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FUEL GAS CLEANUP PARAMETERS IN AIR-BLOWN IGCC

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ABSTRACT

Fuel gas cleanup processing significantly influences overall performance and cost of IGCC power generation. The raw fuel gas properties (heating value, sulfur content, alkali content, ammonia content, "tar" content, particulate content) and the fuel gas cleanup requirements (environmental and turbine protection) are key process parameters. Several IGCC power plant configurations and fuel gas cleanup technologies are being demonstrated or are under development. In this evaluation, air-blown, fluidized-bed gasification combined-cycle power plant thermal performance is estimated as a function of fuel type (coal and biomass fuels), extent of sulfur removal required, and the sulfur removal technique. Desulfurization in the fluid bed gasifier is combined with external hot fuel gas desulfurization, or, alternatively with conventional cold fuel gas desulfurization. The power plant simulations are built around the Westinghouse 501F combustion turbine in this evaluation.

INTRODUCTION

Various forms of coal and biomass gasification combined-cycle (IGCC) power generation are currently being demonstrated throughout the world to establish the general technical and economic viability of the technologies (EPRI, 1995; EPRI, 1996; Bridgwater and Boocock, 1997). These demonstration projects are applying variations in several major process parameters:

- entrained (single and two-stage), fluid bed, and fixed bed gasification,
- oxygen- and air-blown gasification,
- fuel gas cooling techniques (quench, indirect steam generation)
- conventional cold fuel gas cleaning, and advanced hot fuel gas cleaning,
- combustion turbine type, firing conditions and equipment adaptations,
- air separation integration and steam integration alternatives.

Coal- and biomass-derived fuel gases must be cleaned to meet power plant environmental requirements (SOx, NOx, and particulate emissions) and to satisfy turbine protection specifications (particulate, alkali vapors, several metals). It has been demonstrated that conventional cold fuel gas cleaning techniques can meet both of these requirements. Two Westinghouse 501Ds were operated at the Dow Chemical, Plaquemine, Louisiana coal gasification plant (predecessor to Destec gasifier) starting in 1987. The cold fuel gas cleaning system on this oxygen-blown, entrained gasifier met Westinghouse turbine specifications and resulted in more than 125,000 hours of operation of the turbines with greater than 95% availability.

Cold fuel gas desulfurization systems, operating at about 38°C (100°F), have improved their performance and reduced operating costs by adding a hot gas filter operating at 300 to 540°C (570 to 1000°F) to remove particulates before the fuel gas is desulfurized (Zon, 1996; Breton and Stultz, 1996). Hot fuel gas desulfurization, operating at 430 to 540°C (800 to 1000°F) has also been developed because of its potential improvements in overall power plant efficiency. Hot fuel gas cleaning systems (zinc-based regenerative sorbents) are being demonstrated in U.S. Clean Coal Technology programs (Demuth, 1996; Black and McDaniel, 1996).

While hot fuel gas cleaning is expected to provide thermal performance advantages over conventional cold fuel gas cleaning, there currently exists limited understanding of the magnitude of their relative merits and the influence of key fuel and process parameters. Westinghouse has conducted previous studies to assess the integration and performance of IGCC with

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their fleet of combustion turbines (Newby et al., 1995; Newby et al., 1996; Bannister et al., 1996; Yang et al., 1997). This paper describes IGCC sulfur removal considerations for an air-blown, fluidized bed gasification process coupled with a Westinghouse 501F combustion turbine, and assesses the estimated power plant performance results as a function of several fuel properties and sulfur removal parameters.

IGCC GAS CLEANING/ SULFUR REMOVAL PROCESS OPTIONS

In air-blown, fluidized bed gasification of coal, it has been demonstrated that bulk fuel gas desulfurization can be performed directly within the fluid bed gasifier by feeding dolomite or limestone to the gasifier, at temperatures of 815 to 1038°C (1500 to 1900°F), to sulfur removal levels as high as about 95%. The reaction conversion performance and rates have been studied extensively in the literature (Abbasian and Rehmat, 1991). The reaction solid product, CaS, must be transformed into an environmentally stable solid waste by oxidation to $CaSO_4$, or by conversion to some other stable product (Katta et al., 1994). The use of dolomite or limestone in the fluid bed gasifier has the added benefits of increasing the carbon gasification rate, reducing the carbon content of the gasifier ash, and reducing the content of tars and other higher hydrocarbons in the raw fuel gas.

Downstream of the gasifier, the fuel gas can be cooled to an appropriate temperature for second-stage, or polishing desulfurization within an external fuel gas cleaning system. Second-stage desulfurization can be performed by using a commercial, cold gas desulfurization process operating at about 38°C (100°F), or an advanced, hot gas desulfurization process operating at about 540°C (1000°F). The commercial, cold gas desulfurization process is preceded by a hot gas filtration device that removes nearly all of the particulate from the fuel gas. Other fuel gas cleaning functions, such as HCl removal and hydrolysis, are also integrated into the cold fuel gas cleaning process. The advanced, hot fuel gas cleaning processes use regenerable solid sorbents based on zinc oxide combined with other metal carriers (e.g., various forms of zinc titanate, or commercial Z-Sorb® - Phillips Petroleum Co.). Other gas cleaning functions, such as HCl removal might also be performed in the process to enhance the durability of the regenerative desulfurization sorbent. The hot fuel gas desulfurization may be either preceded by a hot gas filter or followed by a hot gas filter depending on the nature of the desulfurizer process. Fluid bed, transport bed, and moving bed forms of the desulfurizer have been under development and are currently being demonstrated. Alternative hot fuel gas regenerable sulfur sorbent types continue to be developed (DOE, FETC Contractors Conf., 1997).

Thus, it is possible to conceive of several fuel gas desulfurization schemes for fluid bed gasification that might be applied to IGCC depending on the coal sulfur content and the level of desulfurization required in the power plant. Five of these schemes are illustrated in Figure 1:

1. bulk desulfurization within the gasifier only
2. bulk desulfurization within the gasifier followed by second-stage, hot fuel gas regenerative desulfurization
3. bulk desulfurization within the gasifier followed by second-stage, conventional cold fuel gas desulfurization
4. external, hot fuel gas regenerative desulfurization only
5. external, conventional cold fuel gas desulfurization only.

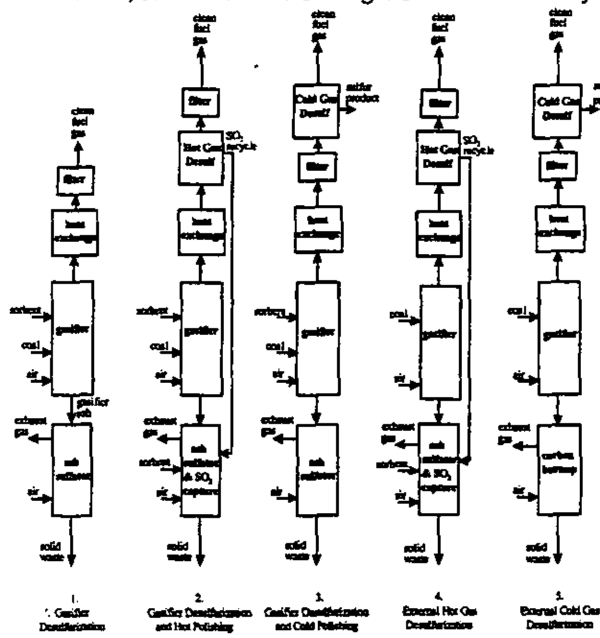

Figure 1. Process Schematics for Alternative IGCC Sulfur Removal Approaches

The figure shows only the main process steps, and the main inlet and outlet steams for each scheme. The functions of the gasifier ash processing system change with each scheme and are listed in the figure. The overall sulfur removal capabilities of the first scheme, in-gasifier sulfur removal, is limited to about 95%, while the other schemes can achieve greater than 99% sulfur removal. Each scheme may have a significant influence on the air-blown IGCC power plant process complexity, availability, thermal performance and economics. These influences would be expected to differ for an oxygen-blown, fluidized bed IGCC power plant.

AIR-BLOWN IGCC PLANT PROCESS INTEGRATION

The air-blown, fluid bed IGCC consists nf the four major process sections illustrated in Figure 2: 1) the Coal/Sorbent Feeding Block, 2) the Gasification Block, 3) the Fuel Gas Cleaning Block, and 4) the Power Island. Another plant system of importance is the water treatment system. Figure 2 indicates the relationships between these sections in this air-blown IGCC process. The IGCC plant integrates these process sections in several areas:

- The Power Island's combustion turbine utilizes the fuel gas generated by the Gasification Block.
- The Power Island's combustion turbine supplies pressurized air through booster compressors to the Gasifier Block's gasifier, the Fuel Gas Cleaning Block's sorbent regenerator, and the Coal/Sorbent Feeding Block for pressurization and transport.

- The Power Island's steam bottoming power cycle supplies pressurized feed water to the Gasification Block and the Fuel Gas Cleaning Block, and intermediate pressure steam to the Gasification Block's gasifier. It subsequently receives steam at several pressure levels from the Gasification Block and the Fuel Gas Cleaning Block.
- The condensate system of the Power Island's steam bottoming cycle is integrated with the Gasification Block and the Fuel Gas Cleaning Block by serving as a heat sink for the low level waste heat generated.
- The Fuel Gas Cleaning Block provides recycle fuel gas to the Gasification Block for various solids transport needs.
- The water treatment system handles the integrated needs of the Fuel Gas Cleaning Block and the Power Island.

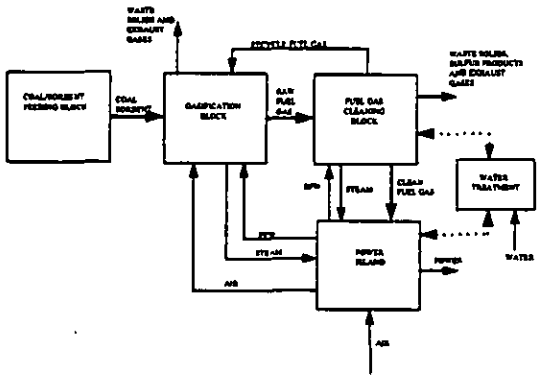

Figure 2. Air-Blown IGCC Power Plant Process Blocks

In general, sulfur removal is performed in two process steps, as in Figure 1, schemes 2 and 3. Bulk sulfur removal is first conducted within the Gasifier Block by feeding a cheap, once-through sorbent, limestone, into the fluid bed gasifier. Subsequently, polishing or second-stage sulfur removal is conducted at high temperature in the Fuel Gas Cleaning Block using an advanced, regenerative sulfur sorbent system. Polishing sulfur removal using conventional cold fuel gas cleaning is also evaluated. While the power plant process integration considerations are substantial in this air-blown IGCC power plant, they are far simpler than in the equivalent oxygen-blown IGCC power plant.

EVALUATION BASIS

The parameters in this evaluation are the fuel properties (coals and biomass), the fuel gas desulfurization scheme, and the level of sulfur removal required. The basis for the power plant simulation is described below.

Fuel Properties

The four fuels listed in Table 1 are considered in the evaluation. Three coals, a high-sulfur, U.S. Eastern bituminous coal (Pittsburgh #8), a low-sulfur bituminous Australian coal (Blair Athol), and a representative Indian lignite were considered. Also, a biomass fuel, bagasse from Hawaii was considered. Both the as-received and as-fed compositions and heating values of the fuels are listed. It is unlikely that biomass (bagasse) could be supplied in sufficient quantity for the power plant application evaluated here, and this case is simply treated as a hypothetical study parameter relating to the composition of the biomass fuel.

Table 1. Coal and Biomass Compositions

	Pgh #8 (U.S.)	Blair Athol (Australia)	Lignite (India)	Bagasse (Hawaii)
	As received (wt%)	As received (wt%)	As received (wt%)	As received (wt%)
C	69.4	74.0	48.0	29.12
H	4.5	4.5	4.0	3.10
O	6.1	5.0	12.3	23.37
N	1.2	1.7	0.6	0.25
S	2.9	0.4	2.1	0.03
Ash	9.9	9.9	8.0	3.84
Moisture	6.0	4.5	25.0	40.29
Volatile matter	35.9	29.4	36.1	48.67
Fixed carbon	48.2	56.2	30.9	7.20
LHV - MJ/kg (Btu/lb)	28.9 (12,450)	30.1 (12,950)	19.1 (8,222)	10.6 (4,580)

Fuel Gas Cleaning Parameters

The IGCC power plant utilizes the fuels listed in Table 1 while satisfying representative environmental emissions standards for modern, greenfield power plants in the U.S. relating to sulfur oxides, nitrogen oxides, particulate, solid waste, and liquid effluents. Fuel Gas Cleaning Block processes based on both advanced, hot fuel gas cleaning and on conventional, cold fuel gas cleaning were evaluated. Table 2 lists the sulfur removal performance factors applied in the evaluation as well as the sulfur removal process options considered, in Figure 1. In the biomass case, it is assumed that no sulfur removal is required. Particulate and NOx power plant stack emissions are controlled by hot gas particulate filters and dry, low-NOx combustors. The high ammonia content expected in the biomass-derived fuel gas will make low-NOx performance more difficult to achieve, and additional ammonia cracking in the fuel gas may be required. In the case of biomass, limestone is used as an inert fluid bed material, and only a small makeup for system losses is needed. The gasifier sorbent type is a representative limestone having 86 wt% calcium carbonate content. The analogous cold fuel gas cleaning performance factors are listed in Table 3. The cold fuel gas concepts are illustrated in Figure 1.

Table 2. Hot Gas Desulfurization Parametric Cases Performance Factors

	Pgh #8 (U.S.)			Blair Athol (Australia)			Lignite (India)			Bagasse (Hawaii)
Sulfur Removal Scheme	2	4	1	2	4	1	2	4	1	None
Gasifier sulfur removal (%)	90	0	95	75	0	70	90	0	95	0
Limestone Ca/S molar feed ratio	2.0	0	3.0	1.5	0	1.5	2.0	0	3.0	small makeup
Second-stage (hot) desulfurizer sulfur removal (%)	95	99.5	0	80	95	0	95	99.5	0	0
Second-stage (hot) sorbent Zn/S molar feed ratio	0.03	0.03	0	0.03	0.03	0	0.03	0.03	0	0

1: Bulk desulfurization in gasifier only
2: Bulk desulfurization in gasifier plus second-stage, hot desulfurization
4: External, hot desulfurization only

Table 3. Cold Gas Desulfurization Parametric Cases Performance Factors

	Pgh #8 (U.S.)		Blair Athol (Australia)		Lignite (India)	
Sulfur Removal Scheme	3	5	3	5	3	5
Gasifier sulfur removal (%)	90	0	75	0	90	0
Limestone Ca/S molar feed ratio	2.0	0	1.5	0	2.0	0
Second-stage (cold) desulfurizer sulfur removal (%)	95	99.5	80	95	95	99.5

3: : Bulk desulfurization in gasifier plus second-stage, conventional, cold desulfurization
5: External, conventional, cold desulfurization only

Combustion Turbine

The combustion turbine applied in this evaluation is the Westinghouse 501F. The 501F engine is a 3600-rpm heavy duty combustion turbine designed to serve the 60-Hz power generation needs. The technologically advanced engine represents one of the latest in the evolutionary cycle that continues a long line of large single-shaft, heavy duty combustion turbines (Scalzo et al., 1996). Some major 501F characteristics based on natural gas fuel are:

- Air flow, kg/s (lb/s): 436 (961)
- Number of compressor stages: 16
- Compression ratio: 14.6
- Number of combustor cans: 16
- Rotor inlet temperature, °C (°F): 1316 (2400)
- Number of turbine stages: 4
- Number of cooled turbine rows: 6
- Turbine exhaust gas flow, kg/s (lb/s): 445 (981)
- Exhaust temperature, °C (°F): 607 (1125)
- Output - simple-cycle (MW): 164
- Output - combined-cycle (MW): 260
- Efficiency - simple cycle (% LHV): 36.0
- Efficiency - comhined-cycle (% LHV): 56.8

To date, 77 of the 501F/701F machines have been sold, and the 38 units currently operating have accumulated a combined, approximate 250,000 operating hours. The longest operating 501Fs are located at the FPL, Lauderdale plant. The 4 units at this site have operation for more than 4 years, accumulating about 132,000 hours with an average reliability of 99.6% and a average availability of 94.6%.

Plant Conditions

The power plant is assumed to be a new, combined-cycle plant located at a greenfield site. It is operated as a base loaded plant. Ambient conditions were fixed at ISO conditions for the evaluation. The power plant boundaries in the evaluation encompass the entire coal and sorbent receiving, handling and preparation systems the Coal/Sorbent Feeding Block), all power plant normal auxiliaries, and the solid waste handling and storage systems.

Process Assumptions

The fluidized bed gasifier used is representative of several types being developed, such as the KRW/Kellogg fluid bed gasifier, the IGT U-Gas fluid bed gasifier, and the Rheinbraun HTW. Several aspects of the Gasification Block and Fuel Gas Cleaning Block (hot fuel gas cleaning) process flow diagrams are similar to the KRW/Kellogg process flow diagrams for the Sierra Pacific, Pinon Pine IGCC power plant (Sierra Pacific Power Co., 1994).

A process flow diagram for a cold fuel gas cleaning system used for polishing sulfur removal was developed from information available in the open literature (Biasca et al., 1987; Bechtel Group and Burns & Roe, 1983; Fluor Engineering, 1978).

The IGCC power plant was simulated on ASPEN PLUS™, a process simulator providing state-of-the-art process estimatioa capabilities for such process applications. A detailed stage-by-stage model of the 501F combustion turbine was applied in the simulation. Equilibrium gasifier behavior was assumed except for carbon conversion and sulfur removal, where empirical conversion criteria was applied.

The process and cycle conditions were not optimized in the evaluation, but acceptable conditions were selected and applied and only limited cycle variations were considered.

The gasifier assumptions in Table 4 were selected based on prior fluid bed gasifier experience with similar coals and biomass. The gasifier inputs of air, steam, and recycled fuel gas, relative to the coal feed, were selected to produce the desired gasifier temperature and reaction kinetic conditions suitable for each fuel. The range in gasifier temperatures evaluated for the bagasse fuel results from tradeoffs between carbon conversion, tar formation and cracking, and the tendency for ash agglomeration in the fluid bed. Estimates of handling/feeding, gasification and cleanup component pressure drops, heat losses, auxiliary power consumption, auxiliary fuel consumption, steam consumption and generation, etc. were made as a function the process stream rates and conditions from available process information for similar components and applications. Standard assumptions used in Westinghouse commercial cycle estimates for power island component heat losses, pressure drops, mechanical losses, efficiency factors and auxiliary losses have been applied.

Table 4. Fluid Bed Gasifier Conditions and Performance Assumptions

	Pgh #8 (U.S.)	Blair Athol (Australia)	Lignite (India)	Bagasse (Hawaii)
Gasifier temperature -°C (°F)	982 (1800)	982 (1800)	927 (1700)	760 (1400) 816 (1500) 871 (1600)
Gasifier steam rate (% of carbon feed rate)	15 - 25	15 - 25	15	5 - 10
Carbon Conversion (%)	94	94	96	95
Coal feed drying required (wt% moisture in coal feed)	None	None	10	15

The fuel gas particulate device is a ceramic candle barrier filter type. It operates at a filter temperature of 538°C (1000°F) and is designed to maintain a maximum pressure drop of 5 psi. The polishing, or second-stage hot fuel gas sulfur removal system is an advanced hot fuel gas desulfurization system using regenerative Z-Sorb® (Phillips Petroleum Co.) in a fluidized bed contactor. The steam bottoming cycle steam conditions are: 69 bar/ 510°C/ 510°C (1000 psia /950°F /950°F)

IGCC PLANT DESCRIPTION

The power plant description is built around the IGCC process with in-gasifier desulfurization and second-stage hot or cold fuel gas cleaning (schemes 2 and 3 in Figure 1). Process modifications needed for the other variations in IGCC schemes are also described (Figure 1, schemes 1, 4 and 5). It should be notes that the ASME is developing a Performance Test Code (PTC) that will define the procedures for the performance testing of gasification combined cycle plants (Bannister et al., 1997). This code will define the boundaries of the overall power plant and of the two major plant sections, the gasification block and the power island.

Coal/Sorbent Feeding Block

The equipment and processes in this block are based on dry feeding and are commercially available with significant industrial experience. The Block consists of coal/sorbent receiving and handling, coal/sorbent crushing, sizing and drying, and coal/sorbent pressurization and feeding units. The coal/sorbent receiving and handling facilities are conventional systems, which are similar to those being used in many existing coal-fired plants.

Coal and sorbent are crushed to <6.35 mm (1/4") size. Crushed and dried coal is pneumatically transported to the coal pressurization and feeding system. This system includes receiving vessels, lock hoppers and feed hoppers. The receiving vessels separate the coal from its transport gas and then transfers the coal to the lock hoppers. The pressurized coal is metered using a screw conveyor and is transported to the gasifier pneumatically using pressurized air provided by the Power Island equipment. A similar system is used for sorbent (limestone) feeding to the gasifier. It is important to include this Block in IGCC power plant performance estimates so that auxiliary power losses and auxiliary fuel consumption can be properly estimated. This block may utilize significantly different fuel feeding equipment with biomass fuel.

Gasification Block

The gasification process can handle a wide variety of fuels and produces a low-thermal-value fuel gas. A typical configuration for the Gasification Block is shown in Figure 3. It consists of the gasifier and the equipment needed for processing the gasifier waste solids (ash, char, and spent limestone sorbent).

The gasifier is a refractory-lined pressure vessel with inlet and outlet nozzles for feed gases and solids, and exit gases and solids. The gasifier also utilizes a set of recycle cyclones to maintain sufficient particle residence times in the reactor. The gasifier operating pressure is selected to satisfy the pressure requirement of the combustion turbine. Coal, limestone (sulfur sorbent), steam, air, and recycle fuel gas are fed to the fluid bed gasifier. Coal and sorbent are fed pneumatically with transport air. Sorbent is fed to the gasifier to accomplish bulk sulfur removal within the vessel. The recycle fuel gas acts as an inert gas for purges, as a transport gas for reactive solids, and as a solids stream coolant.

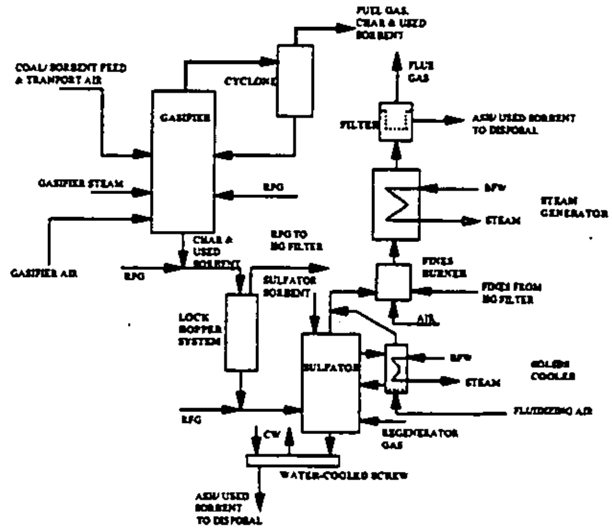

Figure 3. Gasification Block Process Schematic

The solids drained from the gasifier contain char and spent sorbent in the form of CaS that must be processed to render it environmentally acceptable. The carbon in the solid drain must also be utilized to achieve acceptable plant performance. The drained gasifier solids are depressurized and reacted in a fluidized bed reactor (the sulfator) with exhaust gas from the polishing sulfur removal system regenerator (see Figure 4). The regenerator exhaust gas contains oxygen and sulfur oxides that react with the gasifier waste solids to convert the spent sorbent into an inert forms of $CaSO_4$. The process also captures the polishing sulfur in the form of $CaSO_4$ so that normal sulfur products (elemental sulfur or sulfuric acid) need not be generated. Additional sorbent may be added to the sulfator for this purpose. Most of the carbon in the gasifier drain is also combusted in either the sulfator or in the fines burner that follows the sulfator. The flyash removed by the fuel gas filter in the Fuel Gas Cleaning Block is also recycled to the sulfator to utilize its contained carbon (see Figure 4). Steam is generated from the sulfator and fines burner exhaust gas for export to the Power Island. The temperature of the sulfator is controlled by a fluidized bed solids cooler and solids recirculation loop.

Hot Fuel Gas Cleaning Block

Figure 4 describes the Fuel Gas Cleaning Block for the hot fuel gas cleaning process. It contains a fuel gas cooler, a polishing sulfur removal system, a hot gas filter system, and a recycle fuel gas system. Each of these are briefly described.

Fuel gas cooler. The hot, raw fuel gas leaving the Gasification Block is cooled to 538°C (1000°F) in the fuel gas cooler. The design may be either a fire-tube design or a water-tube design depending on the designers preference with respect to the control of heat transfer surface fouling. High-pressure, super-heated steam is raised in the cooler.

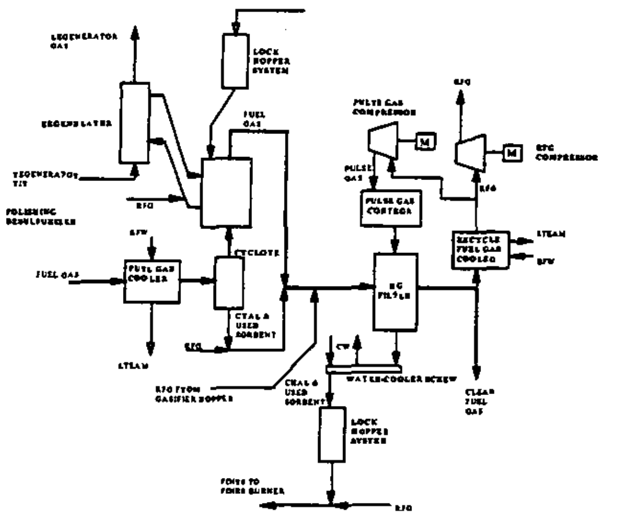

Figure 4. Hot Gas Cleaning Block Process Schematic

Polishing sulfur removal system. In Figure 4, the hot fuel gas cleaning system contains a fluidized hed desulfurizer that reacts the fuel gas H_2S with a zinc-based polishing sulfur sorbent. The polishing sorbent is circulated by dense-phase pneumatic transport to a fluidized hed regenerator. The regenerator operates at about 649°C (1200°F) and reacts air with the utilized sorbent to generate an SO_2-rich regenerator gas and a reusable sorbent. The reactions may need to be moderated by the addition of steam also. The regenerated polishing sorbent is circulated back to the desulfurizer. Makeup polishing sorbent is also added to the desulfurizer. Economics demand that the polishing sorbent losses be very small. The sorbent regenerator produces a concentrated, gaseous sulfur oxide stream that is suitable for conversion to elemental sulfur, sulfuric acid using processing similar to that used in low-temperature fuel gas cleaning. In the evaluated process, gypsum is generated for final disposition as part of the Gasification Block (Figure 3). No HCl removal, ammonia removal or hydrolysis is performed in the selected process.

Hot gas filter. The desulfurized fuel gas is passed through a ceramic filter at 538°C (1000°F) to remove particulate to levels needed to satisfy environmental and turbine protection requirements. The particulate collected in the desulfurizer cyclone, and entrained flyash from the gasifier hopper (Figure 3) are sent to the hot gas filter to improve the filter performance and to improve the process economics.

A ceramic candle filter system has been used in the evaluation. The filter system includes a pulse gas compression system that uses recycle fuel gas as the pulse gas media.

Recycle fuel gas system. A portion of the cleaned fuel gas is utilized for inert gas and transport gas purposes. It is withdrawn following the ceramic filter and is cooled and compressed to provide for this need.

Cold Fuel Gas Cleaning Block

In the cold fuel gas cleaning process diagram, Figure 5, the fuel gas is first cooled to 538°C (1000°F), just as in the hot fuel gas cleaning case. The 538°C fuel gas then passes through a ceramic filter to removal particulate. The partially-cleaned fuel gas from the filter is then cooled further, down to about 38°C (100°F), both raising steam and preheating cleaned fuel gas. The cleaned fuel gas is available at a temperature of about 41°C (105°F) and is preheated to the extent possible. The pressure drop across the gas-gas heat exchanger would be fairly large to keep the equipment compact.

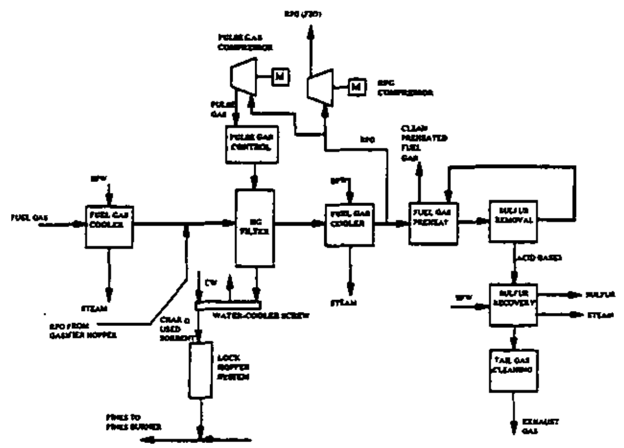

Figure 5. Cold Fuel Gas Cleaning Block Process Schematic

Typically, the fuel gas from the particulate removal unit would be routed to a catalytic hydrolyzer to convert the minor nitrogen contaminant (HCN) to NH_3 and COS to H_2S. The fuel gas would be heated before entering the hydrolyzer to the appropriate conversion temperature using medium pressure steam. No ammonia removal or hydrolysis is performed in the selected process.

In the cold fuel gas sulfur removal process, the partially-cleaned fuel gas sulfur contaminants (primarily H_2S and COS) are removal by the Selexol Process. A portion of the fuel gas carbon dioxide, about 15%, is removed as well. The partially-cleaned fuel gas enters at about 100°F, and exits at about 105°F to go to the fuel gas preheater.

The removed acid gases are treated in a conventional Claus sulfur recovery process. The Claus sulfur recovery unit is a two-stage catalytic unit where acid gases are combusted and reacted to produce salable elemental sulfur. Acid gases containing NH_3 and H_2S are combusted in the Claus furnace. NH_3 is combusted to form molecular nitrogen (N_2) and one-third of the H_2S is converted to SO_2. SO_2 and the remaining H_2S react in two catalytic stages to form elemental sulfur and water. The process generates steam for export to the Power Island.

The tail gases from the Claus plant go to a Beavon/Stretford tail gas cleaning process. In this unit, the small amount of unconverted sulfur compounds in the tail gas from the Claus unit are completely converted to H_2S. Gas from the reactor is cooled and treated for H_2S removal by absorption with solvent. The H_2S is then recycled back to the Claus sulfur recovery unit for conversion to elemental sulfur. The process consumes a small amount of auxiliary fuel provided by clean gasifier fuel gas. The process also generates a small amount of steam for export to the Power Island. The vent gas from the tail gas process contains a small content of H_2S and is incinerated before being exhausted.

<u>Process Modifications For Alternative Sulfur Removal Schemes and Biomass</u>

The Biomass fuel, bagasse, is assumed to require no desulfurization, and the process was modified to reflect this. The sulfator and external desulfurization systems were eliminated in this case, and the only fuel gas cleaning function was the hot gas filter for particulate control. At the cleanup temperature of 540°C (1000°F) the alkali vapor content of the fuel gas is expected to be acceptable for turbine corrosion specifications.

The IGCC plant descriptions presented above considered the cases where both the gasifier sulfur removal and the external, second-stage sulfur removal functions were operated simultaneously. In the alternative sulfur removal schemes considered, the following process modification were made:

- In-gasifier sulfur removal only (Figure 1, Scheme 1): the gasifier ash sulfation system was retained, hut without additional limestone feeding since no second-stage sulfur removal system was present to feed regenerator SO_2 to the sulfator. The external, second-stage desulfurization system was eliminated from the process diagram in this case.
- External sulfur remnval only (Figure 1, Schemes 4 and 5): Even though gasifier ash sulfation was not required in these cases, the sulfation system was retained as a fluidized bed reactor to burn ungasified carbon in the ash and tn capture sulfur (SO_2) from the external desulfurization regenerator as $CaSO_4$. A small makeup feed of limestone was maintained to the gasifier in this case, and limestone in sufficient amount for capturing the regenerator SO_2 in the sulfator was used.

<u>Power Block</u>

The combined cycle portion of the IGCC power plant is based upon the Westinghouse 501F combustion turbine, a three pressure level reheat heat recovery steam generator (HRSG), and a twn case, axial exhaust steam turbine. Figure 6 shows the process diagram of the combined cycle. Steam is generated in the Gasificatinn Block, the Fuel gas Cleaning Block, and in the Power Island. The high exhaust energy from the combustion turbine lends itself to a three pressure-level type HRSG system in which high pressure (HP), intermediate pressure (IP), and low pressure (LP) steam is produced. In addition, a reheat section is provided in the HRSG to improve overall cycle efficiency. The HP steam is admitted directly into the HP steam turbine element, the IP steam is admitted into the cold reheat steam header, and the LP steam is admitted directly into the IP/LP steam turbine element. The Power Island also contains the compressor equipment needed to provide gasifier air, coal/sorbent transport air, pressurization air, and regenerator air.

The heat sink for the cycle is a wet type condenser/cooling tower arrangement. The condenser design is optimized to maximize cycle performance and to allow for 100% steam turbine bypass operation.

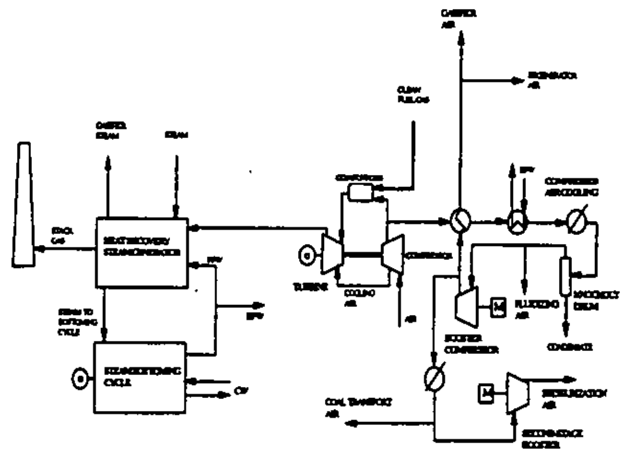

Figure 6. Power Island Schematic

IGCC POWER PLANT PERFORMANCE

The estimated clean fuel gas heating value for the four study fuels are listed in Table 5. The fuel gas composition is nearly identical for the corresponding hot fuel gas and cold fuel gas cleaning cases. The fuel gas composition estimated reflects a close approach to equilibrium at the gasifier outlet. Empirical conversion factors were also applied that relate to the approach of the water-gas-shift reaction to equilibrium, and the generation of methane, hut these had little impact on the power plant thermal performance. The fuel gas heating value (LHV) listed in Table 5 is typical of air-blown, low-thermal-value fuel gases. The fuel gas low heating-value and diluted composition allows efficient combustion with low generation of NOx when applying properly designed combustors. Over the range of conditions considered, the fuel gas molecular weight ranges from 23.7 to 25.0.

Table 5. Clean Fuel Gas Heating Value

	Pgh #8 (U.S.)		Blair Athol (Australia)		Lignite (India)		Bagasse (Hawaii)
Gas Cleaning Type	Hot	Cold	Hot	Cold	Hot	Cold	Hot
Heating Value MJ/nm^3 (Btu/scf)	5.4-5.8 (145-157)	5.4-5.8 (144-154)	5.9-6.8 (158-160)	6.1-6.3 (165-168)	4.8-5.5 (129-149)	5.1-5.5 (136-149)	3,9-4.9 (185-132)

Fuel gas constituents influencing the turbine maintenance, such as particulate and alkali vapor, were estimated to be at acceptahle content in the fuel gas to satisfy existing turbine specifications for both the hot fuel gas cleaning and cold fuel gas cleaning cases. Development testing of hot gas filters in gasification fuel gases confirm the small-scale, short-term capability of hot gas cleaning to meet turbine protection requirements, but full-scale demonstration is needed to establish this as a reliable, long-term capability.

The estimated emissions from the power plant are listed in Table 6. These estimated emissions are consistent with the capabilities of the equipment as claimed in the literature, and have yet to be demonstrated at a large scale. The emissions shown are representative of both the hot and cold fuel gas cleaning under the design conditions established for this evaluation. The emissions for SOx, NOx and particulate are expressed in the forms of volume or mass fraction at the stack, and mass per unit of fuel energy input, and are significantly lower than current standards require.

Table 6. IGCC Power Plant Emissions

Nitrogen oxides at stack: 10 ppmv
Particulate at stack: 2-3 ppmw

Case	Fuel sulfur (wt%, daf)	Sulfur Removal Scheme	Sulfur Removal overall % (gasifier/external)	Solid Waste lb/lb of coal	Fuel Gas Sulfur Content (ppmv)	Stack Gas Sulfur (ppmv)	Stack Gas SO_2 ng/J (lb/MBtu)
Pgh #8							
	3.5	Hot In-gasifier - Hot External	99.5 (90/95)	0.33	28	13	10.3 (0.024)
		Hot In-gasifier	95 (95/0)	0.39	298	140	99.9 (0.232)
		Hot External	99.5 (0/99.5)	0.25	25	11	10.3 (0.024)
		Hot In-gasifier - Cold External.	99.5 (90/95)	0.32	29	15	10.3 (0.024)
		Cold External	99.5 (0/99.5)	0.17	26	13	10.3 (0.024)
Blair Athol							
	0.5	Hot In-gasifier - Hot External	95 (75/80)	0.13	41	18	13.3 (0.031)
		Hot In-gasifier	70 (70/0)	0.12			79.7 (0.185)
		Hot External	95 (0/95)	0.12	32	14	13.3 (0.031)
		Hot In-gasifier - Cold External.	95 (75/80)	0.12	37	17	13.3 (0.031)
		Cold External	95 (0/95)	0.11	35	16	13.3 (0.031)
Lignite							
	3.1	Hot In-gasifier - Hot External	99.5 (90/95)	0.29	30	15	11.0 (0.255)
		Hot In-gasifier	95 (95/0)	0.35	364	190	109.8 (0.255)
		Hot External	99.5 (0/99.5)	0.23	25	14	11.0 (0.255)
		Hot In-gasifier - Cold External.	99.5 (90/95)	0.29	30	15	11.0 (0.255)
		Cold External	99.5 (0/99.5)	0.16	27	14	11.0 (0.255)
Bagasse							
	0.05	Hot/ No desulfurization	0	0.05	114-133	70	56.4 (0.131)

Solid waste generated by the power plant, listed in Table 6, is relatively large, being almost twice the power plant coal ash mass rate. The solid waste rate in the plant is sensitive to the coal sulfur content and the nature of the bulk sulfur sorbent used. While cold gas cleaning has the potential to be applied to reduce emissions to levels lower than assumed as the design basis for this evaluation, and lower than the capabilities of hot gas cleaning, these lower emissions require the consumption of more energy and result in lower plant thermal efficiency.

The thermal performance results for the described IGCC power plant are listed in Table 7. Some results from previous IGCC process evaluations for entrained oxygen-blown gasification, and for a 501G combustion turbine are also shown in the table. The table lists results as a function of the fuel type, fuel gas cleaning type (hot or cold), showing the net plant efficiency (LHV).

The net electrical outputs are:

- U.S. Bituminous coal with hot second-stage fuel gas cleaning: 261-262 MWe
- U.S. Bituminous coal with cold second-stage fuel gas cleaning: 243-274 MWe
- Australian Bituminous coal with hot second-stage fuel gas cleaning: 259 MWe
- Australian Bituminous coal with cold second-stage fuel gas cleaning: 269-272 MWe
- Indian Lignite with hot second-stage fuel gas cleaning: 246-247 MWe
- Indian Lignite with cold second-stage fuel gas cleaning: 259-276 MWe
- Bagasse with hot fuel gas cleaning: 234-236 MWe.

The estimated net electrical output of the power plant is greater with cold fuel gas cleaning, reflecting the greater generating capacity of the steam turbine bottoming cycle in this case.

Examination of Table 7 shows that the net plant efficiency is related to the fuel properties (heating value, moisture content, sulfur content) and the required sulfur removal load by Blair Athol (Australia) > Pgh #8 (U.S.) > lignite (India) > bagasse (Hawaii) which is consistent with general expectations. Compared to the equivalent natural gas-fired power plant, the net plant efficiency is lower than the natural gas power plant as:

Blair Athol (Australia): 10.3 - 12.6 percentage points,
Pgh #8 (U.S.): 11.6 - 18.9 percentage points,
lignite (India): 12.8 - 20.6 percentage points,
bagasse (Hawaii): 19.2 - 21.4 percentage points.

The comparison of the sulfur removal schemes was consistent for all of the fuels, and their ranking with respect to net power plant efficiency is:

hot external fuel gas cleaning > hot internal plus hot external > hot internal > hot internal plus cold external > cold external.

It should be noted that in this comparison the hot internal desulfurization was required to achieve a less stringent level of sulfur removal than the other schemes due to the performance limitations of this scheme. The net plant efficiency variation for each coal over all five schemes was:

Blair Athol (Australia, 0.5 wt% sulfur): 2.0 percentage points,
Pgh #8 (U.S., 3.5 wt% sulfur): 7.3 percentage points, and
lignite (India, 3.1 wt% sulfur): 7.8 percentage points.

The lower the sulfur content of the coal, the less important the choice of sulfur removal scheme become to the IGCC plant efficiency.

Table 7. Combined-cycle Performance Sensitivity to Sulfur Removal Requirements

Gasifier	Oxidant	Turbine	Fuel sulfur (wt%, daf)	Sulfur Removal System	Sulfur Removal overall % (gasifier/external)	Net Plant Efficiency (% LHV)
Entrained (Fluor, 1978)	Oxygen	501F	Ill #6 (4.3)	Cold External	80.2 (0/80.2)	39.2
					98.6 (0/98.4)	37.8
Entrained (Newby et al., 1996)	Oxygen	501F	Bituminous (1.2)	Cold External	99.3 (0/99.3)	44.7
				Hot External		46.0
	Oxygen	501G	Bituminous (1.2)	Cold External	99.3 (0/99.3)	48.2
				Hot External		49.7
Fluid bed (Yang et al., 1997)	Air	501F	Pgh #8 (3.3)	Hot In-gasifier + cold External	98 (86/85)	43.9
				Hot In-gasifier + Hot External		45.0
Fluid bed (this study)	Air	501F	Pgh #8 (3.5)	Hot In-gasifier + Hot External	99.5 (90/95)	44.0
				Hot In-gasifier	95 (95/0)	43.8
				Hot External	99.5 (0/99.5)	45.2
				Hot In-gasifier + Cold External	99.5 (90/95)	41.6
				Cold External	99.5 (0/99.5)	37.9
	Air	501F	Blair Athol (0.5)	Hot In-gasifier + Hot External	95 (75/80)	46.4
				Hot In-gasifier	70 (70/0)	
				Hot External	95 (0/95)	46.5
				Hot In-gasifier + Cold External	95 (75/80)	45.2
				Cold External	95 (0/95)	44.5
	Air	501F	Lignite (3.1)	Hot In-gasifier + Hot External	99.5 (90/95)	42.5
				Hot In-gasifier	95 (95/0)	41.8
				Hot External	99.5 (0/99.5)	44.0
				Hot In-gasifier + Cold External	99.5 (90/95)	40.1
				Cold External	99.5 (0/99.5)	36.2
	Air	501F	Bagasse	Hot/ No desulfuring	0	33.4-37.6

Overall, the hot gas cleaning schemes show significant advantage over the cold fuel gas cleaning schemes with respect to net plant efficiency. The hot internal plus hot external scheme shows the follnwing advantages over the hot internal plus cold external scheme:

Blair Athol (Australia, 0.5 wt% sulfur): 1.3 percentage points,
Pgh #8 (U.S., 3.5 wt% sulfur): 2.4 percentage points,
lignite (India, 3.1 wt% sulfur): 2.4 percentage points,

The hot external scheme shows the following advantages over the cold external schemes:

Blair Athol (Australia, 0.5 wt% sulfur): 2.0 percentage points,
Pgh #8 (U.S., 3.5 wt% sulfur): 7.3 percentage points,
lignite (India, 3.1 wt% sulfur): 7.8 percentage points.

The biomass fuel (bagasse) showed a significant 2.2 percentage point variation in net plant efficiency with respect to the choice of gasifier temperature, with the efficiency increasing as the gasifier temperature is decreased. This trend must be weighed against the tendency for the formation of tars in the fuel gas and increased gasifier ash carbon content as the temperature is decreased, versus the tendency for greater bed agglomeration and greater alkali vapor release as the gasifier temperature is increased.

Hot fuel gas cleaning has claimed potential economic benefits over cold fuel gas cleaning, as well as the potential for significant power plant thermal efficiency improvement as is listed in Table 7, but its reliability and environmental performance are currently uncertain. The power plant capital investment and cost-of-electricity have not been estimated in this evaluation, so the relative cost impacts of hot and cold gas cleaning cannot be addressed. The Sierra Pacific, Pinon Pine IGCC, using the air-blown, KRW fluid bed gasifier will be the first integrated hot fuel gas cleaning demonstration. Its operation, starting in late-1997, will provide the full-scale performance data required to reduce the uncertainty in this technology.

Comparison of these results with other projected plant net thermal efficiencies from other reported studies or demonstration plant results must be made with caution since the scope and bases of reported evaluations and the related boundaries of the plant are frequently not well defined.

CONCLUSIONS

Combustion turbines can be adapted for the utilization of low-thermal-value fuel gases generated by coal gasification. The fuel gas cleaning system must achieve contaminant levels that satisfy the combustion turbine requirements, as well as emissions performance that can satisfy future, stringent environmental demands. The ability of conventinnal cold fuel gas cleaning to achieve these technical requirements has been demonstrated. Hot fuel gas cleaning is now being demonstrated in the U.S. in Clean Coal Technology Programs.

Within this study, it has been shown that IGCC power plant fuel properties (heating value, moisture content, sulfur content) and the plant sulfur removal requirement has significant impact on the power plant net efficiency. Lower sulfur content and lower sulfur removal requirement will increase the net plant efficiency. The sulfur removal scheme applied also significantly influences the plant efficiency. Hnt fuel gas cleaning schemes are favored nver cold fuel gas cleaning schemes with respect to net plant efficiency by greater than 7 percentage points for high-sulfur coals. It is also expected that hot fuel gas cleaning schemes are favored over cold fuel gas cleaning schemes with respect to the economics of power generation. In fluid bed gasification, the use of in-gasifier desulfurization for bulk sulfur removal can enhance the emissions performance that can satisfy future, stringent environmental demands. The ability of conventional cold fuel gas cleaning to achieve these technical requirements has been demonstrated. Hot fuel gas cleaning is now being demonstrated in the U.S. in Clean Coal Technology Programs.

Within this study, it has been shown that IGCC power plant fuel properties (heating value, moisture content, sulfur content) and the plant sulfur removal requirement has significant impact on the power plant net efficiency. Lower sulfur content and lower sulfur removal requirement will increase the net plant efficiency. The sulfur removal scheme applied also significantly influences the plant efficiency. Hot fuel gas cleaning schemes are favored over cold fuel gas cleaning schemes with respect to net plant efficiency by greater than 7 percentage points for high-sulfur coals. It is also expected that hot fuel gas cleaning schemes are favored over cold fuel gas cleaning schemes with respect to the economics of power generation. In fluid bed gasification, the use of in-gasifier desulfurization for bulk sulfur removal can enhance the power plant efficiency and, it is expected, the power plant economics.

The coal-fired IGCC plant efficiencies with the Westinghouse 501F combustion turbine are estimated to be as high as 46.5 % (LHV) for low sulfur coal, and 45.2 % (LHV) for high-sulfur coal, about 10 percentage points lower than the equivalent natural gas-fired power plant. Advanced combustion turbines, such as the 501G are expected to approacb IGCC power plant efficiencies of 50% (LHV).

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