A Single IGCC Design for Variable CO2 Capture

by

Luke F. O’Keefe
Richard C. Weissman
Richard A. De Puy
Texaco Power and Gasification
White Plains, New York

John Griffiths
Nathan East
The Jacobs Consultancy
Croydon, England

John M. Wainwright
General Electric Power Systems
Schenectady, NY

ABSTRACT

Global warming and the production of greenhouse gases (GHG) have become an important issue in many countries around the world. While there has been a heightened sense of awareness that the combustion of fossil fuels produces the majority of the controllable carbon dioxide released to the atmosphere, there have been few substantive solutions that produce economically realistic solutions. Moreover, some fossil fuels, like coal, are viewed negatively due to their relatively high carbon content per BTU. Integrated Gasification Combined Cycle (IGCC) offers the option of a realistic, economically viable potential for reducing, by pre-combustion capture, significant amounts of CO_2 while using existing, commercially proven technologies.

Texaco has sponsored a study by The Jacobs Consultancy in cooperation with General Electric using a 900 MW IGCC power plant configured to remove 75% of the feed carbon as CO_2 pre-combustion. By performing a “sour shift” of the syngas, most of the carbon monoxide is converted into carbon dioxide and an equal volume of hydrogen. The fuel for the combustion turbine consists largely of hydrogen and water vapor, the carbon having been removed prior to entering the combustion system. Carbon is removed from the fuel at relatively high concentration, providing a simple, economic solution to the desire to produce power with low CO_2 emissions from inexpensive, widely available fuel.

The flow scheme is designed such that the power plant can be built and operated without CO_2 removal and then later upgraded to low CO_2 emissions at minimal additional cost. The flow scheme is based on commercially proven technology using processes that are in operation today. Overall performance and capital cost estimates will be presented.

INTRODUCTION

Major strides have been realized over the years to improve the efficiency of converting fossil fuels to power. While these improvements naturally lead to a reduction of CO_2 emissions, these may not be sufficient to satisfy the proposed GHG targets, particularly for fuels containing large carbon components, such as coal. The use of IGCC in the process flow scheme described in this paper captures more than 75% of the carbon in the feedstock and efficiently converts the energy into clean power.

The flow scheme contains a “shift” catalyst that converts carbon monoxide in the syngas to carbon dioxide by reaction with water. For each molecule of carbon dioxide produced, there is a corresponding yield of one molecule of hydrogen.

$$\mathbf{CO + H_2O \rightarrow CO_2 + H_2}$$

The Shift reaction is an essential ingredient for this IGCC flow scheme incorporating the capture of carbon dioxide.

This approach has three different features:

1. The flow scheme is modeled in detail from coal feedstock to net power output, modeling readily available technology with computer simulators in a typical commercial application.

2. A group of licensors and suppliers, who together can provide the technology and equipment, have actively collaborated in the integration, design, performance calculations, validation and cost estimate of the overall plant.

3. Most importantly, the same flow scheme (and plant) can be used whether CO_2 is being captured or not. This would be an advantage if there were insufficient near term economic justification for CO_2 capture, but a desire in the future, if warranted. In essence, one can build an IGCC plant to operate without CO_2 capture and, with minor modifications, change the operation to capture the CO_2 from the syngas fuel.

DISCUSSION

Basis for the Study

The authors aim is to present a concept using currently available commercial technology. The study basis includes the following:

(a) The same flow scheme is used, whether capturing CO_2 or not. This allows for a phased approach, with CO_2 exported from the process in a second phase.

(b) The same ASU, Gasifier, Acid Gas Removal System and Combined Cycle Unit (CCU) are used, whether capturing CO_2 or not.

(c) No development work is required before commercialization.

(d) Commercially proven equipment, with reference lists, are used throughout.

(e) Supply companies are internationally recognized and respected.

(f) These companies can provide performance guarantees for their scope of supply.

(g) The project can undergo detailed design, procurement, construction and commissioning by a single turnkey contractor.

(h) The turnkey contractor can offer guarantees for overall cost and performance.

(i) Minimal integration between ASU, Gasification, and CCU.

(j) The key licensors and suppliers for gasification, heat recovery, shift reactor, acid gas removal, sulfur recovery and combined cycle plant are actively involved, to approve the performance assigned to their particular equipment, in the context of the whole scheme.

Process Description

The purpose of this process design is to provide an IGCC plant with the option to capture and export carbon dioxide. The plant uses Texaco Quench gasifiers followed by a sour shift system, a physical absorption acid gas removal, a sulfur recovery system, and a combined cycle unit consisting of two GE 9FA gas turbines and a single steam turbine (see Figure 1).

This scheme is described in two modes of operation, "Without CO_2 Capture" and "With CO_2 Capture". An IGCC built today may not have a commercial need to capture CO_2, unless there were the potential for enhanced oil recovery (EOR) through CO_2 injection, or sequestration in an aquifer (e.g. under the North Sea). A future option for CO_2 removal is readily available through some minor modifications to the plant.

Without CO_2 Capture

ASU and Gasification

Two 3,000 metric tonnes/day Air Separation Units produce 95% purity oxygen at 103 bar. Coal slurry, having greater than 60% solids, is prepared and gasified at a pressure of 83 bar with the oxygen into two Texaco Quench Gasifiers. The raw syngas is thoroughly scrubbed of particulates, and sent to heat recovery and CO Shift.

Heat Recovery and CO Shift (Low Temperature Gas Cooling)

The particulate free raw syngas passes through a medium pressure (MP) boiler that trims the steam to a molar steam to dry gas ratio of about one. The syngas is preheated and passed through a catalytic treatment system which shifts the bulk of the carbon monoxide in the syngas to carbon dioxide, and then through a COS hydrolysis catalyst to produce a gas containing only H_2S as a sulfur compound.

The heat from the Shift reaction is recovered as High Pressure (HP) steam that is use in the steam cycle of the Combined Cycle Unit (CCU). The syngas, containing only trace impurities other than H_2S, is cooled to 40°C before acid gas removal.

Acid Gas Removal (AGR)

The AGR uses a physical absorption system that takes advantage of the high pressure of operation. Rectisol™, Purisol™ and Selexol™ are suitable for this service. In this flow scheme, Selexol™ has been used.

In the non-CO_2 capture mode of operation, selective sulfur removal is required. The high proportion of CO_2 in the syngas is to be retained to increase power production in the syngas expander and gas turbine as well as to suppress NO_x formation.

An intermediate pressure let down stage of the rich liquor from the AGR absorber preferentially desorbs the CO_2. This is returned to the absorber, leaving the sulfur (in the form of hydrogen sulfide) to pass on in the liquor to the stripper column. The stripped sulfur gases are passed to an oxygen-blown Claus plant and the tail-gases recycled to the absorber.

Fuel Preparation and Power Production

Following acid gas removal, the syngas is preheated using steam raised from Low Temperature Gas Cooling, and then expanded through a power generating expander to the pressure required by the gas turbine fuel control system. The fuel gas is then saturated to minimize NO_x formation, and finally superheated with a steam heat exchanger before being directed to the gas turbine combustors.

The CCU itself comprises two GE 9FA gas turbines fitted with individual HRSGs feeding a single steam turbine. The gas turbines have standard low BTU combustors, using fuel nozzles sized to accommodate syngas flow. The ability to operate a gas turbine on fuel with high concentrations of hydrogen has been demonstrated both in the laboratory and in commercially operating IGCC plants(1) (2). The GE steam turbine is part of a standard triple-reheat steam cycle.

With CO_2 Capture

The flow scheme is the same when operating with CO_2 capture mode. The control and flexibility of the operation are retained. Indeed, the conditions are identical to the non-capture case to the AGR. In this case the CO_2 absorbed in the liquor is not returned to the inlet of the absorber after stripping, but sent to a compression system for export. (This design configuration, including CO_2 capture, is currently in operation at several Texaco licensed units used for production of fertilizers.) This removes 75% of the carbon originating from the fuel and results in the following downstream performance changes:

1. A smaller quantity of dry syngas generates less power in the syngas expander.

2. The absence of CO_2 to suppress flame temperature means that a much higher degree of syngas water saturation is required (increased from 11% to 41% by volume).

The net result is a relatively small drop in net plant output and thermal efficiency. However the operating characteristics of the gas turbine and entire combined cycle unit are maintained.

Performance Summary

The performance of the flow scheme, with and without carbon dioxide capture, has been calculated to show net output and overall thermal efficiency. The results are summarized in Table 1.

The coal feedstock is Pittsburgh #8. A capture of 75% of the carbon in the coal has been chosen, but this could be higher. No provision is made for the drying and compression of the CO_2 that leaves the Battery Limits of the process at atmospheric pressure.

The flow scheme and the units of which it is composed have been computer modeled as follows:

- The ASU, Gasification, AGR and CCU were modeled by suppliers using in-house simulators.

- Jacobs modeled Heat Recovery and Gas Treatment (CPG) using Aspen Plus®.

The capture of 75% of the carbon in the coal results in a loss of efficiency of only two percentage points and a decrease in net output of 3%, or 26MW.

The reduction in performance is caused by the export of carbon dioxide before it can be expanded and the need to replace the CO_2 with water vapor for saturation of the syngas fuel. The extra energy required for this extra saturation is taken at the expense of the steam cycle.

Table 1: Performance Summary		
Case	No CO_2 Removal	CO_2 Removal
Feed	Pittsburgh #8 (83 bar)	Pittsburgh #8 (83 bar)
Rate (t/h) (Dry)	237.0	241.6
Rate (t/y) (Dry)	1,896,000	1,933,000
Oxygen (t/h) (as 100%)	233.9	238.5
GT Feed Composition (mol%, dry)		
Carbon Monoxide	7.35	5.80
Hydrogen	48.58	48.28
Carbon Dioxide	31.79	3.20
Water	11.02	41.49
Methane	0.01	0.01
Argon	0.51	0.50
Nitrogen	0.74	0.72
Power		
Expanders (MW)	26.2	20.6
Gas Turbines (MW)	572.3	586.4
Steam Turbines (MW)	388.4	354.9
ASU Consumption (MW)	93.6	95.4
Internal Consumption (MW)	28.9	28.1
Net Output (MW)	864.5	838.3
Efficiency		
Overall Net Efficiency (% LHV)	41.0%	39.0%
By Products		
Sulfur (t/h)	5.7	5.8
Carbon Dioxide (MTPD)	-	12,250.

Capital Cost Estimate

Estimation of Capital Cost

Each major unit (ASU, Gasification [including Low Temperature Gas Cooling and the AGR], and CCU) can be defined inside precise Battery Limits with minimal inter-connections.

These standard units have reference lists, and operate within previously experienced parameters. The suppliers were fully informed of the operating characteristics of units upstream and downstream of their own, and actively participated in the flow scheme development process.

Jacobs, using in-house data from previous study work, estimated the balance of the plant, including the CPG Heat Recovery and Shift System. The plant costs (in $MM US Gulf Coast) and the Balance of Plant are summarized in the following table:

Table 2: Capital Cost Estimate	
Without CO_2 Capture	$ Million U.S.
Air Separation Plant	105.
Gasification	301.
Combined Cycle Unit	374.
Balance of Plant	62.
Total Installed Cost	842.

The cost of capital is $974/kW in mid 2001 $U.S.

Upgrading the unit to capture CO_2

Some investment costs can be deferred if it is anticipated that CO2 capture is not required during initial operation. A saturator system sized for the smaller circuit may be installed for initial commissioning and operation, and increased in size with a parallel installation when CO_2 capture is planned. The gas turbine fuel nozzle orifices will be resized for optimum operation without CO_2 in the fuel. The cost for the equipment modifications to capture CO_2 is estimated to be between \$5 and \$10 million. There will also be additional costs associated with CO_2 compression, which will largely depend on the specific sequestration/utilization application being employed. This illustrates an important objective of the study team, to develop a flow scheme that would only need a small investment to reconfigure the plant.

PROCESS DETAILS

Air Separation Unit

In the proposed scheme the ASU is self-standing, with oxygen supplied “over-the-fence” (i.e. without ASU/gas turbine integration or air supply/nitrogen return). Integration of the ASU with the CCU may be considered for NO_x control or performance enhancement in future optimization if warranted.

The Quench Gasifiers and Shift Reaction

High Pressure Quench

A quench gasifier utilizes the heat of the gasification reaction to provide a very high level of saturation and is ideal preparation for a shift reactor. The reaction heat provides an excess of steam content in the syngas for shifting, and most of the energy is effectively recovered as explained below.

The water gas shift reaction is equimolar. That is, each molecule of carbon monoxide that is shifted to carbon dioxide requires a molecule of water vapor. To encourage the reaction to shift to carbon dioxide, much more water needs to be available for reaction. A normal starting point is to have as least as much water vapor as dry syngas. To add this water as steam is inefficient. A better technique is to saturate the hot syngas from the gasifier by directly quenching it with water. This cost of doing this is significantly lower than the cost of raising steam for direct addition to the syngas.

Sour Shift

The shift reaction was first practiced on the “water gas” made in cyclic low-pressure coke gasifiers to produce hydrogen for ammonia production (The coke referred to is gasworks’ coke, not petroleum coke, and is the sulfur free by-product of coal pyrolysis for the production of town gas). The catalyst was robust, reliable and, being based on iron oxides, relatively cheap.

Today, sour shift catalyst is available from several catalyst suppliers. An example of its use is the Ube Ammonia plant in Japan (3), which has been successfully operating with four Texaco Quench gasifiers followed by a sour shift catalyst system since 1983.

Heat Recovery

An HRSG in the combined cycle unit recovers the gas turbine exhaust heat to feed the steam cycle. This flow scheme utilizes some of this steam energy to raise the enthalpy of the gas turbine fuel by preheating and saturating it with water. This is more thermodynamically and economically advantageous than utilizing all of the energy in the steam turbine.

In IGCC, the CCU is preceded by a gasifier with a typical “cold gas efficiency” of 80%. This means that only 80% of the feedstock chemical energy is being fed to the gas turbine, the rest being released as heat. This has to be efficiently recovered to maintain a high overall IGCC thermal efficiency.

It is generally recognized that this gasification heat would be best fed to the gas turbine to maximize CCU efficiency. There is a practical limit to the amount of fuel preheat employed due to materials and safety concerns, but gasification heat can also be used in the production of the inert additive needed to reduce syngas fuel flame temperature, and hence reduce NO_x production. Here, gasification heat is used to moisturize the fuel for this purpose.

For non-shifted flow schemes using a quench gasifier (as per the three Italian Refinery Projects ISAB, Sarlux and API), the gasification heat is used for raising low-pressure steam and for saturating syngas fuel. The ISAB flow scheme in particular uses a proprietary scheme known as Simple CPG (4) (Clean Power Generation) to maximize the input of gasification waste heat to the gas turbine.

With shifted schemes, gasification heat recovery can be improved. The system adopted for the flow scheme described in this paper is Catalytic CPG (5).

The shift of water and carbon monoxide to hydrogen and carbon dioxide with the release of heat has benefits related to recovery of energy. The exothermic shift reaction produces superheated syngas, which can be used to make high-pressure steam. Shifting also increases the mass flow of dry gases in the syngas. This will lead to increased Syngas Expander output, especially if the carbon dioxide is not removed.

Acid Gas Removal (AGR)

The syngas is cooled after shift and heat recovery to a low enough temperature for wet acid gas removal. The AGR requirements are to remove sulfur compounds only from the syngas when the IGCC plant is operating without CO_2 capture, and to selectively remove both sulfur compounds and CO_2 when in capture mode.

It is proposed to use a physical absorption and separation process such as the Selexol™ process licensed by UOP, which has a proven record in successful IGCC application. High syngas pressure will also favor a physical process. The AGR inlet syngas quality and operating conditions will not change when moving from the removal of sulfur only mode to the removal (separately) of sulfur and carbon dioxide mode. The major changes in operation are obviously downstream of the Selexol™.

UOP has confirmed that Selexol™ is capable of removing either sulfur selectively, or both sulfur and CO_2 in a single unit.

NO_x Control

Suppression of gas turbine NO_x formation when using low heating value fuels (e.g. syngas) is achieved through the lowering of flame temperature by the injection of inert gases, such as nitrogen, moisture or carbon dioxide, into the fuel gas (6) (7). The availability and practicality of bringing these inerts into the combustor usually limits the degree of choice. Nitrogen requires integration with the ASU, which may not be optimum in all cases.

In this scheme, syngas saturation is used to reduce NO_x to 25 ppmvd at 15% O_2 and to improve plant output using otherwise rejected heat. This requires no expensive demineralization because carbon dioxide produced in the shift reaction and not captured for export reduces the need for any additional nitrogen or water suppression.

Previous Studies

Carbon dioxide capture in an IGCC fitted with a catalytic shift system has been studied many times before (8) (9) (10) (11). In all cases, the performance and cost of the shifted flow scheme is compared with that of a separate flow scheme not containing a shift reactor. The difference in capital cost per megawatt is substantial and the anticipated drop in efficiency for the insertion of the shift and subsequent CO_2 capture system is never quoted as less than five percentage points. The implication is that the with and without schemes are totally separate plants which would mean a massive re-design and re-build when changing to CO_2 capture mode.

CONCLUSIONS

The flow scheme presented here involves a small cost expenditure for changing to CO_2 capture mode, and the decrease in efficiency is approximately two percentage points. The scheme demonstrates the economic impact of CO_2 capture can be a lot less than previously thought. The flexibility to build and operate a conventional IGCC plant and to convert later to CO_2 capture enhances the likelihood that such plants will be seriously considered by power developers in the near future.

The flow scheme presented in this paper is a solution for the fossil-fuel power generator seeking a new plant design that can conform to potential future regulations. A power station based on this scheme would be a front-runner in terms of environmental performance, capital cost per unit of output and thermal efficiency. The design philosophy presented in this paper aims to minimize potential commercial problems and produce a robust technology thus reducing contingency allowances and insurance costs.

Technically, a proven concept, the shift reactor, has been introduced into a standard IGCC flow scheme to bring the following advantages, in addition to that of enabling the pre-combustion capture of carbon dioxide:

- Efficient heat recovery.
- Enhanced COS hydrolysis.
- Enhanced hydrogen concentration of the syngas, thus reducing the cost of H_2 export.

Future Work

The figures given in this paper are valid but not optimized. There are a considerable number of operating parameters that can be adjusted to improve performance and/or lower capital costs. The procedure for calculation has now been established and is available for evaluating specific opportunities. The scheme is commended as the way forward for clean coal electricity generation.

ACKNOWLEDGEMENTS

The authors of this paper wish to acknowledge the work effort of all that contributed to this effort including representatives from UOP, Praxair (Jerry Paolino), BOC and Air Products. In particular, we wish to express our thanks to Ashok Anand, Patrick May and John Sanders of General Electric Power Systems.

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Figure 1: Simplified Process Flow Diagram