1.2
Integrated Coal Gasification Combined Cycle (IGCC)

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1.2-1 Introduction

Integrated Coal Gasification Combined Cycle (IGCC) refers to the technology of converting coal to a fuel gas by contacting it with a mixture of oxygen (or air) and steam, burning the fuel gas in a combustion turbine/generator, using the waste heat from the turbine to raise steam, and sending the steam to a steam turbine for additional power generation. IGCC has a number of technical advantages, but until recently, higher capital costs plus the availability of cheap natural gas have limited its application. However, as pollution limits become more stringent and natural gas prices increase, the superior performance of IGCC will make it increasingly attractive, particularly as technical advances reduce costs.

Gasification is a well-proven technology that had its beginnings in the late 1700s. In the 19th century, gasification was used extensively for the production of "town gas" for urban areas. Although this application has all but vanished in the 20th century with the widespread availability of natural gas, gasification has found new applications in the production of fuels and chemical feed stocks and in large-scale power generation. Today, gasification technology is being widely used throughout the world. A study conducted in 2004 indicated that there were 156 gasification projects worldwide. Total capacity of the projects in operation was 45,000 MW (thermal) with another 25,000 MW (thermal) in various stages of development.

1.2-2 The Gasification Process[1]

The major difference between combustion and gasification from the point of view of the chemistry involved is that combustion takes place under oxidizing conditions, while gasification occurs under reducing conditions. In the gasification process, a carbon-based feedstock in the presence of steam and oxygen at high temperature and moderate pressure is converted in a reaction vessel called a gasifier to synthesis gas, a mixture of carbon monoxide and hydrogen, generally referred to as syngas. The chemistry of gasification is quite complex and involves many chemical reactions, some of the more important of which are:

$$C + O_2 \rightarrow CO_2 \qquad \Delta H_r = -393.4\ \text{MJ/kmol} \tag{1}$$

$$C + \tfrac{1}{2} O_2 \rightarrow CO \qquad \Delta H_r = -111.4\ \text{MJ/kmol} \tag{2}$$

$$C + H_2O \rightarrow H_2 + CO \qquad \Delta H_r = 130.5\ \text{MJ/kmol} \tag{3}$$

$$C + CO_2 \leftrightarrow 2CO \qquad \Delta H_r = 170.7\ \text{MJ/kmol} \tag{4}$$

$$CO + H_2O \leftrightarrow H_2 + CO_2 \qquad \Delta H_r = -40.2\ \text{MJ/kmol} \tag{5}$$

$$C + 2H_2 \rightarrow CH_4 \qquad \Delta H_r = -74.7\ \text{MJ/kmol} \tag{6}$$

Reactions (1) and (2) are exothermic oxidation reactions and provide most of the energy required by the endothermic gasification Reactions (3) and (4). The oxidation reactions occur very rapidly, completely consuming all of the oxygen present in the gasifier, so that most of the gasifier operates under reducing conditions. Reaction (5) is the water-gas shift reaction, which in essence converts CO into H_2. The water-gas shift reaction alters the H_2/CO ratio in the final mixture but does not greatly impact the heating value of the synthesis gas, because the heats of combustion of H_2 and CO on a molar basis are almost identical. Methane formation, Reaction (6), is favored by high pressures and low temperatures and is, thus, mainly important in lower-temperature gasification systems. Methane formation is an exothermic reaction that does not consume oxygen and, therefore, increases the efficiency of gasification and the final heating value of the synthesis gas. Overall, about 70% of the fuel's heating value is associated with the CO and H_2 in the gas, but this can be higher depending upon the gasifier type.

Depending on the gasifier technology employed and the operating conditions, significant quantities of H_2O, CO_2, and CH_4 can be present in the synthesis gas, as well as a number of minor and trace components. Under the reducing conditions in the gasifier, most of the fuel's sulfur converts to hydrogen sulfide (H_2S), but 3-10% converts to carbonyl sulfide (COS). Fuel-bound nitrogen generally converts to gaseous nitrogen (N_2), but some ammonia (NH_3) and a small amount of hydrogen cyanide (HCN) are also formed. Most of the chlorine in the fuel is converted to HCl with some chlorine present in the particulate phase. Trace elements, such as mercury and arsenic, are released during gasification and partition among the different phases, such as fly ash, bottom ash, slag, and product gas. Table 1 shows typical gas compositions for some of the more commonly used gasifiers.

Table 1. Composition of Raw Syngas from Coal Fed Gasifiers

Gasifier Technology	Sasol/Lurgi[1]	Texaco/GE Energy[2a]	BGL[2b]	E-Gas/Conoco Phillips	Shell/Uhde[2c]
Type of Bed	moving	entrained	moving	entrained	entrained
Coal Feed Form	dry	slurry	dry	slurry	dry
Coal Type	Illinois No. 6	Illinois No. 6	Illinois No. 6	Illinois No. 6	Illinois No. 5
Oxidant	oxygen	oxygen	oxygen	oxygen	oxygen
Pressure, MPa (psia)	0.101 (14.7)	4.22 (612)	2.82 (409)	2.86 (415)	2.46 (357)
Ash Form	slag	slag	slag	slag	slag
Composition, vol%					
H_2	52.2	30.3	26.4	33.5	26.7
CO	29.5	39.6	45.8	44.9	63.1
CO_2	5.6	10.8	2.9	16.0	1.5
CH_4	4.4	0.1	3.8	1.8	0.03
Other HC	0.3	-	0.2	-	-
H_2S	0.9	1.0	1.0	1.0	1.3
COS	0.04	0.02	0.1	0.1	0.1
N_2 + Ar	1.5	1.6	3.3	2.5	5.2
H_2O	5.1	16.5	16.3	-	2.0
NH_3 + HCN	0.5	0.1	0.2	0.2	0.02
HCl	-	0.02	0.03	0.03	0.03
H_2S/COS Ratio	20/1	42/1	11/1	10/1	9/1

Sources:

[1] Rath, "Status of Gasification Demonstration Plants," *Proc. 2nd Annu. Fuel Cells Contract Review Mtg.*, DOE/METC-9090/6112, p. 91.

[2] *Coal Gasification Guidebook: Status, Applications, and Technologies*, Electric Power Research Institute, EPRI TR-102034, 1993. 2a: p. 5-28; 2b p. 5-58; 2c: p. 5-48.

Many other reactions, besides those listed, occur. In the initial stages of gasification, the rising temperature of the feedstock initiates devolatilization of the feedstock and the breaking of weaker chemical bonds to yield tars, oils, phenols, and hydrocarbon gases. These products generally react further to form H_2, CO, and CO_2. The fixed carbon that remains after devolatilization reacts with oxygen, steam, CO_2, and H_2.

Gasifier Types:

All gasifier technologies generally fall into one of three generic types of reactor: moving-bed (also call fixed-bed), fluidized-bed, and entrained flow. In a moving-bed gasifier, large particles of coal move slowly down through the bed while reacting with gases moving countercurrenly. Reaction "zones" are often used to describe the reactions occurring along the length of the gasifier. In the drying zone at the top of the gasifier, the entering coal is heated and dried by the countercurrent flow of syngas, while simultaneously cooling the syngas before it leaves the gasifier. The moisture content of the coal mainly controls the temperature of the discharge gas from the gasifier. Because of the countercurrent operation of this gasifier, hydrocarbon liquids can be found in the product gas which has been problematic for downstream operations; however, techniques have been devised to capture the hydrocarbons and recycle them to the lower part of the gasifier. As the coal continues down the bed, it enters the carbonization zone where the coal is further heated and devolatilized by higher temperature gas. In the gasification zone, the devolatilized coal in converted to syngas by reactions with steam and CO_2. In the combustion zone near the bottom of the reactor, oxygen reacts with the remaining char to consume the remaining carbon and to generate the necessary heat for the gasification zone. Depending upon the operation of the combustion zone, the moving bed gasifier can be made to operate in one of two distinct modes, i.e., dry ash or slagging. In the dry-ash version, the temperature is maintained below the ash slagging temperature by the endothermic reaction of the char with steam in the presence of excess steam. In addition, the ash below the combustion zone is cooled by the entering steam and oxidant. In the slagging version, much less steam is used so that the temperature of the ash in the combustion zone exceeds the ash fusion temperature of the coal and molten slag is formed. Moving-bed gasifiers have the following characteristics:

- Low oxidant requirements;
- Production of hydrocarbon liquids, such as tars and oils;
- High "cold-gas" thermal efficiency, when the heating value of the hydrocarbon liquids is included; and,
- Limited ability to handle fines.

Fluidized-bed gasifiers operate in a highly back-mixed mode, thoroughly mixing the coal feed particles with those particles already undergoing gasification. Coal enters at the side of the reactor, while steam and oxidant enter near the bottom, thereby suspending or fluidizing the reacting bed. Char particles entrained in the raw gas leaving the top of the gasifier are recovered by a cyclone and recycled back to the gasifier. Ash particles removed below the bed give up heat to the incoming steam and oxidant. Because of the highly back-mixed operation, the gasifier operates under isothermal conditions at a temperature below the ash fusion temperature of the coal, thus avoiding clinker formation and possible collapse of the bed. The low temperature operation of this gasifier means that fluidized-bed gasifiers are best suited to relatively reactive feeds, such as low-rank coals and biomass, or to lower quality feedstocks, such as high ash coals. Fluidized-bed gasifiers have the following characteristics:

- Accept a wide range of solid feedstocks, including solid waste, wood, and high ash coals;
- Uniform, moderate temperature;
- Moderate oxygen and steam requirements; and,
- Extensive char recycling.

In entrained-flow gasifiers, fine coal particles react with steam and oxidant, generally pure oxygen, at temperatures well above the fusion temperature of the ash. The residence time of the coal in these gasifiers is very short, and high temperatures are required to achieve high carbon conversion. Because of the high reaction temperatures required compared to the other gasifier types, oxygen consumption is higher because of the need to combust more of the feedstock to generate the required heat. To minimize oxygen consumption, and hence cost, these gasifiers are usually supplied with higher quality feed stocks. Entrained-flow gasifiers can operate either in a down-flow or up-flow mode. Entrained-flow gasifiers have the following characteristics:

- Ability to gasify all coals, regardless of rank, caking characteristics, or amount of fines, although feedstocks with lower ash content are favored;
- Uniform temperature;
- Very short feed residence time in the gasifier;
- Solid fuel must be very finely divided and homogeneous;
- Relatively large oxidant requirement;
- Large amount of sensible heat in the raw gas;
- High-temperature slagging operation; and,
- Entrainment of some ash/slag in the raw gas.

Syngas Cleanup

Before syngas can be burned as a fuel or converted to chemicals, liquid fuels, or hydrogen, impurities in the gas, as shown in Table 1, must be reduced to levels that depend upon the requirements of the downstream process. To clean the syngas, chemical solvents, such as monoethanolamine (MEA), diethanolamine (DEA), and methyl diethanolamine (MDEA), and physical solvents, such as methanol (Rectisol) and mixtures of dimethyl ethers of polyethylene glycol (Selexol), operating at ambient or lower temperatures are employed. The selection of the technology for gas cleanup is dependent on the purity requirements of downstream operations and whether of not capture of carbon dioxide is required.

With all of these technologies, the syngas is contacted with the scrubbing liquid in a packed column. In the amine-based systems (MEA, DEA, MDEA), weak chemical compounds are formed between H_2S and the amine. Compounds such as COS are unaffected by the amine and must first be hydrolyzed to H_2S if deeper sulfur removal is required. The rich amine is then pumped to a second packed column, operating at a higher temperature, where the H_2S is stripped from the solvent and sent to sulfur recovery, typically a Claus unit. The lean amine is cooled and returned to the absorber. The Rectisol process uses chilled methanol, at a temperature of about -40°F to -80°F, as the solvent. In this case, the H_2S and other sulfur-containing compounds, such as COS, dissolve in the methanol but do not react with it. The methanol is regenerated by flashing, and the lean solvent is then returned to the absorber. Like the Rectisol process, H_2S and other sulfur-containing compound are quite soluble in the Selexol solvent, which operates at about 0°F to 100°F. The rich solution is sent to a regeneration column, where a combination of reduced pressure and stripping at an increased temperature is used to remove the absorbed acid gases. The regenerated solvent is returned to the absorber. In current IGCC systems, absorption processes are used to remove H_2S, with a minimum of CO_2 removal, since CO_2 in the fuel gas improves turbine performance. However, should it become necessary to also recover CO_2, these processes can be configured to remove both H_2S and CO_2.

Once the synthesis gas is sufficiently cleaned, various options exist for its utilization, such as the production of electricity via IGCC or the production of chemicals, hydrogen, and liquid fuels by water-gas shift and Fischer-Tropsch (F-T) technology. In IGCC, the clean synthesis gas is sent to a combustion turbine, where the gas is burned to produce electricity. The energy contained in the exhaust gas from the gas turbine is recovered in a heat recovery steam generator (HRSG). Steam from the HRSG goes to a steam turbine for the production of additional electricity. Approximately, two-thirds of the total electricity generated in the IGCC plant is produced by the gas turbine and one third is produced by the steam turbine. Because of the sulfur removal process discussed above, SO_2 emissions are very low. Likewise, eliminating ammonia from the syngas in the gas cleaning system and adding a diluent (nitrogen or moisture) to the fuel gas prior to combustion to lower combustion temperature in the turbine results in very low levels of NOx emissions, even in the absence of selective catalytic reduction (SCR).

There is growing concern that the increased concentration of CO_2 in the atmosphere from the burning of fossil fuels is contributing to global warming with undetermined consequences. This concern had resulted in the development of the Kyoto Protocol, which sets limits on CO_2 emissions for the signatory countries. An obvious target for CO_2 reductions is large stationary point sources, such as coal-fired power plants. Studies to date have indicated that recovery of the CO_2 from the flue gas from these plants is very expensive and inefficient. Because the flue gas is at about atmospheric pressure and the CO_2 concentration is typically less than 15%, large volumes of gas have to be treated and the driving force for CO_2 absorption is low.

With coal gasification, the situation is different. The CO_2 partial pressure in the product gas from the gasifier is much higher due to the higher pressure of the syngas (typically 500-700 psi). The higher pressure and the absence of nitrogen dilution result in a much lower gas volume to be treated (on the order of only 0.5% to 1% the volume of flue gas). Furthermore, by using a water-gas shift unit, CO in the fuel gas can be converted to H_2 and CO_2 before CO_2 capture. With this approach, nearly all the carbon in the gasifier feed can be captured as CO_2 for use or sequestration. Major potential uses for the captured CO_2 include enhance oil recovery (EOR) and enhanced coal bed methane recovery (ECBM). Smaller uses include feedstock for chemicals manufacture and as a fertilizer in greenhouses, but these uses are much too small to have an impact on CO_2 emissions. If it becomes mandatory to reduce greenhouse gas (GHG) emissions, it is likely that CO_2 will be sequestered by injection into deep saline aquifers, abandoned oil and gas fields, and unminable coal seams.

1.2-3 IGCC Systems

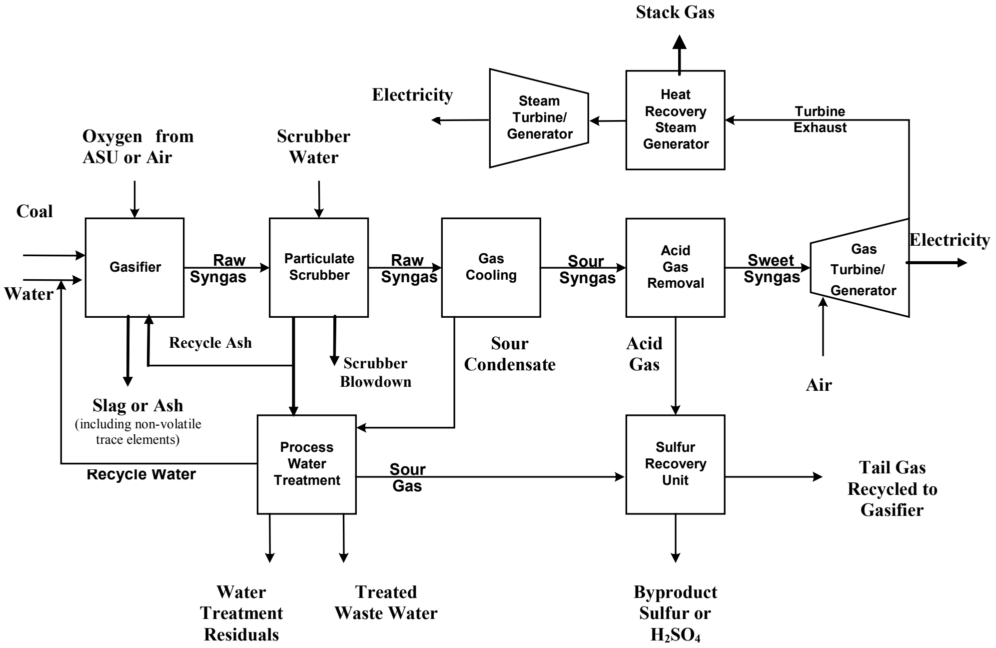

Fig. 1. Schematic of Generic IGCC Power Plant

IGCC involves the integration of a number of technologies, as shown by the schematic diagram in figure 1. The technologies involved include air separation, gasification, syngas cleanup (including sulfur recovery), and power generation. Figure 2 presents some of the options for the various technology blocks in the gasification based systems. Improvements in any of these technologies will result in an improvement in IGCC. In a typical IGCC unit, coal, oxygen and steam are fed to the gasifier, where they are converted to raw syngas. The syngas is then cooled and cleaned of particulate matter, ammonia, and sulfur compounds. The cleaned gas is sent to the gas turbine where it is mixed with air and burned. Nitrogen from the air separation unit or steam may be added to the syngas to lower the combustion temperature and reduce NOx formation. The hot exhaust from the combustion turbine goes to a HRSG to raise steam for a steam turbine. The combination of a combustion turbine plus a steam turbine bottoming cycle increases the efficiency of IGCC.

If it is desired to produce hydrogen, either as a product or to permit CO_2 recovery, then a water-gas shift reactor is included along with an acid gas removal system. The hydrogen can be used as a fuel for fuel cells, for petroleum refining, as a chemical intermediate, or burned in the combustion turbine. In this case, the only combustion product is water, and the only pollutant is a small amount of NOx.

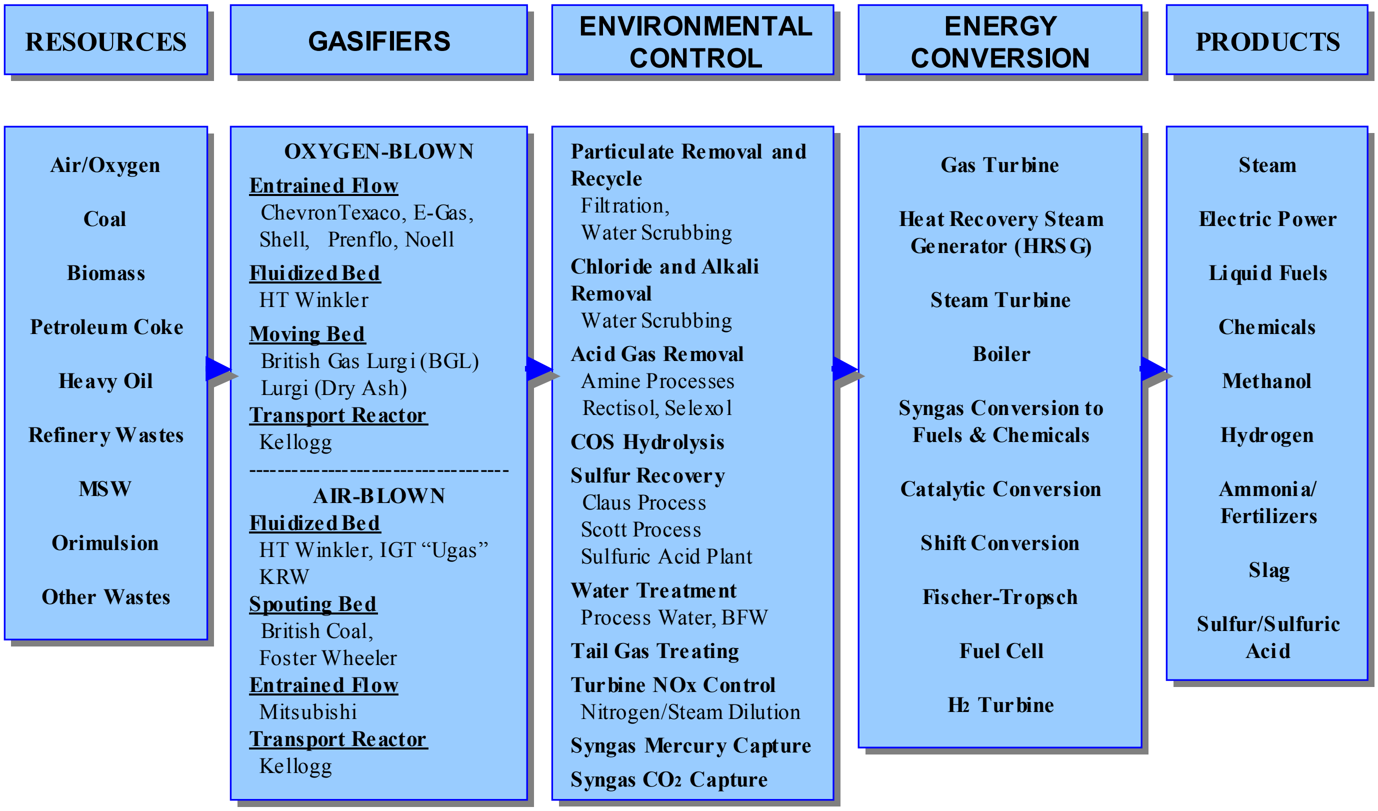

Fig. 2. Gasification-Based Energy Conversion System Options

1.2-4 Gasifier Improvements

Reliability and performance of the gasifier are key factors impacting the commercial deployment of IGCC technology. Today, single train IGCC plants, such as the Wabash River and Tampa Electric plants, have typically not achieved availabilities in excess of 80% for any sustained period of time. However, for gasification to be accepted for utility applications, availabilities in excess of 90% are required. For other applications, such as in refineries and chemical plants, the availability of the gasifier must be over 97%. Today, these high availabilities can be accomplished, but only through the addition of a spare gasifier at an increase in capital cost. To achieve gasifier high availability, several areas of gasifier operation need to be improved.

Feed injectors are considered to be the weakest link in achieving a high on-stream factor, particularly with slurry-fed systems. A typical injector is reported to last from two to six months; however, a minimum life of 12 months is desired. Computational fluid dynamic (CFD) modeling around the injector may help to elucidate the factors that lead to failure. New materials and/or coatings for existing materials are needed to provide protection from sulfidation and corrosion at high reactor temperatures. New injectors are currently being developed based on rocket engine technology to achieve the target life and improve carbon conversion in the gasifier.

Injector life also appears to be dependent on whether a dry or wet feed system is used. In a dry feed system, injector life is usually better, possibly due to the absence of a large amount of evaporating water. Although improved life has been reported, operations with dry feed systems at high pressures are problematic because of the use of lock hoppers. To eliminate lock hoppers, a high pressure dry feed pump is under development which could result in a significant cost reduction for dry feed systems.

For those gasifiers employing refractories to protect the pressure vessel, such as Texaco (now owned by GE Energy) and E-Gas (now owned by Conoco Phillips), new materials that have a useful life in excess of three years must be developed and demonstrated. Depending upon the severity of the gasifier operation and the feedstock being used, refractory liners typically last from six to 18 months. Rebricking a gasifier typically requires three weeks of downtime and costs $1-2 million. If a gasifier must be rebricked once a year, availability is automatically reduced by 5-6%. New refractory materials under development have shown considerable resistance to slag attack under simulated gasifier conditions and are currently being evaluated in commercial coal gasifiers.

Actively cooled gasifiers, such as the Shell gasifier, which has steam tubes imbedded in the refractory liner, mitigate the refractory problem, but this route is usually more expensive. A new actively cooled liner that is potentially less expensive than other approaches is under development.

Thermocouples used to measure the temperature inside the gasification zone are reported to last about 30-45 days. Failure of the thermocouples is due to corrosion resulting from slag penetration into the refractory and stresses caused by temperature cycles. When thermocouples are lost, the gasifier is typically controlled based on a prior correlation of gasifier temperature versus the methane content of the exit gas. New instrumentation capable of operating in the gasification environment with an expected lifetime of more than a year is required. Several new temperature measuring devices are being developed and tested with a promise of improved performance.

Gas Cleanup Improvements

Current synthesis gas cleaning technologies employ chemical or physical solvents and operate at ambient or lower temperature. In an IGCC plant, these technologies typically account for 12-15% of the total capital cost of the plant. Amine-based systems are suitable for meeting today's emission requirements, but they are not capable of achieving the limits of future potential regulations nor are they applicable for cleaning syngas for chemicals production. For the latter case, more expensive and energy intensive technologies, such as Rectisol, must be employed. What is needed are technologies capable of achieving the performance of a Rectisol unit but at equal or lower cost than an amine system. Considerable effort is currently underway to develop improved sorbents technologies that operate at moderate process temperatures while reducing acid gas concentrations to desired levels at a reduced cost and improved thermal efficiency. Integrated operation in a coal gasifier will be necessary to demonstrate the impact of trace contaminants in coal-derived syngas on the performance, longevity, and regenerability of any new sorbent.

Selective catalytic oxidation has the potential for achieving sulfur levels well below 1 ppm while operating at moderate process temperatures. In this approach, a small quantity of oxygen is injected into the synthesis gas stream and reacts with H_2S over a catalyst to form elemental sulfur. To achieve the desired performance, either the COS in the raw gas stream must be hydrolyzed to H_2S or a new catalyst must be developed to directly convert COS to elemental sulfur.

For these approaches to be commercially attractive at a moderate process temperature, technologies are needed that can remove other trace contaminants at similar process conditions. Technologies for NH_3, chlorides, and Hg removal are being developed and tested. Although not currently regulated, effort is also being focused on the removal of arsenic (As), selenium (Se), and cadmium (Cd) with emphasis on multi-contaminant removal technologies to achieve near-zero emissions of all contaminants.

1.2-5 Gas Separation Improvements

Cost effective and efficient gas separation technologies are vital in the production of hydrogen from coal. Gas separation operations occur in two major areas: the separation of oxygen from air for use in the gasifier and the separation of the shifted synthesis gas into pure H_2 and CO_2 streams. Cryogenic technologies are currently employed for the production of oxygen; however, these plants are very capital and energy intensive. The cryogenic air separation unit in an IGCC plant typically accounts for 12-15% of the total plant capital cost and can consume upwards of 10% of the gross power output of the plant.

Advanced dense ceramic membranes possessing both ionic and electronic conductance are being developed as a high temperature approach for air separation. A preliminary engineering analysis comparing these advanced membranes with conventional cryogenic technologies has been performed, and the results indicate that the advanced membranes have the potential for significantly reducing the capital cost of an IGCC plant with a corresponding 1-2 percentage point gain in thermal efficiency. Although many challenges remain in material composition and processing to produce defect-free, chemically and thermally stable membranes with commercially relevant fluxes, significant progress has been made.

Separation of hydrogen from shifted synthesis gas, either derived from coal or natural gas, is a key unit operation of any fossil-energy-based hydrogen production system. Membrane technologies have been, and continue to be, explored quite extensively by many investigators. Engineering studies comparing conventional coal gasification processes for producing hydrogen with advanced membranes and other technologies indicate that there is substantial incentive to develop advanced H_2/CO_2 separation technologies.

Membranes can generally be divided into either organic or inorganic. Organic membranes appear to have limited applications for coal-based hydrogen production routes because of their extreme sensitivity to process conditions and trace contaminants. Instead, the bulk of the work for hydrogen separation is focused on inorganic membranes. Inorganic membranes can be classified as either porous or dense, and the latter can be further subdivided into metallic or solid electrolytes (ceramic). One promising membrane uses a manufacturing process that precisely controls the pore size distribution to allow primarily hydrogen to diffuse through the pores, thereby achieving very high separation factors.

Considerable effort has also been devoted to metallic membranes, most of which are based on palladium (Pd). Although initially thought to be promising, these membranes have been found to be susceptible to degradation from the presence of both sulfur and CO. There have been reports of metal alloys that show very high hydrogen fluxes at temperatures around 750^{o}F, but the stability of these membranes in the presence of trace contaminants from coal gasification must be determined.

1.2-6 Conclusions

Markets and drivers are changing rapidly. Environmental performance is becoming a greater factor as emission standards tighten and market growth occurs in areas where total allowable emissions are capped. Also, reduction of CO_2 emissions is one of the challenges in response to global climate change. There is a need for more environmentally sound processes, more efficient and reliable systems, and higher profitability. Industries need technologies that can match these requirements—a way to remain flexible, reduce risk, decrease emissions, increase stockholder return on investment, and consume fewer resources. Gasification is a technology that can meet these requirements. So far, the majority of existing applications have been geared toward the production of a single product or a constant ratio of two or more products per facility. The potential of gasification in expanding markets is in its ability to use low-cost and blended feedstocks and its multi-product flexibility. With deregulation, rapidly changing market demands, fluctuation in natural-gas prices, and increased environmental concerns, gasification has the potential to become a cornerstone technology in many industries.

In particular, IGCC could become a dominant technology in the power industry because of the following advantages:

- Ability to handle almost any carbonaceous feedstock;
- Ability to efficiently clean up product gas to achieve near-zero emissions of criteria pollutants, particulates, and mercury at substantially lower costs and higher efficiencies;
- Flexibility to divert some syngas to uses other than turbine fuel for load following applications;
- High efficiency because of the use of both gas turbine and steam turbine cycles;
- Ability to cost effectively recover CO_2 for sequestration, if required;
- Ability to produce pure H_2, if desired;
- Greater than 50% reduction in the production of solid by-products; and,
- Substantial reduction in water usage and consumption.

1.2-7 Notes

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1. *For a more complete discussion of gasification, refer to the following reports:* *"Gasification*," by C. Higman and M. van der Burgt, (Elsevier: Gulf Professional Publishing, 2003); "Major Environmental Aspects of Gasification-Based Power Generation Technologies," by J. Ratafia-Brown, L. Manfredo, J. Hoffmann, and M. Ramezan, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, December 2002.

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Mr. Gary J. Stiegel has been with the Department of Energy's National Energy Technology Laboratory over twenty-nine years and is currently Technology Manager for Gasification. In this capacity, he is responsible for strategic planning, budget formulation, program development and oversight, and outreach activities for DOE's Office of Fossil Energy's gasification program.

Prior to his present assignment, Mr. Stiegel served as the Program Coordinator for the Department's Indirect Liquefaction and Gas-to-Liquids programs and spent ten years in R&D focusing on coal hydrogenation and the refining of coal-derived liquids.

Mr. Stiegel has a Bachelors and Masters degree in chemical engineering and a Masters in Business Administration from the University of Pittsburgh.

Prior to joining the Department of Energy, Mr. Stiegel was a process engineer for Union Carbide Corporation. During his career, Mr. Stiegel has published over fifty technical articles on various aspects of coal conversion and reactor engineering and is a registered Professional Engineer in Pennsylvania.

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Dr. Ramezan has over twenty five years of diverse experience in engineering, research & development, program management, marketing, energy technology assessment, process evaluation, personnel management, and technical services support in the areas of advanced energy systems and environmental control technologies. Specific project examples include: an environmental assessment of IGCC power systems, analysis of gasification-based multi-product systems with CO_2 recovery, and life cycle assessment of advanced power systems. Dr. Ramezan received his B.S., M.S., and Ph.D. degrees in Mechanical Engineering from West Virginia University. He is a registered professional engineer and a member of ASME. He has authored more than 80 technical papers and has received numerous awards. Dr. Ramezan previously taught courses and conducted research in the areas of thermal-fluid sciences.

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Over 40 years experience in the areas of petroleum refining, petrochemicals, synthetic fuels, and energy conversion. Actively engaged in the preparation of many topical reports and post project assessments for the DOE's Clean Coal Technology program. Specific project examples include the Tampa Electric Company and the Wabash IGCC projects. Received his BS, MS, and Ph.D. degrees in Chemical Engineering from Carnegie-Mellon University. He is a member of ACS, and has coauthored numerous technical papers and reports related to energy technology.