Next generation coal gasification technology

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Abstract

Worldwide, a small number of integrated gasification combined cycle power plants (IGCC), based on high-efficiency coal gasification technologies, are operated commercially or semi-commercially, a few more are under construction, and a number of demonstration projects, some including carbon capture and sequestration (CCS), are at an advanced stage of planning. Various coal gasification technologies are embodied in these plants including different coal feed systems (dry or slurry), fireproof interiors walls (fire brick or water-cooled tubes), oxidants (oxygen or air), and other factors. Many of these designs are now several decades old but new cycles and systems are emerging to further improve the efficiency of the coal gasification process. This report draws upon the published literature and commentary from experts in industry and academia working in the coal gasification sector to present and summarise recent developments.

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Acronyms and abbreviations

AC	air compressor
ADT	acid gas dewpoint temperature
AHAT	humid air turbine
APG	Alter (NRG) Plasma Gasifier
ASU	air separation unit
CANMET	Canada Centre for Mineral and Energy Technology
CCGT	combined cycle gas turbine
CCS	carbon capture and sequestration
CE-CERT	(Bourns) College of Engineering – Centre for Environmental Research and Technology
CES	clean energy systems
CRGT	chemically recuperated gas turbine
CRIEPI	Central Research Institute of Electric Power Industry
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DLN	dry low NOx
DME	dimethyl ether
DOE	Department of Energy
EIAC	Energy Independence of America Corporation
EPRI	Electric Power Research Institute
FT	Fischer-Tropsch
HHV	higher heating value
HPT	high pressure turbine
HRSG	heat recovery steam generator
HTHG	high temperature hydrogasification
HTT	high temperature turbine
GT	gas turbine
ICAD	intercooled aeroderivative
IEAGHG	IEA greenhouse gas (programme)
IGCC	integrated gasification combined cycle
IGFC	integrated gasification fuel cell
IGSC	integrated gasification steam cycle
ITP	intermediate pressure turbine
LHV	lower heating value
LPT	low pressure turbine
MCFC	molten carbonate fuel cells
MHD	magneto hydrodynamics
NCCC	National Carbon Capture Centre
NEDO	New Energy and Industrial Technology Development Organisation
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
ORC	Organic Rankine cycle
PAFC	phosphoric acid fuel cells
PC	pulverised coal
PDTF	pressurised drop tube furnace
PEFC	polymer electrolyte fuel cells
PRB	Powder River Basin
SCR	selective catalytic reduction
SNG	substitute natural gas
SOFC	solid oxide fuel cells
SPRINT	spray intercooled turbine

ST	steam turbine
STIG	steam injection
TES	thermal energy storage
TIC	turbine inlet chilling
UCR	University of California, Riverside
UGC	underground coal gasification
US EPA	United States Environmental Protection Agency
WAC	water atomisation cooling
WPC	Westinghouse Plasma Corporation

Contents

1 Introduction

Worldwide, a small number of integrated gasification combined cycle power plants (IGCC), based on high-efficiency coal gasification technologies, are operated commercially or semi-commercially, a few more are under construction, and a number of demonstration projects, some including carbon capture and sequestration (CCS), are at an advanced stage of planning.

Various coal gasification technologies are embodied in these plants including different coal feed systems (dry or slurry), fireproof interiors walls (fire brick or water-cooled tubes), oxidants (oxygen or air), and other factors. Many of these designs are now several decades old but new cycles and systems are emerging to further improve the efficiency of the coal gasification process.

This report draws upon the published literature and commentary from experts in industry and academia working in the coal gasification sector to present and summarise recent developments.

In researching this topic, a number of commentators opined that 'next generation coal gasification' is likely to be based on systems including underground coal gasification (UGC) (Kleiner, 2008; World Coal Association, 2011; UCG Association, 2011). Demonstration projects and studies on UGC are under way in a number of countries, including the USA, Canada, Western and Eastern Europe, Japan, Indonesia, Vietnam, India, Australia and China, with work being carried out by both industry and research establishments. However, UGC has recently been reviewed by Couch (Couch, 2009) and consequently is not considered further here. The role of large complexes concentrating on the production of power (via hydrogen) and chemicals are considered topics in their own right and have been reviewed recently (Collot, 2003; Carpenter, 2008). Consequently they are only included here where a significant aspect (for example, enhanced carbon dioxide recovery) merits their inclusion.

1.1 Overview of IGCC technology

IGCC is a high efficiency power generation technology which gasifies coal to generate the fuel ('syngas') for a high efficiency gas turbine. Compared with conventional pulverised coal (PC) fired power plants IGCC has potentially many advantages including:

- High thermal efficiency on a par with the best existing PC plants and potential for further increases (for both technologies). Shell estimate an IGCC generation efficiency based on their gasifier of 46–47% net, LHV basis (44–45% net, HHV basis), for bituminous coals with an FB-class gas turbine (Van Holthoon, 2007, 2008). The highest report efficiency for an IGCC is 41.8% HHV basis (Shell gasifier powering an F-class turbine, fuelled with Pittsburgh coal) (Dalton, 2009).
- Good environmental characteristics that match or exceed the latest PC plants. The plant's high thermal efficiency means that emissions of CO_2 are low per unit of generated power. In addition, emissions of SOx, and particulates are reduced by the requirement to deep clean the syngas before firing in the gas turbine.
- Reduced water consumption. IGCC uses less water since 60% of its power is derived from an air-based Brayton cycle reducing the heat load on the steam turbine condenser to only 40% of that of an equivalent rated pulverised coal fired plant. Additionally, through the direct desulphurisation of the gas, IGCC does not require a large flue gas desulphurisation unit which consumes large amounts of water, thereby reducing water consumption in comparison with a conventional pulverised coal fired power plant. Further gains in reducing water use can be achieved when CCS is incorporated into the plant.

A simplified version of a coal-fuelled IGCC cycle is shown in Figure 1. Current gasification technologies are detailed in a recent IEA Clean Coal Centre Report (Fernando, 2008), and the

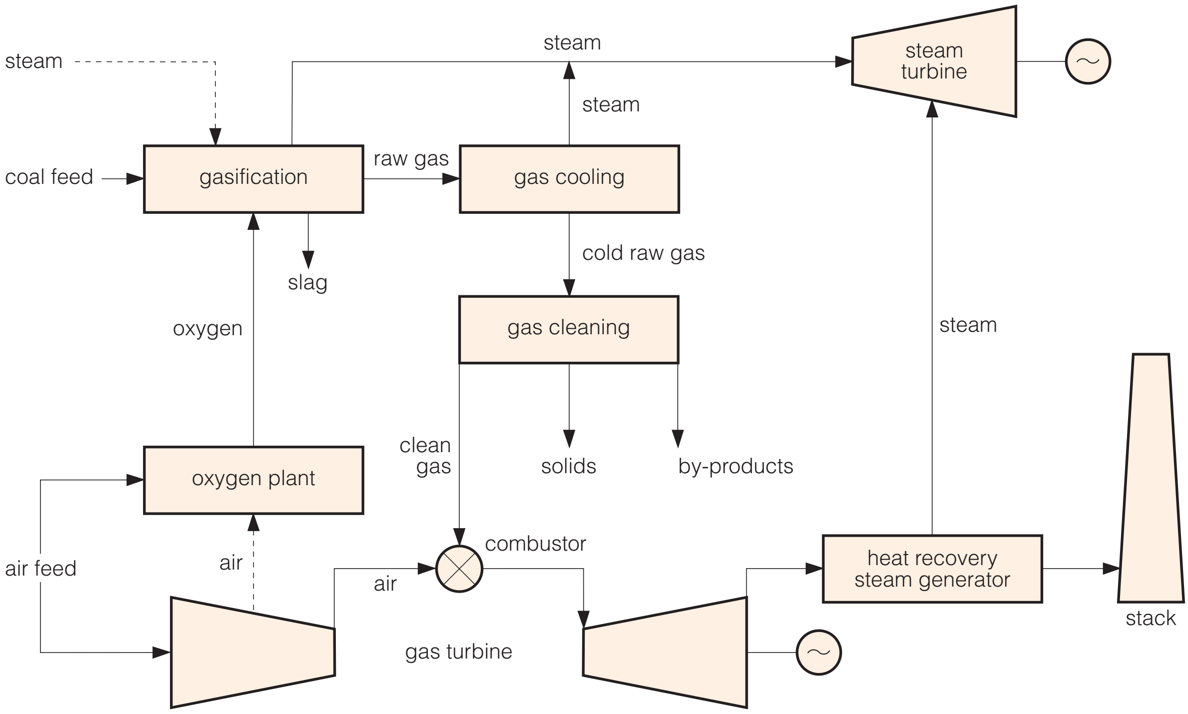


Figure 1 Integrated gasification combined cycle without CO_2 capture – major component systems (Henderson, 2008)

principle of IGCC has been described many times (see, for example, Henderson, 2004, 2008). Gas cleaning is typically undertaken by water scrubbing or the dry removal of solids, followed by hydrolysis of COS to H_2S, then scrubbing to remove H_2S. There are many possible plant configurations, because gasifier designs vary significantly and IGCC has a large number of process areas that can use different technologies. The deep cleaning needed to protect the gas turbine enables emissions of particulates and SO_2 to be very low (Henderson, 2007). Totally dry gas clean-up at elevated temperatures ('hot gas clean-up') may eventually be applied, with advantages in efficiency, but is not currently available for commercial IGCC.

1.2 Future directions

The US Department of Energy's (DOE) Office of Fossil Energy considers that future gasification concepts that merit study include those that offer significant improvements in efficiency, fuel flexibility, economics and environmental sustainability (Tennant, 2011). Fuel flexibility is considered to be especially important given that future gasification plants could conceivably process a wide variety of low-cost feedstocks, in addition to coal, such as biomass, municipal and other solid wastes, or combinations of these feedstocks. A development of note, being studied by the DOE, is the so-called 'transport reactor' based on an advanced circulating fluidised bed reactor, in which a chemical sorbent can be added to capture sulphur impurities. This unit is described in more detail in a later section of this report.

Another important area for research is the development of efficient and economical oxygen separation technologies. Currently, producing oxygen involves a complex, energy-intensive cryogenic process. A lower cost alternative being explored by the DOE is based on innovations in ceramic membranes to separate oxygen from the air at elevated temperatures. Membrane research is also concentrating on less expensive materials that can selectively remove hydrogen from syngas so that it can be used as a fuel for turbines, future fuel cells or refineries, or in hydrogen-powered vehicles. Other gas separation research is focused on removing carbon dioxide from syngas. Research is continuing into new types of pollutant-capturing sorbents that work at elevated temperatures and do not degrade under the harsh conditions of a gasification system. Also, new types of gas filters and novel cleaning approaches are being examined.

Gasification produces less solid wastes than other coal-based power generation options, and these wastes can have commercial value. Gasifier slag is being used for road construction and investigations are under way to use the solid material produced when coal and other feedstocks (for example, biomass, municipal waste) are utilised in the gasification process. Some plants produce sulphur of sufficient purity for sale as a commercial product.

Thus, most IGCC developments tend to be evolutionary in nature, building upon the performance of established components and materials. The requirements for future plants are therefore concentrated generally on further developments of those systems; particularly larger and more efficient gas turbines, higher duty steam cycles, more efficient oxygen separation processes including ion-membrane technologies in the longer term, and improvements to ancillary components – for example solids pumps (Henderson, 2008; Minchener, 2005). The relative complexity and high integration of IGCC plants while contributing to their overall high efficiency also makes them vulnerable to 'risk adverse' investors, including prospective utility customers (Edwards and Chapman, 2005) and this also acts to focus improvements on stepwise upgrades. This view was confirmed by conversations with several of the 'main players' working on the development of key components in the gasification system (Schoff, 2011). However the importance of R&D into novel concepts was confirmed but it was not considered possible to contribute information on strategy and results to a non-confidential report such as this.

In compiling this report a number of potentially significant developments and directions pertinent to future coal gasification processes have emerged, and are outlined below. These are:
- improved theoretical gasification cycles;
- improvements to gas turbine operation;
- cycles for enhanced power generation

2 Improved theoretical gasification cycles

A number of improved and non-conventional cycles have been developed that may contribute to future higher efficiency coal gasification plants. There is evidence in a resurgence of interest in these cycles with respect to coal gasification in the recent technical literature, and so examples are outlined and discussed below.

2.1 Graz cycle

The Graz cycle (*see* Figure 2) consists of a high temperature Brayton cycle (compressors C1 and C2, combustion chamber and High Temperature Turbine HTT) and a low temperature Rankine cycle (Low Pressure Turbine LPT, condenser, Heat Recovery Steam Generator HRSG and High Pressure Turbine HPT) (Heitmeir and others, 2006).

The syngas from a conventional gasifier together with an approximately stoichiometric mass flow of oxygen is fed to the combustion chamber, which is operated at a pressure of 40 bar. Steam and a CO_2/H_2O mixture is supplied to cool the burners and the liner. A mixture of steam, CO_2, O_2 and N_2 leaves the combustion chamber at an average temperature of 1400°C. The fluid is expanded to a pressure of 1.053 bar and 579°C in the HTT. Cooling is performed with steam from the HPT, increasing the steam content at the HTT exit. Since a further expansion down to condenser pressure would not result in a reasonable water condensation, the hot exhaust gas is cooled in the following HRSG to vaporise and superheat steam for the HPT. After the HRSG, approximately 45% of the cycle mass flow is further expanded in the LPT.

The Graz cycle is suitable for all kinds of fossil fuels, but particularly efficient when used with syngas from coal gasification. In a theoretical study of a coal-derived syngas Graz cycle, Heitmeir assumed that syngas was supplied from a gasifier at 500°C, and with a composition typical for an oxygen blown coal gasification plant (syngas mole fractions: 0.1 CO_2, 0.4 CO, 0.5 H_2). The composition of the working fluid at HTT exit was 69% steam and 31% CO_2 (mass fractions). Then, half of the cycle mass flow was expanded in the LPT and fed to the condenser, where the lower steam content led to a slightly higher optimum pressure of 0.05 bar.

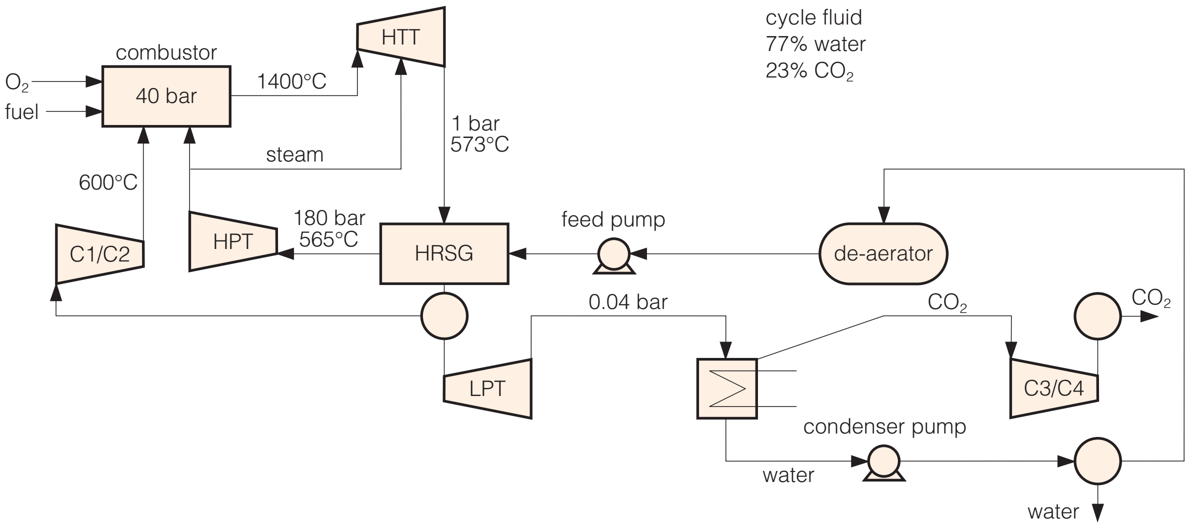


Figure 2 Graz cycle (Heitmeir and others, 2006)

Critical points in implementing Graz cycles for coal gasification plant are the combustion chamber and the high temperature turbine but the other plant components are readily available. It has been predicted that the cycle could reach a thermal efficiency of 52.5% with a plant exhaust consisting of almost pure CO_2 facilitating subsequent geological storage.

2.2 Water cycle

The water cycle is a cycle that utilises reheat and a recuperator in a Rankine-like power cycle that features water recirculation. Figure 3 shows an example of a system based on the water cycle where the cycle is fed by a coal gasifier.

In the combustor at 83 bar, liquid water is flashed into steam and heated to 900°C through the combustion process (2) and expanded to 8.3 bar in a high pressure steam turbine (3). The steam is then passed through a reheating combustor where it is heated to an exhaust temperature of approximately 1300°C (4). After expansion to 0.1 bar (5), the stream is passed through a recuperator (6), condensed (7), and carbon dioxide is removed (8). Some of the water is also removed before it is pumped to 83 bar (1), sent through the recuperator (6), and fed into the combustor (16).

An analysis of this type of power cycle has indicated estimated efficiencies in the lower 40% range, including carbon dioxide liquefaction (Houyou and others, 1997) but not including losses in coal gasification stage. Bolland and others (Bolland and others, 2001), in their analysis of the water cycle, noted that the overall efficiency of the plant is highly sensitive to the outlet pressure of the first combustor, claiming 0.7–1.3 percentage point efficiency gains for each 100°C the temperature is raised. By their calculations, a high pressure of 200 bar with an exit temperature from the combustor of 1400°C would produce a total plant efficiency of 53%. Although many components of the water cycle are based on mature technologies, the best steam turbines cannot yet handle the high pressures and temperatures needed to push the efficiency values beyond those of simple post-combustion technology. It is suggested that steam turbine technology might be mixed with high pressure and temperature gas turbine technology to produce a working prototype plant capable of 50% efficiencies, but it is recognised that current technology places the plant at the 40% efficiency level. A significant body of research is considered necessary to reach a level where the plant can reach the higher efficiency calculated (Kvamsdal and others, 2007).

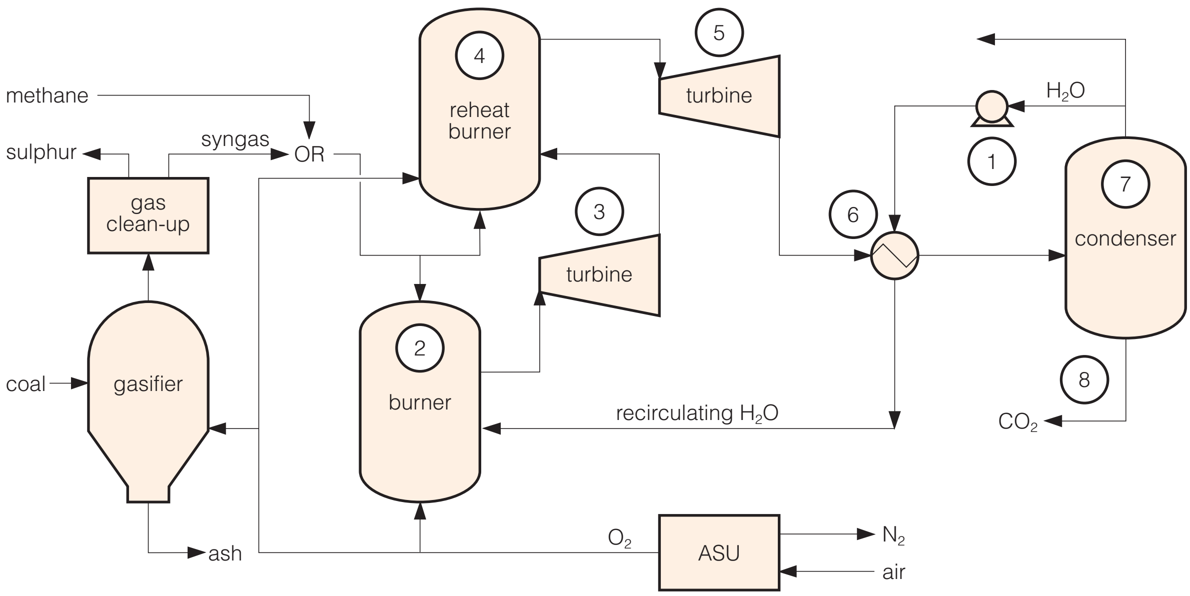


Figure 3 Water cycle-based coal gasification process (Houyou and others, 1997)

2.3 CES cycle

The CES system which uses a CO_2/H_2O turbine is an interesting development. It is described in more detail in Section 4.4 in the context of the Jacobs IGSC, based on this cycle.

2.4 Matiant cycle

The Matiant cycle is based on a regenerative Brayton cycle with a supercritical CO_2 Rankine cycle with carbon dioxide recirculation as the working fluid. Figure 4 shows a coal gasification plant based on the Matiant cycle.

Supercritical CO_2 at 300 bar is heated in a recuperator (1) before being expanded in a gas turbine to 40 bar (2). The gas is then heated through a second recuperator (3) before being burned in a high pressure combustor at 40 bar to 1300°C (4). After passing through a gas turbine where the pressure drops to 9.3 bar (5), the gas is reheated in a reheat combustor to a temperature of 700°C (6). The fluid expands through a second turbine to 1 bar (7) before losing more energy to the recuperator that heats the supercritical CO_2 (1 and 2). After this stage, water is condensed (8) and removed before the carbon dioxide is compressed in an intercooled compressor to 70.5 bar and liquefied at 29°C (9). After excess carbon dioxide is removed, the liquefied CO_2 is pumped (10) to 300 bar and passed into the recuperator (1). A claimed benefit for this cycle is that the carbon dioxide can be pumped in its liquid phase to 300 bar, saving energy on gas compression. An analysis of this cycle by Houyou and others (Houyou and others, 1997) reports efficiencies of 44–45%. However, this figure does not take into account losses associated with the gasification of coal.

In a comparison of different cycles by Alexander (Alexander, 2007), he opined that the Matiant cycle faces daunting technological challenges. Although the cycle faces similar technological barriers to other processes with respect to CO_2 based gas turbine issues, the Matiant cycle has an additional hurdle in the production of a supercritical CO_2 turbine that can expand the fluid from a high pressure of 300 bar and a temperature of 500°C. Another problem associated with the cycle scheme claimed by Bolland and others (2001) is the requirement of large amounts of internal heat exchange between hot streams. In particular, the exhaust stream that is cooled enters the heat exchange equipment at 1 bar and 940°C, and suggests possible problems for the heat exchanger technology. The size and capital costs of these heat exchangers could also prove problematic. Some proposed designs in the power industry that may prove beneficial in this cycle include the use of printed circuit heat exchangers

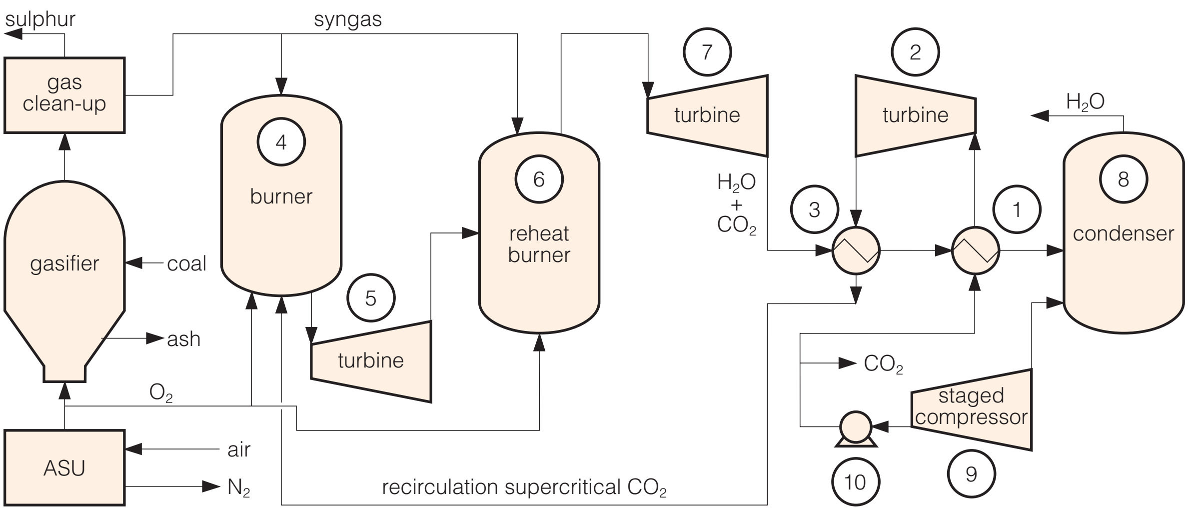


Figure 4 Matiant cycle-based coal gasification process (Houyou and others, 1997)

instead of shell and tube style heat exchangers. The printed circuit exchanger variant allows a large reduction in size and capital expenditure for the same heat exchanger effectiveness. Bolland and others (2001) and Alexander (2007) have also expressed concerns on the sensitivity of the cycle to parasitic losses.

2.5 E-Matiant cycle

In a variation on Matiant cycle, the E-Matiant cycle claims to address some of the issues raised by the basic Matiant cycle. The E-Matiant cycle is a Brayton type cycle that removes the high pressure expander and eliminates the reheat combustor. Carbon dioxide in the E-Matiant cycle remains in the gaseous phase and is compressed through an intercooled compressor stack. The maximum pressure in this cycle is reduced to 110 bar. Figure 5 shows an example cycle layout.

A cleaned syngas from a gasifier is burned (1) and the exhaust gas, consisting of carbon dioxide and water, is passed through a turbine (2) and then a recuperator (3) before passing into a condenser (4). The carbon dioxide is compressed in a staged intercooled compressor (5) before being heated in the recuperator (3). This gas is then fed back into the burner to control combustion temperatures (1). Cycle analysis by Houyou and others places the cycle efficiency in the 47% range but again this efficiency value does not include losses associated with the coal gasifier. The major advantage to this design is claimed to be the elimination of the high pressure and temperature supercritical CO_2 turbine that would require development for the Matiant cycle. However, a CO_2 gas turbine would be required operating at 110 bar at the combustor outlet. Additionally, the cycle still contains large amounts of internal heat exchange equipment and its overall efficiency is still highly dependent upon the efficiency of the intercooled compressor stack.

2.6 Kalina cycle

The Kalina cycle, was invented in the mid-1980s as an alternative to the conventional Rankine cycle (Kalina, 1982). The Kalina cycle uses a binary working fluid of an ammonia-water mixture to drive a turbine-generator. By varying the composition of the binary fluid, variable vaporisation and condensation points are achieved with the result that thermal energy is captured more efficiently per unit of fuel input, creating higher cycle efficiency. The plants currently in commercial operation using the cycle have demonstrated efficiency gains of 15–50% relative to conventional thermal technologies, along with 15–20% lower emissions of NOx, SO_2 and particulate matter as a result of lower fuel

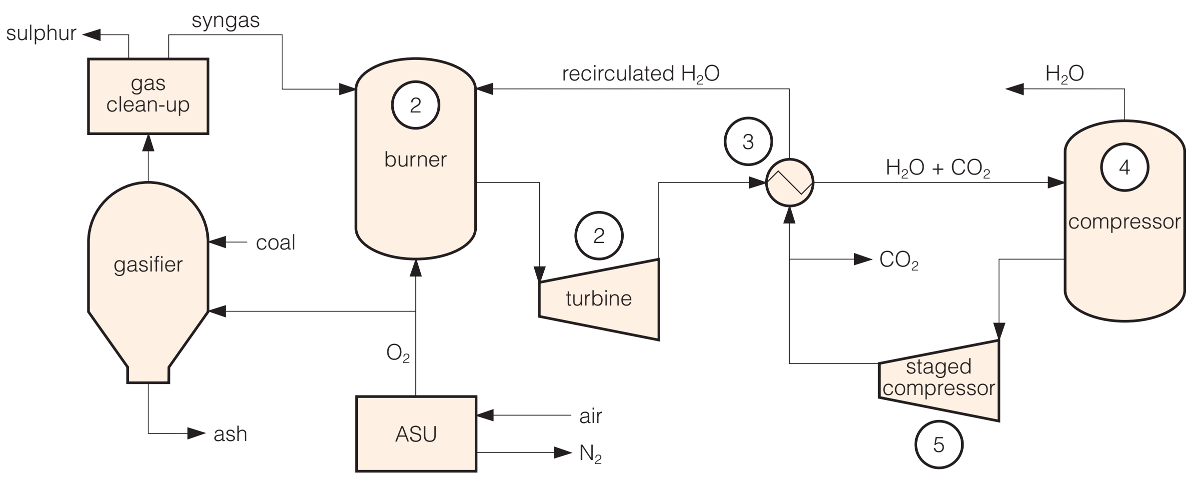


Figure 5 Example of E-Matiant cycle variant (Houyou and others, 1997)

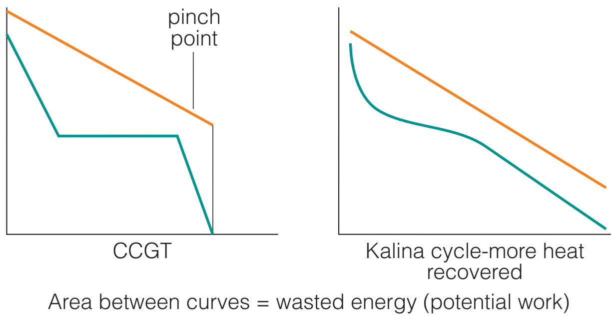


Figure 6 Kalina versus CCGT Rankine cycle (Kalina, 1982)

consumption (Power Engineering, 2002). The range of heat source temperatures varies between 98°C and 900°C, with turbine throttle conditions of 30–114 bar. Figure 6 illustrates the thermal advantages of the Kalina cycle over a comparable CCGT Rankine cycle.

2.7 Organic Rankine cycle (ORC)

The organic Rankine cycle's principle is based on a turbogenerator working as a normal steam turbine to transform thermal energy into mechanical energy and finally into electric energy through an electric generator (Turboden, 2011). However, instead of steam, the ORC system vaporises an organic fluid with a molecular mass higher than water, leading to a slower rotation of the turbine and lower pressure and erosion of the metallic parts and blades. The ORC cycle has a high overall energy efficiency: 98% of incoming thermal power in the thermal oil is transformed into electric energy (around 20%) and heat (78%), with limited thermal leaks; only 2% due to thermal isolation, radiance and losses in the generator; the electric efficiency obtained in non cogenerative cases is much higher (around 24% and more). Advantages claimed for the organic Rankine cycle include:

- high turbine/thermodynamic cycle efficiency;
- turbine low mechanical stress;
- absence of moisture during the vapour expansion, responsible for the erosion of the blades;
- simple start-up procedures;
- automatic and continuous operation;
- simple maintenance procedure;
- no operator attendance required;
- long life of the plant (>20 years);
- no need to demineralise water.

2.8 Summary

The basic thermodynamic cycles pertinent to coal gasification plant have been long established, but novel combinations of these cycles and the use of alternative fluids to water/steam offer the prospect of higher efficiencies. However, these gains are at present theoretical and in some cases require the development of technologies significantly in advance of current best practice. Moreover, some cycles (such as Matiant) are vulnerable to the inevitable parasitic losses present in a highly integrated process such as a coal gasification plant.

3 Improvements to gas turbine operation

In considering future developments to coal gasification systems, the role of the gas turbine is of fundamental importance. Developments to gas turbines (higher inlet temperature and pressure, resistance to particulates loadings) are outside the scope of the current report, and have been reviewed recently by Smith (2009). However, techniques for maximising the efficiency of current turbines may be relevant to emerging technologies and so important developments are summarised below.

Hodrien (2008), in reviewing developments in gas turbine-based cycles, distinguished between advanced combined cycle systems and advanced simple systems. While the trend for existing coal gasification plants is towards large facilities, there may be potential for smaller, more flexible units that can follow load and operate on a mixture of fuels. For combined cycles systems Hodrien considered that developments were likely to include improvements to the steam 'bottom cycle' and the use of Kalina and organic Rankine cycles. Figure 7 shows a modern steam turbine configured with a heat recovery steam generator (HRSG) and three pressure levels with superheat and reheat. HRSGs are specialised waste heat recovery boilers and are designed for large gas volumes with minimum pressure drop so the impact on gas-turbine efficiency is minimised. Using an HRSG with auxiliary or supplemental fuel firing in a duct burner can increase steam production, control steam superheat temperature, or meet process steam requirements. HRSG designs can also directly incorporate selective catalytic reduction (SCR) technology for NOx control.

Hodrien opined that advanced simple systems might become attractive for mid-range generation applications where they offer advantages over larger gasification facilities – specifically, better part-load efficiency, better 'hot-day' efficiency and lower NOx. These enhanced simple systems would have better efficiencies than simple GT at lower cost and increased flexibility over CCGT. Advanced simple GT cycles considered by Hodrien included:

- catalytic combustion;
- reheat improvements;
- inlet-chilling;
- spray-intercooled (SPRINT);
- intercooled (ICAD);
- steam injection (STIG);
- humid air turbine (AHAT cycle);
- chemically recuperated GT (CRGT cycle).

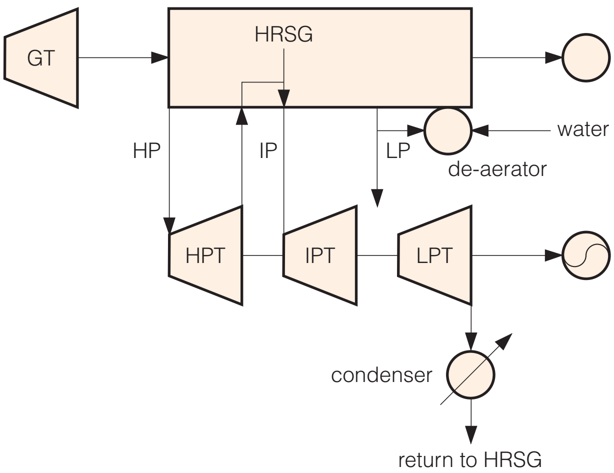


Figure 7 Three-pressure reheat steam cycle (Hodrien, 2008)

3.1 Catalytic combustion

Active interest in catalytic combustion for power generation increased during the early 1990s as it became clear that continued pressure for reduced emissions may not be met simply by redesign of conventional combustors (Smith, 2009). A new approach of partial conversion in the catalyst bed and the use of metal catalyst substrates to circumvent thermal shock issues became increasingly successful, demonstrating low NOx potential for gas turbine applications. Ultimately, two different systems emerged: a fuel-lean catalyst system developed by Catalytica Inc and a fuel-rich catalyst system developed by Precision Combustion Inc (Smith and others, 2006). Details of the technologies are given by several authors in the gas turbine handbook of the US DOE (NETL, 2006).

In catalytic combustion, fuels oxidise under lean conditions in the presence of a catalyst. Catalytic

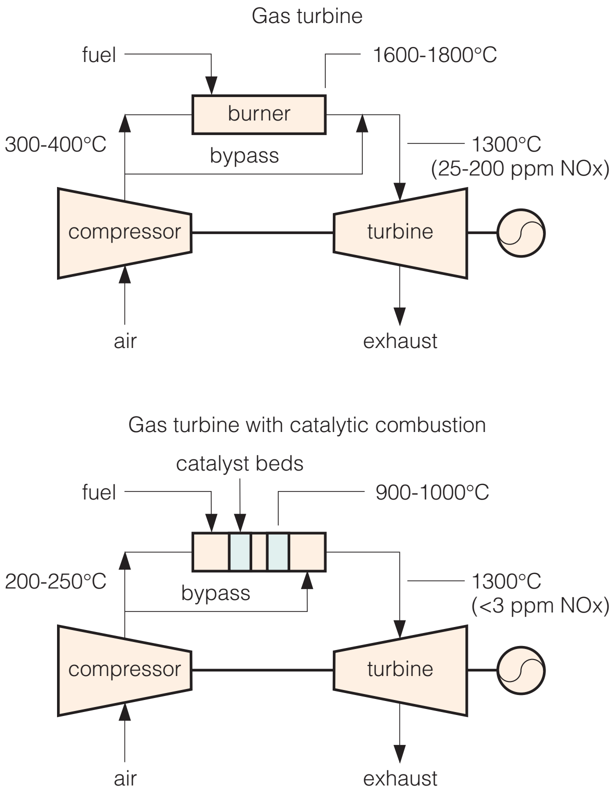


Figure 8 Catalytic combustion (NETL, 2006)

combustion is a flameless process, allowing fuel oxidation to occur at temperatures below approximately 930°C, where NOx formation is low. The catalyst is applied to combustor surfaces, which cause the fuel-air mixture to react with the oxygen and release its initial thermal energy. The combustion reaction in the lean premixed gas then goes to completion at design temperature (*see* Figure 8). Data from ongoing long-term testing indicates that catalytic combustion exhibits low vibration and acoustic noise, only one-tenth to one-hundredth the levels measured in the same turbine equipped with dry low NOx (DLN) combustors.

Gas turbine catalytic combustion technology is being pursued by the developers of combustion systems and gas turbines and by government agencies, most notably the US Department of Energy and the California Energy Commission. Past efforts at developing catalytic combustors for gas turbines achieved low, single-digit NOx ppm levels, but failed to produce combustion systems with suitable operating durability. This was mainly due to cycling damage and to the brittle nature of the materials used for catalysts and catalyst support systems. Catalytic combustor developers and gas turbine manufacturers are now testing durable catalytic and 'partial catalytic' systems that are overcoming the problems of past designs. Catalytic combustors capable of achieving NOx levels below 3 ppm are in full-scale demonstration and have entered early commercial introduction. Catalytic combustors must be tailored to the specific operating characteristics and physical layout of each turbine design (Energy and Environmental Analysis, 2008).

3.2 Reheat improvements

Reheat combustion has been proven in over eighty units to be a robust and highly flexible gas turbine concept for power generation (Güthe and others, 2008). Advantages claimed include a greater quantity of fuel to be burnt and more power generated within metal temperature limits. The principle of reheat combustion is outlined in Figure 9.

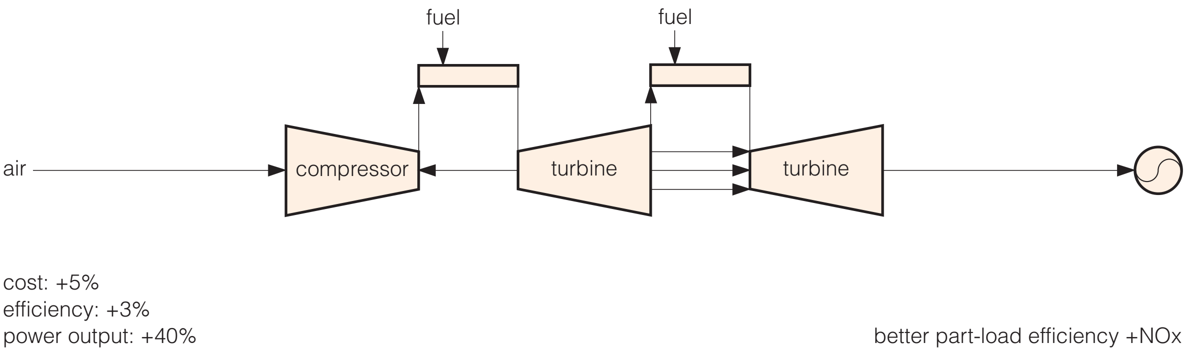


Figure 9 Principles of gas turbine reheat combustion (Güthe and others, 2008)

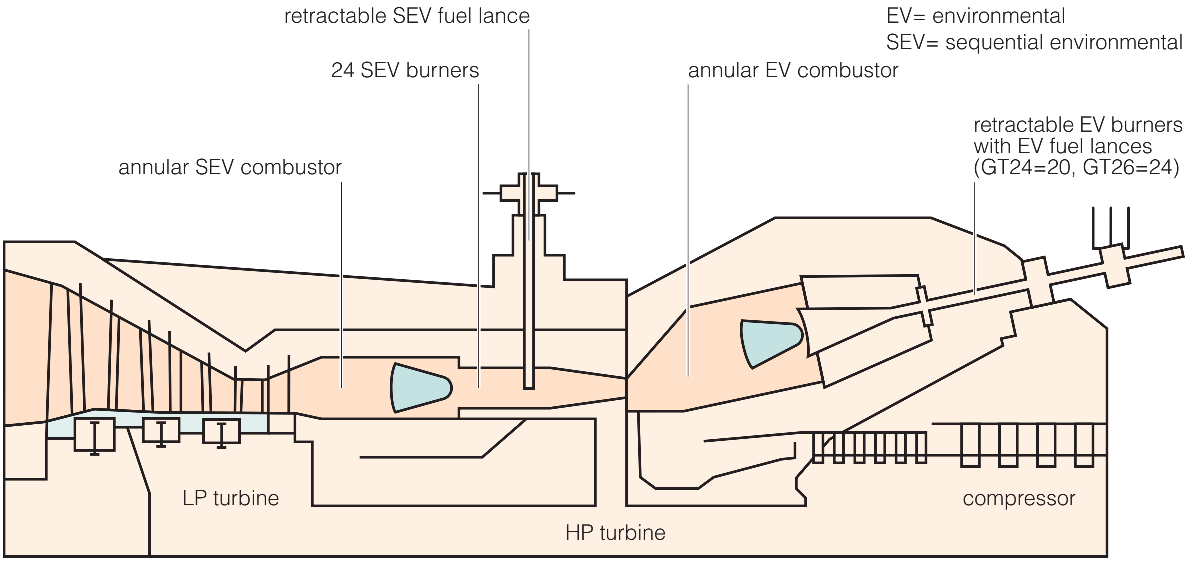


Figure 10 Alstom GT26 reheat combustion gas turbine (Henderson, 2007)

A gas turbine incorporating the sequential combustion concept consists of a high-pressure combustor followed by a high-pressure turbine, a low-pressure combustor and a low-pressure turbine. Low NOx emissions of below 15 ppm are possible in the current sequential combustion engines as the reheat engine has an intrinsic emission advantage based on moderate temperatures in the first combustion stage combined with low emission production in the second stage combustor. High power density and efficiency can be achieved despite lower turbine inlet temperature by the second expansion in the low pressure turbine. A high degree of operational flexibility, such as turn down to 40% load and fast load up while maintaining low emissions, is possible by keeping the exhaust temperature constant in a wide operation range. This enables the heat recovery steam generator (HRSG) to remain in operation even at low load. An example of a modern gas turbine incorporating reheat combustion is the Alstom GT 26 (*see* Figure 10). This unit and the GT26B are described in more detail in the IEA case study of the Enfield NGCC plant (Henderson, 2007).

3.3 Inlet chilling – evaporation

Inlet chilling techniques such as 'fogging' through evaporation are particularly suited to hot countries where gas turbine power output is lowest at the time and season of maximum demand. It increases air density and consequently mass flow at low cost, but is only effective if the inlet air is dry (*see* Figure 11). Fog systems create a large evaporative surface area by atomising the supply of water into billions of very small spherical droplets (Mee, 1999). Droplet diameter plays an important role with

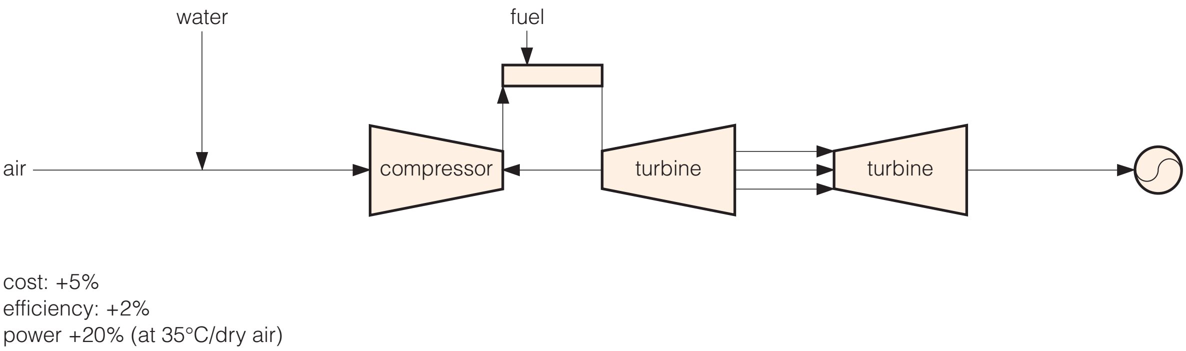


Figure 11 Inlet chilling – 'fogging' (Mee, 1999)

respect to the surface area of water exposed to the air stream and, therefore, to the speed of evaporation.

Over the years, many different methods of water atomisation have been employed for cooling and humidification systems, with centrifugal disks and compressed air nozzles being the most common. Neither method, however, proved cost-effective in producing micro-fine fog droplets. Current systems work by forcing water through a small orifice and either getting it to swirl, or impacting it on a pin (impaction pin nozzle). The result is an expanding cone of water that breaks into small droplets. Nozzles that create a swirling action are effective, but much of the energy in the water jet is consumed in the swirling process so that the droplets produced are considerably larger than nozzles that employ an impaction pin. Because of their efficiency and small droplet size, impaction pin nozzles with orifice diameters from five to seven thousandths of an inch are most commonly used for fog cooling on gas turbines. Operating pressure is an important variable and doubling the operating pressure results in a droplet that is about 30% smaller. Typical operating pressures for turbine cooling fog systems range from 70 to 200 bar.

3.4 Inlet chilling – refrigeration

A second option for inlet chilling is refrigeration (*see* Figure 12). This also increases air density and mass flow, albeit at a higher cost than ‘fogging’ due to the use of some of the extra power produced. However, refrigeration still works if the inlet air is wet. Mechanical chiller systems can cool the inlet air to lower than wet bulb temperature and when properly designed can maintain any desired inlet air temperature down to as low as 6°C, independent of ambient wet-bulb temperature. The mechanical chillers used in these systems can be driven by electric motors, steam turbines or engines. Drawing the inlet air across cooling coils, in which either chilled fluid or refrigerant is circulated, cools it to the desired temperature. Mechanical chiller-based turbine inlet chilling (TIC) systems are more capital-intensive than evaporative systems, and when using electric motors these systems also have the highest parasitic loads. The chilled water can be supplied directly from a chiller, or from a TES (Thermal Energy Storage) tank that stores ice or chilled fluid. A TES system is typically used when there are only a limited number of hours per day when inlet air cooling is needed. TES can reduce overall capital costs because it reduces the chiller capacity requirements as compared to the capacity required to match the instantaneous on-peak demand for cooling. Since the chillers in TES systems are operated during the off-peak period using low-cost electricity for charging the TES tank, such a system increases the net power capacity during the on-peak period.

Absorption Cooling systems are similar to the mechanical refrigeration systems except that instead of

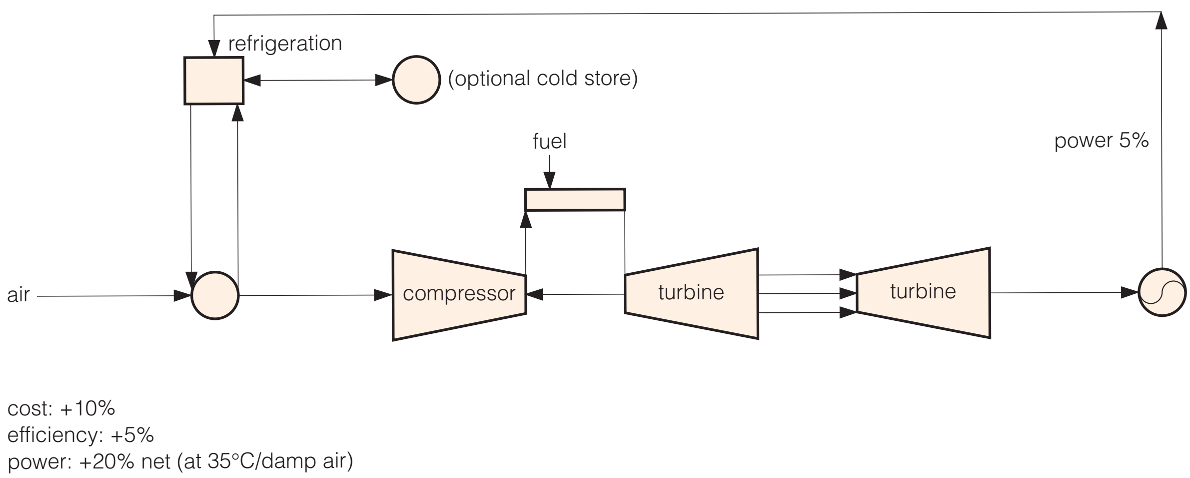


Figure 12 Principle of inlet chilling by refrigeration (Mee, 1999)

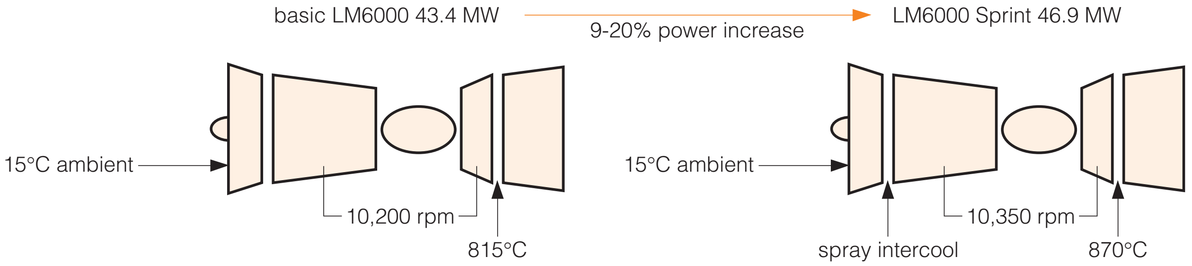


Figure 13 Schematic of SPRINT technology (GE Aero Energy Products, 2011)

using mechanical chillers, these systems use absorption chillers that require thermal energy (steam or hot water) as the primary source of energy and require much less electric energy than the mechanical chillers. Absorption cooling systems can be used to cool the inlet air to about 10°C. These systems can be employed with or without chilled water TES systems. Absorption chillers can be single-effect or double-effect chillers. The single-effect absorption chillers use hot water or 1 bar steam while the double-effect chillers require less steam but need the steam at higher pressure (8 bar). Compared to mechanical chillers, absorption cooling systems have lower parasitic loads but higher capital costs. The primary successful applications of absorption chillers in power plants are where excess thermal energy is available and can be utilised for this application.

3.5 Spray-Intercooled (SPRINT)

Another variant on increasing the kinetic energy of the input stream is GE Power's SPRINT system which is based on an atomised water spray injected through spray nozzles into the compressor (GE Aero Energy Products, 2011). Water is atomised using high-pressure air taken off the eighth stage air bleed. The water-flow rate is metered, using the appropriate engine control schedules (*see* Figure 13). This technology is claimed to significantly increase the mass airflow by cooling the air during the compression process. The result is more power, a better heat rate and a gas turbine without any increase in maintenance costs. At higher ambient temperatures SPRINT's effectiveness is claimed to increase; in hot weather power output is increased by 9% at ISO and is increased by more than 20% where the temperature exceeds 28°C.

3.6 Intercooled (ICAD)

The CAGT intercooled aeroderivative (ICAD) engine is based on intercooling aeroderivative engines (for example, the GE 90, PW4000, and the Rolls-Royce Trent). In aircraft form, these engines operate with multiple fan stages on one shaft, the HP compressor on a second shaft, and with overall pressure ratio >30. The premise was to replace the fan stages with a LP compressor and increase the overall pressure ratio (>40) by 'zero staging' the LP compressor, then intercooling between the LP and the existing HP compressor. Power outputs would be in the 100–125 MW range with efficiencies >45%. (Rao and others, 2006) The major mechanical changes from aircraft to ground-based engine involved a new LP compressor using lower cost materials, combustor changes to meet NOx emissions, some HP turbine changes to handle increased flow and to reduce cost, and a new, lower cost LP turbine to expand to atmospheric pressure. Additional shaft length to accommodate scrolls for the intercooler would also be needed. The key to keeping development costs to a minimum was keeping gas path the same, thereby allowing the compressors, especially the high compressor to remain unchanged, except for materials.

3.7 Humid Air turbine (AHAT cycle)

AHAT is an abbreviation of 'advanced humid air turbine,' a gas turbine system that uses humid air. Whereas in conventional combined cycle gas turbine plants the exhaust heat from the gas turbine is used to produce steam and drive a steam turbine, AHAT plants use a humidifier to increase the moisture content of the compressed air used in combustion to increase the output of the gas turbine. The basic concept of an AHAT system is shown in Figure 14. A water atomisation cooling (WAC) system is installed at the intake air channel of the compressor. A portion of the atomised water droplets evaporate at the compressor entrance where they provide intake air-cooling. The remaining droplets evaporate during compression inside the compressor and mitigate the rise of the air

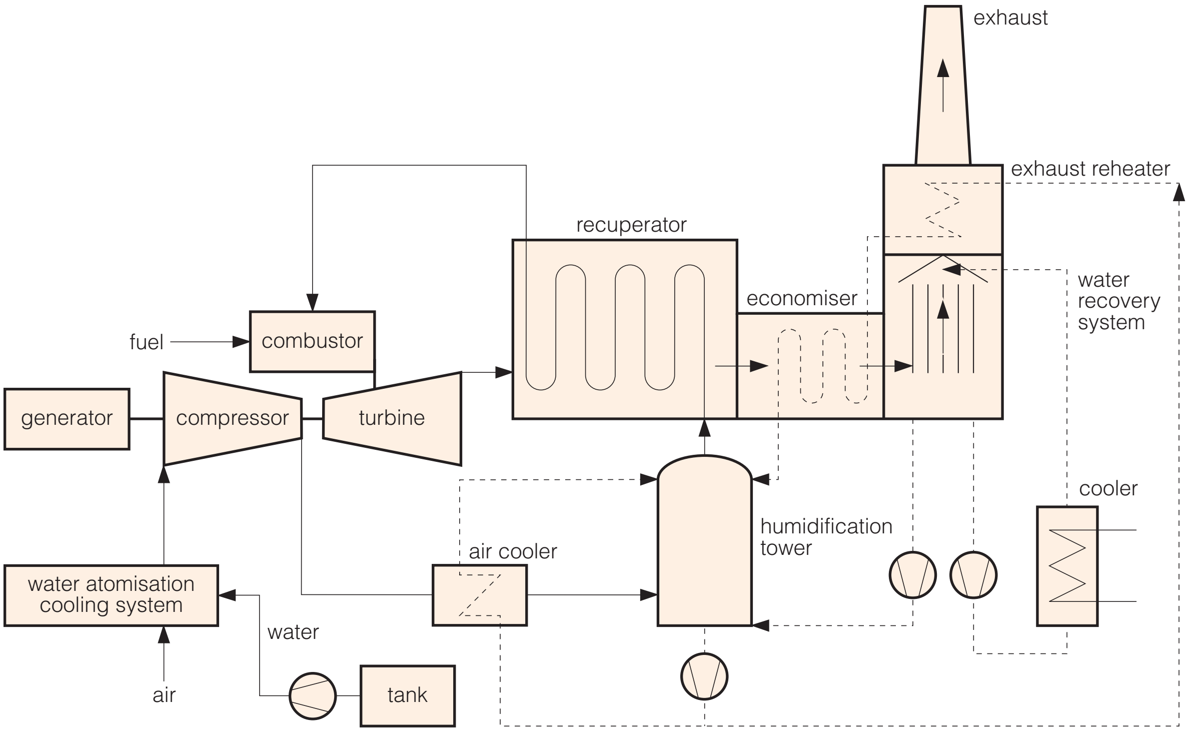
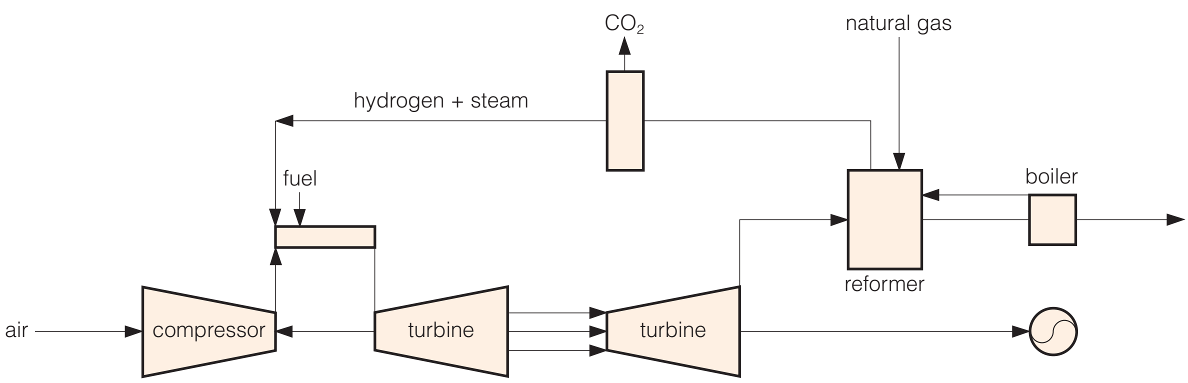


Figure 14 AHAT cycle (Ikeguchi and others, 2010)



cost: +30%
efficiency: +9%
power +30%

Figure 15 CRGT cycle (Nakagaki and others, 2003) temperature. The moisture then contacts the warm water in the humidification tower, exits the compressor and passes to the air cooler. Thus, the flux and specific heat of the working fluid increase and turbine power correspondingly increases.

This approach is claimed to provide high efficiency, low cost and good operating characteristics because it does not require an exhaust gas boiler or steam turbine and can effectively recover the exhaust heat downstream of combustion in the gas turbine and use it to generate electricity. The use of a high-humidity combustion unit also achieves a low level of NOx without using NOx scrubbers (Ikeguchi and others, 2010). The AHAT cycle has a claimed thermal efficiency as high as combined cycle, even though it has no steam turbine.

3.8 Chemically Recuperated GT (CRGT cycle)

Small- and medium-sized gas turbines are widely used for distributed power and combined heat and power. However, must of their generating efficiencies are less than 35% because of the use of a simple cycle. Chemically recuperated gas turbine (CRGT) is an advanced cycle, which recovers exhaust heat by endothermic reaction converting fuel into hydrogen-rich gas, and several workers report that CRGT would be an effective route to improving the generating efficiency of the simple cycle GT. Also, CRGT using methanol steam reforming has been demonstrated, but the components and system operation have not been assessed with a syngas feed. In studies with a natural gas feed a chemically recuperated system was implemented on a commercial 4 MW simple cycle GT and the effects of several parameters on the static mass and heat balance surveyed. On the basis of a typical mass and heat balance, a heat recovery reformer was designed by numerical analysis considering mass and heat transfer and chemical reactions (Nakagaki and others, 2003). On the downside, the CRGT is a highly advanced concept and a complex system requiring considerable process expertise(*see* Figure 15).

3.9 Summary

Gas turbine technology is fundamental to the overall process efficiency of coal gasification plant. Continuous development has pushed inlet temperatures and pressures ever higher, with concomitant increases in efficiency. In parallel with these developments, a number of techniques have been developed to improve the efficiency of existing gas turbines, often under particular conditions local to the site of operation. Additionally, improvements in emissions control technologies closely tied to the turbine operation ensure compliance with existing and probable future regulations.

4 Cycles for enhanced power generation

4.1 Advanced IGCC/IGFC with energy recovery technology

A new development under way in Japan aimed at increasing the efficiency of the coal gasification plants is the A-IGCC/A-IGFC (Advanced IGCC/IGFC) system that directs recycled heat from gas turbines or fuel cells back into steam reforming gasifiers designed for enhanced exergy recovery (exergy is the maximum useful work possible during a process that brings the system into equilibrium with a heat reservoir). Figure 16 shows the concept of recovering thermal energy based on the exergy concept (Iki and others, 2009).

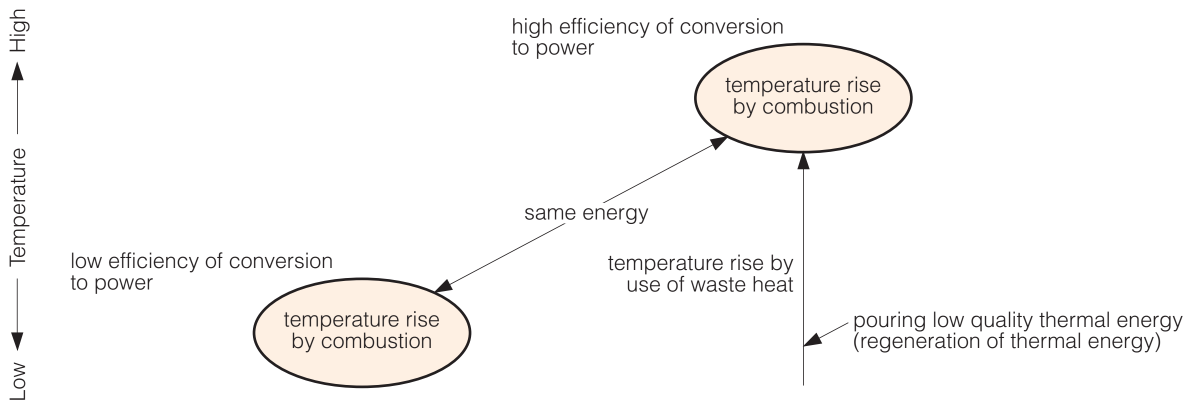


Figure 16 Concept of recovery of low quality thermal energy (Iki and others, 2009)

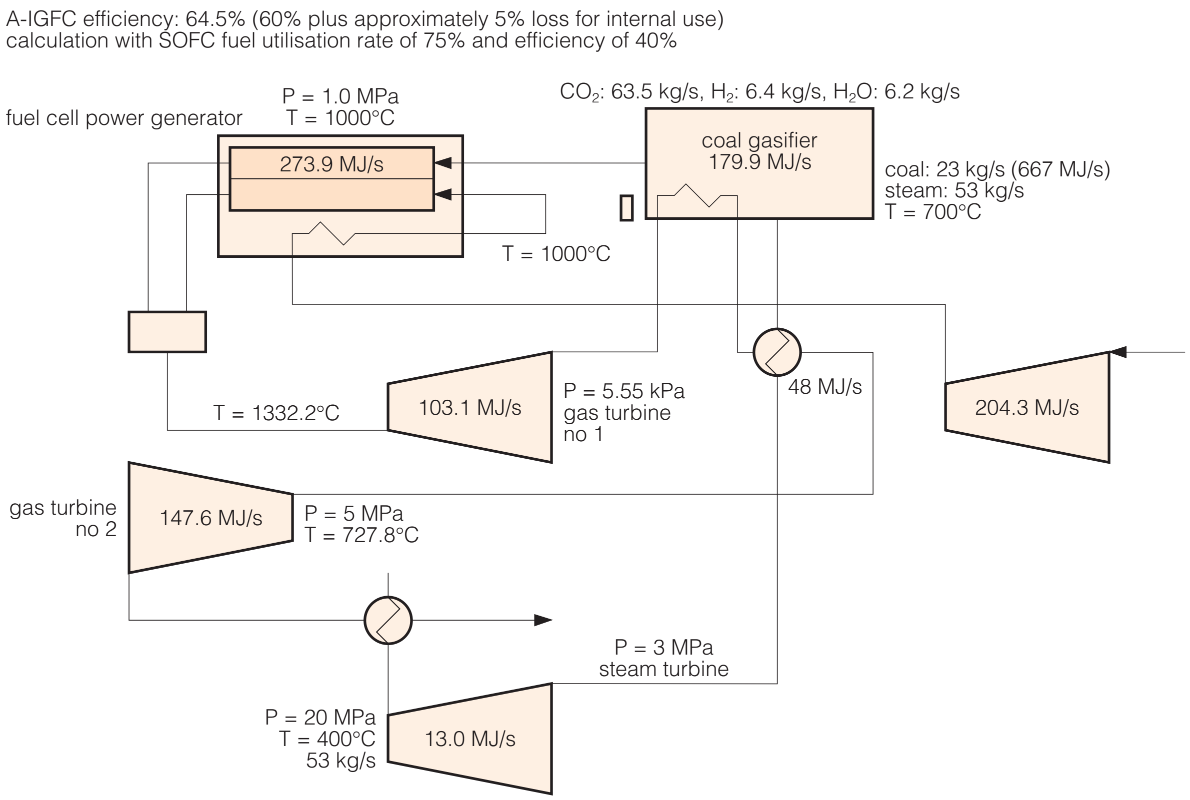


Figure 17 Schematic drawing of a basic A-IGFC process (Iki and others, 2009)

With exergy recovery, the A-IGCC, using 1700°C gas turbines, is expected to provide a generation efficiency of 57% and the A-IGFC, employing fuel cells, is expected to provide a generation efficiency as high as 65%. Figure 17 sets out the basic A-IGFC processes. The existing IGFC, integrates a gasifier, fuel cells, gas turbines and a steam turbine into a cascade-based system.

Hydrogen-rich gas produced in the gasifier is purified and then sent to the fuel cell. Part of the fuel gas that has not been used in the fuel cell unit is transferred to the gas turbines for power generation. However, this process results in a low fuel utilisation rate, and the inlet temperature of the gas turbines is limited to approximately 1100°C; thus the power generation efficiency is only around 55%. In the exergy-recovering concept the IGFC reuses the high-temperature heat generated by the fuel cells in the gasifier for steam reforming gasification by making use of an endothermic reaction. Figure 18 sets out the energy flows underlying this principle.

The exhaust gas of the gas turbine supplies the endothermic heat of steam reforming – energy and exergy are transferred to hydrogen from the coal and exhaust gas in the reformer. Figure 19 shows the basic layout of an IGCC incorporating the principle of chemical recuperation.

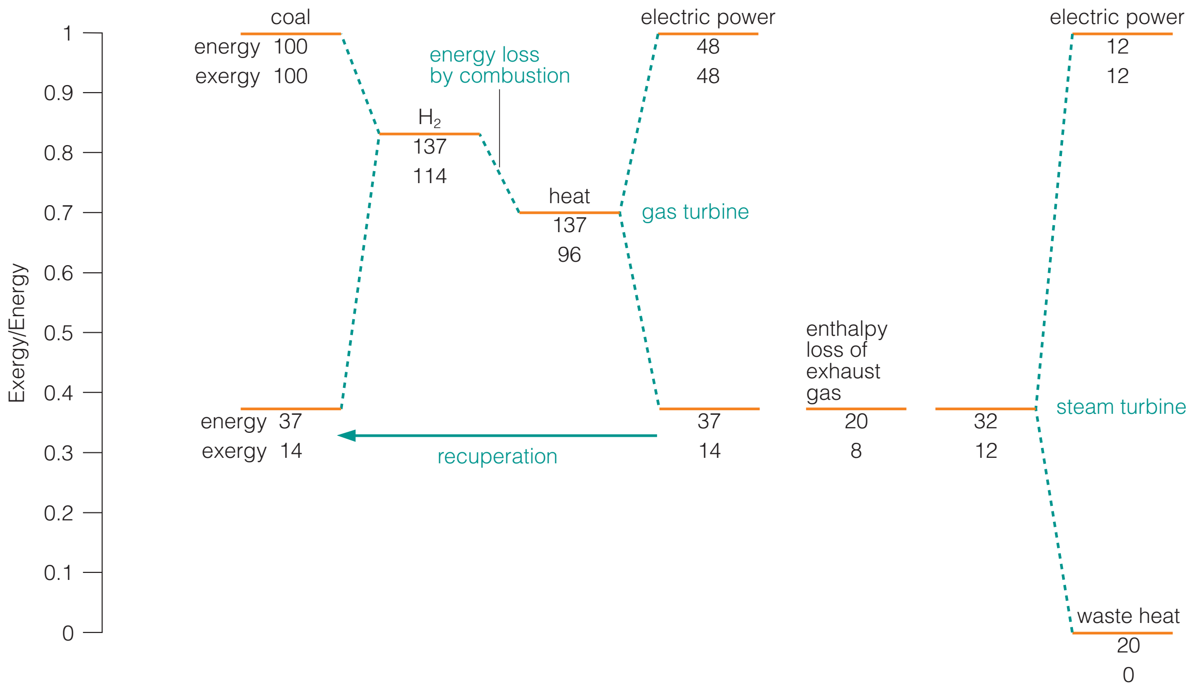


Figure 18 Energy flows in IGCC with recuperation (Iki and others, 2009)

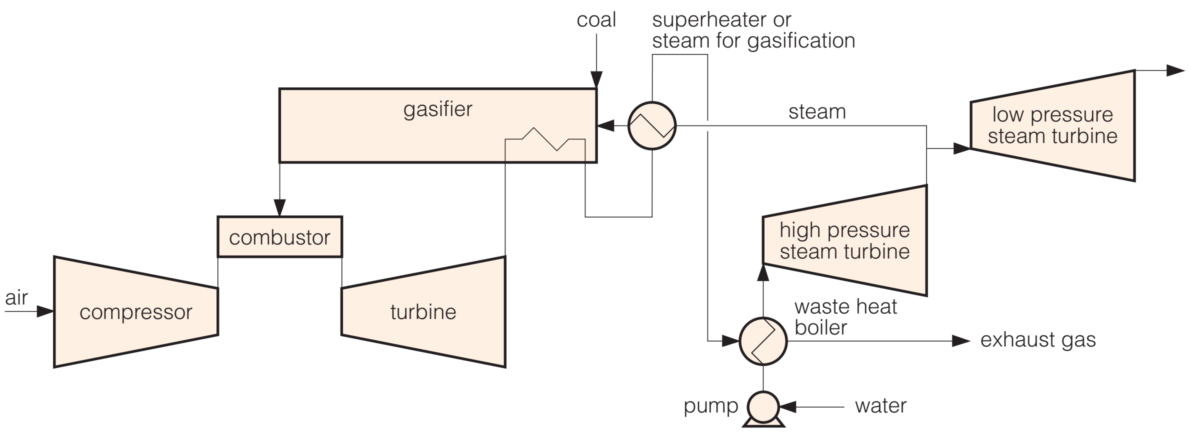


Figure 19 Basic structure of IGCC with chemical recuperation (Iki and others, 2009)

Table 1	**Properties of coal used in process simulation** (Iki and others, 2009)
Carbon, %	69.4
Hydrogen, %	4.9
Total sulphur, %	0.1
Combustible sulphur, %	0.04
Non-combustible sulphur, %	0.06
Nitrogen, %	0.9
Oxygen, %	24.7
Higher heating value, kJ/kg	28200
Specific heat, kJ/kg-K	1.8

Table 2 Gasifier conditions (Iki and others, 2009)

	normal	autothermal
Supply		
Coal, kg/s	23.63	23.63
°C	25	200
O_2, kg/s	10.6	7.9
°C	25	25
H_2O, kg/s	16.4	16.4
°C	700	700
Heat, MJ/s		41
Product, kg/s		
CO	29.2	30.0
CO_2	10.0	8.7
H_2	1.8	2.1
CH_4	0.8	0.8
C_2H_4	0.3	0.3
C_2H_6	0.05	0.05
C_3H_6	0.24	0.24
HCN	0.14	0.14
N_2	0.1	0.1
H_2O	8.0	5.5
Temperature, °C	841	831

In a detailed study of the this concept, an Aspen process simulator HYSYS, was used for cycle simulation of a unit based on a circulating fluidised bed gasification system with a steam reforming coal gasifier and a partial combustion stage for the gasification char. A subbituminous coal was selected for study and its elemental analysis is given in Table 1. Autothermal condition required 41 MW of heat input while the selected coal's energy content was 23.63 kg/s, (667 MW). The temperature of the coal was 200°C, hence the sensitive heat of the coal supplied from waste heat is about 7.4 MW (1.1%) [HHV].

Gasification of the coal was assumed to take place in two stages: heating and steam reforming of coals in the gasifier, followed by the oxidation of the remaining char by pure oxygen in a partial oxidation furnace. The circulating fluidised bed materials and unburnt chars supply endothermic heat for reforming from the partial oxidation furnace to the gasifier. Pure oxygen is supplied at the stoichiometric ratio for char combustion in the partial oxidising furnace. The temperature of the partial oxidising furnace is 950°C and steam was supplied to the gasifier at a temperature of 700°C. The temperature of the gasifier was 800°C. Gasifier conditions were fixed as given in Table 2. The hydrogen-rich gas produced in the gasifier and the CO rich gas produced in the partial oxidising gas were mixed and supplied to the gas turbine combustor. The mixed gas temperature was 841°C at normal conditions.

The aim of the study was to estimate the basic performances of IGCC and A-IGCC with the subbituminous coal to provide information for the design of components for an A-IGCC plant. Therefore, simple models were employed for the gas and steam turbines. The adiabatic efficiencies of the turbine and compressor were set so that the efficiency of 1500°C IGCC was 48% (HHV) and its electric power 320 MW as the base case. The net efficiency of the IGCC was 43% (HHV) with power for station operation fixed at 5% (HHV). In this case, the adiabatic efficiency of a compressor gas turbine compressor is 80%, the adiabatic efficiency of a turbine of a gas turbine is 85%, the adiabatic efficiency of a steam turbine is 88%, and the adiabatic efficiency of a condensation turbine is 86%.

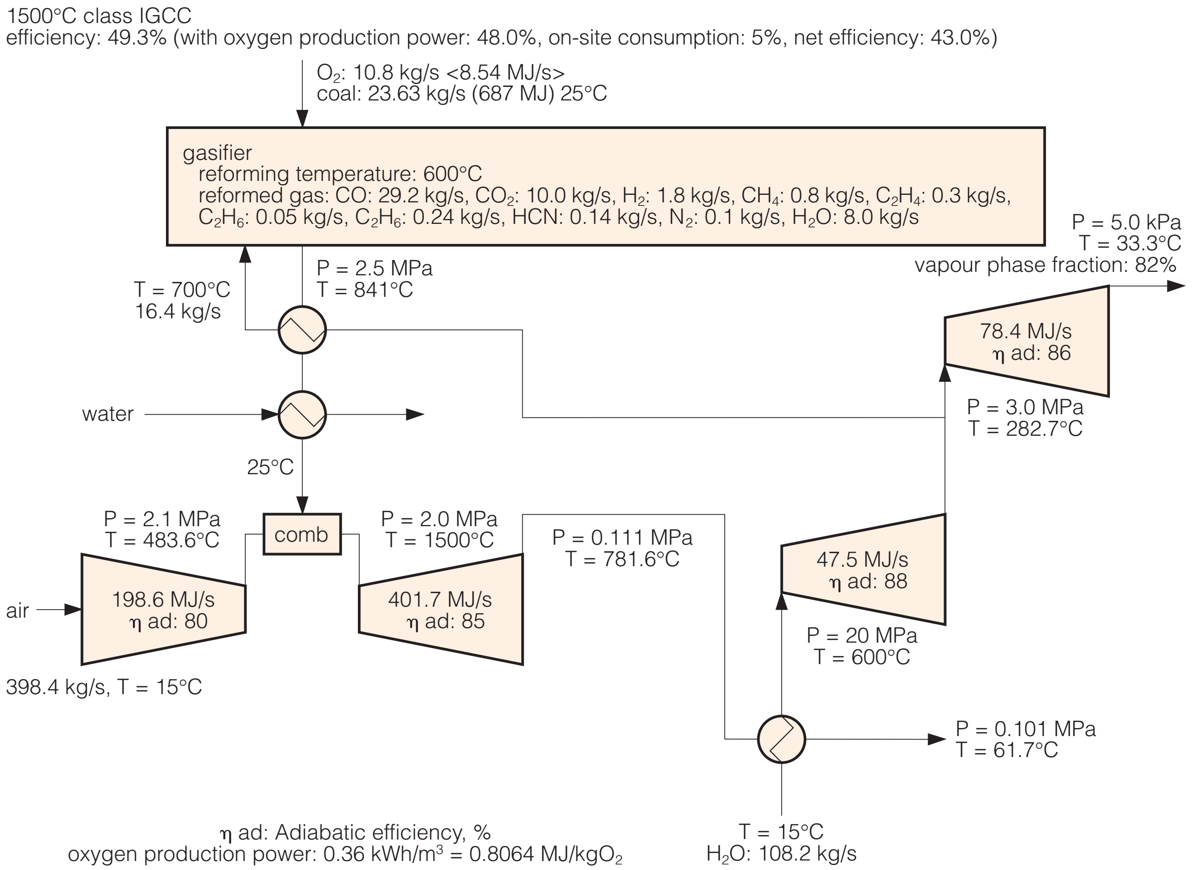


Figure 20 Performance of 1500°C class IGCC (Iki and others, 2009)

Figure 20 shows the standard case of a 1500°C class IGCC. The output of the gas turbine is 203 MW and the output of the steam turbine is 116 MW.

A simulation of the IGCC operated under autothermal conditions gave a significant increase in output (*see* Figure 21).

Hydrogen and carbon monoxide were shown to increase and steam decreased in the reformed gas mix. The output of the gas turbine was 218 MW and the output of the steam turbine was 136 MW. The increase of the power of the steam turbine was found to be larger than that of the gas turbine. If hot gas clean-up technologies can be developed, hot reformed gas can be supplied to the gas turbine combustor and the thermal efficiency of A-IGCC can reach 56.7% (HHV) as shown in Figure 22.

In this case the output of the gas turbine is 233 MW and the output of the steam turbine is 141 MW. Eventually, if gas turbines are developed that accept a gas inlet temperature of 1700°C, 1700°C class A-IGCC becomes possible (*see* Figure 23).

4.2 Oxy-fuel IGCC system with CO_2 recirculation for CO_2 capture

A novel concept aimed at incorporating the principles of flue gas recirculation to IGCC for CO_2 capture has been described by Oki and others (Oki and others, 2011). Figure 24 outlines the concept the ‘oxyfuel IGCC system with CO_2 recirculation for CO_2 capture’. This process claims a significant advantage compared to conventional configurations in that a shift reactor and CO_2 capture unit are not required.

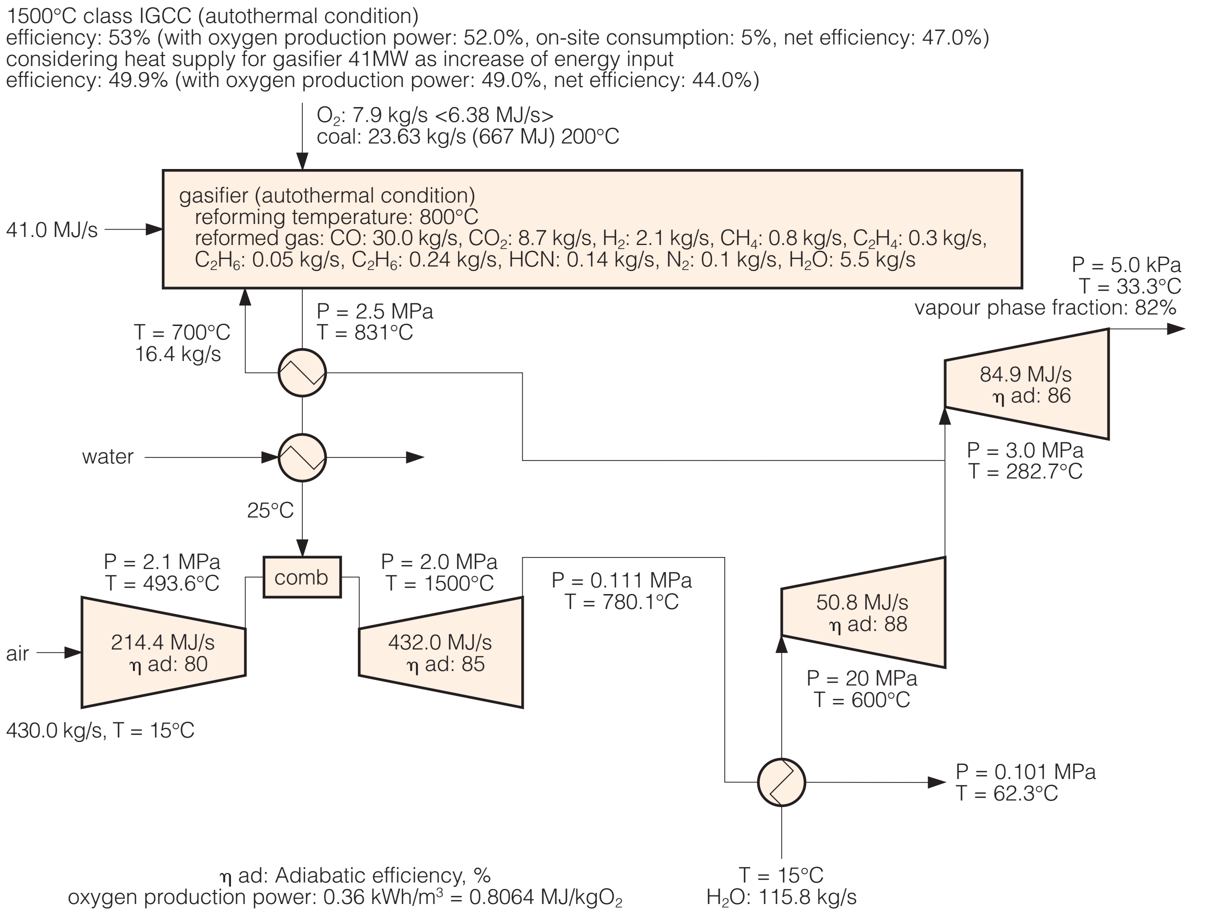


Figure 21 Performance of 1500°C class IGCC under autothermal condition (Iki and others, 2009)

Figure 25 shows a more detailed schematic of a system based on this concept (Shirai and others, 2007). Recycled flue CO_2 gas is used to feed pulverised coal into a gasifier together with some oxygen. The gas turbine combustor is a so-called ‘closed gas turbine’, using recycled flue gas with some added oxygen. Exhaust gas from the turbine consists mainly of CO_2 and H_2O, therefore after recovering heat in an HRSG, the required amount of flue gas is compressed and recycled to the gas turbine. The residual flue gas is fed to a water scrubber, Hg removal system and mist separator. After these treatments the flue gas becomes rich in CO_2. Process flue gas is bled off for gasification and combustion, and the residue is compressed and sent to a storage site.

Figure 26 sets out the claimed improvements in efficiency that arise from the absence of a shift converter and CO_2 separation unit.

Since CO_2 can act as a gasification agent, the increase of CO_2 concentration in the gasifier is claimed to enhance the efficiency of the gasifier, compared to that of an oxygen-blown unit.

The high concentration of CO_2 in the gasification step is clearly an area for study and CRIEPI have been undertaking work to analyse reactions of this type under high pressure in a pressurised drop tube furnace, PDTF (*see* Figure 27).

CRIEPI have estimated potential improvement in cold gas efficiency of 2% and a drastic reduction in the formation of char (*see* Figure 28) attributable to the gasification reactions enhanced by higher concentrations of CO_2. In planned further studies, CRIEPI’s 3 t/d gasifier will be used in conjunction

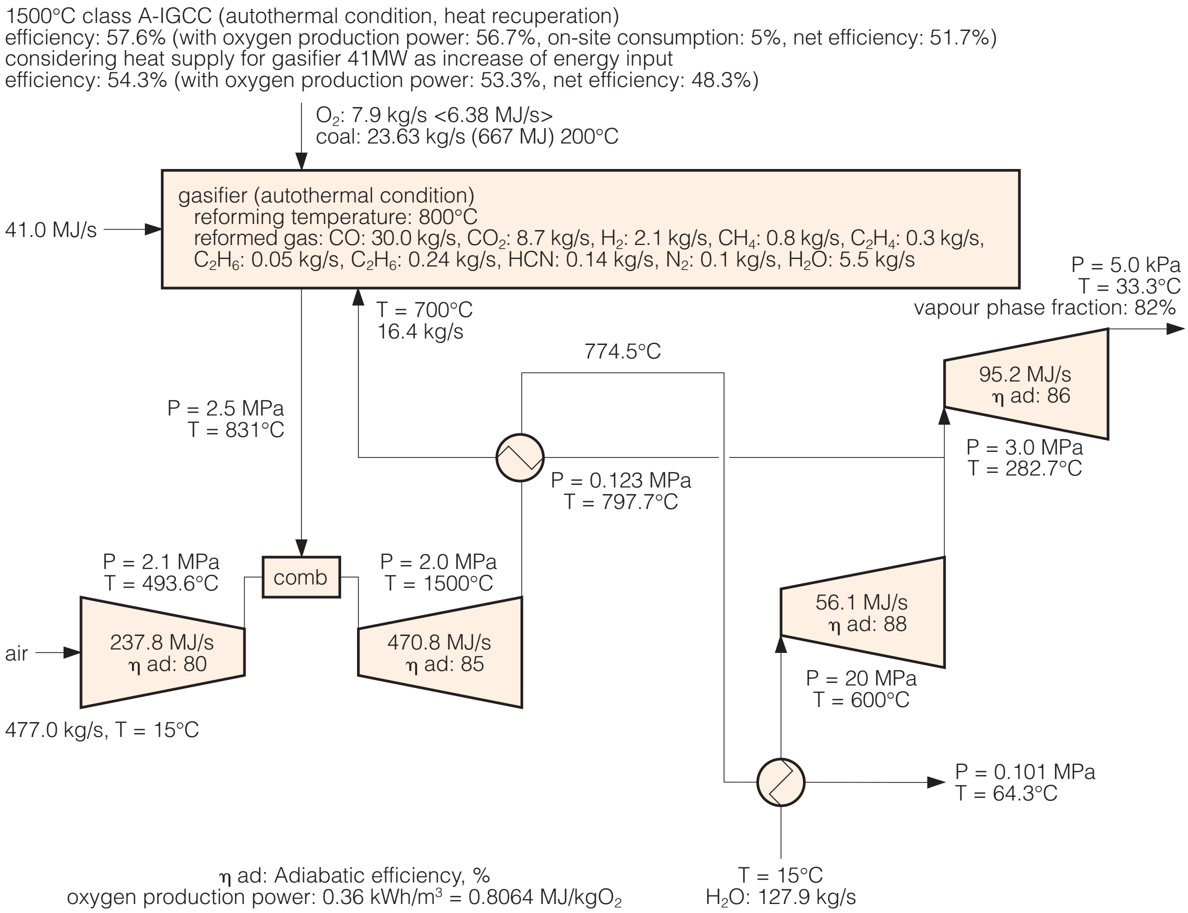


Figure 22 Performance of 1500°C class A-IGCC (Iki and others, 2009)

with an online sampling scheme. This gasifier is essentially a two-stage air-blown unit, but it can vary O_2 concentration between 0% and 30%. Recent modifications in the form of a CO_2 gas supply system will facilitate evaluations of the effect of CO_2 gas on coal gasification performance.

A potential drawback of a high CO_2 gasification based system is carbon deposition, because deposition in the desulphurisation matrix may deteriorate the catalyst. To clarify the risks of carbon deposition and develop a method to prevent the deterioration of the catalyst, further studies are planned

4.3 'Coal without carbon' next generation technologies

In their recent review on the prospects for 'Coal without Carbon' the Pettus and others (2009) profiled seven selected advanced 'next generation' gasification technologies that were considered to offer advantages over the technologies currently in operation, or near commercialisation. The technologies were:

- Bluegas™ from GreatPoint Energy – a method for producing substitute natural gas directly from coal and other carbonaceous materials using a single fluidised bed gasifier with an entrained catalyst.
- Calderon Process from Energy Independence of America Corporation – a method for producing dual streams of clean synthesis gas (or 'syngas') – one hydrogen-rich, one carbon monoxide-rich – from the staged pyrolysis of coal and other carbonaceous material followed by air-blown slagging gasification of the char.

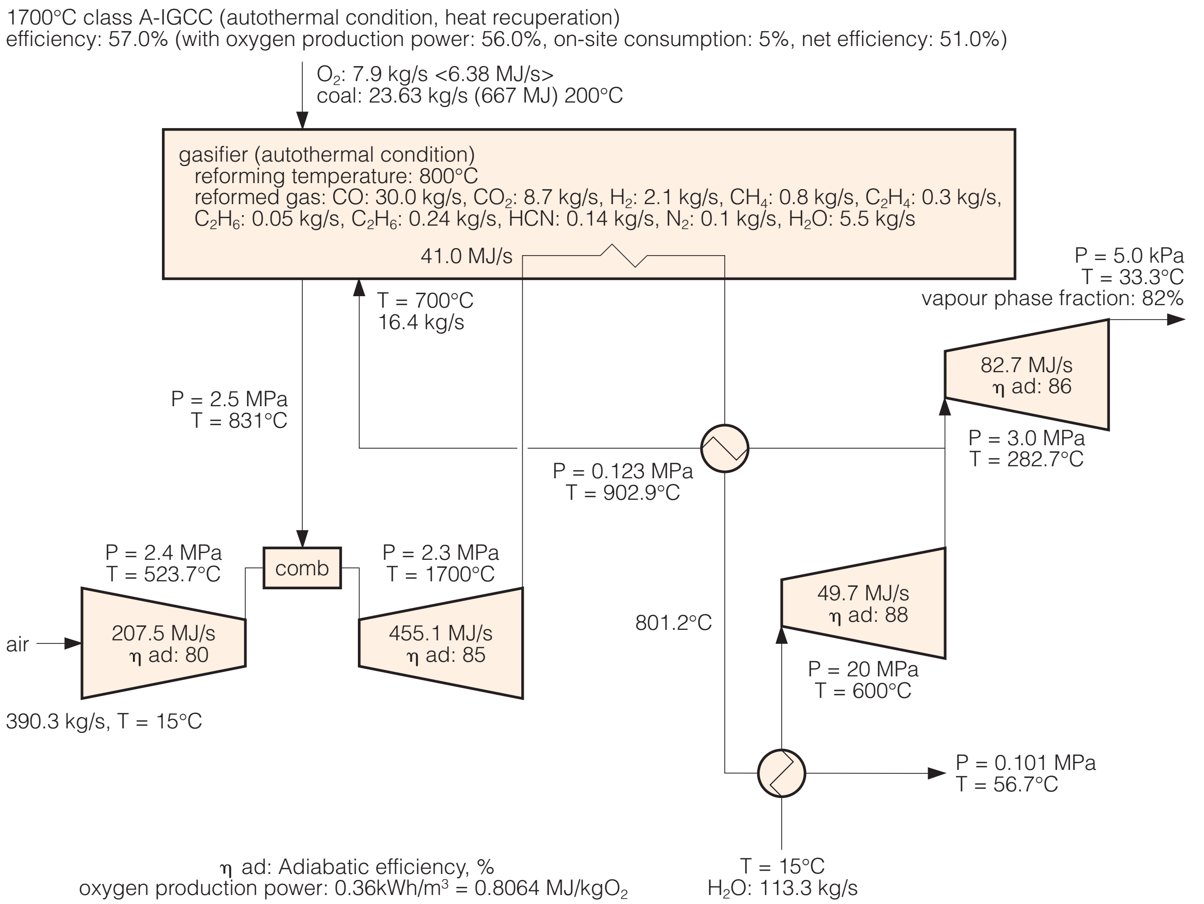


Figure 23 Performance of 1700°C class A-IGCC (Iki and others, 2009)

- Viresco Process (formerly the CE-CERT process) from Viresco Energy – a method for producing syngas for chemicals production and power generation using thermally-forced steam hydrogasification of moist carbonaceous fuels coupled with steam methane reforming.
- HTHG from ThermoGen Hague – a process for producing substitute natural gas from low-rank coal using very high temperature steam gasification without significant oxygen.
- HydroMax from Alchemix – a method for producing synthesis gas from coal and other carbonaceous materials using molten bath technology adapted from the metal smelting industry;
- Wiley Process from SynGasCo – a method for producing synthesis gas from coal and other fuels using pyrolysis, gasification, and non-catalytic syngas reforming at moderate temperature and low pressure without the addition of external oxygen.
- Ze-gen – a method of producing synthesis gas from organic waste and other carbonaceous materials using liquid metal gasification technology drawn from the steel industry.

More detailed comments on each of these technologies drawn from the review follow.

4.3.1 Bluegas™ from GreatPoint Energy

The Bluegas™ process from GreatPoint Energy – called 'hydromethanation' – uses a fluidised bed reactor to produce substitute natural gas (SNG, predominantly methane) directly from carbonaceous material using an integrated set of thermally-balanced, catalyst-promoted gasification and methanation reactions. The overall thermal efficiency of the single-step process is claimed to be much higher than more conventional SNG production which relies on separate processing steps for

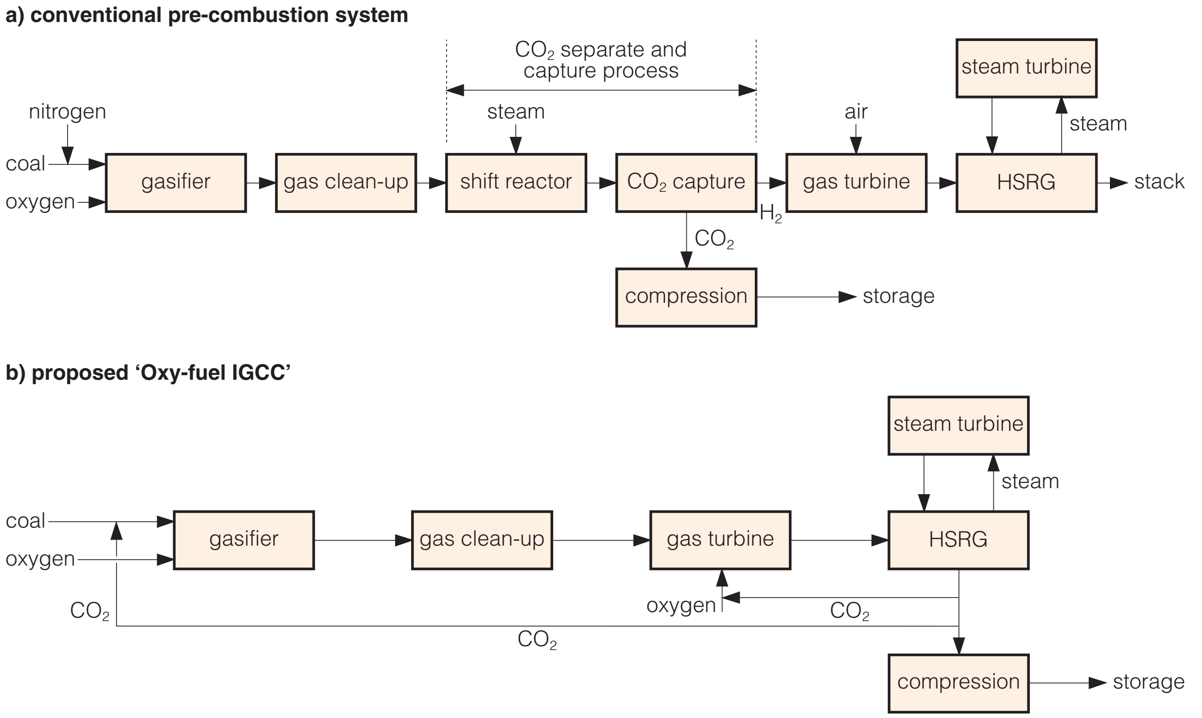


Figure 24 Concept of newly proposed 'Oxy-fuel IGCC' (Oki and others, 2011)

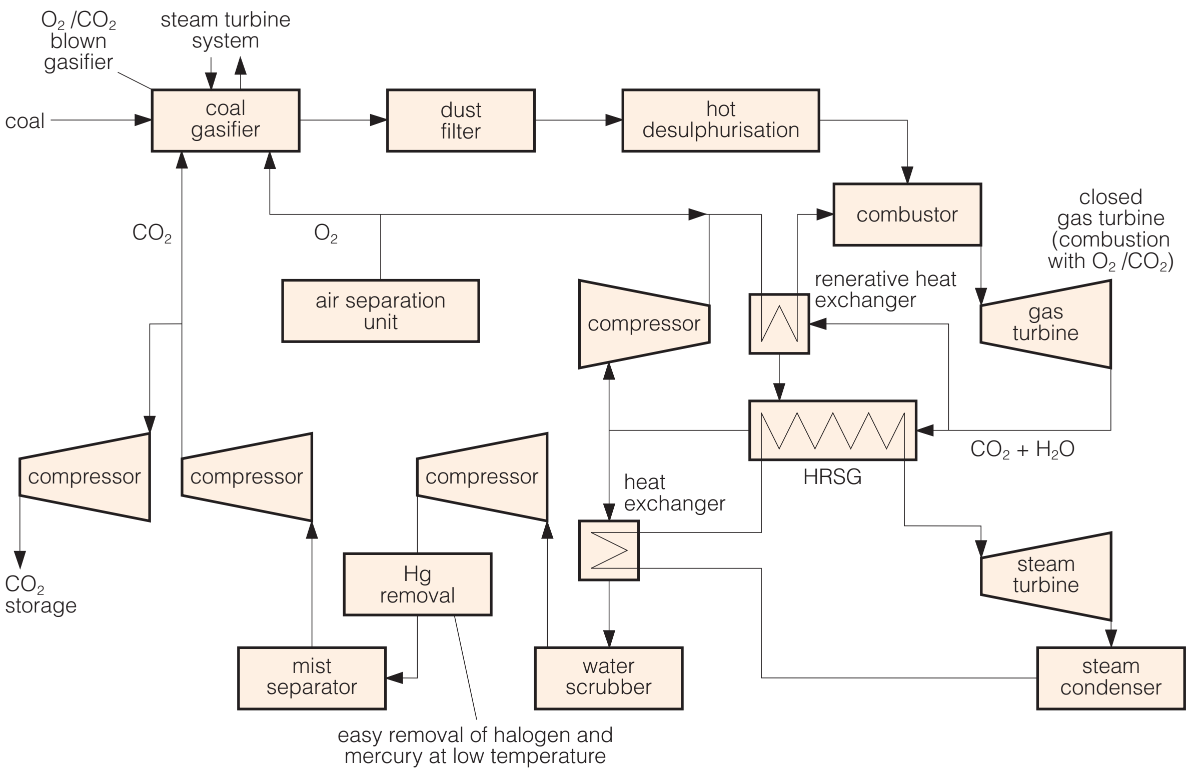


Figure 25 Detailed schematic diagram of newly proposed 'Oxy-fuel IGCC' (Shirai, and others 2007)

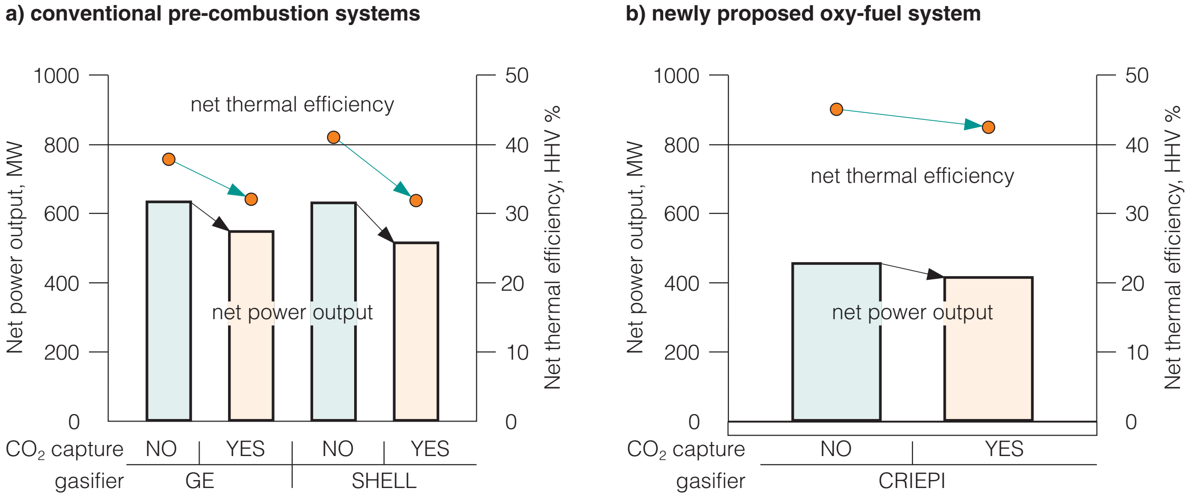


Figure 26 Comparison of thermal efficiency and net power output (Shirai and others, 2007)

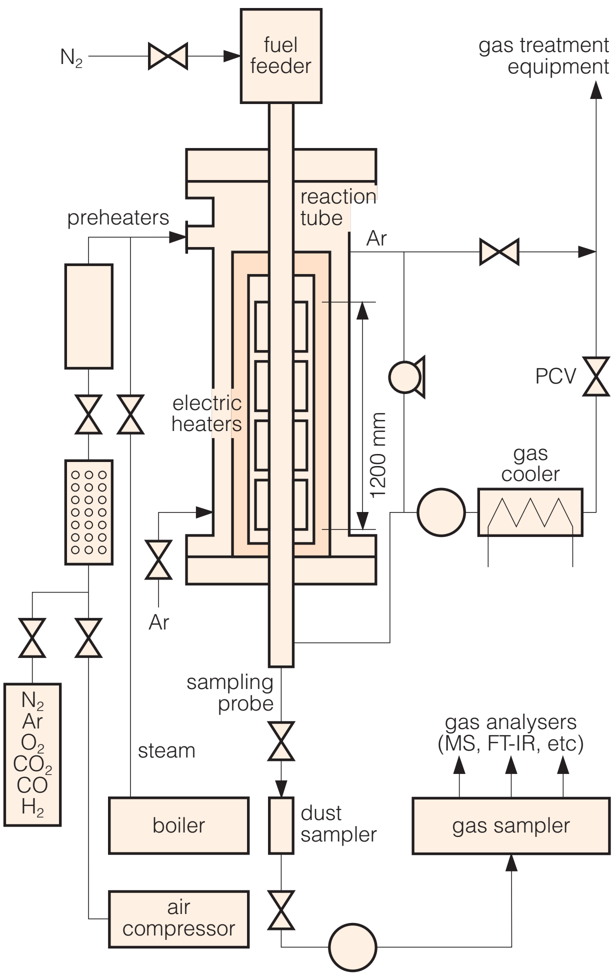


Figure 27 Schematic diagram of CRIEPI PDTF (Oki and others, 2011)

gasification, water-gas shift, and methanation. Conventional technologies can separate CO_2, sulphur, and other impurities from the methane produced, resulting in pipeline quality natural gas. GreatPoint reports that coal (including Power River Basin subbituminous), petcoke, and biomass can be used with the process. GreatPoint has leased a 1–3 t/d flex-fuel gasifier at the Gas Institute in Illinois to perform testing on a range of feedstocks. These tests are reported to have validated the performance characteristics of the hydromethanation process.

The chemistry of catalytic hydromethanation involves reacting steam ($2H_2O$) and carbon (2C) to produce methane (CH_4) and carbon dioxide (CO_2) according to the following reaction:

$$2C + 2H_2O \rightarrow CH_4 + CO_2$$

The first step in the hydromethanation process is to combine the catalyst with the feedstock to ensure that the catalyst disperses throughout the matrix of the feedstock for effective reactivity. The catalyst/feedstock material is then loaded into the hydromethanation reactor where pressurised steam is injected to fluidise the mixture and ensure constant contact between the catalyst and the carbon particles. In this environment, the catalyst facilitates multiple chemical reactions between the carbon and the steam on the surface of the coal or biomass.

These reactions (shown below) catalysed in a single reactor and at the same low temperature, generate a mixture predominately composed of methane and CO_2.

steam carbon $C + H_2O \rightarrow CO + H_2$

water gas shift $CO + H_2O \rightarrow H_2 + CO_2$

hydrogasification $2H_2 + C \rightarrow CH_4$

The overall combination of reactions is thermally neutral, requiring no addition or removal of energy, making it highly efficient. The proprietary catalyst formulation is claimed to be produced from abundantly available, low-cost metal materials specifically designed to promote gasification at the low temperatures where water gas shift and reactions concurrently take place. The catalyst is continuously recycled and reused within the process (shown in Figure 29).

As part of the overall process, the Bluegas™ technology claims to be able to recover contaminants in coal, petroleum coke and biomass as useful by-products. In addition, roughly half the carbon in the feedstock is removed and captured as a pure CO_2 stream suitable for sequestration.

A Bluegas™ demonstration facility for testing a wide range of feedstocks has recently entered commercial operation in Somerset, Massachusetts, and the company reports that external technical review indicates the process is ready for scale-up to commercial application. Plans are in place for a commercial demonstration project in China with a large power company and GreatPoint is investigating other opportunities in North America.

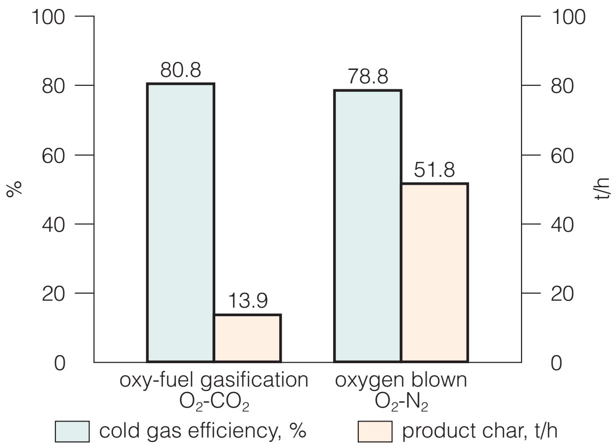


Figure 28 Comparison of estimated gasification performance (Oki and others, 2011)

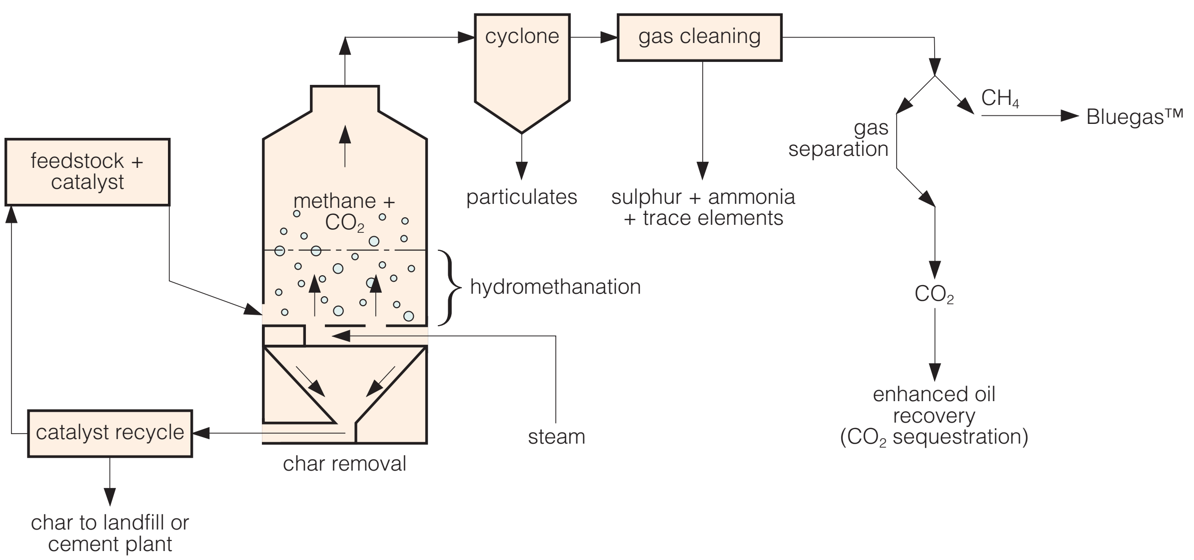


Figure 29 Bluegas™ hydromethanation process (Pettus and others, 2009)

4.3.2 Calderon Process from Energy Independence of America Corporation

The Calderon Process under commercialisation by Energy Independence of America Corporation (EIAC) uses a sequence of pyrolysis reactors and hot char gasifiers to produce two distinct syngas streams – a hydrogen-rich stream from the pyrolysis reactions and a low-energy stream from the char gasifiers – with the former suited to methanol or other chemicals production and the latter suited to power generation in a combined cycle gas turbine (CCGT) (*see* Figure 30). The technology has developed out of coking and blast furnace experience in the steel industry. Crushed, run-of-mine coal is fed without pre-treatment into a horizontal pyrolysis reactor with small amounts of oxygen followed directly by gasification of the hot, porous char in a vertical air-blown slagging gasifier. The company reports that any type of coal can be used, and multiple configurations are possible (for example, electric power, liquids, SNG). EIAC has developed a proprietary sorbent-based hot gas clean-up technology for use with their process, and is involved in development of a process to convert residual nitrogen and CO_2 in combustion flue gas into fertiliser. A demonstration unit with capacity of approximately 10 t/h was operated at reduced throughput in the late 1980s and early 1990s in Alliance, Ohio, and EIAC reports that the pyrolysis, char gasification, and solids handling aspects of the technology were demonstrated successfully, as was the proprietary hot gas clean-up system. The process has been evaluated on a confidential basis by Bechtel Corporation and other commercial entities, and a conceptual design for a 640 MWe (net) commercial power plant has been developed.

Calderon (Calderon, 2007) report several advantages of the process over alternative systems, specifically:
- low oxygen usage – 10% of O_2-entrained flow gasification systems;
- gas with mass for higher efficiency in power generation at the combined cycle;
- modular technology with built-in redundancy;
- four reactors connected to two char gasifiers, can be operated in any combination;
- flexibly scaleable;
- refractory life expected to be similar to blast furnace lining life (13 to 18 years);
- lower capital and operating costs.

The Calderon Process is calculated to be 23% more efficient in converting coal to power than oxygen-

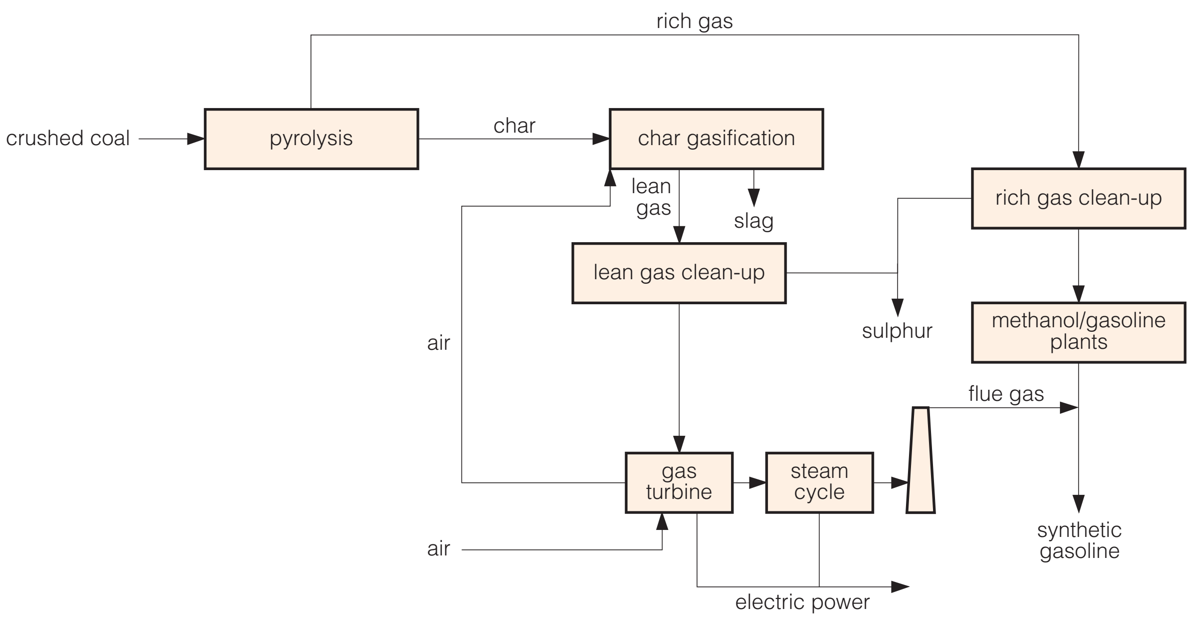


Figure 30 Schematic diagram of the Calderon Process (Calderon, 2007)

blown entrained flow systems and no shift reaction is required to convert syngas to methanol. Solid carbon is produced as a char by-product and may be steam activated for use as an absorbent, for example as an in-house source of activated carbon for mercury control and for other chemical uses. The lean gas presents much lower NOx combustion emissions than natural gas and is similar to blast furnace gas. It is claimed that conventional sulphur recovery and removal are not required.

4.3.3 Viresco Process from Viresco Energy

The Viresco Process is a gasification technology based on a combination of steam hydrogasification and reforming. The process was originally developed by the Bourns College of Engineering – Centre for Environmental Research and Technology (CE-CERT) at the University of California, Riverside (UCR). The carbonaceous feedstock is first converted to a fuel gas, containing a significant quantity of methane. This is accomplished by means of steam hydrogasification, where the carbonaceous feed simultaneously reacts with steam and hydrogen. The fuel gas is then subjected to gas clean-up and then reformed to generate synthesis gas (carbon monoxide and hydrogen). In the third step, the synthesis gas is converted in to a synthetic fuel over a high-efficiency catalyst. Examples of such synthetic fuels are Fischer-Tropsch (FT) diesel, methanol and dimethyl ether (DME). The fuel gas can also be converted into electric power. The production of high energy density liquid fuels such as the FT diesel is the primary focus of Viresco Energy. The process is claimed to offer several advantages over conventional air or oxygen blown gasification in the usage of waste streams as feedstocks or co-feedstocks, and the process is attractive since oxygen is not required. The slurry feed enables the use of wet feedstock such as biosolids while comparable thermo-chemical conversion processes using wet feeds such as biosolids may spend considerable amount of energy on water removal. The co-utilisation of biosolids with higher energy content feedstocks such as coal is claimed to help to achieve the desired feed-to-water ratios. It is reported that external reviews of the technology have concluded that the Viresco Process has the potential for reduced capital costs and higher conversion efficiencies than conventional partial oxidation based processes. A 5 kg/h pilot demonstration unit is under development, and a 20 t/d pilot plant is proposed for Alton, Utah.

4.3.4 HTHG Process from ThermoGen Hague

ThermoGen Hague's high temperature hydrogasification (HTHG) process uses very high temperature steam raised in a hydrogen-fired furnace to convert carbonaceous feeds, especially reactive material like Power River Basin subbituminous coal, into hydrogen-rich syngas followed by hydrogasification to produce substitute natural gas. In one of its configurations, the process uses two moderate-pressure, moderate-temperature reactors in series, with hydrogen provided to the second (hydrogasification) reactor (and a boiler for raising steam) from shifted syngas produced in the first reactor. Coal is pulverised and is fed dry into the first reactor. The company reports that the process requires little or no external oxygen supply, that it does not depend on a catalyst in either of the reactors, and that syngas can be cleaned with conventional technology (including separation and compression of CO_2 produced from the water-gas shift reactor). Continuous production of steam exceeding 800°C in the hydrogen furnace is claimed to be possible by ThermoGen Hague's proprietary ceramic heat exchanger, which was developed by the company based on experience in high-temperature heat recovery in the secondary aluminium and steel industries. The company reports that other key elements of the technology have been demonstrated in other settings, including high-temperature steam gasification (by US Bureau of Mines in the 1940s and 1950s) and char hydrogasification (by GTI and others in the 1970s). The development of a bench-scale reactor is reported to be in progress.

4.3.5 HydroMax from Alchemix

The HydroMax process under commercialisation by Alchemix Corporation uses a molten bath

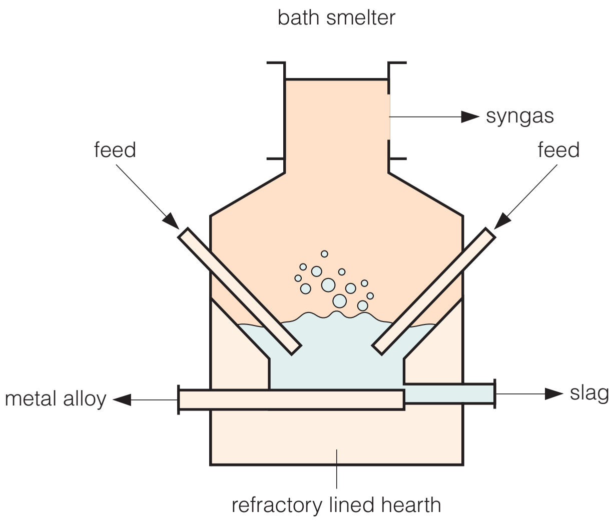


Figure 31 HydroMax process (Pettus and others, 2009)

technology adapted from the metal smelting industry to produce low pressure, high temperature, moderate-Btu syngas from carbonaceous (*see* Figure 31). Bath smelting technology is widely used to convert the oxides or sulphides of tin, iron, lead, zinc, copper and nickel into metal. Over 100 bath smelters are operating around the world. The popularity of bath smelters stems from their high reliability, low cost and control of emissions. In the HydroMax technology, hydrocarbons are injected into molten iron where the liquid or solid hydrocarbons injected are quickly reduced to syngas. Various other materials contained in the hydrocarbons, such as sulphur and mercury, will also be gasified and subsequently removed. Inert material such as calcium, silica and alumina will form a slag. This slag can be tapped periodically and made into saleable cement or bricks. Metals that may be contained in the hydrocarbon feed, such as nickel and vanadium, will be captured in the liquid phase, periodically tapped and ultimately recovered, as an enriched iron alloy. The company reports that cold gas efficiency of the gasification process can be as high as 84% for some high-Btu fuels when the company's proprietary 'chemical quench' (reaction of char and CO_2 to produce carbon monoxide) is used. The syngas produced by the process can be cleaned by conventional processes and used for production of hydrogen, substitute natural gas, or chemicals (such as methanol). In the process the molten bath acts as both a heat transfer medium and an oxygen carrier, splitting water molecules to produce hydrogen and to convert carbon to carbon monoxide gas. When materials such as petcoke are processed, metals recovery (for example nickel and vanadium) can be significant.

The HydroMax process has been developed since 2000 by a team including Alchemix, Pittsburgh Mineral and Environmental Technology, Commonwealth Scientific and Industrial Research Organisation (CSIRO), Diversified Energy, and others. The process has been tested in a 0.3 metre diameter pilot-scale bath smelter at CSIRO. To complete detailed design for a first commercial plant, a concept for a 1.0 metre diameter pre-commercial demonstration plant has been developed. Much larger bath smelters (8 metre diameter) are already in use in the metal smelting industry. Alchemix reports that the gasification and downstream processing have been modelled using Aspen-Plus and FactSage. Advantages claimed for the process include:

High thermal inertia

High thermal inertia is the result of the heat stability that is achieved by having a great mass of molten metal that is resistant to variations in moisture, energy or the ash content of feedstocks. Conventional gasification technology characteristically loses efficiency and reliability when there are substantial variations in feedstock moisture and thermal content. It is claimed that high thermal inertia allows HydroMax to be more efficient, reliable and flexible allowing the process to accept a wide variety of feedstocks and combinations of feedstocks;

Recovery of metal values

In some feedstocks, such as petroleum coke, there are commercial quantities of high value metals such as vanadium and nickel. These metals can be captured directly using HydroMax technology and sold as co-products. In these cases, the value of these metals may add substantially to the revenue received from the production of hydrogen, electricity or other primary products;

Recovery of cementitious materials

Fuels such as coal contain significant amounts of ash, mainly silica and alumina. The HydroMax technology requires the use of fluxing materials such as, calcium, in the form of lime or limestone. When slag is tapped periodically from HydroMax reactors, it may be used directly as cement or blended to make cement or bricks. The heat required to make cement conventionally is substantial, as is the carbon dioxide (CO_2) released in its production. By producing cement as a co-product of HydroMax operations, it is claimed that net CO_2 emissions per unit of cement could be reduced substantially compared with conventional production methods.

4.3.6 Wiley Process from SynGasCo

The Wiley Process developed by Thermal Conversions Inc and commercialised by SynGasCo utilises a two-step pyrolysis and gasification/non-catalytic steam reformation process at low pressure and moderate temperature to produce a moderate-Btu syngas without the need to supply external oxygen or air. Fuel (especially petcoke or coal) is fed dry, and steam from an external source is added to sustain the reactions. Syngas is cleaned with a cyclone ash removal system, a proprietary 'ion-water' technology that results in solid by-product containing sulphur, mercury, and other contaminants, and a moisture condensation system. The company reports that the system has an overall cold gas efficiency of 70% after accounting for syngas used to produce process heat and steam. A pilot plant with 175 t/d design capacity was constructed in 2007 in Denver and is now operating as a test facility at the University of Toledo. The unit has used petcoke, Powder River Basin coal, Ohio coal, woodchips, and rice hulls, and can use other moist carbonaceous feedstock. Syngas produced from the process is used to offset natural gas used in the university's boiler systems, and technical evaluation of the process is ongoing, including work by the University of Toledo and DOE-funded work by TSS Consultants on behalf of the City of Gridley, California. Commercial plans for the process include re-powering of smaller, lower-efficiency boilers in the US coal power fleet.

4.3.7 Ze-gen Process

Ze-gen Inc has developed a system for gasifying organic feedstocks using a molten iron bath produced within a channel induction furnace of the type commonly used by the steel industry. Feedstock and oxygen are introduced into the molten bath using submerged lances, and moderate-Btu syngas is produced at low pressure. The company reports that standard syngas clean-up (for example, particulate removal) can be used if necessary. Ze-gen's technology was developed by integrating existing commercial technologies into a new technology platform, and a large-scale demonstration facility is operating in Massachusetts. The company plans to develop this technology into small modules that can be used to provide syngas to existing industrial consumers of natural gas and fuel oil, or alternatively can be used to provide gas for blending in natural gas pipeline systems. Although originally designed to take advantage of waste feedstocks, it is reported to be effective at coal conversion.

4.4 Integrated Gasification Steam Cycle

The concept of IGSC is through the gasification of coal in a quench gasifier, followed by combustion of the resulting syngas, with oxygen and water, in a modified gas turbine fitted with a novel form of oxy-burner, derived from rocket technology, the CES burner (*see* Figure 32) (Griffiths, 2009).

The CES burner (*see* Figure 33) is supplied with fuel and oxygen at high-pressure at near stoichiometric conditions and complete combustion takes place in the first zone of the burner. The combustor temperature is moderated by the injection of water directly through the burner to produce a steam/CO_2 working fluid (the 'flue gas' in the IGSC application) to be delivered to the turbine of the

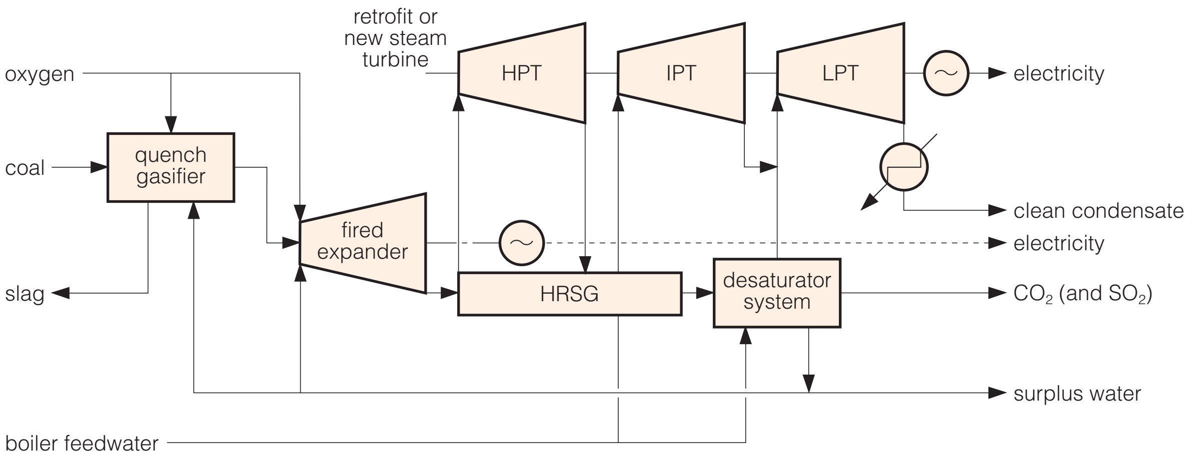


Figure 32 Schematic of Integrated Gasification Steam Cycle (Griffiths, 2009)

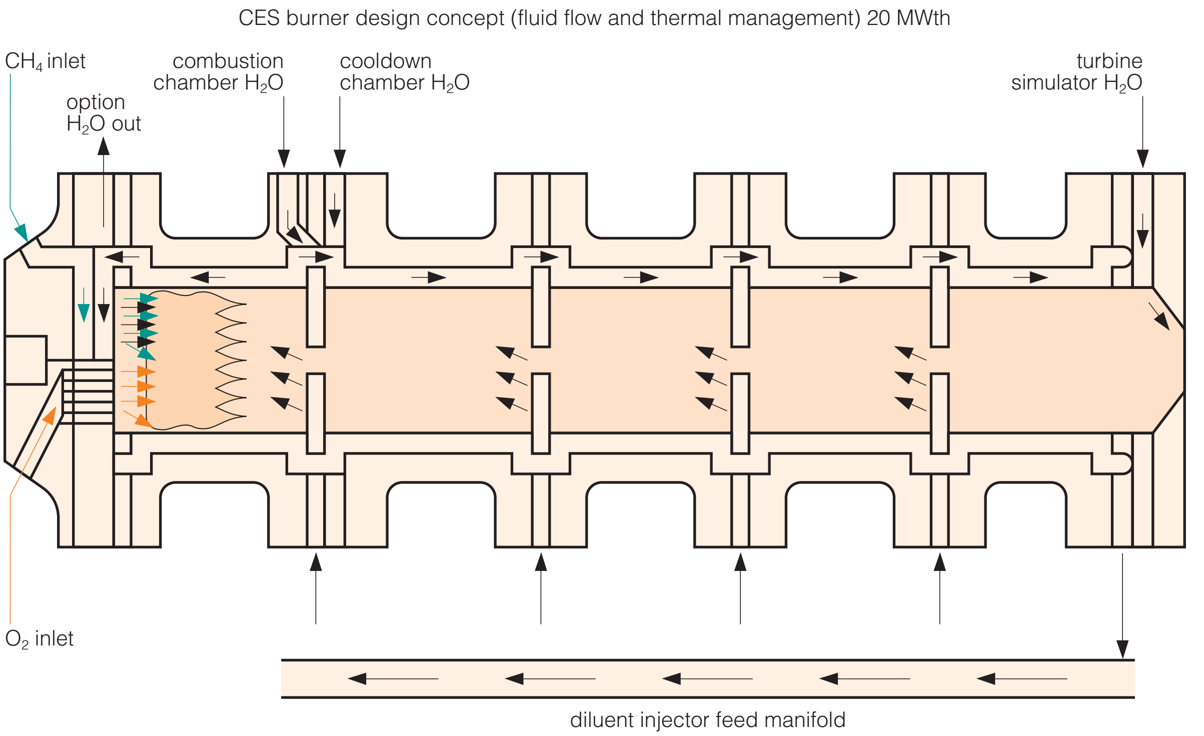


Figure 33 CES burner (Griffiths, 2009)

fired expander. In this first zone of the burner, water is injected to maintain the combustion zone at 1650–1760°C, while in the downstream cool down chambers, more water is injected to quench the steam/CO_2 'flue gas' to the required inlet temperature of the fired expander's turbine, below 1500°C.

The burner consists of a number of photo etched platelets carefully assembled into a block through which the reactants flow and mix. Combustion takes place on the surface of the block at the outlets of the holes. The block is designed such that water is always present to prevent excessive temperatures occurring, which means that high combustion temperatures can be used without melting the metal and without refractories. The CES burner is claimed to be very stable in operation and capable of operating at very low loads.

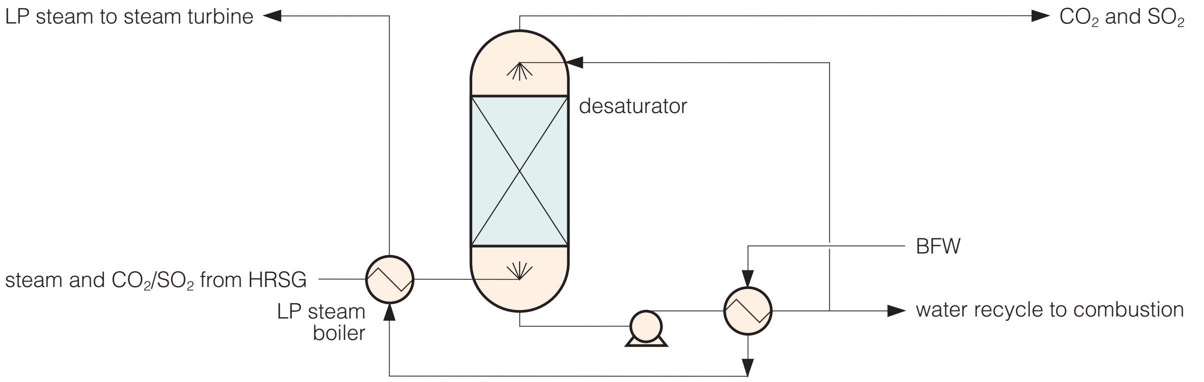


Figure 34 Jacobs desaturator (Griffiths, 2009)

This turbine, which is called the 'fired expander', drives a generator. The exhaust from the combustion is passed through an HRSG and the resulting steam used to generate further electricity. Thus the process is a combination of gasification with Brayton and Rankine cycles, as used in 'conventional' IGCC, but the IGSC has a working fluid of steam and CO_2 as opposed to the normal N_2 and CO_2. Downstream of the HRSG, the exhaust gases, which consist of steam mixed with CO_2 are directly quenched with circulating cold water to condense all the steam, leaving the CO_2 to be collected and compressed. The IGSC design work has been carried out by a consortium with consisting of Jacobs Engineering as the lead partner.

Because near-pure oxygen is used for combustion, there is no need for a large integral air compressor as incorporated in conventional gas turbines, and only a simplified expander is retained from the original gas turbine design, which is fitted with CES burners to become the fired expander. The 'flue gas' from the fired expander consists mainly of steam with around 20% CO_2 rather than the conventional flue gas of nitrogen, oxygen and CO_2 in a natural gas combined cycle or IGCC. To optimise the energy cost of compressing the CO_2 left after condensation of the steam in the 'flue gas', the back-end of the HRSG is run at an elevated pressure, around 10 bar. The steam in the 'flue gas' is separated from the CO_2 by counter-current direct quenching with cold water in Jacobs desaturators, that are commonly used in the chemical industry to separate non-condensable syngases from evaporated (*see* Figure 34).

The main body of the plant is run in a sulphurous condition – that is with all the sulphur in the coal feedstock being retained in the 'flue gas' as SO_2 which is removed during the compression of the captured CO_2. It is essential therefore, that, for materials protection, the 'flue gas' does not fall below the acid gas dewpoint temperature (ADT) in any section of the plant whose materials of construction are not preselected to withstand acid condensation. For this reason: start-ups and shut-downs must commence and end respectively using a sulphur-free feedstock such as natural gas; and the HRSG is designed such that its 'flue gas' exit temperature, and that of all feedwater admitted to the HRSG, is above the ADT. The IGSC is claimed to be very suitable as a retrofit to existing coal-fired power stations resulting in 100% CO_2 capture and an increase in electricity output of about 60%.

4.5 Integrated coal gasification fuel cell combined cycle

A possible future configuration in coal gasification systems is the integrated coal gasification fuel cell combined cycle (IGFC) which gasifies coal for use in triple combined power generation, combining three different types of generation systems: fuel cells, gas turbines and steam turbines. This type of system is expected to provide a power generation efficiency of 55% or higher, if successfully developed, and to reduce CO_2 emissions by approximately 30% from the level of existing pulverised

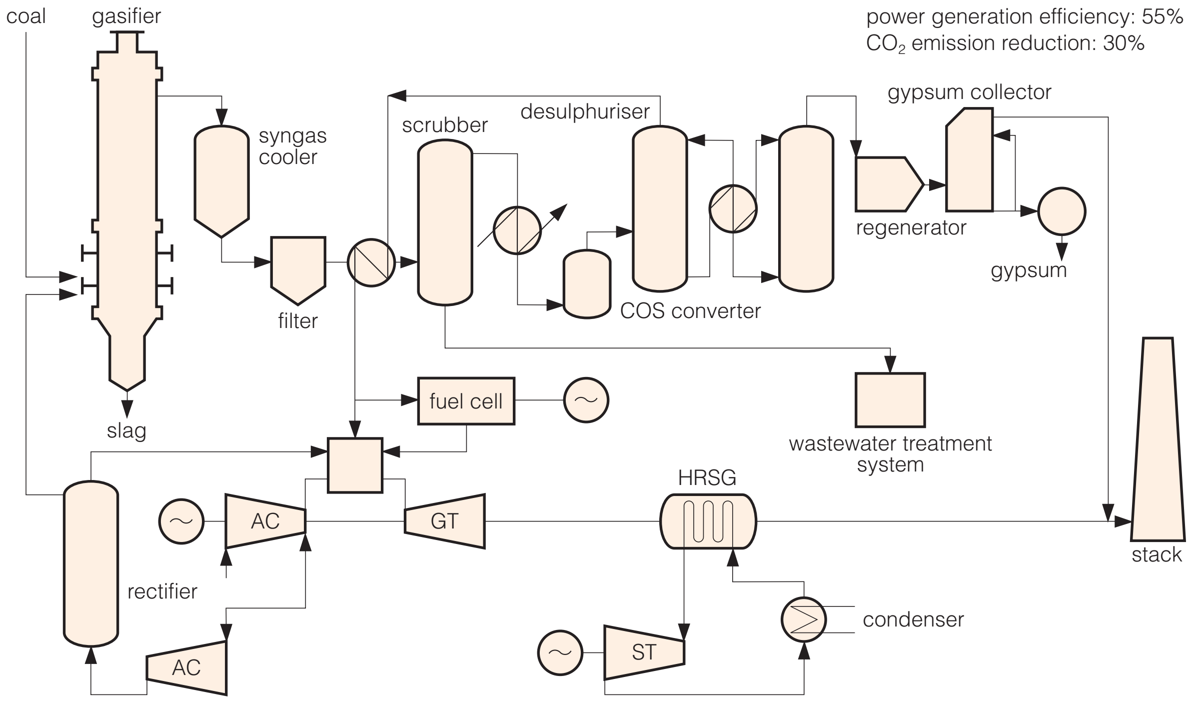


Figure 35 Conceptual IGFC plant (NETL, 2010)

coal fired power generation systems. Although IGFC is widely expected to become a coal-fired power generation technology of the future, there are still many challenges to be overcome for commercialisation, including the development of inexpensive high-efficiency fuel cells (NETL, 2010). A schematic for a conceptual IGFC plant is shown in Figure 35.

Fuel cells employ the electrochemical reaction between hydrogen and oxygen to directly generate power and can be classified by electrolyte material into phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), and solid polymer electrolyte fuel cells (PEFC) (*see* Table 3).

Among the fuel cells above, MCFC and SOFC operate at high temperatures and are expected to be highly-efficient technologies for next-generation large-scale power plants due to the following features: (1) they can be used in combination with gas turbines, and (2) they can accept coal gas. SOFC produce power through an electrochemical reaction between hydrogen, which has been derived from gasified fuel, and oxygen in the air. This mechanism is the reverse process of the electrolysis of water. The traditional power generation system burns fuel to generate heat and converts the heat into electrical energy. Unlike this system, fuel cells derive electrical energy directly with lower energy losses and higher generation efficiency. SOFC, consisting of ion-conducting ceramics, generate heat at temperatures as high as 900°C to 1,000°C during the chemical reaction. Combined with gas turbine generation, SOFC can provide higher generation efficiency than other types of fuel cells.

4.6 Rocketdyne gasifier

The Rocketdyne gasifier (*see* Figure 36) is an oxygen-blown, dry-feed, plug-flow entrained reactor reported as being capable of achieving carbon conversions approaching 100% (Fusselman and others, 2007). The gasifier is based on Rocketdyne rocket engine technology which is reported to produce a compact, long-life, efficient gasifier with good performance and relatively low capital cost. The

Table 3 Types of fuel cell (NETL, 2010)

Type	Phosphoric acid (PAFC)	Molten carbonate (MCFC)	Solid oxide (SOFC)	Solid polymer electrolyte (PEFC)
Electrolyte	Phosphoric acid aqueous solution	Li/Na carbonate	Stabilised zirconia	Solid polymer membrane
Ionic conductor	H+	CO_3^{2-}	O^{2-}	H+
Operating temperature	Approx. 200°C	Approx. 650–700°C	900–1000°C	70–90°C
Generation efficiency (HHV)	35–42%	45–60%	45–65%	30–40%
Raw materials and fuels	Natural gas, methanol, naphtha	Natural gas, methanol, naphtha, coal	Natural gas, methanol, naphtha, coal	Natural gas, methanol, naphtha
Application	Co-generation and distributed generation	Co-generation and distributed generation, substitute for thermal power generation	Co-generation and distributed generation, substitute for thermal power generation	Co-generation and portable power supply, automobiles

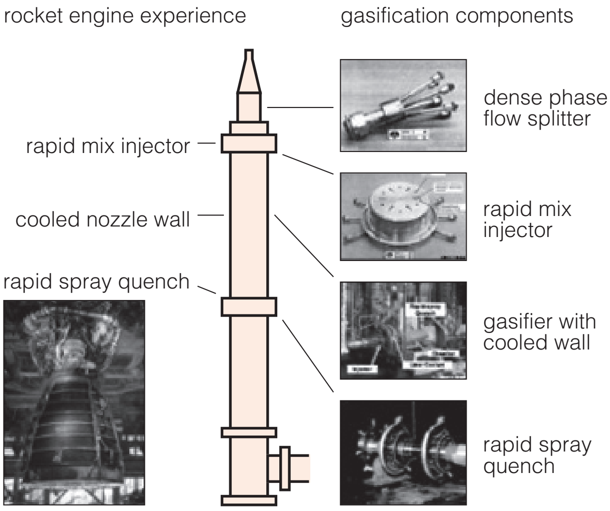


Figure 36 Rocketdyne gasifier – main components (Fusselman and others, 2007)

injector design uses multi-element injection to mix the coal with hot steam and oxygen while rapidly dispersing the coal across the reactor's cross-section. Efficient cooling of the injector face plate is claimed to give an injector life greater than the two to six months typical of existing water-slurry gasifier injectors. The gasifier lining results in a solid layer of slag on the gasifier side of the liner. This layer is expected to protect the refractory underneath, enabling an operational life much greater than the six to eighteen month life typically observed for non-cooled refractory brick in existing gasifiers. The high temperature raw syngas would need to be cooled to about 370°C before entering a commercially-available cyclone and candle-type filter for fly ash removal. This is accomplished by rapid spray quenching the produced raw syngas with water. The dry feed system, rapid mix injector, and cooled refractory liner are expected to enable the gasifier to process all ranks of coal.

The advantages of the compact gasifier over alternative systems were summarised as:
- 90% size reduction (gasifier);
- 50% lower cost (gasification system);
- 99% availability (gasification system);
- 99% carbon conversion;
- 80–85% cold gas efficiency;
- dry feed system;

Figure 37 Rocketdyne gasifier (Darby, 2010)

- low oxygen consumption;
- gasify all ranks of coal, petcoke, and biomass blends;
- high pressure/water spray quench;
- ideal for H_2 production;
- low cost CO_2 sequestration.

The current test gasifier is shown in Figure 37.

Darby (2010) presented an update of progress of compact gasifier development where data was sought to enable the design of larger gasification units. The tests aimed to demonstrate performance with respect to:
- carbon conversion;
- cold gas efficiency;
- protective slag layer;
- particulate removal;
- feedstock flexibility;
- verify operating environments;
- validation of computer models;
- obtain preliminary life data;
- refine operating procedures.

A programme of hot fire testing was initiated in December 2009 and after a short series of checkout tests 46 tests were undertaken with Illinois No 6, oil sands petcoke, Alberta subbituminous coal totalling 36 hours of test time. Over 150 hours of long duration testing on Illinois No 6 coal was completed corresponding to 144 hours of operation in 181 hour window. Eight operating set-points were completed where material balances closed within ±2%. Future work planned includes six additional long duration tests to be completed by the first quarter of 2011 on Illinois No 6, oil sand petcoke, and Alberta subbituminous coal.

4.7 National Carbon Capture Centre transport gasifier

The US National Carbon Capture Centre (NCCC) oversaw work on the development of a gasification system based on the transport gasifier, a circulating fluidised bed reactor which was designed based on successful operations of fluid bed catalytic cracking. The benefits of the transport gasifier are claimed to include:
- based on technology in use for 70 years which does not require expansion joints;
- equally effective gasification in either air- or oxygen-blown modes of operation, making it suitable for power generation or production of liquid fuels and chemicals;
- high reliability non-slagging design, which may extend refractory life;
- operation without burners enhances reliability and minimises maintenance requirements;
- use of coarse, dry coal feed, which requires fewer, lower power pulverisers, and less drying than other dry-feed gasifiers;
- cost-effective operation and high carbon conversion particularly with high moisture, high ash, and low rank fuels, including subbituminous and lignite coals;
- excellent heat and mass transfer due to a high solids mass flux, with a solids circulation rate 80 to 100 times greater than the coal feed rate.

Syngas produced in the gasifier is cooled, filtered in a hot gas particulate control device, and is used in

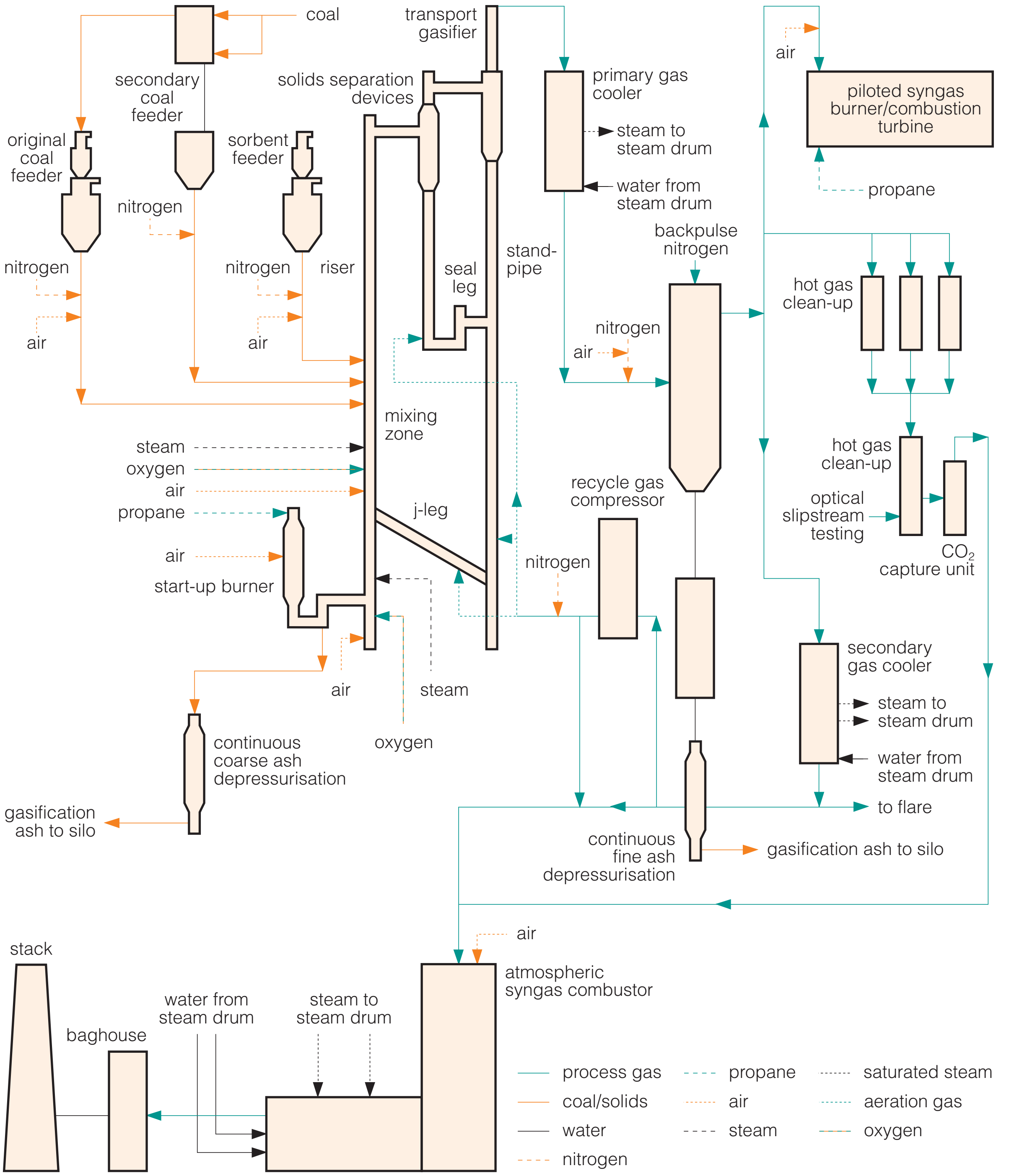


Figure 38 Transport gasifier gasification process flow diagram

testing a variety of gas clean-up technologies and other components such as high pressure solids handling equipment, advanced instrumentation, hot gas filter components, and gas analysis equipment.

Figure 38 illustrates the flow diagram of the gasification process based on the transport gasifier. A lock hopper assembly supplies fuel to the pressurised gasifier, while a separate system supplies sorbent, if necessary, to capture sulphur in the fuel. A burner is available to heat the gasifier from ambient conditions to a temperature suitable for adding coal, but is only necessary during start-up.

The gasifier consists of an assembly of refractory-lined pipe that includes a mixing zone, riser, solids separation and collection unit, and solids recycle section. The solids from the separation and collection unit enter the lower portion of the mixing zone and combust to provide the heat necessary for the gasification reactions. The coal and sorbent are fed to the gasifier in the upper mixing zone, where the hot circulating solids travelling upward from the lower mixing zone provide the heat necessary to devolatilise and gasify the coal in the riser, producing syngas and gasification ash. The continuous coarse ash depressurisation system, located beneath the gasifier, allows for the removal of gasification ash to control the gasifier bed inventory. The transport gasifier operating temperature for Powder River Basin (PRB) subbituminous coal and lignite is nominally 950°C. The gasifier has a maximum operating pressure of 20 bar and a thermal capacity of about 12 MW. The syngas and solids mixture from the mixing zone flow through the riser to the solids separation unit. The separation system removes the majority of solid particles and sends them via the recycle section to the lower mixing zone for combustion, while the syngas exits the solids separation unit and proceeds to the primary gas cooler and the particulate control device. Although the carbon content in the circulating solids is relatively low, the high circulation rate ensures that sufficient carbon is present to provide the heat necessary to maintain sufficient gasifier temperatures. Nitrogen or recycled syngas is used to fluidise the solids recycle sections to ensure that the circulating solids flow properly. Air or oxygen is used for combusting the recycled carbon, while steam provides a means for dispersing the oxidant and regulating the temperatures when using pure oxygen.

After leaving the solids collection unit of the gasifier, the syngas flows into the primary gas cooler at a temperature of approximately 930°C. The primary gas cooler decreases the syngas temperature to about 430°C before the gas enters the particulate control device. The gas flows into the vessel through a tangential entrance, around a shroud, and through the filter elements into the plenums. Virtually all the particulate from the syngas is removed by the particulate control device using candle-type filters. The particulate control device contains a tube sheet holding up to 91 filter elements that are attached to one of two plenums. A failsafe device located on the clean side of each element is designed to stop solids leakage in the event of a filter failure by acting as a back-up filter. High pressure gas is used to periodically pulse clean the elements to remove the accumulated solids, forcing the filter cake to fall to the particulate control device cone and into the continuous fine ash depressurisation system. A common ash silo collects the solids removed.

The filtered syngas exiting the PCD continues to either a combustion turbine for producing electricity or to the secondary gas cooler and the atmospheric syngas combustor, where the gas is burnt and all reduced sulphur compounds (H_2S, COS, CS_2) and reduced nitrogen compounds (NH_3, HCN) become oxidised. Upon leaving the syngas combustor, the flue gas flows through a heat recovery boiler to cool the gas and to generate steam. The cooled gas then passes through a baghouse and out of an exhaust stack. A slipstream test unit is also available for testing various catalysts and sorbents for removing syngas contaminants before sending the syngas to the atmospheric syngas combustor or to a fuel cell. To improve heating value and reduce nitrogen consumption, a recycle gas system can send a portion of the syngas back to the gasifier as fluidisation gas.

4.8 Alter NRG plasma gasification system

Alter NRG have developed a plasma gasification system (*see* Figure 39) based on Westinghouse Plasma Corp (WPC) technology designed to provide (van Nierop and Sharma, 2010).

Inside the plasma torch, a plasma stream is created by the interaction between air (other gases can also be used) and an electric arc created between two electrodes. The interaction of the gas with the electric arc dissociates the gas into electrons and ions enabling the gas to become electrically and thermally conductive. Torches can be turned up and down to maintain reaction temperatures as feedstocks with higher and lower Btu values are processed and/or feedstocks with higher or lower values of ash/glass/metals are processed. The APG is a refractory-lined vessel that stands about

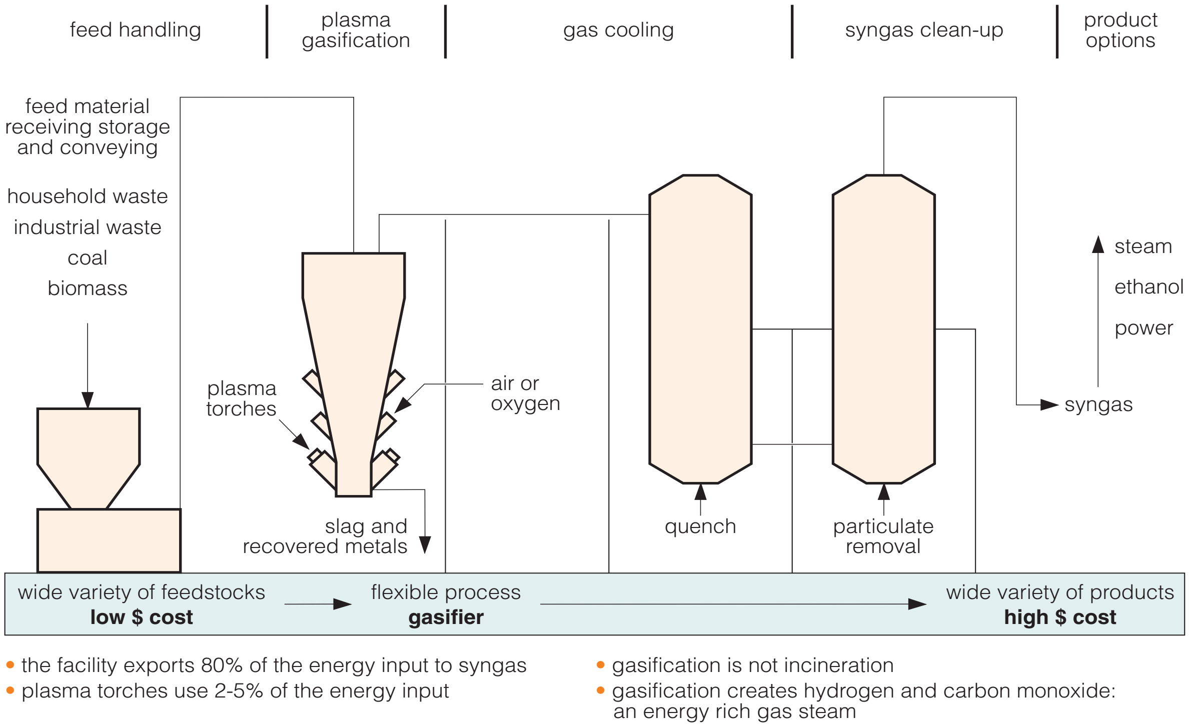


Figure 39 Alter NRG plasma gasifier (van Nierop and Sharma, 2010)

60 feet (18 metres) tall. Plasma torches, which provide heat for gasification and melting, are located around the periphery near the bottom of the reactor. The heat from the torches is used to heat up a bed of foundry coke and the temperature at the centre of the coke bed very near the plasma torches is greater than 3000°C. The temperature at the top and bottom of the coke bed is approximately 1650°C. Air and/or oxygen inlets are located just above and below the top of the coke bed. After the feedstock is converted to syngas it exits the top of the reactor at a temperature of approximately 900–1000°C where it begins several gas clean-up steps before the syngas can be converted into various energy products.

The Key Advantages of the Westinghouse Plasma Gasification Technology are claimed to be:

- self-stabilised and non-transferred arc;
- operation on many gases – air, oxygen, nitrogen, etc;
- wide variety of torches available with power input from 80 to 2400 kW;
- high thermal efficiency;
- plasma torches have no moving parts resulting in high availability;
- torch consumables are quickly replaced without shutting down the gasifier;
- long electrode life;
- minimal feedstock preparation;
- operation at ambient pressures allowing for simple feed systems and online maintenance of the plasma torches;
- low gas velocities allowing for greater feed flexibility and eliminating most expensive pre-treatments of feed stock;
- environmentally responsible operation since syngas that is created has very low quantities of NOx, SOx, dioxins and furans;
- inorganic components get converted to molten slag which is removed as vitrified by-product – safe for use as a construction aggregate;
- lower capital and operating costs because air is used as an oxidant – some competitors' designs require air separation units;

- syngas composition (H_2 to CO ratio, N_2) can be matched to downstream process equipment by selection of oxidant and torch power consumption.

The extreme temperatures within the reactor ensure that all organic material is converted to syngas and that any material that cannot be gasified is melted and flows out as molten slag. Long residence times within the reactor ensure there is sufficient time to crack any tars and minimise particulate carryover, a systemic problem for many other gasification systems.

4.9 Magneto Hydrodynamics (MHD)

Although the history of MHD goes back to the 1940s (Alfvén,1942), recent interest has revived the topic (Baxter and others, 2003; Hustad and others, 2009). MHD generators convert fuel directly into electric energy by burning or gasifying coal at a high temperature and then seeding the gas with electrolytes to yield a hot, ionised gas stream (plasma). This stream is forced through a duct within a magnetic field where an electric current is generated and captured by electrodes. MHD generators are more efficient than typical steam powered devices, and have the added advantage that the hot gases can then be passed into a turbine to produce additional power. The basic principle of MHD electrical generation is shown in Figure 40.

Because MHD systems operate without any rotating or moving parts it is possible to reduce mechanical losses and operate at elevated temperatures and by using a topping cycle to increase the overall cycle thermal efficiency above what is possible for more conventional Brayton and Rankine based cycles.

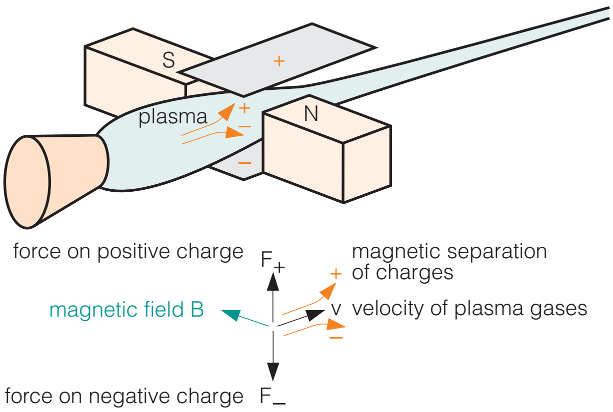


Figure 40 Principle of MHD (Alfvén,1942)

During the 1970s and 80s international research and development on MHD was funded in more than a dozen countries; in particular in the USSR where a 25 MWe gas-fired MHD plant produced heat and power for residents of Moscow until the early 1990s, and there were advanced plans for a 500 MWth commercial-size power plant. In the USA extensive work was conducted by the Department of Energy (DOE) in collaboration with industry from 1987 to 1994 in a Proof-of-Concept Program. This included a 50 MWth coal-fired MHD generator operating in Butte, Montana, and component tests for a coal-fired MHD bottoming (steam) cycle at University of Tennessee (Hustad and others, 2009).

Magnetohydrodynamic (MHD) power generation utilises the high-temperature (around 2400 K) plasma interacting with lines of magnetic force to induce electromotive force. The temperature of the exit gas from a magnetic hydro-electricity generator unit is fairly high, around 2200 K, so combined with steam turbine generating equipment, a combined cycle system of MHD power generation can produce relatively higher efficiency. In a conceptual MHD system based on gasification, clear conductive syngas enters the MHD generation channel. Mathematical modelling of this system has shown that gasification-based MHD results in higher yields of higher electric power as the syngas passes through the MHD generation channel. This is attributed to a higher mass flow rate as compared to a combustion-based MHD system. An additional benefit of the gasification route is the absence of significant quantities of particulates in the system.

Kayukawa (Kayukawa, 2000) compared the efficiencies of six MHD topping combined power generation systems and one gas turbine topping combined system driven by different combinations of fuel and oxidant supply schematics and classified them on the bases of overall chemical reaction models for the combustion and gasification processes. The primary fuel modelled was carbon, simulating coal. The fuel types considered were coal and coal-synthesised gases which were provided by different gasification process. The oxidant was either pure oxygen, oxygen enriched air, or air. In the MHD topping cases, the oxidant was preheated to an appropriate temperature. The enthalpy extraction of the corresponding power generation units in the topping and bottoming systems and the temperatures at the inlets of regenerators as well as at the stacks were assumed to be identical in all cases, except the inlet temperatures at the recuperative air heaters and the steam generators. A gasification system with an MHD topping and a combined gas turbine and steam turbine bottoming exhibited the highest plant efficiency.

Harada (Harada, 2008) considered the advantages of a number of systems based on steam cycles including an MHD-based system with CO_2 recovery (*see* Figure 41). Coal would be gasified in an atmosphere of oxygen using existing gasification technology.

Hydrogen and CO produced are burnt at high temperature to produce a plasma jet at a temperature of approximately 2800°C. Downstream of the MHD generator, heat is recovered by a regenerative coal gasification process, fuel pre-heating, and steam de-composition. The energy penalty for the oxygen production plant may be recovered by virtue of the highly efficient MHD electrical generation step. It is known that only MHD generators can be operated at such high temperatures. The total plant efficiency has been estimated at over 50% with CO_2 recovery (Kayukawa, 2000).

Harada studied the properties of magnetohydrodynamic (MHD) plasma based on syngas (CO, H) combustion products with a shock tube facility. The experiments were carried out under various MHD generator load and shock tube operation conditions. Important characteristics of syngas plasma such as temperature, electric field, conductivity, and total output power were directly measured and evaluated. Special attention was paid to the influence of syngas composition (CO:H:O ratio). The results show that syngas combustion can provide high plasma ionisation and attainable plasma electrical conductivity has an order of 60–80 S/m at gas temperature 2800–3000°C.

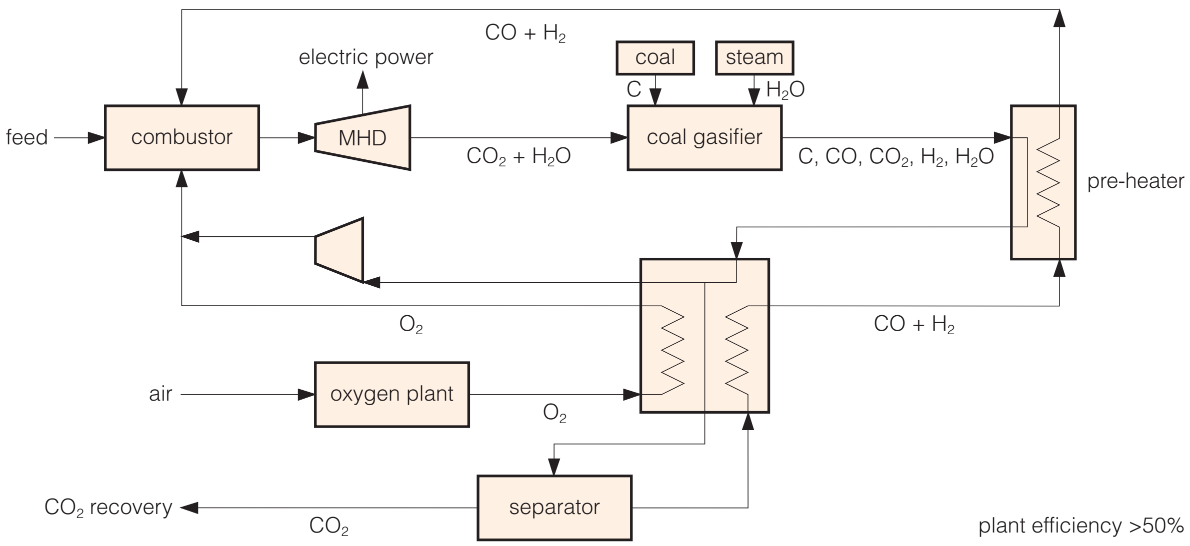


Figure 41 CO_2 recovery type MHD generator plant (Harada, 2008)

4.10 Summary

While the main types of gasifier outlined in the introduction continue to evolve, a series of alternative approaches to coal gasification have emerged. These range from systems with enhanced energy recovery, through gasifiers operating in a CO_2 rich atmosphere to innovative technologies and combinations of technologies. Some of these units are well-established at the pilot plant scale and show promise for further scale-up.

Even older technologies that have received intermittent interest over the last fifty years, such as MHD, are beginning to show signs of a modest revival. It is unclear which of these approaches is likely to be a 'winner' since the nature of investment in larger-scale plant tends to be conservative. That said, many of these systems offer potentially valuably advantages in respect of lower capital costs, or in dealing with 'difficult' coals perhaps starting to feature in niche applications, or in retrofits to existing coal plant as legislation on CO_2 emissions strengthens.

5 Conclusions

The integrated gasification combined cycle power plants (IGCC), based on high-efficiency coal gasification technologies, and which are operated commercially or semi-commercially and those under construction or at an advanced stage of planning, are based on long-established designs. New cycles and systems are emerging to further improve the efficiency of the coal gasification process.

The basic thermodynamic cycles pertinent to coal gasification plant have long been established, but novel combinations of these cycles and the use of alternative fluids to water/steam offer the prospect of higher efficiencies. However, these gains are at present theoretical and in some cases require the development of technologies significantly in advance of current best practice. Moreover, some cycles (such as Matiant) are vulnerable to the inevitable parasitic losses present in a highly integrated process such as a coal gasification plant.

Gas turbine technology is fundamental to the overall process efficiency of coal gasification plant. Continuous development has pushed inlet temperatures and pressures ever higher, with concomitant increases in efficiency. In parallel with these developments, a number of techniques have been developed to improve the efficiency of existing gas turbines, often under particular conditions local to the site of operation. Additionally, improvements in emissions control technologies closely tied to the turbine operation ensure compliance with existing and probable future regulations.

While the main types of gasifier outlined in the introduction continue to evolve, a series of alternative approaches to coal gasification have emerged. These range from systems with enhanced energy recovery, through gasifiers operating in a CO_2-rich atmosphere to innovative technologies and combinations of technologies. Some of these units are well-established at the pilot plant scale and show promise for further scale-up.

Even older technologies that have received intermittent interest over the last fifty years, such as MHD, are beginning to show signs of a modest revival. It is unclear which of these approaches is likely to be a 'winner' since the nature of investment in larger-scale plant tends to be conservative. That said, many of these systems offer potentially valuably advantages in respect of lower capital costs, or in dealing with 'difficult' coals perhaps starting to feature in niche applications, or in retrofits to existing coal plant as legislation on CO_2 emissions strengthens.

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