner, any utility user could select the builder of the plant who would license it through the industry representative from the CGIA developer. Therefore, if utility A prefers vendor AA to build the plant perhaps because vendor AA previously had built the existing facility, vendor AA would pay a license fee through EPRI to the CGIA developer (similar to the way Lurgi licenses their gasifiers). The value of this scenario is its ability to immediately implement the CGIA concept simultaneously to all users through all qualified vendors. This maximizes CGIA utilization. Since the CGIA developer would provide process guarantees and equipment manufacturers the hardware and performance guarantees, the third party licensing authority would provide only their sanction of the technology (no guarantee liability).

There is solid justification for the consideration of the addition of CGIA systems to existing coal fired utility plants. The majority of the most costly of the capital cost items of the power plant already exist. These include coal receiving/handling/storage/reclaim, water sourcing/purification/treatment/disposal, electricity generation/conditioning/distribution, and the most costly of all, the boiler island itself. Unlike other repowering strategies which require replacement of the boiler island, this study presents a way to simply add on the IGCC system to the existing coal plant with minimum modification to the existing infrastructure. The result is also an approximate 20% increase in power output while simultaneously reducing the plant's stack gas emissions by well in excess of 90% for SO2, NOx, and particulates.

6.2. Integration & Matching of Commercial Gasification IGCC Applications

The initial efforts of combining the various systems which comprise the Commercial Gasification IGCC Applications (CGIA) revolved around establishing an engineering level mass and energy balance sufficient to identify the processes involved. Appendix C includes reasonably complete mass and energy balances for the nominal 50 MWe, 100 MWe, 200 MWe, and utility retrofit/repower cases. Several combinations of inputted coal analyses with actual and predicted coal gasifier outputs were studied to both get an idea of ranges and constraints to be expected when changing coals.

Once satisfied that the mass and energy balances were reasonably accurate, the empirical relationships developed by others (Figure 1),[1] with actual coal gasifier operating experience of the type of gasifier selected were superimposed into the balances (both Microsoft Excel and Lotus were used to build the spreadsheets).

Gasifier sizing consistent with an expected 85% plant availability [2] criterion was utilized. Based on previous industry experience and projections of new gasifier concepts expected to adequately deal with the adverse consequences of caking and low ash fusion coals, the typical coal throughput of a 14 foot diameter fixed-bed, air-blown gasifier operating at 300-450 psi was set at 17 tons per hour to accommodate US bituminous coals.

It was determined that it made logical sense to select available combustion turbines which, when combined with an unfired heat recovery steam generator/turbine set (Brayton plus Rankine cycles), would produce power outputs close to the three plant sizes selected for the study (STAG). Thus, the three nominal sizes became approximately 45 MWn, 120 MWn, and 240 MWn.

Low BTU Gas Analysis vs. Water (GE Data)
Points @ 4.43% & 6.26% H2O are Projected

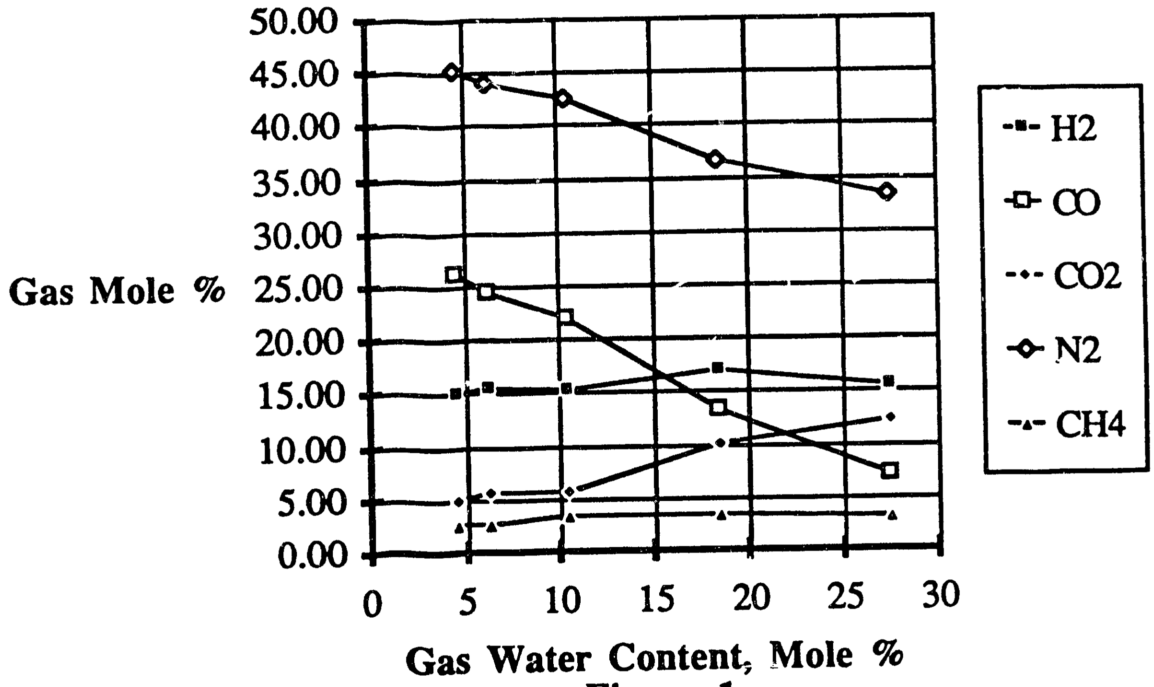

Figure 1

Initial cost assessments indicated that the smallest plant size was going to be uneconomical due to the relatively high equipment and development costs with respect to power output. It should be noted, however, that the smallest plant also potentially had the highest efficiency. The GE/LM 5000 PC which was selected for the 50 MWe case was then reconsidered as a fully Steam Injected Gas Turbine (STIG) configuration. In this mode it was initially expected that the lower cost of eliminating the steam turbine and higher power output would improve its overall cost effectiveness. It was found that due to the high mass flows of the low BTU coal gas to the turbine combustor, the machine was steam input (hence power output) limited by surge margin limitations (3) of its manufacturer. This was especially true when high steam flows to the gasifier were needed. This limitation prompted the consideration of the use of water to the booster compressor inlet in lieu of steam to the gasifier.

The perception that cogenerators and Independent Power Producers (IPP's) are not likely to to be interested in CGIA due to its high costs in the smaller size ranges of interest to them, combined with the realization that utilities are currently mandated [4] to reduce emissions from their largest coal fired power plants, suggests that utilities will evaluate all available technological solutions, and will find the added MWe output from CGIA an attractive alternative to IPP's for their load growth needs.

As previously stated in Section 4, a comparison of the CGIA scheme with retrofit wet limestone scrubbers revealed that the "N'th" CGIA plant is less costly to install than the wet scrubber system on an evaluated basis. Such considerations as the comparative cost of the wet scrubber retrofit, a capacity credit for the additional MWe produced with the more efficient CGIA system, and an additional capacity credit for the additional parasitic power load attendant with the wet scrubber system all combined to favor the CGIA approach.

The operating costs (Table 1) reveals that the CGIA scheme has a lower fuel cost per kwhr consistent with its greater efficiency than the original coal fired power plant. The itemized per kwhr cost of the wet scrubber is automatically increased by 3% since it uses up 3% of the plant's input energy in parasitic power draw. In addition, the wet scrubber also suffers from the cost of limestone sorbent,

Table 1

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291)		GE7191F	J-1538
Date:	Feb-91	by:	RSS
Plant Size Studied (MWg)	240	(MWn)	223
"N"th Coal Fired Turnkey Constr Cost ($/KWg)	1081	($/KWn)	1,163
	Calculated 10 Yr Levelized Operating Costs (mils/kwh)		
Coal,Sorbent,Residue Disp.,SO2 Recov.,Catal.	17.22		
Opn. Labor,O&M Premium,G&A,Insur&Taxes	7.22		
Maint.,Equip.Res.,Util.,Consumables,Misc.	4.71		
TOTAL OPERATING COSTS	29.15		
PLANT COST INCL CONTINGENCIES	28.73		
TOTAL COST OF ELECTRICITY (COE)	57.88		

higher water consumption, and waste disposal. The CGIA is substantially credited for its elemental sulfur, sulfur dioxide, or sulfuric acid byproducts.

Additional benefits of the CGIA system include a reduction in total water utilization of the original coal fired plant in contrast to a significant increase in water consumption for the wet scrubber scenario. Also, the condenser/cooling tower capacity is sufficient to accommodate the flow from the additional low pressure steam turbine.

Additional efforts to develop a least cost strategy for ultimate sulfur recovery from the concentrated HGCU regeneration loop bleed SO_2 stream (Appendix G) focused on the direct sulfur recovery process (DSRP), a ReSOx (TM of Foster Wheeler Energy Corp.) process substituting gasifier ash carbon for anthracite, a scaled down sulfuric acid manufacture plant (H_2SO_4), and direct recovery of liquid sulfur dioxide (DRLSO2).

The (DRLSO2) approach was selected as the optimum short term sulfur recovery strategy. This selection was the result of a combination of favorable installation cost effectiveness coupled with current high market prices for liquid SO_2. We suspect the price advantage of liquid SO_2 is due to its broader market usefulness in contrast to either elemental sulfur or sulfuric acid (recognizing H_2SO_4 demand far outweighs any other market use).

At present, liquid SO_2 is used commercially in the pulp and paper industry for sulfite pulping, and is used as an intermediate for on-site production of bleaches. A substantial merchant market for sulfur dioxide is used in the production of chlorine dioxide at the mill site by the reduction of sodium chlorate in sulfuric acid solution and also in the production of sodium dithionite by the reaction of sodium borohydride with sulfur dioxide. It is also used for stabilization of pulp brightness after hydrogen peroxide bleaching.

In food processing, sulfur dioxide has a wide range of applications as a fumigant, preservative, bleach, and steeping agent for grain and dried fruits. It is also used in wine making to selectively destroy undesired bacteria, molds, and wild yeasts. In molasses manufacture, sulfur dioxide is used for bleaching and microbiological growth prevention. In making fructose corn syrup, sodium bisulfate from SO_2 is added to the enzymatic isomerization step to prevent undesired microbial action. Corn syrups in the United States usually contain 15-40 ppm of sulfur dioxide. The high fructose corn syrup sweetener is an expanding market. The largest producers are indigenous to the mid-west USA, thus they are in close proximity to many coal fired utility plants.

In water treatment, SO2 is used to reduce residual chlorine from disinfection and oxidation. This technology is used in potable water treatment, sewage treatment, and industrial waste water treatment.

In the petroleum industry, SO2 is used as an oxygen scavenger to prevent corrosion. Sulfur dioxide acts as a catalyst modifier in certain processes for oxidation of o-xylene or naphthalene to phthalic anhydride.

In mineral technology, SO2 is used as flotation depressants for sulfide ores. In electrowinning of copper from leach solutions from ores containing iron, SO2 prereduces ferric to ferrous ions to improve current efficiency and copper cathode quality. Sulfur dioxide also initiates precipitation of metallic selenium from selenous acid, a by-product of copper metallurgy.

While this liquid sulfur dioxide market advantage may be only short term, nevertheless, it currently exists. This may be a distinct advantage for the first to N'th GCIA facility. Eventually, the market demand for SO2 may not be sufficient to support the supply (assuming CGIA plants 2 through N all produce liquid SO2). Ultimately, the greater sulfuric acid market will likely mandate that form of sulfur recovery. Since the greatest cost concern revolves around CGIA plants 1 to N, the current economic advantage of the liquid SO2 market is used in the economic analyses in this report, while the equipment list has been expanded to include that which is needed to produce sulfuric acid.

6.3. Standardized Module Design & Performance Concept

It is essential within the guidelines of this study that the CGIA concept be considered mature with an "N'th" plant cost structure. This consideration, however, begs the question as to how and when the technology will reach such maturity. In order to provide for an assumed "fast track" to maturity, this study will also assume that the CGIA concept is so well thought out that it can be completely reduced to a pre-engineered "standard design". There is significant precedence for such a presumption. Such entrepreneurial cogeneration and independent power producer companies as Cogentrix, Inc., have taken the standard plant concept to successful fruition utilizing mature stoker coal plant technology. Their results typify the cost savings potential [10] of mature standardized systems as described by EPRI's Technical Assessment Guide (TAG). A finalized design, as might be expected for a standard plant requires much less contingency than a simplified (one of a kind) design. Based upon the success of IPP's as described above, standard "N'th" plant complete modular replicative designs may save 40% of project capital cost of one of a kind plants.

An example of the potential cost effectiveness of this concept can be seen in Figure 2. In the example, an ash silo baghouse fan motor is either specified as a standardized piece of equipment which can be purchased with quantity discounts. It will produce a considerable savings in contrast to the individual plant design process which individualizes every ash silo baghouse fan motor resulting in multiple cost markups from sub-vendor to sub-vendor.

From the performance perspective, the CGIA concept lends itself to shop fabrication in 14 foot diameter truck shippable sizes. Irrespective of whether applied to aeroderivitive or stationary frame designs of combustion turbines, the gasification island can be designed for 600 psig and operated at whatever pressure is consistent with the particular combustion turbine's pressure ratio requirement. Since the system requires a booster compressor, it can be designed to overcome the coal gasification and hot gas cleanup island's system resistance to be compatible with any conceivable combustion turbine.

6.3.1. 50 MWe STAG Cogeneration/IPP CGIA Design

6.3.1.1 STAG

This configuration utilizes a GE LM5000PC aeroderivitive combustion turbine with an unfired heat recovery steam generator (HRSG) at 600 psig/650F. It generates 34 MW from the Brayton cycle, plus 14 MWg from the Rankine cycle (11). Accounting for an estimated 3 MWe system parasitic power used, its net power generation output is approximately 45 MWn.

Plant Standardization Concepts

Example:

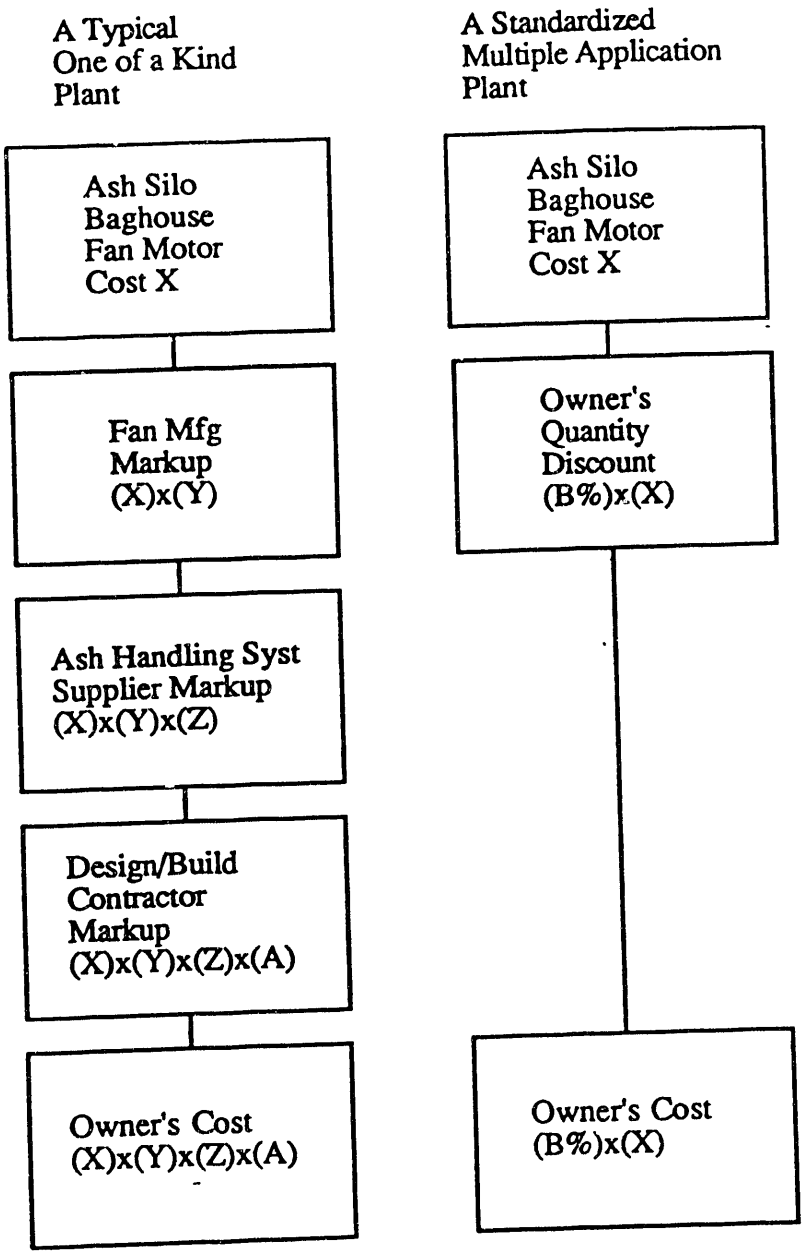

Figure 2

6.3.1.2 STIG

An alternative STIG configuration utilizes a GE LM5000PC aeroderivitive combustion turbine with an unfired heat recovery steam generator (HRSG) at 600 psig/650F, but without a steam turbine/generator. All steam generated is injected either into the high pressure compressor, combustor, or into the low pressure section of the expander. It generates 49 MWe, all from the Brayton cycle. Accounting for an estimated 3 MWe system parasitic power used, its net power generation output is approximately 46 MWn.

6.3.1.3 Cost Sensitivity

This smallest of the plant configurations is the most costly per unit of power output. For this reason, the consideration of the STIG configuration seemed to be a logical way to save on system cost by eliminating the steam turbine/generator. In addition, a simplified less costly coal receiving system, typical of smaller cogeneration and IPP configurations was utilized in the design. In spite of such efforts to lower the total plant costs, it appears this size CGIA concept will be most difficult to justify based on the results of the economics of this study.

The consideration of a STIG configuration improved the overall plant economics, but, even this arrangement is limited by combustion turbine surge margins. As a result, the configuration could not be operated at maximum power output even when water injection upstream of the booster compressor was utilized in an effort to reduce steam flow to the gasifier and subsequently to the combustion turbine's expander.

6.3.2 100 MWe STAG Cogeneration/IPP CGIA Design

6.3.2.1 STAG

This configuration utilizes a GE 7111EA combustion turbine with an unfired heat recovery steam generator (HRSG) at 1265 psig/935F. It generates 84 MW from the Brayton cycle, plus 47 MWg from the Rankine cycle. Accounting for an estimated 10 MWe system parasitic power used, its net power generation output is approximately 121 MWn.

6.3.2.2 Utility Configuration

An alternative STAG configuration utilizes a GE 7111EA combustion turbine with an unfired heat recovery steam generator (HRSG) at 1265 psig/935F. It generates 84 MW from the Brayton cycle, plus 48 MWg from the Rankine cycle. Accounting for an estimated 10 MWe system parasitic power used, its net power generation output is approximately 122 MWn.

6.3.2.3 Cost Sensitivity

This configuration was considered large enough to necessitate a unit train coal receiving system, and its Rankine cycle operating conditions was somewhat limited by its unfired HRSG configuration and relatively low turbine exit gas temperatures. As a consequence, it is also economically marginal for serious consideration in contrast to more conventional systems.

6.3.3. 200 MWe STAG Cogeneration/IPP, Utility CGIA Design

6.3.3.1 STAG

This configuration utilizes a GE 7191F combustion turbine with an unfired heat recovery steam generator (HRSG) at 1465 psig/1000F/1000F. It generates 150 MW from the Brayton cycle, plus 86 MWg from the Rankine cycle. Accounting for an estimated 16 MWe system parasitic power used, its net power generation output is approximately 220 MWn.

6.3.3.2 Utility Configuration

An alternative STAG configuration utilizes a GE 7191F combustion turbine with an unfired heat recovery steam generator (HRSG) at 1465 psig/1000F/1000F. It generates 150 MW from the Brayton cycle, plus 89 MWg from the Rankine cycle. Accounting for an estimated 16 MWe system parasitic power used, its net power generation output is approximately 223 MWn.

6.3.3.3 Cost Sensitivity

This configuration resulted in a cost effective CGIA system as shown in Figure 3. At 4.5¢/kWh to 6¢/kWh, such a system would be very economical in many parts of the US today. Tables 2a through 2f identify the detailed cost breakdown for the 200 MWe size CGIA concept starting with known combined cycle plant costs and integrating the necessary coal and coal gasification systems.

6.3.4 Utility Industry Applications

6.3.4.1 Retrofit/Repowering

There is solid justification for the consideration of the addition of CGIA systems to existing coal fired utility plants. The majority of the most costly of the capital cost items of the power plant already exist. These include coal receiving/handling/storage/reclaim, water sourcing/purification/treatment/disposal, electricity generation/conditioning/distribution, and the most costly of all, the boiler island itself. Unlike other repowering strategies which require replacement of the boiler island, this study presents a way to simply add on the IGCC system to the existing coal plant with minimum modification to the existing infrastructure. The result is an approximate 20% increase in power output while reducing the plant's stack gas emissions by well in excess of 90% for SO2, NOx, and particulates.

Figure 3

Plant Cost Sensitivity GE7191F

223 MWe CGIA, N'th Plant

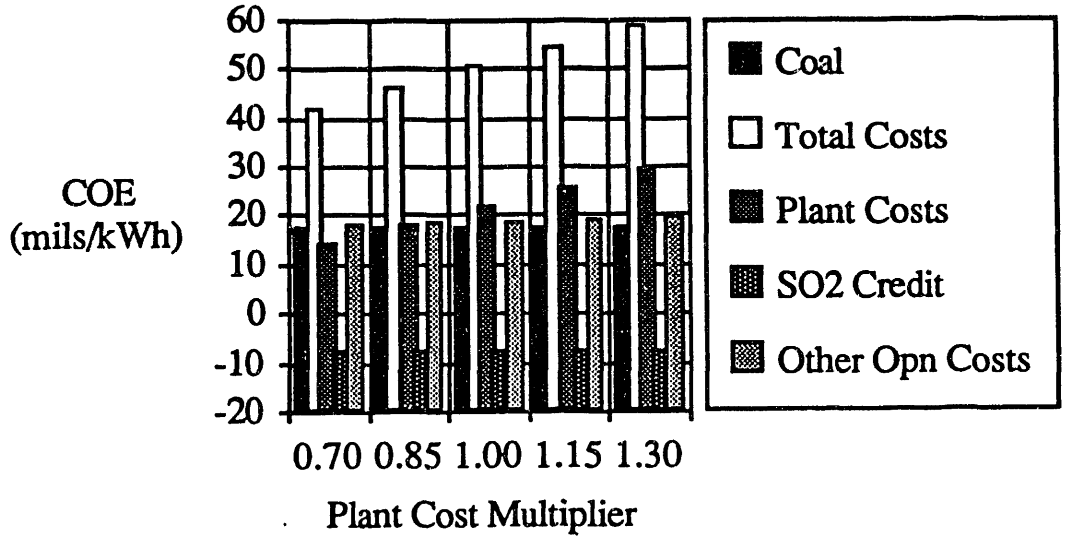

Table 2a

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date:	Feb-91	by:	RSS
Plant Size Studied (MWg)	240	(MWn)	223
"N"th Coal Fired Turnkey Constr Cost ($/KWg)	954	($/KWn)	1027

System Description: 1-Stage Dry Bottom Fixed Bed Coal Gasifiers, ZnFe Moving Bed (GE type)
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)

Number Trains & Section Description	Total Flow & Units	1st Plant SectionCost, ($)	N-th Plant Section Cost, ($)	N-th Learning Reduct (%)	N-th Plant Cost ($/kwn)
1 ea, Coal Handling	28800TPD	11,865,859	11,865,859	0	53
1 ea, Briquetting System	4800 TPD	7,775,283	6,220,226	20	28
8 ea, Gasification & Ash	164 - lb/sec	32,947,566	26,358,053	20	118
4 ea, Hot Gas Cleanup System (GE type)	164 - lb/sec	19,991,070	11,994,642	40	54
1 ea, Gas Turbine	GE7191F	48,590,000	38,872,000	20	174
1 ea, HRSG, (Includes CO Catalyst & SCR)	111 - lb/sec	17,356,847	17,356,847	0	78
1 ea, Steam Turbine	91 MWe	22,041,760	22,041,760	0	99
4 ea, Booster Compressor	111 - lb/sec	5,666,100	5,666,100	0	25
1 ea, Sulfur Dioxide Recovery Proc (SO2RP)	9 K - lb/hr	9,573,649	5,744,189	40	26
Sub-total		175,808,134	146,119,676		655
BalanceofPlant(% sub-t w/out proc conting)	36%	62,789,676	37,673,806	40	169
TOTAL PROCESS CAPITAL		238,597,810	183,793,482		824
Fully Standardized Designed N'th Plant			143,158,686	40	642
Engineering (Only)	8%				
Engineering (Contractor's) Fees	21%	49,332,144	29,599,286	40	133
(Incl Proj&ConstMgt, Testing/Startup, Design/Build Contr Fees, but NOT Opn, Data Col & Rptg, Admin, Dspsn) (%ofTotal Process Capital)					
Project Contingency (%ofTotal Process Capital)	13%	31,017,715	18,610,629	40	83
TOTAL PLANT INVESTMENT		318,947,669	191,368,601		858
Allowance for Funds During Construction, (AFDC)	13%	30,095,000	18,057,000		81
WorkCap,Taxes,Royal,Devel,Permits,Legal, Fuel Inven, Spare Parts, Underwriter Costs	10%	23,223,371	17,333,223		78
Land(HistoricalSiteCostsforCo-generation)	0.7%	2,091,000	2,091,000		9
Acreage @ $8,500 per Acre = 246					
TOTAL CAPITAL REQUIREMENT		374,357,040	228,849,824		1,026

Table 2b

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: 2/5/91 by: RSS

Plant Size Studied (MWg) 240 (MWn) 223

TypicalGasFiredTurnkeyConstrCost($/KWg) 548 ($/KWn) 590

	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
COGENERATION SYSTEM GROUP INCLUDING STRD CONTROLS, ELECTRICAL, BLDG, CIVIL, STRUCT, ARCHETEC, MECHAN					
Gas Turbine/Gen Syst(Incl Cogen Plt I&C)	$27,000,000				
Steam Turbine/Generator System	$16,955,200				
StartUp&BackupFuel(NatGas)PrepSystem	$1,650,200				
Condenser & Vacuum Systems	$1,228,150				
TURBINE ISLAND	$46,833,550	$11,609,121	$58,442,671	262	18
Aux Blr for Startup/Emerg PwrGen (Optional)	$0	$0	$0		
HtRecovSteamGenerator(w/COCatyl&SCR)	$12,707,000	$3,541,673	$16,248,673		
HRSG Ductwork & Stack (Incl)					
BOILER ISLAND	$12,707,000	$4,649,847	$17,356,847	78	5
Cooling Tower					
Evaporative Makeup,Circ Water,&AuxSys					
SUB TOT COOL'G TWR SYST	$1,770,450	$241,000	$2,011,450	9	0.6
Raw Water Well, Pumps,Fire Prot System					
Demineralizer, Treatment & Storage					
Treated Water Pumping & Control					
CondensateRet,WaterChem,Filtr,StorTanks					
Chem Treat & Cooling Systems					
Feed Water Heaters&Deaerator					
FEEDWATER & WATER TREATMENT SYST	$5,697,650	$1,435,856	$7,133,506	32	2
Generation Plant Electrical System (Incl)					
Sub Station,X-fmrs,Switchyard (Incl)					
and Balance of Plant Electrical	$10,253,000				
Power Transmission Lines	$1,100,000	$821,486			
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$11,353,000	$5,290,793	$16,643,793	75	5
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions Monitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$4,744,200	$1,347,595	$6,091,795	27	1.8
BUILDINGS (Contr Rm,Lav,HVAC,CompAir)	$1,623,200	$725,463	$2,348,663		
PAINTING/INSUL/LAGG'G/SCAFFOLDING	$352,800	$103,330	$456,130		
COGENERATION SYST SUB TOTAL	$85,081,850	$25,403,005	$110,484,855	495	34
ADD. DESIGN ENGINEERING@8%	$8,838,788		$8,838,788		
ADD. PROJECT MANAGEMENT@3%	$2,209,697		$2,209,697		
ADD. CONSTRUCTION MGT@3%		$3,314,546	$3,314,546		
ADD. TEST'G @1% (2% test&strtup)	$1,104,849		$1,104,849		
ADD. START UP COSTS @1%	$1,104,849		$1,104,849		
ADD. DES/BUILD CONTR'S FEE@7%	$4,419,394		$4,419,394		
SUB TOT INDIRECT COSTS	$17,677,577	$3,314,546	$20,992,123	94	6
SUB TOTAL COGENERATION TURNKEY CONSTRUCTION COST	$102,759,427	$28,717,551	$131,476,978	590	40

Table 2c

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: Feb-91 by: RSS

Plant Size Studied (MWg) 240 (MWn) 223

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,081 ($/KWn) 1,163

COAL GASIFICATION ADDERS	Equipment ($)	Installation ($)	Total ($)	($/KWn)	Per Cent ofConst$ (%)
Coal Rail Spur					
Coal Receiving, Storage & Handling System					
Coal Fines Briquetting System	$8,328,713	$3,537,146	$11,865,859	53	4
Mobile Equip(2-B'dozers,Fr Loader,LiftTrk)					
SUB TOTAL COAL FACILITIES	$14,227,062	$5,414,080	$19,641,142	88	6
COMBUSTOR MOD. for COAL GAS FIRING	$4,400,000	$2,272,500	$6,672,500	30	2
AIR HANDLING FLOW MODULE	$5,454,000	$1,363,500	$6,817,500	31	2
BOOSTER COMPRESSOR&INTERCOOLER	$5,302,500	$363,600	$5,666,100	25	2
ADDITIONAL PROCESS WATER SYSTEM	$909,000	$276,725	$1,185,725	5	0.3
HighPressureAir&GasDuctwork&Cyclones,					
Coal Feed & Lock Hopper Systems (Incl)					
Gasifiers (Lurgi Mark IV Comparable)					
Ash Handling Lock Hopper System (Incl)					
Grate, Leveller, & Stirrer Drives (Incl)					
GASIFIER ISLAND	$44,355,184	$20,566,176	$64,921,360	291	20
HOT GAS CLEANUP UNIT(GE ZNFeSyst)	$10,630,000	$7,959,477	$18,589,477	83	6
ZnFe Outlet Gas Cyclones & Ductwork					
Regeneration Compressor & Heat Exch					
SO2 Recovery Plant	$6,064,000	$3,509,649	$9,573,649	43	3
SulfurCondensateHandling,Storage&Loadout,					
Catalyst Conveying & Loadout (Incl)					
ZincFerriteSorbentConveying&Storage(Incl)					
FLUE GAS CLEANUP SYSTEM AUXILIARIES	$1,092,118	$309,475	$1,401,593	6	0
Bottom Ash Handling System					
Ash Storage Silo & Outloading System (Incl)					
SUB TOTAL ASH HANDLING SYSTEM	$764,621	$267,549	$1,032,170	5	0.3
High Pressure Interconnect'g Piping					
Interconnecting Coal/Sorb System Piping					
Additional Fire Protection Pumps/Piping					
Additional Plant Air Compressors/Piping					
Add'l Instru Air Compressors,Filters/Piping					
SUB TOT ADDITIONAL PIPING SYSTEMS	$1,997,447	$3,918,363	$5,915,810	27	2
Gasification Syst Excav, Fdns, & Backfill					
Gasification System Roadways/ Parking					
Rail Spur to Cogeneration Plant (1,100 ft)					
Gasification Syst Site Drainage/Leach Field					
SUB TOT ADDITIONAL CIVIL WORK	$1,362,206	$4,866,792	$6,228,998	28	2
SUB TOT ADDITIONAL BUILDINGS	$1,969,500	$636,300	$2,605,800	12	1
Generation Plant Electrical System (In Strd CC System)					
Sub Station,X-fmrs,Switchyard (In Strd CC System)					
Gasification System Electrical					
SUB TOT ADDITIONAL ELECTRIC SYSTEM	$2,231,595	$1,515,000	$3,746,595	17	1
Distrib'tdContrSyst(DCS),CentrCntrlFacility					
Emissions&GasQualityMonitors(Additional)					
INSTRUMENTATION&CONTROL SYSTEMS	$3,711,750	$1,515,000	$5,226,750	23	1.6
ADD.INSUL/LAGG'G/PAINT/SCAFFOLD'G	$492,375	$1,401,375	$1,893,750	8	0.5
COAL GASIFIC'N EQUIP ADDERS	$117,852,872	$56,155,561	$161,118,919	723	49

Table 2d

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: 2/5/91 by: RSS

Plant Size Studied (MWg) 240 (MWn) 223

1st Project Turnkey Cost ($/KWg) 1,081 ($/KWn) 1,163

	Equipment	Installation	Total	($/KWn)	Per Cent of Const$ (%)
ADD. DESIGN ENGINEERING@8%	$12,889,514				
ADD. PROJECT MANAGEMENT@3%	$4,833,568				
ADD. CONSTRUCTION MGT@3%					
ADD. TEST'G @1% (2% test&strtup)	$1,611,189				
ADD. START UP COSTS @1%	$1,611,189				
ADD. DES/BUILD CONTR'S FEE@7%	$11,278,324				
SUB TOT ADDIT. INDIRECT COSTS	$32,223,784	$2,891,262	$35,115,046	157	11
SUB TOT COAL GASIFICATION TURNKEY CONSTRUCTION COST	$252,836,083	$87,764,374	$327,710,943	1,470	100

Table 2e

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: 2/5/91 by: RSS

Plant Size Studied (MWg) 240 (MWn) 223

1st Project Turnkey Cost ($/KWg) 1,081 ($/KWn) 1,163

	Total	($/KWn)	Per Cent of Const$ (%)
OWNERS COSTS	$2,091,000	9	
Site	$661,740	3	
Development	$4,356,000	20	
Working Capital	$1,267,364	6	
Permits	$70,897	0	
Legal Fees	$3,267,000	15	
Taxes & Royalties	$2,671,000	12	
Fuel Inventory	$4,059,000	18	
Spare Parts	$34,254,000	154	
Interest During Construction	$9,422,520	42	
Underwriters' Costs			
CONTINGENCY & RISK (@ % OF TOTAL PROCESS CAPITAL STATED BELOW) 13.00%	$35,308,491	158	
SUB TOTAL OWNERS COST	$97,429,012	437	
INSTALLED PROJECT TOTAL	$425,139,955	1,906	N/A

Table 2f

IGCC Plant Costing, J-1538, (DE-AC21-89MC26291) GE7191F Project No. J-1538

Date: Feb-91 by: RSS

Plant Size Studied (MWg) 240 (MWn) 223

"N"th Coal Fired Turnkey Constr Cost ($/KWg) 1,081 ($/KWn) 1,163

MWn 223

	Calculated 10 Yr Levelized Operating Costs (mils/kwh)
Coal Plus Oil/Gas for Strt/Emrg	17.74
ZnFe,NOx,CO,DSRP Catalysts	6.44
Residue Disposal	0.77
Operating Labor+O&M Guar Premium+G&A	4.03
Insurance & Local Taxes	3.19
Maintenance & Equip Reserves	4.16
Util.&OperatingConsumables(NoAuxPwrIncl)	0.47
Other (Miscellaneous)	0.08
SO2 Recovery Plant	-7.73
TOTAL OPERATING COSTS	29.15
PLANT COST INCL CONTINGENCIES	28.73
TOTAL COST OF ELECTRICITY (COE)	57.88

6.3.4.2 New Utility Applications

New utility applications will be more economical than retrofitted installations due primarily to the ability to employ low Btu gas fired HRSG's of the "Ranch" style since a coal fired boiler design is not necessary to burn such coal derived gas. Such boiler designs will easily address the 2400 psig/1000F SH/1000F RH cycle (perhaps with forced steam circulation), and such items as steaming economizers and low feed water temperatures can be designed into the system resulting in low flue gas exit stack temperatures. These designs will enjoy the ability to utilize staged firing and NOx reburning techniques, as well as provide for access to temperature regions where ammonia injection and selective catalytic reduction of NOx can be accomplished. There is little doubt that the ambitious goal of 0.1 lb/MBtu of Nox emissions is achievable with this series style application of NOx control techniques.

6.3.4.3 Cost Sensitivity

Figure 4 illustrates the economy of size associated with power plant cost per kilowatt which holds true even when relatively small modular subsystems are contemplated. Modular equipment considerations enhance plant availability, and the low cost of power production from combining the most efficient of the Brayton with the Rankine thermodynamic cycles will insure the highest dispatching and capacity factors wherever the CGIA concept is utilized.

Air-Blown Fixed Bed IGCC Plant Costs

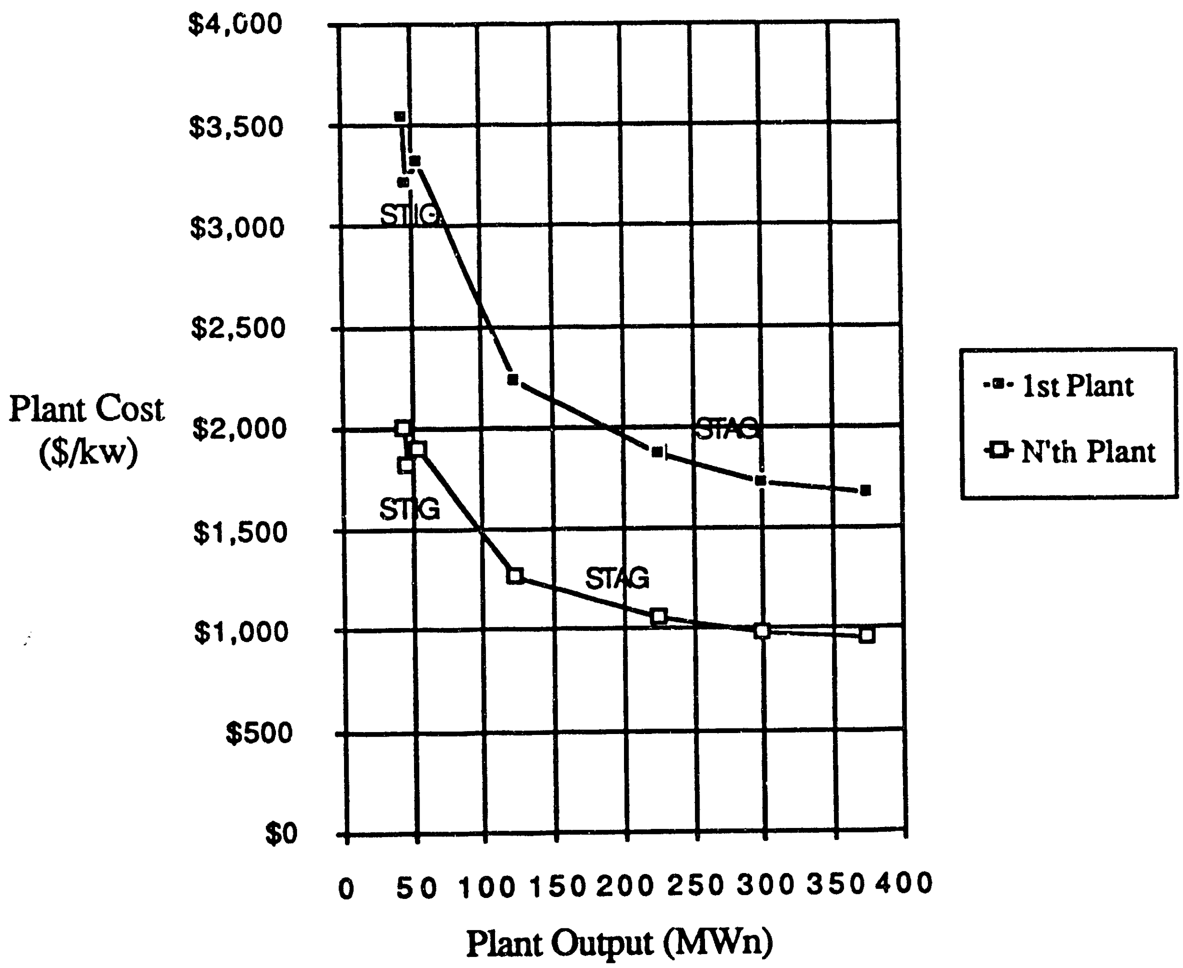

Figure 4

6.4. Independent Agency Overview & Licensing

6.4.1 The Licensing Concept

6.4.1.1 Electric Power Research Institute (EPRI)

It is proposed that an independent utility industry representative organization evaluate the CGIA concept and follow its emergence as it develops through the demonstration sized retrofitted plant, and using its own criteria, agrees to sanction the technology assuming its performance is acceptable. The developer of the CGIA technology would then merely license the technology to the utility industry through the third party (EPRI or equal). In this manner, any utility user could select the builder of the plant who would license it through the industry representative from the CGIA developer. Therefore, if utility A prefers vendor AA to build the plant perhaps because vendor AA previously had built the existing facility, vendor AA would pay a license fee through EPRI to the CGIA developer (similar to the way Lurgi licenses their gasifiers). The value of this scenario is its ability to immediately implement the CGIA concept simultaneously to all users through all qualified vendors. This maximizes CGIA utilization. As another example, a utility user who has existing Babcock & Wilcox pulverized coal fired boilers would likely prefer to have Babcock & Wilcox build the CGIA add-on facility. The utility would contract with Babcock & Wilcox, who would license CGIA technology from the EPRI and a portion of the royalty paid would flow to the CGIA developer of the standardized CGIA technology. Currently, the Lurgi Mark IV fixed-bed coal gasifier is produced in a very similar fashion. Lurgi does not build their gasifier, but rather, licenses it to users through a third organization who actually builds them under license. Although agencies like EPRI normally develop technologies and license them to suppliers, such organizations possess the appropriate expertise to evaluate and sanction useful technologies developed by others, especially where the products developed were made available to all suppliers and users alike.

6.4.1.2 Alternative Agency Considerations

Although EPRI would be a logical selection for the duty of sanctioning and licensing because they are the research and development arm of the entire utility industry in this country, the Edison Electric Institute (EEI), Association of Edison Illuminating Companies (AEIC), and American Public Power Association (APPA) are all capable of providing such a service although understandably, their charters might not currently contemplate such a function.

6.4.2 The Opportunity Window

It is believed that there currently exists an opportunity window which is not likely to present itself in the future. Some one hundred and seven (107) of the nation's largest coal fired utilities are presently being mandated to clean up their emissions from their existing facilities. This new policy has resulted in the utility industry giving new consideration as to how best to accomplish the desired end. Such potential strategies as wet scrubbers, dry scrubbers, atmospheric fluid combustion boilers, pressurized fluid combustion boilers, oxygen-blown integrated gas combined cycles, and others are all likely to be given consideration. Since the CGIA concept has so many desirable features to include low cost, it would be the concept of choice except for the fact that it is not mature enough for immediate commercialization. Any course chosen for the development of the CGIA concept must consider the present urgency of need. A great number of commercialization opportunities will be lost before and until the concept can be accelerated through development into a much needed mature state. Further development of a detailed standardized plant design should be immediately undertaken.

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