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An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology

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Acronyms

AGR	Acid gas removal
ASU	Air separation unit
CC	Combined cycle
DLN	Dry low NO_x
GT	Gas turbine
HP	High pressure
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
IGV	Inlet guide vane
MWGS	Membrane water gas shift
SCR	Selective catalytic reduction
SEWGS	Sorption enhanced water gas shift
SOFC	Solid oxide fuel cell
SRU	Sulfur recovery unit
TGT	Tail gas treatment
TIT	Turbine inlet temperature
WGS	Water gas shift

1 INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

1.1 Introduction

The integrated gasification combined cycle (IGCC) produces electricity from a solid or liquid fuel. First, the fuel is converted to syngas which is a mixture of hydrogen and carbon monoxide. Second, the syngas is converted to electricity in a combined cycle power block consisting of a gas turbine process and a steam turbine process which includes a heat recovery steam generator (HRSG). The combined cycle technology is similar to the technology used in modern natural gas fired power plants.

Coal based IGCC plants are still not fully commercial. A number of demonstration plants with electric output up to 300 MW have been built in Europe and the US, all with financial support from government. The motivation for pursuing this technology is the potential for better environmental performance at a low marginal cost. This is especially true for mercury removal and CO_2 capture. In order to compete with conventional pulverized coal plants under current environmental regulation, the main challenges facing the IGCC technology today are capital cost and availability.

1.2 Classification of gasifiers

A number of gasifier technologies have been developed to various extents, and they may be classified as shown in Table 1 below. Operating temperature for the different gasifiers is to a large extent dictated by the ash properties of the coal. Depending on the gasifier, it is desirable either to remove the ash dry at lower temperatures (non-slagging gasifiers) or as a low viscosity liquid at high temperatures (slagging gasifiers). For all gasifiers it is essential to avoid that soft ash particles stick to process equipment and terminate operation.

Table 1. Characteristics of different gasifier types (adapted from [10])

Gasifier type	Fixed bed	Fluidized bed	Entrained flow
Outlet temperature	Low (425-600 °C)	Moderate (900-1050 °C)	High (1250-1600 °C)
Oxidant demand	Low	Moderate	High
Ash conditions	Dry ash or slagging	Dry ash or agglomerating	Slagging
Size of coal feed	6-50 mm	6-10 mm	< 100 μm
Acceptability of fines	Limited	Good	Unlimited
Other characteristics	Methane, tars and oils present in syngas	Low carbon conversion	Pure syngas, high carbon conversion

The four major commercial gasification technologies are (in order of decreasing capacity installed):

1. Sasol-Lurgi Dry Ash
2. GE (originally developed by Texaco)
3. Shell
4. ConocoPhillips E-gas (originally developed by Dow)

The Sasol-Lurgi gasifier (developed by Lurgi) has extensive commercial experience at Sasol's synfuel plants in South-Africa. It is of the fixed bed type and non-slagging. The other three gasifiers are of the entrained flow slagging type. GE with its former Texaco gasifier and Shell have significant commercial experience with gasification, while ConocoPhillips has less experience with their E-gas technology (formerly owned by Destec). Still, the three companies GE, Shell and ConocoPhillips are all perceived as the three major players with respect to future IGCC projects which seem to concentrate on entrained flow slagging gasifiers.

Fluidized bed gasifiers are less developed than the two other gasifier types. Operating flexibility is more limited for this class of gasifiers because of performing several functions (e.g. fluidization, gasification, sulfur removal by limestone injection) at the same time, and there are too few independent variables for the desired process optimization [10]. The Pinon Pine demonstration IGCC plant utilizing an air blown KRW[1] fluidized bed gasifier was not able to start up successfully in project period from 1998 to 2000. This gasifier involves ash removal through controlled agglomeration (sticking together) of the ash particles. In 2004, US DOE announced a $235 million grant to Southern Company's future 285 MW Orlando IGCC project in Florida which will be based on the KBR[2] Transport reactor. This fluidized bed type gasifier has been developed at smaller scale, and it is potentially well suited for low rank coals with high moisture and ash contents.

1.3 IGCC process description

Figure 1 shows the main blocks of a coal based IGCC plant similar to the recent demonstration units. The coal is supplied to the gasifier where it is partially oxidized under pressure (30-80 bar). The plant uses oxygen as oxidant and therefore has an air separation unit (ASU). In the gasifier, which is of the entrained flow slagging type, the temperature may exceed 1500 °C. The high temperature ensures that the ash is converted to a liquid slag with low viscosity, so that it may easily flow out of the gasifier.

[1] Kellogg Rust Westinghouse
[2] Kellogg Brown and Root

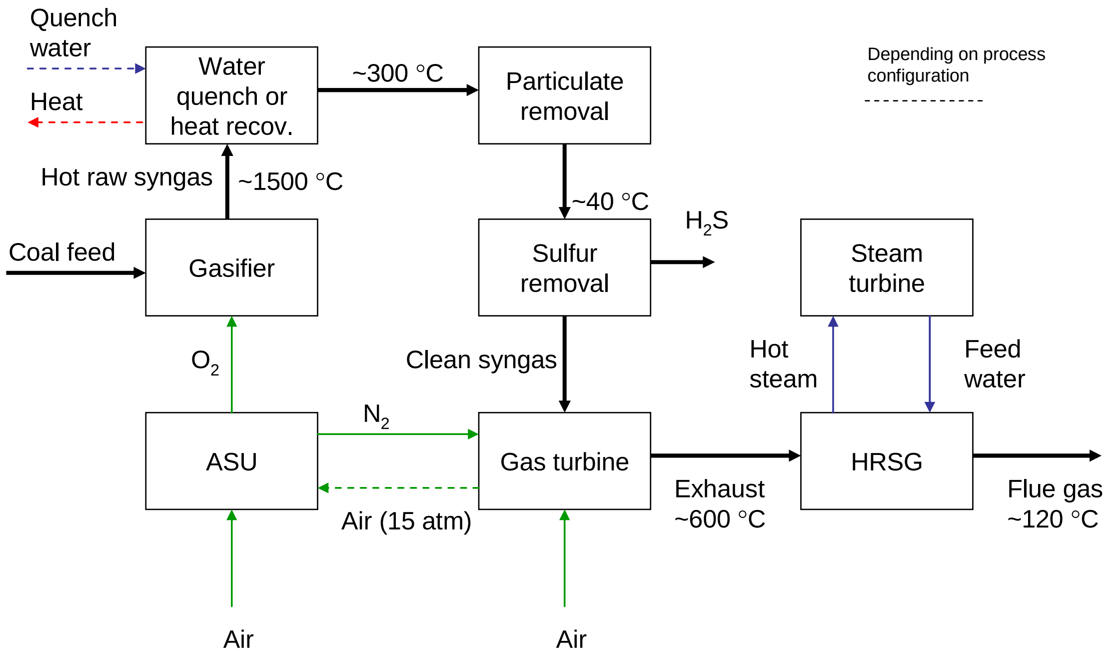

Figure 1. IGCC process without CO_2 capture

In addition to its chemical energy (heating value), the hot raw syngas contains sensible heat which may be recovered in heat exchangers to produce steam for the steam turbine. The use of syngas coolers for this purpose increases efficiency, but adds capital costs. In theory, it would be desirable to clean the raw syngas without cooling (as the sensible heat would be utilized most efficiently when delivered to the gas turbine), but the proven technologies for gas clean up operate at near ambient temperatures. In the gas clean up process, particles, sulfur and other impurities are removed. At this point, CO_2 may also be captured. Because of the high partial pressures of the species and the low volume flow of syngas, the gas clean up process is very efficient and low cost compared to traditional flue gas cleaning.

The clean syngas is then fed to the gas turbine for production of electricity. Gas turbines for syngas operation are commercially available. Compared to natural gas operation, some minor modifications in combustors and operating conditions are required.

The gas turbine may also be integrated in two different ways with the ASU. If not conflicting gas turbine operation characteristics, any excess nitrogen from the ASU should always be utilized by the gas turbine for NO_x reduction and increased power. Therefore, the so called “degree of integration” often discussed, has rather to do with the percentage of air required in the ASU which is supplied by the gas turbine. E.g. 100 % degree of integration means that 100 % of the ASU air is bled from the outlet of the gas turbine compressor (no separate ASU air compressor). Full integration will result in the highest electrical efficiency, however partial integration will result in the maximum power[3] and also improved operational flexibility (shorter start up time).

[3] A case specific study is needed to determine the degree of integration which leads to maximum power and therefore lowest capital cost in $/kW

Most of the sensible heat in the hot gas turbine exhaust gas is recovered in the heat recovery steam generator (HRSG) which supplies the steam to a turbine for additional electricity production.

1.4 Performance without CO_2 capture

1.4.1 Efficiency

Electrical efficiencies around 40 % (LHV) have been achieved in existing commercial scale demonstration plants. Because the power block of an IGCC plant is similar to that of a natural gas combined cycle (NGCC) plant, the efficiency of the latter is a natural reference for the IGCC plant. Currently, NGCC efficiencies are approaching 60 % (LHV). The efficiency penalty of an IGCC compared to an NGCC is mainly explained by effects in the gasification process. In order to reach the slagging temperatures, the fuel is partially combusted which means that chemical energy is converted into heat. The ratio of the chemical energy in the product syngas and the chemical energy in the coal feed (LHV cold gas efficiency) is typically around 0.7–0.8. Depending on configuration, some of the produced heat may or may not be recovered. Either way, a significant efficiency penalty or exergy loss arises because heat is a lower quality energy form than chemical energy. Furthermore, the production of the oxygen for gasification requires auxiliary compression work. In addition to these major points, current IGCC gas turbines may be less efficient because of restrictions in turbine firing temperatures.

Several factors influence the efficiency:

- *Coal type*: Coals of high rank can be gasified more efficiently than coals of low rank. The higher moisture and ash content of low rank coals require a higher degree of oxidation (more oxygen) to achieve slagging temperatures because of the energy needed to vaporize the moisture and melt the ash. Most recent studies have focused on high rank coals.
- *Gasification technology*: Gasifiers with a dry feed are more efficient than gasifiers with a slurry feed because less water must be vaporized. Gasifier technologies which include syngas coolers for heat recovery of the sensible heat of the hot gas, are more efficient than those with a water quench.
- *Degree of ASU integration*: Integration of the air separation unit with the gas turbine increases the electrical efficiency. By supplying part or all of the ASU air from the GT compressor outlet, less efficient compression in a separate compressor is reduced or avoided.
- *Technology level*: Gas turbine technology and turbine inlet temperature will together with the choice of steam cycle have a significant impact on electrical efficiency.

While the three first bullets addresses the efficiency gap between an IGCC and an NGCC, the last bullet points to the fact that improvements in combined cycle technology will also benefit the IGCC. A review of recent studies of IGCC plants indicates efficiencies in the range 38.0-47.4 % (LHV). The wide range is explained by the above factors.

1.4.2 Availability

The risk of low IGCC availability is still an issue. Figure 2 shows the history of availabilities for the demonstration IGCC plants. It can be seen that most of the plants were able to reach the 70-80 % range after a number of years. However, by adding a spare gasifier, it seems likely that IGCCs can provide availabilities equivalent to that of NGCCs. At the Eastman Chemicals plant the gasifier has been 97.97 % onstream over a three year period. According to Bechtel, a next IGCC plant should be able to achieve around 85 % availability without back-up fuel or a spare gasifier [26].

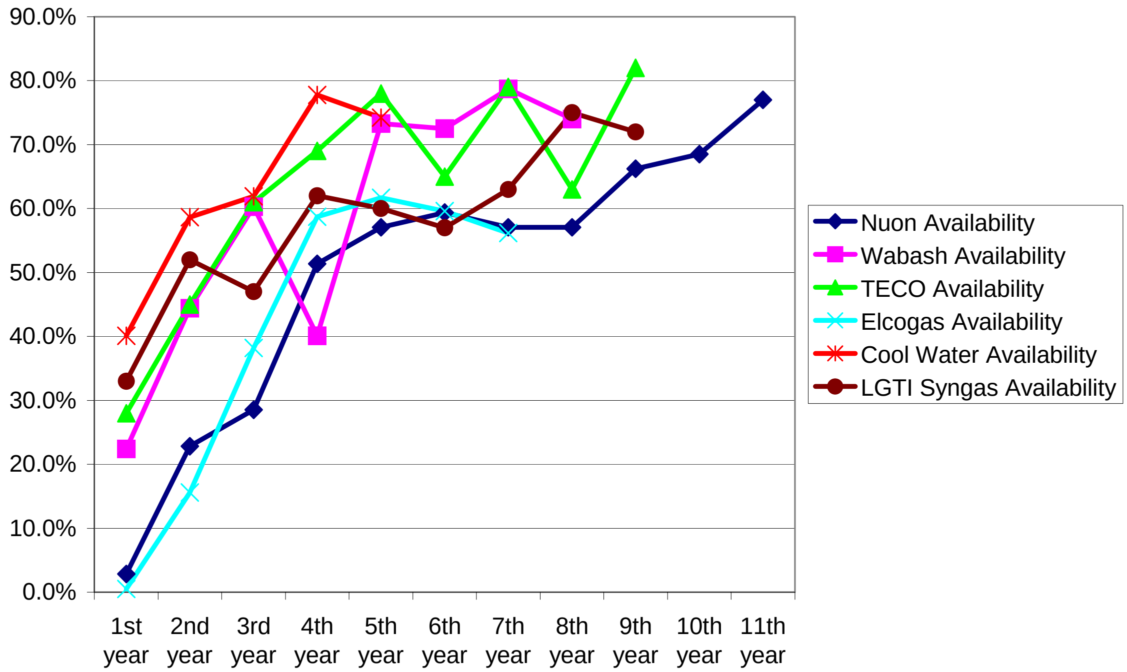

Figure 2. IGCC availability history (excluding operation on back-up fuel). Graph provided by Jeff Phillips, EPRI [24]

1.4.3 Environmental performance

An inherent advantage of the IGCC process is the potential for low emissions by using fuel gas clean up – instead of flue gas clean up. Because of the high partial pressures, impurities can be removed more effectively and economically compared to conventional clean up of the large volume flow of the combustion flue gas.

Table 2

Pollutant/ Environmental issue	Performance
SO_2	Commercial processes such as MDEA and Selexol can remove more than 97 % of the sulfur so that the clean syngas has a concentration of sulfur compounds < 20 ppmv. The more expensive Rectisol process can similarly achieve a concentration of < 0.1 ppmv [18]. SO_2 emissions of 0.15 lb/MWh has been demonstrated at the ELCOGAS plant in Puertollano, Spain [30].
NO_x	The emissions are similar to those of a natural gas fired combined cycle plant. Dilution of syngas with nitrogen and water are used to reduce flame temperatures and lower thermal NO_x formation to levels < 15 ppm[4]. Further reduction to single digit levels are possible with selective catalytic reduction (SCR), but have some disadvantages such as ammonia slip, increased requirement for sulfur removal and reduced power output.
Mercury	Commercial technology for mercury removal is available. 99.9 % removal from syngas has been demonstrated [30]. The cost of Mercury removal has been estimated to \$ 3 412/ lb for IGCC vs. \$ 37 800/ lb for PC plants.
Other emissions	Emission of CO is caused mainly by incomplete combustion in the gas turbine. Permit levels are typically 15 ppm. VOC[5] emissions also result from incomplete combustion, and compliance with permit levels is normally done by calibrating VOC emissions to CO emissions. PM[6] includes solid charcoal and slag particles and liquid drops from cooling tower operation.
Trace elements	A large number of the periodic table is present in coals in trace amounts, and currently there is an incomplete understanding of how these trace elements partition between the slag, fly ash, syngas and gas clean up streams.
Solid wastes	IGCC produces about half the amount compared to conventional PC plants. The solid waste is also less likely to leach toxic metals which are encased in the solidified slag [30]. The slag is a useful by-product with a value.
Water use	IGCC uses 20 % - 50 % less cooling water than conventional coal plants [30]. The reason is that the steam cycle represents a smaller part of power generated.

1.4.4 Key IGCC technology issues

The range of choices in gasifier technology may be represented by the slurry feed GE gasifier with a water quench and no heat recovery versus the dry feed Shell gasifier with syngas coolers. This results in the GE gasifier having lower costs, but also lower efficiencies [16].

For high rank coal (bituminous coal), studies conclude that the slurry feed GE quench gasifier has lowest capital cost for plants without and with CO_2 capture [14][16][17]. For low rank coals such as lignite, less data are available, but the Shell gasifier seems to the lower cost option.

In addition to reduced efficiency, low rank coals with more moisture and ash require larger sized process equipment to deal with the increased mass flows due to the lower energy density coal feed. As moisture or ash content increases, the operating temperature is maintained by supplying

[4] Short for ppmvd@15% (parts per million dry at 15 % O_2)
[5] Volatile organic compounds
[6] Particulate matter

more oxygen (which means more of the coal heating value is converted to heat), and the gasifier cold gas efficiency[7] goes down. High ash content coals also require a larger capacity slag handling system. Table 3 indicates the change in capital cost of the different process units in response to the effects of increased moisture, ash and sulfur in the coal.

Table 3. Change in capital costs due to changes in feed coal

Process unit	Increased moisture	Increased ash	Increased sulfur
Fuel preparation	+	+	
Gasifier	+	+	
ASU	+	+	
Slag handling		+	
Heat recovery	?	+	
Sulfur removal			+
Gas turbine			
Steam cycle		+	

For an IGCC based on the slurry feed E-gas gasifier, Table 4 shows that both the efficiency (heat rate) and the capital cost is affected significantly by the increased moisture and ash content of the lower rank coals such as lignite. Although data are not available for the less efficient GE gasifier, it seems likely that the negative impact of coal rank would be similar or worse. A study by the Canadian Clean Power Coalition indicated that the dry feed Shell gasifier was the more economical than slurry feed E-gas and GE gasifiers for an IGCC with CO_2 capture [17]. If this is the case, the Shell gasifier would also be more economical for a plant without capture. This latter point is explained by the higher penalty of Shell IGCCs for CO_2 capture.

[7] Defined as chemical energy in the produced syngas divided by the chemical energy in the coal feed. May be specified using either lower or higher heating value.

Table 4. Effect of coal type on E-gas IGCC systems. Adapted from [14]

Coal type	Pittsb. #8	Illinois #6	PRB	Lignite
Heating value, Btu/lb (HHV ar)	13100	11000	8200	7500
Ash % dry basis	7.5	12.5	17	20
Slurry conc. (% dry solids)	66	63	56	50
Relative feed rate	1	1.25	1.8	2
Number of gasifiers	2	2	3	4
Relative heat rate Btu/kWh HHV (Base 8380)	1.00	1.06	1.14	1.22
Relative capital cost (per kW)	1.00	1.09	1.24	1.39

Slurry feed gasifiers are more negatively affected by high moisture content than dry feed gasifiers. Even if dry feed gasifiers must dry the coal before gasification at a cost, they avoid large amounts of steam in the reactor volume and therefore the accompanying capacity reductions.

Gas turbines need only minor modifications to use syngas as fuel and are available from manufacturers like GE and Siemens. There are some effects of using syngas as fuel which influences the gas turbine performance. Because of the low heating value of syngas, more mass flow of fuel is supplied to achieve a certain limiting turbine inlet temperature. In addition nitrogen from the ASU and syngas saturation contribute to higher mass flow through the turbine and more power output. Compared with the natural gas as fuel, depending on syngas composition, there may be a higher fraction of water vapor in the gas turbine exhaust. This will increase heat transfer and put more strain on materials, and it will be required to decrease the turbine inlet temperature to maintain design material life [28]. This reduction means a lower efficiency for the power block.

Integration between the air separation unit and the gas turbine may be beneficial for lower cost, increased efficiency, power output and NO_x reduction. Part or all of the ASU air may be supplied from the GT compressor outlet to reduce or avoid the less efficient ASU compressor. The degree of integration is defined as the fraction of the ASU air supplied from the GT. In general 100 % integration gives highest efficiency, but partial integration gives maximum power output and improved operability with quicker start up times. The nitrogen from the ASU should be used for NO_x reduction and power augmentation to the extent it is compatible with gas turbine operating characteristics. The use of nitrogen instead of water injection for NO_x reduction is also beneficial to avoid an exhaust gas with high moisture (and therefore avoiding reduced turbine inlet temperatures and efficiency reductions). The current consensus seems to be that future IGCC plants should be built with partial air integration.

1.4.5 Maturity

Experience with coal based IGCC plants on commercial scale exist from several demonstration projects with government support (see Table 5).

Table 5. Commercial scale coal/petcoke based IGCC demonstration plants

Project participant/ Plant name	Location	Electric output (net)	Gasifier type (current owner)	Gas turbine	Dates of operation
Southern California Edison/ Cool Water	Barstow, CA	100 MW	GE with heat recovery	GE 7E	1984 - 1988
Dow (Destec)/LGTI	Plaquemine, LA	160 MW	ConocoPhillips E-gas	Siemens SGT6-3000E	1987 - 1995
Nuon/ Nuon Power Buggenum	Buggenum, The Netherlands	253 MW	Shell	Siemens SGT5-2000E	1994 - present
Destec and PSI Energy/ Wabash River	West Terre Haute, IN	262 MW	ConocoPhillips E-gas	GE 7FA	1995 - present
Tampa Electric Company/ Polk Power Station	Mulberry, FL	250 MW	GE with heat recovery	GE 7 FA	1996 - present
Elcogas/ Puertollano	Puertollano, Spain	298 MW	Prenflo	Siemens SGT5-4000F	1998 - present
Sierra Pacific Power Company/Pinon Pine	Reno, NV	99 MW	KRW air blown fluidized bed	GE 6FA	1998 – 2000 (18 start-up attempts, failed to achieve steady state operation)

In 2004, several commercial alliances formed to offer IGCC customers “one stop shopping” in the future. GE purchased ChevronTexaco’s gasification business and announced cooperation with Bechtel. ConocoPhillips announced a similar alliance with Fluor. Also, Black & Veatch joined Uhde for execution of Shell gasification projects in the US. This is clear sign of the increasing interest in gasification and IGCC.

All the components needed in an IGCC plant are commercially available. Several demonstration projects based commercial gasifiers have been carried out and they have shown that problems have occurred – but also that they have been manageable.

In order to compete with pulverized coal plants, the major challenges for new large IGCCs will be to demonstrate higher availabilities and lower capital costs.

1.5 Performance with CO_2 capture

1.5.1 Process description for IGCC with CO_2 capture

When considering capture of CO_2 in the IGCC design, two additional process blocks are needed (besides the compression of CO_2 for transportation):

- A shift reactor in which the CO reacts with H_2O to H_2 and CO_2
- An absorption process for capture using the Selexol process or other processes based on physical solvents, or an MDEA process based on chemical solvents

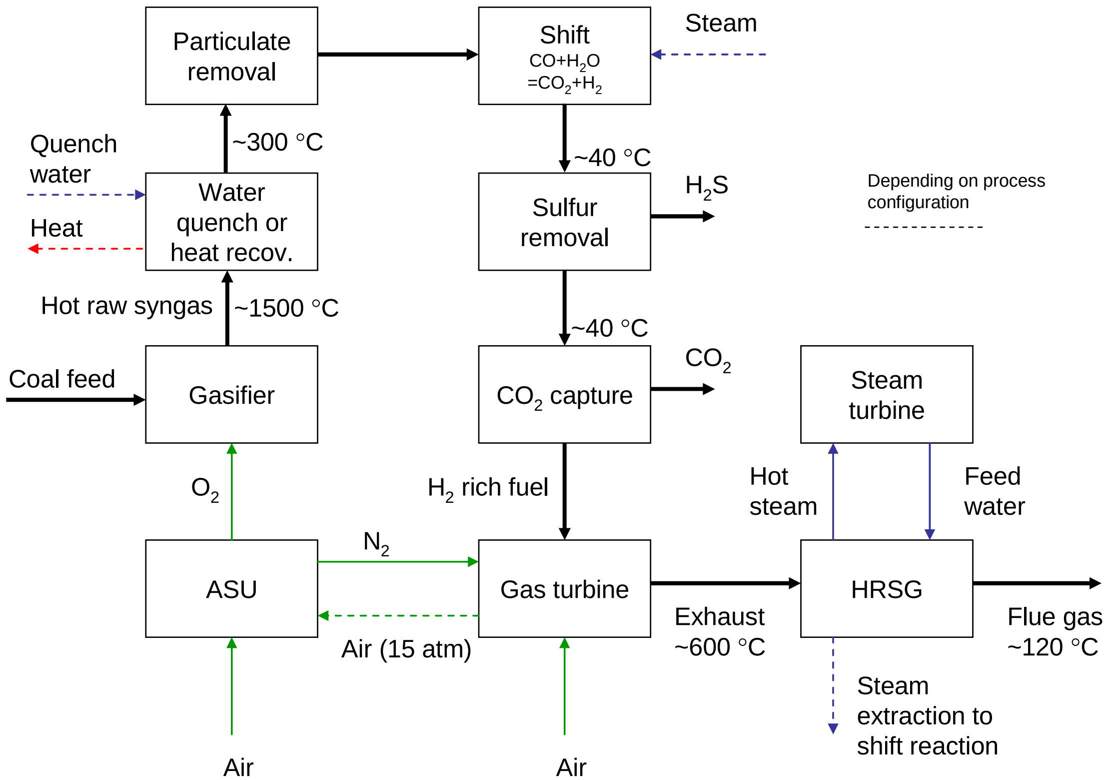

Figure 3. IGCC process with CO_2 capture

In the shift reactor, the heating value of the CO is transferred to H_2 and the carbon atoms end up in the CO_2 molecules. It has been found that a so called sour shift upstream the sulfur removal (see Figure 3) is more energy efficient and has lower cost than a clean shift downstream of the sulfur removal.

It should also be noted that most of the other components in the plant such as fuel handling systems, the gasifier and the air separation unit will "see" different material flows through them in a plant with capture as opposed to a plant without capture. This is a complex issue which is currently not fully resolved. If one assumes that the gas turbine needs a fixed amount of chemical energy per unit time (MW heating value), the coal feed and oxygen flows need to be increased to make up for chemical energy lost in the exothermic shift reaction which converts some of the raw syngas chemical energy to sensible heat. On the other hand, current gas turbines need a reduction in firing temperature on hydrogen rich fuels. This is an argument for reduced flow of chemical energy to the turbine. Therefore, a case specific study would be necessary to quantify the effect of CO_2 capture on the coal feed rate and oxygen consumption.

1.5.2 Efficiency

The reduction in electrical efficiency for a plant with CO_2 capture is explained by the following factors:

- Exothermic shift reaction produces heat from syngas fuel and required coal feed rate to provide necessary rate of chemical fuel energy to the gas turbine increases. The produced heat is less efficiently converted to electricity than chemical energy (fuel heating value).
- If the steam/carbon ratio is too low (as for Shell gasifiers), steam must be supplied from the steam cycle and is equivalent to an electricity production loss
- CO_2 compression work

If a chemical solvent such as MDEA has been used (as opposed to a physical Selexol solvent), there is also a significant energy loss for regeneration of the solvent. Restrictions on the firing temperature of current gas turbines will also result in an efficiency reduction.

The GE quench gasifier is less penalized than the Shell gasifier because the steam required for the shift reaction already is present in the syngas, while the Shell gasifier requires steam which must be taken from the steam cycle and is equivalent to a loss in electricity production. For example, one study showed that the efficiency penalty (LHV) for a case with the GE gasifier was only 6.5 %-points (from 38.0 % to 31.5 %), but 8.6 %-points (from 43.1 % to 34.5 %) for the Shell case [16]. However, the Shell case still had the highest efficiency with CO_2 capture.

A review of recent studies of IGCC plants with CO_2 capture indicates efficiencies in the range 31.5-40.1 % (LHV). The wide range is explained by the factors mentioned earlier.

1.5.3 Maturity

Most processes required for CO_2 capture from IGCCs have been demonstrated at commercial scale. For example, commercial chemical plants for production of ammonia require hydrogen and therefore include a shift reaction and separation of CO_2.

An advanced gas turbine (F class or higher) has not been demonstrated on near 100 % hydrogen fuel [24]. However, for an IGCC application which involves an air separation unit, there is no reason to combust a pure hydrogen stream in the turbine, rather it is beneficial to dilute with nitrogen to reduce NO_x emissions and increase power output. Current GE guarantees involve fuel specifications, which limit maximum CO_2 capture to around 85 % [12]. According to Norman Shilling, GE these limitations are related to the current fuel supply system and does not represent a major challenge to modify [27]. A fuel mixture of 50 % H_2 and 50 % N_2 by volume would be an acceptable fuel [28] and would therefore impose no limitation on CO_2 capture.

1.6 IGCC related research and improvement potential

1.6.1 Research and development areas

This section, largely based on [16], will discuss areas where current research and development may improve different IGCC components to achieve increased efficiency and reduced costs in future plants.

Gas turbines:
Recently developed H-class turbines for natural gas have firing temperatures of 1430 °C and have efficiencies (LHV) of around 40 % in simple cycle operation (only the gas turbine) and around 60 % in combined cycle operation. The high efficiency is explained by the high firing temperatures which are possible because of advanced blade cooling systems and thermal barrier coatings. Further efficiency improvements are possible within:

- Compressor staging with intercooling
- Fuel firing in stages
- Improved materials for coatings and hot parts

For these more advanced gas turbines, the exhaust gas temperature will be higher than the 600 °C which is normal for current F-class turbines. At higher temperatures, the once-through supercritical HRSG design in the steam cycle will become increasingly interesting.

In addition, the use of syngas or hydrogen-rich mixtures as gas turbine fuel instead of natural gas requires some special considerations:

- Combustion system. Premix combustion systems for natural gas can not be used. Diffusion combustors (including dilution with nitrogen/steam) are used in existing IGCCs. Current work focuses on new combustors for hydrogen rich fuels.
- Surge and torque limitations. The volumetric energy density of syngas and hydrogen is much less than that of natural gas, and therefore the flow rate of fuel is several times higher to supply about the same amount of fuel chemical energy to the combustor. A higher mass flow through the turbine (e.g 15 %) results. These changed mass flows may require modifications of either the compressor or turbine to avoid compressor surge (inability of the compressor to operate) and exceed the mechanical limit on the shaft torque.
- Firing temperature. The increased mass flow and water content of the gas through the turbine leads to enhanced heat transfer. In order to maintain material temperatures at the same level, the firing temperature must be reduced or more effective cooling systems or coatings developed.

Gasifier:
Areas where improvements are desired include:

- Feed injector lifetime
- Refractory lifetime or elimination of need for refractory liners
- Thermocouple lifetime
- Coal feed systems
- Slag removal
- Development of a two stage, dry feed gasifier
- Gasifiers suitable for low rank coals

To increase the efficiency of the gasifier, a dry feed system with a second point of feed injection would be desirable. The effect of the second gasification stage is to lower the outlet gas temperature by using thermal energy from the first stage in the endothermic gasification reactions. The principle is also referred to as a “chemical quench” and the effect is increased cold gas efficiency (more chemical energy and less thermal energy in the output).

Among the attempts to develop gasifiers which are more suitable for low rank coals, is the KBR Transport gasifier which will be used in Southern Company's future 285 MW Orlando IGCC project in Florida. In 2004, DOE announced a $235 million grant to this project. Fluidized bed gasifiers operate at lower temperatures (non-slagging) so that no energy is needed to liquefy the ash. However, there is currently less success with fluidized bed gasifiers than the other types of gasifiers. Most experience with these types of gasifiers is with air as the oxidant.

Air separation using ITMs:
Both Air Products and Praxair are involved in efforts to develop ionic transport membranes (ITMs) based on ceramic materials which selectively transport oxygen ions when operated at high temperatures (800-900 °C). The ITM would be integrated into the IGCC process be feeding it air from the gas turbine compressor outlet (see
Figure 4). Studies indicate that application of ITMs could increase IGCC efficiency by 1 %-point or more. According to Air Products the cost of air separation could be reduced by about 30 % and the plan is to build the first commercial scale ITM units in 2009 [1].

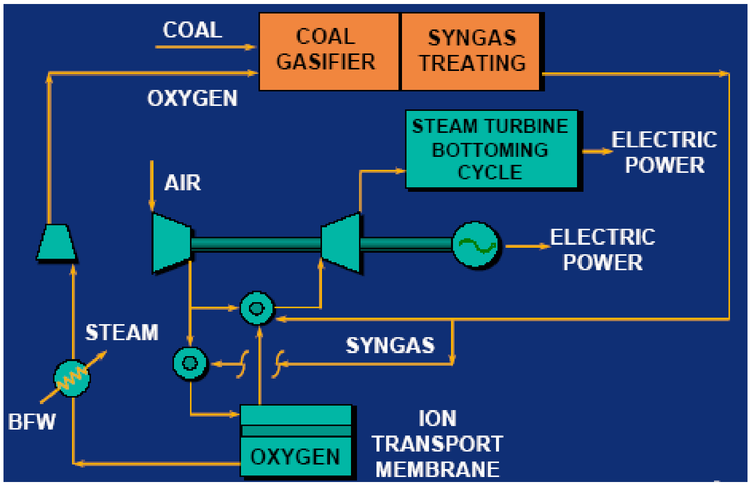

Figure 4. Integration of ITM into IGCC process [1]

Shift reaction and CO_2 capture:
The exothermic shift reaction (or water gas shift reaction) transfers the fuel heating value from CO to H_2 and transfers the carbon from CO to CO_2. The existing method for shift conversion is taking place in two stages at two different temperature levels in the presence of H_2S. Finally, H_2S and CO_2 are removed from the syngas in two sequential stages by use of a solvent.

As part of the CO_2 Capture Project (CCP), development of the so called sorption enhanced water gas shift (SEWGS) process was initiated. In this process, the low temperature shift reactor is replaced with the SEWGS system, which operates as a pressure swing adsorption unit and consists of multiple fixed bed reactors packed with shift catalyst and high temperature (~500 °C) CO_2 adsorbent. Regeneration of the adsorbent is accomplished by counter current steam purging. The advantages of the SEWGS process include:

- High conversion of CO because of simultaneous CO_2 removal
- Hydrogen mixture with steam enters the gas turbine at high temperature

According to [3], the SEWGS system could in principle be applied to a coal based IGCC (not only the studied natural gas scenario), but then the challenge of hot desulfurization and possibly other gas clean up would need to be addressed (see discussion about hot gas clean up) – or else, a significant part of the potential benefit would be lost. Further development regarding the adsorbent performance is required. The CCP project concluded that developing the SEWGS technology was associated with less risk and was more near term than the alternative MWGS concept which will be discussed next [2].

The membrane water gas shift (MWGS) concept is an alternative method to combine the shift reaction and CO_2 separation. In principle, this process carries out the shift reaction while at the same time separating out H_2 through a membrane. This would happen in a so called membrane reactor, however the CCP concluded that three sequential stages with reaction/separation would involve less risk, e.g. when changing the catalyst. The MWGS have similar advantages to those of the SEWGS regarding high temperature operation. One disadvantage is that recompression of the hydrogen permeate is required. The CO_2 stream is available at very high pressure, but may need some treatment to oxidize remaining hydrogen. Also for the MWGS technology, the presence of sulfur and other contaminants in a syngas stream would be a significant challenge. Currently, no sulfur tolerant hydrogen membranes with adequate H_2/CO_2 selectivity have been developed [2].

For both the SEWGS and MWGS technologies the potential efficiency improvements are expected to be modest, while the potential reductions in capital costs may be significant as indicated by the CCP study. The application of these technologies in natural gas fired pre-combustion capture plants would be less challenging than in IGCC plants with capture.

Hot gas clean up (HGCU):
HGCU processes remove particulates, sulfur compounds and other pollutants at higher temperatures than in the traditional processes such as water scrubbers and acid gas removal systems. The drivers for developing HGCU have been the potential benefits of higher process efficiency ("feeding" the thermal energy of the syngas directly to the gas turbine is more efficient than raising steam is syngas coolers), the elimination of sour water treating and "black mud", and cost reductions. Until the late 1990s, most HGCU programs pursued operating temperatures close to the maximum limit of 1000 °F (~540 °C) which is compatible with efficient removal of alkali components which would harm the gas turbine. At this temperature alkali vapors condensate on particle surfaces and may therefore be removed in the particle filter [18].

So far, the only HGCU technology which is commercially applicable is particulate removal (candle filters) based on ceramics or sintered metals. For other HGCU processes such as hot desulfurization there has been decreasing interest lately, in part because of disappointing results in finding solid sorbents with the necessary attrition resistance. The capture of mercury and CO_2 further complicates the HGCU concept as these components also would need development of HGCU technologies which presently is considered very challenging. Further development of

HGCU technologies for removal of components other than particulates is not considered to be very promising [16][18].

Advanced power cycles:
Integrating high temperature fuel cells such as solid oxide fuel cells (SOFCs) with IGCC systems results in a thermodynamic cycle with very high potential efficiencies. The fuel cell first converts H_2 and CO directly to electrical energy with heat as a by product which subsequently is utilized in a gas turbine. In the case of natural gas fired power plants, SOFC/GT cycles may (see Figure 5) achieve efficiencies (LHV) around 70 % without CO_2 capture and around 65 % with CO_2 capture [20]. For integration of SOFCs with coal based IGCCs, one study reports potential efficiencies (LHV) of around 57 % without capture and around 50 % with capture [23]. Although the fuel cell technology is very attractive from a thermodynamical perspective, the necessary cost reductions for commercialization have not yet materialized. For IGCC applications, the question of gas clean up processes must also be considered in order to protect the fuel cell.

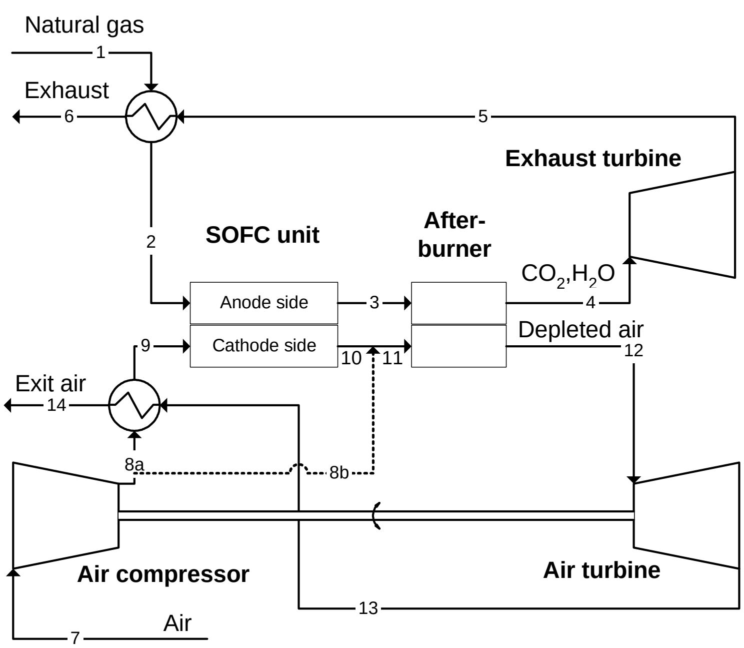

Figure 5. Advanced power cycle combining fuel cell and gas turbine technology. Note that the SOFC unit has been simplified, it also includes reforming of natural gas to CO and H_2 not shown [20]

1.6.2 Improvement potential

In a study carried out by Foster Wheeler, the potential improvements in key IGCC components were evaluated and the performance and costs of a year 2020 plant with and without CO_2 capture were quantified for a bituminous coal [16]. The results shown in Table 6 assume the successful application of the following technologies in the year 2020 plants:

- Dry feed, two-stage entrained flow gasifier
- Gas turbine (further advanced than H-class)

- Once-through supercritical HRSG
- Ion transfer membrane (ITM) air separation

Table 6. Comparison of current IGCC technologies and year 2020 plants [16]

	Without CO_2 capture			With CO_2 capture		
	GE	Shell	2020 plant	GE	Shell	2020 plant
Efficiency (%,LHV)	38.0	43.1	48.9	31.5	34.5	43.2
Capital cost ($/kW)	1187	1371	1129	1495	1860	1248

These improvements are significant. Should they materialize, a year 2020 plant with capture would be more efficient than today's IGCCs without capture - at roughly the same cost. As discussed above, there are also other technologies which could contribute to even further improvements. Besides the potential technical improvements, the ongoing efforts such as that of GE to come up with a standard IGCC design would also lower the costs.

2 MAJOR IGCC BLOCKS AND COMPONENTS

2.1 Gasification

2.1.1 Classification of gasifiers

There are three main classes of gasifiers (see Figure 6):

- Fixed bed gasifiers
- Fluidized bed gasifiers
- Entrained flow (slagging) gasifiers

Fixed bed gasifiers[8] and fluidized bed gasifiers have low (425-650 °C) and moderate (900-1050 °C) outlet gas temperatures, respectively. Entrained flow gasifiers have high outlet temperatures (1250-1600 °C) and operate in the slagging range (the ash is fully liquid with low viscosity). A thorough description of the different gasifier technologies is given in [10].

The three commercial gasifier technologies with largest total installed capacity are the GE gasifier (developed by Texaco), the Shell gasifier and the Sasol-Lurgi dry ash gasifier (developed by Lurgi). The Sasol-Lurgi gasifier is of the fixed bed type, and 97 gasifiers (of a total 152 worldwide) are currently operated by Sasol in South Africa, producing syngas for Fischer-Tropsch liquids. Probably because of economic considerations related to gasifier throughput, the clear majority of recent gasification projects have chosen gasifiers of the entrained flow type such as the GE and Shell gasifiers. The ConocoPhilips E-gas gasifier has less commercial experience, but is also considered a major contender among the entrained flow gasifiers. Table 7 summarizes some characteristics of the three major entrained flow gasifier technologies.

Benefits of entrained flow gasifiers include:

- Ability to handle practically any coal as feed
- Syngas is free of oils and tars
- High carbon conversion
- Low methane production, suitable for synthesis gas products
- High throughput because of high reaction rates at elevated temperature

A penalty for some of the above benefits is the relatively high oxygen consumption required to achieve the high temperature (slagging temperature). The high outlet temperature of the gasifier means that chemical energy of the coal has been converted to sensible heat. This is equivalent to lower cold gas efficiency[9]. However, it is possible to recover some of the sensible energy in syngas coolers by producing steam for electricity generation. This will be discussed in later sections.

[8] also referred to as moving bed gasifiers because the bed in which the coal is gasified moves slowly downward

[9] The cold gas efficiency is defined as the chemical energy in the syngas divided by the chemical energy in the coal. The assumption of higher or lower heating value should be specified when stating a number.

Table 7. Major entrained flow gasifiers [24]

Technology Name/ Design Feature	GE Energy (formerly Texaco)	E-Gas (ConocoPhillips)	Shell
Feed System	Coal in Water Slurry	Coal in Water Slurry	Dry Coal. Lock Hopper & Pneumatic Conveying
Gasifier Configuration	Single Stage Downflow	Two Stage Upflow	Single Stage Upflow
Gasifier Wall	Refractory	Refractory	Membrane Wall
Pressure (psig)	500-1000	Up to 600	Up to 600
Notes	Offered as Quench or with Heat Recovery	Currently only offered with Heat Recovery	Currently only offered with Heat Recovery

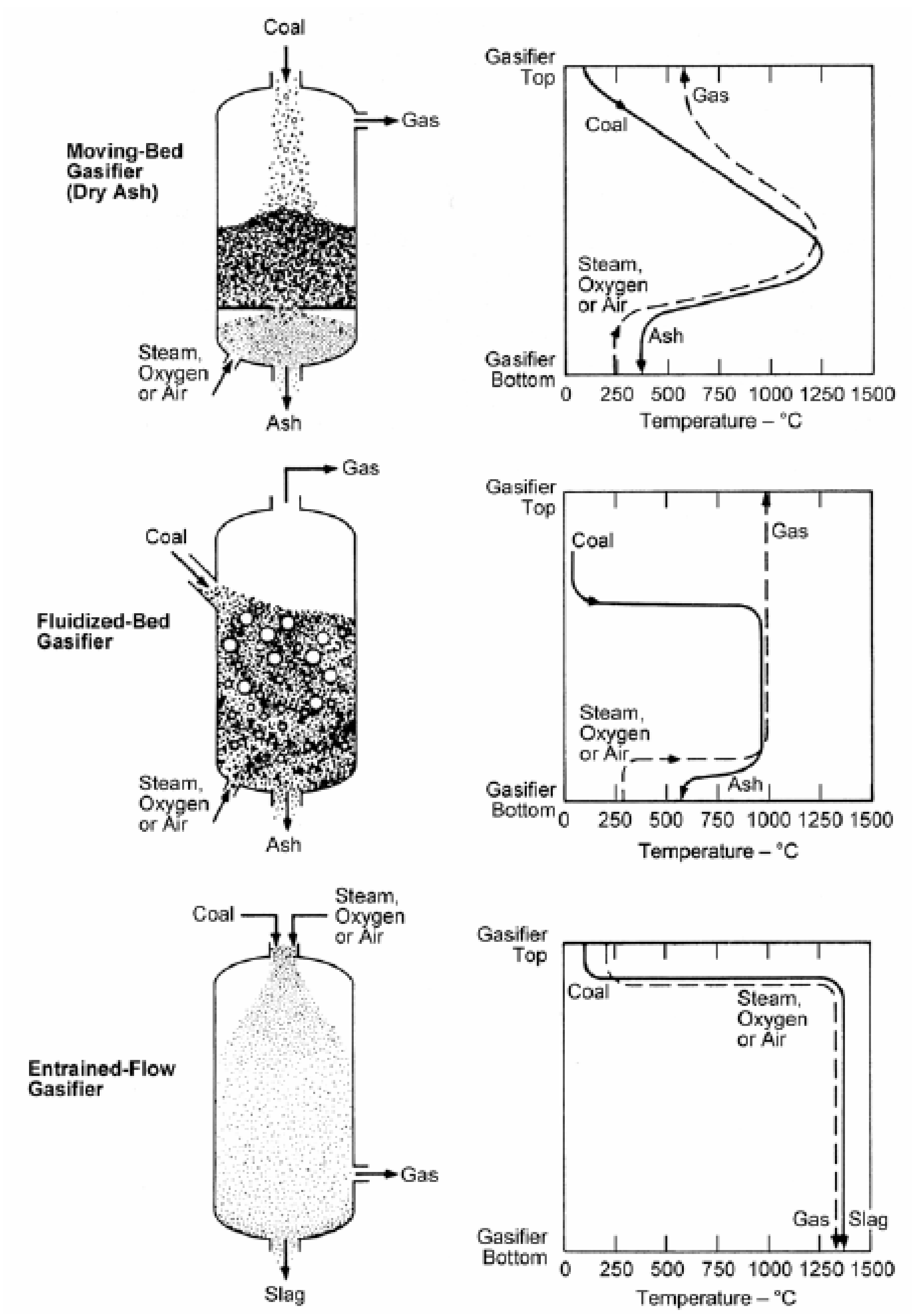

Figure 6. The three major types of gasifiers [13]

2.1.2 The Shell and GE gasifiers

Besides being the gasifiers with most commercial experience, the Shell and GE gasifier technologies are well suited to represent the range of entrained flow gasifiers in terms of capital cost and efficiency [16]. The Shell technology has the highest efficiency and the highest capital cost, while the GE technology has the lowest efficiency and the lowest cost [14].

The Shell coal gasification process (see Figure 7) uses a dry feed system. Coal is pulverized and typically dried to 2 % moisture before being pressurized with nitrogen in lock hoppers. The gasification pressure is commercially proven up to around 40 bar and the operating temperature may exceed 1500 °C. To control the inner gasifier wall temperature, water is circulated in a membrane wall to generate steam for utilization in the power cycle. The ash is converted to slag and the majority of it leaves the gasifier in a liquid flow and is solidified in a water bath. The rest of the slag is entrained in the gas flow and poses a potential fouling problem for downstream process equipment. Therefore, the hot syngas is quenched by recirculated cold syngas to prevent the fly ash from having sticky surfaces. After the quench, the sensible heat of the raw syngas is recovered in syngas coolers which produce steam for electricity production. A dry solids removal system such as a candle filter separates out the fly ash. Finally, a wet scrubbing system removes any remaining particles down to a very low level and also other impurities.

The GE gasifier (formerly known as the Texaco gasifier) uses a slurry feed system. Coal and water is sent to a grinding mill from which a slurry is produced. The dry solids concentration is typically around 65 %. A pump delivers the slurry to the gasifier at a pressure of up to 80 bar. The gasifier is refractory lined and typically operates at around 1400 °C. Two versions of the GE gasifier are available: a solution without heat recovery (see Figure 8) and one with heat recovery (see Figure 9). The version without heat recovery has a water filled quench chamber where the hot syngas is cooled down to around 300 °C and the liquid slag solidifies. The version with heat recovery has no quench (neither with water or gas recycle) but utilizes a radiant syngas cooler which brings the temperature down to around 800 °C. More sensible heat is recovered in a convective syngas cooler. In both process versions, a wet scrubber is used for particle removal. In the following, we will focus on the quench version as this technology represents stronger contrast to the Shell gasifier.

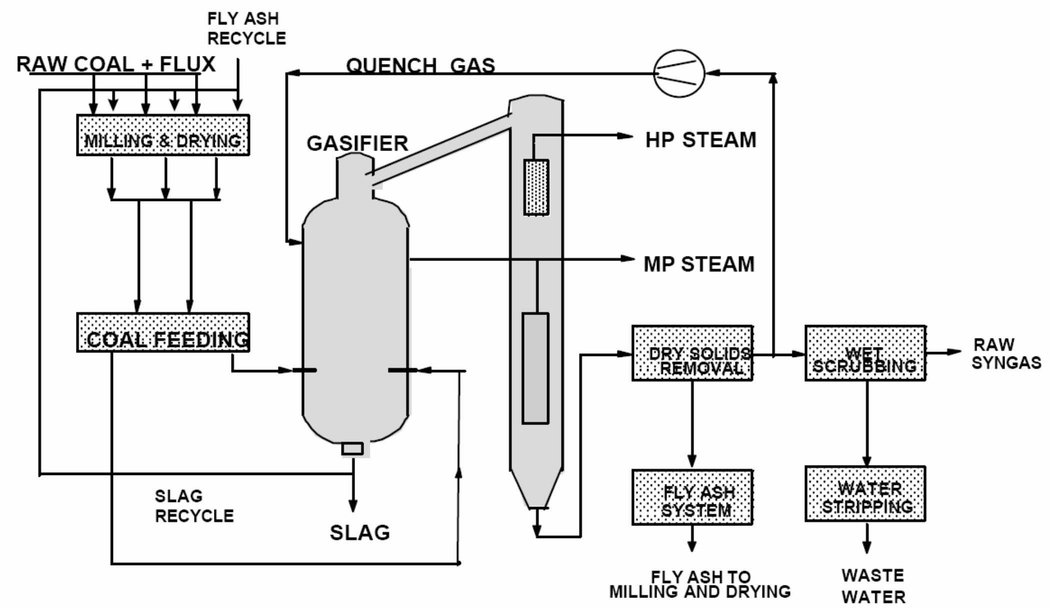

Figure 7. The Shell gasification process [16]

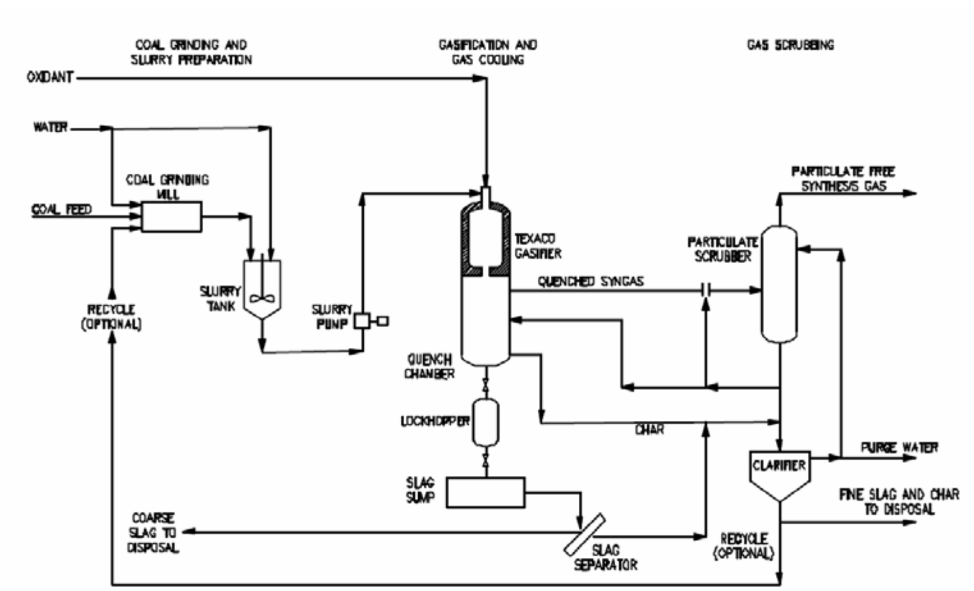

Figure 8. The GE gasifier with total water quench [16]

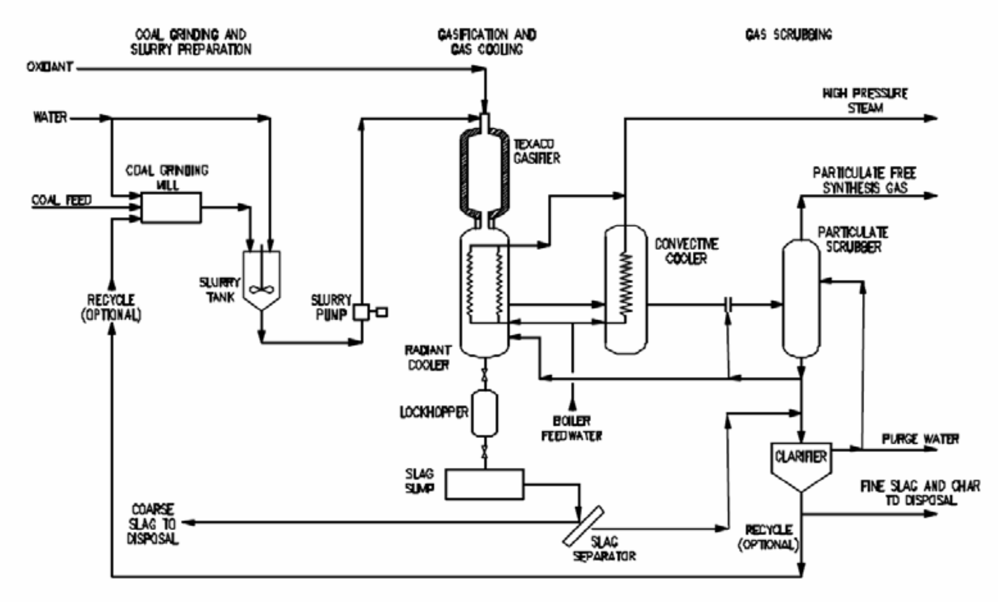

Figure 9. The GE gasifier with heat recovery [16]

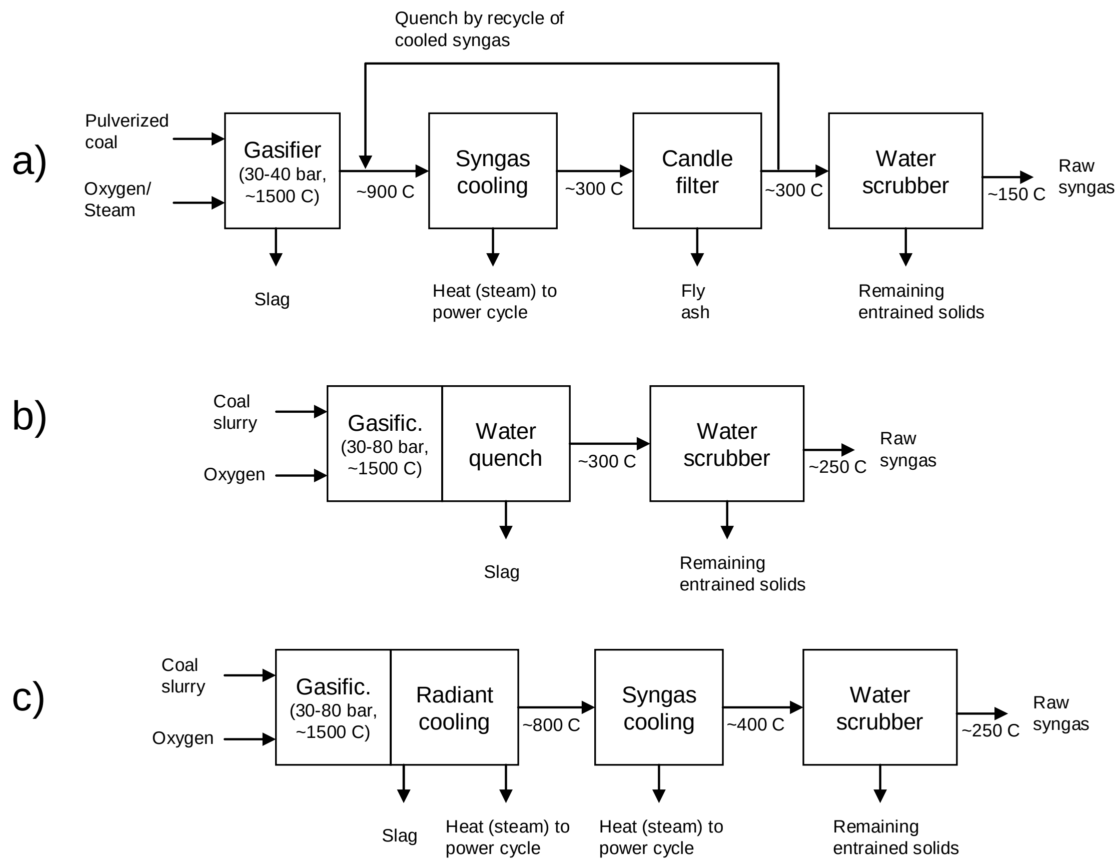

Figure 10. Simplified process flow diagrams of a) The Shell gasifier, b) The GE gasifier with total water quench, and c) The GE gasifier with heat recovery

Figure 10 shows simplified process descriptions of the gasifier technologies discussed above. While the GE gasifier is offered both with and without heat recovery, the Shell gasifier is currently only offered with heat recovery. The GE gasifier requires more oxygen since more heat is needed to vaporize all the water in the slurry. The higher oxygen consumption has two effects which reduce efficiency. First, the cold gas efficiency goes down because more coal is oxidized. Second, the production of oxygen increases the auxiliary electricity consumption. The oxygen requirement of the Shell gasifier with its dry feed system is smaller, and it is therefore more thermodynamically efficient. Both gasifiers, however, are most efficient for bituminous coals. For lower rank coals with high moisture and/or ash content the efficiency the GE gasifier is more negatively affected than that of Shell.

Operation under high pressure is beneficial to increase the capacity of the gasifier reactor volume and thereby reduce capital cost. It will also be beneficial to downstream processes such as CO_2 capture because of increased partial pressures. If the gasifier pressure (e.g. 80 bar) is significantly higher than the fuel pressure (e.g. 30 bar) required to the gas turbine combustor, then it may be economical to include a syngas expander to produce electricity from this pressure energy. However, a study has shown that while the GE technology benefits from high pressure in terms of both cost and efficiency, the Shell technology does not [16]. This is explained by Shell's dry feed system which is costly and inefficient when the delivery pressure is high. In contrast, GE's slurry feed system is very advantageous in these respects.

The availability for a single gasifier is higher for a Shell gasifier, because it has a water membrane wall and not a refractory which requires more maintenance time. In practice, GE therefore must include a spare gasifier to ensure high overall availability.

In general, the syngas composition is relatively insensitive to coal type [10]. The H_2/CO ratio is normally around 0.5 for the Shell gasifier and around 1 for the GE gasifier. Table 8 shows an example of the syngas composition at the outlet of the scrubber for the two technologies. The high mole percent of water in the GE case makes this technology well suited for a subsequent shift reaction and CO_2 capture without addition of valuable steam.

Table 8. Examples of syngas composition at scrubber outlet (mole %) [16]

Gasifier	Shell	Shell	GE
Scrubber temp.	128 C	160 C	243 C
CO	56.40	49.60	15.60
H_2	29.70	26.30	15.10
CO_2	1.40	1.30	7.30
H_2O	7.00	18.10	61.00
Ar	0.70	0.60	0.80
N_2	4.53	3.86	
H_2S	0.24	0.21	0.12
COS	0.02	0.02	
Others	0.01	0.01	0.08
Sum	100.00	100.00	100.00

2.2 Gas clean up

2.2.1 Chemical components of raw syngas

The major components of the syngas at the outlet of an entrained flow slagging gasifier are CO, H_2, CO_2 and H_2O. Some N_2, Ar and small amounts of CH_4 will also be present. This section will consider some of the other components which may be present in the raw syngas to different extents[10]. Table 9 provides a summary of the components highlighted in this discussion.

[10] This discussion focuses on components that have received attention in the literature. It is by no means a complete list of all possible trace components.

Table 9. Some of the trace components in the raw syngas

Sulfur compounds	H_2S, COS
Nitrogen compounds	HCN, NH_3
Chlorine compounds	HCl, NH_4Cl, other MeCl
Fly ash/slag	Uconverted C and ash
Other compounds	Pb, Hg, As, HF, $Ni(CO)_4$, $Fe(CO)_5$,

Sulfur compounds:

The major part (>90 %) of the sulfur components in the feed are converted to hydrogen sulfide (H_2S) and the rest to carbonyl sulfide (COS). Compounds such as SO_x and CS_2 are essentially absent in the syngas. Up to 99.8 % of the coal sulfur can be removed in the acid gas removal process. As COS in not easily removed, a hydrolysis unit (or shift reactor in case of CO_2 capture) is required to convert the COS to H_2S prior to the acid gas removal.

Nitrogen compounds:

Nitrogen enters the gasifier both as molecular nitrogen (supplied with the coal or oxygen stream) and as fuel bound nitrogen. It has been found that gasifiers normally produce some hydrogen cyanide (HCN) and ammonia (NH_3), but negligible amounts of NO_x because O_2 is not in surplus (reducing conditions). It seems that most HCN and NH_3 originate from fuel bound nitrogen and not from the molecular nitrogen which has strong chemical bonds. The proportions of HCN and NH_3 are dependent on the coal characteristics. One should also consider two potential problems with HCN: 1) it can react with amines and degrade it, and 2) it acts as a poison for some catalytic processes (e.g. Fischer-Tropsch synthesis). Both HCN and NH_3 have very high solubilities in water, and may therefore be removed in water scrubbing [10].

Chlorine compounds:

Most of the chlorine content of the coal will be converted to hydrogen chloride (HCl) gas. Metals in the coal will also form chlorides such as ammonium chloride (NaCl) with melting points in the range 350-800 °C. Chlorine compounds from the coal will also react with ammonia to form ammonium chloride (NH_4Cl) which becomes a solid at around 280 °C. The chlorides may foul the syngas cooler surfaces if not addressed in the design. Much of the chlorides may be removed in a water scrubber.

Solid carbon and ash:

Some amount of char (unconverted carbon) and ash will always be entrained in the exit flow of the gasifier. The quench ensures that these particles will be non-sticky to prevent fouling issues. After capture in a filter or scrubber, these particles may be recycled to the gasifier to increase the carbon conversion efficiency.

Other trace components:

Besides the major components of the coal feed, which is covered by the ultimate analysis, it has been found that a substantial part of the periodic table is represented in coals. Examples of such trace elements which are present at the ppmw level are lead (Pb), mercury (Hg) and arsenic (As).

The formation of metal carbonyls such as nickel carbonyl ($Ni(CO)_4$) and iron carbonyl ($Fe(CO)_5$) also seems probable [10]. Also, some hydrogen fluoride (HF) is formed in the gasifier [25].

2.2.2 Syngas quenching

At the outlet of the gasifier reactor the temperature of the syngas is around 1500 °C and the fly ash (or slag) is in liquid form. To protect downstream process equipment from fouling, a quench is needed to solidify the slag and make it non-sticky. There are four main alternatives for quenching [10]:

- Radiant syngas cooling
- Water quench
- Gas recycle quench
- Chemical quench

The radiant syngas cooler is available in one version of the GE gasifier. Here, the hot gas flows into a radiant boiler where saturated steam is generated. It is an expensive piece of equipment which can be prone to fouling. At the Tampa IGCC demonstration plant, problems with the seals protecting the cooler shell from hot syngas caused five forced outages from 1997 to 2001, but the operators felt a solution was close [21].

A water quench uses sensible heat from the syngas to vaporize water. The quench may be total as in the simplest version of the GE gasifier where the syngas is saturated with water vapor, or it may be partial where the syngas is only cooled down to around 900 °C. In the latter case, heat recovery by production of HP steam would be included. In both cases, the addition of water drives the water gas shift reaction to increase the H_2/CO ratio which is beneficial in the case of CO_2 capture.

Quenching by recycle of cooled syngas is applied in the Shell gasifier. After particle removal in the candle filter, about half of the syngas flow which has a temperature around 300 °C is recompressed and recycled to the gasifier outlet. By mixing the 1500 °C hot syngas with the recycle stream, a cooling down to around 900 °C is achieved. Heat is then recovered in a convective syngas cooler.

Chemical quench is a concept which has less experience, but offers some interesting advantages. The principle is the addition of a second gasification step which uses the sensible heat in the hot syngas, and not oxygen, to gasify the coal feed with water. This ensures that the second stage is non-slagging (slag is solid). Because the outlet gas temperature is decreased and has less sensible heat, the cold gas efficiency is increased. A disadvantage is that some tars, which make gas clean up more complex, may be formed. ConocoPhilips's slurry feed gasifier (E-gas) incorporates this principle.

2.2.3 Syngas coolers

Unless the hot syngas has been totally quenched with water, it typically has a temperature of around 900 °C and therefore needs further cooling before downstream gas clean up processes. There are two classes of syngas coolers for steam production:

- Fire tube boilers
- Water tube boilers

Both types have been operated successfully in different plants [10]. Of the two types, fire tube boilers are lower in cost. In this design, the hot raw syngas flows inside the tubes, while high pressure steam is generated on the outside. This means that the tubes are subjected to an external pressure. Depending on the design, maximum steam pressure is between 100 and 150 bar. Water tube boilers can handle higher steam pressure. The Tampa plant has good experience with their fire tube boilers, but bad experience with their gas to gas heat exchangers which were used to recover low temperature syngas heat (after the fire tube boiler) to preheat clean syngas to the gas turbine. Deposits were building up in the gas-gas exchanger and this led to corrosion and cracking of the tubes which caused raw syngas to enter the gas turbine and damage the blades. It was the decided to remove this gas-gas exchanger [21].

2.2.4 Particle removal

Dry solids removal systems use candle filters that can remove all solids from the gas at temperatures between 300 and 500 °C. Above 500 °C, alkali compounds may pass the filters in significant amounts. Below 300 °C, the filters may be blinded of deposits of ammonium chloride (NH_4Cl) [10]. Including cyclones upstream will reduce the loading on the filters and therefore also the risk of breakage.

Wet solids removal systems use water scrubbers operating at a temperature lower than the dewpoint of the gas so that the smallest solid particles can act as nuclei for condensation and ensure efficient operation.

Even if an IGCC plant has a candle filter it usually also adds a wet scrubbing system for removal of remaining impurities such as chlorides and ammonia.

2.2.5 Shift

The water gas shift reaction (or just the shift reaction) is used to change the chemical composition of the syngas towards more H_2 and less CO:

$$CO + H_2O \Leftrightarrow H_2 + CO_2 \qquad \text{- 41.2 MJ/kmol} \qquad (1)$$

The heating value per mole is less for H_2 (241.8 MJ/kmol) than for CO (283.0 MJ/kmol), which means that chemical energy is converted to heat (exothermic reaction). A low temperature favors the equilibrium for maximum hydrogen production. The reaction is normally carried out in two stages, a high temperature shift and a low temperature shift, and thus benefiting from high reaction rates at higher temperature and a more favorable equilibrium at a lower temperature. Typical operating temperatures are between 200 °C and 500 °C with different catalysts. The minimum molar H_2O/CO ratio[11] is around 2. If there is not sufficient water vapor present in the syngas, steam is extracted from the steam cycle.

[11] Normally referred to as the steam/carbon ratio (S/C)

Figure 11 shows the principle processes for gas clean up for cases without and with CO_2 capture. If CO_2 capture is not considered and the syngas is used only to feed the turbine (no chemical or fuel production), then a shift would not be included. However in this case, a separate hydrolysis reactor would be required to convert COS to H_2S for easier sulfur removal. If there is a shift reaction, this conversion takes place simultaneously and no separate reactor is needed. When CO_2 capture is considered there are two alternative processes for the shift reaction:

- Sour shift (or raw shift)
- Clean shift

A study has concluded that the sour shift is the preferred process with respect to costs and efficiency. The GE gasifier with quench is clearly not suited for the clean shift as a lot of valuable steam in the syngas would have to be condensed before the sulfur removal, and then before the shift, a lot of steam would have to be added again. For the Shell gasifier, the clean shift has some advantages like cheaper catalyst and easier sulfur removal as less CO_2 is present. However, the more complex clean shift with more heating and cooling turns out to be unattractive in terms of capital cost (+$77/kW) and efficiency (-1.5 %-points) for the IGCC plant [16].

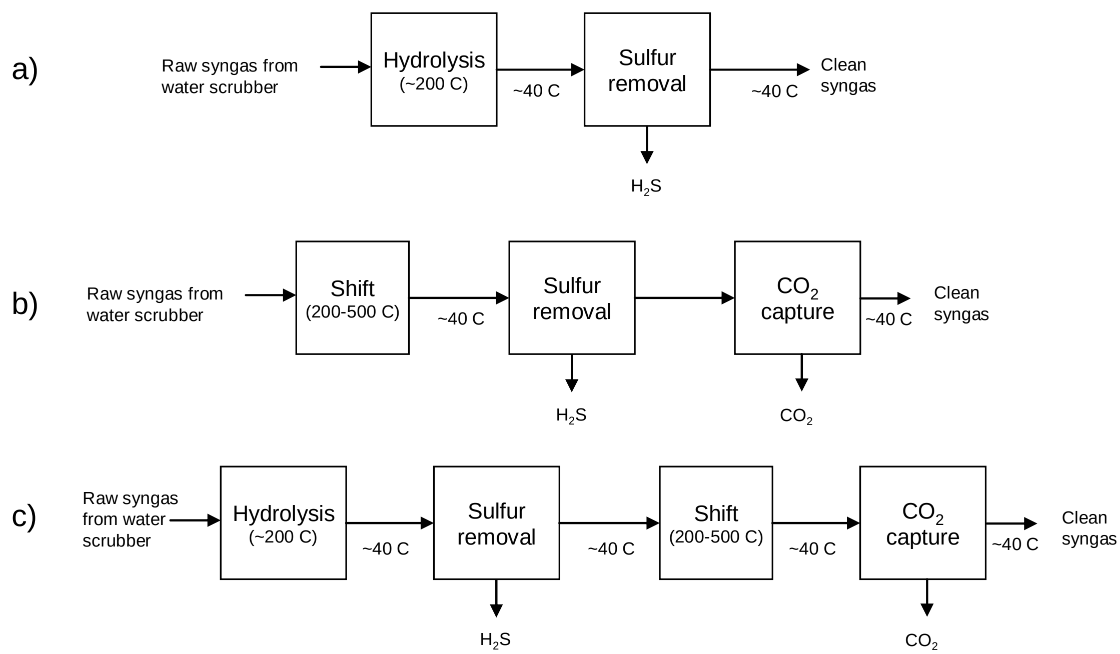

Figure 11. Simplified process flow diagrams; a) No shift conversion, b) Sour shift conversion, and c) Clean shift conversion

2.2.6 Sulfur removal

The sulfur removal process consists of three steps:

- Acid gas removal (AGR)

- Sulfur recovery unit (SRU)
- Tail gas treating (TGT)

The AGR process removes the sulfur from the syngas. In current IGCC plants, the two processes of choice are based on absorption in a liquid solvent [18]:

- Chemical solvents based on aqueous methyldiethanolamine (MDEA)
- The Selexol process based on a physical solvent

Both methods are capable of reducing total sulfur (H_2S + COS) to levels below 20 ppmv in the cleaned syngas. For CO_2 capture a second stage AGR would be added to remove the CO_2 from the sulfur free syngas. If the syngas will be used to produce chemicals, deep sulfur removal will be required to protect the catalyst downstream. In this case the more expensive Rectisol physical solvent AGR process may be applied. This process is a standard solution in chemical applications such as methanol and ammonia [10]. Chemical solvents AGR processes also require steam in the stripping process to regenerate the solvent, while physical solvents are regenerated only by staged flashing techniques.

The standard solution for the SRU is the Claus process which produces elemental sulfur from H_2S by substoichiometric combustion with air or oxygen. Many versions of this process are available [18]. The sulfur may be fixed as elemental sulfur in liquid or solid form, or as sulfuric acid.

The thermodynamics of the Claus process is such that one does not achieve high enough degrees of sulfur recovery without some treating of the tail gas, which usually contain mostly H_2S and SO_2, but also small amounts of COS, CS_2 and elemental sulfur vapors. The TGT process involves hydrogenation of the sulfur species to H_2S which is then absorbed in a liquid solvent. Figure 12 shows two alternative TGT arrangements where a) a second dedicated absorber is used to capture the H_2S from the gas leaving the hydrogenation/hydrolysis step (first part of the TGT), and b) the recycle of this gas to the AGR unit. The most widely used Shell Claus Off-gas Treating (SCOT) applies alternative a), while alternative b) which eliminates the incinerator emission has been used at the Puertollano and Sarlux IGCC plants and also chosen in a recent IEA engineering study [10] [16][18].

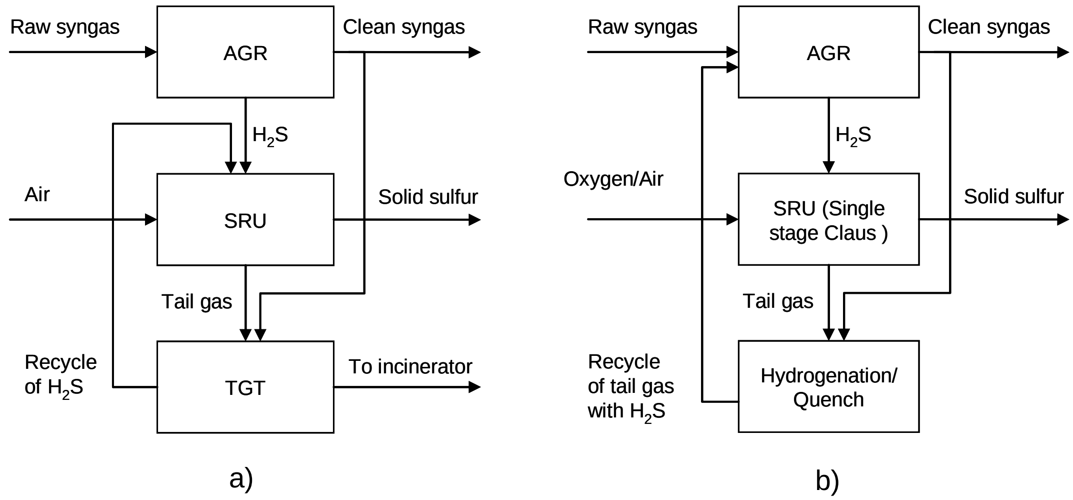

Figure 12. TGT alternatives. a) Dedicated absorber for H_2S in TGT. b) Integration with upstream absorber for H_2S capture

2.2.7 CO_2 capture

As mentioned in the previous section, CO_2 capture would involve adding a second stage to the AGR process for treatment of the sulfur free syngas. A two stage Selexol process seems to be the preferred process for selective removal of sulfur and CO_2. The stripping steam requirements of the Selexol process are also smaller than that of MDEA processes [18].

If combined capture of H_2S and CO_2 in one stream is acceptable for the downstream storage or EOR project, there will be significant cost savings because of a simpler AGR process and elimination of the SRU and TGT units in the sulfur removal process. A study quantified these savings as shown in Table 10, and it is shown that the increased capital cost per kW due to CO_2 capture may be reduced with around 25 % [16].

Table 10. Engineering estimates of benefit of combined capture of CO_2 and sulfur

	Shell IGCC	GE IGCC
Capture penalty, basecase ($/kW)	489	308
Capture penalty, combined capture ($/kW)	355	227
Benefit of combined capture ($/kW)	134	81
Benefit of combined capture (%)	27%	26%

2.3 Air separation

The commercial technology used for oxygen production in IGCC plants is cryogenic air separation, which may be defined as the separation of air into component gases by distillation at low temperatures. Cryogenic air separation has single train O_2 production capacities of 3200 tons/day and is recognized for high reliability. Major suppliers of the technology are Air Products, Air Liquide, BOC Gases, Praxair and Linde.

The major energy requirement of the process is the air compression work. Typically, the air to the ASU is compressed to around 5 bar, and the oxygen (typically 95 % O_2, 3.5 % Ar and 1.5 % N_2 by volume) and nitrogen product streams are available at around 1 bar. However, the process may also operate at elevated pressure such that the air fed to the ASU is at a pressure closer to that of the gas turbine compressor outlet. This makes it feasible to supply part or all of the ASU air from the gas turbine compressor. In this case, the ASU product streams are at around 5 bar which reduces the recompression work.

2.4 Gas turbines

Gas turbines were designed for natural gas and oil fuels, but are also commercially available for operation on syngas. GE, Siemens, Mitsubishi and Alstom offer gas turbines which could be applied in larger scale IGCC plants. The two coal IGCC demonstration plants in the US (Tampa and Wabash) used the GE 7FA turbine, while the two European plants at Buggenum and Puertollano used the Siemens SGT5-2000E (previously called V94.2) and the SGT5-4000F (previously called V94.3).

2.4.1 NO_x emissions from gas turbines

Gas turbines which run on natural gas use so called dry low-NO_x (DLN) combustors. In these, the fuel is pre-mixed with air to lower the peak flame temperatures and reduce the formation of thermal NO_x. They are referred to as dry, because no injection of water or steam is used to reduce flame temperatures (in contrast to earlier practice). However, when using syngas or hydrogen mixtures, the DLN combustors can no longer be used. The reason is the danger of flashback caused by the high flame propagation speed of hydrogen. It is therefore necessary to use traditional diffusion combustors with a diluent for NO_x control. The existing IGCC demonstration plants use a combination of nitrogen (from the air separation unit) together with water (syngas saturation) to dilute the fuel before combustion with air. By this method it is proven possible to reach a NO_x concentration of around 10 ppmv (at 15 % O_2) in the exhaust gas at the Tampa plant. To achieve lower NOx emissions than this with available technology it would be necessary to add post-combustion clean up systems such as selective catalytic reduction (SCR) which is not straightforward in IGCC plants. For example, a very high degree of sulfur removal would be required to protect the SCR catalyst.

2.4.2 Gas turbines on syngas

Syngas which typically has only 25 % of the volumetric heating value compared to natural gas, therefore requires roughly 4 times higher flow rate to maintain the same turbine inlet temperature (which is desirable to maintain high efficiency of the power block). Potentially, the increased mass flow of fuel and therefore the higher mass flow rate through the turbine will lead to an increased power output from the turbine. If the fuel is diluted with nitrogen or water for the purpose of NO_x control, the potential for increased GT power output is even higher. As an example GE currently rates their 7FA at 171.7 MW for natural gas and at 197 MW for syngas [11].

However, depending on the gas turbine technology and fuel under consideration, there may be several limitations for the full realization of this increased power output potential:

- Compressor surge
- Gas turbine torque
- Turbine inlet temperature and material lifetime

2.4.3 Compressor surge limitation

A higher mass flow rate through the turbine may increase the pressure at the compressor outlet (back pressure) too much, so that the compressor runs into surge and the air flow no longer can be maintained. The amount of pressure increase the compressor can tolerate before this occurs is referred to as the compressor surge margin which is a characteristic of the design of a given compressor. If surge becomes a problem therefore depends on the type of gas turbine, but it seems that this is an issue for the majority of available large gas turbines.

The pressure increase at the turbine inlet (and thus also at the compressor outlet) can be explained by the theory for flow through a choked nozzle which states that in order to get a higher mass flow through a nozzle of fixed geometry, the inlet pressure must either increase or the inlet temperature must be reduced. As mentioned above the turbine inlet temperature should, however, be kept as high as possible, consistent with material limitations to ensure a high combined cycle efficiency. There are several other possible strategies to resolve the surge limitation problem:

- Modify the turbine of the GT
- Modify the compressor of GT
- Integration with the air separation unit

Turbine modification:
The turbine can be modified with an increased cross sectional area to allow a higher flow rate with less pressure increase. At the Tampa plant, which uses the GE 7FA gas turbine, the first stage turbine nozzles were replaced with the nozzles from the earlier 7F model in order to increase the cross sectional area to handle the higher mass flows.

Compressor modification:
The Siemens SGT5-2000E (previously V94.2) is also available in a modified version which is intended for syngas operation in IGCC plants which have no air integration (see later section). This gas turbine model is the SGT5-2000E(LCG) (previously V94.2K) which has one additional compressor stage, and can therefore operate at a higher overall pressure ratio without surge problems. The ISAB IGCC plant in Italy which uses asphalt as feedstock and has no air integration between the GT and ASU has two of these gas turbines.

Air integration between GT and ASU:
This principle is further discussed in Section 3. It involves bleeding off some of the air at the outlet of the GT compressor, and utilizing this air in the ASU. Also, a certain amount of nitrogen product from the ASU may be brought back the GT. This concept makes it possible to reduce the total mass flow through the turbine by bleeding off more air mass flow than the mass flow of nitrogen brought back. The two European plants at Buggenum and Puertollano apply this principle which enables the use of standard Siemens gas turbines with respect to the compressor

and turbine. Air integration may therefore represent a solution to apply gas turbines which would otherwise need redesign to work on syngas.

2.4.4 Gas turbine torque limitation

The mechanical ability of the gas turbine rotor to handle increased power output is another limitation for maximum GT power output. For example, the current GE 7FA has a maximum power output of 197 MW due to this limitation. According to GE, the 7FB (in commercial operation and rated at 184.4 MW for natural gas) is planned to be available for syngas in 2006 with a higher torque rotor, and rated at 210 MW [22].

2.4.5 Turbine inlet temperature and material lifetime

The turbine inlet temperature[12] (TIT) is an important variable with respect to the electric efficiency of the combined cycle. It is desirable to operate with a TIT as high as possible to increase the efficiency. However, in order to protect the materials of the turbine, it is necessary to have a cooling system.

Modern gas turbines on natural gas have TITs above 1300 °C (with some even above 1400 °C). At the same time, the maximum tolerable metal temperatures of the stator and rotor blades are around 870 °C and 815 °C, respectively [1]. To avoid that the metal temperatures increase beyond these limits, a combination of air cooling and blade thermal barriers are used. About to be commercialized is a new technology using steam cooling with higher TIT and improved efficiencies. Since 2003, GE's first 9H gas turbine featuring a closed-loop steam cooling system has been in operation at Baglan Bay power station in the UK. The first 60 Hz version of the same gas turbine is scheduled to be in operation in 2008 at a Calpine power plant in California [7].

When a gas turbine is run on syngas or a hydrogen mixture instead of natural gas, the exhaust gas may consist of more than the usual 8 % volume of water vapor. Depending on the fuel mixture's hydrogen content and the amount of water added to reduce NO_x formation (e.g. syngas saturation), the resulting amount of water vapor in the gas turbine exhaust may be less or higher than the 8 %. The significance of increased exhaust volume percent of water vapor has to do with increased heat transfer effects that increase the metal temperatures, and thus shorten the lifetime of the turbine materials. The increased mass flow through the turbine also causes enhanced heat transfer. Therefore GE recommends decreasing the turbine inlet temperature (TIT) by a certain amount if it is desirable to maintain 100 % of the design lifetime [22]. The higher the volume percentage of water vapor, the more the TIT needs to be reduced. Unfortunately, reducing the

[12] The turbine inlet temperature (TIT) is not uniquely defined. Different temperatures could be meant by this term. There are three relevant definitions [1]: 1) The temperature at the exit of the combustor (at the inlet of the first turbine stator), 2) The temperature at the outlet of the first turbine stator (at the inlet of the first rotor). At this point the temperature is typically 40-70 °C lower compared to def. 1, due to the cooling air or steam for the first stator. This definition of the TIT is used by GE who refers to it as "firing temperature". 3) The calculated temperature (not physical) that would result from mixing all the cooling air with the combustor exhaust gas. This temperature is typically 70-110 °C lower compared to definition 2. Siemens uses this definition also known as the "ISO TIT". It should be added that all three definitions would be identical for a gas turbine without cooling. In the text, def. 2 will be used if nothing else is said.

TIT also have negative impacts, e.g. on total plant efficiency. Therefore, economic assessments are needed to draw conclusions.

The use of water for NO_x reduction has, as described above, some significant drawbacks. In this respect, GE prefers nitrogen (from the ASU) as a diluent instead [22]. However, the nitrogen involves a booster compressor which also represents a cost and an energy penalty[13]. The four demonstration plants all have chosen to use a mix of nitrogen and water for NO_x control.

2.4.6 Gas turbines on hydrogen as only fuel

In contrast to gas turbines running on syngas (mixture of carbon monoxide and hydrogen), there are no existing turbines running on hydrogen as the only fuel[14]. Currently, GE is the only supplier who offer guarantees for fuels with high hydrogen content and their fuel specifications demand that the maximum hydrogen content is 65 % and that the volumetric energy density of the fuel is no less than 200 Btu/scf [12]. The implication of this is that an amount of CO needs to be left in the fuel, thus limiting the maximum possible degree of CO_2 capture to around 85 % for current designs [24].

Experiments performed by GE in their combustion test stand show that NO_x emissions can be kept lower than 10 ppmvd (at 15 % O_2) by diluting hydrogen with nitrogen and steam [31]. A consequence of using a hydrogen rich mixture (hydrogen and nitrogen) as gas turbine fuel is that the moisture content in the exhaust may be higher. The addition of water/steam for further reductions in NO_x emissions will contribute to higher moisture content. Because of water's physical properties, heat transfer is increased in the turbine both by radiation and convection [22]. When considering hydrogen as a fuel, GE is emphasizing the need for further understanding and development of [28]:

- Advanced blade materials and thermal barrier coatings interactions with high moisture/ high temperature gas
- Studies and experiments to optimize tradeoffs between efficiency and RAM (reliability, availability and maintainability)

In practice, this will probably mean that the turbine inlet temperature (TIT) of the gas turbine must be reduced to avoid shorter lifetime of the blade materials and coatings. This reduction in TIT will reduce the efficiency of the combined cycle.

[13] The nitrogen compressor requires electricity. If the ASU supplies nitrogen at 1 bar, as is normal for stand-alone ASUs, the recompression energy is high. But, if the ASU supplies nitrogen at around 5 bar, as is normal for ASUs integrated with the gas turbine, the recompression energy is low.

[14] Even if the hydrogen is the only fuel, it may be mixed with non-fuels such as nitrogen and water to reduce NO_x emissions.

3 IGCC SYSTEM ISSUES

3.1 Gasification and coal quality

Most IGCC studies have focused on bituminous coals and indicate that the GE quench gasifier is most economical without CO_2 capture, and more economical when CO_2 is captured [14][16]. Currently, there is a lack of information in the literature on IGCCs based on lower rank coals such as lignite and sub-bituminous coals. In general, increased moisture and/or ash contents cause higher capital cost and lower efficiency for both dry feed and slurry feed gasifiers.

Increased moisture content requires more energy to vaporize the water and increased ash content means a greater mass flow of inerts which must be heated up. Therefore, both increased moisture and ash content have the effect of higher oxygen consumption and lower cold gas efficiency.

Dry feed gasifiers can dry the coal before gasification so that the gasifier does not have to process the extra steam from coals with high moisture content. Drying of the coal to around 2 % moisture as required by the feed system, may be achieved by burning a fraction of the produced syngas, or thermodynamically more ideal by extraction of steam at the lowest possible temperature level in the steam cycle.

Slurries of coal with high moisture content achieve lower solids concentration, and therefore a large amount of steam must be vaporized and then processed in the gasifier. This contributes to a reduction of the capacity per gasifier volume because the residence time per unit volume is reduced. A study showed that the E-gas slurry feed gasifier may need four gasifier reactors instead of two when using lignite as opposed to bituminous coal [14].

Even if both the dry feed and the slurry feed gasifiers have their capacities and efficiencies reduced for low rank coals, slurry feed gasifiers are penalized more heavily because of the extra moisture which partially occupies the volume of the gasifier. This conclusion is supported by a study that evaluated power plants with and without CO_2 capture for Canadian coals. For the capture cases, it was concluded that the GE quench gasifier was most economical for the bituminous and sub-bituminous coals, while the Shell gasifier was superior for lignite [17]. In conclusion, dry feed gasifiers such as Shell seem to outperform slurry feed gasifiers for low rank coals with high moisture content.

3.2 Integration of the gas turbine and the air separation unit

3.2.1 What is meant by integration?

The figure below shows a principle sketch of how the gas turbine (GT) may be integrated with the air separation unit (ASU). An air bleed from the compressor outlet of the GT can supply part or all of the air required by the ASU. Typically, the total air required by the ASU amounts to around 20-25 % of the GT compressor air. The degree of (air) integration is usually defined as the percentage of the total ASU air required coming from the GT compressor. The two existing US IGCC demonstration plants have 0 % integration, while the two European plants have 100 %

integration. Even if the air integration is 0 %, it may still be beneficial to use nitrogen from the ASU for NO_x reduction (this is practice at the Tampa plant).

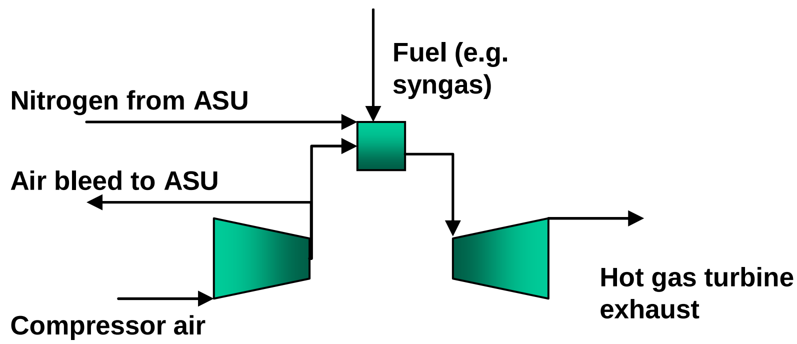

Figure 13

If the ASU is to be integrated with the gas turbine, a so called elevated pressure ASU has some benefits. It operates at a higher pressure, and it can therefore use the air compressed in the gas turbine (which is normally available at higher pressure than required by the ASU) more efficiently. The nitrogen product is available at higher pressure than atmospheric, which means less recompression energy to use it for NO_x reduction and increased power in the gas turbine.

3.2.2 What are the benefits of integration?

The possible benefits of integration are:

- Increased efficiency
- Increased power output
- Reduced investment cost (e.g. saves ASU air compressor)

3.2.3 Why may integration be problematic?

The drawbacks of high integration are:

- Lengthy start up times (at Buggenum which is 100 % integrated a separate ASU air compressor was later installed to achieve quicker start ups)
- ASU can not start up without GT running
- Less operational flexibility
- 100 % integration does mean maximum efficiency, but not mean maximum power (explained in Section 3.2.4)
- Risk of lower availability

3.2.4 Maximizing power or efficiency?

A study by Foster Wheeler studied the impact of different degrees of GT/ASU integration for an IGCC plant utilizing two GE 9FA gas turbines [6]. It is emphasized that the following numerical results are specific to this case study. The gas turbine model, the gasification process, and the coal quality can all influence this type of analysis.

According to the Foster Wheeler study, the following assumptions were made:

- The GE 9FA is surge limited and has a maximum power output of 286 MW on syngas (total of 572 MW)
- All the available N_2 from the ASU is used in the GT for NO_x reduction
- In order not to exceed the GT maximum power output of 286 MW per turbine, inlet guide vanes (IGVs) are applied to reduce the air flow through the compressor if necessary

The figure and table below summarizes the findings of the study. Figure 14 shows that the GT power output is constant for integration degrees of 46.2 % or less (Region 1), and a drop in GT power as a linear function of higher degrees of integration (Region 2). At 46.2 % integration (dotted line), the GT can avoid surge by bleeding of compressor outlet air to the ASU. However, at lower degrees of integration, less air goes to the ASU. Therefore, the compressor air flow is reduced by adjustment of the IGVs with the amount required to keep the maximum GT power at the limit. At higher than 46.2 % integration, the use of IGVs are no longer required because the air bleed to the ASU is so large that the GT power drops below the maximum limit.

If the auxiliary power of the ASU is taken into account, one finds that the net power (GT power minus the ASU aux. power) has its maximum at 46.2 % integration. Going from 0 % integration to the maximum net power point, it is clear that the net power must increase as the GT power is kept constant while the ASU power is decreasing. For integration degrees higher than 46.2 %, GT power drops of more quickly than the saved auxiliary ASU power, and thus net power is a falling function of integration degree.

Not included in the Foster Wheeler study, was an analysis on the effect of integration on efficiency. In Figure 14, the efficiency of converting syngas to net work (GT power minus ASU power) is shown. This efficiency is not equal to the total electrical efficiency of the IGCC plant, but it is related to it. (As a preliminary estimate, one can assume that a 1 %-point change in the efficiency in the figure corresponds to a change of 0.7 %-points in the total IGCC efficiency.) The efficiency plot shows efficiency as an increasing function of integration from 0 % to 100 %. Thus, 100 % integration results in the highest efficiency. As observed from the graph, the slope of the efficiency graph increases markedly at the point of maximum net power (46.2 % integration). In Region 1 of the figure, there is an increase in the net power, but also an increase in the syngas consumption of the gas turbine (higher turbine mass flow requires more syngas to maintain constant turbine inlet temperature). In Region 2, however, the net power is reduced, but the syngas consumption is reduced more, thus the increased slope.

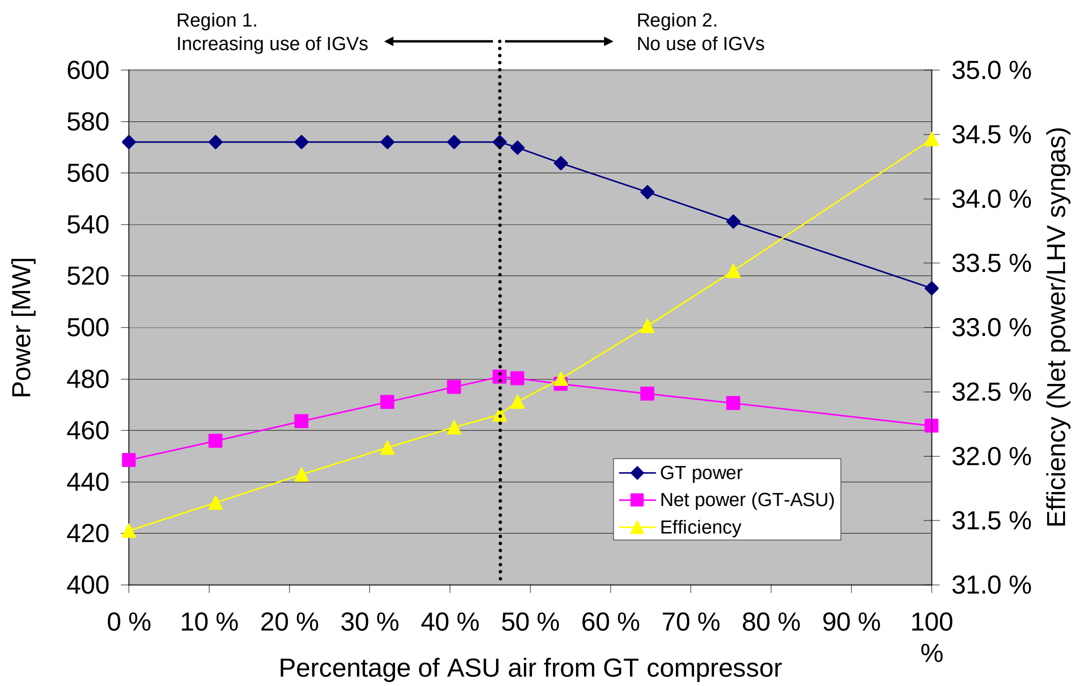

Figure 14

Table 11

Integration degree	%	0.0 %	10.8 %	21.5 %	32.2 %	40.5 %	46.2 %	48.4 %	53.8 %	64.6 %	75.3 %	100.0 %
Air extraction	t/h	0	100	200	300	376	429	450	500	600	700	929.2
N2 injection	t/h	697	697	697	697	697	697	697	697	697	697	697
N2+air+syngas	t/h	4914.8	4944.6	4974.1	5003.7	5026.6	5042	5021	4971	4871	4771	4542
N2/fuel ratio		1.84	1.83	1.81	1.79	1.78	1.79	1.8	1.82	1.86	1.89	1.99
Syngas	t/h	378.8	380.9	385.1	389.4	391.6	389.4	387.2	383.0	374.7	368.8	350.3
Air through turbine	t/h	3839.0	3866.7	3892.0	3917.3	3938.0	3955.6	3936.8	3891.0	3799.3	3705.2	3494.7
Air through compr.	t/h	3839.0	3966.7	4092.0	4217.3	4314.0	4384.6	4386.8	4391.0	4399.3	4405.2	4423.9
Syngas	MW	1427	1441	1454.9	1468.9	1479.7	1487.4	1481.4	1466.5	1436.8	1407	1340
GT power	MW	572	572	572	572	572	572	569.9	563.9	552.6	541.2	515.2
ASU consumption	MW	123.6	116.1	108.5	101	95.2	91.2	89.6	85.8	78.3	70.7	53.4
Net power (GT-ASU)	MW	448.4	455.9	463.5	471	476.8	480.8	480.3	478.1	474.3	470.5	461.8
Efficiency		31.4 %	31.6 %	31.9 %	32.1 %	32.2 %	32.3 %	32.4 %	32.6 %	33.0 %	33.4 %	34.5 %

3.2.5 Conclusions about maximum power or efficiency

Here, it will be attempted to draw some more general conclusions based on the case study results in the previous section. **An important observation is that maximum net power and maximum efficiency does not occur at the same degree of integration.**

Maximum efficiency:
The point of maximum efficiency is found at 100 % integration. It seems that the major effect which explains this is the compression energy saved by using the larger, more efficient GT compressor instead of the smaller, less efficient ASU compressor.

Maximum net power:
The point of maximum net power is found where the GT compressor air bleed to the ASU is just sufficient to avoid the surge or torque limit. At lower air bleeds (less integrated), net power is

reduced because of constant GT power and increased ASU power. At higher air bleeds (more integrated) net power is also reduced as GT power is reduced faster than the reduction in ASU power.

While maximum efficiency will (probably) always occur at 100 % integration, the point of maximum power depends on several case specific considerations:

- Gas turbine model
- Coal type
- Gasifier technology

All these will impact the point of maximum net power. The coal type and gasifier give the amount of oxygen required, and therefore the nitrogen production. Potentially, all this nitrogen may be used for NO_x reduction in the gas turbine and together with surge/torque limits then determine the air bleed needed from the GT to the ASU. If no air bleed is needed, maximum power would be achieved at 0 % integration.

To get an idea of the improvement potential of integration on efficiency and power, the Foster Wheeler data indicate that:

- The total IGCC efficiency increases with around 2 %-points for full integration compared to no integration
- The increase in net power (of the GT and ASU combined) is around 7 % for the optimal integration (with respect to power) compared to no integration

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5 APPENDIX

5.1 Lower vs. higher heating value

The chemical energy in a fuel is normally stated as either lower or higher heating value with units MJ/kg or btu/lb, where 1 MJ/kg corresponds to around 430 btu/lb.

When a fuel is combusted, all hydrogen (which may be present in the fuel in various chemical compounds) will initially be converted to water vapor. The higher heating value (HHV) considers the heat released upon condensation of this water vapor (latent heat/ heat of vaporization/condensation), while the lower heating value (LHV) excludes this heat.

Because of these choices of definitions, the LHV is always lower than the HHV by a certain amount depending on the amount of hydrogen in the fuel. The following equation calculates the difference between the HHV and LHV in MJ/kg:

$$\boxed{\mathrm{HHV}-\mathrm{LHV}=\frac{2.016}{2.016+16.0}\times y_{\mathrm{H_2}}\times 2.442\ \mathrm{MJ/kg}=y_{\mathrm{H_2}}\times 21.8\ \mathrm{MJ/kg}}$$

where the term 2.442 MJ/kg is the heat of vaporization of water at 20 °C and $y_{\mathrm{H_2}}$ is the mass fraction of all hydrogen in the fuel.

An efficiency related to the chemical energy in the fuel should always state if LHV or HHV has been assumed. In Europe, LHV tend to be more common than in the US. In the gas turbine industry LHV is always used (also in the US), but fuel prices normally assume HHV. It can therefore be concluded that there is some potential for confusion in this area.

5.2 Energy penalties and efficiency penalty

When comparing the performance of a reference power plant without capture and a power plant (green field or retrofit) with capture, there are three different measures commonly used:

1. Energy penalty (fractional reduction in power output per unit of fuel)
2. Energy penalty (fractional increase in fuel consumption per unit of electricity)
3. Efficiency penalty (percentage points change in efficiency)

All these measures are calculated from the efficiencies of the reference plant (η_{ref}) and the capture plant (η_{ccs}). Consider the example for an IGCC with and without capture, using efficiencies (LHV) from a recent study for a Shell IGCC:

$\eta_{\mathrm{ref}} = 0.431$
$\eta_{\mathrm{ccs}} = 0.345$

1) Energy penalty (alternative 1)

$$\frac{\eta_{\mathrm{ref}}-\eta_{\mathrm{ccs}}}{\eta_{\mathrm{ref}}}=\frac{0.431-0.345}{0.431}=20.0\%$$

2) Energy penalty (alternative 2)

$$\frac{\eta_{\text{ref}} - \eta_{\text{ccs}}}{\eta_{\text{ccs}}} = \frac{0.431 - 0.345}{0.345} = 24.9\%$$

3) Efficiency penalty

$$\eta_{\text{ref}} - \eta_{\text{ccs}} = 0.431 - 0.345 = 8.6\% - \text{points}$$

While the two alternative energy penalty measures are relative quantities expressed in fractions or percentages, the efficiency penalty is an absolute difference expressed in percentage points.

5.3 Various losses and net electricity generated

This section deals with the various losses which need to be considered when estimating the efficiency of a power plant. A thermodynamic process simulation tool such as Aspen Plus can provide the necessary "raw" energy balance data for a modeled power plant. However, additional losses (besides those considered in the process model itself) should be considered in order to calculate the electrical efficiency of the plant. For example, general process simulators do not consider mechanical and generator losses, auxiliary losses and transformer losses.

The work associated with compression and expansion of fluids in turbomachinery is modeled by assuming so called isentropic (adiabatic) or polytropic efficiencies which consider the deviation from an ideal, loss-free thermodynamic process. These efficiencies are typically tuned so that the fluid state (e.g. outlet temperature of a turbine) calculated by the model matches real process equipment data.

Figure 15 illustrates the various energy losses from the fluid work calculated in the process simulator. The fluid work, P_{fluid}, represents the total work done by the fluids in the power generating turbomachinery. To account for friction in the shafts and conversion losses in the generator, a combined mechanical and generator efficiency is defined as:

$$\eta_{\text{mech\&gen}} = \frac{P_{\text{gross}}}{P_{\text{fluid}}}$$

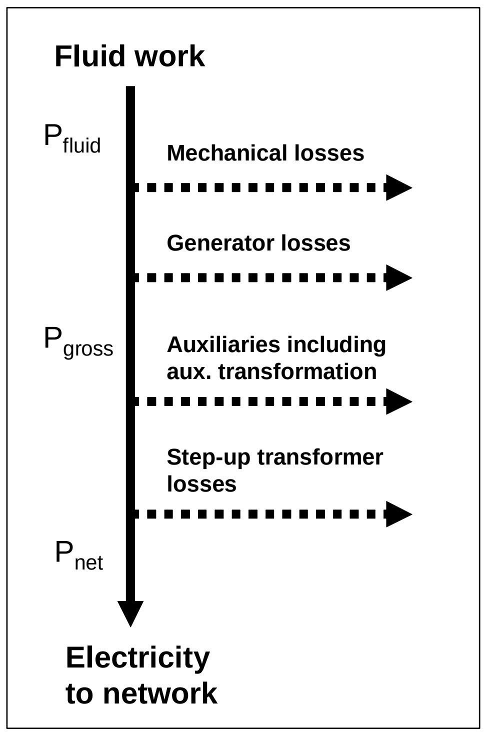

Figure 15

which has a typical value of 98.5 %, and P_{gross} is the electric power available at the generator terminals.

Auxiliary power strongly depends on the plant type. For IGCC plants, the major consumer is the air separation plant if it has a separate compressor. Several other consumers such as pumps, solids handling systems and lighting etc belong in this category.

Finally, if high voltage generators are not applied, it is necessary to increase the voltage of the electricity before export to the grid. This may be done with a 99.5 % efficient transformer. The final amount of electricity to the net is denoted P_{net}. It is this variable which should be divided by the chemical energy in the fuel (LHV or HHV) to obtain the electrical efficiency of the plant.