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COMPARISON BETWEEN OXYGEN-BLOWN AND AIR-BLOWN IGCC POWER PLANTS: A GAS TURBINE PERSPECTIVE

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ABSTRACT

The gasifier in an Integrated Gasification Combined Cycle (IGCC) Power Plant gasifies coal using an oxidant gas that facilitates partial combustion and effective gasification of the coal feed. When electricity generation is the prime objective of the IGCC facility this oxidant can be ambient air, or gaseous oxygen produced from an Air Separation Unit (ASU). Gasification technology providers are presently divided in their type of offering and information in the public domain does not effectively guide End Users in the advantages and disadvantages of the two gasification methods as applicable to the particular project being developed.

This paper highlights key design aspects that should guide End Users in making an effective assessment and perform detailed evaluation of the gasification technologies for the particular IGCC project in consideration.

INTRODUCTION

An entrained flow slagging gasifier is a reactor that provides a contained high-pressure and high-temperature environment for the fed coal to partially burn (react with an oxidant) and release sufficient heat to melt all the ash content into molten slag, while providing a reducing environment to convert the carbon in the coal into carbon monoxide. Steam is added to the gasifier to moderate the temperature of the gasification process, although other moderators can be used instead. Under the extremely hot conditions within the gasifier, coal devolatalises into gases like methane, carbon monoxide, carbon dioxide and other elements like oils, tars and char (carbon). The total residence time within the entrained flow gasifier is in the order of few seconds.

In addition to devolatalisation described above, the following reactions take place within the gasifier reactor vessel:

$$C + O_2 \rightarrow CO_2 \qquad (1)$$

$$C + \frac{1}{2}O_2 \rightarrow CO \qquad (2)$$

Reactions (1) and (2) consume the oxidant supplied to the gasifier and are exothermic reactions, releasing heat in the gasifier.

$$C + H_2O \rightarrow CO + H_2 \qquad (3)$$

$$C + CO_2 \rightarrow 2CO \qquad (4)$$

Reactions (3) and (4) are reversible endothermic reactions and proceed significantly slower than reactions (1) and (2).

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (5)$$

Reaction (5) is the CO Shift reaction. This reversible reaction is slightly exothermic in the direction shown.

$$CO + 3H_2 \rightarrow CH_4 + H_2O \qquad (6)$$

$$C + 2H_2 \rightarrow CH_4 \qquad (7)$$

Reactions (6) and (7) are exothermic methanation reactions. However, these reactions are more prevalent in gasifiers that operate at lower temperatures.

In addition to these fundamental reactions, sulphur in the coal gets converted into hydrogen sulphide (H_2S). A small portion of the sulphur also converts into carbonyl sulphide (COS) in the reducing environment present in the gasifier.

The reducing environment also encourages the reaction of fuel bound nitrogen into ammonia. However, the ammonia quickly breaks down into nitrogen and hydrogen in the high temperature environment. Thus, the ammonia content in the produced syngas is a function of the gasification temperature. Small amount of hydrogen cyanide (HCN) is also produced.

A detail description of the gasification reactions can also be found in reference [1]

GASIFIER TYPES & RELEVANT CHARACTERISTICS

This paper focuses on entrained-flow type gasifiers as this is the preferred gasifier type for hard coals, and has been selected for majority of commercial-sized IGCC facilities. All entrained-flow gasifiers are of the slagging type.

Reference [2] provides a good description of different gasifier types. The purpose of this article is not to cover these in detail, but to touch upon some key technologies with characteristic process differences. While considering these gasifier types in this paper, provision for carbon capture has been considered. Following entrained-flow gasifier types are addressed in this paper:

- Dry-fed, membrane-wall type reactor, oxygen-blown gasifier with recycle gas quench and syngas cooler (e.g., Shell, Prenflo, Siemens), as illustrated in Figure 1.
- Slurry-fed, refractory-lined reactor, oxygen-blown gasifier with water quench or syngas cooler (e.g., GE-Texaco gasifier), as illustrated in Figure 2.
- Two-stage, dry-fed, membrane-wall type reactor, air-blown gasifier with chemical quench and full char recycle (e.g., MHI gasifier), as illustrated in Figure 3.

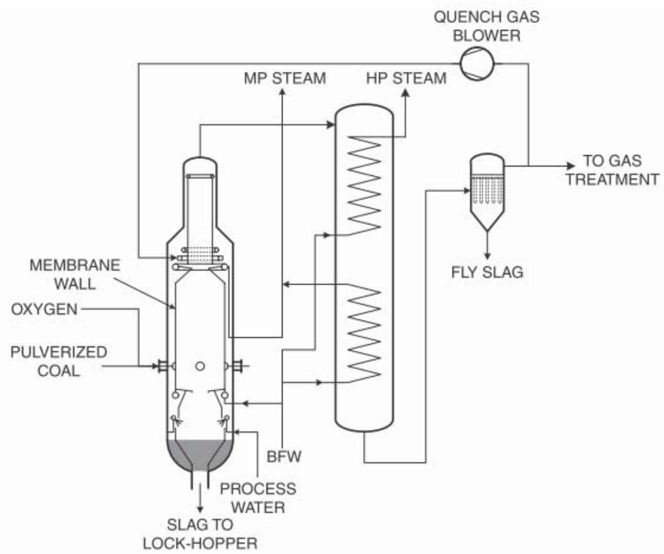

Figure 1 Schematic: Shell Coal Gasification Process[1]

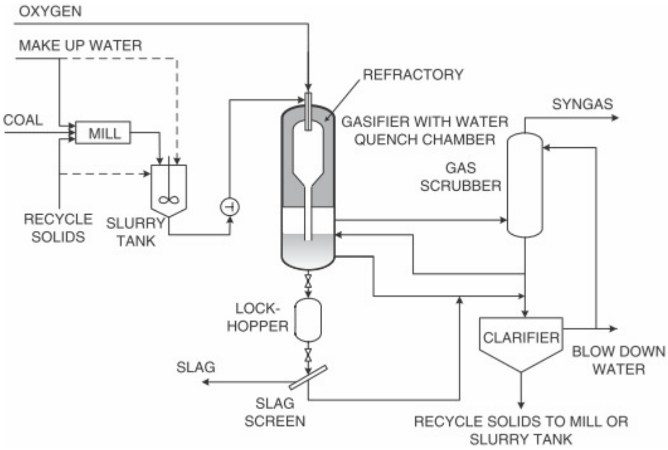

Figure 2 Schematic: GE-Texaco Coal Gasification Process[1]

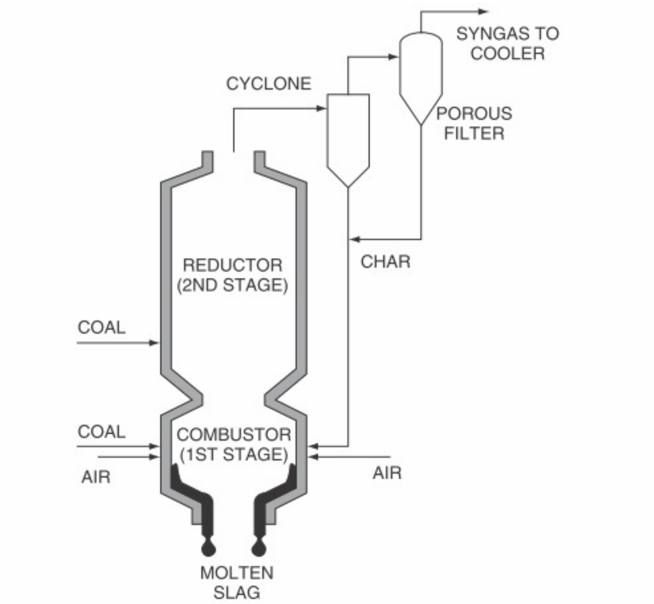

Figure 3 MHI Coal Gasification Process[1]

A slurry-fed gasifier requires 20% ~ 25% more oxygen as oxidant as compared to a dry-fed gasifier since more heat is required to vaporise all the water in the slurry. As a result, more carbon in coal is oxidised to carbon dioxide in a slurry-fed design, which reduces the cold gas efficiency. This problem is further aggravated on low-rank coals with high moisture content, as the inherent moisture in coal does not make any contribution to the transport properties of the slurry, and water must still be added in large quantities (30% to 40% of coal mass flow) in order to pump the coal. Increased auxiliary power consumption due to the increased size of the ASU reduces the overall plant efficiency. The slurry fed design utilises a slurry pump to feed the coal slurry into the gasifier, and this does allow the gasifier to be operated at very high pressures, typical of coal to chemical plant facilities. However, such high pressures are not required for an IGCC plant, as fuel supply pressure to the gas turbine is generally less than 30 bar a.

In contrast, the ASU size and power consumption for a dry-fed, oxygen-blown gasifier is lower, while its cold gas efficiency is higher for the same grade of coal. These gasifiers also use a gas quench in the gasifier at 900°C using cooled and scrubbed syngas at approximately 200°C[3]. The quench temperature is high enough to allow for effective heat recovery, while being cold enough to solidify molten slag particles carried over in the syngas flow path. This solidification of slag particles is essential to prevent fouling of the syngas cooler and other downstream equipment. However, as compared to a chemical quench used in a two-stage air-blown gasifier, this quench circuit requires a robust compressor design with parasitic auxiliary power demand.

The two-stage, dry-fed air-blown gasifier splits the coal feed flow to two distinct zones. The lower first stage operates under exothermic, high temperature, slagging conditions receiving coal and the oxygen-enriched air flow as oxidant. The remaining coal feed is added to the upper stage, which acts as a chemical quench of the gases from the first stage. This upper stage operates under endothermic conditions, and is a non-slagging stage. The particulate matter in the syngas contains char and un-reacted carbon. This is removed from the gas downstream of the syngas cooler, and recycled to the lower first stage. In this way, this gasifier not only achieves very high carbon conversion, but also ensures that all ash is removed from the system as slag. A point of interest is to note that the MHI gasifier does not introduce steam in the gasifier, which is unlike the other gasifier types that utilise steam as a moderator in the gasification process.

An advantage of the two-stage design is that the slag being produced in an exothermic zone, its quench water does not contain toxic gases and chemicals otherwise associated with slag water produced on single stage gasifiers. This greatly simplifies and reduces the costs for process water treatment in the two-stage dry fed air blown gasifier, as compared to the other options.

OXIDANT TYPE & RESULTING SYNGAS COMPOSITION

When oxygen is used as the oxidant, this has to be produced in an ASU that consumes significant amount of auxiliary power, reducing the overall efficiency of the power plant.

In contrast, in an air-blown gasifier, atmospheric air is pressurised and used as oxidant. The air-blown technology still uses a much smaller ASU (approximately 15% capacity as compared to the ASU for an oxygen-blown plant of same size) – but, this is provided only to generate nitrogen gas required to safely convey coal into the gasifier. By-product oxygen generated from this ASU is often mixed with the air supply for gasification, thus using oxygen-enriched air as the oxidant. Occasionally, particular coal types may require the oxygen enriched air to achieve necessary slagging conditions within the gasifier, and then can influence the size of the ASU for the air-blown gasifier.

The type of oxidant used for gasification (air or oxygen) also affects the syngas composition produced from the gasifier. Typical compositions from air-blown and oxygen-blown gasifiers are provided in the table below:

Table 1 Typical Scrubbed Syngas Composition from Gasifiers (mol%) [4]

Component	MHI Air-blown	O2 Blown Dry Feed	O2-Blown Slurry Feed
Temperature	120°C	180°C	210°C
CO	30.50	54.5	38.4
H_2	10.50	28.2	27.5
CO_2	2.80	3.8	12.0
H_2O	5.00	9.1	20.0
Ar	0.5	1.0	0.1
N_2	50.9	3.4	1.5
H_2S	0.001	0.13	0.11
CH_4	0.5	0.0	0.1
TOTAL	**100.00**	**100.00**	**100.00**

The concentration of the sulphur constituents (H_2S and COS) is dependent on the sulphur content of the coal feed. Also, halogen compounds present in the coal are washed away in the scrubbing process downstream of the gasifier.

Syngas from air-blown gasifiers will contain nitrogen. Also, the methane content will be higher in air-blown two-stage gasifier.

In contrast, the high water content in the slurry fed gasifier favours the CO Shift reaction within the gasifier, resulting in higher H_2:CO ratio, and higher CO_2 content as compared to dry-feed gasifiers. The influence of this on CO shift design is discussed in a later section of this paper. The methane content is markedly lower in slurry fed design, only increasing slightly with increasing gasifier operating pressure.

The syngas composition affects the type of syngas treatment, in particular when the power plant is designed for carbon capture. Power consumption of the syngas treatment is also influenced by the syngas composition at the inlet and outlet. Presence of nitrogen in the syngas, as in air-blown gasification technology, does increase the power consumption of the Acid Gas Removal (AGR) unit.

SYNGAS COMBUSTION CHARACTERISTICS IN GAS TURBINES

Firing syngas in gas turbines designed & optimized for natural gas operation results in a higher fuel gas flow rate, than natural gas firing and the mass flow rate into the turbine must increase. Either the total pressure or the critical nozzle area must increase to accommodate this increased mass flow. Thus, for the same expander section gas molecular weight and total temperature as natural gas firing, the compressor pressure ratio must increase and/or the axial compressor mass flow rate must decrease while firing syngas.

Operating at higher pressure ratio has the following drawbacks:

- Turbine aero foils are thermally and aerodynamically overloaded; and
- Compressor will operate closer to the surge limit – which introduces risk of compressor damage with aging of blades & transient changes during operation.

With this large fuel flow and high pressure ratio operation, suitable modification of the gas turbine components or operational restriction will be required.

On the other hand, high gas turbine flow results in the gas turbine producing more output power, as the ratio of expander mass flow is higher than the compressor mass flow. But, this increase in gas turbine output comes at the cost of the following factors:

- Increased operating pressure of the gasifier to generate syngas
- Increased discharge pressure of the ASU (in oxygen-blown gasification)
- Increased pressure of the diluent (if separately added, and as required in oxygen-blown gasification) at the elevated pressure for the syngas firing gas turbine, and
- In an oxygen-blown technology, inefficiencies arise due to the need to separately heat the diluent nitrogen from the ASU using steam from the power block. Nitrogen temperature has to approach the fuel supply temperature to the combustor not only to avoid thermal shock, but to ensure stable combustion conditions.

Accordingly, this increased gas turbine output while firing syngas is produced at an increased overall plant heat rate as compared to the operation of the gas turbine on natural gas. This aspect does not favour the overall plant life cycle economics.

SYNGAS COMBUSTION METHODS IN GAS TURBINES & INFLUENCE OF GASIFICATION TECHNOLOGY

Modification strategies to avoid the aerodynamic limits and surge scenario described in the previous section can be one or a combination of the following:

a) Use VIGV (Variable Inlet Guide Vanes) to reduce compressor mass flow rate. And firing temperature may be reduced according to compressor surge limit.

b) Air compressor is downsized from the standard gas turbine, and the air flow is reduced by adjusting the height of compressor blades (tip cut).

c) Expander inlet nozzle redesign. This is an alternative that increases the capital expenditure of the gas turbine. A manufacturer may choose this path for the need to maximise output on syngas firing, when the compressor map does not have enough surge margin to support it.

d) Air Integration with the Gasification Plant. In this strategy, air is bled from the axial compressor of the gas turbine, at or near its discharge to the combustors, allowing its operation with a larger surge margin as compared to strategies a) and b) above, while firing syngas. This is also the only strategy that results in an overall plant heat rate reduction accompanied by capital cost reductions, when compared with the strategies described above. However, operating IGCC plants demonstrate that this strategy is most effectively adopted on air-blown gasification (as successfully demonstrated at Nakoso, Japan), as opposed to oxygen-blown gasification (based on the problems faced with air-integration in European IGCC projects). The technical reasons for this are explained in the following section.

ROLE OF AIR INTEGRATION

For a given coal type, the overall performance of the Integrated Gasification Combined Cycle (IGCC) power plant is influenced greatly by the nature of integration between the gasification unit, syngas treatment unit and combined cycle power block. Several references [5, 6] highlight the efficiency gains that are exhibited by incorporating full air integration between the gasification plant and the gas turbine.

The gasifier block compresses large quantities of air to produce its oxidant. In an oxygen-blown gasifier, this air is supplied to the ASU, while in an air-blown gasifier, this can be directly injected into the gasifier. Air-side integration is achieved by extracting compressed air from the gas turbine axial compressor, at a suitable pressure, for supplying to the gasifier block. As explained later, syngas combustion characteristics necessitate and can derive benefit by this air extraction. And, the type of gasification technology influences the effectiveness of this air integration.

Full air-side integration affects the mass flow of air supplied to the gas turbine combustor, and the expansion flows over the turbine. Expansion flow rate over a syngas fired gas turbine is determined by the syngas combustion strategy adopted by a gas turbine manufacturer. A point to note here is that air integration and the gas turbine strategy to handle syngas combustion are inter-related.

As the extracted air from the gas turbine compressor has to pass through an ASU in an oxygen-blown gasifier, ASU size (residence time) and performance do affect the overall integration. The ASU uses a "heat integrated" double column (thermal coupling between the reboiler & condenser system) directly in the main process flow (oxidant flow). Any dynamic changes in the gas turbine load / gasifier demand, immediately affects the oxygen and nitrogen purity, with minor excursions in the direction of lower purity potentially initiating a trip condition. Thus, the ASU dynamic response represents a very non-linear behaviour (sinusoidal damped response, at best). The cryogenic nature of the process also introduces large response lags (in the order of minutes, and even hours), and every disturbance introduced has to be tracked by model predictive control techniques. The ASU response is not only dependent on the magnitude of change, but also the direction of any process change.

In the second International Freiberg Conference on IGCC held on 9th and 10th May 2007, with reference to the European IGCC plants using oxygen-blown gasification technology, and using air integration between gas turbine and gasifier through the ASU, Chris Higman mentioned that operational difficulties associated with controls and start-up procedures have led to the industry to leaving the full air-side integration route – although with some regret at not exploiting the maximum efficiency [7]. This also explains why several other oxygen-blown gasification projects considered later do not incorporate air-integration between the gas turbine and the ASU.

In contrast, the air-blown IGCC plant at Nakoso in Japan has been operating in the full air-integration mode without any control issues experienced at the oxygen-blown facilities. In this mode, all the gasification air requirements are met by the air extracted from the gas turbine. At this plant there is no direct interaction between the extracted air from the gas turbine and the much smaller ASU provided for nitrogen production. This technology therefore potentially offers improved plant reliability. This provides an overall plant design with lowest possible heat rate.

Most importantly, full air-integration does not impose the aerodynamic need to operate the gas turbine to produce more output than that produced while firing natural gas, thus resulting in superior life cycle cost performance for the power plant facilities.

NITROGEN ADDITION AS DILUENT

As explained in reference [8] syngas combustion (due to the presence of CO and H_2) is characterized by high stoichiometric flame temperatures and higher flame speeds due to the presence of hydrogen. These factors necessitate the use of a diluent like nitrogen in the syngas fuel prior to combustion in the gas turbine.

Another key role played by nitrogen content in syngas is NOx abatement. While steam or water can supplement it for NOx abatement this may not be preferred for the following reasons:

- Higher thermal conductivity of water does adversely affect the hot gas path, causing significant increases in gas turbine maintenance costs;
- Increase in water content in the gas turbine exhaust flue gases increases the acid dew point, limiting the amount of heat recovery in the Heat Recovery Steam Generator (HRSG) and affecting the overall plant efficiency.
- Another drawback of water / steam injection is the increased water consumption, which may not be favourable for most projects executed in a water-constrained world.

Another potential diluent and NOx abatement agent can be CO_2 – but its thermal conductivity is similar to that of steam under gas turbine firing conditions, and therefore may not be preferred.

Thus, with the use of diffusion combustors, nitrogen remains the diluent of choice for syngas combustion.

With an oxygen-blown gasifier, the produced syngas only contains traces of nitrogen, introduced as carrier gas in a dry-feed gasifier. However, the ASU, while producing the oxygen required as oxidant also produces large quantities of nitrogen gas as a by-product. This nitrogen gas is therefore blended in the syngas immediately upstream of the syngas combustors or directly at the combustors as head-end diluent.

However, the nitrogen extracted from the ASU is at very low temperatures, and has to be heated in usually a series of heat exchangers to the hot syngas fuel temperature (typically more than 150°C), for effective blending. The ASU, being a cryogenic process, varying the nitrogen flow with the plant load, and varying the steam for nitrogen heating prior to leading it to the combustor, pose a significant control challenge. Being temperature control, the system response can be sluggish resulting in variations in the heating value of the fuel blend led to the combustors, and also the temperature of the fuel mix.

These variations in diluent concentration and temperature result in variations in the Modified Wobbe Index (MWI), which is a key characteristic of the gas turbine combustor design. MWI is defined as follows:

$$Modified\ Wobbe\ Index = \frac{LHV}{(SG)^{0.5}}\left[\frac{T_{STD}}{T}\right]^{0.5} \qquad (8)$$

where,

LHV = Lower Heating Value of the fuel in MJ/kg

SG = Specific Gravity of the gas with respect to air

T = Temperature in K

While diffusion combustors (unlike DLN combustors) are more tolerant to MWI variation, the fluctuations in MWI can be particularly severe with power plant load changes, and will require development and demonstration of advanced control schemes to ensure effective Wobbe Index control.

On the other hand, with an air-blown gasification technology, nitrogen remains an inherent constituent of the syngas, and does not pose any blending or temperature control issues for firing in gas turbines.

It must be noted that all gasification technologies when equipped with carbon capture (CO shift and CO_2 absorption processes) will potentially introduce variations in H_2, CO and CO_2 concentrations with load changes & upsets that will affect the MWI. Accordingly, technology solutions that minimise such fluctuations in MWI and maintain stable combustion conditions, will be vital to reduce O&M costs of the gas turbine.

SYNGAS COMPOSITION & CO SHIFT PERFORMANCE

The Water-Gas Shift reaction or CO Shift reaction is an equilibrium reaction that converts carbon monoxide by reacting with steam into hydrogen and carbon dioxide, and is moderately exothermic. The reaction is expressed as follows:

$$CO + H_2O \leftrightarrow H_2 + CO_2 \quad \Delta H = -41\ kJ/kmol \qquad (9)$$

While reviewing this chemical reaction, it is important to realise that carbon monoxide (a fuel burning component) is converted into CO_2 for carbon capture, and represents a loss in heating value. Also, steam from the power block required for the shift reaction represents another loss to the system. Some of this loss can be recovered in the form of heat recovery immediately downstream of the CO Shift reactor.

The CO shift reaction, being exothermic, is favoured in the forward direction (to maximise CO_2 yield) by a lower temperature. However, a higher temperature favours the kinetics in the reactor. Under the typical syngas conditions leaving the syngas scrubber, several types of shift catalysts are commercially available, viz., high-temperature & low-temperature shift catalysts, sour shift (requiring H_2S) and sweet shift catalysts. This paper focuses on the use of high-temperature sour shift catalyst, as this is more easily applied to

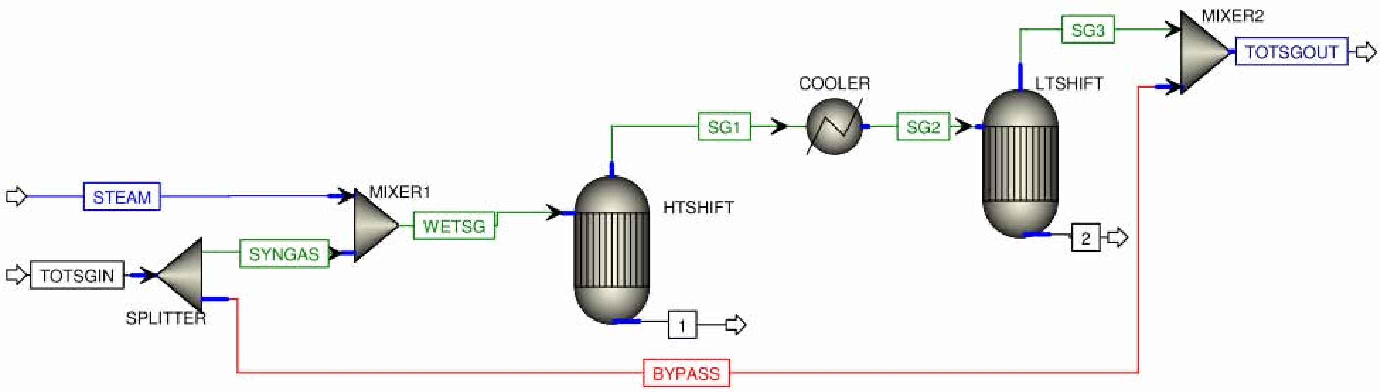

Figure 4 Simplified CO Shift Scheme modeled in Aspen Plus®

most IGCC configurations with carbon dioxide capture using a physical solvent.

In order to review the influence of the gasification technology on the CO Shift reaction, a simplified model was setup in Aspen Plus®. This is shown in Figure 4. Actual schemes for CO shift for IGCC plants with carbon capture are more complicated, with the use of feed-product heat exchangers and steam generation to maximise heat recovery, while allowing for most efficient conversion of CO to CO_2 with least possible energy penalty.

Main specifications for the Aspen Plus® model are listed below:

- Steam to dry gas ratio at the final outlet (stream TOTSGOUT) set to 0.3, defining the steam requirement for the shift.
- Steam conditions of 300°C and 4 MPa A are used, as steam under such conditions can be typically obtained from the Heat Recovery Steam Generator (HRSG) in the power block.
- Temperature approach to equilibrium for the high temperature shift and low temperature shift reactors set at 85°C and 50°C, respectively.
- Inlet temperature to low temperature shift reactor set at 280°C. This decides the cooler duty.
- Only the syngas flow that allows 65% capture is passed through the shift reactors. Remainder gas is bypassed through the BYPASS stream.

For the three gasification technologies being studied here, the syngas compositions given in Table 1 were used as feed syngas compositions (stream TOTSGIN). The model runs adjusted the steam flow rate supplied for shift and the bypass flow rate to obtain the target CO_2 concentration in the outlet syngas.

The simulation results of the model runs are presented in Table 2. Following inferences are drawn from the information in this table:

- As steam is not added in the air-blown dry feed technology, the water content in the inlet syngas is markedly lower. The water content here is due to the moisture inherent in the coal and as formed by the combustion of volatiles in the coal, under the gasifier conditions. Water content in the oxygen-blown dry-fed gasifier is higher due to the addition of steam in the gasifier. Similarly, water content in the oxygen-blown slurry-fed gasifier is due to the water used to slurry the coal.

Table 2 Gasification Technology & CO Shift

Parameter	Air-blown Dry Feed	O2 Blown Dry Feed	O2-Blown Slurry Feed
Syngas Flow Rate, kg/h	250,000	250,000	250,000
Target Carbon Capture	65%	65%	65%
CO_2 in Feed Syngas	2%	3.8%	12%
H_2O in Feed Syngas	10%	28.2%	27.5%
CO Shift Bypass Flow	33.7%	30.3%	37.8%
Steam:DG Ratio at Outlet	0.3	0.3	0.3
Steam Supply to CO Shift Reactors, kg/h	87,820	139,500	67,500
Slurry Water to gasifier, kg/h	---	---	37,000

- The CO_2 content in the syngas from the oxygen-blown slurry-fed gasifier is markedly higher due to the need to raise the temperature of slurry water to the gasification temperature of approximately 1500°C. This reduces the duty for the shift conversion, resulting in lower steam requirement for the shift reaction. However, a higher product concentration at the inlet to a high temperature equilibrium reactor can potentially increase the size of this reactor for the same degree of overall shift across the reactor.
- However, for proper comparison between the technologies, it is essential to make an assessment of the amount of water that has to be added to the gasifier for slurrying the coal. Reference [9] provides an estimate of coal consumption for a slurry fed GE Texaco gasifier and the corresponding syngas production rate. Also, reference [1] states that the slurry used for feeding into the gasifier requires 30% to 40% liquid water. This forms the basis for estimating the slurrying water in Table 2.
- From an overall efficiency perspective, it is also important to draw a distinction between the steam added for the CO Shift reactors and slurry water heated in the gasifier. The steam added to the CO shift is generated by heat recovery in the power block by

heating boiler feedwater to approximately 300°C. Whereas, the slurry water must be heated to the gasification temperature of 1500°C by coal combustion and production of CO_2, which is bound to be more inefficient, despite heat recovery in the syngas cooler.

- The main reason why shifting the syngas from the air-blown gasifier imposes lower total water / steam requirement is due to the presence of nitrogen in the syngas. The CO Shift reaction is an exothermic reaction. The steam added not only meets the reaction requirements, but also acts as a heat sink in removing the heat generated within the reactor and thereby aiding the forward reaction. Unlike the oxygen-blown processes, the nitrogen in the syngas produced from the air-blown gasifier acts as the heat sink, reducing the total steam requirement to achieve the desired conversion to CO_2. This reduction in steam requirement offers opportunity to improve the overall plant efficiency.

Thus, in principle, the CO Shift reaction on syngas derived from an air-blown gasifier does offer potential to reduce the steam/water requirement for this reaction and potentially improve the overall plant performance.

SYNGAS COMPOSITION & ACID GAS REMOVAL

Acid Gas Removal (AGR) processes remove H_2S and CO_2 from the shifted syngas in an IGCC plant designed for carbon capture. There are two broad categories of commercial scale CO_2 removal technologies deployed in the industry. These are the physical solvent technologies and chemical solvent technologies. Membrane technologies are still under various phases of development, and therefore, not considered here.

In principle, these absorption technologies process shifted syngas in series of absorbers – separately designed for H_2S and CO_2 removal. Efficiency and capital cost of any absorption process is dependent on the concentration of the compound to be absorbed in the feed gas, and the ease with which the solvent can be regenerated to release the captured gas.

For a given IGCC plant output, an air-blown IGCC has to process larger flow rate of syngas because of the higher N_2 content in the syngas. The nitrogen content results in a lower partial pressure (concentration) of the acid gas in the feed to the AGR. This results in physically larger equipment installed in the Acid Gas Removal system. Also, the solvent circulation flows can be significantly higher than that required for an oxygen-blown IGCC plant for the same acid gas removal efficiency. This requires more power for the solvent circulation compared to O_2-blown IGCC. Parasitic power consumption for the AGR system in Air-blown IGCC is therefore expected to be 20-40% higher and inversely proportional to the partial pressure of CO_2 in the feed gas.

CONCLUSION

Two-stage, dry-feed air blown gasification technology shows some distinct advantages over oxygen-blown gasification technologies, whether these are dry-fed or slurry fed. These advantages relate to advantages in operational costs, reduced waste disposal issues, and better controllability. Significant differences are summarised below:

- Significantly smaller ASU that offers significant gains in overall plant efficiency
- Elimination of ASU in the air-integration path allows for full air-side integration without the operational challenges faced by an oxygen-blown gasifier with full air-side integration
- Full air-side integration avoids the need to operate the gas turbine (designed for natural gas) above the natural gas output rating – reducing the O&M costs associated with the gas turbine.
- The use of a chemical quench eliminates high temperature quench gas / water systems and equipment
- The exothermic slagging zone in the two-stage gasification process ensures that slag water does not contain toxic gases and chemicals typically generated in the reducing environment of a single stage gasifier. This greatly simplifies the process wastewater systems and reduces related costs.
- A full char recycle ensures carbon conversion efficiencies approaching 99.9%. Also, the fly ash waste stream or black water stream otherwise generated in the single stage oxygen-blown processes is eliminated with the air-blown technology discussed here, saving associated disposal issues and costs.
- With the air-blown technology nitrogen is inherently present in the syngas led to the gas turbine and the fuel does not have any Wobbe Index control issues with power plant load changes.

A major disadvantage with the air-blown technology is the increased cost of H_2S and CO_2 removal in the AGR system.

While selecting a gasification technology for an IGCC plant with carbon capture, End Users must consider several design factors beginning with the suitability of the technology for the coal type to the specification of trace elements in the

CO_2 stream produced for sequestration. Several opportunities exist within the plant for effective integration and heat utilisation. These opportunities offer to improve efficiency of the plant, but invariably increase the capital and/or operating expenditures.

The system design and integration is further complicated by the different technology packages provided by different technology providers. Performance of these systems, not only on a macroscopic level (efficiency, cost, etc.) but in their ability to control micro-contaminants and define waste stream constituents play a vital role in deciding the overall plant cost and economics. There is therefore the need for the End User to assess all such technology and integration aspects to avoid continuing cost escalation on a complex system that IGCC plant is. Hopefully, this paper has served in highlighting some of the issues relevant to IGCC technology selection.

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