Recent operating experience and improvement of commercial IGCC

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Abstract

IGCC has today reached a status where experience is available from first and second generation plants, built in the 1970s/1980s and in the 1990s respectively, as commercial-scale demonstration plants for coal-based applications. These plants feature variations on gasification technology and subsequent environmental controls and in operating them a number of technical and commercial lessons have been learned that will help to improve the next generation of IGCC projects.

The report reviews and summarises the state-of-the-art and operating experience of several commercial IGCC plants worldwide, setting out the lessons learned and plans for future development embracing such issues as the changes or modifications to plant made to overcome the operational problems and to improve the reliability and availability of the plant. Since IGCC is considered a 'capture ready' technology for CO_2 abatement, the current status with regard to the incorporation of carbon capture and storage systems (CCS) has been reviewed. Finally, the report outlines the issues associated with assessing the risks in commercialising IGCC plant.

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Acronyms and abbreviations

ADV	average daily value
AGR	acid gas removal
ASU	air separation unit
CCS	carbon capture and storage
CCT	clean coal technology
CCU	console control unit
CFD	computational fluid dynamics
CRIEPI	Central Research Institute of Electric Power Industry, USA
DCS	distributed control system
EAGLE	Energy Application for Gas, Liquid and Electricity
EPC	Engineering Procurement and Construction
FEED	Front End Engineering Design
GT	gas turbine
HHV	higher heating value
HP	high pressure
HRSG	heat recovery steam generator
HTW	High Temperature Winkler
IGCC	Integrated Gasification Combined Cycle
IP	intermediate pressure
JCCM	Spanish Science and Innovation Ministry and Regional Government
LHV	lower heating value
LIN	liquid nitrogen
LOX	liquid oxygen
MDEA	methyl-diethanol-amine
MHI	Mitsubishi Heavy Industries
NEDO	New Energy and Industrial Technology Development Organisation, Japan
NETL	National Energy Technology Laboratory, USA
NGCC	natural gas combined cycle
PC	pulverised coal
PPA	power purchase agreement
PRENFLO	pressurised entrained flow
PSA	pressure swing absorption
SGC	syngas cooler
TECO	Tampa Electric Company, USA
US DOE	Department of Energy, USA

Units used

% m/m	% mass/mass
% w/w	% weight/weight
% w/w ar	% weight/weight as-received
bar	100,000 Pascals
GWe	gigawatts electrical
kg	kilogramme
kJ/kg	kilojoules per kilogram
L/m^3	litres per cubic metre
mg/kg	milligrams per kilogram
mg/m^3	milligrams per cubic metre
mg/L	milligrams per litre
MJ/kg	megajoules per kilogram
MJ/s	megajoules per second
ml/kg	millilitres per kilogram
mm	millimetres
MPa	mega Pascals
MW	megawatts
MWe	megawatts electrical
MWth	megawatts thermal
°C	degrees celsius
ppm	parts per million
s	seconds
t/d	tonnes per day
wt%	weight per cent

Contents

1 Introduction

Coal gasification by which coal is converted into a fuel gas rich in hydrogen and carbon monoxide has been undertaken industrially for over two hundred years. The oil crises of the early 1970s prompted a renewed interest in advanced coal utilisation technologies as an alternative to increasingly expensive oil supplies. One technology, integrated (coal) gasification in a combined cycle (IGCC), offered the promise of generating power from coal at high efficiency with low emissions and this sparked research and development activity aimed at demonstrating and commercialising these plants.

In IGCC, coal is gasified and the gasification products are purified to remove pollutants and particulates before entering one or more gas turbines attached to power generators. Heat recovered from the gas turbine exhaust gases can be used to generate steam to drive additional steam turbines. IGCC for power generation has been reviewed in a number of Clean Coal Centre reports, most recently by Barnes (2011), Fernando (2008) and Henderson (2004, 2008). A schematic of a generalised design of an IGCC plant is shown in Figure 1.

IGCC has today reached a status where experience is available from first and second generation plants, built in the 1970s/1980s and in the 1990s respectively, as commercial-scale demonstration plants for coal-based applications. These plants feature variations on gasification technology and subsequent environmental controls, and in operating them a number of technical and commercial lessons have been learned that will help to improve the next generation of IGCC projects.

The report reviews and summarises the state-of-the-art and operating experience of several commercial IGCC plants worldwide setting out the lessons learned and plans for future development embracing such issues as the changes or modifications to plant made to overcome the operational problems and to improve the reliability and availability of the plant. Since IGCC is considered a 'capture ready' technology for CO_2 abatement, the current status with regard to the incorporation of carbon capture and storage systems (CCS) has been reviewed. Finally, the report outlines the issues associated with assessing the risks associated with commercialising IGCC plant.

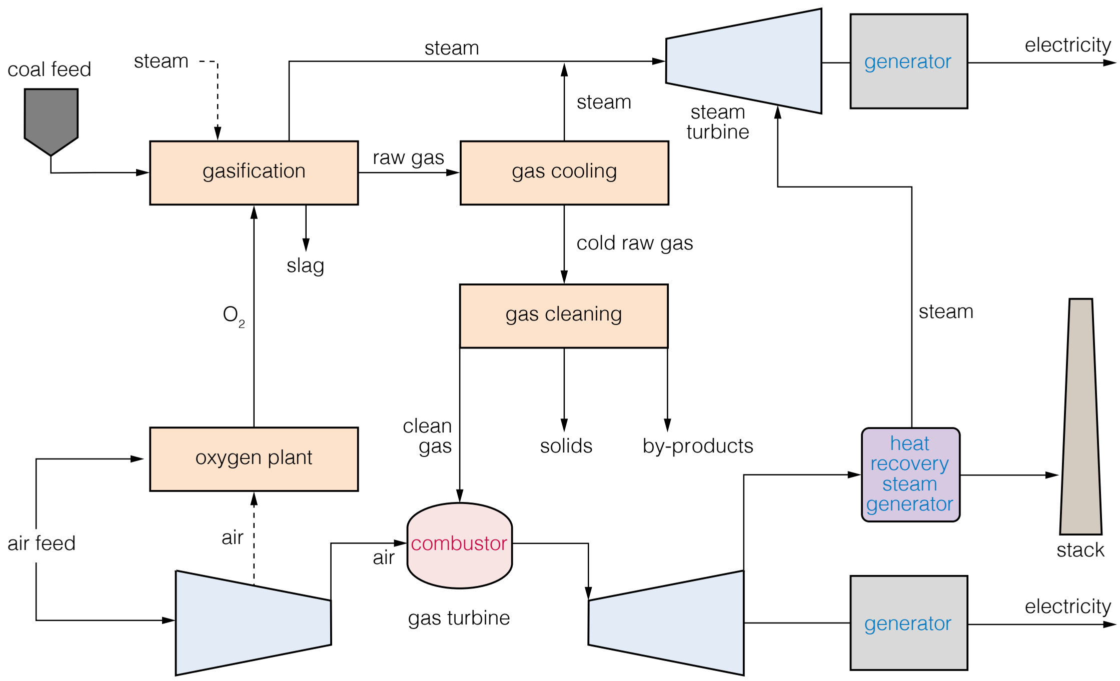


Figure 1 Integrated gasification combined cycle without CO_2 capture – major component systems (Henderson, 2008)

2 Overview of established IGCC power plants

2.1 Buggenum IGCC

Nuon's Buggenum power station, located in the Netherlands, was the world's first IGCC plant of commercial size and was built as a demonstration plant for a test period of four years at the beginning of 1994. The plant has been in commercial operation since 1998 and has accumulated approximately 80,000 hours of operation (Kehlhofer and others,1999; Ansaldo Energia, 2010). The plant consists of a fully integrated high pressure air separation unit (ASU), a coal pre-conditioning system, a Shell dry pulverised coal fed oxygen blown gasifier (*see* Figure 2), a two-step gas cooling system with recycle gas that brings the temperature of the syngas down to approximately 800ºC, followed by a convective cooler where high and intermediate pressure steam is generated. Fuel is prepared in three 55% roller mills where the coal is ground to an average particle size less than 100 microns. The pulverised coal is partly dried in the mills before final drying is carried out by burning a portion of the syngas to heat the coal. Two trains of lock hoppers are employed to bring the coal to plant pressure, before it is conveyed pneumatically to the four side-mounted burners using high purity nitrogen as a carrier gas. The gasifier operates at 2.48 MPa and a temperature of 1600°C resulting in a carbon conversion rate of over 99%. The gasifier wall is surrounded with a steam generating membrane to contain the high temperature reaction. Slag produced in the gasifier exits through a quench bath followed by lock hoppers. There is no slag crusher used at the slag lock hopper outlet.

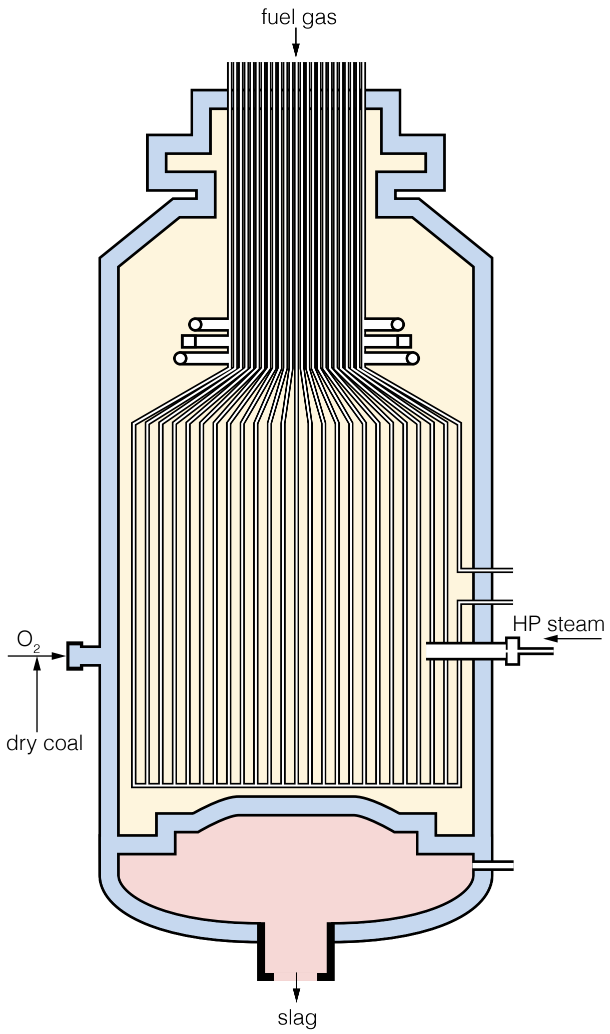


Figure 2 Shell gasifier used in Buggenum IGCC (NETL, 2013a)

Fly ash is removed by a cyclone and a ceramic candle filter, while a wet scrubbing unit removes halides. Sulphur is removed and recovered using carbonyl sulphide/hydrocyanic acid (COS/HCN) hydrolysis and a Claus plant, Sulfinol wash, gas saturator and water clean-up system (Kehlhofer and others, 1999; Ansaldo Energia, 2010; Shell 2013). A simplified process flow diagram of the Buggenum plant is shown in Figure 3.

The power cycle is based on a Siemens V94.2 gas turbine operating in a combined cycle with a net electrical output of 253 MW, along with a turbine inlet temperature of 1060°C. The installed turbine was the first field test for a Siemens syngas combustion system and the burner design has been adjusted to enable easy transition to different syngas compositions and heating values. The ASU produces 95% pure oxygen for use in the gasifier, in addition to high purity nitrogen. Pure nitrogen generated by the ASU is used as a carrier gas for the dry-feed gasifier, and is also used for purging. Additional nitrogen is compressed and used as dilution nitrogen in the gas turbine to compensate for the increased fuel mass flow, which is a consequence of the lower heating

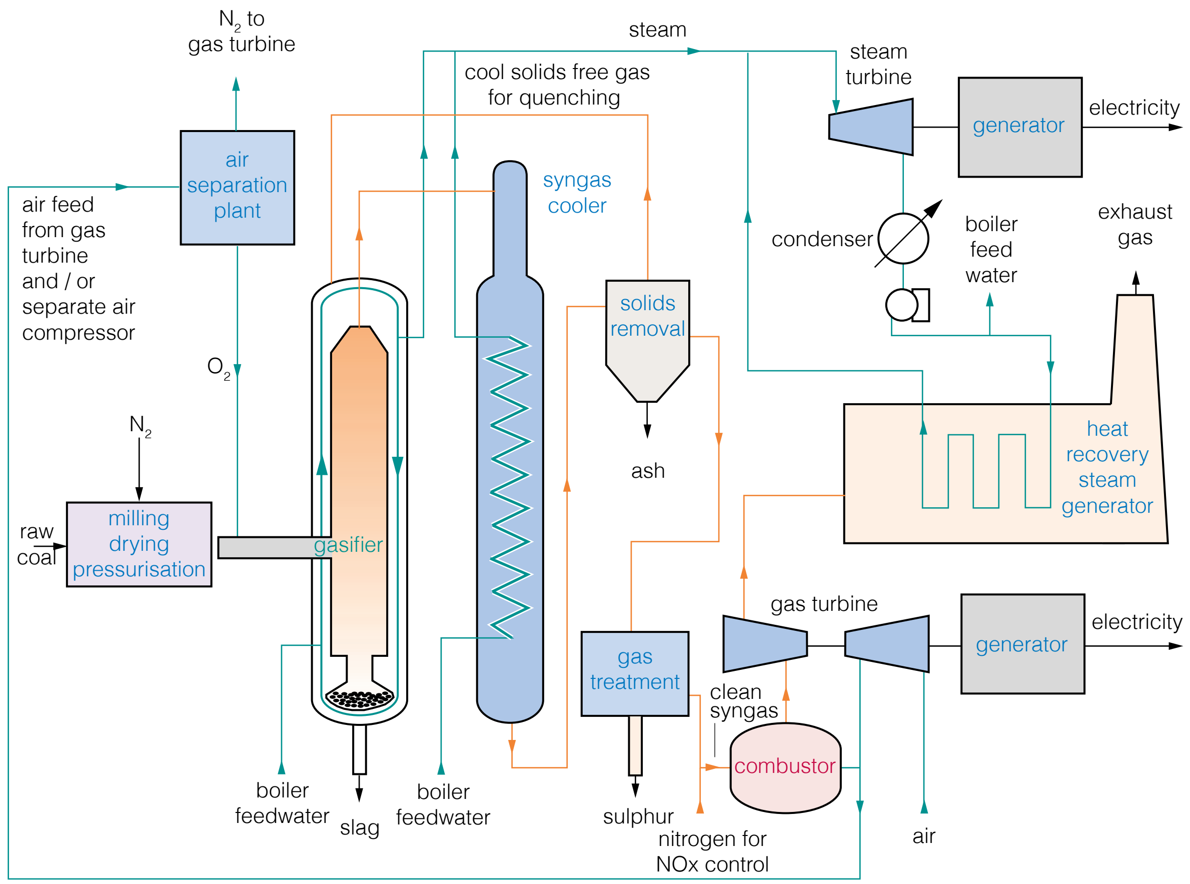


Figure 3 Schematic of the Buggenum IGCC plant (Shell, 2007)

Table 1	**Typical syngas composition from Buggenum IGCC (vol%)** (Kehlhofer and others, 1999; Ansaldo Energia, 2010)
H_2	12.3
CO	24.8
H_2O	19.1
N_2	42.0
Ar	0.6
CO_2	0.8
CH_4	0.0
O_2	0.4

value of the syngas, as compared with natural gas. The low NOx emissions, 6–30 ppm (by volume at 15% O_2), are controlled by water saturation and nitrogen dilution from the ASU upstream from the saturator. Typical syngas composition of the Buggenum plant is presented in Table 1, showing the high nitrogen content together with the active components of hydrogen, carbon monoxide and water vapour. The H_2/CO ratio is approximately 0.50 (Kehlhofer and others, 1999; Ansaldo Energia, 2010).

The gas and steam turbines are mounted on a single drive train which powers a 285 MWe generator. After in-plant electricity consumption in the ASU, gas production areas, and the combined cycle unit is subtracted, total net power production is 253 MWe. After solving commissioning problems with the gas turbine encountered during the test period, the IGCC plant has had an overall availability of approximately 80% and an overall plant efficiency of 43% (Hannemann and others, 2002). In order to achieve CO_2 emission reductions targets, the plant has more recently been operated successfully with co-gasification of coal and biomass at loadings up to 30 wt%. Biofuels that have been successfully co-gasified include chicken litter, sewage sludge and milled wood, and other possibilities have been investigated, including pet coke (Van Dongen and Kanaar, 2006).

2.2 Nakoso IGCC

In 1986, eleven Japanese corporations and nine regional utilities, the Electric Power Development Co and the Central Research Institute of Electric Power Industry (CRIEPI) established the Engineering Research Association for IGCC Systems. Between 1991 and 1996, under the banner of the New Energy and Industrial Technology Development Organisation (NEDO), the association successfully operated an entrained-bed coal gasification pilot plant rated at 200 t/d (25 MW equivalent) for 4770 hours. The longest continuous operating period was 789 hours. Additional technical data were acquired from a 24 t/d gasifier at the Nagasaki R&D Centre of Mitsubishi Heavy Industries (MHI).

Based on this work, and in collaboration with the Japanese Government, the consortium went on to design a highly efficient and reliable air-blown IGCC plant optimised for electric power generation. A 250 MW IGCC demonstration plant, called the 'Nakoso' plant based on the name of the area where the plant is located, was constructed. The IGCC demonstration plant project was led by Clean Coal Power R&D Co Ltd, which was founded in June 2001 as a result of the collaboration. MHI supplied the gasifier, syngas clean-up system, gas turbine, steam turbine and the heat recovery steam generator (HRSG). After completion of the design, construction and delivery of the plant, a series of demonstration tests were conducted at the 'Nakoso' IGCC plant from September 2007.

The Nakoso IGCC design (*see* Figure 4) is based on technology from Mitsubishi Heavy Industries and uses a pressurised, air-blown, two-stage, entrained-bed coal gasifier (*see* Figure 5) and a dry coal feed system. In-house studies concluded that air-blown IGCC is better suited for commercial power production than oxygen-blown IGCC because the latter technology's air separation unit (the source of the oxygen) represents a heavy auxiliary load.

The air-blown gasifier converts pulverised coal to synthesis gas (syngas). Char in the syngas is removed in a cyclone and porous filter, while H_2S is removed in a desulphurisation unit. Air for the gasifier is extracted from the combustion turbine compressor. The gasifier has a membrane waterwall that eliminates the need for refractory lining. Within the gasifier, a two-stage mechanism initially burns the coal and recycled char at high temperature at a high air/fuel ratio, and then the combustor's hot gas is reduced in the upper section of the gasifier, lowering the level of unburnt carbon in the ash, and discharging molten slag. The hot gas leaving the upper section is cooled by an internal gas

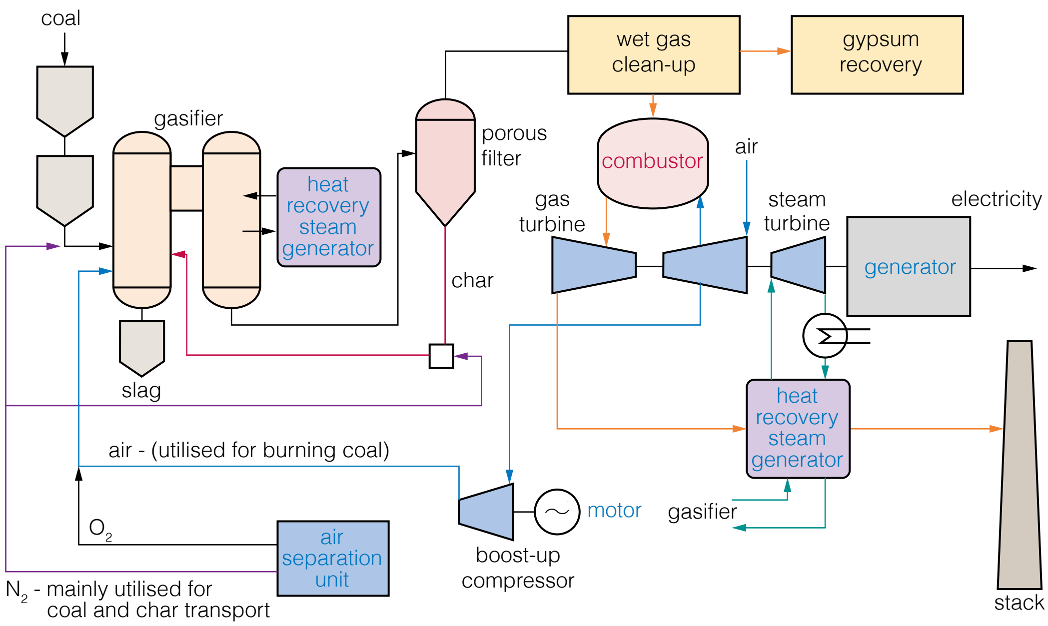


Figure 4 Schematic of the Nakoso IGCC (Watanabe, 2010)

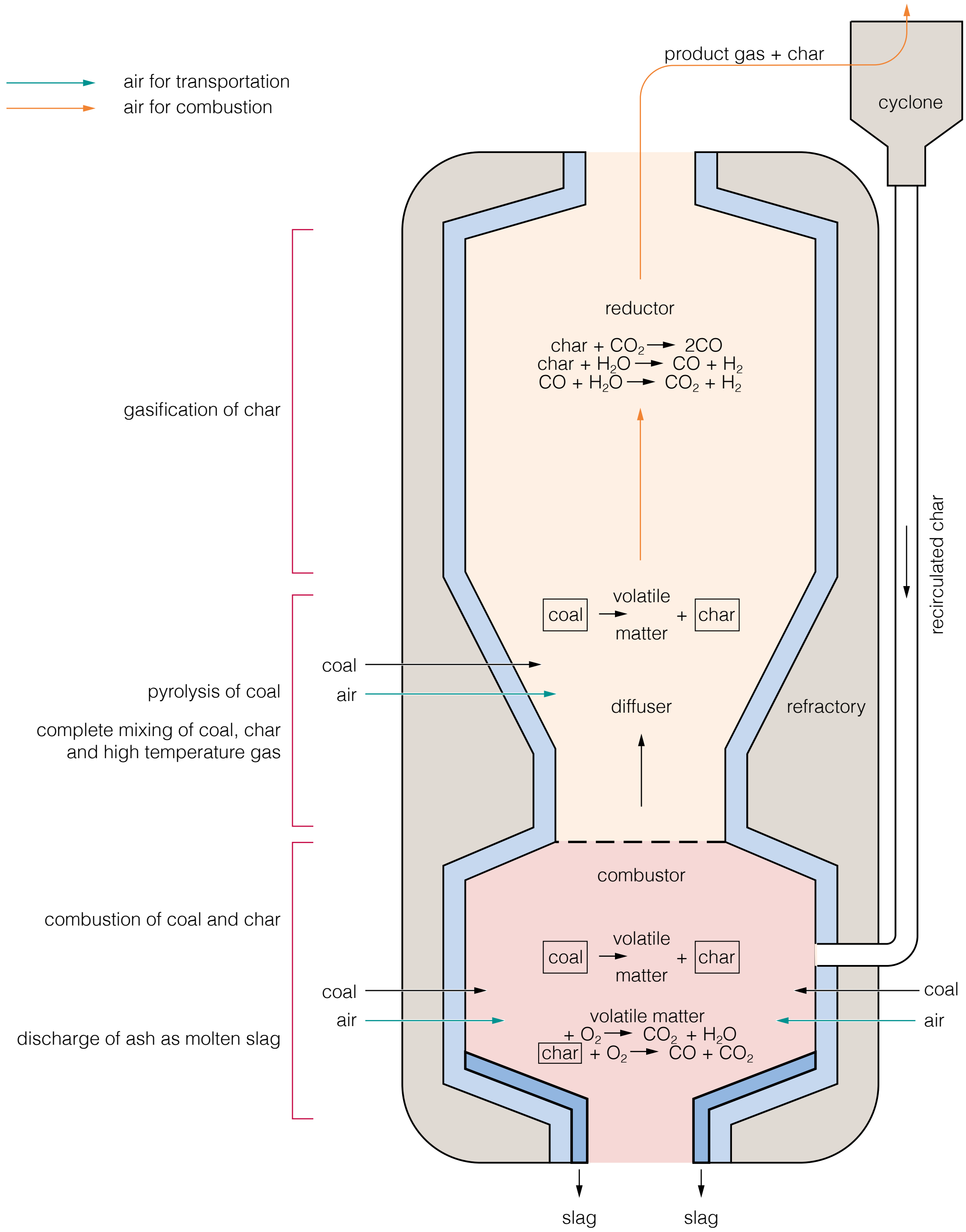


Figure 5 MHI gasifier used in the Nakoso IGCC (Inumaru and others, 1990)

cooler/steam generator integrated into the heat recovery steam generator (HRSG). Any char in the syngas is separated out by the cyclone or porous filter and recycled to the combustor. MHI claim a carbon conversion efficiency of 99.8%. A porous filter removes remaining particulates before the syngas enters a commercial methyl-diethanol-amine (MDEA) and carbonyl sulphide (COS) converter/acid gas removal system. This unit washes the syngas to remove sulphur and trace elements. Sulphur in the form of H_2S is oxidised and absorbed in a high-performance limestone-gypsum unit that produces high-grade, saleable gypsum in the sulphur conversion/recovery unit.

An MHI 701DA-type combustion turbine was selected for syngas combustion with power generation based on its track record in combined cycle and other low calorific fuel gas projects.

Table 2 **Performance and environmental specifications of Nakoso IGCC plant** (Wasaka and others, 2003)		
Capacity	250 MW gross	
Coal consumption	Approximately 1700 t/d	
System	Gasifier	Air blown and dry feed
	Gas treatment	Wet (MDEA) + gypsum recovery
	Gas turbine	1200°C-class (50 Hz)
Efficiency (Target values)	Gross	48% (LHV) 46% (HHV)
	Net*	42% (LHV) * 40.5% (HHV)
Flue gas properties (Target values)	SOx	8 ppm
	NOx	5 ppm
	Particulate	4 mg/m^3

* A target net thermal efficiency of 48–50% would be expected in a commercial IGCC plant employing a 1500°C class gas turbine but in this plant a 1200°C-class gas turbine was adopted to reduce costs

The specifications of the Nakoso IGCC are summarised in Table 2 (Wasaka and others, 2003).

2.3 Puertollano IGCC

The Puertollano IGCC power station, located in the central south part of Spain, was launched as a demonstration project in 1992 and was selected as a target project by the European Commission under the THERMIE program to assure reliable clean coal technology for the future power generation (Elcogas, 1998). The power station was taken into commercial operation with syngas in March 1998, with natural gas in October 1996, and was designed with a targeted net electrical output of 300 MW and an electrical efficiency of 42.1% (net). The plant is, like the Buggenum one, fully integrated with the ASU but without any start-up air compressor. It uses a coal blend based on subbituminous coal and petroleum coke with a normal composition of 50:50 by weight.

The IGCC power station, as illustrated in Figure 6, consists of the following main units (Alarcón, 2011):
- ASU;
- coal pre-conditioning;
- PRENFLO gasifier;
- gas cleaning;
- sulphur recovery (Claus);
- gas conditioning;
- power generation.

The coal feed is first mixed with limestone to reduce the melting point of the ash and milled in two roller mills. The coal is then fed to the drying system for achieving the moisture content required for effective feeding to the gasifier and then pressurised to 3 MPa in a lock hopper system before entering the gasifier. Nitrogen from the ASU is used for pressurisation and as a carrier gas. The gasifier is of the entrained oxygen blown type (PRENFLO technology), and was developed by Krupp Koppers (Blumenhofen, 2010). Pulverised coal is burnt together with oxygen, at a purity of 85% provided by the ASU, inside the gasifier where it is mixed with steam produced in the gasifier. The operating pressure and temperature are 2.5 MPa and 1500–1700°C respectively. The majority of the ash is

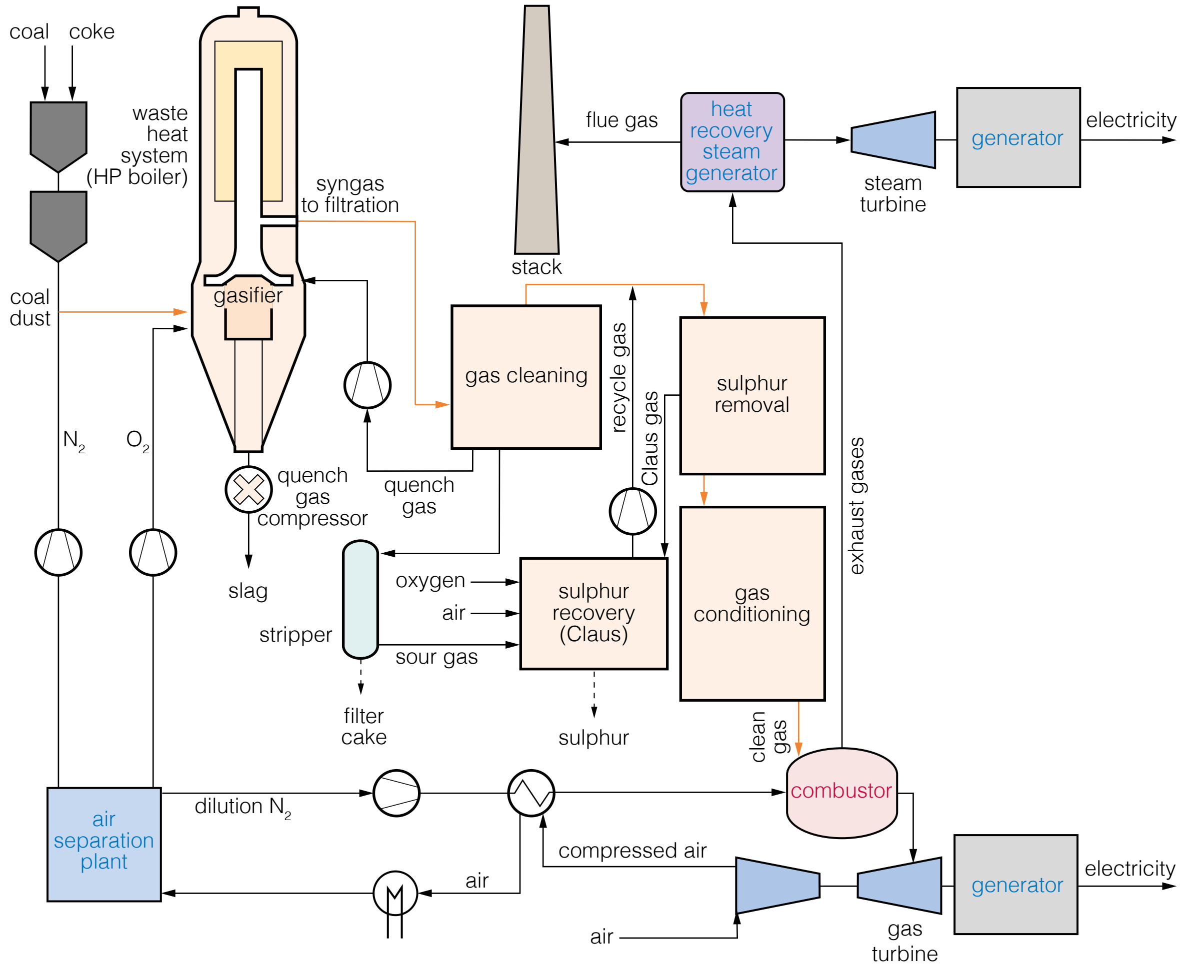


Figure 6 Schematic of the Puertollano IGCC power station (Collot, 2002)

removed from the bottom of the gasifier in liquid form (slag). The raw gas leaving the gasifier containing some entrained ash is cooled to 800°C (the point at which ash becomes solid) using recycled gas at a temperature of 235°C. The syngas is then further cooled in two steps using convection boilers. In the first boiler the gas is cooled to 400°C producing high pressure (HP) steam (12.7 MPa) and then further cooled to 235°C in the second boiler whilst intermediate pressure (IP) steam is generated. The HP and IP steam is sent to the heat recovery steam generator (HRSG) for reheating and expansion in the steam turbines (Méndez-Vigo and others, 1998).

The syngas is filtered through ceramic candle filters, where the fly ash is retained. The cleaned syngas is then passed to the wet scrubbing and desulphurisation units where desulphurisation is carried out in an absorption column using MDEA as the active alkaline solvent compound. Before the gas is sent to the gas turbine it is first saturated and diluted with waste nitrogen from the ASU. Since the oxygen content in the residual nitrogen is relatively high, the mixing of waste nitrogen in the syngas takes place as close as possible to the gas turbine to minimise the risk of auto ignition. The saturation and nitrogen dilution in combination with the low NOx burners in the gas turbine results in a contamination level of NOx of less than 60 mg/m^3 (15% O_2). The recovery of sulphur is completed in the Claus unit where H_2S is converted to elemental sulphur.

2.4 Tampa Electric Polk Power IGCC

The Polk IGCC power station in Tampa, Florida, USA was built and is operated by the Tampa Electric Company (TECO) and was partially funded under the US DOE's Clean Coal Technology Programme (Tampa Electric Company, 2002; McDaniel and others, 1998). The Polk power station consists of

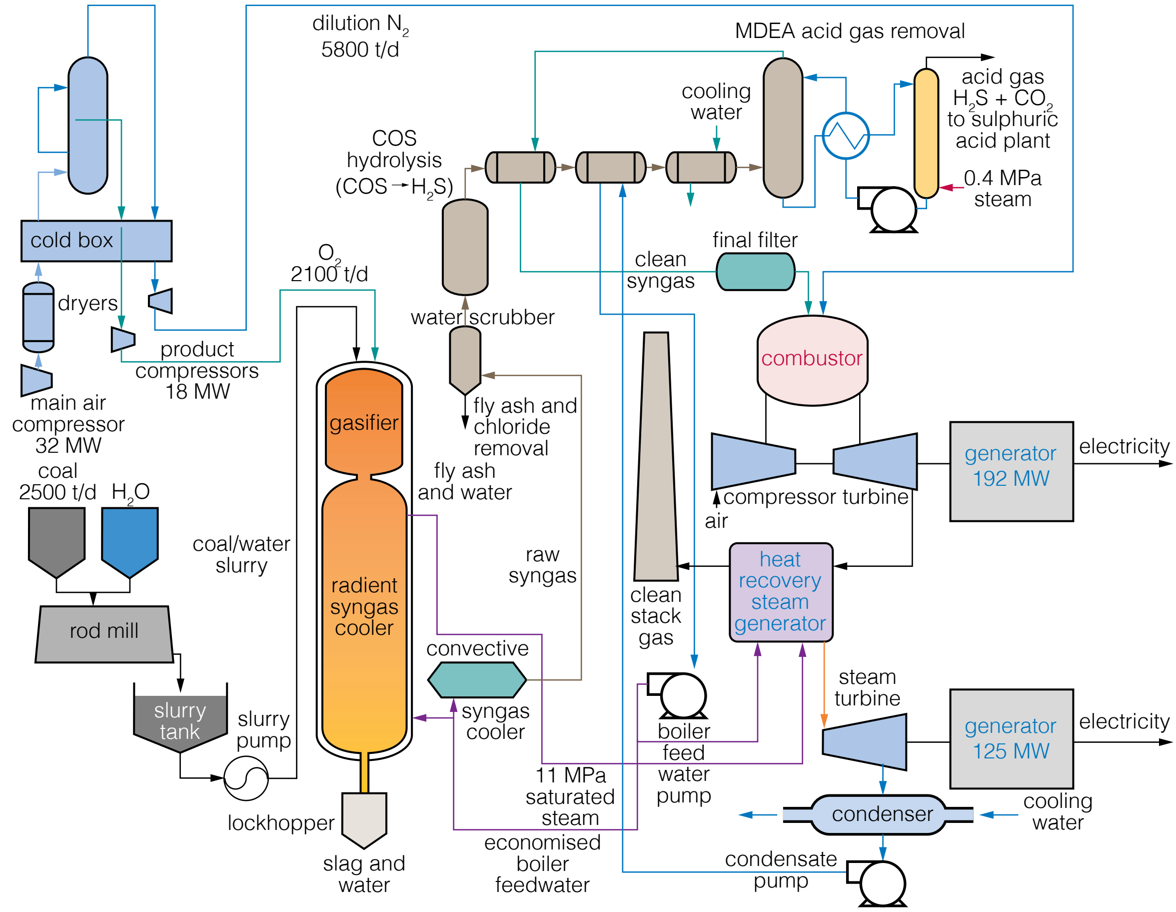


Figure 7 Schematic of the Tampa Electric Polk Power IGCC (NETL, 2013b)

three units, the 250 MWe IGCC plant and two 180 MW simple cycle combustion turbines utilising natural gas which have operated commercially since 2000 and 2002 respectively. The IGCC facility began commercial operation in 1996 and uses an oxygen blown, entrained flow, slurry fed gasification technology licensed by Texaco. The plant is shown in the simplified process flow diagram in Figure 7.

The non-integrated ASU separates air cryogenically into nitrogen and oxygen at 95% oxygen purity. The coal preparation unit consists of a wet-rod mill in which the coal feed, medium bituminous coal (the gasifier is able to handle other feedstocks such as petroleum coke or biomass), is crushed and mixed with recycled water, fines and ground into a slurry. The coal slurry which contains about 60–70% solids is then pumped to the gasifier by high pressure charge pumps. The gasification unit is designed to handle about 2200 t/d of coal (dry basis). In the gasifier the coal/water slurry is mixed with the oxygen in injectors and the water in the slurry acts as a temperature moderator and as a hydrogen source for the gasification process. The gasifier operates at a temperature of 1315–1430°C and produces a raw syngas composed mainly of hydrogen, carbon monoxide and carbon dioxide. The gasifier is designed to achieve a carbon conversion rate above 95% in a single pass. The raw syngas leaving the reactor is first cooled in a radiant syngas cooler producing high pressure steam and then further cooled in two parallel convective syngas coolers where additional high pressure steam is generated. The syngas leaves the convective cooler at a temperature of approximately 430°C into a scrubber, where fine particles and halogen compounds are removed with water washing. The scrubbed gas enters the COS hydrolysis section where COS is converted to H_2S, the latter compound being more easily removed from the syngas. The syngas then enters various heat exchangers in the low temperature gas cooling section where heat is recovered for preheating clean syngas and reheating the steam turbine condensate. Before the gas enters the final cold gas clean-up it is cooled to 40°C in a small trim cooler. The cold gas clean-up system consists of a traditional amine scrubber absorber, which removes sulphur from the syngas by a circulating MDEA solution. The clean syngas is

Table 3 Typical syngas composition in Tamps Polk IGCC (vol%) (Tampa Electric Company, 2002; McDaniel and others, 1998)

	Typical coal	Petroleum coke
H_2	37.95	34.02
CO	44.06	48.29
N_2 + others	2.38	3.08
Ar	0.88	1.00
CO_2	14.73	13.61

reheated, filtered, saturated and delivered to the gas turbine combustor. A typical syngas composition used in Tampa Polk IGCC power station is given in Table 3.

The sulphur removed together with the sour gas from the process water treatment unit is sent to the Claus sulphur plant for recovery of elemental sulphur. The Claus plant produces steam and 200 tonnes of 98% sulphuric acid, which is marketable. Most of the unconverted carbon separated from the slag and water in the lock hopper at the radiant syngas cooler exit is recycled to the slurry preparation section. This slurry is also marketable for blasting, grit, roofing tiles and construction building products. Since all the water used in the gasification process is cleaned and recycled there is no discharge water from the gasification system. Chloride build-up in the process water system is prevented by letting the water pass through a brine concentration unit where the chlorides are removed in the form of marketable salts.

The power block at Tampa Polk is a General Electric combined cycle which has been modified for IGCC. The gas turbine is a GE 7FA machine, adapted for syngas and distillate fuel combustion. Low sulphur fuel oil is used for start-up and establishing of syngas production from the gasification plant. The gas turbine generates 192 MWe (gross) burning syngas with N_2 dilution or 160 MWe (gross) on distillate fuel. The turbine outlet temperature is approximately 570°C. Gas turbine waste heat is recovered for boiler feed water and steam production in a conventional HRSG. In order to control NOx emissions and lower peak flame temperatures the maximum amount of nitrogen from the ASU is injected after hydrating the syngas. During operation with back up distillate fuel oil, NOx emissions are controlled by water injection (Geosits and Schmoe, 2005).

The HRSG has medium and high pressure steam production stages and steam is heated to a temperature of about 540°C before being delivered to the steam turbine. The steam turbine is a double flow reheat turbine with low pressure crossover extraction with a nominal production of 123 MWe (gross).

2.5 Vresova IGCC

The Vresova IGCC power station is operated by Sokolov Coal Corporation (SUAS) and is one of the world's largest coal-fired IGCC plants at a capacity of 400 MWe (gross). It is located in the Czech Republic and has been an important centre for the demonstration of clean coal technology with a history of continuous development (Bucko and others, 2000; Modern power stations, 2008). The IGCC consists of twenty-six Lurgi-type fixed bed gasifiers, using 2000 t/d of brown coal from SUAS's local mines and a recently installed gasifier from Siemens, which provides additional syngas from the tars produced by the fixed bed gasifiers. Options for replacing the fixed bed gasifiers with more modern technology have been investigated including the High Temperature Winkler (HTW) process, which is based on fluidised bed technology. A schematic diagram of the IGCC power station is given in Figure 8 (Bucko and others, 2000; Modern power stations, 2008).

The twenty-six water-jacketed fixed bed gasifiers are arranged in a counter current arrangement with gasification occurring in several stages. The coal is milled to a size range of 3 mm to 25 mm, evenly distributed and introduced at the top of the gasifier. The oxygen and steam are introduced into the gasifier vessel by means of lances mounted at the sidewalls at the height where combustion and slag formation occur. The coal descends through the gasifier and is transformed into char before it enters the gasification zone. Finally, any residual carbon is oxidised and the ash melts to form a slag. The

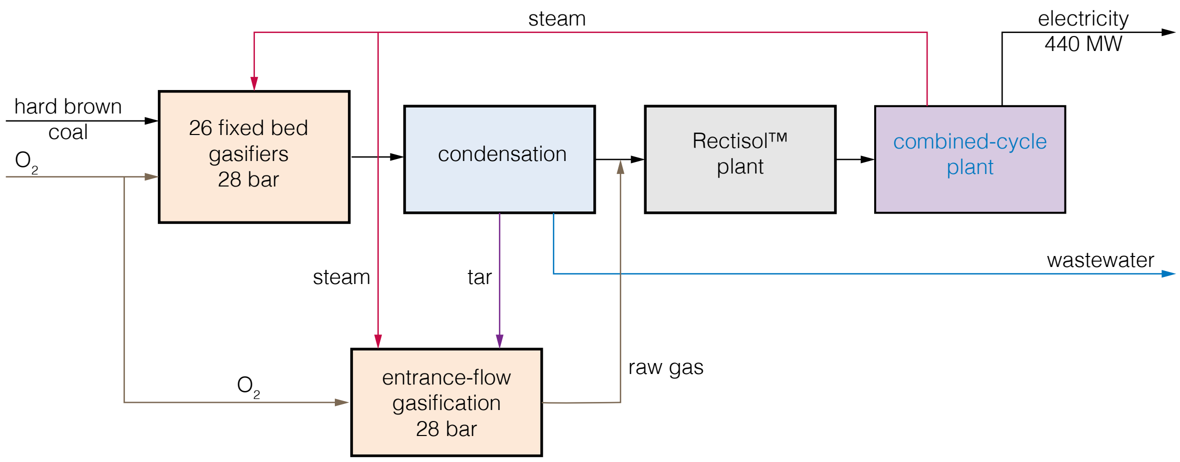


Figure 8 Schematic of the Vresova IGCC power station (University of Stavanger, 2010)

slag is collected in a quench vessel and then removed by a lock hopper in the bottom of the gasifier. The pressure difference between the quench chamber and the gasifier regulates the flow of slag between the two vessels. The raw syngas exits through an opening at the top of the gasifier at a temperature of approximately 570°C and passes into a water quench vessel and a boiler feedwater preheater where the gas is cooled to approximately 200°C. Entrained solids and liquid components are sent to a gas liquid separation unit. Soluble compounds such as tars, oils and naphtha are recovered and recycled to the top of the gasifier and/or reinjected through the sidewall lances (Modern power stations, 2008; H M Associates and others, 2003).

The raw gas exiting the gasifier is further cooled to 30°C before it enters the Rectisol® unit for the removal of various impurities. The Rectisol® process consists of an initial wash of the syngas by a mixture of water and hydrocarbons which removes crude naphtha, ammonia, HCN and any remaining ash that would damage downstream plant through abrasion. The gas is then washed with cold methanol where H_2S and COS are removed. The total sulphur content of the clean gas is approximately 13 mg/m^3. The clean syngas leaving the Rectisol® unit has a pressure of 0.2–0.25 MPa and is further compressed before it is delivered to the gas turbine (Modern power stations, 2008). Sulphur recovery is achieved by a wet sulphuric acid (WSA) plant where the sulphur compounds are burnt and converted to SO_3 in a catalytic process. The sulphur trioxide is then reacted with water vapour to produce H_2SO_4 at a purity of 95% which is a marketable product. The power block at Vresova consists of two identical combined cycles (Modern power stations, 2008):

- a Frame 9E (9171E) gas turbine, supplied by EGT under licence from General Electric;
- a double pressure HRSG without supplementary firing and a steam turbine, supplied by ABB.

Syngas is used as primary fuel in the gas turbine with natural gas as back-up fuel. In order to reduce flame temperature steam injection is also utilised. The steam cycle is closely integrated with the rest of the plant, thus providing the possibility to both extract and supply steam to the HRSG, which results in high flexibility and reliability. The thermal efficiency of the gas turbine is 34.8% while the overall combined cycle efficiency is 50.5% (without district heating) (Modern power stations, 2008).

2.6 Wabash River IGCC

The Wabash River IGCC Power station was selected in 1991 by the US Department of Energy (US DOE) as a Clean Coal Technology (CCT) demonstration project aiming at enhancing the utilisation of coal as a major energy source. Construction of the gasification facility was started in 1993 and commercial operation began in the end of 1995. The demonstration period lasted until December 1999 (US DOE, 2001).

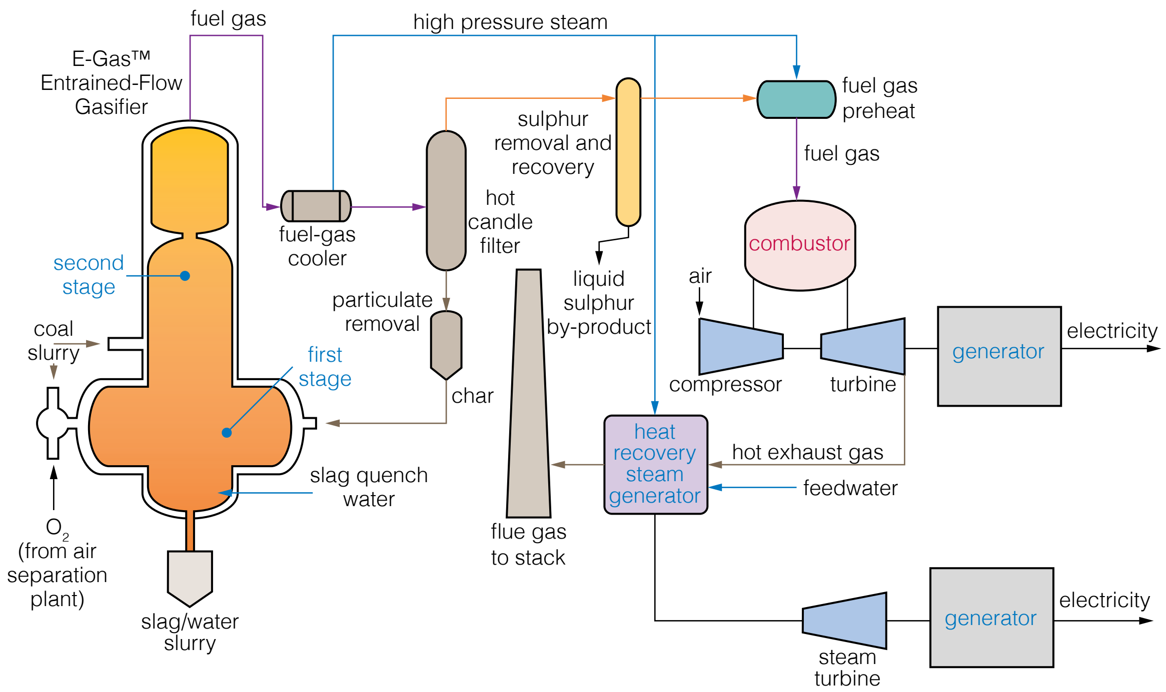


Figure 9 Schematic of the Wabash River IGCC power station (University of Stavanger, 2010)

The plant is located in Indiana, USA and has a net electrical power output of 262 MWe and an overall thermal efficiency of approximately 40%. The gasification process used in Wabash River is Global Energy's two-stage E-Gas™ technology featuring an oxygen blown, entrained flow, refractory lined gasifier with continuous slag removal. The plant was designed to use a range of local coals, with a limit on the sulphur content of 5.9%. The main coal used in the plant was bituminous Illinois Basin coal, but operation has also included petroleum coke. In contrast to the Buggenum and Puertollano plants the ASU at Wabash River is not integrated with the power station (Ansaldo Energia, 2010). As shown in the process flow diagram in Figure 9, the coal is first prepared as a slurry with water and fed to the first stage of the gasifier.

Oxygen with a purity of 95% is provided from the ASU and the coal is partially combusted to maintain a temperature of 1370°C. Raw fuel gas is produced as the coal reacts with the oxygen and steam. The molten ash at the bottom of the vessel is removed while the raw gas is fed to the second gasification stage where additional coal/water slurry reacts with the syngas to enhance the raw gas heating value and cool down the gas through the evaporation of water and the endothermic gasification reactions. The raw syngas exits the second stage of the gasifier at a temperature of 1038°C and is then further cooled in a heat recovery boiler, producing high pressure (11 MPa) saturated steam.

2.7 Wakamatsu EAGLE IGCC

The EAGLE IGCC is a project funded by the Electric Power Development Company of Japan, in collaboration with Japan's New Energy and Industrial Technology Development Organisation (NEDO) and is based at J-Power's Wakamatsu Research Institute in Kitakyushu City, Japan (Wasaka and others, 2003). EAGLE is an acronym that stands for Energy Application for Gas, Liquid, and Electricity and the goal of the project is to develop a Japanese-built, oxygen-blown, entrained-flow coal gasifier, suitable for multipurpose applications, including the generation of electric power and production of synthetic fuels, chemicals, and hydrogen. After a series of feasibility studies beginning in 1995, a 150 t/d pilot plant was constructed in 2001, commissioned in 2002 and has been operating up to the present day. The most recent activities include the evaluation of various coal feedstocks and

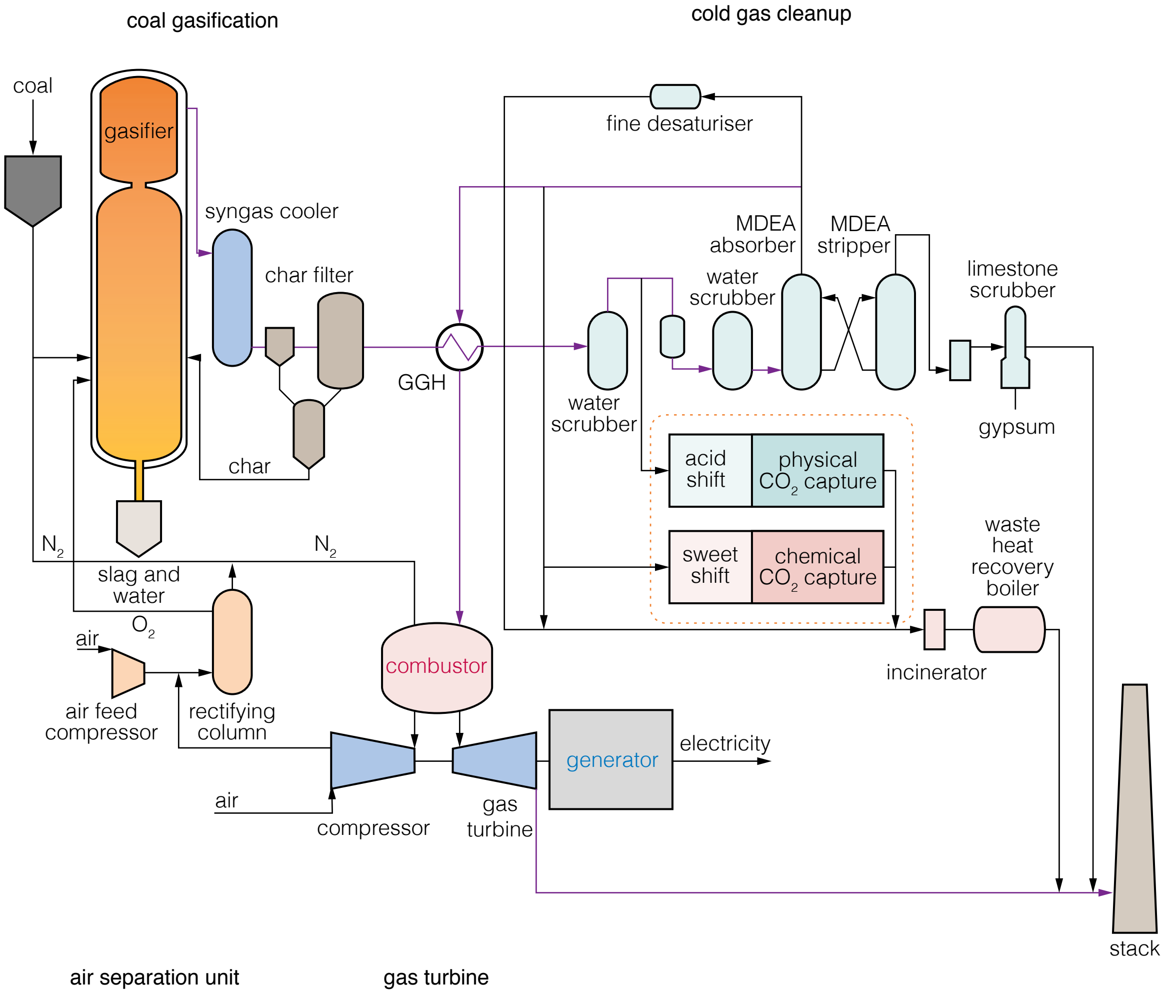


Figure 10 Schematic of the EAGLE IGCC pilot plant (Sasatsu, 2013)

options for carbon dioxide (CO_2) capture (Sasatsu, 2013). A flow diagram of the EAGLE IGCC pilot plant with modifications for CCS activities (within the dash-dot line) is shown in Figure 10.

The EAGLE gasifier is a two-stage, pressurised, up flow, entrained-flow gasifier with the bottom stage operating in slagging mode, with a second non-slagging stage on top to increase overall gasification efficiency. The gasifier operates in oxygen-blown mode and has the unique feature of a tangential feed injection and burner system which allows a spiral flow pattern to be developed along the inter-reactor wall between the upper and the lower reactor stage. This flow pattern is claimed to create a longer residence time for the coal particles increasing the overall gasification efficiency, and helps to facilitate slag removal as the spiral flow pattern creates a pressure differential between the wall and the centre of the gasifier which draws the slag toward the bottom of the gasifier for discharge. Table 4 summarises the main specifications of the EAGLE IGCC plant (Sasatsu, 2013).

Dry coal is conveyed into the gasifier with a pneumatic system using nitrogen or recycled gas. The reactor interior is protected by a water-cooled membrane wall; both features are similar to Shell and Siemens designs. Figure 11 shows a simplified drawing of the EAGLE gasifier and the overall gasification reactions occurring. The gasifier mode of operation consists of introducing a portion of the coal feed into the first (bottom) stage where high temperature slagging occurs, but with a relatively large amount of oxygen. The remaining coal and oxygen are introduced into the second (top) stage, where the hot gas drives the endothermic gasification reactions. The relative amount of coal/oxygen feed distribution into each stage can be varied depending on the nature of the coal to optimise performance balancing high gasification efficiency against stable slag discharge. The second stage is

Table 4 Main specifications of the EAGLE IGCC plant (Sasatsu, 2013)

Coal gasifier	Oxygen-blown two-stage spiral-flow gasifier			
Coal feed	150 t/d			
Gasification pressure	2.50 MPa (gauge)			
Syngas composition	CO	48%	N_2	24%
	H_2	22%	H_2S	200 ppm
	CO_2	5%	COS	100 ppm
	CH_4	1%		
Gas clean-up system	Cold gas clean-up with methyl-diethanol-amine (MDEA)			
Clean syngas flow	13,000 m^3/h			
Sulphur concentration in cleaned syngas	5–10 ppm at absorber outlet <1 ppm at fine desulphurisation outlet			
Sulphur recovery unit	Limestone wet scrubbing			
Air separation unit	Pressurised cryogenic separation			
Air feed	27,700 m^3/h			
Air pressure	1.1 MPa (gauge)			
Oxygen flow	4850 m^3/h			
Oxygen purity	95.0 vol%			
Gas turbine	Simple open cycle			
Power	8000 kW			
Compressor	Axial flow seventeen stage			

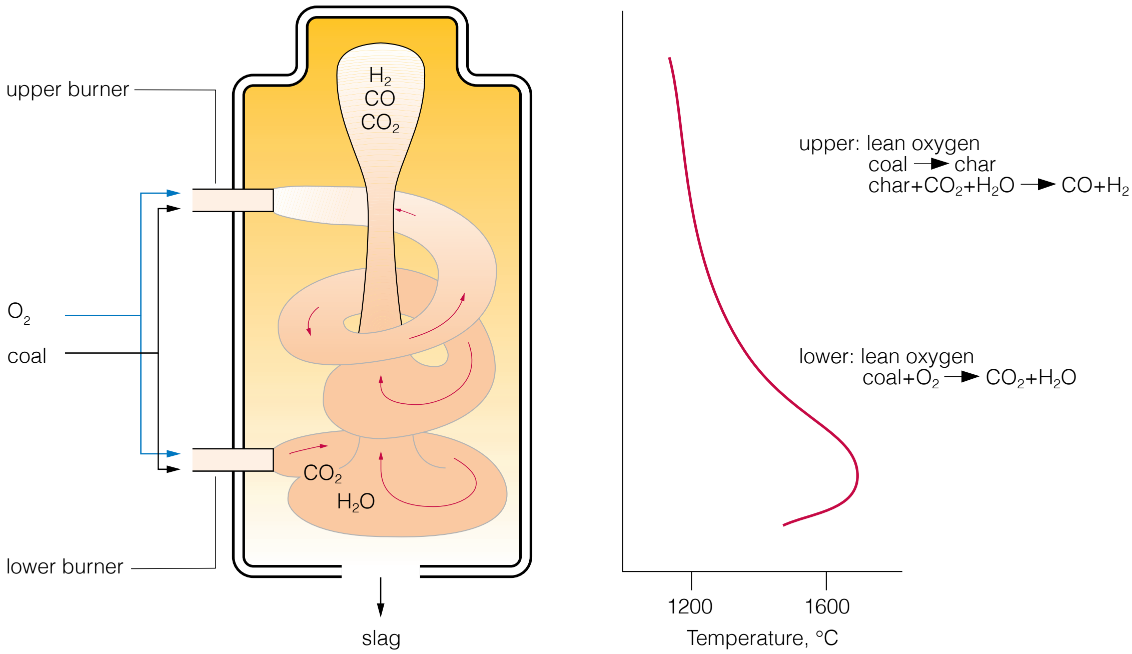


Figure 11 EAGLE gasifier and overall gasification reactions (Sasatsu, 2013)

almost non-slagging. Particulate matter in the syngas contains unreacted char and dry ash and these are removed using a cyclone separator and a filter element made from iron and aluminium downstream of the syngas cooler, and recycled to the first stage allowing almost all the ash in the system to be removed as slag.

Cold gas clean-up is employed to meet the strict tolerance limits for demanding final uses such as fuel cells, as it is difficult for hot gas clean-up to remove the ammonia and halogenated compounds to the required limits. Water scrubbers remove water-soluble halogenated compounds and ammonia. Carbonyl sulphide (COS) in the syngas stream is converted into hydrogen sulphide by the hydrolysis of COS with a titanium oxide catalyst. Highly concentrated hydrogen sulphide is absorbed with methyl-diethanol-amine (MDEA) and the acid gas regenerated is burnt and converted into gypsum by gypsum-limestone wet scrubbing. A substream of the roughly-desulphurised coal syngas is finely desulphurised with an adsorbent made of zinc oxide (ZnO). The cleaned syngas is fed to an incinerator and a gas turbine.

Oxygen is supplied to the gasifier by an air separation unit (ASU) in the form of a pressurised cryogenic air separation unit that operates at a pressure of 1.08 MPa. The ASU can generate 99.5% pure nitrogen and 95% pure oxygen. Raw air is provided with a stand-alone four-stage compressor. Most of the nitrogen is used for coal and char transportation, and NOx reduction at the gas turbine combustor.

3 Operating experience of major coal-fired IGCC plants

3.1 Buggenum IGCC

From the early days of operation, the focus of attention on process improvements at the Buggenum plant has been to achieve high levels of availability. This requirement became particularly important post 2000 when the plant's mode of operation changed from baseload to load-following as a consequence of the newly liberalised Dutch power pool where prices for load-following plant command a premium over baseload plant. Until 2002 coal was supplied to the plant by GKE, a subsidiary company of the Dutch electricity producers. GKE bought many different types of coal on the world market and made blends for the different coal-fired power stations in The Netherlands to fulfil their specifications. Batches supplied to Buggenum were approximately 2000–10,000 tonnes so the plant operators had to switch coal several times a week.

This was believed to contribute to the formation of slag lumps, causing blockages in the outlet of the slag accumulation and sluice vessels, even after increasing the size of the valves from 8" to 12" (20 cm to 30 cm). The problem was solved by improved gasifier control and an adequate coal specification. From 2002 onwards, coal was supplied to the Buggenum IGCC in larger batches, enabling engineers and operators to optimise gasifier settings (Kanaar, 2002). During 2002 the IGCC achieved the availabilities shown in Table 5.

Table 5 Buggenum IGCC availabilities for whole plant, and gasifier alone (%) (Kanaar, 2002)

Overall availability, whole plant	96.4
Planned shut-down	3.3
Unplanned shut-down	0.3
Overall availability, gasifier	86.1
Planned shut-down	8.3
Unplanned shut-down	5.6

Progressive improvements have increased plant availability although in 2011 and 2012 the plant was in operation from September through April only, for commercial reasons. The highest number of operating hours was achieved in 2008 and 2009 when the plant was operating on syngas for almost 6800 h/y (Schoenmakers, 2013).

Table 6 Operational issues for the Buggenum IGCC (Wolthers and Phillips, 2002, 2007)

Syngas production	Syngas and wastewater treatment
• formation of slag deposits • Discharge and processing of slag fines • Damage heatskirt • Bridging in pulverised coal sluicing vessel • Leakages from the syngas cooler • Severe fouling of the top of the syngas cooler • Processing of slag bath water	• Failure of ceramic candles • Problems with the pH-control syngas scrubber • Degradation of Sulfinol • Contamination of water with Sulfinol • Plugging of the wastewater equipment • Separation and processing of salt crystals • Zero liquid discharge/surplus process water
Combined cycle, ASU and auxiliaries	**Minor problems**
• Gas turbine burners (humming, overheating) • Problems with the production of make-up water for the steam cycle • General controls (ASU) • Hydrothermal ageing of molecular sieve reagents • Oxygen distribution (compressor, back-up) • Damage seals in the LIN/LOX pumps	• Leakages in/from: – hot gas filter blow back nozzle (trip) – slag bath circulation system (trip) – LIN-vaporiser, cracks due to thermal shock – Caustic line, halogens wash column • GT trip due to calibration work in ASU • quench gas compressor trip (instrumentation problem) • Fly ash transportation (plugging) • Slag transportation chain snagging

The issues that have presented obstacles to plant operation have been reviewed by Wolters and Phillips (2002, 2007). These are summarised, grouped by technology, in Table 6.

Shell gasifier heat skirt

Although the water-cooled membrane wall systems in the Shell gasifier are considered proven components with a predicted lifetime of 25 years, in the Buggenum plant the heat skirt at the bottom of the reactor chamber was found to require regular repair. In the original design the heat skirt was an uncooled unit consisting of a metal plate with an insulation layer and refractory, and had a lifetime of only 5000 hours. In 2006 this was redesigned as a water-cooled heatskirt and has operated successfully. Following this improvement, the design modification has been incorporated into standard Shell gasifier specifications (Chhoa, 2005).

Slag formation

Buggenum experienced problems with the formation of slag lumps as described above. Improved operator training and better control over the coal procurement have eliminated this problem. Both fouling and leakage have occurred in the gasifier but again this was mostly connected with changes in coal and improved operation has solved the problem.

Erosion/corrosion

Erosion/corrosion has been experienced in the slag discharge piping but replacing the original piping using duplex steel has solved the problems. Processing of the slag bath water (ie separation of the fines from the water) was also an early problem but this was solved by installing a different kind of separator (a lamella-based unit).

Syngas cooler issues

Several leakages occurred in the water/steam system of the syngas cooler, caused by flaws in the mechanical design. The origin of the leaks lay in vibration and the lack of flexibility in the tube layout in the cooler. A redesign and refit of more flexible tube connectors have solved this problem (*see* Figure 12). Fly ash deposits have also blocked the top part of the syngas cooler several times. A study of the conditions for deposit formation led to better control of syngas temperature at the cooler inlet and this has prevented sintering of the fly ash during subsequent operation.

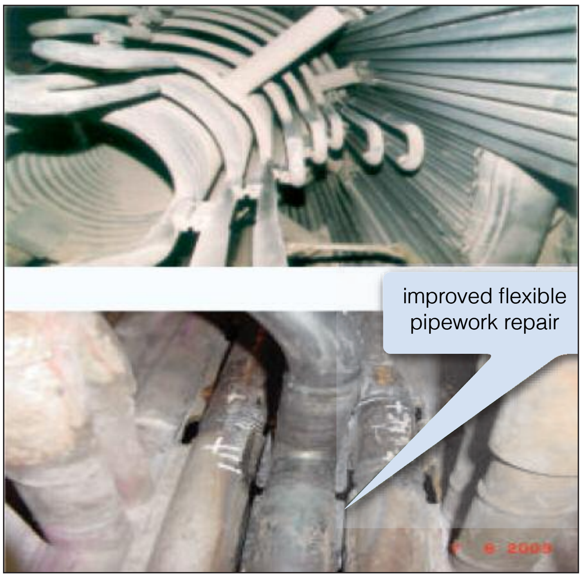


Figure 12 Enhanced repair of the pipework in the Buggenum syngas cooler (Wolters, 2003)

Hot gas clean-up

Initially there were problems with the ceramic filter plugging which had to be replaced at intervals of about 4000 hours. Improvements by the manufacturer (Pall Schumacher) increased the lifetime of the filters to over two years. The improved filter design has subsequently been incorporated into the Puertollano plant.

Coal feeding issues

The capacity of the pulverised coal lockhoppers used to be a limiting factor for the maximum plant capacity. This has been solved by several modifications, both hardware and software, and through better control of the coal moisture content.

System integration

Some IGCC operators have claimed that full air-side integration between the gas turbine and air separation unit is often a cause of plant instability. The Buggenum operators believe that as a consequence of integration, problems occur if the gasifier is operated at too high a temperature, reducing the cold gas efficiency. In order to achieve a higher temperature, the oxygen/fuel ratio has to be increased. At the same time the heating value of syngas decreases because of an increase of CO_2 and water content. So, at given fuel input, the oxygen requirement increases while the thermal input of the gas turbine decreases. These effects combined have a large impact on the pressure balance. In the end the flow of feed air to the ASU becomes too low introducing control problems. If the gasifier temperature is controlled at the design temperature of 1500°C, or slightly higher, there are no issues regarding air-side integration (Schoenmakers, 2013).

Minor control and operation issues

The plant's syngas scrubber was found to suffer from corrosion when operating at low pH and the system of automatic pH measurement and control has proved to be unreliable. pH control is therefore now based on manual analyses, overcoming the problem. An additional issue arose with respect to pH control where a water sample for pH measurement was extracted from the water recycle loop downstream from the caustic dosing point. Consequently, the measurement did not indicate the lowest pH value in the system, which is at the bottom of the packed bed. As a result of subsequent poor pH control, the wall thickness of the first scrubber vessel decreased so much that it had to be replaced in 1999. In order to solve this issue, the new vessel was equipped with a nozzle below the packed bed where, through an inserted pipe, a sample to the pH measurement device could be extracted from the water leaving the packed bed, before the caustic addition. This system worked well with only a minor outage when a candle of the fly ash filter fractured leading to the sampling system being blocked with fly ash. Sampling was temporarily switched back to the water recycle loop until repairs could be affected.

The Sulfinol unit in Buggenum has generally proved to be reliable but high temperatures have caused thermal degradation of the fluid, in one case leading to excessive foaming and subsequent tripping of the gas turbine through carryover of the Sulfinol solution into the syngas saturator's water system. Thermal degradation has been slowed down by installing a pressure reducer in the steam supply to the regenerator reboilers, lowering the skin temperature. Over the years the build-up of heat-stable salts has become more of a problem and more frequent reclaiming was necessary to ensure sufficient Sulfinol quality and avoid load limitations.

Minor problems have been reported with the molecular sieve valve selection where these automatic valves must switch on a very short cycle and must be both robust and tight.

In 2010 the operator interfaces were replaced by a new system, ABB 800 x A. The operating systems of both the CCU (Siemens Teleperm) and the rest of the plant (ABB Contronic-E) have never been changed and since these systems are obsolete it is becoming increasingly difficult to get spare parts. The original DCS systems are still fully functional and reliable.

Biomass co-gasification specific issues

The Buggenum IGCC has accumulated a considerable body of experience with the co-gasification of biomass with coal, especially white wood pellets. The maximum biomass contribution was approximately 15% on an energy basis. However several limitations became apparent, resulting from the fact that the plant was designed for the gasification of coal only. Minor issues of handling were resolved but one fundamental issue remained. The Buggenum entrained-flow, slagging gasifier is operated at 1500°C. While that temperature is suitable for the gasification of coal, it is too high for the gasification of biomass. The cold gas efficiency for gasification of biomass at a high temperature is lower, resulting in higher contents of CO_2 and water vapour in the syngas and a higher heat input to the syngas cooler. A programme of study led to the conclusion that the thermal pre-treatment of biomass offered a huge advantage and a series of tests in the gasifier were found to be in accordance with favourable thermodynamic calculations. The decrease of cold gas efficiency was much lower as compared to the co-gasification of untreated wood, which made it possible to replace up to 70% of the coal feedstock by torrefied wood without modifications to the plant (Schoenmakers (2013).

Carbon capture and storage
Based on experience with Buggenum a demonstration capture plant has been constructed aimed at capturing 0.8% of syngas produced by the gasifier. The syngas is converted in three adiabatic shift-reactors and CO_2 is captured using a physical solvent. Storage or liquefaction of CO_2 is not a part of the demonstration project, so the products CO_2 and hydrogen are returned to the combined cycle. During the past two years an extensive research programme has been undertaken with the aim of optimising the process for the future Magnum IGCC plant located in Eemshaven, in the north of The Netherlands (Power-technology.com, 2012). The plant, Nuon Magnum, is being built by the Netherlands-based energy company, Nuon, and the company is investing approximately €1.5 billion in the project. The production capacity of Nuon Magnum is about 1200 MW, which is sufficient to meet the rising electricity demand in the area. Nuon launched the construction of the plant in 2007. However, delays in obtaining environmental related permits caused it to stop construction in May 2008 but Nuon resumed construction in September 2009. The project is being developed in two phases. Phase I involves construction of a natural gas combined cycle power plant, which will be converted into an Integrated Gasification Combined Cycle (IGCC) plant during Phase II.

In April 2011, Nuon decided to postpone phase II of the project due to a rise in raw material prices and pending negotiations with the environmentalists. The plant was expected to be commissioned in 2012 but the project has been postponed until 2020 at least. However the combined cycle units have been built and they are due to be commissioned within the next few months.

Future plans
On 18 March 2013, Nuon informed the 140 employees of the Willem-Alexander plant in Buggenum that the plant would be closed on 1 April citing persistent low energy prices combined with the high cost basis of the plant making profitable operation impossible. The co-utilisation of biomass did not improve the overall economics (Schoenmakers, 2013).

3.2 Nakoso IGCC

As one of the more recently constructed IGCC plants, the Nakoso unit has not accumulated the body of experience of some of the older plants. That said, the developers have had the opportunity to learn from the older plants and to incorporate modifications from these units into similar systems at Nakoso (Watanabe, 2012; Sakamoto and others, 2012; NEDO, 2011; Sakamoto, 2010; Watanabe, 2010a,b; Clean Coal Power R&D Co Ltd, 2010; Ishibashi, 2009). The plant has operated continuously for over 3000 hours and issues that required remedial action and techniques that maintain high availability have been identified as follows.

Coal-feeding system
Unsteady coal feeding caused a difficulty on the gasifier operation during trial operations in 2007. The problem was solved by modification of the coal feeding system by improving the pressurisation control of the hopper and improving the fluidisation in the bottom cone of the hopper.

Slag condition monitoring system
Based on the experience of other slagging gasifier-based plants, the operators were aware that slag blockages were a potential risk to gasifier operation. Consequently, the Nakoso plant has been fitted with a slag condition monitor that uses image analysis and sound to determine if there is a risk of a blockage occurring. This system has proved to be very successful and the gasifier has operated in a very stable condition with no slag-related incidents.

Some minor equipment-related incidents were noted during the plant's durability test but were confined mainly to the auxiliary facilities as shown in Table 7.

Table 7 Incidents requiring remedial action in the Nakoso IGCC test period (Watanabe, 2010, 2012; Sakamoto, 2010; Sakamoto and others, 2012; NEDO, 2011; Clean Coal Power R&D Co Ltd, 2010; Ishibashi, 2009).

Incident	Plant system	Cause	Cure
Leakage from gland packing of a rotary valve below the porous filter	Char recycle system	Inadequate tightening of a packing gland caused the gas	Proper control of tightening the packing
Trip of slag discharge conveyor	Slag treatment system	The scraper of the drag chain conveyor jumped off its track and stuck onto the gutter of the bottom plate, and caused overloading of the conveyor motor	Improvement of the conveyor structure
Leakage of coal from the pulverised coal collector	Pulverised coal supply system	Filter cloth tore and pulverised coal accumulated in the bag filter was oxidised and increased in temperature	Monitoring device added and operation procedure improved
Leakage of No 2 extraction air cooler tube	Gasifier air supply system	Inadequate and irregular tube material selection caused corrosion. Air leaked to the condenser and resolved oxygen concentration in condensate water increased	Tube material correctly changed
Leakage of char gasifier burner cooling tube	Gasifier	Inadequate positioning of the burner front edge caused erosion of the burner cooling tube	Proper control of positioning the burner front edge

Carbon capture and storage

Japan CCS Co Ltd, was founded in May 2008 with investment from 29 companies, including electric utility companies and oil companies, in order to promote a full-scale investigation of CCS and to develop a large-scale demonstration programme for a system combining IGCC and CCS. As shown in Figure 13, Iwaki City, Fukushima Prefecture, Japan, where the Nakoso demonstration plant is located, is adjacent to a depleted gas reservoir below the ocean floor and this is considered appropriate for a CCS site. Since 2008, Japan CCS has been conducting a feasibility study to execute a CCS demonstration project using the Nakoso IGCC plant with funding from the Japanese Government (Hashimoto and others, 2009). The study is currently under way, investigating the geological, engineering and legal/financial aspects of the proposed capture route.

Other issues

A special note must be made concerning the fact that the Nakoso IGCC incurred severe damage from the tsunami that followed the earthquake on 11 March 2011 (Oettinger, 2012). Immediately after the tsunami struck, the IGCC system halted its operation safely and although many facilities were submerged there was no un-repairable damage in the main IGCC system. In early April the restoration work began despite further aftershocks on 11 and 12 April. The work continued through June and July and operation recommenced on 28 July. After initial settling down, the plant has recorded continuous operation for 2238 hours.

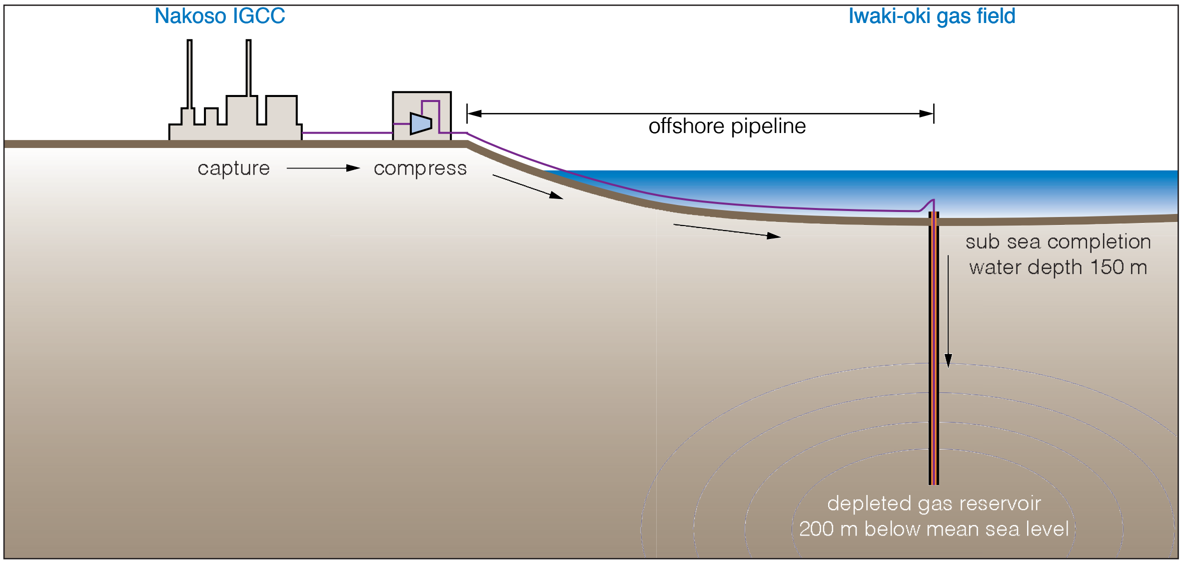


Figure 13 Conceptual sketch of CCS demonstration at the Nakoso plant (Sakamoto, 2010)

3.3 Puertollano IGCC

The Puertollano IGCC has been in operation since 1998 and has accumulated over 61,500 hours of energy production with syngas, plus over 37,500 operating hours of energy production with natural gas since 1996, as illustrated in Figure 14, along with notes on major outages during that period.

In 2005 the European Commission published an extensive report based on the initial operating period of the plant to identify issues and improvements that could be factored in to improved designs of 'second generation' IGCC plant (European Commission, 2005). Issues relating to the performance and availability of the Puertollano plant have subsequently been reviewed by Hermosa Rodriguez, 2010; García Peña, 2012, 2013; Alarcón, 2011; Elcogas, 2012 and are summarised below.

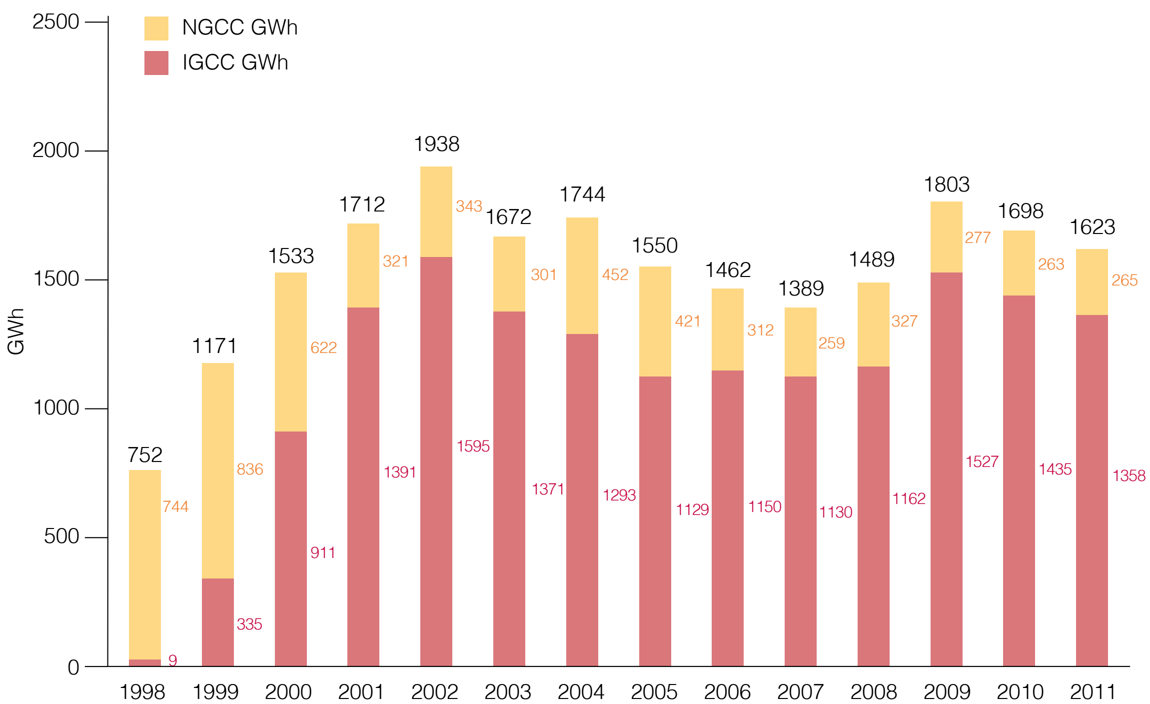


Figure 14 Puertollano IGCC annual energy production 1998-2011 (Alarcón, 2011)

Gas turbine

The model V94.3 prototype originally supplied by Siemens was discontinued after a short production run. Consequently, improvements to the turbine and its components have been more difficult than for other similar plant. Problems with the turbine included the need to optimise the syngas burners to prevent overheating and humming, and to achieve greater stability and increase the remaining life of the hot components. A high rate of ceramic tile wear was observed early in the plant operating programme and preventative inspections were required on a regular basis, typically every 500–1000 hours of syngas use. The issues of imbalance between the burners were tracked back to errors in design from scaling small units to those installed in the plant. A redesign of the burner tip plus a better control strategy has solved these problems.

Gasifier

The gasifier operates with relatively high ash levels which produce a (design) thickness of slag on the wall tubing. That said, the operators believe the plant could operate effectively with very low ash loadings such as that presented by petcoke (0.3% ash). No tars are produced by the gasifier and methane levels are very low (1–3 ppm). During plant shut-downs ash spalling occurs which must be completed through mechanical agitation before maintenance work can proceed when required in the reaction chamber. Problems with the gasifier have centred on gas and water leaks due to blockages and erosion. Specific locations in the membrane wall in the Puertollano gasifier suffer from water leakage caused by local erosion. The cause is in the water distribution where some wall tubes that are connected to the bottom of the bottom header are preferentially blocked by any particulate matter in the boiler water. The result is insufficient cooling of these tubes.

Figure 15 Waste heat boiler fouling – before and after remedial measures (Alarcón, 2011)

Gas leakage has occurred from piping corrosion attributed to the existence of 'cold ends'. In parts of the pipework connected to the syngas system, where no flow is present to maintain a temperature over the dewpoint, a corrosive condensate is produced. These locations include instrument connections and connections for purge nitrogen. The solution was to replace these sections with more resistant materials and to avoid condensation in these parts of the system, for example with ancillary steam heating.

Fouling of waste heat boilers

Fouling of the waste heat boilers has been an ongoing problem meriting some study. Two primary mechanisms for boiler fouling were identified. The first was the presence of 'sticky' ash which was found to be an operational issue and which has been solved by decreasing gas inlet temperature to cooling surfaces and increasing the quench gas flow, so as to reduce the cooler inlet temperature. The second mechanism, blockage by 'fluffy' fly ash was attributed to a too-conservative approach to gas velocities in the design mitigated by increasing the velocity of the flue gas (*see* Figure 15).

Grinding and mixing systems

Puertollano has a complicated feed mix system to ensure an accurate blend of coal and petcoke. Issues with the grinding and mixing system that produce the fuel feed for the gasifier were attributed to the low cost components used in the original design, these not being of the required duty for long-term plant operation. In future designs these would be replaced by robust systems designed for long-term low maintenance use. Additionally the original design is for two feed streams of 60% capacity, rather than a more useful three stream arrangement that would allow maintenance outages without compromising plant load and availability.

Solids handling

Slag and fly ash erosion of components has been experienced where local transport velocities are high requiring the replacement of original materials with abrasion resistant materials. Further improvements have been made by a revision of current operating procedures.

Slag is removed from the gasifier and quenched in a stream of recycled water. The original system employed bag filters to remove slag from suspension in the water stream, but these gave problems of reliability. They have been replaced by a settling tank which performs well. In 2011 the slag crusher at the gasifier outlet was found to be inoperative. On inspection the original crushing teeth had been worn away after fifteen years of intensive operation.

Coal conveying and feeding

Fuel is conveyed into the gasifier by a 'dense phase' system which must be controlled carefully to avoid uneven flows to the gasifier burners. The original start-up system is complex consisting of an igniter and a gas burner which must be operated in sequence to ignite the coal burners. A new system is planned where the coal would be ignited directly using spark ignition within the coal burner.

Hot gas clean-up

Early experience with the hot gas clean-up filters was disappointing, with the lifetime of the filtrating elements being half of that expected (4000 h). The problems with the candle filter unit were traced to poor sealing at the junction of the filter/filter housing. The original filters were replaced with a unit manufactured by Pall Schumacher, and of a design successfully used at the Buggenum IGCC and are operating satisfactorily.

COS catalyst

The original catalyst in the COS sulphur removal system was alumina which required replacement 2–3 times annually. This was replaced with the more expensive, but longer life (3–4 years) titania alternative. The first batch of titania catalyst was damaged through accidental air contamination after three years of satisfactory operation, but this was a general plant issue and not one related to the IGCC technology as such. Damage was also sustained by the COS unit in the second and third batch during the start-up of the conditioning of the catalyst although procedures recommended by the supplier were followed Elcogas decided to switch back to an alumina catalyst temporarily until the correct conditioning procedure was clarified with the supplier – once the procedure was redefined and tested, a titania-based catalyst was reinstalled, and is currently operating satisfactorily.

General plant issues

The plant was designed to be '100% integrated'. The operators believe that this caused problems of lengthy start-up times owing to the necessity to operate the combined cycle components during natural gas start-up. Plant stabilisation could take as long as five days when starting from ambient temperatures at ASU. A new plant would incorporate an external compressor for start-up.

The operators also consider that some issues of plant operation can be traced back to the 'cautious' design of original components and not using materials and technologies that were available, but not in general use. Since commissioning more than 6000 significant plant modification have been identified and enacted.

Carbon capture and storage

In 2005, funding was granted as a National Research Project, by the Spanish Science and Innovation

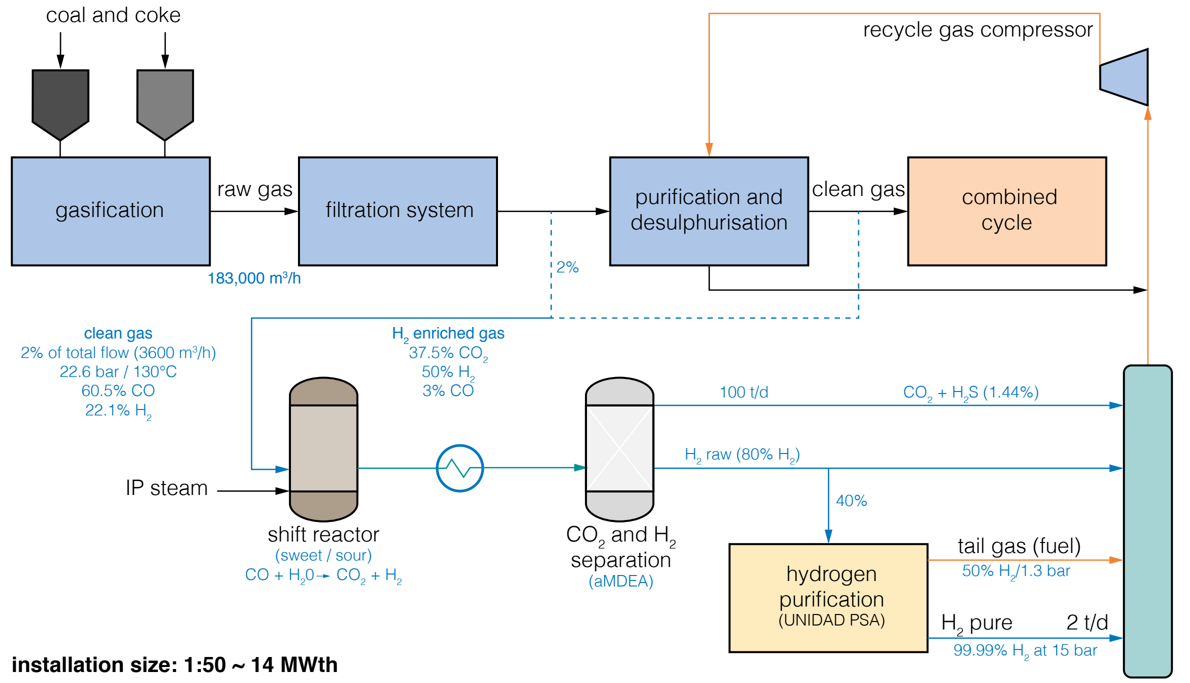


Figure 16 Puertollano IGCC sidestream carbon capture plant (Alarcón, 2011)

Ministry and Regional Government (JCCM) to construct a CO_2 capture sidestream to the Puertollano plant. The budget of the project (engineering, procurement, construction and commissioning) was €13.4 million.

Coal gas at 2.0–2.4 MPa, 14 MWth (2% of the total coal gas produced in the IGCC) was to be used to investigate pre-combustion carbon capture options aiming for a capture efficiency of 90%. No storage studies are foreseen for the immediate future and the captured CO_2 is recycled back to the IGCC. The plant was commissioned in October 2010. The pilot carbon capture plant has a capacity of 100 t/d of carbon dioxide and is operated on demand for R&D projects. The objectives of the R&D work are to (MIT, 2013):

- demonstrate at industrial scale the technical viability of pre-combustion carbon capture technology in a IGCC power plant;
- obtain economic data about CO_2 capture cost representative enough to scale it to full size. .

The conversion and capture process comprises three units: CO to CO_2 conversion unit (using water gas shift technology), CO_2 and H_2 separation unit (using chemical absorption technology), and an H_2 purification unit using pressure swing absorption-desorption (PSA) as shown in Figure 16. The pilot also produces 2 t/d of 99.99% purity hydrogen.

3.4 Tampa Electric Polk Power IGCC

In common with the other IGCC plant reported here, the Tampa Electric Polk Power suffered a number of operational problems that affected on plant availability. These are summarised in Table 8 and described in greater detail below.

Coal feeding

As with Wabash River, the coal water slurry feed pumps at the Polk plant have generally been very reliable. However, the plant operators report that decisions were made during the design stage that eliminated some features that would have improved availability. No details have been disclosed.

Table 8 Tampa Electric Polk Power IGCC operational issues (Tampa Electric Company, 2002; McDaniel and others, 1998).

Topic/Project	Impact
Coal feeding	Minor
Fuel injector tip life	60 days
Refractory wear	Life ~ 2 years
Slag tap blockage	Yes
Corrosion/erosion in circulating slag water	Yes
Syngas cooler fouling and corrosion	Radiant – No CSC – Yes Gas/gas – Yes
Candle filter failure	Not applicable
AGR solvent fouling	Yes
Gas turbine combustor vibrations and hot spots	No

Fuel injector tip life

At Polk, the injector life (and also the refractory life) has improved as the plant has matured and less temperature cycling is experienced. The plant has developed a hot restart technique for recovery after minor trips and has demonstrated a full injector replacement during hot restart, minimising downtime.

Refractory wear

Refractory life for the vertical hot face in the brick lined gasifier at Polk is typically approximately two years. The plant was designed as a demonstration unit and therefore has no spare gasifier.

Slag tap blockage

Early experience at the plant included incidents when blends of Eastern and Western coals produced sudden changes in the wall slag coverage that led to sudden surges in slag flow from the gasifier. These have been resolved (as at Wabash) but the experience leads the operators to recommend the inclusion of a slag crusher in the slag discharge line for future IGCC plants developments.

Corrosion/erosion in circulating slag water

As with the Wabash plant, particulate and aggressive chemical species are a potential problem and careful monitoring is vital to avoid unplanned outages with this plant component.

Syngas cooler fouling and corrosion

The Polk radiant syngas cooler was designed with sootblowing capability. However this vessel has shown very little fouling and the sootblowers are rarely used and the reduced fouling in this vessel has led to a reduced outlet temperature about 166–222°C lower than the design value. The operators suggest that this observation is noted in subsequent plant designs based on similar syngas cooler technology. The fouling and corrosion of the gas/gas exchangers, that heat the clean syngas and nitrogen against the raw syngas leaving the convective syngas cooler, was an early problem at the plant and the horizontal fire tube exchangers were removed with a consequent decrease in net plant efficiency. After the removal of the gas/gas exchangers from service fouling of the horizontal fire tube convective syngas coolers became a major cause of outage. The formation of deposits was often initiated during start-up that would continue to build and sometimes become detached and produce blockage of the inlet tube sheet. Modifications to start up procedures combined with modifications to the inlet gas flow path aided by the use of the Computational Fluid Dynamic modelling have greatly improved the situation and this fouling has not recently been a major cause of outage. Because of fouling problems on the convective cooler of the Polk station, the newer Edwardsport IGCC, still based on a GE gasifier, uses a radiant cooler followed by quench. This decision was based on the results of a study undertaken by Cau (2013).

Candle filter failure

TEC has no gas filter.

AGR solvent fouling

As Wabash

Gas turbine combustor vibrations and hot spots

No problems have been reported by the plant operators.

Carbon capture and storage

In late 2009, Tampa Electric announced (TECO, 2009) that the company intended to partner RTI International to construct a pilot project to demonstrate the technology to remove sulphur and capture and sequester CO_2 from the Polk Power Station IGCC. They announced that RTI would design, construct and operate the pilot plant that would capture a portion of the plant's CO_2 emissions to demonstrate the technology. Construction of the pilot plant, which is designed to capture the CO_2 from a 30% side stream of the coal-fired plant's syngas, was planned for completion in 2013. The CO_2 capture and sequestration demonstration phase would take place over a one-year period. The project is expected to sequester approximately 300,000 tCO_2 more than 1500 m below the Polk Power Station in a saline formation. In describing the RTI process, Gupta and others (2009), portray it as a modular system capable of capturing and sequestering a range of pollutants, including CO_2 (*see* Figure 17).

Relative few details of the process were given, but proven systems seem to be involved such as regenerable CO_2 sorbents. A claimed benefit is the ability to remove and reclaim flu gas components at elevated temperature, with subsequent benefits for plant efficiency and economics. A comparison of a convention clean-up train and the RTI system is given in Figure 18.

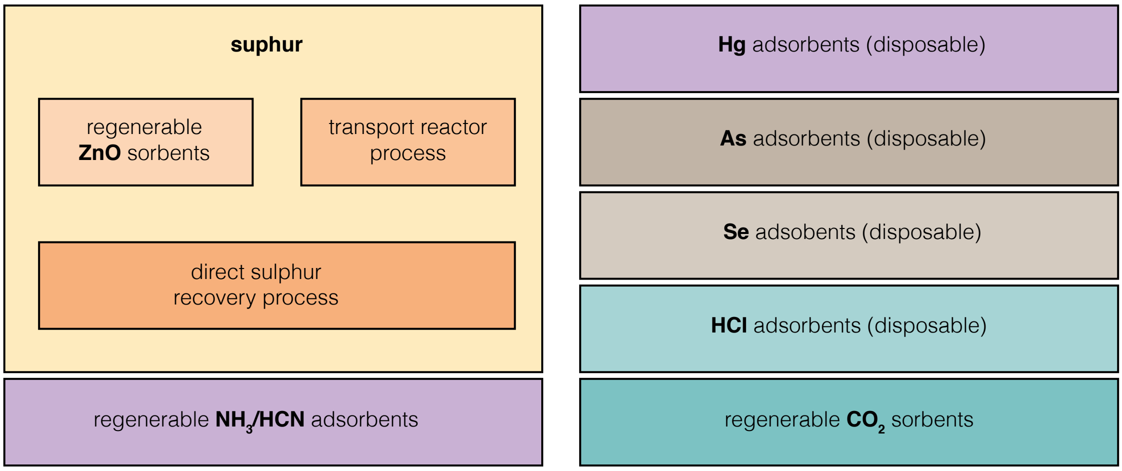


Figure 17 RTI sulphur and CO_2 capture process (Gupta, 2009)

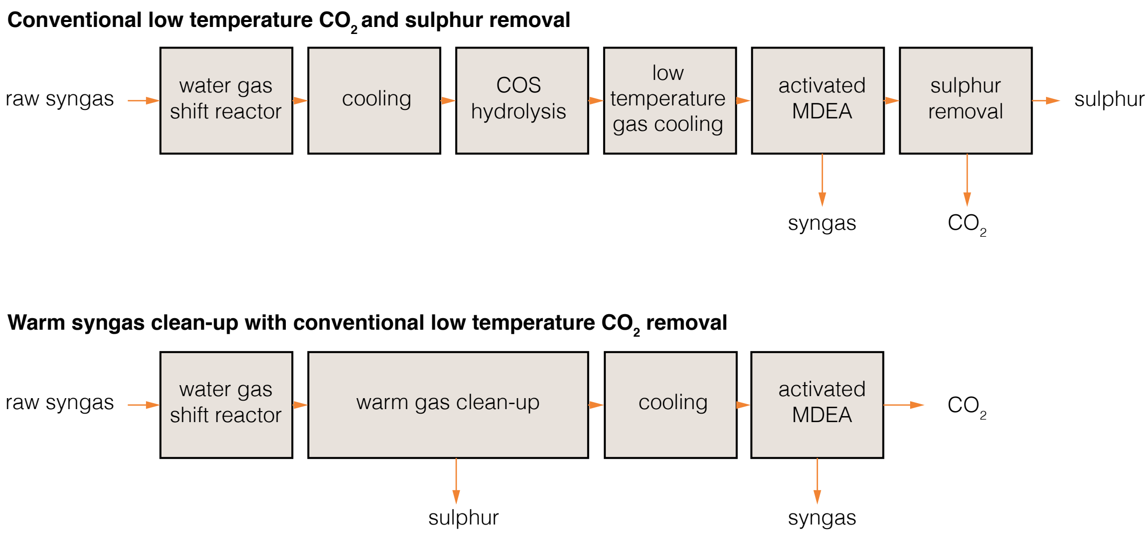


Figure 18 A comparison of conventional sulphur removal and the RTI system with attendant CO_2 capture (Gupta, 2009)

Table 9 RTI warm gas emissions control technology (Gupta, 2009)

	Conventional technology	WGC and conventional CO_2 capture
Sulphur in syngas	<5 ppmv	<1 ppmv
Sulphur in sequestered CO_2	<100 ppmv	<35 ppmv
CO_2 recovery	~75%	>80%

Improvements in cost, thermal efficiency, operability, and reliability are claimed to result from having fewer processing steps.

- Conventional: six stages (shift , COS hydrolysis, S/CO_2 removal, CO_2 clean-up, two stages of cooling);
- WGC + CCS: four stages (shift, WGC, CO_2 removal, one stage of cooling).

Additionally fewer heat exchangers are not needed as the shift reactor exit temperature is a good match for the WGC unit and the operating pressure is optimised for performance (pressure not dictated by AGR). Good environmental performance is also claimed, as shown in Table 9.

3.5 Vresova IGCC

Being based on an older established plant, consideration has been given to improving the Vresova IGCC plant operations and corresponding. The operators report a combination of high operating and maintenance costs, low conversion efficiency, lack of fuel flexibility, and limited capacity for load regulation. There is also a significant impact on the local environment. To overcome these problems, SUAS, in collaboration with several technology suppliers/users including Lurgi, Rheinbraun and Krupp-Udhe, undertook studies into alternative systems and concluded that replacement of the existing Lurgi gasifiers with two new units based on oxygen-blown HTW fluidised bed technology would be the most cost-effective option (Bucko and others, 2000). These would have a combined raw gas capacity of 240,000 m^3/h. They would operate at 900–1000°C and increase carbon conversion to ~93%. The revised system would make use of a significant fraction of the existing plant infrastructure (combined cycle, gas clean-up, fuel feed systems). Potentially, the change to HTW technology would significantly reduce the environmental impact from the site's operations. Over a 20-year period, this change would also reduce CO_2 emissions by 7 Mt (Masaki, 2002).

Other areas of the project receiving consideration include the possibility of co-gasifying up to 10% biomass with the brown coal feed, and the slip stream testing of different CO_2 capture technologies (membranes, cryogenics, adsorbers). Annually, the Vresova site's fixed bed gasifiers produce significant quantities of by-products that include 90 kt of tar (Bucko and others, 2000). It has become increasingly difficult to find cost-effective outlets for this. To overcome this, a further addition to the Vresova plant was made during 2006 with the installation of a new gasifier supplied by Future Energy GmbH. This is a 140 MWth entrained flow unit of the full quench, cooling wall design that operates at 2.8 MPa pressure and 1400°C (Schingnitz and Mehlhose, 2005). This has been installed to gasify generator tars and other liquid by-products produced by the existing fixed bed gasifiers. The new plant was scheduled for handover to SUOS in September 2006 (Kapr, 2006).

3.6 Wabash River IGCC

In common with other IGCC plant, the Wabash River facility suffered a number of operational problems that impacted on plant availability. These have been reviewed by Holt and Wheeldon (2003, 2012) and are summarised in Table 10 and described in greater detail below.

Table 10 Wabash River IGCC operational issues (Holt and Wheeldon, 2003, 2012)

Topic /project	Impact
Coal feeding	No
Fuel injector tip life	60-90 days
Refractory wear	Life ~2 years
Slag tap blockage	Yes
Corrosion/erosion in circulating slag water	Minor
Syngas cooler fouling and corrosion	Yes – but can be cleaned in situ
Candle filter failure	Yes
AGR solvent fouling	Yes
Gas turbine combustor vibrations and hot spots	No

Coal feeding

The coal water slurry feed pumps at Wabash have generally been very reliable, although the operators report that additional capacity would have been a useful back-up in the event of serious failure.

Fuel injector tip life

The fuel injector tip life for the coal water slurry fed gasifiers (60–90 days) is much lower than for the dry coal fed gasifiers (>1 year). The failure is usually due to stress corrosion cracking at the injector tip (where especially hardened metals are used). In the light of this Wabash has developed a scheme for injector replacement in 18 hours. These developments markedly reduce the forced outages due to injector tip failures.

Refractory wear

Refractory life for the vertical hot face in the brick lined coal water slurry fed gasifiers at Wabash and TEC is typically approximately two years. The refractory area in the vicinity of the slag tap is the most prone to wear and repairs are made at each outage. In the light of this the Wabash plant is provided with a spare gasifier, and although it is not currently tied in with the rest of the downstream processing, it is reported that the connection and changeover could be effected in a relatively short time. Ash deposition on the second stage gasifier walls and downstream piping proved problematic in early runs but modifications to the second-stage refractory to avoid tenacious bonds between the ash and the refractory wall and to the hot gas path flow geometry corrected the ash deposition problem.

Slag tap blockage

Slag tap blockage has been a serious problem for a gasifier. The Wabash plant has suffered several incidents. If it occurs the outage can last several days to allow the unit to cool down before mechanically removing the solidified slag. It has nearly always been associated with a change in feed coal properties that unexpectedly changed the slag viscosity. The so-called T250 temperature (the temperature at which the slag viscosity is 250 centipoise) is typically used to give an indication of the temperature at which the gasifier should be run to avoid slag blockage problems. This temperature is monitored in most cases but the slag viscosity measurement is time consuming (~6–8 hours) and there are doubts on the accuracy of coal sampling. The problem of variation in ash fusion properties is more likely to arise with blended coals and particularly any coals or feeds such as petroleum coke that need flux additions to maintain slag mobility.

Corrosion/erosion in circulating slag water

The circulating water from the slag quench chamber contains sharp fine solids and erosion is a constant problem. Long radius bends where possible have been installed to promote a smoother consistent continuous flow and to avoid recirculation pockets. The slag water circuit is often acidic and needs alkali addition. However, the problem is compounded by difficulties encountered in monitoring the pH due to plugging or corrosion of the probes. It is often necessary to add either acid or alkali as needed to keep the pH in the range that avoids corrosion and prevents precipitation.

Syngas cooler fouling and corrosion

Wabash uses a down flow firetube SGC design. Additionally, it has been observed that the E-Gas™ gasification technology allows the survival of trace tar components in the outlet gas, the coking of which sometimes leads to deposits that can break free from the piping surfaces and plug the inlet tube sheet. Through a programme of CFD modelling Wabash operators made gas path modifications to prevent larger particulate matter from fouling the inlet tube sheet. However, deposits do sometimes form within the SGC tubing and a device has been installed that enables periodic tube cleaning in situ. With coal as feedstock, Wabash schedules two outages per year for SGC cleaning – however with petroleum coke feed they experience less fouling. Exposure to moisture during downtime tends to concentrate chlorides and other corrosion products at the scale metal interface that can cause subsequent of the chromium oxide rich scales to spall from the tubes. This process has been suggested as the cause of accelerated corrosion rather than aqueous corrosion during downtime. The presence of sulphides in the scales is suspected as being very susceptible to downtime dew point corrosion. Therefore, measures (for example purging with nitrogen) are taken to avoid the conditions that could lead to downtime corrosion.

Candle filter failure

Wabash experienced early problems with candle fouling and breakage but after gaining some further insights from a slip stream filter test programme they have greatly improved the plant availability. Metallic elements are currently used because their durability has been reported to be better than earlier installed ceramics. Tests on newer ceramic candle filter elements in the slipstream filter have been encouraging and these must now be considered a viable alternative to the metallic units. The Wabash filter operates at approximately 350°C (*see* Figure 19).

Figure 19 Wabash River IGCC gas cleaning system (NETL, 2013c)

AGR solvent fouling

The Wabash plant employs COS hydrolysis ahead of the AGR process to reduce the COS content of the syngas and thereby permit a higher level of sulphur removal. However, the COS hydrolysis reactor also converts some of the CO to formic (HCOOH) and oxalic (COOH COOH) acids. These trace components lead to the formation of heat-stable salts that can be deposited and foul the AGR absorber and stripper trays which increases solvent usage. The solution adopted at Wabash has been to add an online ion exchange membrane system to continuously regenerate the solvent and remove the contaminants from a blow-down slipstream taken off the circulating solvent loop.

Gas turbine combustor vibrations and hot spots

There have been no reported problems with turbine vibrations and hot spots at the Wabash plant.

Carbon capture and storage

At the time of writing there were no published plans to investigate carbon capture and storage at the Wabash plant.

3.7 Wakamatsu EAGLE IGCC

As described in Section 2.7 *above*, the EAGLE IGCC has been in development from 1995 until the present day. The development has been undertaken in three phases as summarised in Table 11 (Sasatsu, 2013).

Since commissioning, the plant has accumulated over 12000 hours of operation (by March 2013) and gasified over 66,000 tonnes of coal. In Phases 1 and 2 of operation all major objectives were achieved

Table 11 Development phases of EAGLE IGCC (Sasatsu, 2013)
Phase 1 (1995–2006) Gasifier development
Development of oxygen-blown entrained flow gasifier
Establishment of gas clean-up technology
Phase 2 (2007–09) Multiple utilisation and coal diversification
Capture of carbon dioxide from coal gas stream through chemical absorption
Investigation of alternative coal feedstocks, including high ash melting point variants)
Research into trace element behaviour
Phase 3 (2010–13) Next generation development, including CCS
Carbon dioxide capture by physical absorption at higher pressures
Trialling of advanced developments
Survey of innovative CO_2 capture technology

Table 12 Historical causes of outages in the EAGLE IGCC plant (Sasatsu, 2013)

	Main reason for plant unavailability	Other factors contributing to outage	Other reasons for loss of operation
Phase 1 (2002–06)	Slag tap blockage	Feed pipe clogged with pulverised coal	Unstable coal and char feeding
	Feed pipe clogged with coal char	Damaged slag crusher gland packing	Slagging at quench section
		Water leakage due to thermal stress cracking of the injector	Reduced fuel injector life
		Melting of membrane bar in upper injection zone	
		Leakage from char feed pipe	
		Candle filter blockage by ammonium chloride	
		Pulverised coal feed pipe fracture	
Phase 2 (2007–09)	Refractory wear	Melting of membrane bar by lower injector flame	Unstable coal and char feeding
	Pipe corrosion	Pipe corrosion in gas recycle line, acid drain line, corrosion under insulation	Measure of coal feed rate
	Slag outlet blockage with high melting point ash coal		High iron slag blockage
Phase 3 (2010–13)		Corrosion under insulation at syngas cooler water circulation control instrument	
		Coal feed flexible pipe fracture	
		Boiler feed pump motor short	

demonstrating the technology with eight types of coal – five in Phase 1, and three in Phase 2. The operating experience allowed the collection of a significant body of maintenance 'know-how' and design data for next generation plant. During operation a number of process issues were experienced and investigated as the more serious of these resulted in unplanned plant outages. The historical causes of unplanned outage for the EAGLE IGCC are summarised in Table 12 and selected examples and process improvements discussed in more detail below (Sasatsu, 2013).

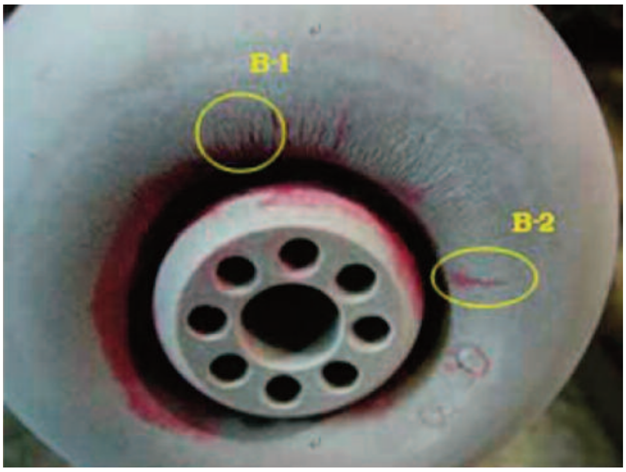


Figure 20 Cracking of coal-oxygen injector surface (Sasatsu, 2013)

Figure 21 Improved injector designs based on SUS310 (top) and Inconel alloy 625 (bottom) (Sasatsu, 2013)

Lower gasifier stage injector

The lower stage of the EAGLE gasifier features four injectors through which coal and oxygen are introduced. The original design of these injectors was based on a cap type configuration where the water-cooled tubes were thickened at the outer surface, which is exposed to the gasification zone, for protection against corrosion and erosion. However, after an accumulated 2179 hours of operation these thickened tubes were found to be developing a series of cracks, thus reducing the life of the injector (*see* Figure 20). The reason for the development of these cracks was thought to be through expansion and contraction cycles following slag build-up and loss on the rigidly mounted injector.

A programme of investigation was undertaken on alternative injector designs to reduce or eliminate these effects and two designs were identified based on spiral configurations and using up-rated materials (SUS310 and Inconel alloy 625) – *see* Figure 21. Both designs were operated for an extended period to evaluate their durability. The design based on SUS310 operated without thermal stress cracking for 1695 hours but was found to have developed some pitting on examination. The design based on Inconel 625 has operated for 3904 hours without any problems. Laboratory thermal stress test results suggest that the combination of more intensive cooling, a reduced binding force and high performance materials will give an injector lifetime greater than 8000 hours.

Reduction of quench gas volume

The syngas outlet to the EAGLE gasifier was originally designed with a section where recycled quench gas could be injected to prevent blockages from slag and char adhering to the waterwall (*see* Figure 22). However, the use of quench gas imposes an efficacy penalty on overall gasifier operation and a programme of tests was initiated to determine if the use of quench gas could be reduced or eliminated.

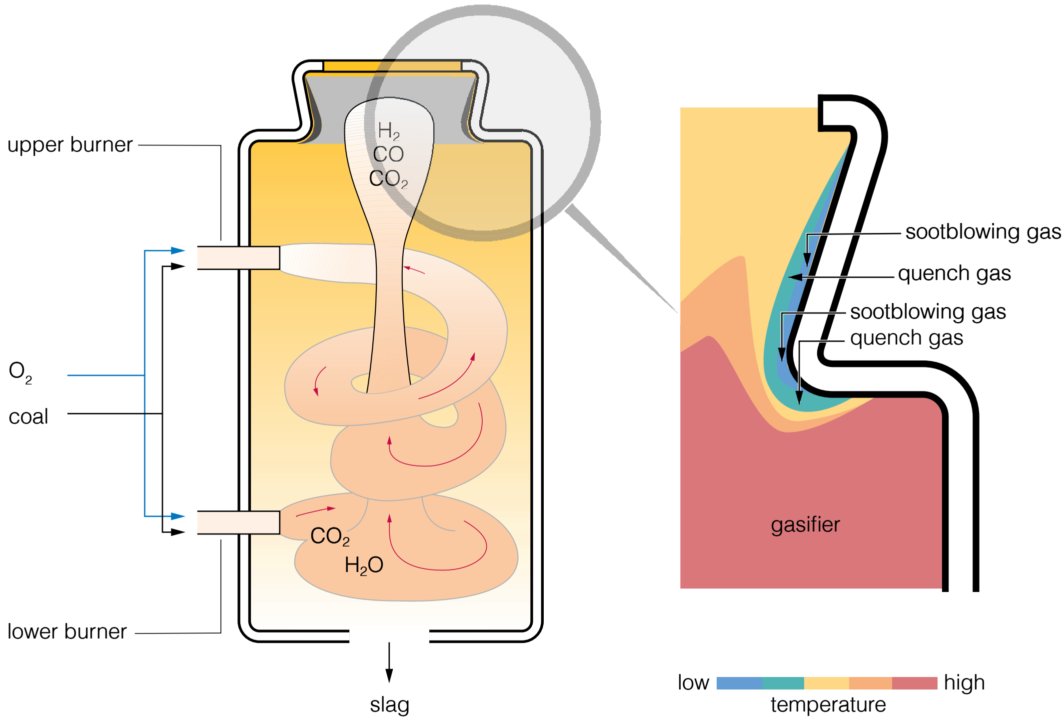


Figure 22 Quench gas provision at gasifier outlet (Sasatsu, 2013)

The pressure drop across the gasifier outlet was monitored and photographs of the outlet taken to determine any build-up of char and slag. The quench gas was carefully reduced from an initial 50%, through 30% and finally to zero, and after 1920 hours of operation the gasifier has not suffered from excessive deposition at the outlet.

Stable discharge of slag

The efficient operation of the gasifier requires that slag produced during gasification drains continuously from the gasifier into the slag quench section without excessive deposition on the slag exit point. The design of the gasifier results in a spiral swirling flow of gas that helps to transport the molten ash downwards while a recirculating stream of syngas heats the gasifier outlet. However, it was found that with some coals an excess of slag could build up and reduce the capacity of the gasifier. A modification was therefore introduced whereby a portion of syngas was burned above the slag quench hopper, and below the gasifier ash outlet, to ensure that the ash remained sufficiently molten and mobile for effective discharge (*see* Figure 23). Operation of this burner below 900°C (for a typical subbituminous coal) has been found to achieve good ash discharge for the range of coals studied.

Improving the stability of the char feeding system

The original design for transporting char into the gasifier was through gravity flow of the char through a rotary feeder – the rate of char feed being controlled by the speed of the rotary valve. However, in practice the feed rate was found to vary significantly and the design was thought to be limited in terms of scalability. A replacement system was installed based on maintaining a differential pressure of nitrogen across a valve and varying the pressure to control char flow. Bridging at the hopper exit was prevented by the use of a stream of nitrogen (*see* Figure 24). The modification was considered successful in overcoming the limits of the rotary valve-based configuration and had additional benefits in being suitable for scale-up and in reducing piping, valves and the overall height of the structure.

Corrosion in the heat exchanges of the gas clean-up system

During Phase 1 of the plant operation, routine examination of the heat exchangers in the gas clean-up section revealed severe problems of corrosion. Corrosion was found in the first water scrubber (*see* Figure 25), the COS heat recover exchanger, the COS outlet cooler and the COS heat exchanger

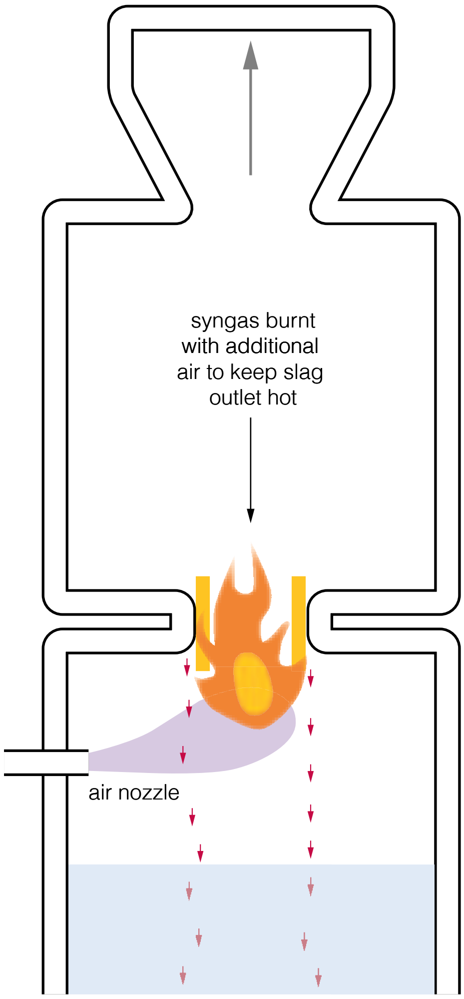


Figure 23 Additional heating at gasifier outlet to ensure stable discharge of slag (Sasatsu, 2013)

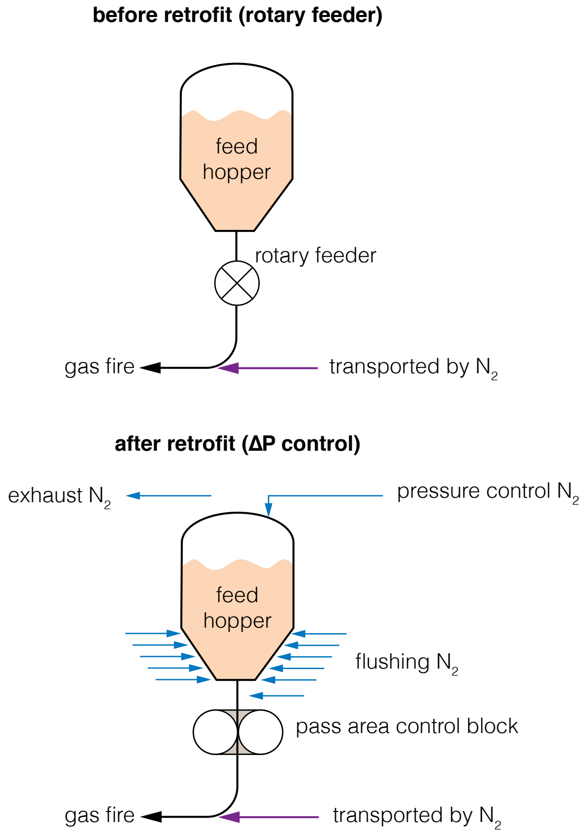


Figure 24 Char feeding system upgrade (Sasatsu, 2013)

outlet. In the case of the COS heat exchanger a 90% reduction in wall thickness was observed for over 70% of the tubes necessitating the replacement of the unit. For the COS outlet cooler an 85% reduction in wall thickness had occurred for a limited number of tubes. The COS heat exchanger outlet suffered from severe deposition of ammonium chloride. An investigation into the causes of corrosion revealed that species such as CO_2, HCOOH, HCl, F and HCN were being concentrated in water droplets and subsequently in condensed water during the water evaporation process (*see* Figure 25).

As countermeasures to the corrosion problem steps were taken to remove particularly aggressive species from the flue gas, for example HCl, and the operational condition of the demister was carefully controlled to prevent droplet formation. A reduction in the HCl content of the gas was effective in preventing the formation of large deposits of ammonium chloride in the COS heat exchanger outlet.

Hot gas filter blockage

Ammonium chloride formation described above was also found to be a major contributor to the blinding of the sintered Fe-Al hot gas filters. A simulation of NH_4Cl formation for different partial pressures of chlorine and at different temperatures identified a window of operation where NH_4Cl deposition could be prevented. Operating the filters within this region proved effective in avoiding further problems (*see* Figure 26).

Low NOx gas turbine combustors

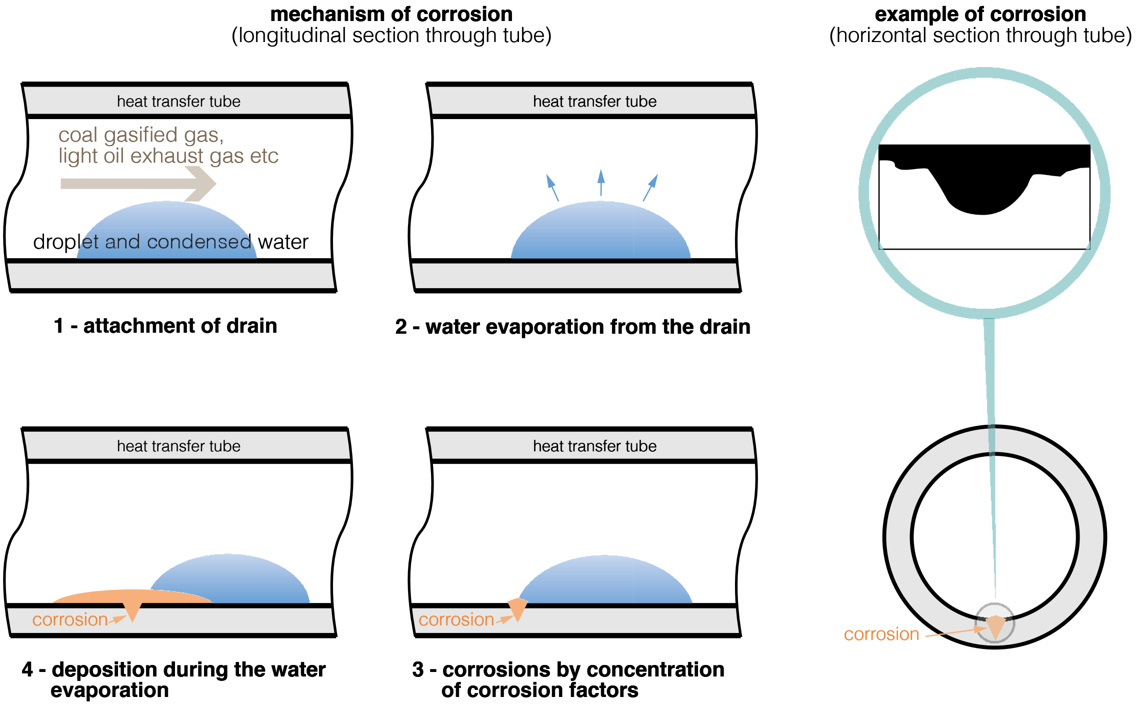
As part of the continuing development of high performance gas turbines designed to run on high

1 Mechanism of corrosion

the corrosion mechanism is believed to be factors such as CO_2, HCOOH, HCl, F and HCN in the (droplet) and (condensed water) are concentrated on the heat transfer tube during the water evaporation process

2 Mechanism of deposition

based on the corrosion mechanism introduced above, corrosion factors deposit on the heat transfer tube after the water has evaporated



Countermeasures

1 remove the corrosion factors (excluding HCl) from the gas through the scrubber and exhaust them outside

2 keep the operational condition of demister appropriate for prevention of droplet generation

Figure 25 Proposed mechanism of corrosion on heat transfer tubes (Sasatsu, 2013)

hydrogen content fuels, alternative designs of turbine combustor were evaluated with a view to reducing emissions of NOx. A burner design with seven cluster jets was found to achieve NOx emissions of approximately 15 ppm at 15% oxygen concentration and full gas turbine load. The burner design produces a lifting flame by inducing a favourable pressure gradient downstream of the burner tip, where converging and diverging swirling flows meet (*see* Figure 27). Despite the flame being set off from the burner tip, the combustor achieved low levels of oscillation amplitude well below the design criteria over the entire load range.

Carbon capture and storage

The EAGLE IGCC has been modified to include the necessary process steps to allow carbon capture and storage and a programme of study is under way to demonstrate the technology using a side stream off the main syngas outlet. The modifications include the installation of a 'sweet shift' reactor water gas shift unit followed by a CO_2 capture stage where the active agent is MDEA. A variant installation employs a 'sour shift' reactor followed by CO_2 capture using a Selexol™ (polyethylene glycol dimethyl ether) process. The modified plant schematic is shown in Figure 28 and the details of the water gas shift and CO_2 capture stages in Figures 29 and 30.

The objectives of the current programme of work are to confirm the applicability and operability of CO_2 capture technology in the IGCC system and to obtain the detailed operational data to evaluate the

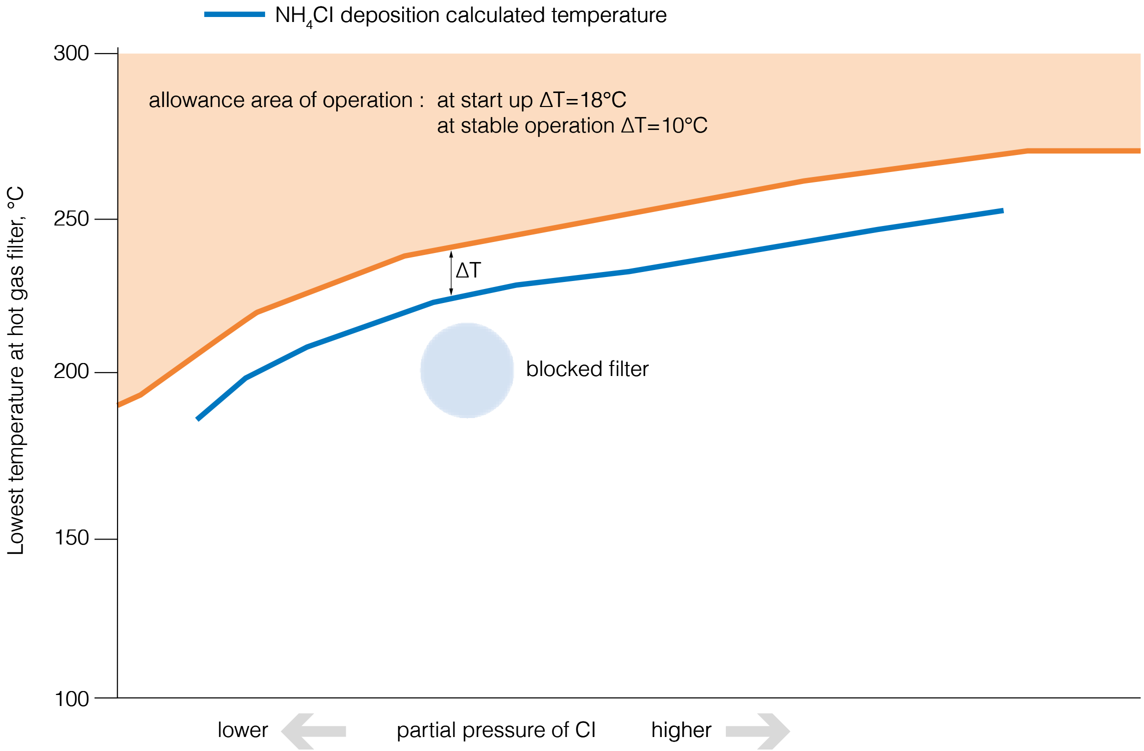


Figure 26 Establishing the operating region to avoid NH_4Cl deposition on hot gas filters (Sasatsu, 2013)

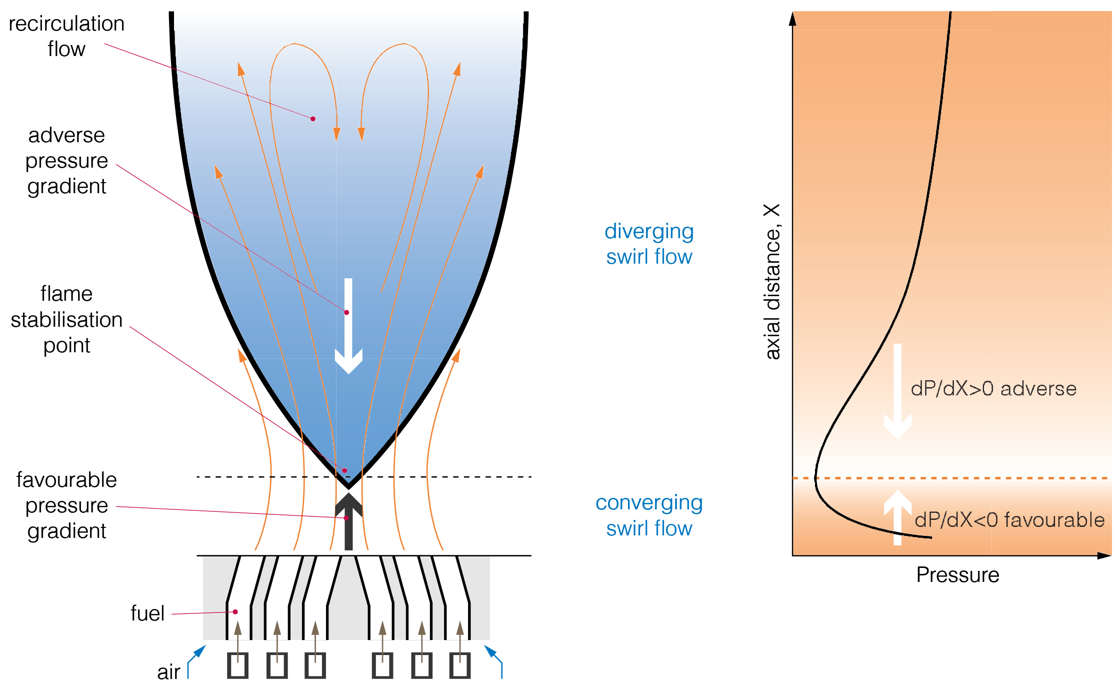


Figure 27 'Lifting flame' low NOx turbine combustor principle (Sasatsu, 2013)

impact of CCS on IGCC operation. The target for the work programme is to reduce the energy penalty associated with CCS using Selexol™ by 10% compare to the Phase 2 result (MDEA process) for a 90% CO_2 capture case. The tests to date have given valuable information on solvent flow rates, solvent temperatures, and steam conditions, and these are being used in a simulation of the IGCC to predict the range of efficiency penalties during plant operation. A snapshot of the most recent performance test date is given in Table 13.

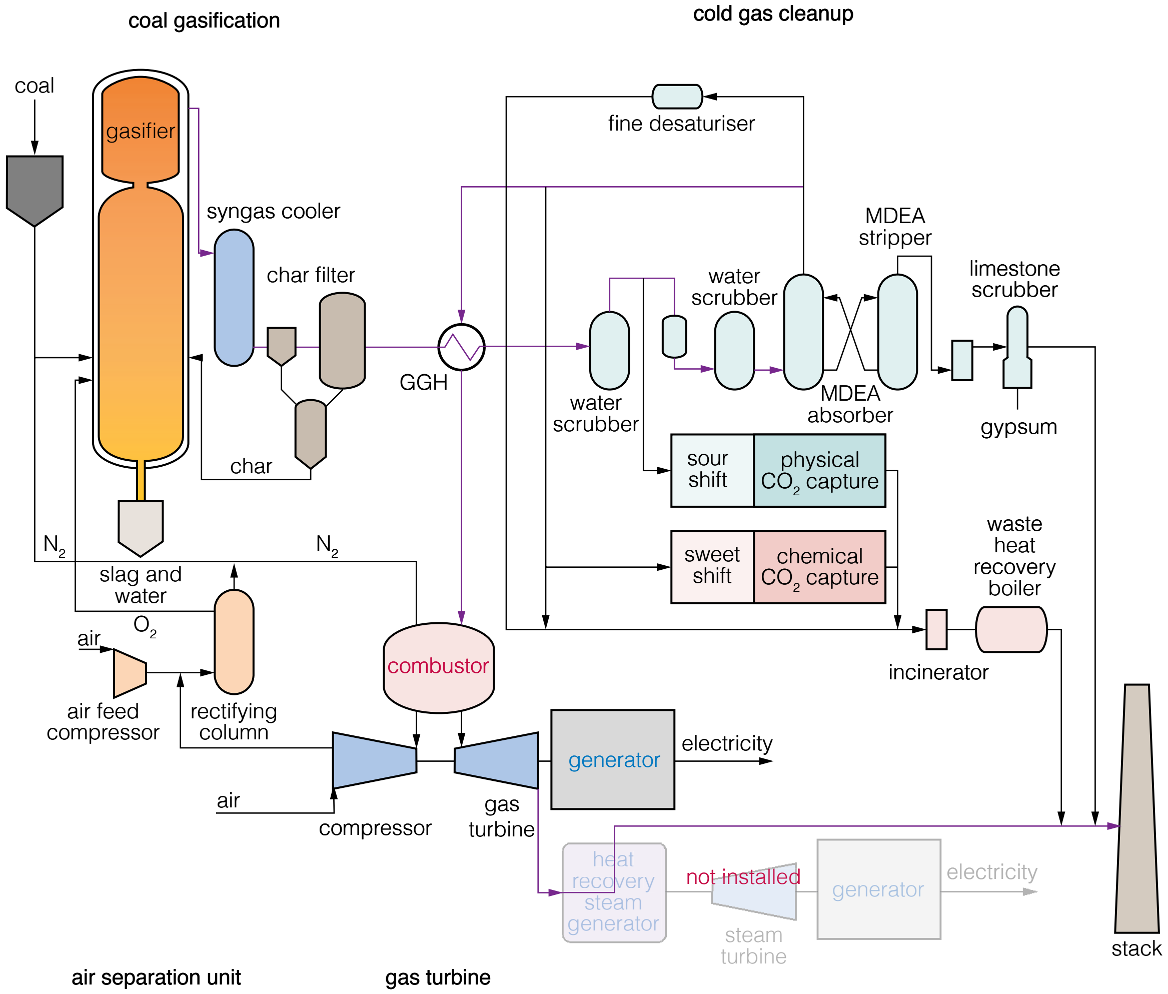


Figure 28 Modified EAGLE plant for CO_2 capture and storage (Sasatsu, 2013)

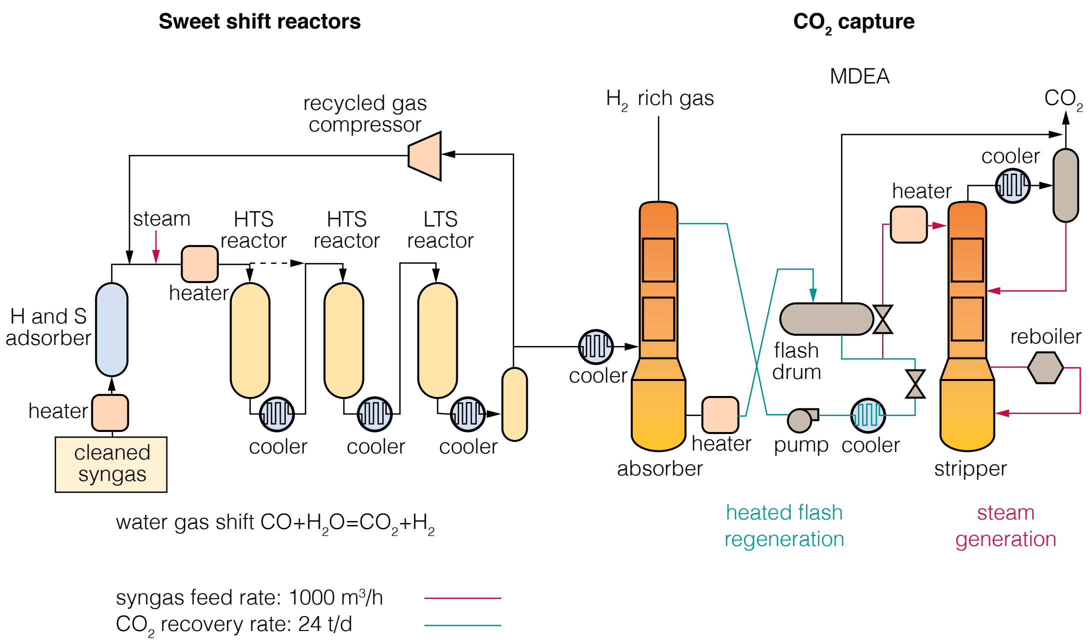


Figure 29 Water gas shift and CO_2 capture systems – MDEA (Sasatsu, 2013)

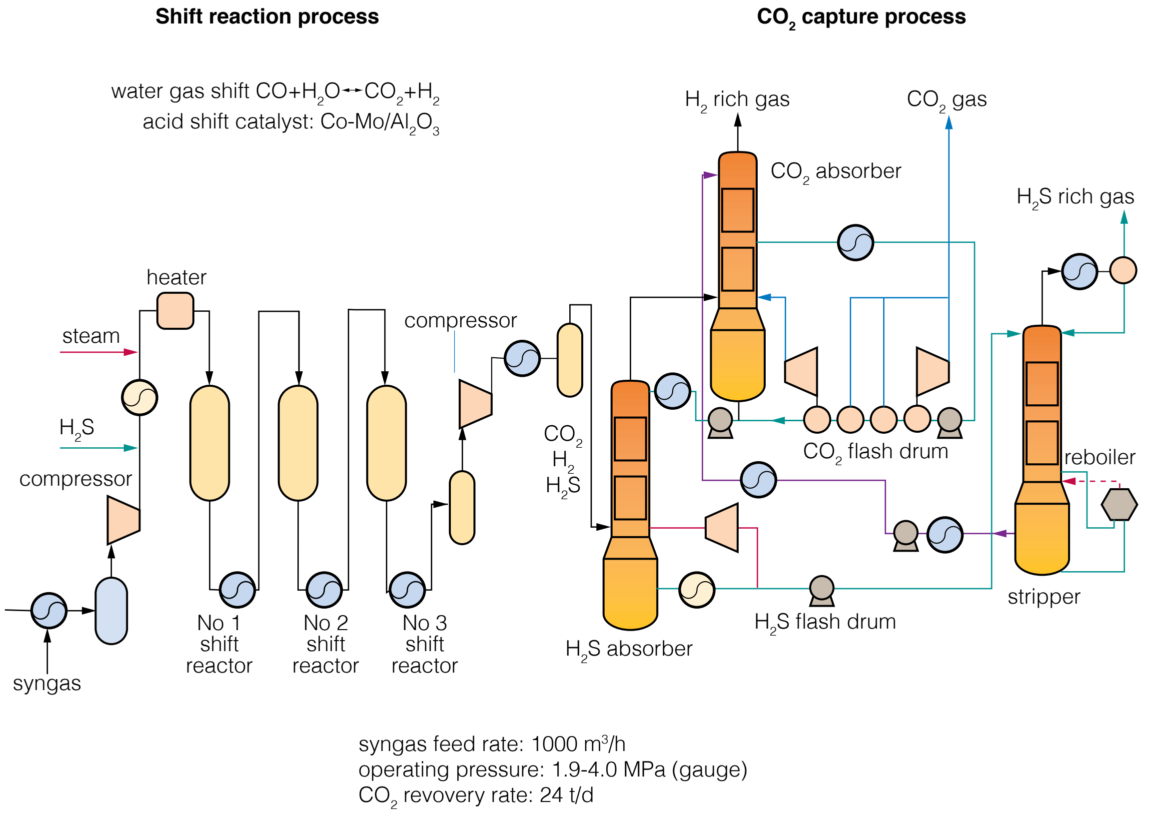


Figure 30 Water gas shift and CO_2 capture systems – Selexol™ (Sasatsu, 2013)

Table 13 Snapshot of 'Sour Shift' + Selexol™ CO_2 system performance (Sasatsu, 2013)

	Test run	Design parameters
Feed gas flow rate	1000 m^3/h	1000 m^3/h
Absorber pressure	4.0 MPa (gauge)	4.0 MPa (gauge)
Solvent flow rate (lean/semi-lean)	2.4/10.4 m^3/h	2.3/10.6 m^3/h
CO conversion ratio	98.2%	96.1%
CO_2 recovery rate	90.2%	91.2%
CO_2 purity	98.9% (dry)	98.2% (dry)

3.8 Gas turbine developments for syngas utilisation

The IGCC plants described above are sufficiently different to warrant separate treatment, although some commonalities are apparent. There is one development however that runs across all IGCC operations and that is the development of high performance gas turbines for utilisation of syngas. This topic has been reviewed recently by Smith (2009) and a brief summary of her findings are included here.

Gas turbine developments are initially on natural gas fired versions but flowing through later to syngas firing technology. The composition of syngas varies widely. Unlike natural gas which mainly consists of CH_4, the combustible components of syngas from coal are mostly H_2 and CO. Carbon removal increases the H_2 content further. Syngases affect operational performance and emissions. The firing temperature of a gas turbine on syngas is about 110–170°C lower than the natural gas fired equivalent.

Future IGCC plants will require CO_2 reduction, probably with zero air integration to reduce operating complexity. Tradeoffs between efficiency, reliability, availability and maintainability (RAM) need to be optimised and validated on the next generation of IGCC demonstration plants. Gas turbine combustor development for 2015, to burn H_2-rich syngas, is based on hybrid, diffusion/premixed burners with fuel flexibility and low NOx emissions to meet emission limits of 3 ppm. Gas turbine manufacturers appear confident that RAM and engine operability would not be affected by adaptations required to retrofit gas turbines developed for natural gas to burn syngas.

The combustion properties of H_2 and CO are quite different from those of CH_4. The high flame speed, high flame temperature and wide flammability range of H_2, along with low ignition energy and low density, may cause blowout and flashback. The large increase in volumetric fuel flow has to be accommodated. Gas turbine designers consider that engine operability and RAM would not be affected by the modifications required for burning syngas. The compressor, fuel system and turbine need some modifications. For example, improvements are required in thermal barrier coatings and film cooling designs. The combustor is affected most by burning syngas/H_2. The flame configurations may be classified into diffusion, premixed and catalytic, developed to achieve stable and efficient combustion with low emissions.

Current commercial IGCC plants have firing temperatures of around 1200–1300°C. More advanced gas turbines are being developed with a firing temperature of over 1400°C. These are based on hybrid burner designs or diffusion flame concepts with advanced secondary air and steam cooling systems. Diffusion flame combustors require low NOx combustion technology for high H_2 fuels without the need for diluent. Staged combustion, lean direct injection, and highly strained diffusion flame combustors may be deployed.

Future IGCC plants will require CO_2 reduction and a typical decarbonised syngas with 90% CO_2 removal contains over 90% H_2. More diluent is required for NOx reduction, depending on several factors such as the type of gasifier, heat recovery and air separation unit. This affects the pressure ratio of the gas turbine with restrictions on compressor performance. Decarbonised syngas may require derating of the turbine firing temperature. The thermal barrier coatings may be adversely affected. Zero air integration, which reduces operating complexity, may be advisable for a plant which is carbon capture ready. Various configurations for CO_2 reduction in IGCC for hard coal result in a wide range of relative losses in the net plant efficiency. The effect of converting to H_2 firing on performance of an IGCC which had been initially optimised for syngas is currently uncertain.

4 Risk assessment issues

4.1 Risks, real and perceived

Financing is a crucial non-technical barrier to the commercial development of advanced clean coal technologies such as IGCC. One of the primary issues in financing a CCT project is the accurate assessment and management of risk associated with that development. The main concern of lenders is that technology under-performance will affect plant operations to the extent that the project is unable to make debt repayments. Lenders do not like lending to new technologies and prefer tried and proven ones that have been financed in the past, and lenders see technology risk as a sponsor risk, particularly in the funding-adverse environment of the last six years. Sponsors will generally try to avoid taking on any significant burden of risk by seeking process guarantees from the manufacturers of CCTs and CCT components to reduce their technology risk exposure, either as warranties or performance bonds. Very large guarantees may be sought for high-risk projects. Unless the manufacturers are large creditworthy companies, they will be required to provide private insurance or bank bonds to cover this risk.

Ecoenergy (2008) set out the relative risk ('risk framework') for a CCT project as follows (*see* Figure 31).

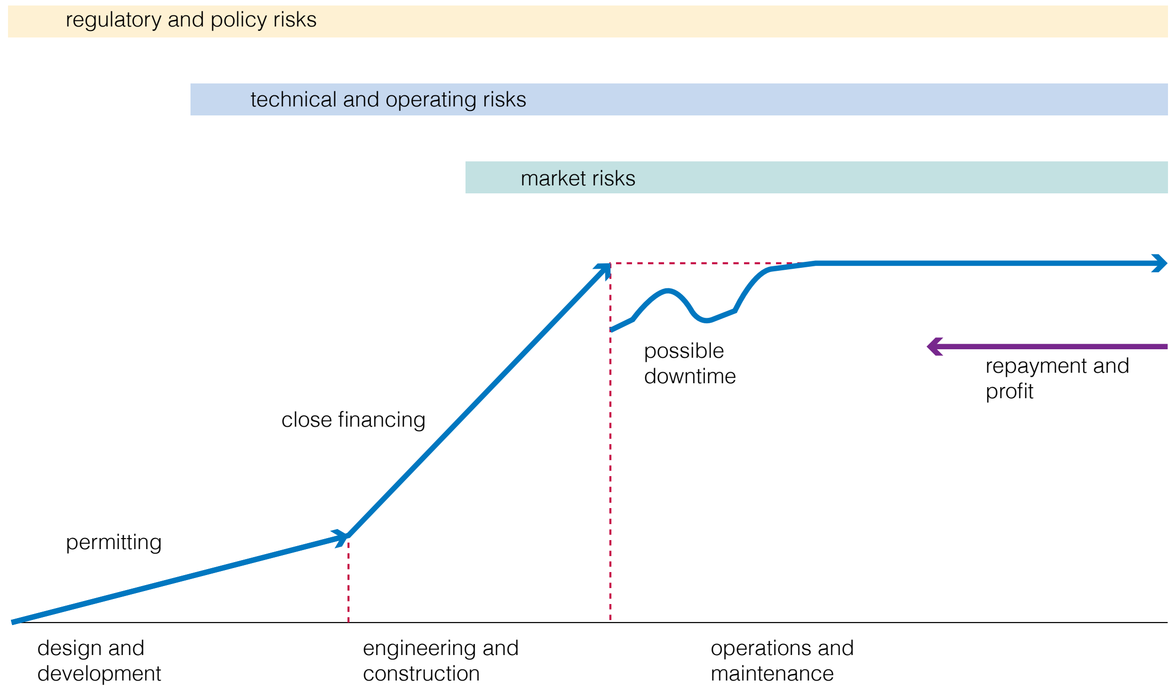


Figure 31 'Risk framework' for CCT projects (Ecoenergy, 2008)

Ecoenergy argues that the 'risk framework' is not an 'R&D roadmap' or rating of technical priorities; neither is it an environmental risk assessment. Rather, it is based on a straight forward assessment of business risks by investment group making the decision to buy or build a plant. The risk-rating framework notes that business risks shift over the project timeline of the design, construction, permitting and operation of a power plant. For an analysis of the risks over the power project timeline the activities can be separated into three basic categories:

1) system technology and operations;
2) regulatory;
3) market risks.

Table 14 sets out the risks identified for a clean coal plant, with carbon capture technology. Interestingly there are differences, sometimes significant ones depending on where in the world the plant is located. A detailed discussion of these issues is outside the scope of the current report, but on this snapshot analysis the best prospects for new plant seem to be in Asia.

Despite the encouragement and support of government and international lenders for IGCC technology there are very considerable barriers that currently make it difficult to achieve its selection and commercial deployment in the power industry. Specifically there are few incentives for ultra clean technology such as IGCC since new PC plants have reduced emissions and in most locations can meet the current standards. Importantly, PC is a very well known and accepted technology in the power industry and most of the new coal plants that are being developed worldwide are PC plants with high efficiency cycles and emissions control technologies. The front-end project development and financing costs are considered to be higher for IGCC and the economic size for a new IGCC plant would probably be 500–800 MW. This would reflect a significant upscaling from current plant and experience and financiers will always tend to seek increased guarantees for any deviation from an existing plant design. A large number of IGCC projects have been announced, offered for sale and then failed to proceed. This alone has created some uncertainty in the minds of potential IGCC customers. Specifically in the USA, there is currently an excess of generating capacity in many USA regions brought about by the building of NGCC plants in 1999-2003 and a general expectation of continuing low natural gas prices from the widespread adoption of shale gas ‘fracking’ technology. This has been exacerbated by the extended economic downturn with little growth, and a limited need for new power plants. As currently offered, IGCC entails a more involved project development cycle than the competing technologies of NGCC and PC. IGCC developments typically start with a screening evaluation of the technologies followed by a Front End Engineering Design (FEED) costing perhaps US$10 million. The FEED is used in turn to solicit Engineering Procurement and Construction (EPC) bids with wrap around guarantees from qualified Engineering. A standard design offered by an EPC would be much more in line with how the power industry is used to handling conventional new power generation projects and the lack of familiarity of IGCC in the power industry plays to this conservatism. Both independent power producers and traditional power companies are very risk averse as there is usually no reward for additional risk taking. Rightly, or wrongly there is also a general power industry perception that the IGCC availability will be lower than PC even if the gasification train is spared. Experience in the chemical and refining industry has not yet been accepted as being sufficiently analogous to power plant operations.

4.2 Assessing and underwriting risk

Insurance is a risk-transfer mechanism whereby a business enterprise, such as a CCT power plant, can shift some of the uncertainties of an enterprise to others – for example, insurance companies. The cost of this transfer will be a known premium, which is usually a very small amount compared with the potential loss. Without insurance there is a great deal of uncertainty for the business enterprise, not only as to whether a loss would occur but also on its potential size. If part of the equipment fails the financial consequences can be severe in terms of both the physical damage to the plant and business interruption while the plant is being repaired. The majority of business enterprises prefer to pay a known cost or premium rather than face the uncertainty of carrying the risk of the whole loss (Carrol, 2008; Schlissel, 2012).

The ‘core’ insurances that typically cover CCTs are Erection All Risks (EAR) and Advanced Loss of Profits (ALOP) policies during construction, and Operational (All Risks including Machinery Breakdown) policies during the future life of the plant. EAR policies provide protection against loss or damage during construction. Cover would normally include the consequences of defective design material and workmanship and protection during testing and commissioning. ALOP policies provide protection against the loss of revenue as a result of delay in commissioning following loss or damage during construction. Operational (All Risks) policies provide protection against loss or damage

Table 14 Overview of business case critical risks for clean coal carbon capture technologies (Ecoenergy, 2008)

Item	Risk type	Business case risk description	Europe	North America	Asia
1	Technical	Capital costs (+ parasitic load) with CCS run too high relative to competing baseload	High	High	High
2	Policy	Electricity rate regulation fails to offer dispatch preference or incentives for CCS	High	High	High
3	Market/finance	Credit financing constraints result in difficult terms (more equity, short debt tenor)	High	High	Medium
4	Policy	Uncertain regulation on CO_2 emissions results in low economic value for CCS	Low	High	High
5	Market/finance	Natural gas prices remain lower making coal with CCS uneconomic	Medium	High	Medium
6	Policy	Incentives for CCS operations (allowances, tax credits) are inadequate for costs	Medium	Medium	High
7	Market/finance	Volatility of (or lack of) carbon allowance prices hinders financing	Medium	High	Low
8	Policy	Water use regulations threaten coal plant operations with CCS (shut-downs)	Medium	Medium	Medium
9	Policy	Lack of clarity about liability for long-term stewardship of CCS hinders financing	Low	High	Low
10	Market/finance	Long-term demand growth fails to justify investment in baseload units	High	Low	Low
11	Technical	Technical performance problems lead to excessive repairs and downtime	Medium	Medium	Low
12	Policy	Older coal units are allowed to run longer posing competitive challenges	Low	Medium	Low
13	Market/finance	Imported coal prices rise or see more volatility raising costs	Medium	Low	Low
14	Technical	Transport of CO_2 proves too costly or logistically difficult	Medium	Low	Low
15	Policy	Lack of public recognition or acceptance of value of CCS hinders permitting	Medium	Low	Low
16	Technical	Injection and storage encounters operating problems triggering higher costs	Medium	Low	Low
17	Market/finance	Interest rates rise threatening financing terms and costs	Low	Low	Low

occurring once the project is in commercial operation. This also includes whilst being overhauled.

The policy wordings will be adapted in each case to limit, to a greater or lesser extent, the amount of risk being transferred to the insurer. For example, the risk transfer to the insurer can be limited by:
- exclusions;
- deductibles (the first part of the claim to be paid by the insured);
- pricing;
- use of captive insurers (which are owned by the insured).

More advanced insurance products recently available in the global insurance marketplace include Efficacy or Non-Damage Performance Insurance. The significance of this type of policy is that the shortfalls in performance are not attributed to equipment breakdown or errors or omissions in design. This is their major difference from traditional Erection and Operation insurance products. Such Efficacy insurance products include:
- contractor's performance which addresses performance shortfalls during acceptance testing resulting in project completion delays;
- system performance which provides coverage against an inability to pay the debt service because of shortfalls in performance over a period of three years;
- comprehensive power plant performance which reimburses the insured for the costs of purchasing power and/or steam because of project delivery shortfalls.

These insurance products would address the significant commercialisation issues facing advanced CCTs. However, most insurance companies do not offer these policies. The reasons for this are thought to be:
- because each application is different, the policies must be customised. This adds to the underwriting expense, which may not be recovered through the premium;
- the causation period from project conception through to financial closure is often very long – years, in fact. Some insurance companies neither have the expertise nor want to take the up-front costs associated with developing such products;
- the global insurance marketplace may not have the capacity (funds available) to sufficiently underwrite projects of this magnitude. This is a very important consideration since the essence of insurance is to spread the risk not only among many policyholders but also among other insurance companies through a mechanism called 'Treaty Agreements'. No single insurance company wants to be exposed to the full magnitude of the risk, which in the case of CCTs could easily exceed US$100,000,000. One claim of that magnitude could bankrupt the company;
- since these policies are as rare as new power plant, there is some question about the number of potential projects that could populate the risk pool. Most insurance companies believe that given, for instance, 100 projects, not more than a handful will result in claims. The ratio of potential claims to policies is determined by the insurance company's appetite for risk. However, no insurance company can survive if the ratio is 1:1 because the premium it earns can never support the amount paid out.

Should an insurance company decide to evaluate the possible risks for an IGCC project, they would use a standard methodology. These differ between insurers, but the methodology used by HSB Engineering Insurance (HSB) serves as a useful example (HSB Engineering Insurance Limited, 2000).

For an existing plant, a survey visit will be carried out by an experienced engineer, followed by detailed input from office-based engineers/analysts. For a proposed new plant, detailed consideration of the planned process is undertaken by an engineer/analyst together with the technology developers, the designers of the process and the constructors.

The methodology is as follows:
- the main components of the plant are identified;
- the process is understood; any grey areas are clarified with sponsors, manufacturers and others;

- possible failure mechanisms and their financial consequences are analysed in detail – NLE Normal Loss Expectancy, PML Probable Maximum Loss, MFL Maximum Foreseeable Loss.

Figures are then calculated for measurement under each heading. Plant financial and contractual arrangements, for example the Power Purchase Agreement (PPA), are assessed and any exclusions or instructions on cover are highlighted for detailed discussion with clients and underwriters. The Business Interruption exposure is calculated, producing an Average Daily Value (ADV) by considering pricing environment, seasonality, suppliers' or customers' extensions. The quality of management, staff and training procedures are assessed, maintenance standard, type and frequency are recorded, operational control, and protection and environmental impact are assessed. Detailed consideration is made of spares availability, leasing options and repair facilities.

5 Lessons learned and concluding remarks

The IGCC plants described in this study have accumulated many thousands of hours operation on a range of coal and, in some cases, co-fuel feedstocks. The plants feature important differences in technology, especially in the selection of gasifiers but also commonalities. IGCC plant is inherently a high efficiency technology from its use of a closely-coupled combined cycle generation, but the complexity necessary for this configuration can also introduce problems with plant availability. Therefore IGCC availability is, perhaps, the most important technical issue governing the success or failure of this coal utilisation option.

All of the plant studies show a similar trend in 'getting to grips' with plant operation and maintenance issues. Figure 32 (Wheeldon, 2012). sets out the rise in plant availability from initial start-up to more established operation, in some cases fully-commercial generation.

Many of the improvements described in this report arise from a careful study of the performance of the plant and the reasons for failure and this is reflected in the figure where plant has generally settled down after about five years' use. The improvement of plant has primarily been undertaken by the plant operators, but the existence of a considerable body of published information and regular systems of information of exchange such as the Freiberg and Gasification Technologies Council Conferences means that developments can benefit from cross-fertilisation. The Nakoso IGCC (Hashimoto and others, 2009) has demonstrated an impressive accumulation of operating experience in a very short time and this may be due to learning lessons from earlier IGCC plant (*see* Figure 33).

However, despite the impressive technical gains that have been made, IGCC still appears to be less attractive to investors than conventional pulverised coal combustion plant. Walker (2007) summarised the market prospects for IGCC thus.

Despite rising expectations since the 1990s, coal-fuelled integrated gasification combined-cycle (IGCC) power generation is now facing several major challenges to broad-based commercialisation. Concerns include cost, competition from technology alternatives, and the timing of any future carbon capture and storage (CC&S). IGCC technology and project developers may still recover their momentum with additional progress on a mix of costs, public sector support, and CC&S policy development. The emergence of potentially cost-effective carbon capture technologies for pulverised coal (PC) plants, however, means that IGCC might eventually compete as one of several options for limiting carbon emissions from coal-fed power generation.

- Preliminary estimates are that IGCC capital costs are 15–20% greater than for PC, but engineering, procurement, and construction contractor risk premiums could increase this cost gap substantially as IGCC power proposals are finalised. This is driving regulatory and market resistance, and vendors and developers are working aggressively to lower IGCC costs and improve competitiveness.
- Public sector cost sharing and other regulatory incentives are essential for IGCC project success, and individual proposals have targeted jurisdictions, locations, and programs to maximise their chances. Still, government support so far has been insufficient to ensure any project's succes;
- broad-based geological carbon sequestration is a primary driver for IGCC, but key logistical and legal/regulatory implementation issues remain unresolved.
- Significant investment in IGCC projects will likely occur over the next eight years only when companies are determined to secure first-mover advantage and policymakers provide sufficient incentives to overcome current cost disadvantages.

In 2006, Excelsior Energy announced the Mesaba Energy Project; a proposal to build a next-generation full-scale integrated gasification combined cycle plant using ConocoPhillips' E-Gas™ technology. The proposed plant would capitalise on the 1600 operational lessons learned from eight

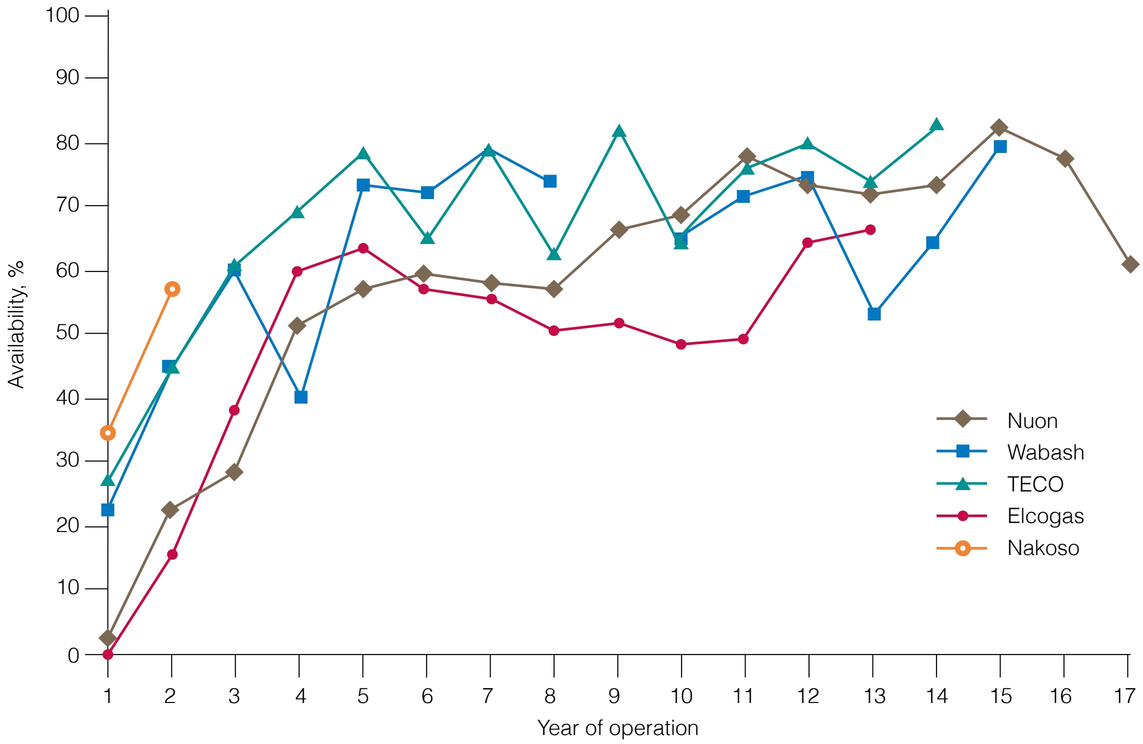


Figure 32 Coal IGCC availability (Wheeldon, 2012)

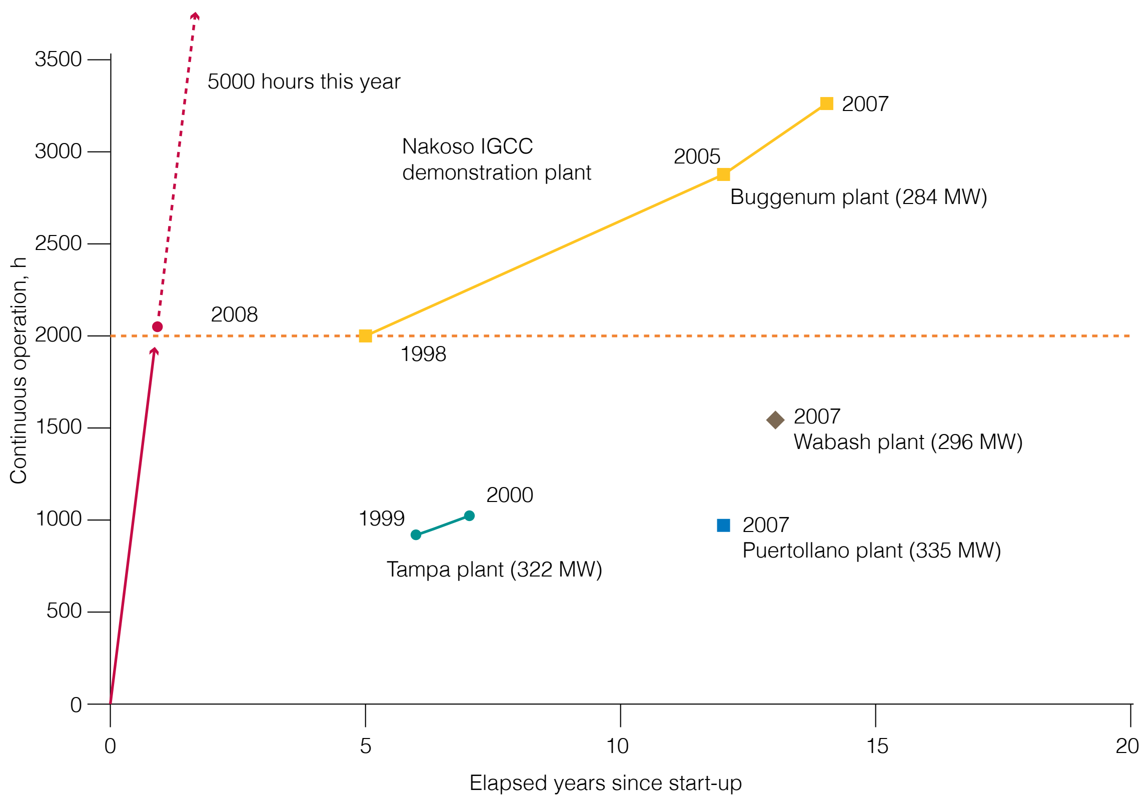


Figure 33 Consecutive operating hours of IGCC plants as a function of years after start-up (Hashimoto and others, 2009)

years of experience at the Wabash River IGCC. The expected benefits for the proposed plant included the elimination of the uncertainty of emerging regulatory programs associated with greenhouse gas emissions, Hg, and fine particulates; availability increases to 90%, up from 77% at Wabash River, a smaller construction footprint including innovations such as an integrated air separation unit with the gas turbine and the flexibility to process both high- and low-rank coals (and petroleum coke, which may have a negative economic value) into a clean synthesis.

However, despite obtaining the necessary permits, issues with plant finance and the long-term prospect of low natural gas prices in the US caused Excelsior to change their plans and Excelsior is now moving forward with the construction of a conventional natural gas plant (Sierra Club, 2013).

Elsewhere, countries with large and strategically important coal deposits are continuing to develop IGCC plants. In April 2012, China's first coal-gasification power plant opened in Tianjin (Tianjin News, 2012). The facility, known as GreenGen, is the world's largest integrated gasification combined cycle (IGCC) generator and is also the first plant built explicitly as a test bed for capturing carbon. The future prospects for IGCC will depend heavily on the performance of plant such as this, and the way in which energy sources such as shale gas develop.

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