High-efficiency power generation – review of alternative systems

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March 2015

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IEACCC Ref: CCC/247

ISBN: 978-92-9029-569-3

Published Date: March 2015

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, , China, the European Commission, Germany, India, Italy, Japan, New Zealand, Poland, Russia, South Africa, Thailand, the UK and the USA .The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

Currently, almost all coal-fired power plants are steam power generating units using the Rankine cycle. The maximum efficiency of a Rankine cycle is restricted by the second law of thermodynamics and is limited to below the Carnot efficiency. Over the past decades, extensive R&D and huge sums of money have been invested into the development of alternative systems, the so-called unconventional power generation concepts. A number of studies have been published on alternative power cycles and hybrid approaches to improve the overall efficiency of power generation by coal. Some of these studies focus on improving the basic power cycle, for example the integrated gasification fuel cell concepts, chemical looping concepts, and a renewed look at magnetohydrodynamic (MHD) and indirect coal combustion gas turbine power cycles. Other analyses seek to replace the working fluid with one that reduces parasitic losses intrinsic to the use of water as the working fluid. Systems based on a supercritical carbon dioxide Brayton cycle have been the subject of a number of studies and R&D. Bottoming and topping cycles are being studied as a means to extract additional energy from the process. This report reviews the R&D activities of and recent advances in these innovative power cycles alternative to the conventional steam Rankine cycle. Analyses and evaluations of these power systems are also discussed in the report.

Acronyms and abbreviations

AFC	alkaline fuel cell
ANL	Argonne National Laboratory
ASU	air separation unit
A-USC	advanced ultra-supercritical
BOP	balance of plant
CAH	convective air heater
CCRP	Clean Coal Research Program
CCS	carbon capture and storage
CCT	clean coal technologies
CDCL	Coal-Direct Chemical Looping Process
CDIF	Component Development and Integration Facility
CFBC	circulating fluidised bed combustion
CFFF	Coal Fired Fuel Facility
CLC	chemical looping combustion
CLOU	chemical-looping with oxygen uncoupling
CSP	concentrated solar power
DCFC	direct carbon fuel ell
DOE	Department of Energy (USA)
ESP	electrostatic precipitators
FBC	fluidised bed combustion
FCE	FuelCell Energy
FW	Foster Wheeler Corporation
GTIT	gas turbine inlet temperatures
HAT	humid air turbine
HHV	high heating value
HIPPS	High Performance Power Generating System
HITAF	high-temperature advanced furnace
HRSG	heat recovery steam generator
ICAD	intercooled aeroderivative
iG-CLC	the in-situ gasification-chemical looping combustion
IGCC	Integrated gasification combined cycle
IGFC	Integrated gasification fuel cell system
LCOE	levelised cost of electricity
LHV	low heating value
LLNL	Lawrence Livermore National Laboratory
LMA	Liquid metal anode
LSM	strontium-doped $LaMnO_3$
LTA	liquid tin anode
MCFC	molten carbonate fuel cell
MGT	micro gas turbine
MHPS	Mitsubishi Hitachi Power systems
MWe	megawatts electricity
NETL	National Energy Technology Laboratory
ORC	organic Rankine cycle
PAFC	phosphoric acid fuel cell
PCC	pulverised coal combustion
PCLC	pressurised chemical looping combustion

PEFC	**polymer electrolyte fuel cell**
PFB	**pressurised fluidised bed**
PFBC	**pressurised fluidised bed combustor**
POC	**proof-of-concept**
R&D	**research and development**
RAH	**radiant air heater**
SC	**supercritical**
sCO_2	**supercritical carbon dioxide**
SECA	**Solid State Energy Conversion Alliance**
SOFC	**solid oxide fuel cell**
TE	**thermodynamic engine**
USC	**ultra-supercritical**
YSZ	**yttrium stabilised zirconia**

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1 Introduction

Achieving a high process efficiency for energy conversion to products such as electricity, synthetic fuel gas and hydrogen while maintaining low pollutant emissions represents a major challenge for any fossil fuel conversion system. This is particularly the case for coal, which is the most carbon intensive among the available fossil energy resources.

Currently, almost all coal-fired power plants are steam power generating units using the Rankine cycle. Improvement to generation efficiency has been steady over the history of the power generation industry and has mainly been related to technological progress including reduction of stack losses, improved combustion, coal drying, advanced controls, reduction in auxiliary power demand, improved steam turbine aerodynamics, flue gas heat recovery, and other measures, as well as increases to the underlying thermodynamic cycle by increases in steam temperature and pressure. Today's state-of-the-art ultra-supercritical (USC) coal-fired power generating units can achieve a net energy efficiency of around 45% (LHV). Intensive research and development (R&D) activities are ongoing to develop advanced ultra-supercritical (A-USC) technology that uses steam temperatures of up to 700°C and is expected to achieve an energy efficiency of around 50% (LHV, net). However, the maximum efficiency of a Rankine cycle is restricted by the second law of thermodynamics. The actual Rankine cycle efficiency is limited to below the Carnot efficiency. Given the present status of the technologies, any further substantial increase in efficiency will be difficult and at high costs. For this reason researchers have turned to the development of alternative systems, the so-called unconventional power generation concepts.

This report reviews the R&D of coal based power generation systems alternative to steam power system. The general goal of the coal technology R&D activities is to ensure a more efficient, environmentally cleaner, more economic, and more flexible use of coal. The efficiency of a coal-fired power plant is of significant importance for the environmental impact associated with the use of coal. The report begins with a brief review, in Chapter 2, of the Rankine cycle system, the current status of coal-fired steam power generation. The technological progress and limitations are discussed. Chapter 3 provides a detailed review of the emerging fuel cell technology. The principle, basic structure and types of fuel cells are addressed, which is followed by discussions of the developments of the three fuel cell systems that can potentially be applied in coal fuelled power plants. The proposed power cycle configurations using fuel cells are assessed.

Magnetohydrodynamic (MHD) power generation systems attracted interests from scientists around the world and extensive R&D was carried out during the 1970s and 1990s. Following a brief description of the MHD system and how it works, the major MHD R&D programmes are outlined in Chapter 4. Various coal fuelled MHD power cycle configurations have been proposed and studied. These power cycle concepts are examined, and the advantages and technical challenges of MHD technology are discussed.

During the 1990s and early 2000s, the US Department of Energy (DOE) funded R&D of High Performance Power Generating System (HIPPS), which is an indirectly coal-fired combined cycle power system. Two variants were developed. The HIPPS technology and the developments of the two systems are reviewed in Chapter 5. The HIPPS power cycle configurations are evaluated, and the opportunities for their application and technical barriers are discussed.

Other R&D activities seek to replace the working fluid with one that reduces parasitic losses intrinsic to the use of water/steam as the working fluid, or one that can obtain a better thermal match with the heat source. A number of thermodynamic cycles alterative to the steam Rankine cycle have been developed or are under development, and some of them are reviewed in Chapter 6. Some of these cycles can be combined with a steam Rankine cycle as a topping or bottoming cycle to form a binary thermodynamic cycle that better resembles the Carnot cycle and improves efficiency. These cycles and their integration with the steam Rankine cycle for more efficient power production are evaluated in Chapter 7. At present, intensive R&D is ongoing to develop chemical looping systems. Power generation based on chemical looping can potentially achieve high efficiency while producing a stream of CO_2 ready for compression and storage. The principles, advantages and developments of chemical looping technology are discussed, and the proposed chemical looping power generation cycles are assessed in Chapter 8. In Chapter 9, the solar-coal hybrid power system, the integration of solar power with a coal steam cycle and the latest developments are examined. And finally, conclusions are drawn in Chapter 10.

Among the alternative power cycles for generating electricity from coal that have been investigated and tested, the integrated coal gasification combined cycle (IGCC) is most developed. In an IGCC system, coal is gasified to produce a gaseous fuel (syngas), which is used to generate electricity using a combined gas and steam turbine process. A small number of IGCC power plants, based on high-efficiency coal gasification technologies, are operated commercially or semi-commercially worldwide and a few more are under construction in China, Japan, South Korea and the USA. Several demonstration projects, some including carbon capture and storage (CCS), are at an advanced stage of planning. The IGCC technology is currently being pursued on a global scale. There are a large number of publications available in the public domain. The IEA Clean Coal Centre also has published several reports providing detailed descriptions and comprehensive review of IGCC systems, the technological developments and applications (Fernando, 2008; Henderson, 2008; Barnes, 2011; 2013; Mills, 2006). Therefore, the IGCC technology will not be discussed in this report.

The direct injection carbon engine (DICE) using coal to fuel diesel engines for power generation is another unconventional power generation concept that has been investigated by scientists and engineers in many countries worldwide over several decades. The concept is not new and firing a washed coal in a form of water slurry in an adapted diesel engine has been technically proven in the USA on pilot-scale and short-term large-scale demonstration. Nicol (2014) has recently conducted a comprehensive review of the previous R&D programmes on coal-fuelled diesel engines and the recent developments of the technology in its latest form, micronised refined carbons (MRC) and DICE, and hence the DICE will not be included in this report.

Extensive R&D and huge sums of money have so far been invested into the development of technologies for more efficient, cleaner, more flexible and cheaper use of coal. As a result of decades of R&D work, novel power generation systems such as the power system based on fuel cells are beginning to emerge in the commercial market while others are under development. If the technologies for alternative power generation systems can be developed into practical systems, they could ultimately have a significant impact on coal-based power generation and provide a range of power generation technologies to meet the challenges for sustainable development.

2 Steam power plants

Coal plays a vital role in electricity generation worldwide. Currently, just over 40% of electric energy is generated by coal-fired power plants globally. The vast majority of these generating units use pulverised coal fired boilers, although about 5% of the units use fluidised bed combustion. Almost all of these are steam power generating units using the Rankine cycle. This chapter provides an understanding, at an overview level, of the steam power generating cycle, the recent technology developments and limitations.

2.1 Rankine cycle

Named after a Scottish professor William John Macquorn Rankine, the Rankine cycle is a thermodynamic cycle of a heat engine that converts heat into mechanical work. The heat is supplied externally to a closed loop, usually by combustion of fossil fuels or nuclear fission. Steam power plants based on the Rankine cycles commonly use water as the working fluid.

The Rankine cycle consists of four processes (*see* Figure 1A):

- process 1–2: a compression process during which the working fluid from the condenser is pumped from low pressure at state l to high pressure at state 2 and then enters the boiler;
- process 2–3: a steam generating process during which the high pressure liquid is heated by an external heat source and converted into dry saturated steam or superheated steam at stage 3;
- process 3–4: a steam expansion process during which the steam expands through a turbine to stage 4, generating power, and enters the condenser as a wet vapour;
- process 4–1: a steam condensation process during which the steam is condensed to stage 1 to become a saturated liquid by rejecting heat.

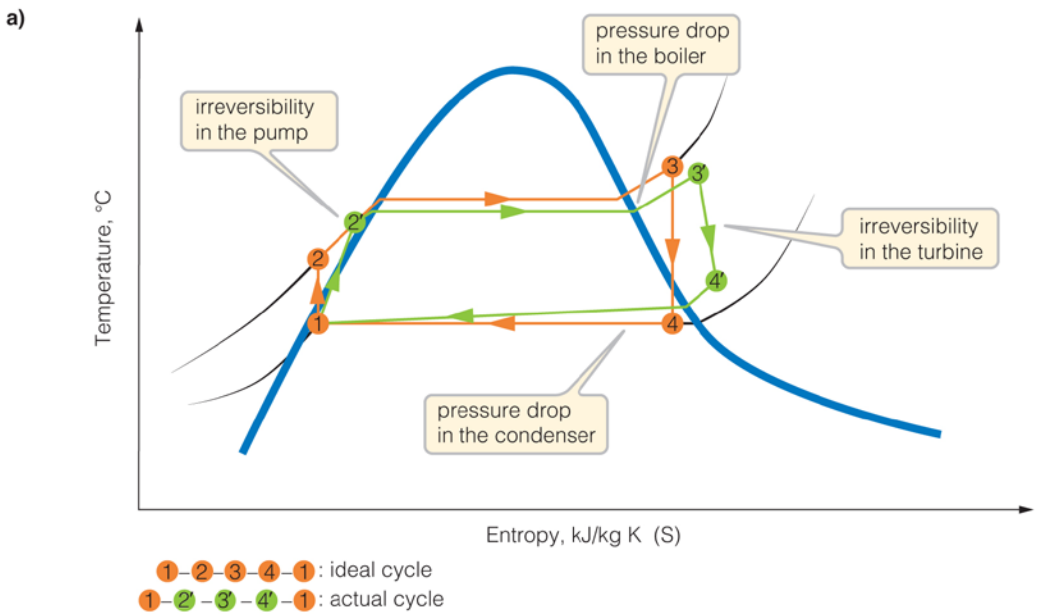

Figure 1A Basic Rankine cycle

In an ideal Rankine cycle (represented by the orange lines in Figure 1A), processes 1–2 and 3–4 are isentropic, that is the entropy of the working fluid remains constant. Processes 2-3 and 4-1 are isobaric, which means that the pressure of the working fluid remains constant.

The actual Rankine cycle (green lines in Figure 1A), however, is far from ideal. It differs from the ideal Rankine cycle as a result of irreversibility associated with each stage of the cycle. The two common sources of irreversibility are the friction and undesired heat loss to the surroundings.

2.2 Rankine cycle efficiency

The thermal efficiency of a Rankine cycle is defined as the fraction of the network output over the total heat input. Due to fluid friction and irreversibility in various components, the efficiency of an actual Rankine cycle is lower than that of an ideal cycle. As the overall thermodynamic efficiency of almost any cycle can be increased by raising the average heat input temperature of that cycle, increasing steam temperature and pressure is often employed as a simple way of improving Rankine cycle efficiencies.

Superheating and reheating

The temperature of saturated steam is limited by the saturation pressure but can be further increased by superheating the saturated steam. The additional work done by the Rankine cycle with superheat is shown in the shaded area in Figure 1B. Superheating the steam in the boiler has an additional advantage. As the water condenses, water droplets formed hit the turbine blades at a high speed causing pitting and erosion, gradually decreasing the life of turbine blades and efficiency of the turbine. The problem is overcome by superheating which produces a drier steam after expansion.

b)

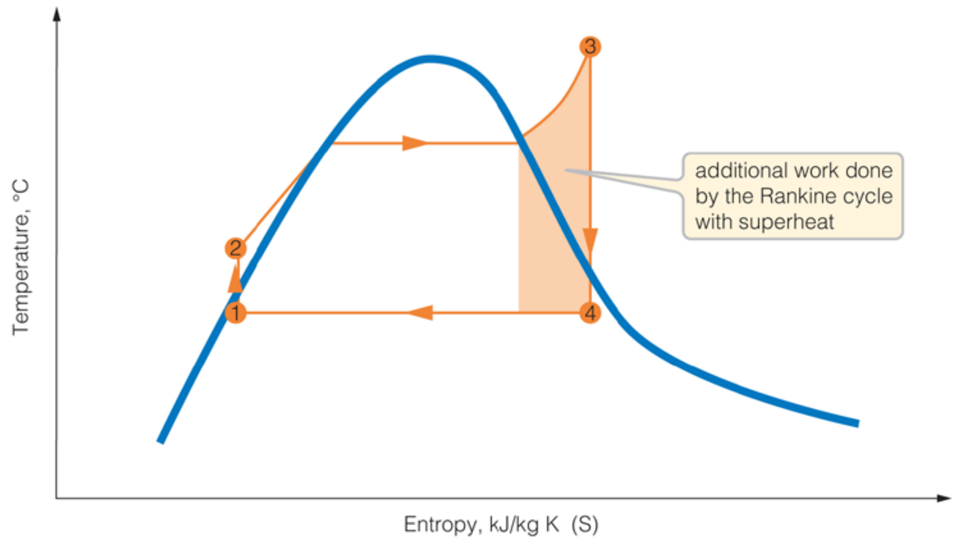

Figure 1B Rankine cycle with steam superheat

It is usual to the modify the Rankine cycle to produce more output work by reheating the steam after expansion in the high pressure turbine and expanding the reheated steam in a second, low pressure turbine. In this variation, two turbines work in series. The first accepts steam from the boiler at high pressure. After the steam has passed through the first turbine, it re-enters the boiler and is reheated before passing through a second, lower-pressure turbine. The reheat temperatures are very close, or equal to, the turbine inlet temperatures, whereas the optimum reheat pressure needed is only one fourth of the original boiler pressure. As illustrated in Figure 1C the T-S diagram of a modified Rankine cycle shows an increase in the work output as represented by the shaded area as a result of reheating the steam. This results in low pressure turbine expansion work, and therefore increases the work output.

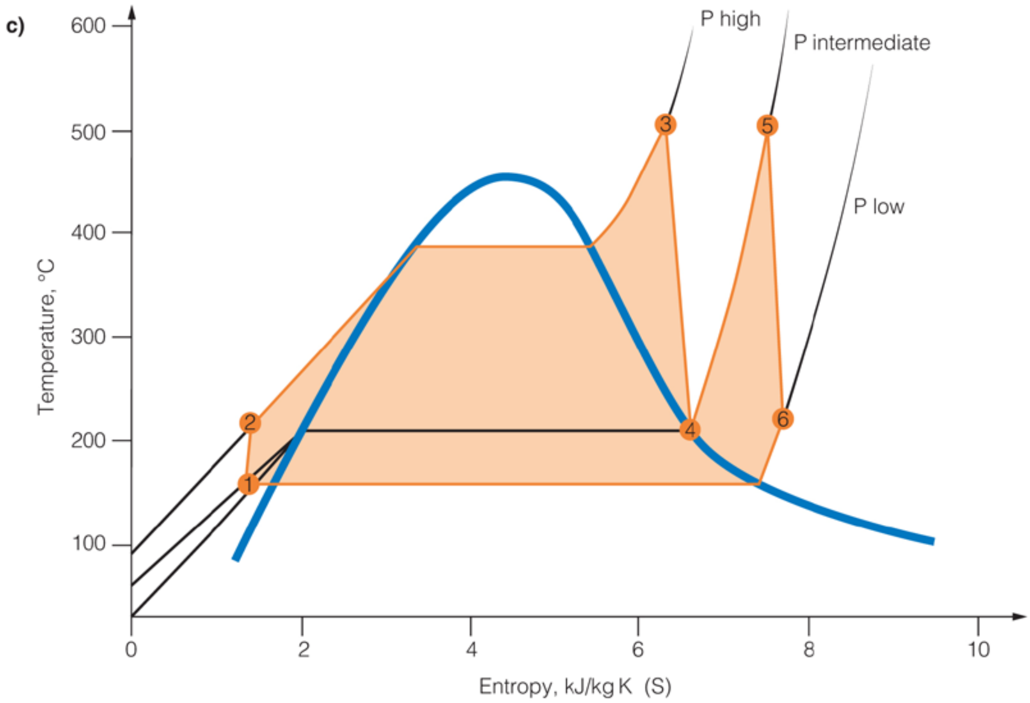

Figure 1C Rankine cycle with reheat

Today, the Rankine cycle with single reheat can be found in most modern power plants, and double reheating can be found in some supercritical steam power plants. However, more than two stages of reheating are found to be unnecessary, since each additional stage increases the cycle efficiency by only half as much as the preceding stage.

Pressure

The effect of decreasing the condenser pressure is to reduce the condenser temperature as the steam exits as a saturated mixture in the condenser at the saturation temperature that corresponds to the saturation pressure. As one can see from Figure 2A, when the condenser pressure is reduced from P_4 to $P_{4'}$, the original cycle 1-2-3-4-1 changes to cycle 1'-2'-3-4'-1'. The additional work done by the cycle with lower condenser pressure is represented by the area 1'-2'-2-1-4-4'-1'. The required heat input is also increased, which is represented by the orange area shown in Figure 2A. However, the increase in heat input is smaller than the increase in network output. The overall effect of lowering the condenser pressure is increased cycle efficiency.

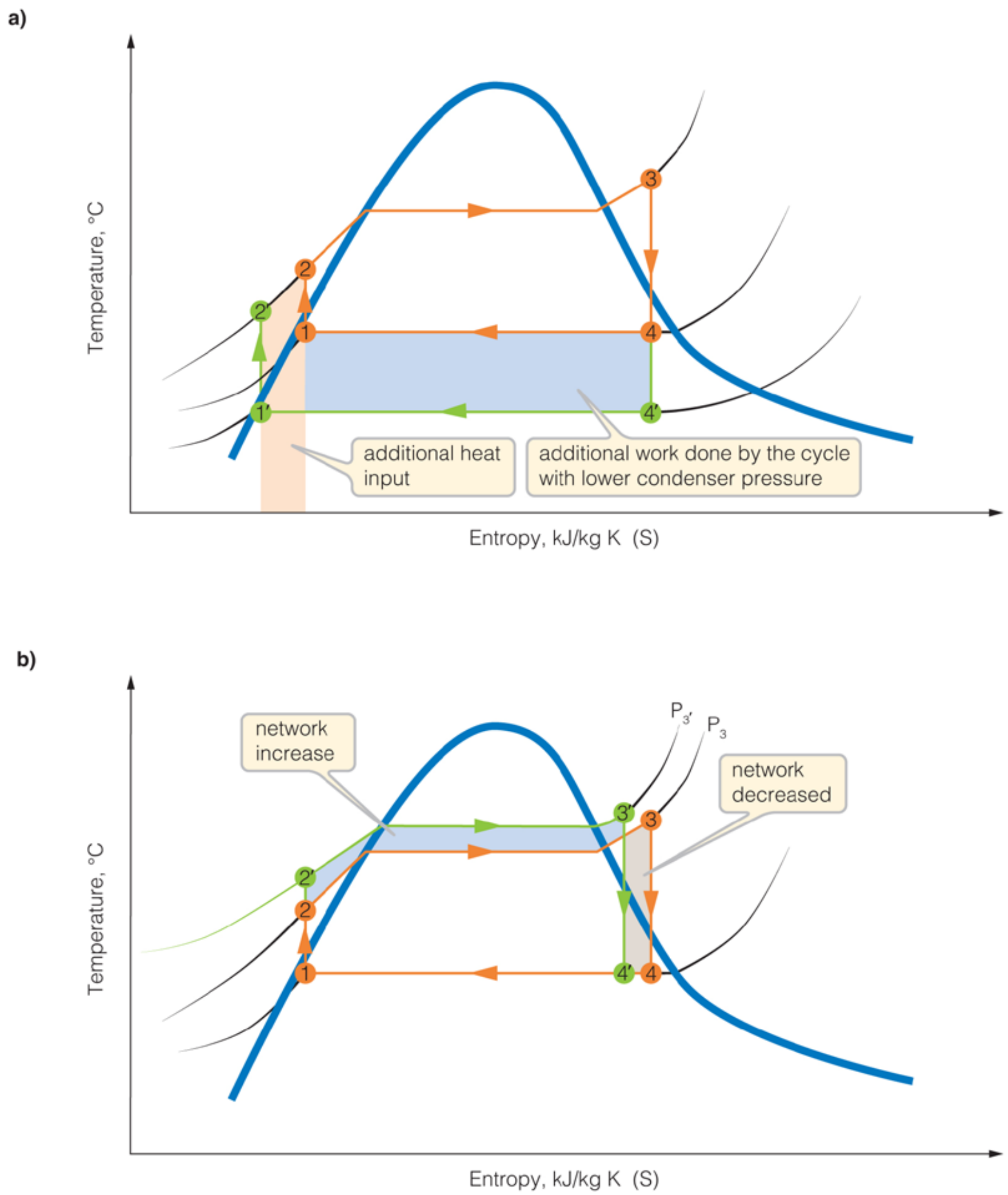

Figure 2 Effects of variations in pressures on Rankine cycle

Similarly, increasing the steam pressure, in effect, increases the average high temperature in the cycle. As shown in Figure 2B, for a fixed maximum turbine inlet temperature, the blue area is the network increase and the grey area is the network decrease when the operating pressure of the boiler is increased from P_3 to $P_{3'}$. Increasing the boiler pressure raises the average temperature of the heat addition process and therefore increases the thermal efficiency of the cycle.

Regenerative Rankine cycle

Another variation of the Rankine cycle is the regenerative cycle, which uses the latent heat (and sometimes superheat) of small amounts of steam to increase the temperature of feedwater flowing to the steam generator. This provides internal transfer of heat and therefore, regains some of the irreversible heat lost when condensed liquid is pumped directly into the boiler. The regenerative cycle effectively raises the nominal cycle heat input and therefore reduces the addition of heat from the boiler. This improves the efficiency of the cycle, as more of the heat flow into the cycle occurs at higher temperature. This process ensures cycle economy.

Supercritical Rankine cycle

As discussed above, increasing the steam temperature and pressure is a simple way of improving the efficiency of a Rankine cycle. However, unless the pressure and temperature reach supercritical levels in the steam boiler, the temperature range the cycle can operate over is quite small. For a Rankine cycle using water as working fluid, this corresponds to steam pressure of lower than 22.1 MPa and temperatures of 374–540°C. The Rankine cycle efficiency can be greatly improved by operating in the supercritical region of the fluid, which is above 22.1 MPa and 540°C. Modern steam power plants commonly adopt supercritical (SC) or ultra-supercritical (USC) steam conditions.

2.3 Coal-fired power generation today

Historically, coal has played a major role in satisfying the world's energy needs. At present, almost two-thirds of coal demand in the energy sector is for electricity generation. Pulverised coal combustion (PCC) is the standard technology for coal-fired electricity generation. First employed in the 1920s, PCC is one of the oldest technologies and it still dominates electricity generation from coal, comprising over 95% of the total global capacity. PCC technology has proven to be simple, reliable, adaptable to most types of coal, and suitable for large power plants.

The average efficiency of coal-fired power generation units varies enormously, from under 30% to around 45% (LHV, net), depending on the age of operating units, the steam conditions, local climatic conditions, coal quality, operating and maintenance skills, and receptiveness to the uptake of advanced technologies. The choice of technology is decided at the time of installation of a power plant, which has a substantial and long-term influence on its life-time efficiency and emissions. At present, a large number of old, relatively small and inefficient plants remain in operation: more than half of all operating plant capacity is older than 25 years and less than 300 MWe in size. A majority of these units (approximately 74% of operating plants) use subcritical steam conditions, some with single reheat (Burnard and Ito, 2012). The average worldwide efficiency increased in recent years from 30 to some 33% due to the replacement of a large number of old, low-efficiency plants by newly built, high-efficiency plants (VGB PowerTech, 2013).

The newly built power plants generally adopt SC or USC technologies that have higher thermal efficiencies. The deployment of SC and USC technologies worldwide has been increasing in recent years although their share of total capacity is still low. Several countries have made significant progress in improving the efficiency of their coal-fired power plants by adopting advanced power generation technologies. Japan and South Korea are the leaders in deploying SC/USC technology with its share of total capacity being higher than 70%. As a result, the average efficiencies in the two countries are in excess of 40% (LHV, net). Since the mid-2000s, China, despite having experienced high growth in coal-fired generation, retired a large number of small (<200 MWe), low-efficiency (mostly aging) coal-fired power plants (10000 MWe annually). At the same time, China has installed a number of large, high-efficiency SC and USC power plants at a pace unparalleled by any other country and the share of SC and USC increased rapidly leading to continued improvement in the nation's average power plants efficiency. Germany has also seen a significant increase in installed SC and USC capacities in recent years. Germany operates the world's largest and most efficient lignite-fired power plants. Recently, work began to upgrade some of the country's aging, low-efficiency power plants to SC/USC plants. Since 2010, India has seen rapid growth in coal-fired generation, and an increase in the share of SC units (Burnard and Ito, 2012; Feng, 2012; Zhao, 2012; BMWi, 2008). SC and USC technologies are now fast becoming the worldwide standard for large capacity power plants.

2.4 Technical advances and limitations

Combustion of coal generates air pollutants such as particulates, SO_2, NOx and mercury. Emissions of these pollutants have significant impacts on our environment and are detrimental to public health. National and international emissions standards have been established to limit air pollutant emissions from coal combustion, and the standards have become increasingly stringent over the years. There has been an evolution of emissions control technologies such as electrostatic precipitators and fabric filters for particulate control, and flue gas desulphurisation systems for SO_2 removal. The IEA Clean Coal Centre (IEA CCC) has published a number of reports that review and describe air pollutant emission control technologies in detail. These reports are available from the IEA CCC's website (www.iea-coal.org).

The biggest challenge faced by the electric power industry today is to control and ultimately reduce CO_2 emissions from coal combustion in response to concern over global climate change. Coal contains a relatively high carbon content per embedded unit of energy, and emissions of CO_2 and other greenhouse gases from coal are higher than the emissions from other fossil fuels. Collectively, the large number of coal-fired power generation units around the world hold potential to make a substantial contribution to a low-carbon future if emissions of CO_2 can be captured and prevented from entering the atmosphere.

2.4.1 Advances

SC and USC PCC

The need to reduce environmental emissions from coal combustion and maintain coal as a competitive power generation option in the 21st century and beyond are the driving force behind the developments of high-efficiency, low-emissions coal power generation technologies. Increases in net plant efficiency have been achieved in recent years by rigorous optimisation of the overall process. Many factors determine the efficiency of a power plant and the most effective measures of improving the plant efficiency include increasing the live steam temperature and pressure, reducing internal losses in the steam turbine and the parasitic load, and raising steam generator efficiency. The most direct and economical means of achieving high efficiency is to increase the temperature and pressure at the steam turbine inlet well beyond the critical point of water.

Limitations on achievable steam parameters are set by the creep properties of construction materials for high temperature boiler sections, live steam piping and other components, as well as high temperature corrosion resistance of superheater and reheater materials. Historically, the steam parameters have increased with the development of improved materials. Today, state-of-the-art USC units operate with steam parameters between 25 MPa and 30 MPa, and superheat and reheat temperatures up to 605°C and 620°C, respectively. With bituminous coal, plants incorporating USC technology can achieve efficiencies of around 45% (LHV, net). Lignite plants can achieve efficiencies >43% (LHV, net). USC plants are already in commercial operation in Japan, Korea, some European countries, and more recently, in China.

Advanced USC technology

Extensive work has been ongoing worldwide to develop advanced USC (A-USC) coal combustion technology to further increase the efficiency of USC. By using A-USC steam conditions of 700°C to 760°C at pressures of 30 to 35 MPa, net plant efficiencies of 50% (LHV) or higher may be achieved. To raise the pressure and temperature of the steam conditions to those of A-USC systems requires the use of super-alloys (non-ferrous materials based on nickel) for plant components. Super-alloys are already established in gas turbine systems, but component sizes in a coal plant are larger, the combustion situation is different, and pressure stresses are higher. Consequently, new formulations and fabrication methods are necessary. A review on the current status of A-USC pulverised coal technology was conducted by Nicol (2013) at the IEA CCC recently.

Comments

Apart from adoption of SC and USC technologies, efficiency improvement in steam power plants has also been achieved by optimisation of the overall power generation process such as reduction of stack losses, improved combustion, coal drying, advanced controls, reduction in auxiliary power demands, increased steam turbine efficiency, flue gas heat recovery, and improved seal design. The boiler efficiency has been increased over the years through improved boiler design and using optimal operating parameters, for instance lower excess air coefficient and flue gas temperature. The boiler design efficiency for a bituminous coal fired boiler now approaches 95% or higher. Efficiency gain is also obtained from advances in steam turbine design resulting in optimised steam turbine aerodynamics and improved performance of steam path components and all internal stationary components. Furthermore, motivated by the desire to take advantage of economy of scale from the standpoint of capital cost and plant efficiency, maximum unit size has increased steadily with time. Today, the capacity of a single PCC unit can reach up to 1300 MWe. In short, PCC is technically mature with high reliability and flexibility. As a result of continued developments and advances in a range of technologies, today's state-of-the-art PCC power plant can have low emissions and high efficiency.

2.4.2 Limitations

As discussed in Section 2.2, the simplest way to improve the Rankine cycle efficiency is to raise steam temperature and pressure. However, this is limited by the resistance of the material to high mechanical stress when working with high temperatures and pressures. For steam power plants, although the temperature in the furnace can reach 2000°C or higher, the turbine blades cannot operate at more than 610°C. The extent to which the temperatures and pressures of steam condition can be maximised ultimately depends on the performance of the materials and developmental status of the materials technology. The EU, USA, Japan, India and China all have material research programmes aimed at developing the next generation of increased steam temperatures and efficiency, known as A-USC or 700°C technology. However, cost is a major challenge to the commercialisation potential of A-USC technology. The far higher temperatures and pressures to which components in an A-USC system are exposed, as well as altered chemical environment, require the use of super-alloys, which are markedly more expensive than steel. Fabricating and welding the materials is much more complicated. Commercial deployment of A-USC is unlikely to begin until the mid-2020s.

The Rankine cycle efficiency can also be increased by lowering the bottom (heat sink) temperature. This can be achieved by using cold coolant and/or by improving the heat transfer in the heat rejection equipment, most prominently in the power plant condenser, which brings the condensation temperature and pressure of the steam closer to the temperature of the coolant. In the temperature range of ambient coolants, an efficiency improvement of up to about 0.5% is obtained from each °C by which the bottom temperature is lowered (Lior, 2002). For example, the Danish Nordjylland unit 3 is a coal-fired USC power generation unit with double reheat. It has the advantage of cold sea water as coolant (around 10°C), which enables a low condensate temperature to be achieved and hence a very low turbine exhaust pressure of 2.3 kPa. This gives a high volumetric flow in the last stage of the steam turbine, raising output and efficiency. However, the availability of cold coolant depends on the geographic location and local climate. It also raises technical challenges such as high wetness of the steam in the last stages of the low pressure turbine and the length of the last turbine blading.

Although adopting double reheat can improve the unit efficiency, it has high cost and is complex and therefore this approach has not been widely deployed in steam power plants. A balance between performance and costs has to be struck.

In short, the maximum efficiency of a Rankine cycle is restricted by the second law of thermodynamics. The actual Rankine cycle efficiency is limited to below the Carnot efficiency which is determined mainly by the highest cycle temperature because the heat exhaust temperature is generally constrained by the temperature of the environment. As well as the huge investments and extensive R&D on improving the efficiency of steam power plants based on Rankine cycle, substantial efforts have been made to investigate alternative power cycles that can potentially achieve high energy efficiencies and low emissions. The following chapters will review the R&D of some of the alternative power generation systems.

3 Fuel cells

Fuel cells are electrochemical devices that convert chemical energy in fuels into electrical energy (and heat) directly. Because the intermediate steps of producing heat and mechanical work typical of most conventional power generation methods are avoided, fuel cells are not limited by the thermodynamic limitations of heat engines such as the Carnot efficiency. Also, because combustion is avoided, emissions of pollutants from fuel cells are minimal and hence, fuel cells can produce power with high efficiency and low environmental impact.

Fuel cell technology has been under development for a range of applications including large-scale power generation, distributed generation of heat and power at load centres such as remote areas, residential and commercial dwellings, and transport (for instance, cars, buses and locomotives). Extensive R&D is ongoing to develop fuel cells for large base-load power plants because of their high efficiency. The technology is highly efficient, has extremely low emissions, can be applied to a range of fuels (depending upon the type of fuel cell), quiet in operation (the fuel cell itself has no moving parts) and scalable from sub-watts to megawatts scale. As such, fuel cells are considered as one of the most promising technological solutions for sustainable power generation.

3.1 Technology overview

3.1.1 Principle and basic structure

Typically, a fuel cell consists of three main components: an anode, a cathode and an electrolyte that is in contact with the anode and cathode on either side. The building block (basic structure) of a fuel cell is shown in Figure 3. A fuel and an oxidant (often oxygen from air), supplied from external sources, are introduced to the anode and cathode side, respectively. The driving force of the operation is the chemical potential gradient of ions across the electrolyte. Fuel cell electrolytes are electronically insulating but ionically conducting, allowing certain types of ions to transport through them. The electrochemical reduction of the oxygen takes place at the cathode to form oxide ions (O^{2-}) that migrate through the electrolyte, to the anode, and oxidise the fuel (hydrogen in this case) releasing water, heat and electrons that flow around an external circuit and do useful work.

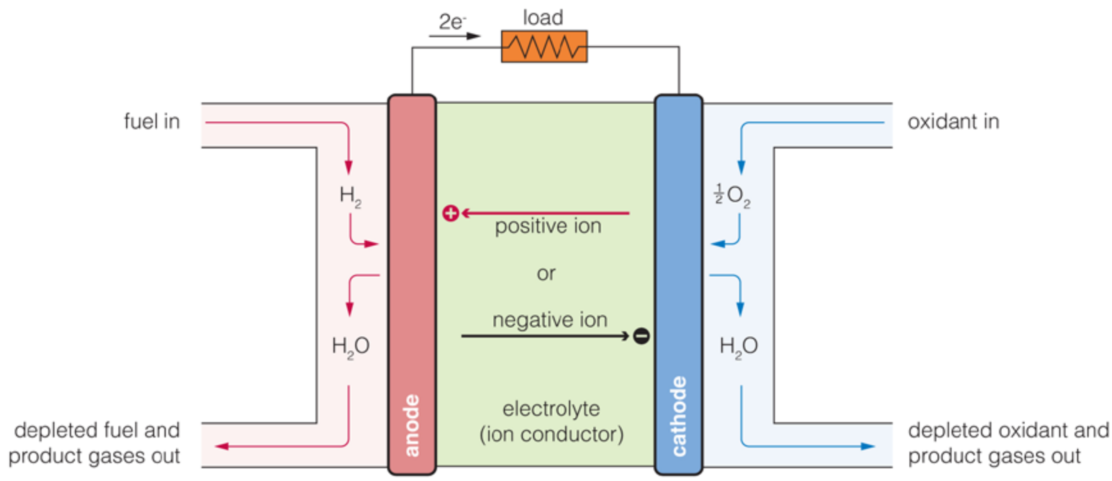

Figure 3 Schematic of an individual fuel cell

In a practical application, fuel cells would be connected in a series of cells in order to obtain higher outlet voltage. When single cells are stacked together to generate more power, two more cell components of interconnect and sealant are required (EG&G Technical Services, 2004; Laosiripojana and others, 2009).

3.1.2 Types of fuel cells

A variety of fuel cells are in different stages of development and they differ from one to another in operating parameters and technical characteristics such as power density and efficiency. However, the fundamental feature of the fuel cell that is different from each other is the electrolyte and therefore, the most common classification of fuel cells is by the type of electrolyte used in the cells. There are five main fuel cell types: 1) polymer electrolyte fuel cell (PEFC), 2) alkaline fuel cell (AFC), 3) phosphoric acid fuel cell (PAFC), 4) molten carbonate fuel cell (MCFC), and 5) solid oxide fuel cell (SOFC). The type of fuel cell and the range of operating temperatures are primarily related to the electrolyte material. Broadly, the choice of electrolyte dictates the operating temperature range of the fuel cell. The operating temperature and useful life of a fuel cell determine the physicochemical and thermo-mechanical properties of materials used in the cell components (electrodes, electrolyte, interconnect, current collector). Aqueous electrolytes are limited to temperatures of about 200°C or lower because of their high vapour pressure and rapid degradation at higher temperatures. Hence, the AFC, PAFC, and PEMFC are considered as low temperature fuel cells, whereas the MCFC and SOFC are high temperature fuel cells. The operating temperature also plays an important role in determining the degree of fuel processing required. In low-temperature fuel cells, all the fuel must be converted to hydrogen prior to entering the fuel cell. In addition, the anode catalyst in low temperature fuel cells (mainly platinum) is strongly poisoned by CO. In high-temperature fuel cells, CO and even CH_4 can be internally converted to hydrogen or even directly oxidised electrochemically (EG&G Technical Services, 2004; Toleuova and others, 2013). The detailed descriptions of the characteristics, advantages and disadvantages as well as the applications of the five main type of fuel cells can be found elsewhere (EG&G Technical Services, 2004; Hermida-Castro and others, 2013). The key technical characteristics of the main fuel cell types are given in Table 1.

Table 1 Technical characteristics of the main fuel cell types(EG&G Technical Services, 2004; Toleuova and others, 2013)

	AFC	PAFC	PEFC	MCFC	SOFC
Electrolyte	Mobilised or immobilised potassium hydroxide in asbestos matrix	Immobilised liquid phosphoric acid in SiC	Hydrated polymeric ion exchange membranes	Immobilised liquid molten carbonate in $LiAlO_2$	Perovskites (ceramics)
Electrodes	transition metals	carbon	carbon	nickel and nickel oxide	perovskite and perovskite/metal cermet
Catalyst	platinum	platinum	platinum	electrode material	electrode material
Interconnect	metal	graphite	carbon or metal	stainless steel or nickel	nickel, ceramic, or steel
Operating temperature, °C	65–220	150–200	40–100	600–700	600–1000
Charge carrier	OH^-	H^+	H^+	$CO_3^=$	$O^=$
Hydrocarbon fuel reforming	yes	yes	yes	No, for some fuels	No, for some fuels and designs
Power density, mW/cm^2	150–400	150–300	300–1000	100–300	250–350
Typical stack size	10–100 kW	400 kW 100 kW (module)	<1–100 kW	0.3–3 MW 300 kW (module)	1 kW-2 MW
Fuel efficiency, %	40–60	55	45–60	60–65	55–65
CO tolerance	poison (<50 ppm)	poison (<1%)	poison (<50 ppm)	fuel	fuel

In parallel with the classification by electrolyte, some fuel cells are classified by the type of fuel used such as direct methanol fuel cells (DMFC) and direct carbon fuel cells (DCFC).

3.1.3 Fuel cell designs

Several types of fuel cell configurations have been developed. The differences among these designs are the method of connecting between each cell, the shape of a single cell, or the flowing of fuel and oxidant through their channels.

Flat plate design

A flat multilayer plate composed of anode, electrolyte, and cathode is used in this design. Individual unit cells are electrically connected with interconnects. Because of the configuration of a flat plate cell, the interconnect becomes a separator plate with two functions: 1) to provide an electrical series connection between adjacent cells, and 2) to provide a gas barrier that separates the fuel and oxidant of adjacent cells. Often, the interconnect plates have small channels that distribute the fuel and oxidant gas flow over the cells. This design is electrically simple and leads to short current paths (which helps to minimise cell resistance).

Depending on the type of fuel cell, the application, and other considerations, the choice of gas-flow arrangement of a flat-plates stack may be cross-flow, co-flow, counter-flow, serpentine flow or spiral flow (EG&G Technical Services, 2004).

Monolithic Design

This design is similar to the shell-and-tube heat exchanger design, as it uses thin cell components and interconnections in a compact corrugated structure. The choice of gas-flow arrangement can be either co-flow or cross-flow. The advantages of this design are compact cells, self-supporting corrugated structures, and thin cell components. However, the main problem of this design is the fabrication of materials. Any difference in the thermal expansion coefficients can result in cell cracking (Laosiripojana and others, 2009). This design applies only to the fuel cells in which the electrolyte is solid.

Tubular Design

Tubular cells have been developed especially for high-temperature fuel cells. In the seal-less tubular cell design, the cell consists of a tubular support tube that is covered with cathode, electrolyte, anode, and interconnection. The oxidant is introduced through the centre of the support tube, whereas the fuel flows at the outside of this support tube. Tubular cells have significant advantages in sealing and in the structural integrity of the cells. However, this design has some disadvantages such as the cell internal resistance and the gas diffusion limitation. They also represent a special geometric challenge to the stack designer when it comes to achieving high power density and short current paths. To minimise the length of electronic conduction paths for individual cells, sequential series connected cells are being developed. The cell arrays can be connected in series or in parallel.

Similar to the seal-less tubular design, segmented cells in series use a tubular porous support tube that is covered with anode, electrolyte, cathode, and interconnection materials. However, in this design, fuel is introduced through the centre of the support tube, while the oxidant flows at the outside of the support tube. In addition, individual segmented cells are connected to each other in series (Laosiripojana and others, 2009; EG&G Technical Services, 2004).

3.2 Fuel cell developments

A potential market for fuel cells is large, base-load stationary power plants operating on coal or natural gas. Another opportunity exists in re-powering older, existing plants with high-temperature fuel cells. MCFCs and SOFCs coupled with coal gasifiers have the best attributes to compete for the large, base-load market. A lot of effort has been made and the work is still ongoing to develop high efficiency, low emissions, coal fuelled power systems using MCFCs and SOFCs. Recently, progress has also been made in the development of direct-carbon fuel cells (DCFC) that convert the chemical energy in carbon directly into electricity without the need for gasification. The following sections provide a brief description of MCFC, SOFC and DCFC and their recent developments.

3.2.1 Molten carbonate fuel cell

Principle of MCFCs

MCFCs use carbonate salts of alkali metals suspended in a porous ceramic matrix as electrolyte. The cell operating temperature is high, at around 650°C in order to keep the alkali carbonates in a highly conductive molten salt form. The higher temperature makes the cell less prone to carbon monoxide poisoning than lower temperature systems and hence MCFC systems can operate on a diverse range of fuels including coal-derived fuel gas, methane or natural gas.

The electrodes reactions for MCFC are as follows:

at the cathode: $2CO_2 + O_2 + 4e^- \rightarrow 2CO_3^{2-}$ (1)

at the anode: $2H_2 + 2CO_3^{2-} \rightarrow 2H_2O + 2CO_2 + 4e^-$ (2)

overall: $2H_2 + O_2 \rightarrow 2H_2O$ (3)

At the operating temperature of around 650°C, the cell reactions proceed vigorously, and the nickel in the anode catalyses the reaction between carbon monoxide and steam producing hydrogen and carbon dioxide. In other words, CO can be used in MCFCs as a fuel. Natural gas needs to be steam reformed in the presence of a suitable catalyst to convert it into a hydrogen enriched gas mixture by the following reaction:

$CH_4 + H_2O \rightarrow 3H_2 + CO$ (4)

Typically the CO_2 generated at the anode is recycled to the cathode where it is consumed. This requires additional equipment to either transfer the CO_2 from the anode exit gas to the cathode inlet gas or produce CO_2 by combustion of the anode exhaust gas and mix this with the cathode inlet gas.

Advantages and disadvantages

Advantages

The relatively high operating temperature of the MCFC results in several benefits: 1) no expensive electro-catalysts are needed as the nickel electrodes provide sufficient activity; 2) both CO and certain hydrocarbons are fuels for the MCFC simplifying the balance of plant (BOP) and improving system efficiency up to low fifties; 3) the high temperature waste heat allows the use of a bottoming cycle to further boost the system efficiency to >60%.

Disadvantages

Two major difficulties with MCFC technology put it at a disadvantage compared to SOFC. One is the complexity of working with a liquid electrolyte rather than a solid. The other stems from the chemical reaction inside the cell. Carbonate ions from the electrolyte are used up in the reactions at the anode, making it necessary to compensate (usually by recycling the anode exhaust) representing additional BOP components. Also, the higher temperatures promote material problems, impacting mechanical stability and stack life.

Recent developments

Fuel cell systems based on MCFC technology have been under development in Italy, Japan, South Korea, USA and Germany. Over the past three decades several corporations have tried to develop MCFC power plants, including GE, United Technologies Corporation and FuelCell Energy (FCE, formerly Energy Research Corporation).

The performance of single cells has improved considerably in the past few decades. The power density of a single cell has increased from about 10 mW/cm^2 to >150 mW/cm^2, and the cell area has been scaled-up by 50%. Stack performance improvement has been achieved in the areas of cell conversion efficiency, thermal management, thermal cycle capability, and high-power operation. Developments in advanced materials have resulted in extended stack life (>40,000 hours) and reduced product cost. The cost of material for a bipolar plate has been lowered by a factor of 7 and advanced corrosion resistant cathode current collectors have reduced corrosion (by a factor of 2) and electrolyte loss (Maru and Farooque, 2005). Comprehensive computer models have been developed and are used to study the hydrodynamics, kinetics, electrochemical, and heat transfer processes and to optimise the cell/stack design. The stack temperature distribution has been improved significantly, allowing 20% higher power operation of full-size stacks without penalty in thermal management. This latest improved design is being incorporated to full-size stacks. The full-size stack capacity has steadily increased. Today, a single cell stack can produce up to 2.8 MW electric; has a stack life of five years and is 9000 cm^2 in area (Maru and Farooque, 2005; Bayar, 2014). Work is ongoing at FCE to further improve the cell technology to increase the output to 3 MWe and increase the stack life to seven years.

The development of an internal reforming MCFC system eliminates the need for a separate fuel processor for reforming carbonaceous fuels. It integrates a reformer within a cell stack so that the heat generated by the cell reactions can be effectively used as the heat of reaction for fuel reforming.

MCFC power systems have now been installed to meet the base load power requirements of a wide range of commercial and industrial customers including waste water treatment plants (municipal, industrial, and food processing), telecommunications/data centres, manufacturing facilities, hospitals, universities, prisons, hotels and government facilities as well as grid support applications for utility customers. Today, the US-based FCE remains the only major commercial developer of MCFCs which manufactures large stationary systems in sizes of 300 kW (DFC300), 1.4 MW (DFC1500) and 2.8 MW (DFC3000). In recent years, there has been a significant increase in the number of MCFC systems installed (from 2010 to 2011, the megawatts of MCFC shipped annually increased almost six times) clearly indicating the commercialisation of this technology. In February 2014, the construction of the world's largest fuel cell power plant, the 58.8 MWe Gyenggi Green Energy Park in Hwaseong, South Korea was completed. The natural gas-fuelled simple cycle power plant uses 21 FCE's Direct Fuel Cell (DFC3000) base units, rated at 2.8 MWe each, and provides continuous baseload power to HwaseongCity's grid. The plant has an efficiency of 47% (LHV) and extremely low emissions. The design values for air pollutant emissions are: NOx 4.54 g/MWh, SO_2 0.045 g/MWh, PM_{10} 0.009 g/MWh, CO_2 444.5 kg/MWh and with waste heat recovery 235.9–308.4 kg/MWh. The plant also has low water consumption. In November 2012, FuelCell Energy's partner in Korea, POSCO Energy, placed an order for a total of 121.8 MW of fuel cell kits which is the largest ever for both the company and the fuel cell industry with a value of $181 million. FCE also built a 14.9 MW fuel cell park in its home state of Connecticut, which has been operational since December 2013. The US's utility company Dominion owns and operates the plant and sells the electricity to Connecticut Light and Power under a 15-year power purchase agreement. To date, some 60 stationary power plant installations using FCE's DFC fuel cells supply baseload power in five countries (FuelCellToday, 2013, 2012; www.fuelcellenergy.com/).

3.2.2 Solid oxide fuel cells

Operating principles

SOFCs have an electrolyte that is a solid, non-porous metal oxide, usually Y_2O_3-stablilised ZrO_2. The cell operates at 600–1000°C. The anode is typically a porous Ni-ZrO_2 cermet and the cathode is commonly a porous strontium-doped lanthanum manganite ($LaMnO_3$).

Hydrogen is normally used as fuel, but carbon monoxide (CO) can also be used as the fuel together with hydrogen. H_2 and/or CO react with O^{2-} at anode releasing water, electrons and heat. The high operating temperature of SOFCs enables the direct oxidation of methane (CH_4, the primary constituent of natural gas). Consequently, the direct use of a hydrocarbon gas instead of hydrogen or carbon monoxide is possible.

Advantages and disadvantages

Advantages

- high efficiency: as with the MCFC, the high operating temperature allows use of most of the waste heat for cogeneration or in bottoming cycles. Efficiencies ranging from around 40% (simple cycle small systems) to over 50% (hybrid systems) have been demonstrated. A system efficiency of 60% (HHV), including >97% CO_2 capture, may be achieved with an advanced catalytic gasifier and pressurised SOFC;
- ease of CO_2 capture: carbon capture is facilitated since the anode (fuel) and cathode (air) streams are separated by the electrolyte. All carbon enters the SOFC with the fuel on the anode side and exits in the anode off-gas as CO_2. The residual fuel in the anode off-gas (approximately 10–15%) can be combusted in oxygen, producing a stream that contains only H_2O and CO_2. Condensing out the H_2O leaves an exhaust stream that contains mainly CO_2 ready for compression and storage;
- fuel flexibility: SOFCs can operate on H_2, and hydrocarbon fuels, including coal-derived syngas and natural gas;

- low water consumption: like all fuel cell systems, water in the anode effluent is easily captured and reused in the system. SOFC systems use approximately one-third the amount of water relative to conventional combustion-based power systems.

In addition, because the electrolyte is solid, the cell can be cast into various shapes, such as tubular, planar, or monolithic. The solid ceramic construction of the unit cell alleviates any corrosion problems in the cell. The solid electrolyte also allows precise engineering of the three-phase boundary and avoids electrolyte movement or flooding in the electrodes (US DOE, 2013; EG&G Technical Services, 2004).

Disadvantages

The high temperature of the SOFC has its drawbacks. There are thermal expansion mismatches among materials, and sealing between cells is difficult in the flat plate configurations. The high operating temperature places severe constraints on materials selection and results in fabrication difficulties. Corrosion of metal stack components is a challenge. These factors limit stack-level power density (though significantly higher than in PAFC and MCFC), and thermal cycling and stack life (EG&G Technical Services, 2004).

Recent developments

The US DOE's Solid Oxide Fuel Cells program is being conducted under the Clean Coal Research Program (CCRP). The research of key technologies in the Solid Oxide Fuel Cells program and the development of the respective power systems are coordinated through the Solid State Energy Conversion Alliance (SECA), which was set up in 2001 consisting of three groups: the Industry Teams, the Core Technology Program, and Federal Government Management. The primary objective of the SECA program is central-station power generation with a coal feedstock that generates cost-effective electricity, with near-zero levels of air pollutants, facilitates >97% CO_2 capture, and has an efficiency of ≥60% (HHV), with minimal raw water consumption. Concerted R&D efforts, especially through the US DOE's SECA program, have resulted in considerable advances in the knowledge and development of SOFC technologies.

Early on, the limited conductivity of solid electrolytes required cell operation at around 1000°C. However, the high temperature imposes some limitations to SOFC, especially to the materials used. Currently, yttrium stabilised zirconia (YSZ) is the most commonly used electrolyte for SOFC. The development of colloidal fabrication and co-sintering processes allows YSZ membranes to be produced as thin films (~10 µm) on porous electrode structures. These thin-film membranes improve the performance and reduce operating temperatures of SOFCs to 650–850°C, leading to the development of compact and high-performance SOFC which utilise relatively low-cost construction materials. Electrolytes made of other materials, such as scandium-doped zirconia and gadolinium-doped ceria or cerium gadolinium oxide, are found to have higher reactivity at even lower temperatures but their applications are limited due to the availability and price of Sc and Gd as well as some technical problems (EG&G Technical Services, 2004; Laosiripojana and others, 2009).

Via improvements in electrolyte and cathode materials and designs, the cell power density has been increased by 36% to approximately 300 MW/cm^3. The active power-generating area of individual cells has increased by over a factor of 5 and stack size has increased by a factor of 25 in recent years. Module stacks rated at approximately 25 kWe have been tested for over 1500 hours and voltage degradation of less than 1%/1000 hours have been observed (US DOE, 2013).

One of the greatest hurdles facing fuel cells has been the cost. Developments in fuel cell technologies such as cell performance improvements, increased power density, enhanced reliability, and advanced manufacturing techniques have resulted in a significant reduction in the cost of SOFCs over the past decade. The stack cost has been reduced from >1500 $/kW in 2000 to around 150 $/kW (2007 US dollar) in 2010 (US DOE, 2013).

SOFCs remain a popular technology, particularly in the stationary power generation sector. The technology is still under development but it is beginning to emerge in the commercial market. Data centre operators like Apple, Google, eBay and Microsoft, have started to experiment with Bloom Energy's SOFCs for clean and distributed power to their Internet operations. In July 2014, US utility company Exelon Corporation announced that it agreed to buy Bloom Energy's SOFC power plants with a capacity of 21 MWe (http://www.bloomenergy.com/newsroom/press-release-07-29-14/). Recently, Bloom Energy also received a €91.5 million investment from German utility E.ON, suggesting E.ON is positioning itself to introduce fuel cell power plants to the European market (FuelCellToday, 2013).

3.2.3 Direct carbon fuel cells

In a DCFC, the overall cell reaction is based on electrochemical oxidation of carbon to carbon dioxide. This reaction proceeds via mechanisms that vary with cell design and electrolyte. Electrolytes that are under development include solid oxide, molten carbonate and molten salt. Depending on the electrolyte, oxygen, carbonate or hydroxide ions participate in the oxidation-reduction reaction.

Molten salt DCFC

The molten salt DCFC uses molten hydroxide (NaOH or KOH) as electrolyte that is contained in a metallic container. Air is purged into the molten salt at the bottom of the container to supply oxygen at the cathode. The metallic container also acts as a cathode. Fuel is fed to the cell in the form of a rod made from graphite or coal derived carbon dipped into the electrolyte. This fuel rod also acts as an anode of the cell and hence it runs as a battery and not as a fuel cell. Typical operating temperatures are in the range 500–650°C.

Molten carbonate DCFC

This type of fuel cell uses molten carbonates as the electrolyte and fine particles of carbon dispersed into the electrolyte as the fuel. Mixed molten carbonates of lithium, potassium and/or sodium are used due to high carbonate conductivity and good stability in the presence of carbon dioxide. The ionic species that carry the charge between the electrodes are the carbonate ions (CO_3^{2-}). The typical operating temperature of this type of fuel cell is in the range of 750–800°C.

The major technical issues related to this type of fuel cell are high cathode polarisation losses, corrosion of metal clad bipolar plates and scaling up. Furthermore, the fuel related issues include lack of a suitable fuel delivery system for long term and continuous operation, poor understanding of the relationship between carbon structure and its chemical and electrochemical reactivity, and electrolyte tolerance to high percentages of contaminants such as sulphur and ash (Badwal and Giddey, 2010).

Solid oxide DCFC

This type of fuel cell uses oxygen ion (O^{2-}) conducting ceramic (typically YSZ) as the electrolyte similar to that in SOFC and operates in a temperature range of 800–1000°C. There are three subcategories of this type of DCFCs differing in materials and design of the anode and the method of fuel delivery to the electrode/electrolyte interface:

- carbon mixed with a molten metal;
- carbon mixed with a molten salt including molten carbonate;
- solid carbon as fuel in a fluidised bed reactor.

Liquid metal anode (LMA) SOFC

In this technology molten metal is used as the anode and solid carbon fuel carrier. The molten (liquid) metal anode resides in a layer between the fuel chamber and the solid electrolyte. The O^{2-} ions react electrochemically with the liquid metal, generating metal oxide which is the active species for the oxidation of the carbon, producing CO_2. However, the exact mechanism occurring and the species involved in the liquid metal anode media are not well defined and depend upon the metal used.

The molten metal blocks direct contact of electrolyte with gaseous impurities and hence reduces electrolyte degradation. Furthermore, the fuel contaminants can become a fuel source themselves as they undergo electrochemical oxidation (Toleuova and others, 2013).

Solid carbon in molten salt

This technology utilises a circulating liquid-molten salt/carbonates containing carbon fuel as the anode and oxygen-ion conducting ceramic as the electrolyte. In one configuration, the cell employs a cathode supported tubular cell geometry. Air is supplied via a concentric tube to the cathode consisting of a metal current collector and strontium-doped $LaMnO_3$ (LSM) as the catalyst layer. The circulating molten salt/carbonates mixed with carbon fuel particles are supplied to the anode, which also has a metal mesh/coil current collector. Various types of fuels such as biomass, coal, coke and tar have been tested on this cell. This type of fuel cell is a hybrid between molten carbonate and solid oxide fuel cells with similar materials issues (corrosion of nickel anode and other cell components, and stability of YSZ electrolyte in molten carbonate environments) (Badwal and Giddey, 2010; Jain and others, 2008).

Solid carbon as fuel in a fluidised bed reactor

This technology is based on direct electrochemical reaction between the solid carbon at the anode and oxygen ions (O^{2-}) being transported through the ceramic electrolyte membrane from the cathode to the anode. The anode side is in direct contact with the carbon particles typically using a fluidised bed reactor. In the fluidised bed reactor, fine particles of carbon fuel are suspended by blowing in a non-reactive gas such as CO_2 through the bottom of the reactor for continuous fuel feed to the anode/electrolyte interface. A collection of unit cells is arrayed along the reactor. Mostly the developmental work on this technology has so far been concentrated on button cells consisting of a ceramic electrolyte disk with a nickel based anode and a LSM based cathode. The major technical issues apart from those associated with SOFC are the solid fuel delivery to anode/electrolyte interface, and a lack of understanding of carbon oxidation reaction mechanisms at the interface (Badwal and Giddey, 2010; Gur and Huggins, 1995).

The DCFC technology is still at an early stage of development and substantial work is needed to take it to the pre-commercialisation stage. To date, most researchers have focused on workable cell designs and testing single cells or small stacks. The power densities are low, typically in the 100–120 mW/cm^2 range compared with 300–600 mW/cm^2 for many other fuel cell types and are strongly dependent on the fuel delivery system and the anode catalyst or current collector used. The status of the DCFC technologies discussed above are summarised Table 2.

Table 2 The status of the DCFC technologies (Badwal and Giddey, 2010)

DCFC technology	Status
Molten hydroxide	Average power densities of 40 mWcm^{-2} for over 540 hours of operation with peak power density of 180 mWcm^{-2}. The maximum efficiency achieved is 60%.
Molten carbonate	Power densities up to 100–120 mWcm^{-2}, and 80% efficiency with fuels such as fossil chars, petroleum coke, carbon blacks.
Solid oxide	
Solid carbon feed	The peak power density achieved is reported to be 140 mWcm^{-2} at 900°C with synthetic carbon agitated with CO_2.
Carbon mixed with molten metal	The peak power density achieved so far is about 160 mWcm^{-2} and 80 mWcm^{-2} respectively from hydrogen and liquid fuel JP-8. Cells, small stacks and systems were built and tested for short periods of time.
Carbon mixed with molten carbonate	The peak power density achieved is 120 mWcm^{-2} using acetylene black as the fuel. A 6 W 6-cell (6 cathode/electrolyte tubes in a single molten salt bath) demonstration stack using different fuels has been tested.

3.2.4 Pressurised fuel cells

Pressurising a fuel cell improves process performance allowing for more efficient cell and system operation. In the USA, efforts are focused on the development of a pressurised SOFC system. Southern California Edison Company operated a 250 kWe tubular prototype SOFC coupled with a conventional gas turbine at the Irvine University campus (California). It was pressurised to 350 kPa and gave 200 kWe; a coupled microturbine gave an additional 50 kWe (EG&G Technical Services, 2004).

In Japan, Ishikawajima-Harima Heavy Industries and Hitachi developed 250-kW stacks and built a 1 MW MCFC pilot plant with an external reformer at Kawagoe, Mie Prefecture, consisting of four 250 kW stacks. The test operation started in July 1999 and ended in January 2000 after 5000 hours of successful test operations. Based on the successful results, Japan then focused on commercialisation and the development of a pressurised 300 kW MCFC cogeneration system, which would be followed by a 750 kW system.

Mitsubishi Hitachi Power systems (MHPS, a joint venture between Mitsubishi Heavy Industries and Hitachi) have been actively developing pressurised, tubular SOFCs and SOFC combined cycle systems. A 200 kW class, atmospheric SOFC-MGT combined-cycle system that integrates tubular SOFCs and a micro gas turbine (MGT) has been developed and tested since 2004. The SOFC-MGT combined-cycle system achieved a net power output of 204 kWe-AC and a net electrical efficiency of 52.1% (LHV). No deterioration of the SOFC voltage was observed after 3224 hours of operation and four thermal cycles (the shut-down start-up process). Continued technological development and design optimisation led to the field-demonstration of a 250 kW (net), pressurised-SOFC-MGT system which started in 2012. During initial tests in 2012, a system efficiency of 50.2% (LHV) was achieved (the target efficiency is 55% or higher) and it had been successfully operated for 4100 hours continuously without voltage degradation. The test also showed that at 1.5 MPa the operating voltage of a cell-stack improved by approximately 10% compared with that of atmospheric pressure using hydrogen fuel, and the current density at 0.85 V almost doubled compared to that at atmospheric pressure (Kobayashi and others, 2014, 2011). MHPS is currently undertaking the development of a triple combined cycle system that integrates pressurised-SOFCs with utility gas turbine and steam bottoming cycle.

The enhanced performance by increasing pressure may be offset by increased costs, particularly those associated with the fuel cell stack enclosure, additional operational risks and a more complex integration with associated subsystems. A deeper understanding is needed of the behaviour of the SOFC material set under pressurised operation and the effect of pressure on cell performance, reliability, and degradation.

3.3 Fuel cell power systems

The fuel flexibility of MCFC and SOFC allows the syngas produced by gasification of coal to be used to fuel the fuel cells. In addition, the high cell operating temperatures offers the best opportunity for thermal integration with coal gasification systems. Various fuel cell power system configurations that can potentially achieve high energy efficiency and excellent environmental performance have been proposed and investigated.

3.3.1 Integrated gasification fuel cell (IGFC) systems

The IGFC power plant is similar to an IGCC power plant, but with the gas turbine power island replaced with a fuel cell power island. Various IGFC power plant design concepts have been developed, generally consisting of three main parts: gasification island, fuel cleaning and processing and power island as shown in Figure 4. The power system configuration varies depending on the choice of technologies. Given the number of technologies available for gasification, syngas cleaning and processing, fuel cell systems and waste heat recovery, a number of IGFC plant configurations have been proposed and studied.

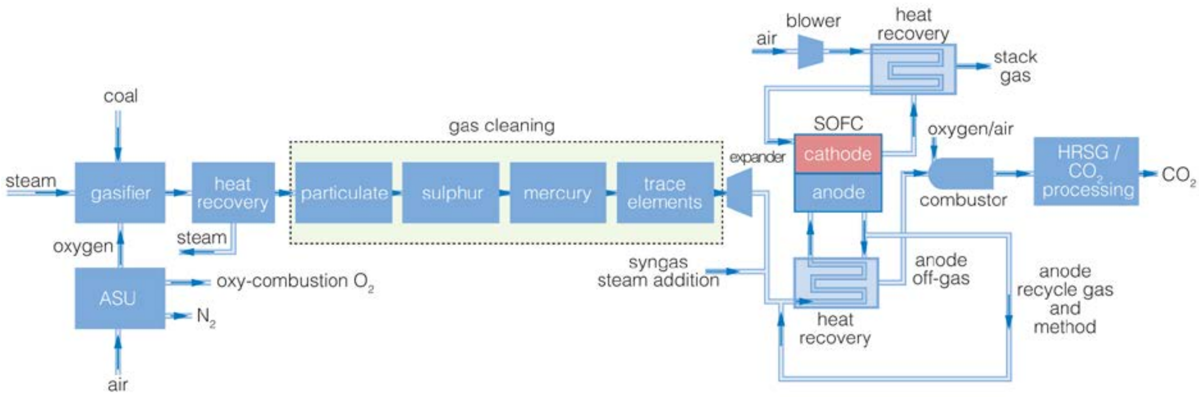

Figure 4 Flow sheet of a coal-fed IGFC system (Keairns and Newby, 2010)

In a recent study, Newby and Keairns (2011) analysed four IGFC plant configurations. All the plants are designed for coal-fed baseload operation with a net plant capacity of 500 MWe, use conventional dry syngas cleaning and polishing technology and all apply advanced, planar, SOFC technology with separate anode and cathode off-gas streams, and incorporate anode off-gas oxy-combustion for nearly complete carbon capture. The plant configurations can be described as follows:

- plant 1 (baseline design): like an IGCC plant, consists of the coal receiving and storage area, the air separation unit, the gasification area, the gas cleaning area, the power island, and the CO_2 dehydration and compression area. An oxygen-blown, entrained-flow gasifier is selected. The power island consists of a syngas expander, the atmospheric-pressure SOFC unit with DC-AC inverters, an anode off-gas oxy-combustor, a heat recovery steam generator and a steam bottoming cycle;
- plant 2: essentially same as plant 1 except pressurised SOFC is utilised;
- plant 3: catalytic gasifier is used to produce a syngas containing higher concentrations of methane, the rest is the same as in plant 1;
- plant 4: catalytic gasifier is used, the rest is the same as in plant 2.

The main results from this study are given in Table 3. Their results (not shown in Table 3) showed that compared with conventional bituminous-coal-fired power plant with 90% CO_2 capture, the IGFC plants could achieve higher electrical efficiency with >98–99% CO_2 removal. The emissions of other air pollutants from the IGFC power plants were also lower. The results in Table 3 clearly show that the introduction of pressurised-SOFC results in a substantial increase in the net plant efficiencies. However, using pressurised-SOFC provides little or no cost benefit over atmospheric-pressure SOFC plants. The researchers claimed that IGFC using an advanced catalytic coal gasifier and atmospheric-pressure SOFC would provide the greatest benefits, with the cost of electricity projected to be significantly lower than IGCC, PCC, and NGCC (natural gas turbine combined cycle) all with CCS.

Table 3 Performance and costs comparison of IGFC power plants with different configurations(Newby and Keairns, 2011)

	Conventional gasifier		**Catalytic gasifier**	
	Atmospheric pressure SOFC	Pressurised SOFC	Atmospheric pressure SOFC	Pressurised SOFC
Coal feed,kg/h	182246	146735	135961	115524
Cell voltage, V	0.816	0.937	0.787	0.912
Plant efficiency, %, HHV	40	49.6	50.5	59.4
Raw water consumption, L per min/MW	13.96	10.00	11.32	8.23
CO_2 emission, kg/MWh	2.5	5.7	1.8	5.7
Capital cost*, $/kW	3001	2436	2194	2026
COE, mills/kWh	96.3	74.2	79.8	66.1
Cost of CO_2 avoided, $/t	46.8	19.3	26.3	9.1
*plant total overnight cost				

In a similar study conducted earlier on IGFC combined cycle power plants that integrated a gasifier with a SOFC system, a gas turbine and a steam bottoming cycle (Grol and Wimer, 2009), the performances of the IGFC plants with three different configurations were evaluated. The results were consistent with those obtained by Newby and Keairns (2011) shown above (*see* Table 4) indicating that IGFC plants can achieve high net plant efficiency with CO_2 capture. The efficiency of Case 1 (using existing BOP and current state of the art SOFC technology) with carbon capture is comparable to that of a typical IGCC plant without carbon capture. Figure 5 compares the efficiencies of the IGFC combined cycle plants with those of PCC and IGCC plants with and without carbon capture. The IGFC plants also have considerably lower water consumption than PCC and IGCC plants.

Table 4 IGFC system summary and performance (Grol and Wimer, 2009)

	Case 1	**Case 2**	**Case 3**
Gasifier	Two-stage, full slurry quench	Catalytic gasifier	Catalytic gasifier
Gas cleaning	Dry gas cleaning	Dry gas cleaning	Humid gas cleaning
SOFC	Atmospheric pressure; single pass; 80% fuel utilisation	Atmospheric pressure; anode recycle; 82% fuel utilisation (overall)	Pressurised SOFC; anode recycle; 85% fuel utilisation (overall)
Steam cycle	SC	SC	none
Plant efficiency, %, HHV	42.3	49.6	56.5
Plant efficiency without CO_2 compression, %, HHV	45.8	52.9	59.9
Water consumption, L/MWh	1250	964	664
CO_2 capture, %	99	99	93

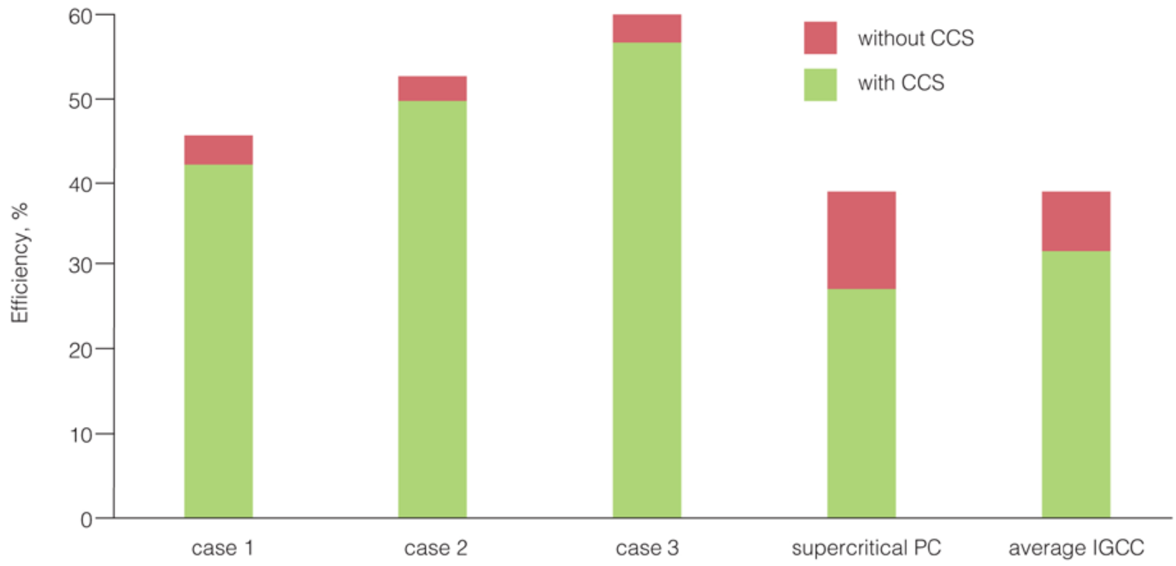

Figure 5 Efficiency comparison (Grol and Wimer, 2009)

Gerdes and colleagues (2009) analysed the performance and costs of IGFC gas/steam turbine combined cycle plants, one using atmospheric-pressure SOFC and the other pressurised SOFC. Both plants use an advanced, catalytic coal gasifier operated with oxygen and steam injection, and oxygen is produced using conventional cryogenic air separation technology. The atmospheric-pressure SOFC IGFC plant uses conventional dry gas cleaning technologies for syngas cleaning, while the pressurised IGFC plant uses advanced humid gas cleaning technologies. The process flow diagrams of the two plants are shown in Figure 6. The results are summarised in Table 5 and are compared to those of a conventional IGCC plant. Again, the results show that IGFC plants with CCS can achieve significantly higher energy efficiency with nearly complete CO_2 capture and substantially lower water consumption than an IGCC plant with CCS. The capital cost and cost of electricity (COE) of IGFC are also lower than that of IGCC. It should be noted that the advanced catalytic gasification technology is still under development and is not yet commercially available.

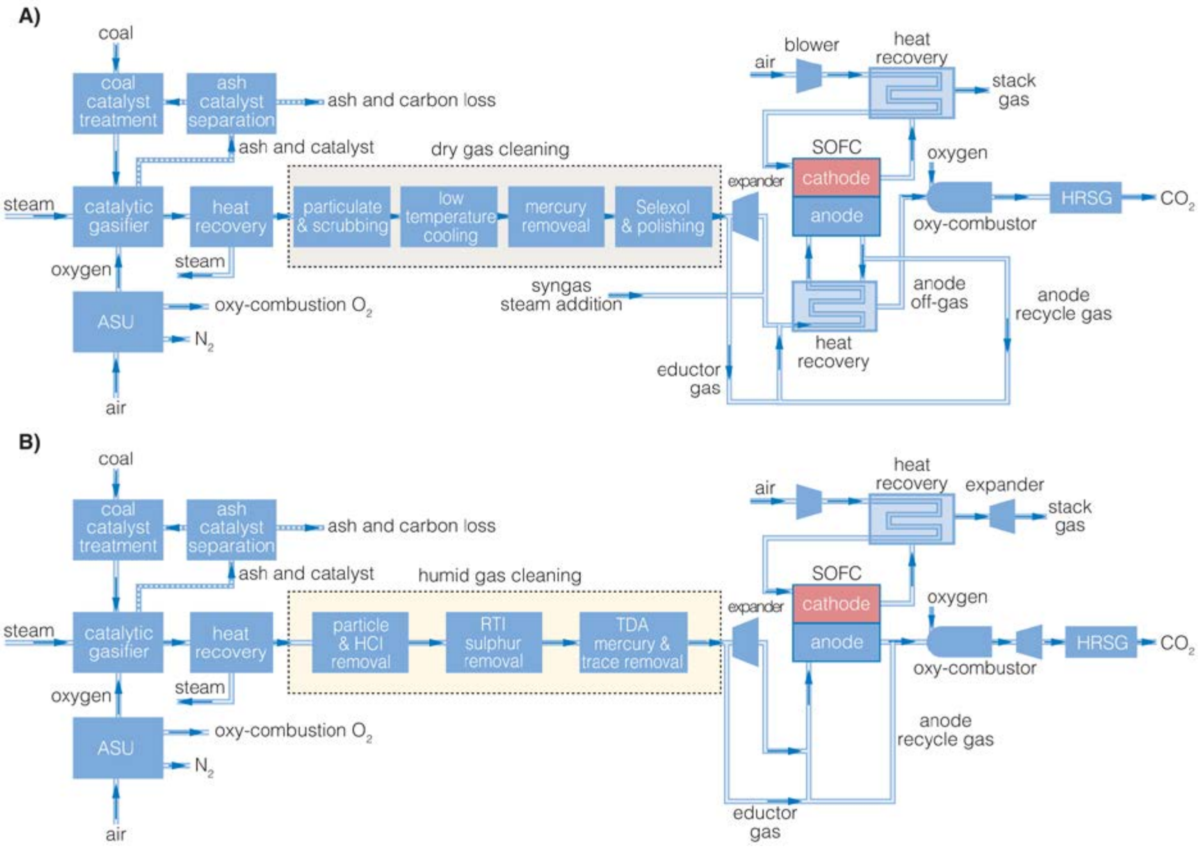

Figure 6 Simplified flow diagram of SOFC IGFC plant – A) atmospheric pressure SOFC IGFC plant, B) pressurised SOFC IGFC plant (Gerdes and others, 2009)

Table 5 Comparison of IGFC and IGCC with CCS (Gerdes and others, 2009)

	IGCC	Atmospheric pressure IGFC	Pressurised IGFC
Efficiency, %	32.5	49.4	56.2
CO_2 emission, kg/MWh	93.44	1.36	1.36
Water consumption, L/MWh	2246	877	782
Capital cost, 2007$/kW	2400	2000	1800
LCOE, cents/kWh	10.2	8.8	7.9

More recently, Lanzini and others (2012) conducted techno-economic analyses of pressurised-SOFC IGFC plants with CCS. The pressurised SOFC was fed with syngas (Direct case) or reformed syngas using the partial methanation process TREMP or HICOM. Their results showed that the IGFC-CCS with HICOM gave best thermodynamic and economic performance (*see* Table 6). When compared with an IGCC-CCS plant, IGFC plants all had higher plant efficiencies and lower costs.

Table 6 Techno-economic performance comparison of IGFC and IGCC (Lanzini and others, 2012)

	IGCC-CCS	IGFC-CCS-Direct	IGFC-CCS-TREMP	IGFC-CCS-HICOM
Power, MWe	517	859	841	915.4
Efficiency, %, LHV	33.5	47.0	46.0	50.1
Total plant cost:				
Million US$	1424	1897	1926	1851
$/kWe	3069	2460	2551	2253
LCOE, $/MWh	109.6	85.6	89.8	78.9

Adams and Barton (2010) evaluated the pressurised-SOFC IGFC combined cycle power plant using different cooling technologies. They found that even with carbon capture, the IGFC plant had higher efficiency (4–10 percentage points) than that of PCC or IGCC plant without carbon capture and consumed significantly less water, as shown in Figure 7. If cooling towers were replaced with dry-cooling technology, net water could be produced and recovered, rather than consumed.

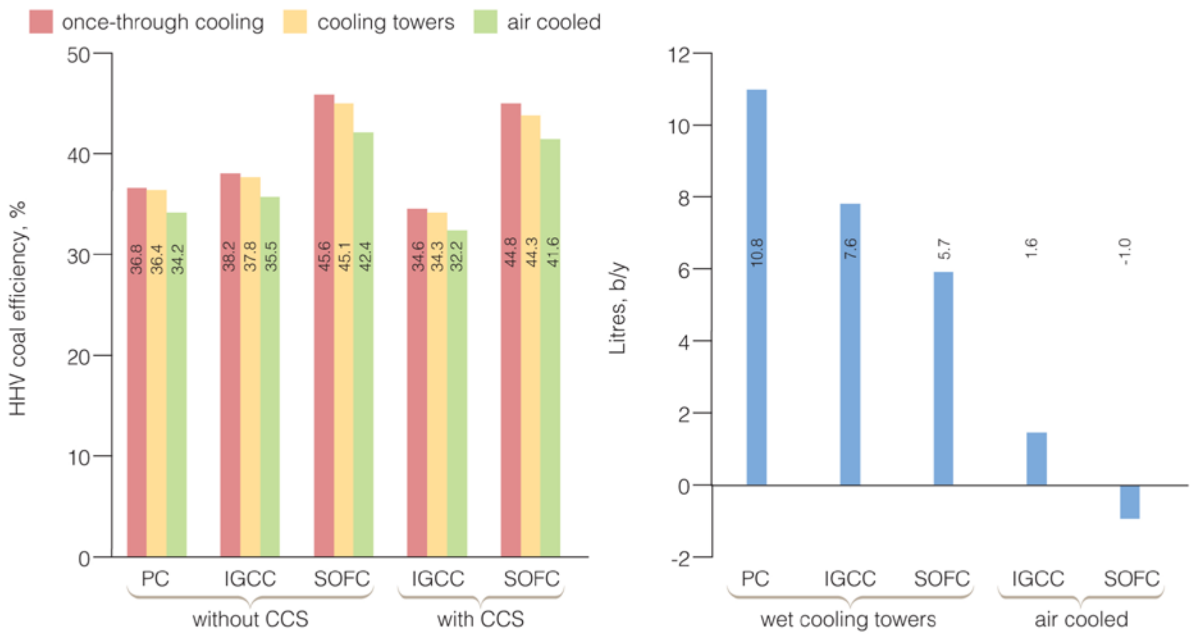

Figure 7 Variations in plant efficiency and water consumption with water cooling technology (Adams and Barton, 2010)

Romano and co-workers (2011) proposed two configurations of pressurised-SOFC IGFC power plant with CO_2 capture based on (a) anode exhaust oxy-combustion and (b) syngas methanation and hydrogen firing, respectively, as illustrated in Figure 8. In the configuration (b), a methanation process is used to increase the methane content of fuel gas and hence reduce the air flow rate needed for SOFC cooling and improve the energy conversion efficiency. The hydrogen firing before the gas turbine and a post-SOFC absorption process for CO_2 capture are used to recover the unreacted hydrogen in the cathode exhaust to fuel the gas turbine and hence increase the turbine inlet temperature. They performed techno-economic analyses of the plants and concluded that a considerable improvement in plant efficiency was achievable using plant

(b) configuration although the integration was highly complex. For a 95% CO_2 capture, a net plant efficiency of 51.6% was calculated, 4.5% points higher than that of IGFC plant (a).

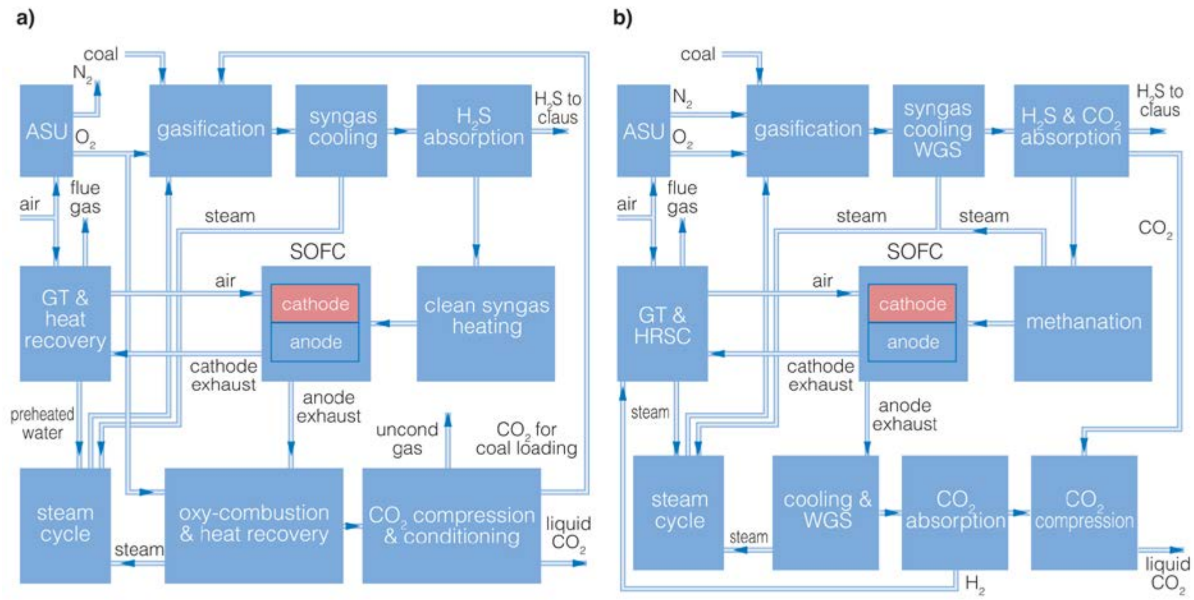

Figure 8 Conceptual layout of the IGFC plants using: (a) syngas fuelled SOFC with anode exhaust oxy-combustion; (b) SOFC with syngas methanation and hydrogen firing (Romano and others, 2011)

Integrated gasification fuel cell (IGFC) is one of the technologies being pursued under J-COAL's (Japan Coal Energy Center) CCT Road Map as a high-efficiency, low-carbon generation technology. The Road Map sets targets as well as research, development and demonstration stages to IGFC as a part of Osaki CoolGen demonstration project. The Osaki CoolGen demonstration project is currently underway in Osaki, Hiroshima; this project is based on a Japanese oxygen-blown entrained-type gasifier. The first phase of this project includes only the IGCC plant, the second phase will include CCS, and the third phase will incorporate fuel cells so that the full IGFC technology is implemented with CCS (http://www.jcoal.or.jp/).

3.3.2 Other proposed fuel cell power cycles

Various power cycle concepts integrating fuel cells with other novel technologies have been explored. Braun and others (2012) proposed an IGFC plant combining SOFC and a bottoming organic Rankine cycle (ORC) for highly efficient power generation. The primary plant concept evaluated was based on a 150 MW pressurised-SOFC integrated with an entrained-flow, dry-fed, oxygen-blown, slagging coal gasifier and gas turbine/ORC combined cycle power generator with CO_2 capture. The system analyses showed that by integrating an ORC up to 8 percentage points of efficiency gain could be obtained, while the use of a steam Rankine cycle in lieu of the ORC could increase the net plant efficiency by another 3.7%. However, operating costs were potentially much lower with ORC than steam power cycles.

For most proposed fuel cell combined power cycles, an externally fired recuperative gas turbine has been adopted. One of the major disadvantages of this layout is the rather low turbine inlet temperature determined by the operating temperature of fuel cells and the unavoidable heat losses of heat exchangers, resulting in lower turbine work while the compressor work remains constant. Consequently, useful work is reduced. To overcome this, Sánchez and others (2009, 2011) proposed to integrate MCFC or intermediate temperature SOFC with a supercritical CO_2 (sCO_2) bottoming cycle. sCO_2 cycle is an innovative technology that uses supercritical CO_2 as working fluid. This technology is under development and is described in detail in Section 6.1 of this report. CO_2 has relatively low critical pressure and temperature leading to a significant reduction in compressor work and therefore an increase in gas turbine generator output.

Table 7 Design performance of MCFC-GT and MCFC-sCO_2(Muñoz de Escalona and others, 2011)

	Air	sCO_2
MCFC		
Current density, A/m^2	1100	
Temperature, °C	650	
Fuel utilisation, %	75	
Carbon utilisation, %	70	
Efficiency, %	50.5	
Gross power, kW	500	
Bottoming cycle		
Compressor inlet, °C/MPa	25/0.1013	35/7.50
Turbine inlet, °C/MPa	377/0.2881	377/21.61
Efficiency, %	26.6	39.9
Power, kW	86.7	129.9
Hybrid system		
Net efficiency, %	55.0	59.4
Net power, kW	540.4	583.6
Gas turbine contribution, %	14.8	20.6

The system proposed is based on an atmospheric pressure fuel cell integrated with a bottoming closed cycle sCO_2 gas turbine as opposed to the open cycle hot air turbine used in conventional hybrid systems. Their analyses showed that the sCO_2 cycle required significantly lower compression work, only 30% of the work generated by the turbine compared to 60% consumed by the hot air turbine. It was reported that although an atmospheric pressure fuel cell was used, the new system could still achieve the same overall efficiency and power output as those pressurised fuel cell power cycles commonly considered. A net plant efficiency of nearly 60% could be achieved by an MCFC-sCO_2 hybrid power cycle. The bottoming sCO_2 cycle achieved 50% higher efficiency than the reference hot air turbine for the same turbine inlet temperature (Sánchez and others, 2009, 2011; Muñoz de Escalona and others, 2011).

In summary, coal-fed IGFC power generation systems can potentially achieve high net plant efficiencies (up to 60%), low air emissions with almost complete carbon capture. Natural gas fuelled FC power plants are already in commercial operation in many parts of the world. Coal-based FC power systems are still under development. In spite of significant advances which have been made in FC technologies, technical challenges remain and substantial work is needed to develop the IGFC system and to optimise the design and operating conditions. The DCFC can simplify the coal-based FC power generation systems considerably but it is still in the early stage of development. If coal-fed FC power generation systems can be successfully developed and put into commercial operations, it will have significant impacts on coal-based power generation.

4 Magnetohydrodynamic (MHD) power generation systems

Magneto hydrodynamics is an academic discipline that studies the dynamics of electrically conducting fluids. An MHD power generator is a device that generates electric power by means of the interaction of a moving conductive fluid (usually an ionised gas or plasma) and a magnetic field. As all direct energy conversion processes, the MHD generator can convert thermal energy of a fuel directly into electricity. In this way the static energy converter, with no moving mechanical parts, can improve the dynamic conversion and work at temperatures much higher than conventional energy conversion processes. The MHD power generation process can be directly coal fired. It accordingly opens up a temperature regime in which no competing process exists and thus offers a means of making more efficient use of coal resources beyond that offered by any other technology. Since the 1970s, several countries have undertaken MHD research programs with a particular emphasis on the use of coal as a fuel.

4.1 Principles of MHD power generation

4.1.1 MHD energy conversion

When an electrical conductor is moved so as to cut lines of magnetic induction, the charged particles in the conductor experience a retarding force in a direction mutually perpendicular to the magnetic field and to the velocity of the conductor. This effect is a result of Faraday's laws of electromagnetic induction. The negative charges tend to move in one direction, and the positive charges in the opposite direction. This induced electric field, or motional EMF (electromotive force), provides the basis for converting mechanical energy into electrical energy.

The electromagnetic induction principle is not limited to solid conductors. The movement of a conducting fluid through a magnetic field can also generate electrical energy. When a fluid is used for the energy conversion technique, it is referred to as magnetohydrodynamic energy conversion. In an MHD converter, the solid electrical conductor is replaced by an ionised gas or plasma.

4.1.2 MHD power generation

The principle of the MHD generator is shown in Figure 9. In an MHD generator, a hot, electrically conductive gas is accelerated by a nozzle and is then injected into a channel at a high velocity. A powerful magnetic field is set up across the channel. The gas is forced through the channel with a kinetic energy and pressure differential sufficient to overcome the magnetic induction force. In accordance with Faraday's law of induction, an electric field is generated that acts in a direction perpendicular to both the gas flow and the magnetic field. The walls of the channel parallel to the magnetic field serve as electrodes and enable the generator to provide an electric current to an external circuit. Typically, the hot, conducting gas is produced by thermal ionisation of the gas at high pressure by combustion of a fossil fuel.

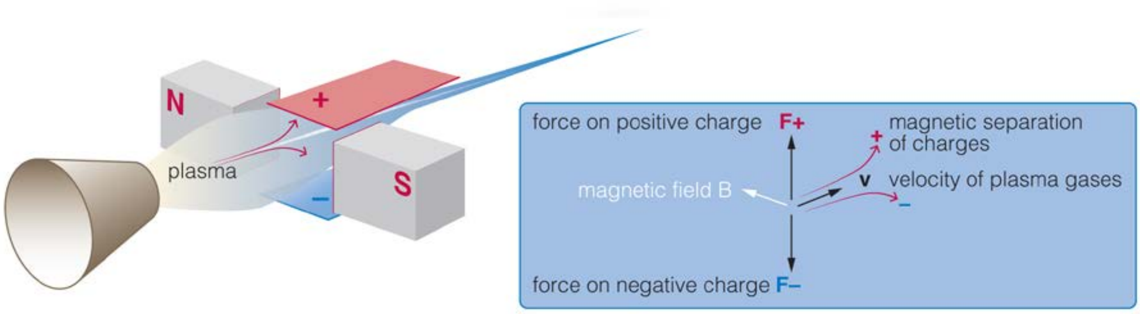

Figure 9 Principle of MHD power generation (Dhareppagol and Saurav, 2013)

The power output of an MHD generator for each cubic metre of its channel volume is proportional to the product of the gas conductivity, the square of the gas velocity, and the square of the strength of the magnetic field through which the gas passes.

An MHD generator produces a direct current output which needs a high power inverter to convert the output into alternating current for connection to the grid.

4.2 MHD systems

The MHD systems are broadly classified into two types: open cycle system and closed cycle system.

4.2.1 Open cycle system

In an open cycle MHD system, combustion gas is used as a working fluid, where the plasma is in a thermal equilibrium state. Natural gas, oil or gasified coal through a coal gasification plant may be used as fuel. For direct coal-fired MHD power generation, coal is first processed and burnt in the combustor at a high temperature of about 2300–2700°C and pressure of up to 1.2 MPa with pre-heated air to generate the plasma. There is a lower temperature limit (around 2000°C) below which the electrical conductivity becomes effectively zero. There may be no physical limit in the upper working temperature insofar as materials can withstand it. To attain such high temperatures, the compressed air, used to burn the coal in the combustion chamber, must be pre-heated to at least 1100°C. A lower preheat temperature may be adequate if the air is enriched in oxygen. The hot gas from the combustor is then added with a small amount of seed material, generally potassium carbonate to increase the electrical conductivity of the gas. The resulting hot pressurised working fluid is expanded through a nozzle, so as to have a high velocity and then passed through the magnetic field of the MHD generator. The hot gas expands through the rocket-like generator surrounded by a powerful magnet. Movement of the gas through the magnetic field causes the positive and negative charged ions to move to the electrodes and constitute an electric current. The gas exiting the generator is cleaned before being discharged into the atmosphere. Since the gas is not circulated and reused it forms an open cycle.

Most experimental studies, so far, have involved the open cycle system, and this approach is applicable to MHD retrofits for existing power stations.

4.2.2 Closed cycle system

As the name suggests the working fluid in a closed cycle MHD system is circulated in a closed loop and is heated by the combustion gases using a heat exchanger. Hence the heat source and the working fluid are independent. Two general types of closed cycle MHD generators are being investigated: the seeded noble gas system and the liquid metal system.

Seeded noble gas system

In this system, the carrier is usually a noble gas such as helium or argon. The electrical conductivity of the working fluid is maintained by ionisation of a seeded material of alkali metal (caesium or potassium), as in the open cycle system. When inert gases are used in closed cycle MHD generators, it is possible to substantially decrease minimum working temperature due to non-equilibrium ionisation.

The carrier gas operates in the form of the Brayton cycle: in a closed cycle system the gas is compressed and heat is supplied by the source, at essentially constant pressure. The compressed gas then expands in the MHD generator, and its pressure and temperature fall. After leaving the generator, heat is removed from the gas by a cooler, this is the heat rejection stage of the cycle. Finally the gas is recompressed and returned for reheating.

Heat generated by fuel combustion is transferred to the carrier gas of the MHD cycle in a primary heat exchanger. The combustion products, after passing through an air preheater and air pollutant emission control systems, are discharged to the atmosphere.

Liquid metal system

In this system, a liquid metal with high electrical conductivity independent of temperature is used with a carrier gas (two-phase working fluid) or a volatile liquid (different from or the same as the electrically conducting fluid) as the working fluid. The liquid metal has the advantage of high electrical conductivity compared to plasmas, and therefore the heat provided need not be too high. The main difficulty with such systems is creating a flow of liquid with a high enough velocity.

An inert gas is a convenient carrier. The carrier gas is pressurised and heated by passing through a heat exchanger within the combustion chamber. The hot gas is then incorporated into the liquid metal to form the working fluid. The latter consists of gas bubbles uniformly dispersed in an approximately equal volume of liquid metal. The working fluid is introduced into the MHD generator through a nozzle in the usual ways. The carrier gas provides the required high direct velocity of the electrical conductor. After passing through the generator, the liquid metal is separated from the carrier gas. Finally the carrier gas is cooled, compressed and returned to the combustion chamber for reheating and mixing with the recovered liquid metal.

One of the advantages of the closed-cycle MHD is that a higher power density can be achieved because of the higher electrical conductivity in the generator channel. This leads to a compact generator with a smaller superconducting magnet as compared to the open-cycle MHD generator, although the closed-cycle power plant system is relatively more complex. Another advantage is that high power output is possible even under relatively low gas temperatures of around 1700°C. It is believed by some that closed cycle MHD systems with high efficiencies and smaller equipment are better suited to small plants with a capacity near 100 MWe, whilst coal-fired open cycle MHD power plants become economical above 200 MWe.

4.2.3 MHD channel efficiency

The physically attainable thermal efficiency of an MHD generator is commonly referred to as the channel enthalpy extraction ratio. The net efficiency of a coal-fired MHD power plant will depend on the plant configuration and the technologies adopted. Once the design concept of a MHD power plant is decided and technologies chosen, the plant efficiency is determined by the MHD channel enthalpy extraction ratio. The enthalpy extraction ratio for a MHD generator may range from 30–35%. The enthalpy extraction ratios experimentally demonstrated so far for an open cycle MHD are 15% with a shock-driven disk channel and 11% with a linear Faraday channel under a magnetic field of 3.2 T (Kayukawa, 2004). For a closed cycle MHD generator, an enthalpy extraction ratio of 19% with a disk MHD generator was achieved by Tokyo Technical Institute (Okuno and others, 2003).

4.3 Major MHD R&D programs

The first major engineering development of a MHD generator was made at Westinghouse Research Laboratory (USA) around 1938. Inspired by this work, researchers around the world started to investigate the concept of MHD power generation.

4.3.1 USA

MHD power generation was first successfully demonstrated by tests at AVCO Everett Laboratory (USA) in 1959 using the Mark I MHD system. It produced about 11 kW and used argon as the working fluid. Over the next three decades, many diversified MHD test facilities were built around the world to conduct MHD experimental research and demonstration. Table 8 shows some of the major facilities.

Research at AVCO Everett continued with financial support from the US DOE. A 20 MWth coal-fired Mark VI MHD system was set up and tests on coal combustor, MHD generator and other components were carried out during the 1970s and 1980s (Bauer and others, 1986; McClaine and others, 1989; Hruby and others, 1986).

Table 8 The major facilities for HMD research (Messerle, 1992; Tong, 1999; Murakami and others, 2007b)

A) Open cycle MHD facilities						
Country (facility)	**Fuel**	**Seed**	**Thermal input (MW)**	**Power output (MW)**	**Magnetic field (T)**	**Operating years**
USA						
LORHO	toluene		300		1.8	1966
AVCO-6	coal	K_2CO_3 (dry)	20	300 (kW, max)	3.0	1975-82
AVCO-7	COM				2.5	1975-82
HPDE	diesel				3.5	1982
CDIF	coal	K_2CO_3 (dry)	50	1.5	3.0	1980-93
CFFF	coal					1980-93
Russia						
U-25	natural gas	K_2CO_3	250	20 (max)	2.0	1974-90
U-25B	natural gas	K_2CO_3	25–30		5.0	1977
Japan						
ETL-5	diesel		25		4.2	1975
ETL-6	diesel		2.5		1.9	1973-77
ETL-7	diesel		15		2.5	1981-89
China						
KDD-2	diesel	K_2CO_3 (wet)	70	2.0	2.1	1981-88
KDM-2	coal		25		2.1	1992-99
SM-4	coal		5		1.75	1992-94
JS-2	coal		4		1.9	1979-96
Australia DISK	ethanol	KOH (fuel)	2		1.4	
B) Closed loop MHD facilities						
Country	Japan	USA	USA	USA	Germany	UK
Institution	Tokyo Tech.	NASA-Lewis	NASA-Lewis	U.FL	P.ARGAS	IRD
Working medium	Ar-Cs	Ar-Cs	He-Cs	He-Cs	Ar-Cs	He-Cs
Temperature, °C	1527–1627	1827	1727	1427	1627	1427
Pressure, MPa	~0.45	0.25	0.14	0.13	0.7	0.6
Thermal input, MW	~0.30	1.6	1.6	0.15	4.7	0.11
Power output ,kW		0.3	2.2	0.001	5	0.001
Magnetic field, T	4.2	1.8	1.7	2.0	1.3	2.2
Operating years	2004 to present	1968-74		1976	1966-70	1964-68

Researchers at the Energy Conversion Division of University of Tennessee Space Institute (UTSI), USA, carried out R&D in the coal-fired open cycle MHD power generation system since 1971 using their Energy Conversion Facility. Their success in MHD power production using char laid the groundwork for coal-fired open cycle MHD power generation. Improvements in the facility and the design concept led to the second generation MHD system, the Coal Fired Fuel Facility (CFFF). In 1982, engineers from the US Argonne National Laboratory (ANL) built a 6 Telsa superconducting magnet for CFFF. Tests were performed to evaluate the overall electrical performance and various aspects of open cycle MHD system. In 1984, the control of SO_2, NOx and particulate emissions from coal-fired open cycle MHD power generation system was investigated and verified at the CFFF.

In the 1980s, the US DOE began a vigorous multiyear Proof-of-Concept (POC) program which was carried out at CFFF and another major MHD test facility, the Component Development and Integration Facility (CDIF) in the USA. The CDIF was federally owned and was constructed in 1980 at the research site of the DOE Western Environmental Technology Office in Butte, Montana with a capacity of 50 MWth. The POC program comprised four parts:

- an integrated MHD topping cycle program – developing technical and environmental data for the integrated MHD topping cycle system through a long-duration (1000 hours) test at the CDIF. This system was a Hall effect duct generator heated by pulverised coal, with a potassium ionisation seed;
- an integrated bottoming cycle program – developing technical and environmental data for the integrated MHD bottoming cycle system through a long-duration (4000 hours) test at CFFF;
- developing the technology required for seed regeneration system;
- preparing conceptual designs of MHD retrofit plants and continuing system studies and supporting research necessary for system testing.

The purpose of the program was to establish an engineering database that could be used by power utility companies to evaluate the benefits and risks of the technology for new and existing power plants. The program was focused on the performance and lifetime of the major components and subsystems of a coal-fired MHD power generation system. In 1993, a milestone was reached by accomplishing 3696 hours of accumulated MHD bottoming cycle operation and 601 hours of topping cycle operation. At CDIF, all the topping components of a MHD-steam combined cycle generation system were tested including continuous slag rejection equipment and an inverter system (Ju and Lineberry, 1996; Galanga and others, 1982; Tong, 1999). Conceptual designs of MHD retrofit to the existing coal-fired Scholz power plant (Florida, USA) and JE Corrette Plant (Billings, Montana, USA) were produced (Labrie and others, 1989; Bernard and others, 1989). This program terminated in 1993 due to national budget restraints.

4.3.2 Russia

There was substantial interest in Russia in developing a MHD power generation system, and research work in the field of MHD energy conversion started in the early 1960s. The world's first large MHD pilot facility, the U-25 became operational in 1971 at the Research Institute of High Temperatures, Russian Academy of Sciences (Moscow). It burned natural gas with oxygen enriched air that was preheated to 1200°C and had a designed capacity of 25 MW. By 1974 it delivered 6 MWe of power. Another feature of the U-25 was that it was equipped with a steam turbine enabling the investigation of engineering problems associated with a MHD-steam combined cycle. The U-25 facility contained all the principal components of potential future commercial power stations that could make use of an MHD generator. A broad range of research was conducted using this facility. The main design parameters of the U-25 were attained, providing technical support for the design of 500 MW U-500 MHD power plant. The U-25 bottoming plant was operated under contract with a Moscow utility, and fed power into Moscow's grid.

In 1992, a coal-fired 25 MWth U-25G MHD facility was installed for the purpose of studying the specific features of operating MHD components in the presence of ash and slag. The pressurised coal feed system, combustor with two-stage combustion chamber and slag removal system were tested, and the interaction between slag and seed was investigated (Kirillov and others, 1992; Ju and Lineberry, 1996). MHD studies at the U-25 have now stopped.

A Co-operative Program between the US and the former USSR on open cycle MHD research began in 1974. A test facility, U-25B was constructed as a bypass loop of the U-25 for the joint tests. ANL designed and built a superconducting magnet for the U-25B. The U-25B generator test program was mainly focused on studies of the performance and operating characteristics of diagonal-wall, window-frame channels under conditions anticipated for commercial MHD power plants (Chernyshev, 1978; Doss and others, 1982).

4.3.3 Japan

The Japanese program in the late 1980s concentrated on the closed cycle MHD power generation system. The first major series of experiments was FUJI-1, a blow-down system powered from a shock tube at the Tokyo Institute of Technology. Using the experience of FUJI-1, a 5 MWe continuous closed-cycle facility, FUJI-2, was built and commissioned in 2004. The FUJI-2 MHD design featured a disk-shaped, Hall-type supersonic generator and a superconducting magnet. The aim was to achieve an enthalpy extraction of 30% and an MHD thermal efficiency of 60%. The experiments extracted up to 30.8% of enthalpy, and achieved power densities near 700 MW/m^3 (Murakami and others, 2007a; 2007b).

In 1981, a 15 MWth, coal-fired, open cycle MHD test facility was set up at Electro-Technical Laboratory (ETL) under the MITI's (Ministry of International Trade and Industry) National MHD Project and accumulated a total of 430 operating hours. Although the MITI's MHD project achieved its objectives, it ended in 1989 and the next stage of the project was never undertaken. Research into open cycle MHD, however, continued in several universities such as Hokkaido University, Tokyo Institute of Technology and Kyoto University. Experimental research of open cycle MHD power generation was carried out at Hokkaido University using a 5 MWth oil-fired open cycle MHD test facility (Iwashita, 1998).

4.3.4 China

Research into MHD power generation in China started in 1962 but earlier work was directed at oil-fired MHD systems. A National Coal-fired MHD program was implemented in 1988. A 25 MWth topping cycle coal-fired MHD test facility was set up in the Institute of Electrical Engineering (IEE) (Beijing), and a 5 MWth bottoming cycle coal-fired MHD facility was installed at Shanghai Power Equipment Research Institute (SPERI). Eight R&D topics were instituted, namely, coal-fired combustor, MHD generator-channel, heat-recovery boiler, inverter system, superconducting magnet, seed recovery, and MHD retrofit. A series of tests were carried out at the two facilities. Improvements in design of the MHD components and supporting systems were made leading to improved performance and extended operation.

4.3.5 Other countries

R&D in the field of MHD power generation was carried out in several European countries. The Italian program began in 1989, and had three main development areas: MHD modelling, superconducting magnet development and retrofits of MHD system to natural gas power plants.

In Poland, investigation into MHD was directed at the construction of coal-fired MHD power generators. Experiments were carried out at the Technical University of Poznan using a 4 MWth test MHD facility and at the Institute of Nuclear Research using a 4.5 MWth MHD test rig. The latter was mainly used for the research of coal combustion and gasification.

In Bosnia, the first patented experimental MHD power generator was built in the Institute of Thermal and Nuclear Technology (ITEN) in 1989.

In Romania, three MHD test facilities, GMHD-01, GMHD-02 and GMHD-03 were built at the Power Equipment Research and Design Institute in Bucharest. In 1991, the Ministry of Teaching and Science decided to stop financing the installation of a superconducting magnet to GMHD-03 due to the high cost. Later, a new MHD disk channel and a liquid fuel and oxygen chamber (1 MWth) were tested at the Institute (Ju and Lineberry, 1996).

An Indian MHD program started in the early 1970s. A 5 MWth pilot plant and component test facility was built. Seventeen major experimental runs were completed by the mid 1990s using gas as fuel. The focus of the pilot-scale experiments was then shifted to slagging coal combustion and MHD channel. A 3 MWth single, tangential, horizontal slagging coal combustor was built and coals of different Indian origin were tested.

The MHD program in Australia was primarily concerned with open cycle, coal-fired MHD power generation. Experiments were conducted at the University of Sydney using an integrated coal-fired linear and disk MHD generator. Work was carried out to develop computer models of linear (2 MWth) and disk-type (3 MWth) MHD generators for real time simulation. The program included studies into the technological problems of coal-fired MHD such as the properties of Australian coals and their slag, interaction of seed with ash and slag, and seed recovery (Messerle, 1989; ILG-MHD, 1984).

At its peak there were more than a dozen countries with government funded MHD programs. The intensive studies resulted in technological developments and advances as well as improved engineering designs in some key components of MHD power generation systems such as MHD generator/channel, seed recovery process, coal combustor, superconducting magnet, materials for high temperature heat exchanger, electrodes and insulator wall designs (Kulkarni and Gong, 2003; Tong, 1999; Ju and Lineberry, 1996; Penco and other, 1996; Knoopers and others, 1991). By the late 1980s, development had reached the point where construction of a complete demonstration system was feasible. However, the performance and economic risks deterred electric power utilities from making substantial investments in such systems. Coal-fired MHD was too expensive to commercialise and could not compete with the advances in gas turbine technology so the focus was shifted to the development of integrated coal gasification combined cycle (IGCC) plants. By the late 1990s budgets had been cut and academic research and activity were all that remained in most countries although the research efforts on the closed-cycle MHD generator continued in the Netherlands and Japan.

4.4 Coal-fired MHD power generation concepts

In power generation applications, MHD generators can combine with various kinds of power conversion devices to form different cycles. In coal-fired MHD power plants, the open cycle MHD system that uses the combustion gas as working fluid is an obvious choice. Past studies have shown that open-cycle MHD power generation has greater potential to produce low-cost electricity. However, MHD power plant concepts using closed cycle MHD systems have also been proposed. Many variations of the system configuration might be possible.

4.4.1 Direct coal-fired MHD-steam combined cycle

The exhaust of an MHD generator is almost as hot as the flame of a conventional steam boiler. This heat can be used to generate more power, which significantly improves the efficiency and economics of fossil fuel fired MHD power generation plants. A typical open cycle MHD-steam binary cycle is shown in Figure 10. This configuration was adopted and tested by the US POC program. It consists of a topping cycle based on a MHD generator and a steam bottoming cycle. A diffuser connects the topping and bottoming cycles. In the topping cycle, coal and seed material (generally potassium salt) are fed together with heated air into the combustor and burnt under a pressure of 0.5–1 MPa to reach the required temperature of around 2500°C. The seeded combustion gas is ionised at this temperature to produce the plasma that flows through the magnetic field in the MHD channel in which the thermal and kinetic energy of the combustion gas is converted into electricity. The diffuser is integrated with the channel to increase the energy extraction. Energy extraction is continued until the temperature becomes too low to have a useful electric conductivity. The combustion gas exiting the diffuser then enters a radiant boiler (steam generator) at a temperature in the range of 1900–2200°C. Energy is extracted in the bottoming cycle by producing steam to drive the steam turbine, which is on the same shaft with an electric generator and compressor, to generate additional electricity and compress the air (and oxygen) needed to the required pressure for combustion. The combustion gas leaving the boiler passes through heat exchanger(s) in which the thermal energy of the gas is recuperated by preheating the combustion air (and oxygen). The low temperature gas from heat recovery exchangers flows through a particulate control device where the particulates are removed and is then discharged through a stack. Seeds are separated from ash and regenerated.

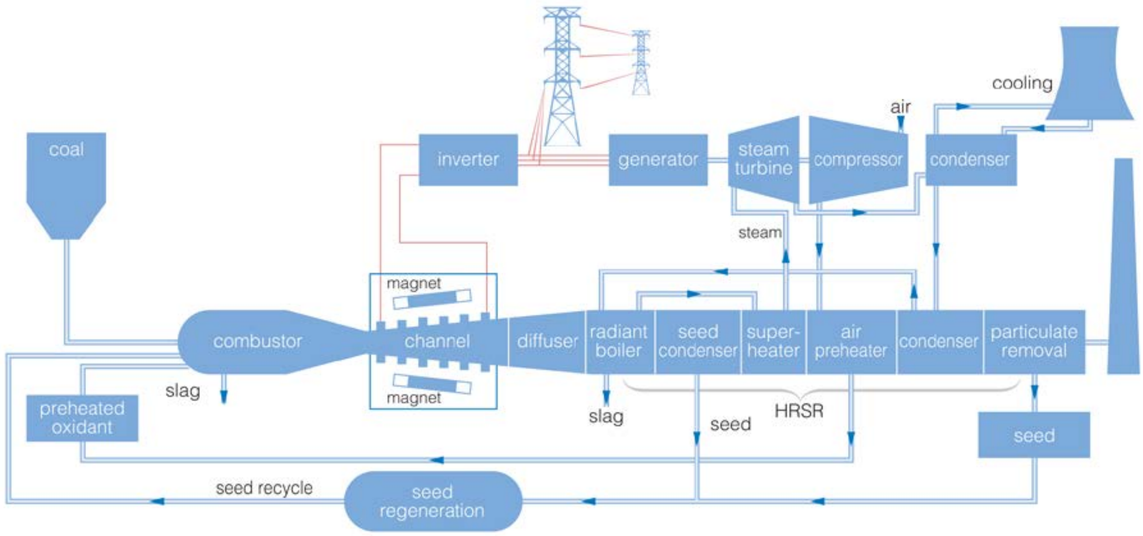

Figure 10 A typical coal-fired MHD-steam combined cycle

In order to control NOx emissions from coal combustion, coal is burnt in the combustor under sub-stoichiometric conditions. Combustion is then completed in a secondary combustor located downstream of the boiler in a bottoming cycle. In the secondary combustor, the sulphur compounds derived from coal are converted to SOx that reacts with potassium ion to form K_2SO_4. This reaction reduces the content of SOx in the combustion gas to below the allowable level. The K_2SO_4 deposits in the combustor, and is collected and transferred to a seed regeneration plant (Kulkarni and Gong, 2003; Duursmaa, 1992).

Besides a radiant boiler and secondary combustor, the heat recovery system in an MHD power plant also includes a steam superheater, steam reheater, air preheater and economiser. Higher oxidant temperature (1370–1650°C) is preferred to achieve high MHD efficiency. An air preheater is therefore installed upstream of the radiant boiler. The combustion gas exiting the MHD diffuser directly enters a refectory heat exchanger to preheat the air (Kulkarni and Gong, 2003). The preheated air fired MHD-steam combined cycle is thought to provide the best efficiency performance. However, the regenerative air heater would have to be operated in a temperature range from ambient temperature at the air inlet port to a MHD exhaust temperature of around 2000°C. Slag condensation and solidification may take place in regions where temperatures are below 1300°C. The change of the thermo-chemical properties of refractory materials which interact with seed-contained slag is also a critical problem (Kayukawa, 2004). Although extensive research work has been done and progress has been made, the high temperature regenerative heat exchanger that is compatible with slagging coal combustion gas is yet to be developed.

4.4.2 Top gasification MHD-steam combined cycle

With this plant concept, coal-derived syngas is used as fuel. The coal is gasified and slag removed prior to the combustion process and therefore clean combustion gas is used in the MHD generator and downstream equipment allowing a more efficient cycle configuration to be adopted. As shown in Figure 11A, the system consists of a gasification island where coal is converted into a syngas by using air (or oxygen) and steam, and a power island based on an open cycle MHD generator combined with a steam power unit. The main components of the gasification island are an air separation unit (ASU) when oxygen instead of air is used for gasification and combustion of coal, a gasifier, and a hot gas cleaning unit (HGCU) where the acid gases such as H_2S and HCl are removed. In order to meet the operating temperature of the HGCU unit the syngas coming out of the gasifier is cooled in a heat exchanger (HEX) by generating the superheated steam for the gasification reactions.

Depending on the type of gasifier (atmospheric or pressurised), the syngas is either compressed or expanded to the operating pressure of the combustor before entering and being burnt in it. The combustion gas is seeded with potassium salt and then flows through the MHD generator where electricity is generated. The heat energy content of the combustion gas exiting the MHD diffuser is recuperated first in a high temperature heat exchanger (HTHE) to preheat the combustion air (or oxygen) and then in a heat recovery steam generator (HRSG) to generate steam for producing additional electricity in the steam power unit. Here, the HTHE is placed directly downstream of the MHD diffuser, because the combustion gas contains no slag. Therefore, the combustion air can be preheated up to 1800°C by a regenerative air heater (Cicconardi and Perna, 2014).

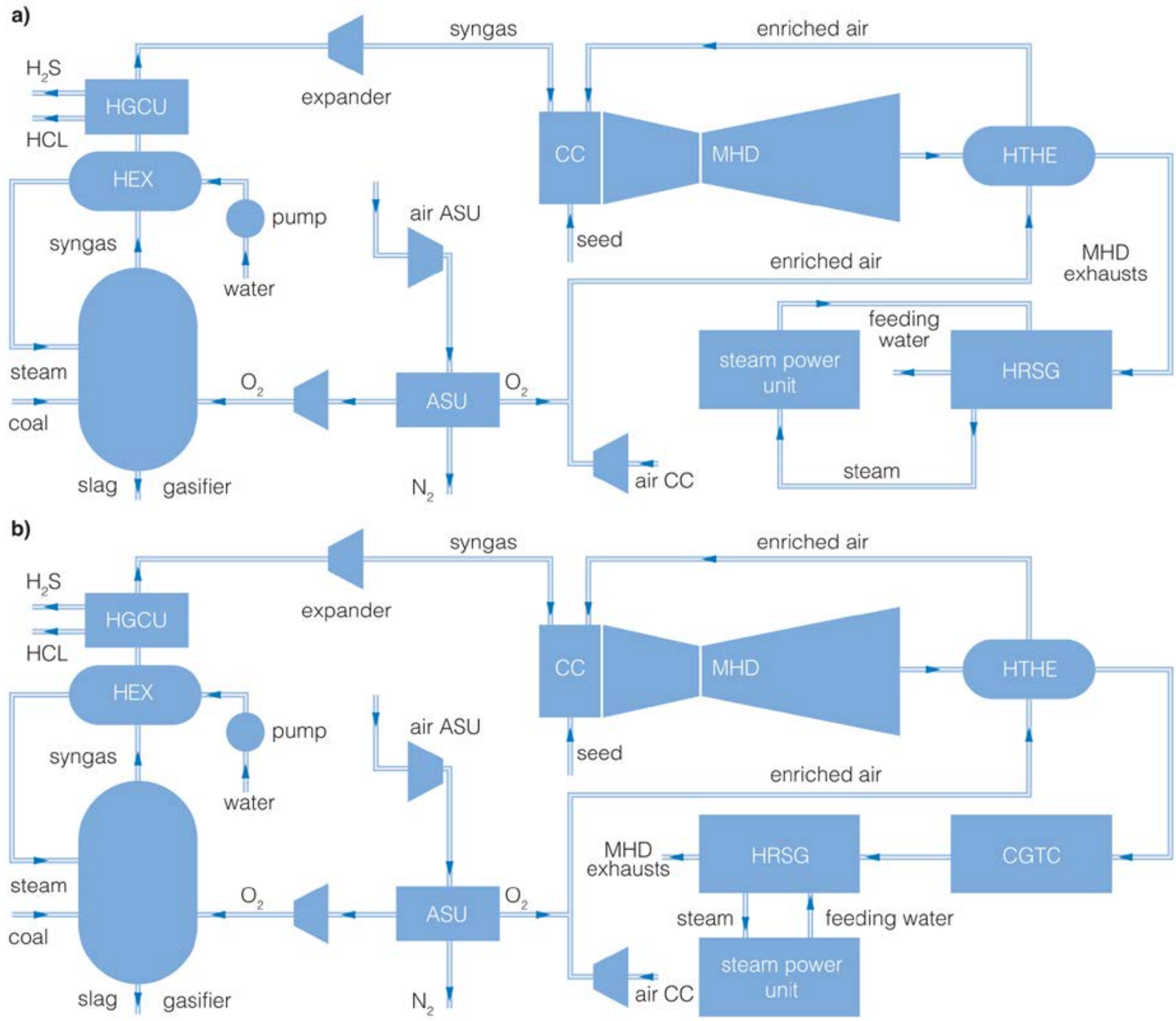

Figure 11 Top gasification MHD-steam combined cycle (Cicconardi and Perna, 2014)

In order to improve the heat recovery of MHD exhausts, Cicconardi and Perna (2014) proposed an advanced integrated gasification-MHD-steam/gas turbine combined cycle as shown in Figure 11B. In this configuration, the MHD generator is integrated with a steam turbine and a closed gas turbine cycle fed with nitrogen. They conducted cycle performance analyses and their results showed that the gasification integrated MHD-steam combined cycle power plant with an air preheating temperature of 1800°C could achieve a plant efficiency of 51% (HHV), compared with 52.8% (HHV) obtained from the direct coal-fired MHD-steam combined cycle plant with an air preheating temperature of 800°C. The gasification integrated MHD-steam/gas turbine combined cycle power plant could achieve a plant efficiency of up to 60% (HHV). Higher efficiencies could be obtained by optimising the operating conditions of the topping (the MHD generator) and bottoming cycles (the steam/gas turbine power units).

4.4.3 Tail gasification MHD-steam combined cycle

The idea of using the thermal energy of the MHD exhaust to gasify coal to produce a syngas that is burnt in a MHD combustor has been around for several decades. As early as 1973, Hals and Gannon (1973) evaluated thermo-chemical coal synthesis with MHD exhausts and a MHD-steam combined system where the MHD generator was operated under recirculation of synthesised fuel. Since then, power generation systems based on MHD-steam cycle with tail gasification have been studied by researchers around the world and various cycle configurations have been proposed (Broun and Pudlick, 1980; Bystrova and others, 1992; Borghi and Ishikawa, 1996; Lu and others, 1999; Kayukawa, 2002a,b; Kayukawa and Wang, 2004; Lu, 2005). More recently, Kayukawa (2002a) proposed a MHD-steam combined system with tail gasification and combustion of preheated syngas using pure oxygen in the MHD combustor. He stressed that, as a coal-fired power generation system, the thermo-chemical, regenerative MHD cycle had unique advantages over the thermo-chemical, regenerative gas turbine combined cycles, most notably the potential for a topping cycle with high system efficiency and no CO_2 emissions. Figure 12 shows a tail gasification MHD-steam combined cycle with a regenerative fuel preheater installed next to the thermo-chemical gasifier and with carbon capture. In this configuration, steam generation is performed in the MHD diffuser in order to match the gasifier exit temperature with the slag melting temperature for the slag rejection. The heat content of the exhaust is effectively recuperated by syngas preheating and generation of steam required for gasification processes sequentially arranged downstream of the gasifier. CO_2 in the syngas is separated from the CO and H_2 at the lowest temperature region of the system and recirculated to the combustor after being preheated to a temperature of about 1400°C.

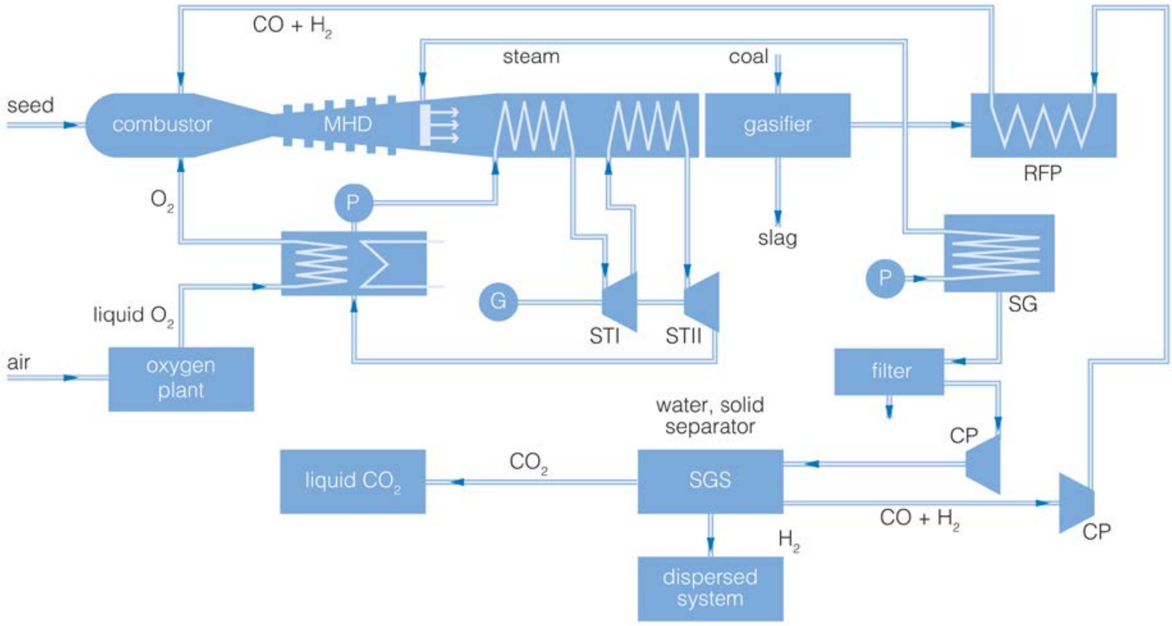

Figure 12 A regenerative tail gasification MHD-steam combined cycle with carbon capture (Kayukawa, 2004)

The most attractive features of the tail gasification are the high regeneration efficiency of thermal-to-chemical energy and the higher combustion heat compared to that of coal, even though the syngas is, in general, a low heat value fuel.

4.4.4 Tail gasification MHD-gas turbine/steam turbine triple cycle

The configuration of this cycle system is very similar to the tail gasification MHD-steam combined cycle discussed above. As shown in Figure 13, the gasifier is arranged next to the MHD diffuser, in which coal gasification takes place when coal and some additional steam are mixed with the MHD exhaust gas. The MHD exhaust heat is regenerated primarily as chemical energy of the synthetic fuel. The heat of syngas is recuperated at the regenerator I (RG I) by generation of steam for the gasifier and for the steam turbine, and by preheating the syngas as well as the oxidant (air or/and oxygen). The cooled gas exiting the RG I passes through a filter where particulates, K_2SO_4 and water are removed from the gas. The syngas is then split into two; one part is sent to a gas turbine loop and the other, after CO_2 is removed from the syngas in the CO_2 separator, is compressed, preheated and then sent to the MHD combustor. The CO_2 containing syngas supplied to the gas turbine loop is burnt with air in a gas turbine combustor. The combustion gas goes to the steam generator (RG II) before it is finally discharged through a stack.

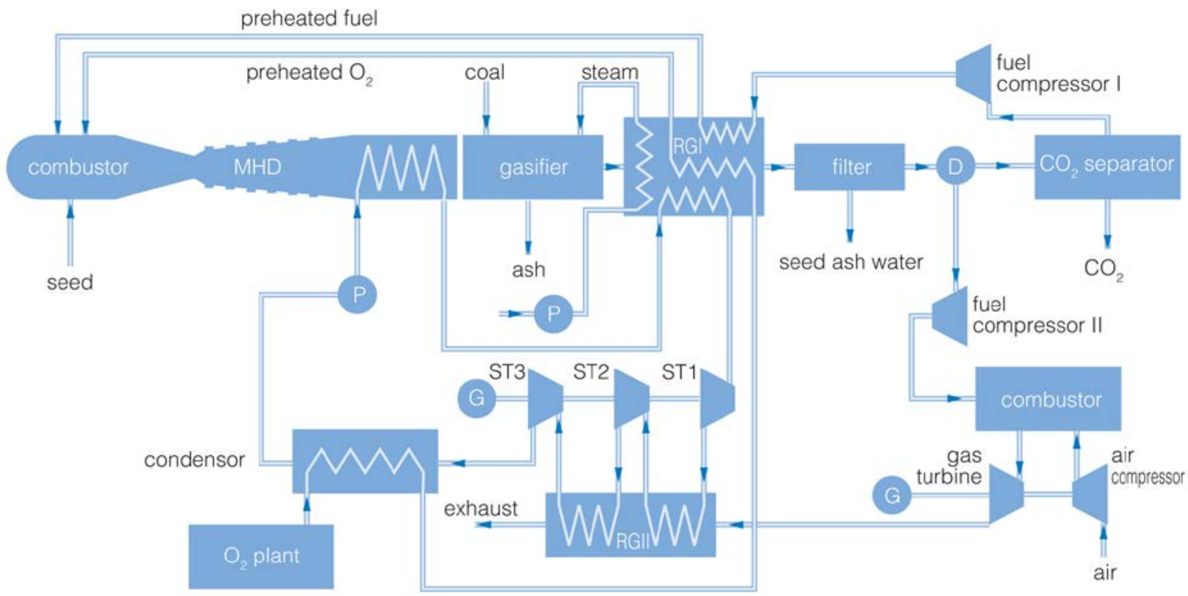

Figure 13 Tail gasification MHD-gas turbine/steam turbine triple cycle (Kayukawa, 2000)

4.4.5 Two-loop coal-fired closed cycle MHD Power plant

The Netherlands MHD Association conducted design studies of open and closed cycle MHD-steam combined cycle for baseload power plant using coal. The design concept used for the closed cycle MHD-steam power generation system is shown in Figure 14. It consists of two loops. The first loop has a coal-fired combustor. The hot gases leaving the combustor are divided into two flows. The first main flow is fed to high-temperature heaters where the working fluid (caesium seeded argon) is heated to a temperature of around 1700°C. The second flow is directed to an oxidiser preheater for the combustor. A gas turbine-air compressor unit is used for the compression and delivery of the oxidiser. The gas turbine utilises combustion products pre-cleaned of particulates in electrostatic precipitators (ESP). The heat content of the gases exiting the gas turbine is used to dry coal in a coal dryer, and the flue gas then passes flue gas cleaning devices before being discharged through a stack. The second loop contains an MHD generator topping and a SC steam-turbo generator bottom cycle. Not shown in Figure 14 are systems for injection, recovery and regeneration of caesium, as well as an argon purification system.

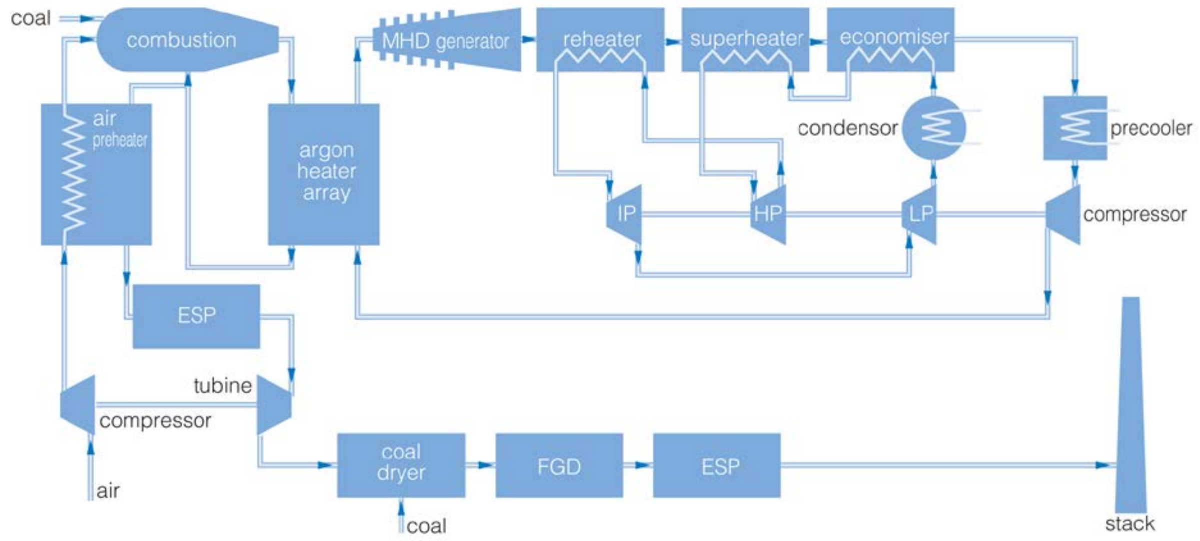

Figure 14 Two-loop coal-fired closed cycle MHD-steam power generation system (Cervenka and van der Laken, 1983)

Cervenka and van der Laken (1983) evaluated the performance and economics of a 500 MWe coal-fired, closed cycle MHD-steam power plant of the two-loop design with the same parameters used in the Netherlands MHD Association's study (Geutjes and Kleyn, 1978). They stressed that closed cycle MHD power plant had certain advantages over open cycle MHD plant including, in particular, a reduction in the maximum temperature in the MHD channel and the utilisation of non-equilibrium ionisation of argon-caesium plasma. Their results showed that, assuming the channel enthalpy extraction ratio was 34.3%, a net plant efficiency of 41.8% could be expected. However, the plant would require the use of a costly high temperature heat exchanger that would account for 35% of capital costs pushing up the cost of electricity (COE).

4.4.6 Inert gas MHD triple combined cycle

Researchers in Japan (Yoshikawa and colleagues, 1989; Furuya and others, 1989) proposed an inert gas MHD triple combined cycle that combines a closed cycle MHD generator with gas turbine and steam-turbo generators, a concept similar to the two-loop MHD-steam power generation system. The main feature of the plant configuration is that a pressurised fluidised bed combustor (PFBC) is used as a secondary combustor. As shown in Figure 15, coal is mixed with compressed air and a portion of recycled exhaust gas (the exhaust gas is added for temperature control) and is then burnt in the primary combustor. The primary combustor is incorporated in a helium (working fluid) heater. The combustion products leaving the primary combustor (helium heater) enter the PFBC, where additional air is supplied to complete the combustion at temperatures of 850–950°C. Limestone is injected into the PFBC for in-furnace desulphurisation. In the PFBC, the heat released from combustion of unburned coal/char is used to raise the temperature of combustion gas and no steam is generated. Therefore, the main function of the PFBC is a combustor and sulphur removal equipment, rather than a boiler. The combustion gas exiting the PFBC, after particulate removal using a hot flue gas cleaning device, is directed to drive a gas turbine. The arrangements for the MHD topping and steam bottoming cycle are essentially the same as those in the two-loop MHD power plant configuration except that a boiler is installed next to he MHD diffuser, upstream of the heat exchanger.

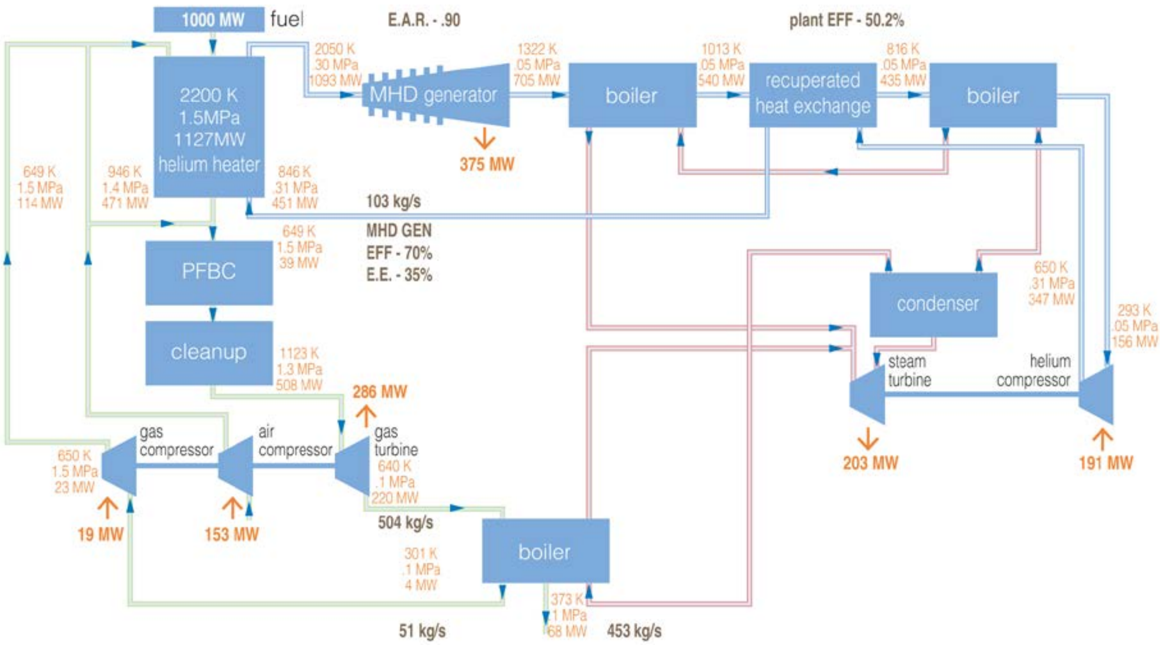

Figure 15 Coal-fired inert gas MHD triple combined cycle power generation scheme (Yoshikawa and others, 1989)

The same researchers further proposed an improved inert gas MHD triple combined power generation cycle, the so called coal-fired MHD/Brayton combined cycle (Yoshikawa and colleagues, 1989; Furuya and others, 1989). In this improved power cycle configuration, the hot helium gas exiting the MHD generator first enters a recuperative heat exchanger and then a steam generator (boiler). On leaving the boiler, the helium gas is compressed and reheated in the recuperative heat exchanger before it is directed to drive a helium gas turbine to produce additional power. The helium gas is then sent back to the helium heater in the topping cycle (*see* Figure 16). The researchers claimed that with this improved power cycle configuration, high plant efficiency could be achieved.

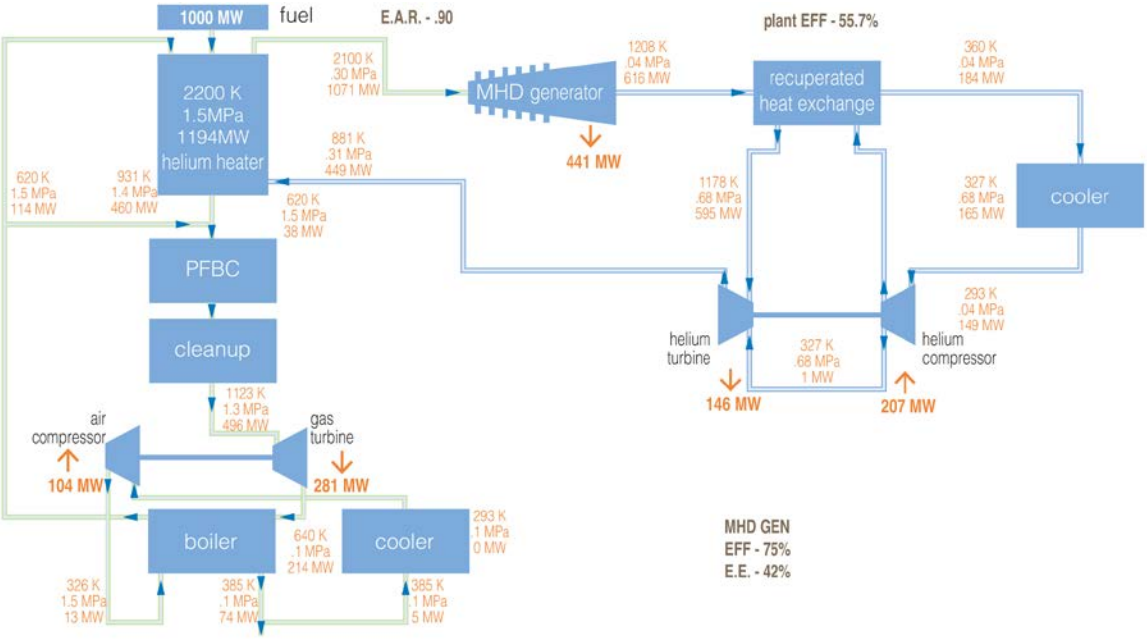

Figure 16 Coal-fired MHD/Brayton combined cycle (Yoshikawa and others, 1989)

A major advantage of using PFBC as a combustor is its low NOx and SO_2 emissions due to low combustion temperature and in-furnace desulphurisation and therefore, the need for flue gas cleaning devices is eliminated.

4.4.7 SOFC topping and MHD bottoming combined cycle

In the proposed SOFC/MHD combined power generation system, a SOFC is used as a topping and a closed cycle MHD generator is used as a bottoming cycle (Inui and others, 2002). The conceptual configuration of the SOFC/MHD combined power generation system is shown in Figure 17. In the topping cycle, fuel and oxygen are fed into the SOFC where electricity is generated at a temperature of around 1000°C. The SOFC operates at atmospheric pressure and consists of an exhaust gas recirculation loop. The gases exiting the SOFC are split into two flows, one is recycled back to the SOFC via a recirculation loop and the second flow is fed to a combustor (incorporated in a helium heater) where the conversion of fuels is completed at temperatures of up to 2100°C. In the bottoming cycle, seeded noble gas (helium) working fluid with a pressure of approximately 0.3 MPa is heated in the helium heater to a temperature of around 2000°C and then flows through the MHD channel to generate electricity. The hot gas leaving the MHD flows through a recuperative heat exchanger where part of its thermal energy is recovered before it is cooled in a gas cooler. The cooled gas is compressed, reheated in the recuperative heat exchanger and then directed to drive a helium gas turbine to produce additional electricity. The helium gas exiting the gas turbine is then sent back to the helium heater to repeat the cycle.

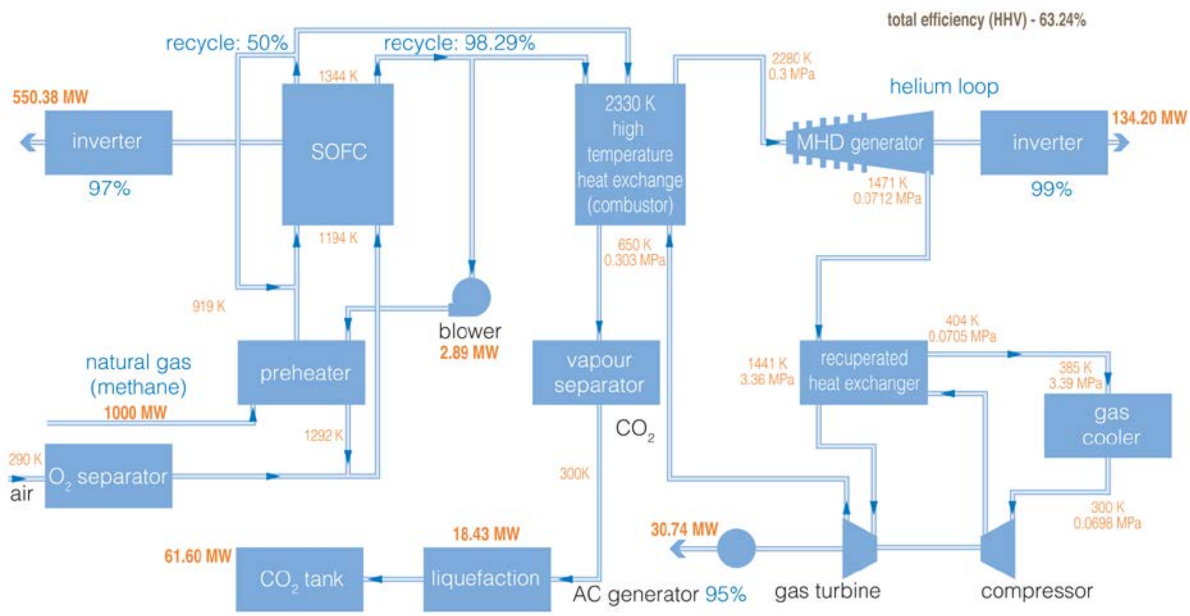

Figure 17 The proposed SOFC/MHD combined power generation system with CCS (Inui and others, 2002)

Because pure oxygen is used as oxidant, the combustion products contain mainly water vapour and carbon dioxide. The water vapour can be easily separated from CO_2 by condensation leaving a flue gas of mostly CO_2 ready for carbon capture and storage. Inui and co-workers stressed that this is an ideal power cycle combination because both the SOFC and closed cycle MHD system operate in their optimum temperature range and high plant efficiency can be expected.

Comments

Although burning coal in oxygen enriched air will increase the complexity and costs of MHD power plants, it is generally agreed that the most promising and economically practical solution is offered by the use of moderate oxygen enrichment (30–40%) and oxidant preheat with MHD exhaust gases in tubular heat exchangers to temperatures of 650–750°C in coal-fired open cycle commercial MHD power plant schemes. In a carbon-constrained world, intensive R&D work has been ongoing to develop oxyfuel fired power generation technologies for CO_2 emissions control. Oxyfuel combustion can be applied to coal-fired MHD power generation systems by simply replacing combustion air with oxygen and no major system modification is required. It is especially suited to coal-fired open cycle MHD power plants. Using coal-oxygen combustion in an open cycle MHD power plant, the oxidant preheating may be eliminated resulting in a reduction in costs. The applications of coal-oxygen combustion in the MHD power generation systems described above for CO_2 emission reduction have been investigated by a number of researchers (Ishikawa and Umoto, 1992; Ishikawa and Steinberg, 1996; Matsuo and others, 1999; Kayukawa, 2002a, 2004; Zaporowski and others, 1989; Inui and others, 2002). The results show that coal-oxygen fired MHD power generation schemes have advantages over the air-fired counterparts and can achieve higher efficiency. Plant efficiencies of over 40% could be obtained even with CCS. Hustad and collegues (2009) recently reassessed integration of MHD with an oxy-combustor that burns natural gas and coal-based syngas with a strong emphasis on CCS. They suggested that oxy-MHD should be assessed as a cycle that could be a potential game-changing approach to efficient power generation using fossil fuels in a carbon constrained commercial environment.

4.5 Advantages and technical challenges

4.5.1 Advantages

The MHD generator operates at high temperatures and therefore, it can potentially achieve higher efficiencies then those obtained by conventional steam power plants. Earlier work on MHD cycle analyses indicates that MHD systems can achieve a plant efficiency of 45–55%, with potential to increase this to 60% (Gruhl, 1977; Ishikawa and Umoto, 1992). An MHD generator has no moving parts, so it can be more reliable. Also, it has the ability to make rapid starts to full load and hence, it is possible to use MHD for peak power generation and emergency service. MHD can be scaled-up to large units. Although it is difficult to predict the costs accurately, findings from technical and economic analyses of MHD power systems suggest that capital costs of MHD power plants could be competitive with and operating costs are lower than those of, conventional steam power plants (Batsyn and others, 1992; Kaproń, 1996; ILG-MHD, 1984). Furthermore, MHD power generation systems should have good environmental performance and be compatible with CCS systems for CO_2 capture.

4.5.2 Challenges

Despite the considerable progress that was made during the 1980s and early 1990s towards the development of commercial-scale coal-fired MHD power plants, several technological breakthroughs are required before MHD power generation systems can be commercialised. Various technical challenges remain in coal-fired MHD technology depending on the power generation cycle configuration. The technical issues that need to be solved include:

- high temperature heat exchanger/air preheater;
- cost-effective seed recovery and regeneration system;
- control of slag removal in MHD combustor;
- high temperature resistant electrodes;
- optimal designs of MHD generator and its components, and durable operation of high temperature MHD channel;
- tail gasification process.

Also, despite the fact that topping and bottoming cycles have been operated and tested, and coal gasification is a mature technology, a plant that integrates two or all of these systems has never been operated. Problems may occur when different processes are integrated together. In addition, problems are likely to arise when the integrated system is scaled up.

In summary, MHD technology provides a potential alternative approach to power generation from coal. Various coal-fired MHD power generation schemes have been proposed. Among the proposed schemes, the direct coal-fired MHD-steam combined cycle described in Section 4.4.1 is the most developed and tested. One of the major advantages of the MHD power generation technology is its potential to achieve high energy efficiency. However, there are several technical barriers and extensive R&D is required to develop a commercial-scale coal-based MHD power plant.

5 Indirect coal-fired combined cycle power system

In recognition of the need to make significant improvements to the overall thermal efficiency of coal-fired power plants, while decreasing their environmental impact and lowering the power production cost, the US Department of Energy (DOE) initiated a research effort for a coal-fired High Performance Power Generating System (HIPPS) as a part of the DOE's Combustion 2000 Program. This concept is based on thermodynamically optimised, indirectly fired combined cycles (IFCC) – a new way of burning coal to achieve high efficiencies and low emissions. It uses a topping Brayton (gas) cycle and a bottoming Rankine (steam) cycle. Clean air is the working fluid, therefore avoiding the expense of hot gas cleanup and/or the corrosion of turbine blades by coal ash. The HIPPS plant concept can be applied to new power plants or adapted to repowering of existing coal-fired plants.

The program devised by DOE had three phases:

- Phase I: Concept Definition and Preliminary R&D, which began in 1992, resulted in a conceptual design of a coal-fired HIPPS plant. Small-scale R&D was done in critical areas of the design;
- Phase II: Engineering Development and Testing, started in 1995. Pilot-scale testing led to the development of conceptual designs for retrofitting HIPPS to two existing coal-fired power plants;
- Phase III: Prototype High Performance Power Plant, was planned to start in 2000.

The DOE's goal for the HIPPS program was high thermodynamic efficiency and significantly reduced emissions. Specifically, the goal was a 300 MWe plant with >47% (HHV) overall efficiency and ≤10% of the then applicable NSPS (New Source Performance Standard) emissions. The plant was to fire at least 65% coal (eventually increasing to >95%) with the balance made up by a premium fuel such as natural gas. Cost of electricity was to be at least 10% less than that from a comparable NSPS power plant. However, due to budget cut, the Combustion 2000 Program was ended after completion of the Phase II in favour of continued support for IGCC R&D, which was viewed as being more fuel and product flexible and closer to commercial readiness.

The main advantage of the HIPPS technology is the possibility of having a combined cycle at initial air heating temperatures of 1000–1100°C (around 1400°C was ultimately envisaged) resulting in high efficiencies without the need for sophisticated hot flue gas clean up technology which is not yet fully available.

5.1 HIPPS power cycle

In the HIPPS power cycle, air compressed to the gas turbine inlet pressure is heated in a coal-fired high-temperature advanced furnace (HITAF). The air (working fluid) does not come into contact with the corrosive coal combustion environment. Either natural gas or a clean coal-derived fuel gas is used to boost the temperature of the air to the desired turbine inlet temperature. The heated pressurised air is then expanded in a gas turbine producing more than half of the cycle's power output. Heat is recovered from both the coal-fired furnace flue gas and the gas turbine exhaust to drive a conventional Rankine steam cycle to maximise electric power production. Some of the turbine exhaust air may be recycled as preheated combustion air for the HITAF. The HITAF, gas turbine and heat recovery steam generator (HRSG) are configured to achieve the required high efficiency of the HIPPS plant.

The technological development of HIPPS followed two different approaches. In one HIPPS process, a fluidised bed coal pyrolyser is used to convert pulverised coal into two components: a low-heating-value fuel gas and solid char. The char is separated and burned in the HITAF at atmospheric pressure, raising superheated steam and preheating the gas turbine air. The fuel gas is burned with the air from the HITAF to further heat this air to the gas turbine inlet temperature. In the other HIPPS process, the HITAF is a directly fired slagging furnace that utilises flame radiation to heat air flowing through alloy tubes located within a refractory wall. The HIPPS plant arrangement is thus a combination of existing technologies (gas turbine, heat recovery units, conventional steam cycle) and new technologies (the HITAF including its air heaters, and especially the heater located in the furnace's radiant section).

5.2 The HIPPS with slagging furnace

5.2.1 The HIPPS process

Figure 18 shows a simplified HIPPS process that uses a slagging furnace. The compressor discharge air is sent to the coal-fired HITAF, where the air is preheated first in a convective air heater (CAH) and then in a radiant air heater (RAH). The HITAF is currently designed to heat air to 930–1000°C. The preheated air then goes to a special topping combustor where natural gas is burned to increase the air temperature to 1260–1370°C. The topping combustor allows full operation of the gas turbine on natural gas alone, increasing the plant's operating flexibility. There are two options for the turbine exhaust: it can be split into preheated combustion air for the HITAF with the remainder going to a heat recovery steam generator (HRSG) as shown in Figure 18; or the entire flow can go to an HRSG. In the latter case, a conventional air preheater is used in the HITAF exhaust. The exhaust from the HITAF is sent to a cleanup system consisting of particulate removal, desulphurisation and, if needed, NOx control.

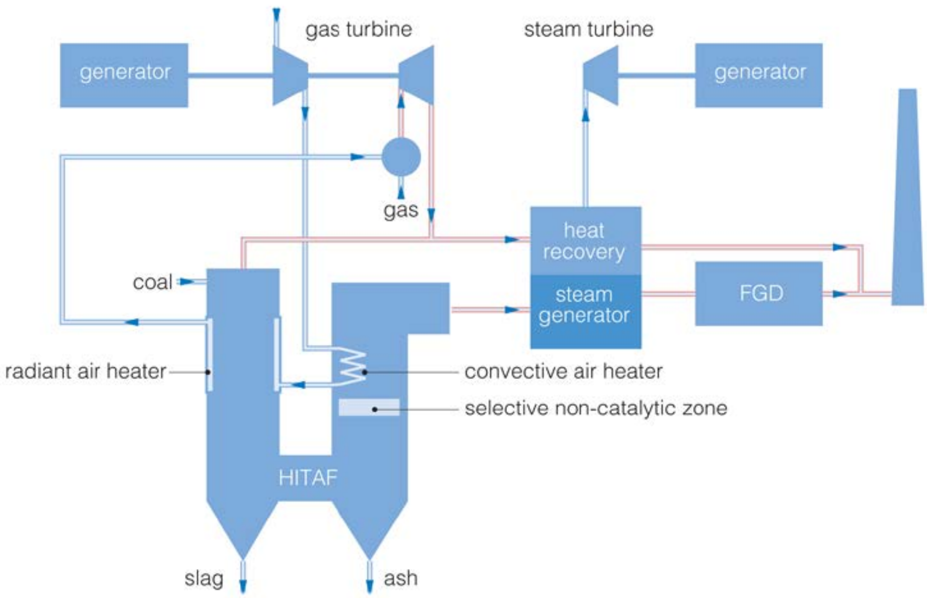

Figure 18 A simplified HIPPS process with slagging furnace (Ruby and others, 1999)

The three major elements of the system are the HITAF, the gas turbine and the steam turbine. The HITAF is the only subsystem in HIPPS that requires development; the other subsystems use technology available commercially or based on commercial technology. The overall efficiency of the system depends on the gas turbine and steam conditions used.

5.2.2 HITAF air heater

The key to the success of the IFCC concept is the development of an integrated combustor/air heater that will fire a wide range of coals with minimal natural gas and with the reliability of current coal-fired plants. The compatibility of the slagging combustor with the high temperature radiant air heater is the critical challenge. United TechnologiesResearchCenter (UTRC, USA) developed a baseline HIPPS plant design that has a total combined-cycle power output of 300 MW, and includes all facilities required for power production. In the baseline design, the compressor discharge air is heated in a HITAF to a temperature of around 925°C. The heat source is provided by combustion of coal. Since air is a poor heat conductor compared to steam, the heat transfer from coal combustion products at about 1650°C to high pressure air will require special structural design of the air heaters in order to avoid excessive mechanical and thermal stresses. Moreover, the mineral content of most coals at typical combustion temperatures produces ash particles in the combustion gas stream, resulting in potential degradation of heat transfer performance, as well as corrosion and erosion of heating surfaces. Although erosion of air heater surfaces by impinging ash particles is not expected to be a problem because gas and particle velocities will not be excessive, special provisions need to be made to minimise heat transfer degradation and to prevent corrosion.

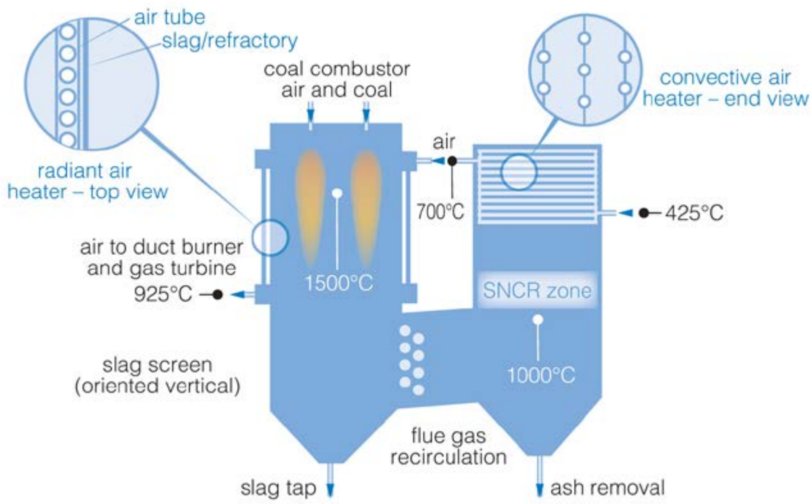

Figure 19 The UTRC design of HITAF (Seery and Sangiovanni, 1998)

The coal combustion temperature must be sufficiently high to attain the high air temperature required for acceptable gas turbine efficiency. Coal combustion under such conditions results in slagging of the coal ash that can potentially foul and corrode heating surfaces. Since it is impossible to maintain the entire air heater hot enough to produce continuous slag flow from all heating surfaces, the transition from wet slag to dry ash is controlled by dividing the air heating into two sections. The intent is to avoid this transition in the presence of heat transfer surfaces which, if it did occur, would tend to cause fouling and corrosion. Two different types of air heater are designed to deal with slag or ash. The radiant air heater (RAH) operates in the higher temperature (slagging) section, while the convective air heater (CAH) operates in the lower temperature (dry ash) region. The air heaters are arranged for counter flow of the air and the coal combustion gas. A slag screen is located between the two air heaters to remove most of the molten slag from the hot gas stream before it enters the convective air heater. To prevent excessive sintering of ash deposits on heater surfaces and to provide a suitable temperature zone for selective non-catalytic reduction of NOx, the combustion gas temperature is reduced to about 980°C by introducing flue gas recirculation immediately upstream of the convective air heater (Seery and Sangiovanni, 1998, 1997). The HITAF design by UTRC and the arrangement of the air heaters and the slag screen are shown schematically in Figure 19.

5.2.3 Air heater design

Through extensive small-scale testing, the alloy-based ‘tubes-in-a-box’ with ceramic tile protection emerged as the most suitable design for the RAH. Figure 20 shows the conceptual design for RAH. The RAH consists of an array of tubes contained in a protected panel that is uniformly heated by radiation and lines the inside walls of the coal combustion furnace. The gas turbine air is distributed to the many small passages within these panels by an arrangement of headers, manifolds, and ducts which are staged to avoid excessive thermal stresses. A ceramic refractory coating or tiles are applied to the fire sides of the hollow panels to prevent slag-induced corrosion. The parallel flow of the hot and cold gas streams enhances draining of liquid slag from the radiant heater surface by producing the highest surface temperature at the lowest point of the heater. Structural support for the entire RAH is provided by a massive structural shelf at the bottom of the furnace, probably consisting of furnace brick masonry. The high temperature coal combustion products at 1538°C or higher heats the panels by radiant transfer and, as the gas turbine air flows through the panels, the air is heated by forced convection from about 705°C to 927°C or higher, depending on heater material and availability of supplemental heating by direct combustion of a premium fuel such as natural gas (Seery and Sangiovanni, 1998).

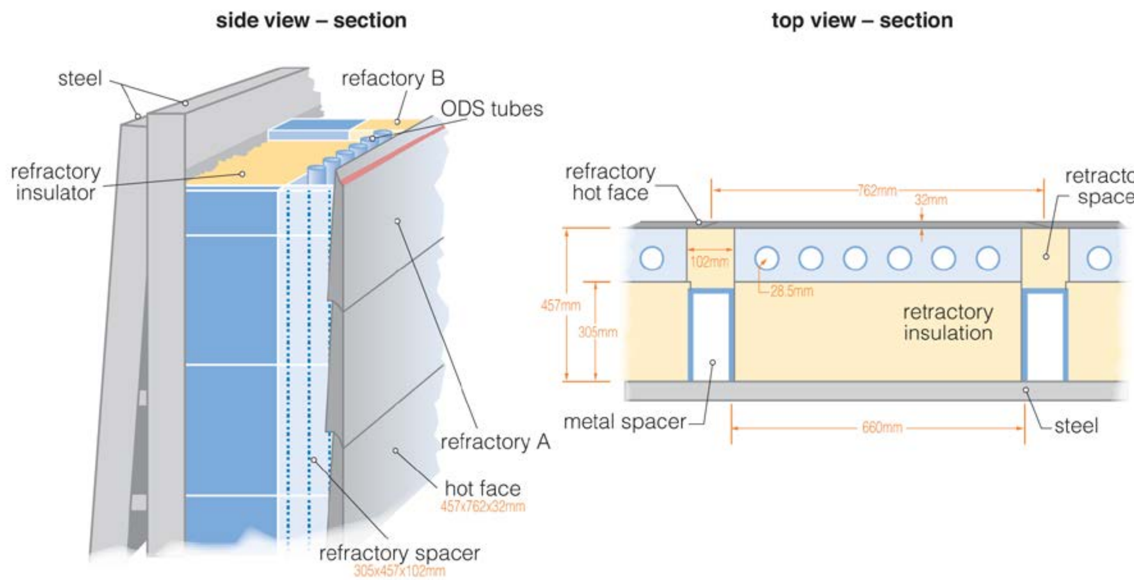

Figure 20 The conceptual design for RAH (Ruby and others, 1999)

5.2.4 Air heater materials

Materials are the key enabling technology for successful operation and commercialisation of the HIPPS system. The use of high temperature heat exchangers in a coal combustion environment, coupled with the cost constraints, make proper materials selection a considerable challenge. Nonetheless, utilisation of state-of-the-art materials and joining methods, as well as advanced oxidation and corrosion resistant coatings, can yield reasonable compromises.

Phase I tests results indicated several potential approaches for the RAH components: 1) use of metal tubing with protective coating(s) and refractory ceramic lining(s); 2) use of structural ceramics such as silicon carbide or silicon carbide/alumina particulate composites, with a protective refractory ceramic lining; and 3) use of fusion cast ceramics such as those used for glass furnace tank linings. The Inco MA754 (oxide dispersion strengthened) was chosen as tubing material for its availability and the material for the refractory tiles which protect the alloy tubes was determined to be a fusion cast alumina based on the Phase I testing (Levasseur and others, 2001; Seery and Sangiovanni, 1998). Results from Phase II testing suggested that a cost competitive HIPPS plant could be built employing MA754. During the tests, the high temperature heat exchanger composed of MA754 alloy produced process air at 950°C and 1.1 MPa for over 2000 hours with a variety of coals. For a short time, conditions of 1100°C and 0.7 MPa were reached (Hurley and others, 2003).

Beyond the testing of the RAH panel with MA754 tubes and Monofrax M tiles for protection, there was a continuing search for lower cost alternatives. Several advanced alloys then capable of commercialisation had been identified which would be suitable for radiator tubes with air outlet temperatures of 1150°C.

5.3 The HIPPS with fluidised bed pyrolyser

A different HIPPS scheme capable of overall cycle efficiencies up to 50% was developed by Foster Wheeler (FW). A unique feature of FW's HIPPS concept is that it integrates the operation of a pressurised fluidised bed (PFB) pyrolyser and a pulverised coal-fired boiler/air heater.

5.3.1 Process description

In Phase 1, a conceptual baseline 300 MWe plant design was developed and the technical and economic analyses found that the design met the project goals. The envisioned HIPPS commercial plant would be a greenfield, coal-fired base-load facility. The plant size was based on using an advanced, heavy-frame, industrial gas turbine with a nominal output of 160 MWe. Additional power generation capacity would be provided by a single reheat steam turbine with steam conditions of 18 MPa/580°C/580°C. The plant was projected to achieve an overall thermal efficiency of 47% (HHV) at full load.

A simplified schematic diagram of this HIPPS process is shown in Figure 21. The key component of the system is the fluidised bed, air blown pyrolyser, which converts the coal into a low-heating value fuel gas and char. It is operated at about 1.65 MPa/923°C under substoichiometric conditions with coal, sorbent and air from the gas turbine exhaust. With the All-coal-fired HIPPS power cycle, the resulting char containing spent and unspent sorbent and coal ash, after being separated from fuel gas, is burned in a HITAF, which heats both air for a gas turbine and steam for a steam turbine. The majority of the air from the gas turbine compressor is first heated in the recuperator and then in the HITAF to 760°C. The tube banks for heating the air are constructed of alloy tubes.

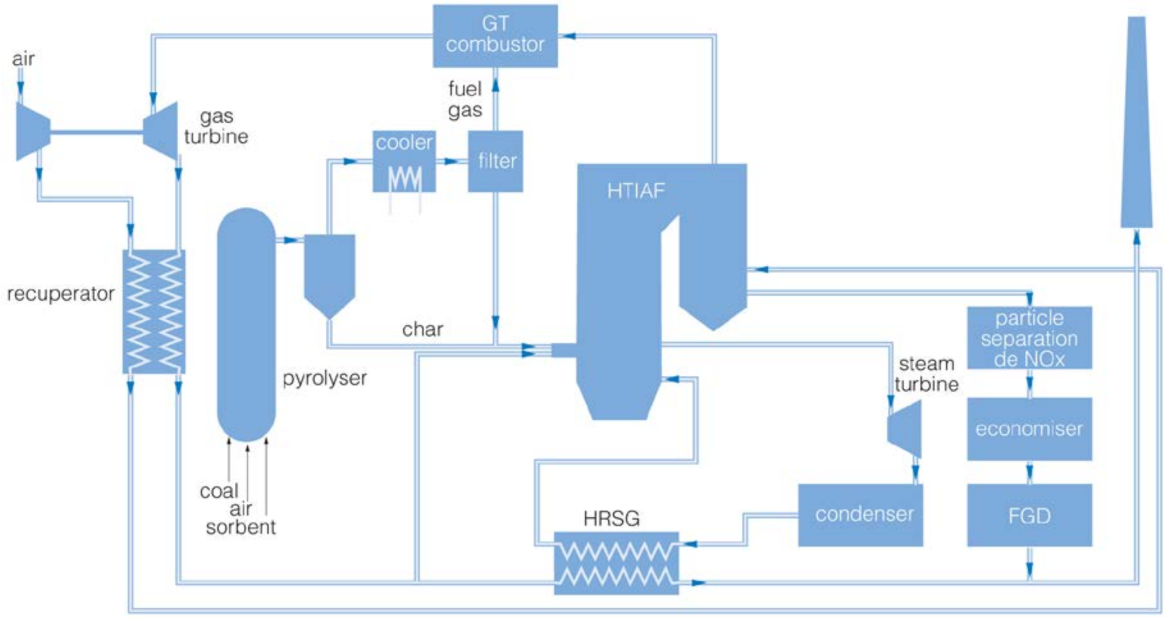

Figure 21 A simplified All-coal-fired HIPPS process (DOE/FETC, 2000)

The fuel gas from the pyrolyser is cooled to about 538°C to condense out alkalis and passed through a filter to remove particulates. The cleaned fuel gas is then fired with the heated air from the HITAF in the topping combustor to raise the gas temperature to 1288°C upon entering the first gas turbine stage. The exhaust from the gas turbine goes through the recuperator, where heat is transferred to the compressor discharge air. A portion of the heated air from the gas turbine is used as combustion air for the HITAF. The remaining heated air goes through a heat-recovery steam generator (HRSG). Emission control of the two fluegas streams can be accomplished by conventional filter, selective catalytic reduction (SCR) and flue gas desulphurisation (FGD) systems.

In an alternative HIPPS cycle, as shown in Figure 22, a ceramic air heater is used to heat the air to temperatures above what can be achieved with alloy tubes. A pyrolyser is used as in the baseline HIPPS design, but the fuel gas generated is fired in the ceramic air heater located in the top section of the HITAF instead of in the topping combustor. Gas turbine air is heated to 760°C in alloy tubes the same as in the baseline design. This air then goes to the ceramic air heater where it is heated further before going to the topping combustor. The temperature of the air leaving the ceramic air heater will depend on technological developments of that component. An air exit temperature of 982°C will result in 35% of the heat input from natural gas (DOE/FETC, 2000).

The two major subsystems that require development in this HIPPS approach are the pyrolyser and the char combustion subsystems.

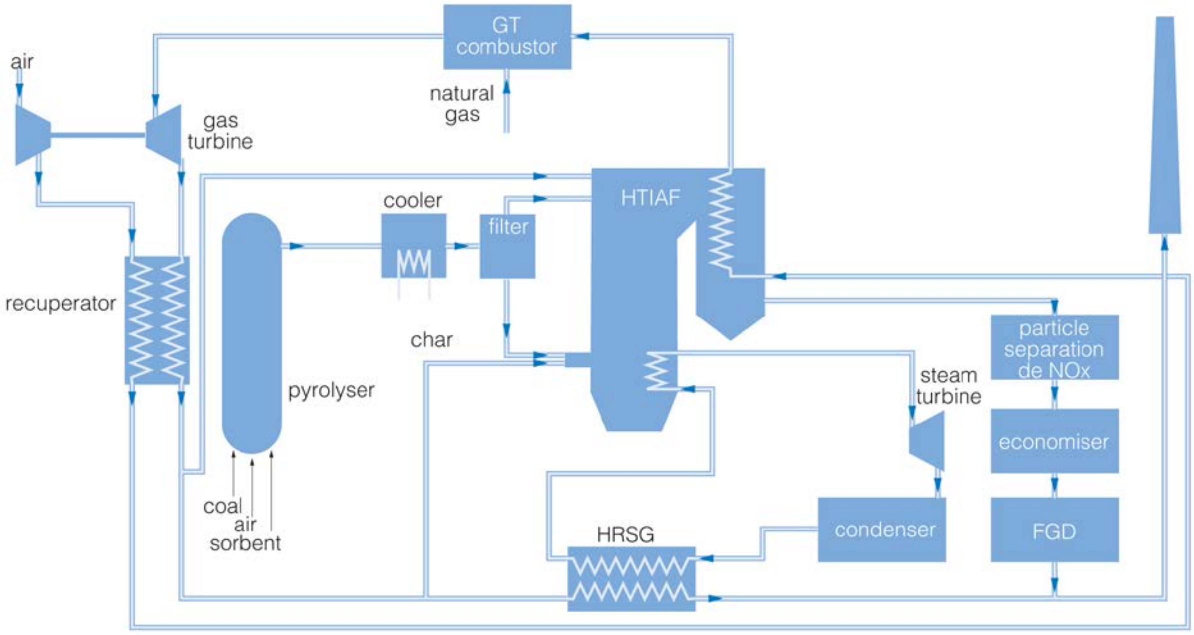

Figure 22 A simplified coal-/gas-fired HIPPS process (DOE/FETC, 2000)

5.3.2 Pyrolyser

The pyrolyser is very similar to what is called the 'carboniser' in the second-generation PFB system. A jetting bed pyrolyser is used for the generation of fuel gas and char. The fuel gas goes to the gas turbine and the char is depressurised, cooled and then conveyed to the pulverisers. A circulating fluidised bed pyrolyser system designed to yield char of suitable size for combustion could also be used and was tested. The jetting bed pyrolyser system with char pulverisation uses technologies that are either commercial or being demonstrated on a large scale (DOE/FETC, 1996).

5.3.3 Pulverised char combustor

A key requirement of HIPPS is that the char generated in the pyrolyser can be efficiently fired in pulverised fuel burners with gas turbine exhaust as the combustion air. This impacts both the design of the pyrolyser and the HITAF burners and furnace. Since the char is low in volatile matter, which makes the fuel harder to burn, it was determined that an arch-fired furnace arrangement would provide the optimum design. In the arch-fired boiler design, the flame is directed downward into the furnace and secondary air is added along the flame path. This results in a long flame and re-entrainment of hot gases into the burner zone, which helps to stabilise the flame. It also provides for increased particle residence time and improved carbon conversion efficiencies.

5.3.4 Char burner design

An innovative char burner was designed for initial testing in the HIPPS program. Char is pneumatically conveyed to the burner and discharged through a pipe into the top cover plate of the burner where it is mixed with the burner air. As mentioned above, a commercial HIPPS plant would use the exhaust from the gas turbine for combustion of the char. Limestone is also pneumatically conveyed into the top plate of the burner, and is introduced 180 degrees to the char injection point. The limestone and the char are mixed with the heated burner air (approximately 427°C) to preheat these feedstocks prior to combustion within the boiler. The two phase (air-char-limestone) mixture is injected into the boiler through a char discharge pipe.

The burner is fitted with a central coal injection nozzle to provide a support fuel, if necessary, to maintain stable combustion.

The final HIPPS char burner component is the tertiary air swirler. The swirler vanes are positioned around the burner discharge pipe and are flush with the interior arch wall of the boiler. The position of the swirler vanes for the HIPPS char burner is adjustable. Swirling of the tertiary air stream is used to promote flame stability, and overfire air is added to minimise the NOx formation (Torpey and others, 1998).

5.3.5 Repowering approach

A simplified version of the HIPPS arrangement, as shown in Figure 23, can be applied to repower existing boilers to improve overall plant efficiency and increase generating capacity. The repowering application of HIPPS is similar to hot windbox repowering where the gas turbine exhaust stream is used as the oxidant for co-combustion of pulverised char and coal. The existing boiler and steam turbine infrastructure are reused with modifications. Additional equipment is required on the front end of the plant. The pyrolyser, coal/sorbent handling and preparation subsystem, char cooling and feeding equipment, fuel gas cooler and ceramic barrier filter, gas turbine and gas turbine combustor are integrated with the existing boiler. This repowering scheme is based on the All-coal-fired HIPPS configuration. As a result of the high-temperature gas turbine exhaust being used as combustion air, the existing air heater is no longer needed. The temperature of the flue gas leaving the existing high-pressure economiser is high enough to provide all feedwater heating duty and hence there is no need for the existing feedwater heaters. Additional economisers can be added upstream and downstream of the boiler to compensate for these heating-duty changes (Wu and McKinsey, 1997).

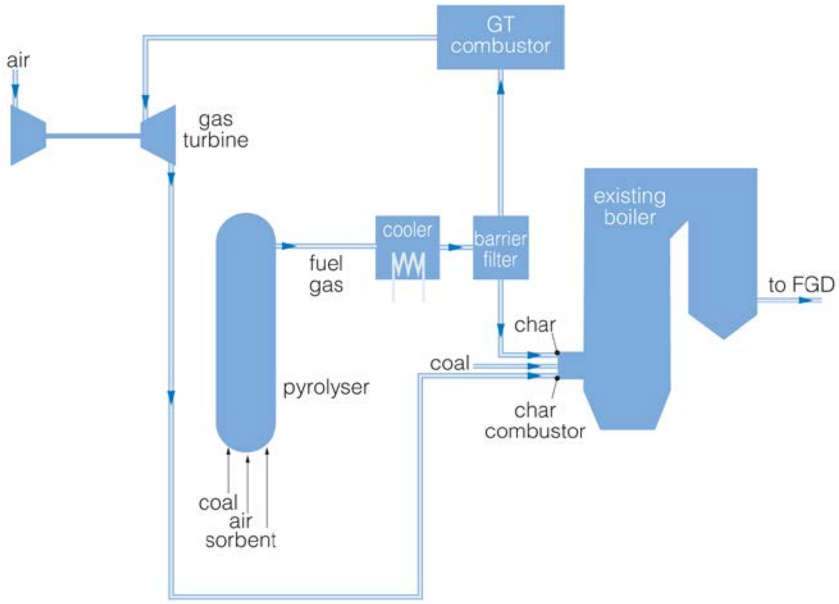

Figure 23 A simplified HIPPS repowering process flow diagram (Torpey and others, 1998)

5.4 HIPPS power cycle configurations

The HIPPS plant design developed by UTRC used essentially off-the-shelf technology in all of its components with the exception of the HITAF. This plant had a nominal capacity of 300 MWe and incorporated a heavy frame gas turbine and a 16.5 MPa/538°C/538°C bottoming steam cycle, which gave an overall efficiency of 47.3% (HHV). This is only one of the many possible cycle configurations and it is used as a baseline plant in order to find the optimum cycle to exploit the HIPPS technology. Based on the baseline HIPPS plant design, Klara and colleagues (1995, 1997) assessed the impacts of steam conditions and gas turbine technology on the HIPPS performance and costs were assessed. Twelve gas turbines were selected as likely candidates for use in a HIPPS cycle to compare the following characteristics:

- low and high gas turbine inlet temperatures (GTIT);
- heavy-frame and aero-derivative machines;
- machines available today and advanced ones;
- standard expansion and reheat expansion;
- 50 Hz and 60 Hz machines, and
- ability to burn fuel gas in addition to natural gas and oil.

The parameters of the selected gas turbines are shown in Table 9 and the cycle study results are shown in Table 10. It can be seen from Table 10 that the highest HIPPS cycle efficiency of over 49% (HHV) could be achieved with the use of General Electric's 7G technology – the air-cooled version of its new, steam-cooled 'H' technology system. However, this configuration had one of the lowest coal fractions (56%). The HIPPS cycle configuration using the Westinghouse 251B11/12 gas turbine had the highest coal fraction (73%), but also the lowest efficiency (44%). The fraction of coal that can be used is decided primarily by the GTIT. Higher GTITs require more clean gaseous fuel, therefore lowering the coal fraction. In general, with current design, to get a coal fraction in the range of 60–70%, the GTIT should be around 1260–1315°C, coal fractions in the 70–80% need GTITs around 1150°C, and 1427°C GTITs yield coal fractions in the 50-60% (Klara and others, 1997). When selecting the HIPPS cycle configuration for a power plant, the HIPPS performance may need to be compromised for the desired high fraction of coal use.

Table 9 Gas turbine parameters (Klara and others, 1997)

Gas turbine (GT)	GT inlet temperature (°C)	Pressure ratio	Heat rate (MJ/kWh, LHV)	Power (MW)	GT exit temperature (°C)	Key feature
ABB GT24	1288	30.0	9.47	173	610	reheat GT
GE 7FA	1288	15.0	10.02	159	593	heavy frame
GE 7G	1427	23.0	9.12	240	572	high GT inlet temperature
GE 9FA	1288	15.0	10.10	226.5	589	50 Hz
GE LM6000	1243	30.0	9.26	40.01	463	aero-derivative
Siemens V64.3A	1316	16.6	9.78	70	565	heavy frame
Siemens V84.3A	1316	16.6	9.47	170	562	heavy frame
Westinghouse 251B11/12	1149	15.3	11.01	49.2	520	fuel gas
Westinghouse 501D5A	1177	14.2	10.43	121.3	538	low GT inlet temperature
Westinghouse 501F	1349	14.0	9.98	167	596	fuel gas
Westinghouse 501G	1427	19.2	9.22	235.24	593	high GT inlet temperature
Westinghouse Trent	1316	35.0	8.66	51.19	426	aero-derivative

Table 10 HIPPS plant efficiency, power output and coal fraction with individual gas turbine (Klara and others, 1997)

Gas turbine	HIPPS efficiency (%, HHV)	Coal fraction (% input)	Net power (kW)
GE 7G	49.33	56.14	402875
Westinghouse 501G	48.50	57.37	383352
GE 9FA	47.91	64.95	402075
Siemens V84.3A	47.64	61.09	300856
ABB GT24	47.55	48.22	279931
GE 7FA	47.43	64.64	276227
Siemens V64.3A	47.42	60.92	127170
Westinghouse 501F	46.51	65.53	284110
GE LM6000	45.96	67.07	75265
Westinghouse 501D5A	45.44	72.08	229402
Westinghouse Trent	45.26	67.51	94620
Westinghouse 251B11/12	44.42	73.35	99221

The UTRC's baseline HIPPS plant design uses subcritical steam conditions of 16.5 MPa/538°C/538°C. The steam (Rankine) cycle efficiency increases with rising steam temperature and pressure. The increase in the net HIPPS plant efficiency with higher steam conditions is shown in Table 11. By configuring HIPPS with a SC steam cycle of 32.5 MPa/593°C/593°C, the net HHV efficiency is improved by 2.1 percentage points compared with a conventional subcritical steam cycle. More efficiency gain could be obtained by further increasing the steam parameters to USC and A-USC conditions. Generally, by increasing the steam cycle conditions, more coal is required in the HITAF; and therefore, the coal fraction increases.

Table 11 The net HIPPS efficiencies with steam conditions (Klara and others, 1997)

Steam condition (MPa/°C/°C)	Efficiency (%, HHV)	Improvement by percentage points		
		Steam conditions	Expansion efficiency	Total
16.5/538/538	47.23			
32.6/593/593/593	49.33	0 (base case)	0 (base case)	0 (base case)
37.9/649/649/649	50.69	0.69	0.67	1.36
41.4/704/704/704	51.69	0.62	0.38	1.00
Supercritical improvements	2.36	1.31	1.05	2.36
Total improvements	4.46			

Table 12 shows the HIPPS performance with varying cycle configuration. It can be seen from Table 12 that for given steam parameters, the net HIPPS cycle efficiency (HHV) varies by almost 4 percentage points and the coal fraction by as much as 16 percentage points depending on the choice of gas turbine technology. Typically, the coal fraction increases with advanced steam conditions, but decreases with advanced gas turbine technology, and the cycle efficiency increases with both the advanced steam conditions and advanced gas turbine technology. Changing the steam cycle conditions had similar effects on efficiency, coal fraction, and net power for each gas turbine. Therefore, the effect of changing the steam condition is somewhat independent of the chosen gas turbine.

Table 12 HIPPS performance with varying cycle configuration (Klara and others, 1997)

Gas turbine	HIPPS performance		
	Efficiency (% HHV)	Coal fraction (% input)	Net power (MW)
GE 7G			
16.5/538/538	49.33	56.1	403
32.6/593/593/593	50.71	60.5	460
37.9/649/649/649	51.90	62.4	495
41.4/704/704/704	52.88	63.4	518
GE 7FA			
16.5/538/538	47.43	64.6	276
32.6/593/593/593	49.47	67.0	309
37.9/649/649/649	50.80	68.6	333
41.4/704/704/704	51.78	69.6	351
Westinghouse 501F			
16.5/538/538	46.51	65.5	284
32.6/593/593/593	48.68	67.9	319
37.9/649/649/649	50.08	69.4	345
41.4/704/704/704	51.10	70.5	364
GE LM6000			
16.5/538/538	45.96	67.1	75
32.6/593/593/593	48.24	69.4	85
37.9/649/649/649	49.69	70.9	92
41.4/704/704/704	50.76	71.9	97
Westinghouse 501D5A			
16.5/538/538	45.44	72.1	229
32.6/593/593/593	47.76	74.1	260
37.9/649/649/649	49.25	75.4	282
41.4/704/704/704	50.34	76.2	299

In phase II study, higher performance gas turbines such as intercooled aeroderivative (ICAD) types were identified as having performance advantages over frame engines operating at the same turbine conditions. An advanced HIPPS/ICAD with 42.8 MPa/705°C steam turbine had an estimated performance of 53% (HHV) using a 55/45 coal/gas fuel ratio. The ICAD also lends itself to use in an advanced gas turbine cycle called the humid air turbine (HAT) cycle. In this cycle, low-grade heat from the gas turbine is used to saturate the compressor discharge air, which is subsequently recuperated against the turbine exhaust. Both the efficiency and the power output are significantly increased. A variety of HIPPS/HAT configurations were investigated. When the coal/gas ratio was decreased to approximately 62/38, and the HITAF radiator outlet temperature increased to 1093°C, HIPPS/HAT efficiencies of over 54% (HHV) were projected (Levasseur and others, 2001).

A HIPPS/Fuel cell hybrid power system was proposed, in which the compressor discharge air is heated in the HITAF to 982°C and then goes to a SOFC where it reacts with H_2 from a steam/natural gas reformer. The effluent from the SOFC is at approximately 1010°C and contains some unreacted H_2 and CH_4. When burned, temperatures of 1149°C are possible. When additional gas is added, the temperature can be raised to the level typical of modern gas turbines. These systems consumed significant fractions of natural gas. At a 40/60 coal/gas ratio, the efficiency is over 61% (HHV of coal plus gas mixture). As the coal/gas ratio increases, the efficiency decreases: 55% at 50/50 and 51% at 60/40. This is because the SOFC participation decreases since the SOFC fraction is a direct function of the natural gas flow (Levasseur and others, 2001).

5.5 Opportunities and barriers

5.5.1 Opportunities and options

HIPPS was being developed as a technology for future Greenfield coal-fired power plants. Some researchers claimed that the HIPPS approach would offer the highest power plant efficiencies of any coal-based design of the time. Coal gasification, even when used with the 'H' class frame gas turbines as identified in the DOE Advanced Turbine System program, reaches efficiencies in the mid 40%. With commercially available technologies at the time, an HIPPS power plant could easily achieve efficiencies of 45% or higher. HIPPS could potentially achieve energy efficiencies of >60% (HHV) using coal or 75% (LHV) using gas. Almost zero emissions of conventional pollutants and Greenhouse gases might be achievable. One of the methods of potentially reaching these goals may be by using a hybrid cycle that combines a thermodynamic cycle such as a Brayton cycle, with an electrochemical cycle like a high temperature fuel cell (Levasseur and others, 2001).

Earlier studies found that repowering an existing coal-fired power plant with HIPPS technology was both technically viable and economically attractive (Klara and colleagues, 1996; Shenker and McKinsey, 1995; Shenker and others, 1997; Wu and McKinsey, 1997). The HIPPS-repowered plant would have a significant increase in efficiency with major reductions in emissions at competitive operational costs, which improved its utilisation and dispatch. Ruby and co-workers (1999) suggested that for near term applications the first generation HIPPS system could adopt the baseline plant design but eliminate the RAH and use only a CAH in the HITAF. The CAH, which can be constructed with materials available today, would still allow air to be heated to relatively high temperatures of 700–800°C. They assessed the role of HIPPS technology in the potential US's repowering market and concluded that, depending on the gas turbine and steam parameters selected and the cycle configuration, power generation from the repowered plant could be increased by 25–200 MWe or more, with plant efficiencies achieving 42–52% (HHV). Economic analyses indicate that the cost of repowering appears to be competitive with the more common approach of using natural gas fuelled gas turbines.

The HIPPS system has a fuel diversity capability. It can be designed to burn biomass, solely or co-fired with coal, which lends itself to the use of advanced technology.

5.5.2 Technical barriers

A major goal of Combustion 2000 was the identification of an All-coal HIPPS plant. A variety of HIPPS configurations were considered. When HITAF radiator outlet temperatures were limited to the 927°C level, All-coal HIPPS had efficiencies in the 41–43% (HHV) range. When advanced materials are used for the radiator and temperatures are allowed to reach 1093°C, efficiencies of 44–45% are projected. When HIPPS/HAT configurations are identified, efficiencies over 48% are estimated (Levasseur and others, 2001). These estimates are made for systems with no natural gas used. To achieve higher efficiencies, natural gas has to be used to further heat the air from the RAH.

Further improvements in system efficiency require an increase in both the air temperature at the air heater exit and the gas turbine inlet temperature. Improved materials and advanced gas turbine technologies will have significant influence on the overall efficiency. The RAH requires the most development and represents a higher technical risk than other HITAF components. The current design limits the temperature of the air from the HITAF radiator outlet to around 927°C. An HIPPS system that uses only CAH in the HITAF was proposed to reduce the technical risk and the cost of the system. With this configuration, system performance would be limited to that of gas turbines with operating inlet temperatures of <871°C for current heater materials and to 982°C for advanced material convection heat exchangers.

Tests of a radiant heater in a coal-fired furnace at the Energy and Environmental Research Center at the University of North Dakota demonstrated the soundness of the UTRC design (Hurley and others, 2003). During the tests, air was routinely heated to temperatures of over 950°C, and temperatures as high as 1100°C were reached for a short period of time. However, problems with refractory durability and the structural design remain to be solved. With the ultimate goal of heating the air to temperatures required for efficient gas turbine operation without using natural gas, new construction materials for RAH need to be identified, and fabrication techniques and advanced oxidation and corrosion resistant coatings need to be developed.

6 Alternatives to steam Rankine cycles

R&D activities seeking to replace the working fluid with one that reduces parasitic losses intrinsic to the use of water as the working fluid, or one that can obtain a better thermal match with the heat source have led to a number of chemicals and materials being identified and tested for use as a working fluid. As a result, several power cycles alternative to steam Rankine cycle have been developed and others are under development.

6.1 Supercritical CO_2 power cycle

6.1.1 CO_2 as a working fluid

CO_2 is an ideal working fluid: low cost, non-explosive, non-flammable, non-toxic, non-corrosive and readily available. Supercritical CO_2 (sCO_2) is a fluid state of carbon dioxide where it is held above its critical pressure and critical temperature which causes the gas to go beyond liquid or gas into a phase where it acts as both simultaneously. Supercritical CO_2 has many unique properties that allow it to dissolve materials like a liquid but also flow like a gas. CO_2 has relatively low critical pressure and temperature: 7.4 MPa and 31°C, respectively. As a result, CO_2 reaches its supercritical state at moderate conditions. Supercritical CO_2 has excellent fluid density and stability while being less corrosive than steam. Its low critical pressure and temperature also allow CO_2 to be compressed directly to their supercritical pressures and heated to their supercritical state before expansion so as to obtain a better thermal match with the heat source.

6.1.2 R&D

The use of sCO_2 in power turbines has been an active area of research for a number of years. R&D of sCO_2 power cycles have been carried out in many parts of the world such as the Czech Republic, France, Japan, South Korea and the USA. Various sCO_2 cycle configurations such as a recompression condensing cycle and the Brayton cycle have been proposed and tested (Dostal and others, 2004).

Closed-loop sCO_2 Brayton cycle

Funded by the US DOE, Sandia National Laboratories and the DOE Office of Nuclear Energy (DOE-NE) have been involved in developing a closed-loop recompression Brayton cycle for nuclear power. This system is one of the first sCO_2 power-producing Brayton cycles operating in the world. The manufacture and assembly of the sCO_2 test loop were completed in May 2008 and tests over a wide range of conditions have been carried out since 2009. The initial results indicated that the basic design and performance predictions were sound (Wright and others, 2010; Sienicki and others, 2011). Sandia National Laboratories is now working to develop large (>10 MWe) sCO_2 Brayton units for various electrical production schemes.

Direct and indirect heating sCO_2 cycle

sCO_2 can be used in either direct or indirect heating scenarios. Indirect heating would use the CO_2 in a closed loop recuperated recompression Brayton or Rankine cycle. Indirect heating could replace steam boilers in coal plants, nuclear power, solar thermal, or heat recovery steam generators used in combined cycles. Indirect heating cycles offer thermal efficiencies greater than 50% and are non-condensing making them ideal for heat sources that offer constant temperatures (such as turbine exhaust).

Earlier work was mostly dedicated to the development of sCO_2 power cycle in nuclear applications. The sCO_2 power cycle is now being considered for application to solar, advanced fossil and other energy applications. The US DOE's Advanced Turbines Program at National Energy Technology Laboratory (NETL) plans to conduct R&D for directly and indirectly heated sCO_2 based power cycles for fossil fuel applications. The focus is on components for indirectly heated fossil fuel power cycles with turbine inlet temperatures at or above 760°C and oxyfuel combustion for directly heated sCO_2 power cycles.

The first fossil-based indirectly heated cycle considered is a non-condensing closed-loop Brayton cycle with heat addition and rejection on either side of the expander (*see* Figure 24). In this cycle, the CO_2 is heated indirectly from a heat source through a heat exchanger, the same way steam would be heated in a conventional boiler. Energy is extracted from the CO_2 as it is expanded in the turbine. Remaining heat is extracted in one or more highly efficient heat recuperators to preheat the CO_2 going back to the main heat source. These recuperators help to increase the overall efficiency of the cycle (NETL, 2014).

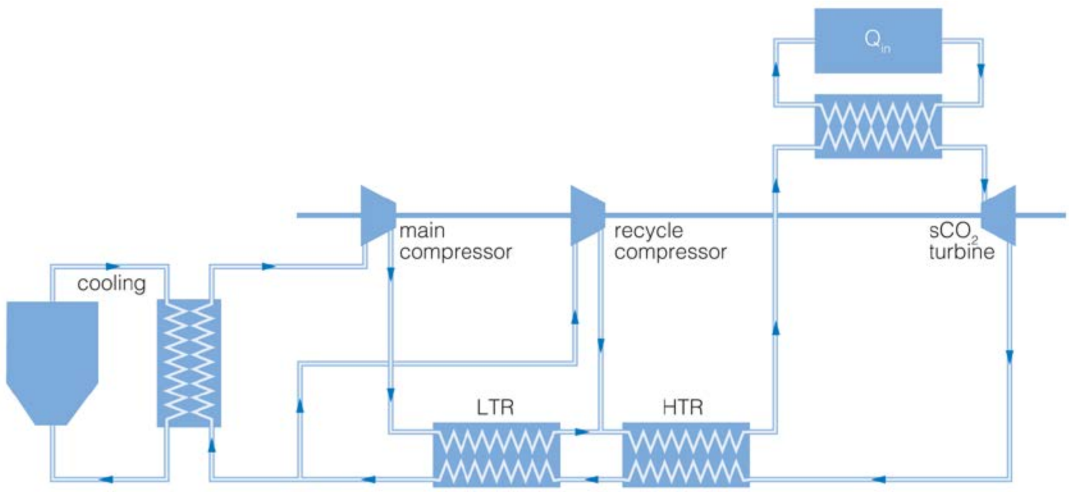

Figure 24 Closed Loop sCO_2 recompression Brayton cycle flow diagram (NETL, 2014)

Fossil fuels, particularly coal, can provide an ideal heat source for sCO_2 cycles. A sCO_2 oxyfuel power cycle has the potential for near 100% CO_2 capture. An oxyfuel directly heated sCO_2 cycle has been proposed and will be investigated by NETL. The directly fired sCO_2 cycles combust fossil fuels with oxygen and the resulting steam/CO_2 mixture is used to drive the turbine, as illustrated in Figure 25. In this particular cycle, the remaining heat in the steam/CO_2 mixture is recuperated to preheat the cooled and compressed CO_2 that is used as the combustion diluent. The mixture is further cooled to condense the water out and then compressed for CO_2 storage (NETL, 2014).

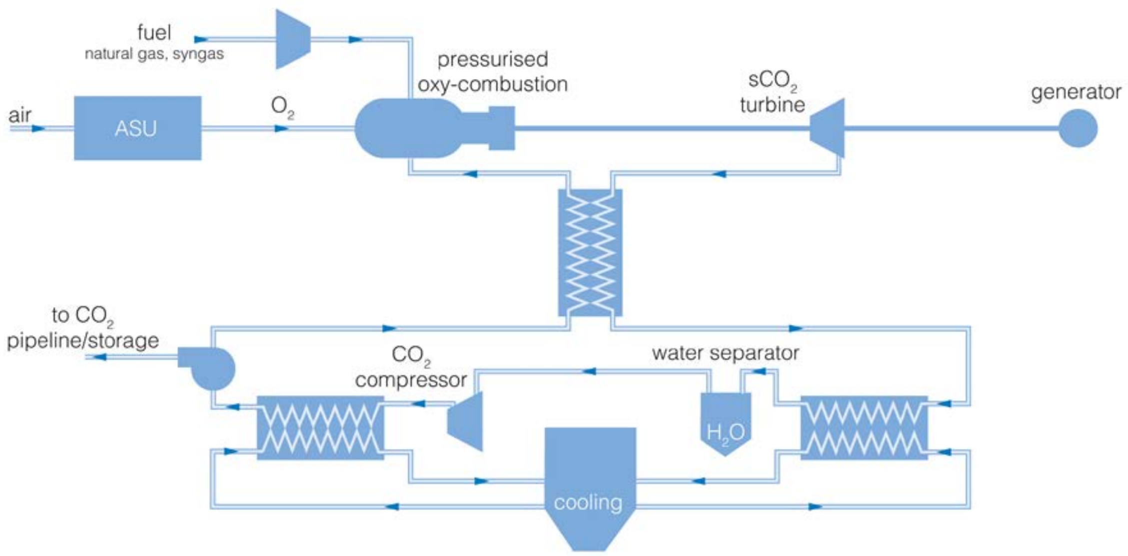

Figure 25 A potential configuration of oxygen fuelled directly heated sCO_2 cycle (NETL, 2014)

In a recent study, three closed-loop sCO_2 Brayton power cycle configurations for a 750-MW new-build power plant were proposed: 1) a recompression cycle with no reheat; 2) a recompression cycle with reheat (similar to a reheat steam Rankine cycle); and 3) a closed Brayton cycle as a high-temperature topping cycle to an ultra-supercritical steam cycle. In addition, a closed Brayton power topping cycle configuration was developed for repowering an existing 500-MW subcritical steam-electric power plant.

The performance of closed-loop sCO_2 Brayton power cycles in the new-build cases was compared with an advanced USC steam-electric power cycle. In the repowering case, the sCO_2 power cycle performance was compared to repowering with an advanced USC steam turbine topping cycle. The analysis was for the power cycle only and did not include thermal integration with the external heat source. The results showed that thermal efficiency of the proposed sCO_2 Brayton cycles exceeded the thermal efficiency of the corresponding steam Rankine cycles by up to 4 percentage points. Also in this study, the conceptual designs for the turbomachinery and heat exchangers required by the full-scale closed Brayton power cycle as well as overall plant layout were developed (EPRI, 2013).

Echogen heat engines

Echogen Power Systems LLC (USA) has developed a sCO_2 waste heat recovery heat engine. A nominal 200 kWe demonstration unit was built in 2010 and tested in 2011. An Echogen EPS100 heat engine with a capacity of 7.5 MWe was built and testing began in 2012. Echogen Power Systems is currently commercialising its ESP100 system (Persichilli and others, 2012). This system is self-contained, closed-loop, and has zero emissions and no water requirements (though water cooling is an option). It is targeted for use in combined-cycle applications.

One of the major features of the Echogen's heat engine is the extremely compact turbomachinery designs. Figure 26 compares an Echogen's 10 MWe sCO_2 turbine that is being designed for commercial service to a commercially available 10 MWe steam turbine. It is clear to see from Figure 26 that sCO_2 turbines are very compact with simpler, single casing body designs while steam turbines usually require multiple turbine stages and associated casings with a corresponding increase in systems packaging complexity for additional inlet and outlet piping (Persichilli and others, 2012).

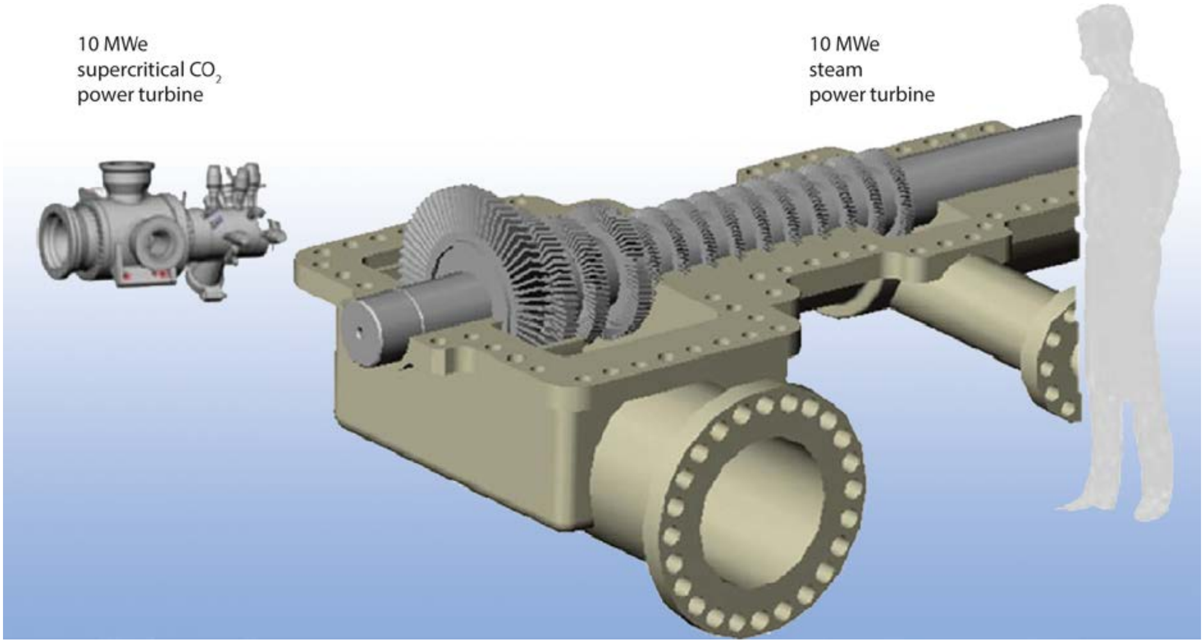

Figure 26 Comparison of an Echogen's 10 MWe sCO_2 power turbine and a 10 MWe steam turbine (Persichilli and others, 2012)

Allam cycle

NET Power is developing an oxyfuel recuperative sCO_2 Brayton cycle, called Allam cycle, for power generation from fossil fuels with target net efficiencies of 51% (LHV) for coal and of 59% (LHV) for natural gas, and full carbon capture. The core process is a gas-fired, high-pressure, low-pressure-ratio Brayton cycle (*see* Figure 27), operating with a single turbine that has an inlet pressure in the range of 20 MPa to 40 MPa and a pressure ratio of 6 to 12. The cycle includes a high pressure oxyfuel combustor that burns a fossil fuel in a pure oxygen stream to provide a high pressure feed stream to a power turbine. An economiser heat exchanger transfers heat from the high temperature turbine exhaust flow to a high pressure CO_2 recycle stream that flows into the combustor, diluting the combustion products and lowering the turbine inlet temperature to an acceptable level. The turbine exhaust flow is cooled to a temperature below 70°C in the economiser before it is further cooled to near atmospheric temperature in an air cooler or with cooling water. Water in the flue gas is condensed and separated, resulting in a stream of predominantly CO_2. The recycle stream is reheated in the economiser before returning to the combustor. The rest of the CO_2 from the high pressure stream is sent to a CO_2 export pipeline (Allam and others, 2013). An Allam cycle is simple, using only a single gas turbine with an oxyfuel combustor and heat exchangers. As a result, it has reduced BOP requirement and a small footprint, and lower costs.

A coal-based Allam cycle can be built on this core process, as shown in Figure 27, and will be fuelled with coal derived syngas. This system integrates an Allam cycle with a commercially available coal gasifier. The low grade heat from the gasifier is recovered to the low temperature region of the high pressure CO_2 recycle, where it is used to heat a side stream from the economiser heat exchanger. The result of this close coupling is near 100% thermal efficiency of the gasifier, thereby driving efficiencies significantly higher than any other coal-based generation system. The syngas is combusted, and the predominant impurities in the turbine exhaust stream are SO_2 and NOx. These, in turn, are converted to H_2SO_4 and HNO_3, which occurs mostly within the cold-end passages of the heat exchanger in the presence of condensed water and excess oxygen. The pressure of the turbine exhaust flow, in the range of 1.6 to 6.6 MPa, ensures that the reaction kinetics are fast. Further, the nitric acid present will largely remove mercury contaminant, and the H_2SO_4 can be converted directly to $CaSO_4$ by reaction with limestone in a simple stirred tank reactor. The $Ca(NO_3)_2$ is water soluble and can be separately recovered if desired (Allam, 2013; Lu, 2014). The development of a syngas combustor is ongoing.

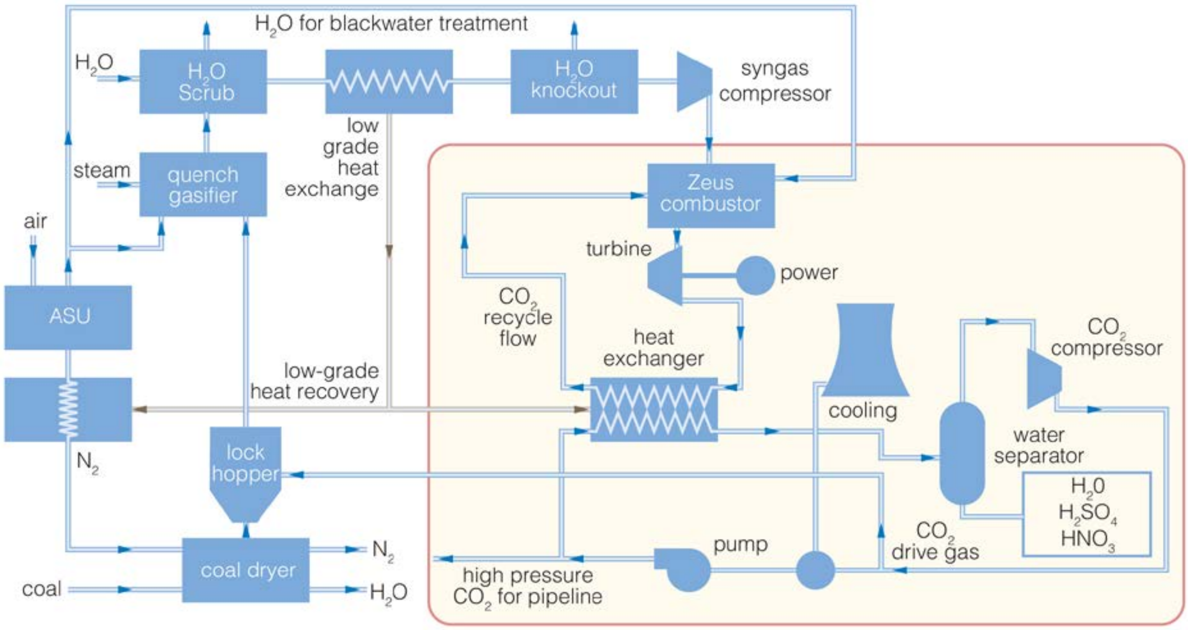

Figure 27 Integrated coal gasification-Allam cycle power system (Lu, 2014)

Recently, NET Power announced that in partnership with CB&I, Toshiba and Exelon Corporation, they will build their first natural gas-fired, direct heated sCO_2 50 MWth demonstration plant in Texas, USA. This power plant will have zero emissions of any kind (no smokestack) and has integrated carbon capture. The plant is a scaled-down version of a larger commercial plant, currently designed at 250 MWe, such that the operability and performance demonstrated by the testing and commissioning programme will be directly applicable to the future scale-up of the system. Toshiba has undertaken the development of the new combustor and turbine that will be required due to the pressures, temperatures, and working fluid of the Allam cycle (Allam, 2013). The plant is anticipated to be commissioned in 2016.

6.1.3 Advantages and challenges

The sCO_2 power cycle is an innovative technology that is attracting increasing attention in the engineering world. A sCO_2 power cycle could potentially achieve a higher thermal efficiency than steam Rankine cycles when operating between the same maximum and minimum cycle temperatures. Earlier work by Angelino (1969) showed that for a cooling water temperature of 5°C and turbine inlet temperature of 700°C, sCO_2 cycle efficiency better than that of a double reheat steam cycle at the same maximum temperature and in excess of 50% was achievable. The superiority of reheat sCO_2 cycles over the double reheat steam cycle is maintained up to a cooling water temperature of 20°C. As a result, sCO_2 power turbines could potentially replace steam cycles in a wide variety of power generation applications. Nuclear power, concentrated solar thermal, fossil fuel boilers, geothermal, and shipboard propulsion systems have all been identified as favourable applications for sCO_2 cycles. The existing steam power generation facilities could, in theory, be upgraded to sCO_2 cycles that would enable greater efficiencies and power outputs as well as lower costs. In addition, the high fluid density of sCO_2 suggests that the size of the turbomachinery used in a sCO_2 power cycle could be much smaller than those used in steam cycle generation, leading to a smaller footprint and lower capital costs. Some researchers believe that sCO_2 power cycles could lower the cost of electricity by approximately 15% over today's steam cycle technologies. Lower installed cost for sCO_2 cycle power systems are due to its smaller footprint and simple cycle design. Lu (2014) compared the levelised cost of electricity (LCOE) of a coal-fuelled Allam power plant with the LCOE of SC PC and IGCC power plants with/without CCS (*see* Figure 28). His results indicated that a coal Allam cycle plant with full CCS could produce power at a cost lower than a corresponding SC pulverised coal combustion or an IGCC plant without carbon capture. Due to the superior thermal stability and non-flammable, non-corrosive nature of CO_2, direct heat exchange from high temperature sources is possible, permitting higher working fluid temperature (and thus higher cycle efficiency). Because sCO_2 is a single-phase working fluid, it does not require the heat input for phase change from water to steam and does not create the associated thermal fatigue or corrosion associated with two-phase flow. Lower operation and maintenance costs for sCO_2 are possible because the water treatment and quality control typically found in steam-based plants are avoided.

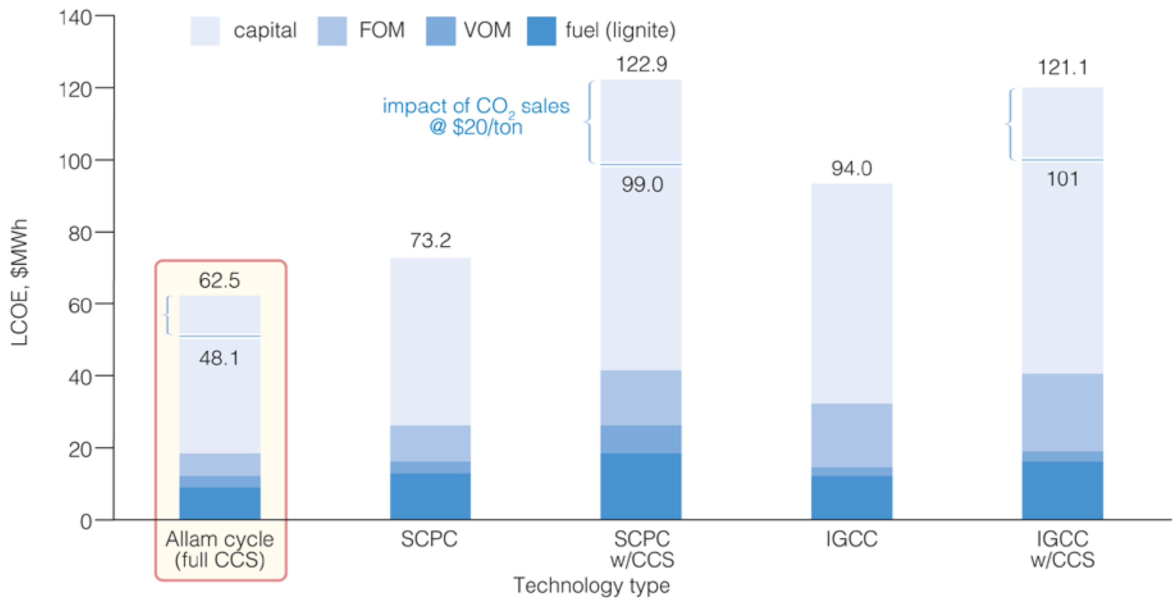

Figure 28 Costs comparison of Allam system with supercritical PC and IGCC power plants (Lu, 2014)

The main challenges of developing this technology include the design of the turbomachinery components and the technologies used in the design, the design of compact heat exchangers that can operate at high temperatures and pressures, and the dynamic control of the whole system. The best materials for manufacturing the turbo machinery, valves, seals that can handle the elevated temperatures and pressures used in sCO_2 cycle needs to be identified. Deployment of the sCO_2 cycle technology at full scale will require recuperative turbines and heat exchangers not commonly in service today, but design and fabrication of these components could be achieved with existing engineering expertise.

6.2 Kalina cycle

The Kalina cycle is principally a 'modified' Rankine cycle, that uses a working fluid comprised of at least two different components with different boiling points, typically water and ammonia. Since the solution boils over a range of temperatures as in distillation, more of the heat can be extracted from the source than with a pure working fluid. The same applies on the exhaust (condensing) end. The use of a binary or multi-component working fluid results in a good thermal match in the boiler or counter-flow heat exchanger due to the variable (non-isothermal) boiling temperature created by the shifting mixture composition. This decreases the thermodynamic irreversibility in heat transfer and therefore improves the overall thermodynamic efficiency. The mixture composition can also be adjusted during operation in order to optimise the plant efficiency when the heat source and/or sink temperatures change.

Several studies have shown that for plants which operate with low or medium temperatures at the turbine inlet the Kalina cycle performs considerably better than a steam Rankine cycle system (Paanu and others, 2012; Walraven and others, 2013; Modi and Haglind, 2014; DiPippo, 2003). The Kalina cycle is thought to be able to produce 10-30% more power than a steam Rankine cycle and increase thermal power output by up to 50% in suitable installations. Another advantage is the smaller size of the whole unit. The footprint of the Kalina plant is about 60% of the size of a steam Rankine plant design (Mlcak, 1996). The Kalina cycle can work with liquid and gaseous heat sources with temperatures between 80°C and 550°C. Water and ammonia is the most widely considered combination, but other combinations such as a mixture of hexamethyldisiloxane and decamethyltetrasiloxane, are feasible. A number of chemicals and their mixtures have been tested for use as working fluid for Rankine cycles (Mahmoud and others, 2013). One drawback of the Kalina cycle is the fact that high vapour fraction is needed in the boiler. The heat exchanger surface can easily dry out at high vapour fractions, resulting in lower overall heat transfer coefficients and a larger heat exchange area. Another drawback relates to the corrosivity of ammonia. Impurities in liquid ammonia such as air or carbon dioxide can cause stress corrosion cracking of mild steel and also ammonia is highly corrosive towards copper and zinc (Paanu and others, 2012).

The Kalina cycle has many designs, either applied individually or integrated together in a number of different combinations, that comprise a family of unique Kalina cycle systems. This is somewhat analogous to the Rankine cycle that has many design options such as reheat, regenerative heating, supercritical cycle, and dual pressure. Each Kalina cycle design has a specific application for different heat sources, such as direct (fuel) combustion, gas turbine combined cycles and low temperature geothermal plants (Mlcak, 1996). Conventional axial flow steam turbines can be used in Kalina cycle plants. This is possible because the molecular weights of ammonia and water are similar (ammonia 17 g/mol and water 18 g/mol).

The Kalina cycle is well suited for applications using low and medium temperature heat sources such as bottoming cycle, geothermal or solar thermal power plant, and industrial waste heat recovery plant. Geothermal power plants using Kalina cycles are in operation in Iceland, Germany and Japan. Kalina cycles for industrial waste heat recovery can also be found in operation in Japan and the USA.

6.3 Organic Rankine cycle

The organic Rankine cycle (ORC) applies the principle of the steam Rankine cycle but uses organic working fluids with low boiling points, instead of steam, to recover heat from a lower temperature heat source. Another advantage of organic working fluids is that a turbine built for ORCs typically requires only a single-stage expander, resulting in a simpler, more economical system in terms of capital costs and maintenance.

The selection of the working fluid plays a significant role in the use of ORC and is determined by the application, the heat source and the level of heat to be used. The fluid must have optimum thermodynamic properties at the lowest possible temperatures and pressures and also satisfy several criteria, such as being economical, non-toxic, non-flammable, environmentally friendly and allowing a high use of the available energy from the heat source. A number of working fluids have been studied for ORC (Andersen and Bruno, 2005; V Maizza and Maizza, 2001; Masheiti and others, 2011). Fluid mixtures were also proposed for ORC. The operation and performance of ORCs using different working fluid were analysed recently by Galanis and co-workers (2009).

ORC is a mature technology, and, like the Kalina cycle, the most important feature is its capability of using different low temperature heat sources for power generation. It has found applications in areas such as waste heat recovery, geothermal, solar thermal and biomass power plant. The modularity and versatility of ORC technology, and the possibility of using it at different temperature ranges also allow it to be retrofitted to existing plants as a bottoming cycle to use the residual thermal energy and produce electricity or heating/process heat by acting as a combined heat and power plant. In recent years, commercial applications of this technology, with power generation capacity ranges of 0.2–2 MWe, have soared worldwide. Interested readers are referred to a recent technical, economic and market review of ORCs for power generation using low-grade heat conducted by Vélez and colleagues (2012).

6.4 Goswami cycle

The Goswami cycle is a novel thermodynamic cycle that uses binary mixtures to produce power and refrigeration simultaneously in one loop. This cycle is a combination of Rankine power cycle and an absorption cooling cycle. It is suitable as a bottoming cycle using waste heat from conventional power cycles or as an independent cycle using low-temperature sources such as solar and geothermal energy. Its advantages include the production of power and cooling in the same cycle, the design flexibility to produce any combination of power and refrigeration, the efficient conversion of moderate temperature heat sources, and the possibility of improved resource utilisation compared to separate power and cooling systems.

In a Goswami cycle, a stream of high pressure binary mixture is preheated and pumped to the boiler, where is it partially boiled. A rectifier is used to purify the vapour by condensing the water, if needed. The rectified vapour is superheated before expanding to a low temperature in an expander such as a turbine. Since the working fluid is condensed by absorption, it can be expanded to a temperature lower than the ambient, which provides a refrigeration output in addition to the power output. The remaining hot weak solution from the boiler is used to preheat the working fluid, and then throttled back to the absorber.

The binary mixture first used was ammonia-water; later, new binary fluids were proposed and studied. However, analysis performed on organic working fluids indicated ammonia-water mixture to be a better choice (Vijayaraghavan and Goswami, 2005).

Proposed by Dr Yogi Goswami in 1995, the Goswami cycle power system is still in the early stage of development. Laboratory investigations of the cycle performance and cycle optimisation have been carried out (Demirkaya and others, 2011; Vijayaraghavan and Goswami, 2006). A review of Goswami cycle was conducted recently by Demirkaya and others (2013).

7 Combined cycles

Efficiency enhancement of a steam power plant operating on a condensing mode is one of the challenging tasks for researchers. Because no single cycle can offer high efficiency due to the intrinsic limitations and the impossibility of operating within a broad temperature range, combined and advanced cycles have been addressed. Steam Rankine cycles can be combined with topping and/or bottoming cycles to form combined thermodynamic cycles that better resemble the Carnot cycle and improves efficiency.

7.1 Topping cycles

A mismatch between the fuel combustion temperature of around 2000°C (adiabatic) and the high pressure steam temperature up to 650°C in conventional steam power plants results in a large thermodynamic losses in steam turbine cycles. Adding topping cycles that operate at high temperatures to the existing steam cycle can increase the total power output and significantly improve the energy efficiency.

A consortium comprised of representatives from Austria, Germany and The Netherlands evaluated a three-module multiple Rankine topping cycle concept which employed potassium in the high-temperature section, diphenyl in the mid-temperature section, and steam in the low-temperature section, with a reported net efficiency of 51%. The concept proposed is a coal-fuelled potassium boiler delivering saturated potassium vapour at 870°C to an intermediate pressure potassium vapour turbine, then through three low pressure potassium vapour turbines in parallel due to the relatively high specific volume of potassium vapour at an exhaust temperature of 477°C. The condensing potassium delivers heat to the boiling diphenyl at 455°C. The potassium cycle employs a single feed-liquid heater. The potassium condenser/diphenyl boiler delivers saturated vapour to a turbine with extraction lines to four feed-liquid heaters. The remaining vapour at the turbine exhaust condenses at 287°C to vaporise steam at 270°C. However, the chosen fluids and arrangements resulted in a high cost with relatively little performance advantage over gas turbine combined cycle plants (McWhirter, 1997).

Angelino and Invernizzi (2006) proposed a combined cycle that uses a liquid metal topping loop that works at high temperature (750–850°C) and low pressure, and a steam Rankine bottoming cycle. They surveyed the past research work on alternative working fluids, such as mercury and alkali metals, to steam for energy conversion and concluded that potassium was the best candidate for this topping cycle application. Performance analyses of the topping/bottoming cycle and the combined cycle with different configurations showed that a combined cycle with optimal cycle thermodynamics could achieve cycle efficiencies of 57.5-60.5%.

In a patented high-temperature ejector-topping cycle (*see* Figure 29), the combustion gas (heat source) is used to evaporate a low saturation pressure liquid, which serves as the driving fluid for compressing the secondary fluid in an ejector. The fluid/vapour mixture exiting the ejector transfers heat to the lower temperature cycle, and is separated by condensing the primary fluid. The secondary fluid is then used to drive a turbine. The inventor claimed that for a system using sodium as the primary fluid and helium as the secondary fluid, and using a bottoming Rankine steam cycle, the overall thermal efficiency can be 6.4% better than that of conventional steam Rankine cycles and better efficiency improvements could be obtained with optimised fluids or operating conditions (Freedman and Lior, 1994).

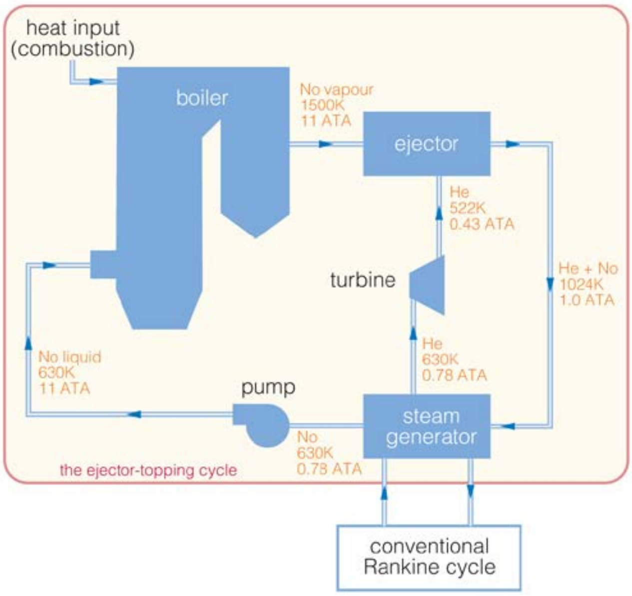

Figure 29 Flow diagram of a high-temperature ejector-topping cycle (Freedman and Lior, 1994)

Yazawa and colleagues (2013, 2014) at Purdue University (USA) recently proposed a combined power cycle composed of a thermodynamic engine (TE) generator topping cycle and a steam-turbine bottoming cycle. TE generators have been investigated for waste heat recovery applications, in which the temperature range is similar to that of saturated steam turbines. However, the solid-state thermoelectric energy conversion is theoretically scalable to temperatures much higher than superheated steam. Figure 30 shows the concept design of a TE topping-steam Rankine cycle power plant. The TE modules are located inside a coal-fired boiler wall constructed of wet steam tubes. The topping TE generator employs non-toxic and readily available materials. The researchers developed a computer model and with it they performed cycle and fuel economy analyses. Their results showed that TE topping generators could add 4–6 percentage points to the overall system efficiency for SC steam turbines that nominally generate power with 40–42% efficiency. They also evaluated the approach of using this incremental topping energy to replace cooling water flow with air-cooled condensers while maintaining current power output and plant efficiency levels.

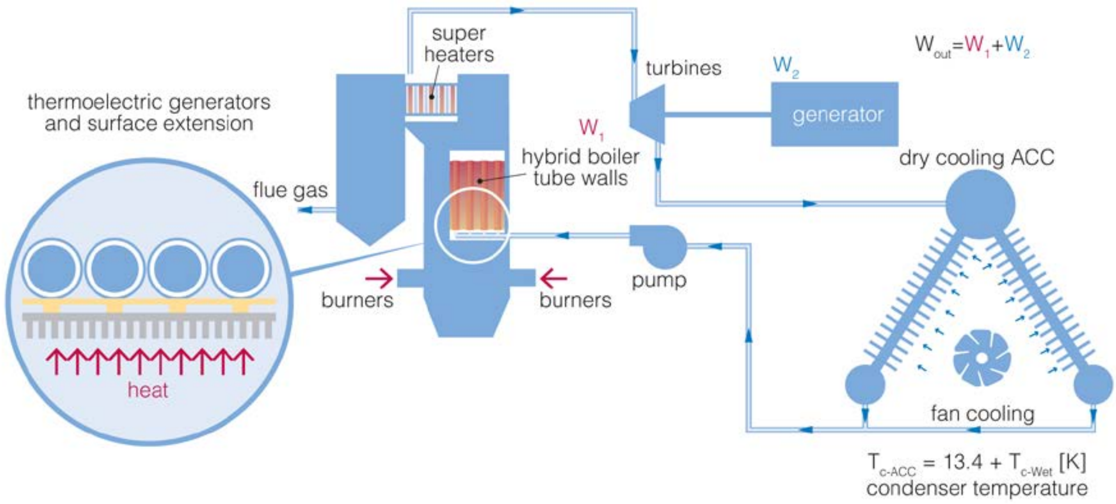

Figure 30 TE topping generator-steam Rankine cycle power plant concept (Yazawa and colleagues, 2014)

7.2 Bottoming cycles

Inherent in any power cycle is the ultimate rejection of a significant amount of thermal energy, which exits the system either by heat transfer in a closed cycle, or via thermal transport by exhaust gases in an open cycle. All heat that is rejected to the environment is heat that is not being used to generate power. Obviously, one method of recovering this waste heat is to integrate a bottoming cycle into the system that uses the waste heat of the topping cycle as its heat source, and therefore improves the overall plant efficiency.

The Kalina cycle can be used as a bottoming cycle in conventional steam power plants to improve the plant efficiency. Murugan and Subbarao (2008a; 2008b) proposed a combined Rankine-Kalina cycle for low grade fuel fired power plant. The thermodynamic analysis of the proposed Rankine-Kalina cycle indicated that the plant efficiency of the combined cycle power plant could be 4 percentage points higher than the corresponding standalone Rankine cycle. Ogriseck (2009) recently studied the integration of a Kalina cycle as a bottoming cycle into a combined heat and power (CHP) plant that operates two coal-fired boilers for baseload power production and two gas-fired boilers for peak power with a total capacity of 100 MWe. The flue gas from the coal boilers has a temperature of 150°C and a mass flow of 112 kg/s. His results showed that the Kalina cycle generated gross electric power of between 320 and 440 kW for 2.3 MW of heat input. The net efficiency of the integrated Kalina plant was 12.3–17.1%. Using a computer model, Singh and Kaushik (2013) studied the possibility of exploiting the low-temperature heat (134.3°C) of exhaust gases from a 59.7 MWe coal-fired power plant to produce additional power using a Kalina bottoming cycle. The results show that under optimal operating conditions, a bottoming cycle efficiency of up to 12.95% and a net bottoming cycle output of 605.48 kWe can be obtained thereby increasing the overall energy efficiency of the plant by 0.277% and the overall exergy by 0.255%.

Similarly, a combined cycle that uses a steam Rankine topping cycle and an organic Rankine bottoming cycle for power generation has also been proposed. Liu and colleagues (2012) evaluated the performances of such a combined Rankine cycle operating with different working fluids and identified some optimum operating conditions. They found that system efficiency could be enhanced by using a regenerator for some of the selected working fluids.

A power plant integrating a Rankine cycle with the Goswami combined power and cooling cycle was proposed recently. A study on the performance of the proposed combined Rankine-Goswami cycle was conducted and the maximum effective first law and exergy efficiencies for an ammonia mass fraction of 0.5 were calculated as 36.7% and 24.7%, respectively, for the base case (no superheater or rectifier process) (Padilla and others, 2012).

7.3 Comments

As discussed in Section 6.1.2 the selection of working fluids plays an important role for the use of a particular heat engine and is determined by the application, the heat source and the level of heat to be used. For example, for a topping cycle a working fluid should be selected with a high critical temperature so that heat transfer takes place at the maximum allowable temperature under the saturation line. Also, the fluid should possess optimum thermodynamic properties under the targeted operating conditions and satisfy several criteria. Substantial work has been carried out in the past to identify and test the suitable working fluids for various applications. A large number of chemicals/materials, such as thermal oil, molten salt, mercury, air, ammonia, sulphur and alkali metals have been investigated or proposed for use as working fluid, and some of the work led to the development of, for instance, sCO_2, ORC, and Kalina cycles. In past, liquid-metal binary (combined) cycles for stationary power plants attracted a lot of interests. Considerable effort during the 1960's led to mercury (Hg) and alkali-metal Rankine-cycle systems being considered as topping cycles. For interested readers, a review of this technology, possible system applications, the required development, and possible problem areas is available (Gutstein and others, 1975).

Hg was recognised as the best available option for a moderate pressure topping cycle at a turbine inlet temperature of around 500°C, well in excess of the critical temperature of water. Binary plants using Hg topping cycle were built and operated before 1950. At that time, binary plant efficiency was much better than that of a steam plant (38% compared to 33% for a 60 MW plant). However, material progress allowed significant increases in steam pressure and temperature and safety problems made mercury-steam cycles obsolete (Angelino and Invernizzi, 2006). Alkali-metal (K, Na) Rankine-cycle systems suffer from corrosion problem so the maximum operational temperature is limited and hence limits the plant efficiency. Nevertheless, R&D of alkali-metal cycles continued mostly for space application. Many more materials are currently being investigated as potential alternative working fluids to steam but will not be discussed here.

As discussed above, many combined cycle concepts for high efficiency coal-fired power generation have been considered. However, progress in developing such combined cycle systems is slow. Despite the successes of ORC and Kalina cycles in geothermal and waste heat recovery applications, investigations of their possible application in coal based steam cycle power plants are mainly confined to cycle analyses and system simulations using computer models. For a combined cycle to operate effectively, both topping and bottoming cycle will have to operate at conditions away from the optimal conditions they would use and therefore a lower efficiency than that as a standalone cycle system. It is critical to identify the optimum operating conditions of the combined cycle in order to obtain the maximum efficiency gain. As discussed in Section 7.2, the cycle analyses/calculations show that the efficiency improvements from the integration of topping/bottoming cycles are moderate. The main concern is whether the benefits from efficiency gains can justify the increased costs and system complexity. Substantial work is needed to identify the optimal design and operating conditions, and to determine the technical and economic viability of the combined cycles reviewed in this chapter and other possible combined cycle concepts.

8 Chemical looping combustion

Chemical looping combustion (CLC) is an indirect form of combustion in which an oxygen-containing solid material, typically a metal oxide, supplies the oxygen to a fuel, and the spent oxygen ‘carrier’ is separately regenerated by a high temperature reaction in an air stream. As there is no direct contact between air and fuel, CLC produces a stream of CO_2 and water vapour from which the CO_2 can be readily recovered by condensing the water vapour, eliminating the need for an additional energy intensive CO_2 separation.

8.1 Principles

Chemical looping combustion (CLC) is based on the transfer of the oxygen from air to the fuel by means of a solid oxygen-carrier that circulates between two interconnected fluidised bed reactors: the fuel and the air reactor. In the endothermic fuel reactor (reducer), the oxygen-carrier is reduced through oxidation of the carbon and hydrogen present in the fuel, thus obtaining a gas stream composed of CO_2 and H_2O. The oxygen carrier is then directed to the exothermic air reactor (oxidiser), where it is re-oxidised with air and regenerated to start a new cycle. The net chemical reaction is the same as usual combustion with the same combustion heat released, but with the advantage of the intrinsic CO_2 separation in the process without an additional step. The heat of oxidation is carried by the high-temperature, high-pressure spent air from the air reactor. The spent air is used to drive a steam/gas turbine combined cycle system for electricity generation.

8.2 Advantages and status of the technology

The main advantage of CLC is the inherent separation of both CO_2 and H_2O from the flue gases so there is a potential for higher efficiency in delivery of energy than for conventional combustion or gasification with CO_2 capture. In addition, CLC minimises NOx formation since the fuel burns in the fuel reactor in an air free environment and the reduced oxygen carrier is re-oxidised in the air reactor in the absence of a fuel, at temperatures lower than that of NOx formation. Another advantage of chemical looping systems is the possible flexibility to co-produce hydrogen or syngas and electricity.

The oxygen carrier plays a key role in the system performance. Oxygen-carrier materials should possess properties including: (a) high oxidation and reduction activity and stability under repeated oxidation/reduction cycles; (b) mechanical strength in fluidised beds and resilience to attrition and agglomeration; (c) low cost and minimal environmental impact. Much of the work on chemical looping consists of developing and testing potential oxygen carriers. Oxides such as NiO, CuO, and Fe_2O_3 and sulphates such as $CaSO_4$ have been widely used as oxygen carriers in chemical looping processes. The use of low cost materials such as natural minerals (for instance, ilmenite) and industrial waste products as oxygen-carriers has also been investigated. Comprehensive reviews of the recent development and evaluation of oxygen carriers can be found elsewhere (Adanez and others, 2012; Henderson, 2010). Results from the reported research suggest that the synthesis of a reactive and stable oxygen carrier is one of the main challenges still facing CLC.

CLC processes can use gaseous fuels such as natural gas and coal derived syngas, liquid fuel and solid materials such as coal, petcoke and biomass as primary fuels. There are two approaches to CLC of coal: the syngas fuelled CLC and solid fuelled CLC. In a syngas-CLC process, the oxygen carrier comes into contact with the gasification products (syngas) from a gasifier. In this process, the fuel is fed into the CLC system in gaseous form although the primary fuel is coal or other solid fuels. To avoid the gasifier, coal and oxygen carrier can be mixed in a uniquely designed fuel reactor. In the in situ gasification CLC (iG-CLC) process, the oxygen carrier reacts with the gasification products of coal generated inside the fuel reactor. Alternatively, in a process called chemical-looping with oxygen uncoupling (CLOU), the oxygen carrier is able to release gaseous oxygen for the combustion of coal inside the fuel reactor. The design of a CLC system and the selection of the suitable oxygen-carrier material are determined by the specific way in which the coal is being converted.

Extensive R&D work has been carried out worldwide over the past years to develop and test chemical looping processes. The continuous process development units (PDUs) have been set up in universities and research centres around the world and are being used to establish the proof-of-concept. Several reporters recently provided detailed descriptions of these PDUs and the ongoing research work as well as discussions of the experimental results (Adanez and others, 2012; Henderson, 2010; Fan, 2010; Hossain and de Lasa; 2008). Computer models have also been established to test and analyse the cycle thermodynamics and performance of the chemical looping processes, and to evaluate their economic and environmental performances. Comparisons of coal-based chemical looping power generation systems with other power generation technologies such as IGCC, PCC and CFBC with CCS indicate that coal fuelled CLC power plants potentially have higher energy efficiency and lower COE (Ekström and others, 2009; Mantripragada and Rubin; 2013).

8.3 Developments of chemical looping processes

A number of chemical looping processes using coal or coal-derived syngas as feedstock are under development. In the Ohio State University's (OSU's**) Coal-Direct Chemical Looping Process** (CDCL)**,** a specially tailored, highly reactive Fe_2O_3 particle is used as oxygen carrier for converting coal to H_2. In this process, Fe_2O_3 particles are introduced into the reducer, together with fine coal powder. By using suitable gas-solid contacting patterns, coal is gasified into CO and H_2. The reductive gas reacts with Fe_2O_3 to form Fe and FeO, while producing a highly concentrated CO_2 and H_2O flue gas stream. The reduced Fe/FeO mixture from the reducer enters the oxidiser to react with steam to generate hydrogen while being oxidised to Fe_3O_4. The resulting Fe_3O_4 exiting from the hydrogen production reactor will be conveyed back to the reducer pneumatically. Whilst being conveyed, the Fe_3O_4 particle will be oxidised to Fe_2O_3. OSU has operated the CDCL sub-pilot system with nearly full conversions of different types of coals while producing over 99% pure CO_2 with a hydrogen production efficiency of close to 80% (HHV). OSU achieved 200 hours of continuous, integrated operation; the longest reported continuous demonstration of a chemical looping pilot process for solid fuel conversion (Tong and others, 2014; Velazquez-Vargas and others, 2012).

The HyPr-Ring Process developed in Japan involves coal gasification using pure oxygen and steam. The equipment for the HyPr-Ring Process consists mainly of a gasifier, a sorbent regenerator, and several heat exchangers. Coal is fed along with CaO, steam, and O_2 to the gasifier. The presence of excess steam in the gasifier drives the reaction toward the formation of H_2. CaO captures CO_2 generated in the water-gas shift reaction, resulting in a product fuel gas comprising a mixture of 91% H_2 and 9% CH_4. The solids from the gasifier consist of mostly $CaCO_3$ and some unconverted carbon, which are sent to a regenerator along with oxygen. The heat generated by combusting the unreacted carbon drives the calcination reaction for CaO regeneration while producing a stream of high purity CO_2 ready for compression. It was estimated that a 77% (HHV) H_2 production efficiency can be achieved using this process without taking into account the energy consumption for CO_2 compression (Lin and others, 2005).

The fundamental concept for the **GE Fuel Flexible** gasification-combustion process is similar to the HyPr-Ring Process except that a metal oxide is used instead of pure oxygen for the calcination reaction. As a result, the reaction scheme for this process involves two chemical loops and, hence, two different looping media. The two loops are operated using three interconnected fluidised bed reactors. In the first reactor, coal is partially gasified with steam to form a mixture of H_2, CO and CO_2. The CO_2 is captured by calcium-based sorbents to form $CaCO_3$. The depletion of CO_2 results in an enhanced water-gas shift reaction toward the formation of H_2. Moreover, sulphur in the coal can also be captured by the sorbent forming $CaSO_3$. As a result, a high-purity H_2 stream is obtained from the first reactor. The solids in the first reactor, which mainly consist of reacted sorbents ($CaCO_3$, $CaSO_3$) and unconverted carbon, are introduced to the second reactor where high-temperature steam is injected. In this reactor, the unconverted carbon reacts with a high-temperature oxygen carrier (mainly Fe_2O_3) from the third reactor to form reduced metal. Furthermore, the heat carried by the oxygen carrier and the high-temperature steam provide heat to regenerate the spent sorbents from the first reactor and therefore, a high-concentration CO_2/SO_2 gas stream is generated from the second reactor. The third reactor regenerates the reduced oxygen carrier obtained from the second reactor by reacting it with air. Heat from all the hot exhaust gas streams is used for steam generation to drive the turbine system and thus, co-producing pure H_2 (in the first reactor) and electricity. Meanwhile, the CO_2 stream from the second reactor is ready for sequestration. The overall energy efficiency for this process is estimated to be 60% (HHV) with 50–50 hydrogen and electricity co-production (Rizeq and others, 2003).

In the **ZECA Gasification Process**, conceived by Los Alamos National Laboratory (USA), coal reacts with steam and recycled H_2 to produce methane. The methane is subsequently reformed to produce H_2. CO_2 is removed by the carbonation of CaO resulting in a nearly pure stream of H_2, which fuels a SOFC to produce electricity with a reported overall energy efficiency of around 57%. The $CaCO_3$ is calcined in a separate reactor to release the CO_2 stream for storage (Gao and others, 2008).

Alstom's LCL process is based on a hybrid combustion-gasification process and contains three different operational configurations for the purpose of effective operations: (1) indirect coal combustion for heat generation; (2) coal gasification for producing syngas, and (3) coal gasification for producing hydrogen. For the first and second configurations, one chemical loop is used, whereas for the third configuration, two chemical loops are used. In the first configuration, two main reactors are used with calcium sulphate as the looping medium. The calcium sulphate is reduced to calcium sulphide by coal in the reducer, forming a high-purity CO_2 stream. The calcium sulphide formed is then combusted in the oxidiser with air. Part of the heat generated from the combustor is used to compensate for the heat required for coal gasification in the reducer, whereas the rest is used to produce steam for electricity generation. The second configuration, although similar, uses a much higher coal to $CaSO_4$ ratio and a higher steam feed rate for the reducer. Thus, the reduction of $CaSO_4$ is accompanied by the formation of CO and H_2 resulting from the presence of an excess amount of carbon and steam. In this configuration, most of the heat generated in the oxidiser is used to offset the heat required for coal gasification in the reducer. The product for this configuration is syngas, and most of the carbon in coal is converted to gaseous CO and H_2. Thus, there is no carbon capture necessary. In the third configuration, pure hydrogen is produced by the introduction of a calciner and an additional chemical loop – a $CaO/CaSO_4$ loop. The idea is to introduce even more steam than the second configuration to conduct the water gas shift reaction in addition to the reduction reaction of $CaSO_4$. CaO is used in the reducer to capture the CO_2 generated by the water gas shift reaction and thus drive the reaction toward the formation of pure H_2 as the product. The heat integration of this configuration includes the utilisation of part of the heat generated from calcium sulphide combustion to calcine calcium carbonate in the calciner, forming CO_2. Hot solid CaSO4/CaO (or inert bauxite) can be used as the heat carrier, transferring the heat from the exothermic reaction ($CaSO_4$ formation) to the endothermic calcination reaction (Andrus Jr and others, 2013).

8.4 Chemical looping power generation cycles

Depending on the type of process chosen, various chemical looping based power plant configurations have been proposed and studied. Henderson (2010) as well as Hossain and de Lasa (2008) recently conducted comprehensive reviews of the earlier studies on CLC based power generation cycles. The following discussions will focus on more recent work on chemical looping power plant.

Alstom recently completed an economic study of LCL-C (the combustion option of LCL) based power plants which incorporated the test results obtained from its 3 MWth prototype facility to compare Alstom's LCL-C to a SC pulverised coal power plants without CO_2 capture and to a SC oxyfired pulverised coal fired power plant with 90% CO_2 capture. The LCL-C plant at 95% CO_2 capture exceeds the DOE's 90% capture goal. All three plants were designed to produce 550 MWe (net), and the steam cycle, fuel, and environmental requirements were the same in all cases. All economics were adjusted to the same basis and are expressed in June 2011 US dollars. Figure 31 shows the process flow diagram of the LCL-C based power plant. The results from this study are shown in Table 13. The results shows that for the LCL-C plant the energy penalty for CO_2 capture is less than 9% compared to that of the equivalent oxy-PC fired plant at 25%. The LCL-C based plant with CO_2 capture is about 15% more expensive than the SC PC plant without CO_2 capture, while the Oxyfired plant with CO_2 capture is over 60% more expensive than the PC plant without capture on a capital cost basis. The recent study also showed that the cost per tonne of CO_2 avoided was about \$25 for LCL-C plant and about \$80 for oxyfired PC plant (Andrus Jr and others, 2013).

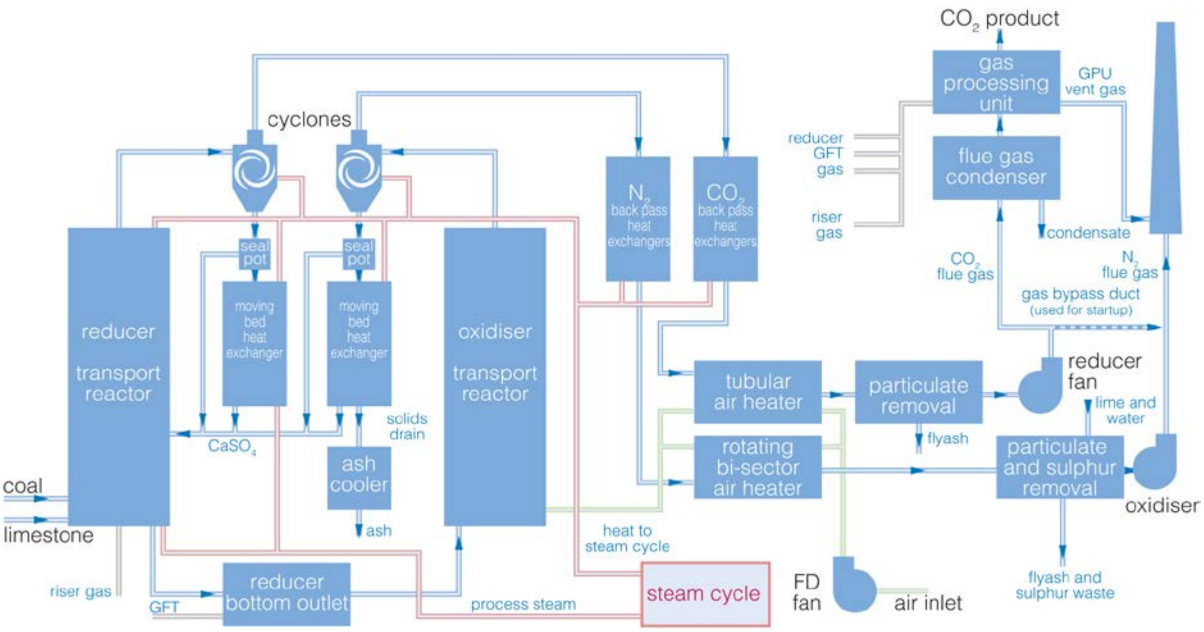

Figure 31 Simplified process flow diagram for a LCL-C power plant (Andrus Jr and others, 2013)

Table 13 Comparison of LCL-C power plant with SC PCC power plants (Andrus Jr and others, 2013)

	SC PCC (w/o CCS)	Oxy-PC-CCS	LCL-C-CCS
Gross power, MW	580.4	785.9	649.7
Net power, MW	550.0	548.7	550.0
Coal flow, t/h	185.8	249.2	203.9
CO_2 capture, %		92.65	>95
CCS energy penalty, %		25.7	8.9
Net plant efficiency, %	39.28	29.20	35.78

Velazquez-Vargas and co-workers (2014) performed a techno-economic study on a 550 MWe (OSU's) CDCL SC power plant. The schematic diagram of the CDCL power plant concept is shown in Figure 32. The results were compared to those of a 550 MWe SC PC power plant without CO_2 capture and with CO_2 capture using monoethanolamine (MEA) absorption, as shown in Table 14. Their results show that the energy penalty for carbon capture is considerably lower for the CDCL process than for the PC plant with an MEA process, leading to significantly improved energy efficiency and reduced costs. This study shows that the CDCL process has the potential to increase the cost of electricity (COE) by 28.8% while removing 96.5% of the CO_2, which meets and exceeds the US DOE's target of 90% CO_2 capture with less than a 35% increase in COE.

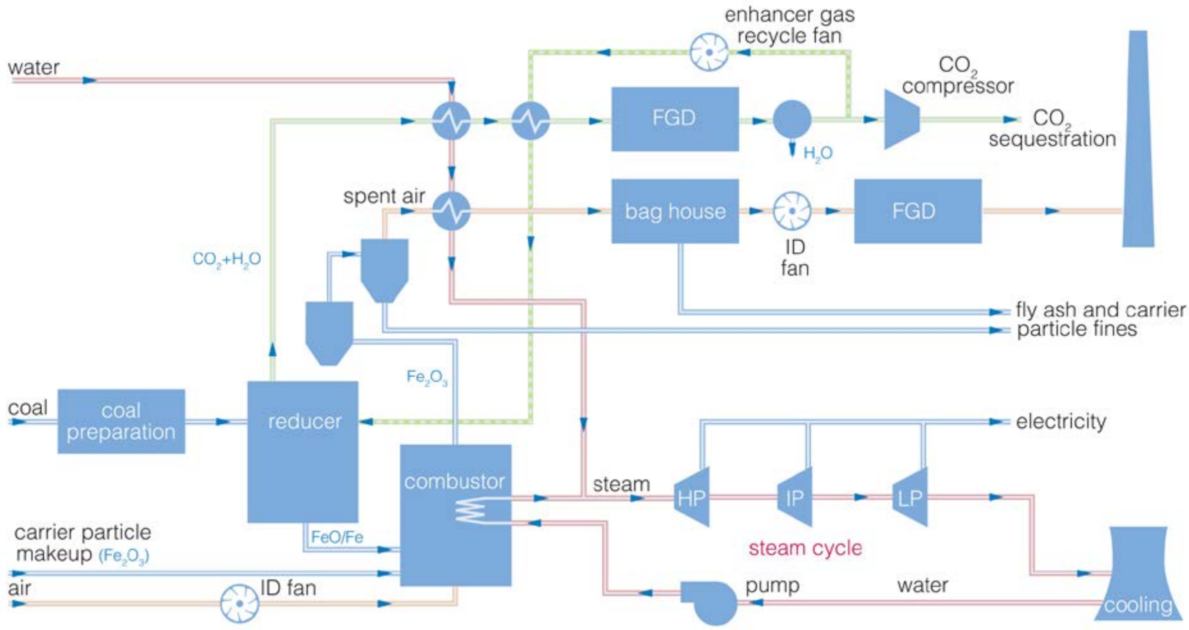

Figure 32 CDCL process for power generation (Velazquez-Vargas and others, 2014)

Table 14 Comparison of CDCL power plant with SC PC power plant with or without CO_2 capture (Velazquez-Vargas and others, 2014)

	SC PCC (w/o CCS) (base plant)	SC PCC-CCS	CDCL plant
Performance			
Coal feed rate, kg/h	185767	256652	203912
Heat input, MWth	1400	1935	1537
Steam cycle gross power, kW	580400	662800	657000
Total auxiliaries, kW	−30410	−112830	−106653
Net power, kW	549990	549970	550347
Gross efficiency. %, HHV	41.4	34.3	42.7
Net efficiency, %, HHV	39.3	28.4	35.8
Energy penalty, %		27.6	8.8
Costs			
Total overnight cost, $/kW	2453	4207	3214
Firstyear COE, $/MWh	80.98	132.56	104.30
Increase over base plant, %		63.7	28.8

Tong and colleagues (2012) proposed the integration of the CDCL process with an SOFC to further increase the process efficiency with net energy efficiency for a 1000 MWth coal power plant achieving 63% (HHV). As illustrated in Figure 33, the H_2 produced in the oxidiser is fed to the anode of a SOFC to produce electricity whilst consuming 85% of H_2 stream. The steam-H_2 mixture from the anode is recycled back to the oxidiser while the lean air from the cathode is sent to a combustor to regenerate the partially oxidised oxygen carrier. The process efficiency is improved with this arrangement as the steam is recycled between the reactor systems without loss in latent heat.

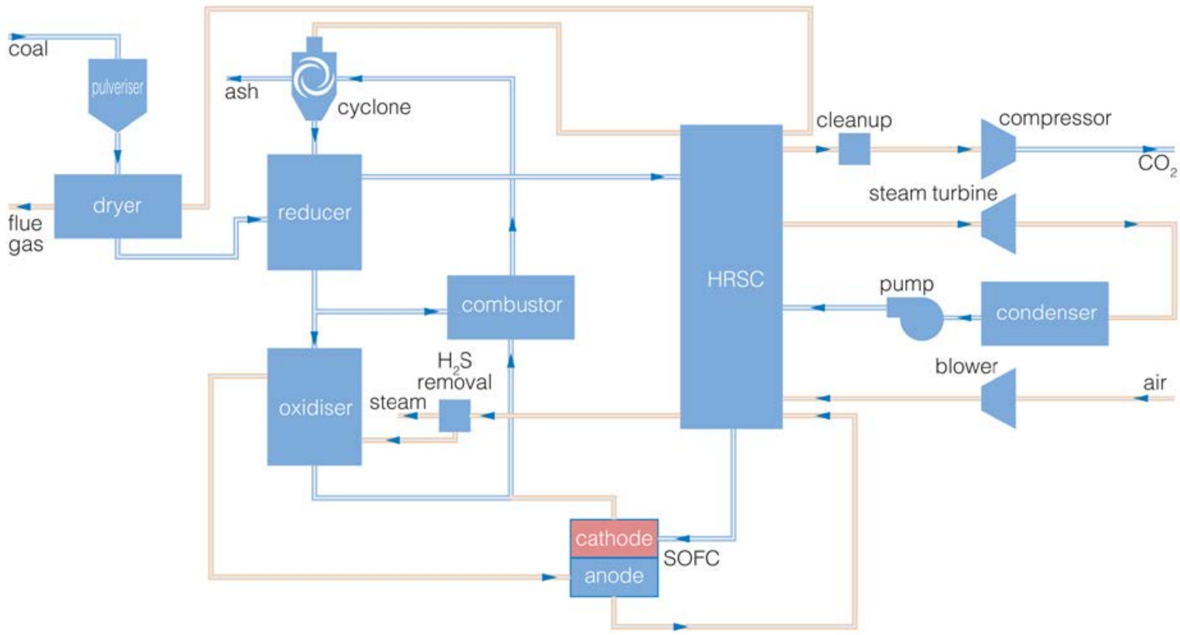

Figure 33 Integration of CDCL with SOFC for power generation (Tong and others, 2012)

Sorgenfrei and Tsatsaronis (2012) evaluated IGCC power plants integrated with iron-based syngas-CLC with different configurations and operating conditions. Two gasification technologies, BGL slagging gasifier and the Shell entrained-flow gasifier, were selected for this study. The option of applying a sCO_2 turbine after the syngas-CLC fuel reactor was also investigated. Five cases were analysed and the case specifications are given in Table 15. The calculated results are shown in Figure 34. The net efficiency varies from 37.2% to 43.6% (HHV) with the BGL gasifier concept being comparatively more efficient. Another advantage of the BGL gasifier concept is its simpler plant design. The net efficiency increases almost linearly with oxidiser temperature. The results also indicate that the addition of a sCO_2 turbine is not beneficial because it reduces the steam turbine output considerably.

Table 15 Specifications of the analysed cases (Sorgenfrei and Tsatsaronis, 2012)

Case	Gasifier type	Airreactor temperature (°C)	sCO_2 turbine
Shell-1	Shell	900	
BGL-1	BGL	800	
BGL-2	BGL	900	
BGL-3	BGL	1000	
BGL-4	BGL	900	yes

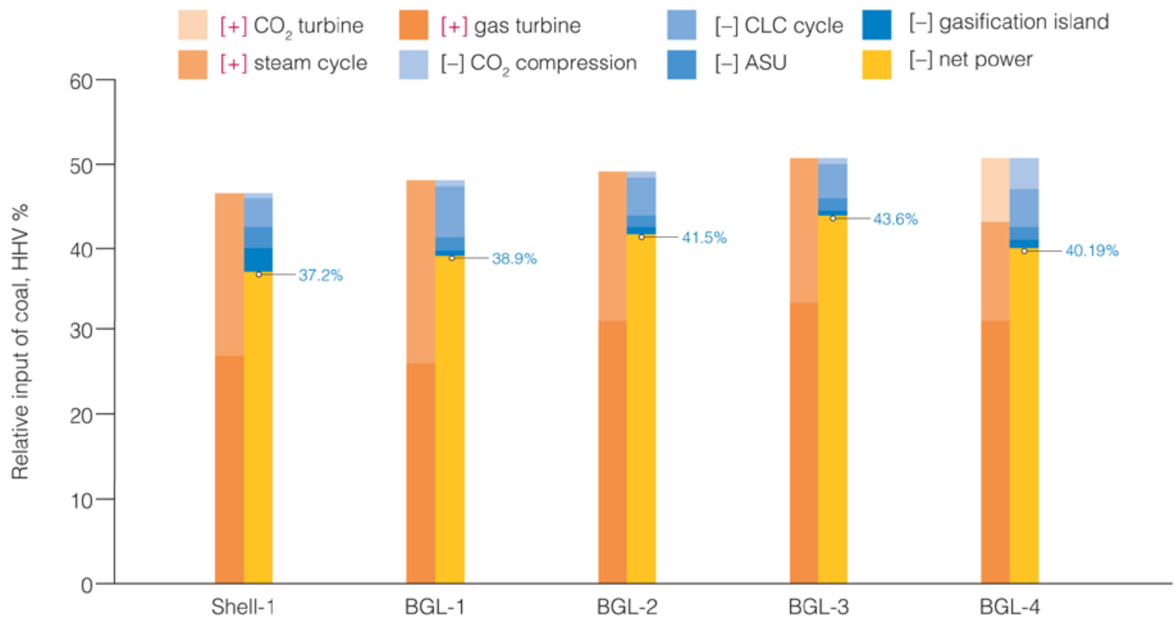

Figure 34 Power distribution and cycle efficiency of the analysed cases (Sorgenfrei and Tsatsaronis, 2012)

If a chemical looping process is operated under pressurised conditions, the energy penalty associated with carbon capture and compression can be greatly reduced. Where combined cycles are used, the CLC system may need to operate at elevated pressure. Although there have been very few CLC tests at pressure, power cycles based on pressurised chemical looping process have been studied. Liu and co-workers (2014) recently completed the US DOE funded techno-economic study on a proposed 550 MWe integrated pressurised CLC (PCLC) combined cycle process. The flow diagram of the proposed process is shown in Figure 35. The configuration of this power plant is a combined cycle with an advanced PCLC (the oxidiser operates at 1.2 MPa) as the heat source to drive an aero-turbine followed by a heat-recovery subcritical steam generator for electricity generation. Four cases were selected to study the economic sensitivity of the proposed PCLC power generation against the reference cases of 550 MWe SC PCC power plant without carbon capture and a 550 MWe SC PCC plant with carbon capture using MEA. An iron-based oxygen carrier made from an industrial waste was used for base case study. The main results for the base case of the PCLC process are shown in Table 16 alongside those of the reference cases. It can be seen from Table 16 that the proposed PCLC combined cycle power generation process can provide an overall net plant efficiency of 46.2% (HHV) with CO_2 pressurised to 15.3 MPa. The net plant efficiency of the PCLC power cycle is 6.9 percentage points higher than that of SC PCC power plant without CO_2 capture (39.3%) and 17.8 percentage points higher than that of SC PCC power plant with MEA absorption process for CO_2 capture (28.4%). A CO_2 capture efficiency of 98.4% with CO_2 quality of 97.7% can be achieved. The increase in COE due to CO_2 capture is 40.5% compared with SC PCC plant with no CO_2 capture, and 23.2% lower than that of SC PCC plant with CO_2 capture. The results also show that 91.2% of sulphur can be captured with the addition of dolomite/limestone, and approximately 90% of mercury is removed from the pyrolysis gas before it enters reducer.

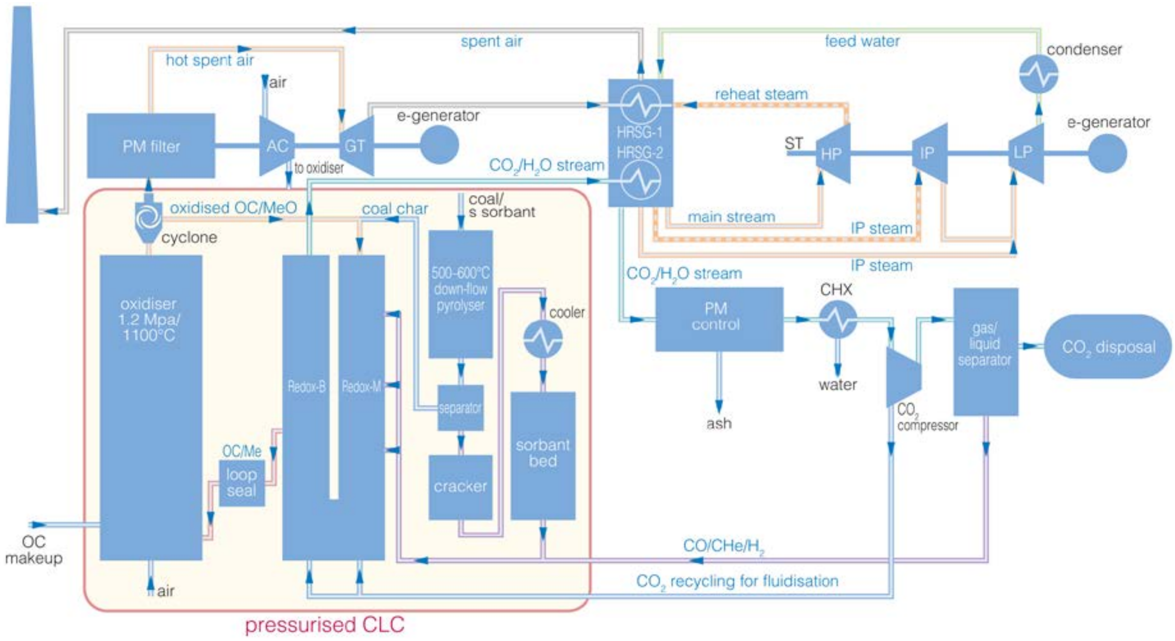

Figure 35 Block flow diagram of pressurised chemical looping process (Liu and others, 2014)

Table 16 Comparison of techno-economic performances of the PCLC process with SC PCC power plant with/without carbon capture

	SC PCC	SC PCC-CCS	PCLC
Performance			
Gross power, kWe	582700	673000	571310
Net plant heat rate, kJ/kWh, HHV	9298	13330	7794
Total auxiliary loads, kW	32660	122940	41760
Net power, kWe	550040	550060	529550
Net plant efficiency, %, HHV	39.3	28.4	46.19
CO_2 capture, %	0	90	99
Costs			
Risk	low	high	high
Total plant costs, 2012 $/kW	2271	3993	3076
Total overnight cost, 2012 $/kW	2766	4861	3788
COE, 2012 $/MWh	70.26	128.59	98.72
LCOE, 2012 $/MWh	89.08	163.06	125.18
Cost of CO_2 avoided, $/t$CO_2$		79.36	34.49

The study on the CDCL process showed that if the process was operated under pressures (for instance, 1.2 MPa) the energy penalty for CO_2 capture could be reduced from 10.6% to 6% (Fan and others, 2012).

9 Solar-coal hybrid power plants

A hybrid power system integrates two or more energy conversion devices into one power generation process. Hybrid power system concepts are not new. The coal-based MHD power generation system (*see* Section 4.4), the IGFC systems (*see* Section 3.3.1) and the proposed integration of CDCL with SOFC for power generation as discussed in Section 8.4 are examples of hybrid systems.

9.1 Solar thermal power system

Solar power is the conversion of sunlight into electricity, either directly using photovoltaics (PV), or indirectly using concentrated solar power (CSP). Concentrated solar power (CSP) systems use lenses or mirrors and tracking systems to focus a large area of sunlight into a small beam. The concentrated heat is then used as a heat source for a conventional thermal power plant. A wide range of concentrating technologies exists and the most developed are the parabolic trough, the concentrating linear Fresnel reflector, the Stirling dish and the solar power tower. Various techniques are used to track the sun and focus light. In all of these systems a working fluid is heated by the concentrated sunlight, and is then used for power generation or energy storage. Thermal storage allows up to 24 hour electricity generation.

A number of commercial solar thermal power plants are now in operation in USA, Spain, Middle East, and many other countries. Solar thermal power plants have high capital costs. Solar-only power plants have to be operated under off-design conditions during most of the day because of the discontinuity and instability of solar radiation making solar power plants less efficient and high in costs. In order to achieve sustainable development of solar thermal power plants in both the short and long terms, attention has been directed toward hybridising solar energy with fossil power plants since the 1990s. The solar gas turbine system and solar boost coal power system are being developed as a result.

9.2 Integration of solar with coal power system

In a solar-coal hybrid power system, solar thermal energy is usually used to supplement the steam cycle to reduce the consumption of coal in the production of electric power at the plant. Solar thermal energy can be used to produce high pressure/high temperature steam. Existing solar thermal designs operate at around 300–400°C compared to typically 500°C or higher in large steam power plants. The temperature of the steam from the solar field is not high enough and further heating must be provided before the steam can be used to power a steam turbine to generate electricity. Channelling the solar generated steam directly into the main turbine raises the overall efficiency of the plant by making the best use of the steam output from the solar field. However, the conditions of the steam coming from the solar array must be matched to the coal-fired steam turbine cycle, which is an engineering challenge.

In an alternative approach, the solar thermal energy is used to heat the feedwater prior to entering the boiler. In a conventional steam power plant, as feedwater enters the feedwater heater, steam is extracted from the steam turbine to heat the feedwater. When the solar heat is added to the feedwater less steam is extracted from the steam turbine which either reduces coal input, increases the unit electrical output or both.

By integrating solar power with a coal-fired power plant the large cost of steam power generation equipment that would be necessary in a standalone solar thermal plant, can be avoided, significantly reducing the COE of the solar portion of the hybrid solar-coal plant. Another advantage is that pairing solar power with a coal power plant that has large-scale energy conversion equipment and a steam cycle operating at high temperatures allows for higher solar energy conversion efficiencies. A thermodynamic analysis of the solar/coal hybrid power plant indicates that the solar thermal to electricity conversion efficiencies of the solar hybrid power plant are higher than those of a solar-only power plant with solar heat input at the same temperature (Yan and others, 2010; Yang and others, 2011). For a 330 MW solar/coal hybrid plant in which solar heat at around 300°C is used to replace the steam extraction to heat the feedwater, the annual net solar-to-electric efficiency could reach up to 21% and the levelised COE (LCOE) could be 20–30% lower than that of the solar-only thermal power plant (Hong and others, 2014). There are several environmental and economic benefits as a result of this solar energy application. By integrating CSP with an existing fossil steam power plant, the amount of coal that would otherwise need to be burned to produce the same amount of electric power is reduced. This would reduce the plant's fuel cost and reduce the emissions of CO_2 and other air pollutants associated with combustion of that amount of coal.

Solar-coal hybrid plants can be new constructions, as well as an addition of solar fields to existing coal plants.

9.3 Solar-coal power systems

Three solar boost coal power projects will be discussed in the following section; each has a different power cycle configuration.

9.3.1 The Colorado Integrated Solar Project

The first demonstration hybrid CSP-coal power plant was built at the US utility company Xcel Energy's Cameo Power Station in Colorado. The plant integrates an existing 44 MW coal-fired unit and a 4 MW CSP installation. Cameo Unit 2 was designed to generate 49 MW operating on coal or natural gas. The unit consists of a two-pressure steam turbine: high-pressure and low-pressure. It has two low pressure feedwater heaters, a de-aerator, and two high pressure feedwater heaters. The solar powered heat exchanger was installed to provide additional feedwater heating in between the two high-pressure feedwater heaters.

The system essentially consists of a closed thermal circuit that enables heat exchange between the heat transfer fluid (HTF), heated by means of parabolic trough solar collectors, and the feedwater. The circuit includes an expansion vessel to allow safe expansion of the HTF as it heats to operating temperature, and a recirculation pump that moves the HTF through the closed circuit. The HTF used in this system is a blend of non-hazardous mineral oils, designed to maintain thermal stability at sustained operating temperatures.

The solar heat is collected in a 6.4-acre solar field. The collectors are parabolic metal structures with specially designed curved, ultra-pure glass mirrors mounted on them. The mirrors concentrate the incoming solar radiation at the focus of the parabola, where a line of receiver tubes, also known as heat collecting elements (HCE), collect and transport the radiant heat. As the HTF circulates through the HCE of the solar field, it is heated to approximately 302°C, and returns to the solar heat exchanger where the fluid is used to heat the high-pressure feedwater. The then cooled HTF cycles back to repeat its circuit through the solar field. Because the HTF expands as it heats to the operating temperature, the system also includes a nitrogen blanketed expansion vessel to contain this additional HTF volume, without over pressuring the system.

The objective of the project was to assess the technical feasibility of integrating concentrated solar thermal technology with conventional coal power generation. The system was expected to operate for approximately one year or until the closure of the Cameo Station in December 2010. The operation began on 30 Jun 2010 and tests were conducted. The results were positive. The generation increased by 300 kW with the solar heat input, and the heat rate was reduced by 1.33–1.38%. The steam extraction to heat the feedwater was reduced by 1.4 t/h. The total coal savings for the project was 238 tonnes. There were no issues in operating the integrated plant (XcelEnergy, 2011).

9.3.2 Sundt Solar Boost Project

Tucson Electric Power (TEP) is working with Areva Solar on a CSP booster to its 156 MWe dual-fuelled (coal/gas) Unit 4 at H. Wilson Sundt Generating Station in Tucson (USA). The project will use Compact Linear Fresnel Reflector (CLFR) solar steam generators to produce up to 5 MWe of CSP during peak demand periods. Unlike the Colorado Integrated Solar Project, the Sundt solar booster will use solar thermal heat to boil water to produce high pressure, superheated steam. The steam will be used directly to supplement the coal power steam cycle for feedwater heating hence simplifying the system design. The annual coal saving from the solar booster is estimated to be 3600 tonnes (www.areva.com). Construction began in April 2014.

9.3.3 Kogan Creek Solar Boost Project

CS Energy's coal-fired SC Kogan Creek Power Station in Queensland (Australia) is adding a solar thermal array to boost the electrical output by 44 MWe. For the same amount of coal burned, the Kogan Creek Solar Boost Project will increase the output of the power station from 750 MWe to 794 MWe – the maximum continuous overload capacity of the existing steam turbine. This solar project is the largest in the southern hemisphere and the world's largest solar integration with a coal-fired power station.

Areva's CLFR technology will be used to focus the sun's heat onto elevated receivers, which consist of a system of tubes through which water flows. The concentrated sunlight boils the water in the tubes, generating high-pressure superheated steam for direct use in the turbine for power generation. The solar generated steam has a temperature of 370°C and pressure of 8.1 MPa, which are not sufficiently high to be used in the high-pressure turbine. This steam will join the steam as it returns from the high-pressure turbine to the boiler for reheating, before continuing on to the intermediate-pressure stage (EnergyNews, 2011). This direct use of steam in the turbine (rather than using the steam to heat feedwater) makes this project both innovative and challenging. The project is currently under construction.

9.4 Latest developments

Prosin and others (2014) proposed a solar-coal hybrid power system in which solar heat is used for air-preheating using a recently developed solid particle receiver (SPR) system. A SPR mounted on a tower surrounded by a heliostat field, uses ceramic particles to directly absorb the incident solar radiation from the sun tracking mirrors. Since the particles are extremely heat resistant and robust, a particle receiver system can absorb very high solar flux densities without the drawbacks associated with metal tube receivers such as hotspots, thermal stresses and thermal fatigue and therefore high efficiencies can be achieved. The hot particles are used directly as the thermal storage medium from which air can be heated by direct-contact heat exchange with the particles. The authors studied the thermodynamics of the proposed system and compared it with solar-coal hybrid plant with feedwater or turbine bleed steam heating using solar heat. They claim that using SPR technology for preheating air in solar-coal hybrid power systems has the potential to considerably increase the solar share of the energy input by 28 percentage points under design conditions and enable 81% higher solar to electric conversion efficiency than the solar feedwater heating option.

There have been several studies on integration of solar power with conventional fossil fuelled steam power plants. Interested readers are referred to a recent review of studies and applications of solar augmentation of conventional steam plants, conducted by Petrov and colleagues (2012).

10 Conclusions

Given the emission constraints and taking into account the importance of coal as an energy source a substantial increase in the efficiency of coal-fired power plants is one of the most important tasks to be resolved. A range of clean coal technologies have been developed or under development to achieve high efficiency, towards zero emission power production. Almost all the coal-fired power plants in operation today use the steam Rankine cycle to generate electricity. Today's state-of-the-art USC PCC plant can achieve a plant efficiency of around 45% and intensive R&D is ongoing to increase this to 50%. However, due to the limitations of the Rankine cycle technology, any further substantial increase in efficiency will be difficult and at high costs. For this reason researchers have turned to the development of alternative systems and as a result, many innovative power cycle concepts have been proposed and investigated.

10.1 Fuel cells

Fuel cells are electrochemical devices that convert chemical energy in fuels into electrical energy (and heat) directly and thereby can produce power with high efficiency and low environmental impact. There are five main fuel cell types under development, among them SOFC and MCFC operate at high temperatures, which offer the best opportunity for thermal integration with coal gasification systems. Decades of extensive R&D activities have resulted in significant advances in fuel cell technology in terms of cell and component design, materials, performance, reduced costs and so on. Recently, progress has been made in the development of DCFC that use solid fuel (carbon) and convert the chemical energy in carbon directly into electricity without the need for gasification. Fuel cells are still under development but they are beginning to emerge in the commercial market.

When coupled with coal gasifiers, SOFCs and MCFCs have the best attributes to compete for the large, base-load power market. Various IGFC power system configurations have been proposed and studied. Results from techno-economic analyses of the proposed IGFC power systems all indicate that these systems can potentially achieve high energy efficiency and excellent environmental performance. The IGFC power systems are capable of achieving high CO_2 capture rates (up to 99%) with low energy penalty. Several studies showed that IGFC systems with carbon capture could potentially achieve high net plant efficiencies in the range of 40–56%, comparable to or higher than SC PCC and IGCC plant without carbon capture.

Gas-fired fuel cell simple-cycle power plants are in commercial operation now. As experience from operating these plants leads to further technological advances/improvements and cost reduction, it can be expected that fuel cell combined cycle and maybe coal-fuelled IGFC power systems will one day emerge as alternative power generation technologies to PCC, CFBC and IGCC systems.

10.2 MHD power systems

An MHD power generator is a device that generates electric power by means of the interaction of a moving conductive fluid and a magnetic field. The MHD generator operates at high temperatures and therefore, it can potentially achieve higher efficiencies than those obtained by conventional steam power plants. Various coal-fired MHD combined cycle power plant concepts have been developed and studied. Earlier work on MHD cycle analyses indicates that MHD systems can achieve a plant efficiency of 45–55%, with the potential to increase this to 60%. MHD power generation systems also have good environmental performance and are compatible with CCS systems for CO_2 emission free power generation from coal.

During the 1970s and 1990s, there were major R&D programs in many countries around the world on developing MHD power generation systems. Substantial progress was made in the development of the coal-based MHD power systems. Many system components were developed and tested and conceptual coal-fired MHD power plant designs were completed. The technology reached the point where construction of a complete demonstration system was feasible. However, due to some technical problems, high costs, the competition from advances in gas turbines and government budgets cuts, the R&D work stalled. With recent technological developments such as advanced materials, oxy-combustion and computer simulations, it may be a good time to take a renewed look at MHD power generation technology. In particular, computer models should be established for techno-economic analyses of MHD power cycles, and to optimise power cycle designs and operating conditions.

10.3 Indirect coal-fired combined cycle power system

The coal-fired High Performance Power Generating System (HIPPS) was developed in the USA as a part of the US DOE's Combustion 2000 Program. The HIPPS concept is based on indirectly coal fired combined cycles (a topping Brayton cycle and a bottoming Rankine cycle) with clean air being the working fluid to achieve high efficiencies and low emissions. The HIPPS plant concept can be applied to new power plants or adapted to repowering of existing coal-fired plants.

Two designs of HIPPS were under development: HIPPS with slagging furnace and HIPPS with fluidised bed coal pyrolyser. The design of the HITAF, air heater and char combustor were the main focus of the technology development. Successful testing of the HITAF demonstrated the ability to heat the working fluid to 1093°C, which surpassed design expectations. Also, tests of the RAH section of the HITAF in a test rig demonstrated the soundness of the basic design.

Improved materials and advanced gas turbine technologies will have a significant influence on the overall efficiency. With today's commercially available technologies, an HIPPS power plant could achieve efficiencies of 45% or higher. HIPPS can potentially achieve energy efficiencies of >60% (HHV) using coal or 75% (LHV) using gas. However, the use of high temperature heat exchangers in a coal combustion environment, coupled with the cost constraints, make proper materials selection a considerable challenge. The current design restricts the temperature of the air from the HITAF radiator outlet to around 927°C resulting in efficiencies of all coal HIPPS of around 41–43% (HHV). With the ultimate goal of heating the air to temperatures required for efficient gas turbine operation without using natural gas, new construction materials for the RAH need to be identified, and fabrication techniques and advanced oxidation and corrosion resistant coatings need to be developed.

Near zero emissions of greenhouse gases and conventional pollutants from an HIPPS power plant could potentially be achieved. One of the methods of reaching these goals is by using a hybrid cycle such as integration with a Brayton cycle or a high temperature fuel cell.

10.4 Alternatives to steam Rankine cycles

The supercritical carbon dioxide (sCO_2) power cycle is an innovative technology that could potentially achieve a higher thermal efficiency than steam Rankine cycles. A sCO_2 cycle has extremely compact turbomachinery designs due to the high fluid density of supercritical CO_2. The reduced BOP requirements and smaller footprint as a result of compact turbomachinery and simple cycle design could lead to lower capital and O&M (operating and maintenance) costs of a sCO_2 cycle power plant.

R&D for directly and indirectly heated sCO_2 based power cycles for fossil fuel applications is being carried out with the focus on components for indirectly heated fossil fuel power cycles with turbine inlet temperature at or above 760°C and oxyfuel combustion for directly heated sCO_2 power cycles. A sCO_2oxyfuel power cycle has the potential for near 100% CO_2 capture. A closed-loop Brayton cycle is envisaged for the indirectly heated fossil-based sCO_2 power cycle. A recent study on three proposed closed sCO_2 Brayton power cycle configurations for a 750 MW new-build power plant indicated that the thermal efficiency of the proposed sCO_2 Brayton cycles exceeded the thermal efficiency of the corresponding steam Rankine cycles by up to 4 percentage points.

A sCO_2 power cycles are potentially applicable to a wide variety of power generation applications. Several companies are now bringing early stage commercial sCO_2 power systems to market. A sCO_2 waste heat recovery heat engine has been developed and is commercially available from Echogen Power Systems LLC (USA). NET Power has recently announced that they will build a natural gas-fuelled, 50 MWth sCO_2 demonstration plant. The plant will use an Allam cycle developed by NET Power, and will produce pipeline quality CO_2 ready for transport and storage and have zero emissions. Coal-based sCO_2 power systems are currently under development.

Thermodynamic cycles alterative to steam Rankine cycle are under development. **Kalina cycle** and **ORC** operate with low or medium temperature heat sources. The Kalina cycle uses a working fluid comprised of at least two different components with different boiling points, typically water and ammonia. Since the solution boils over a range of temperatures as in distillation, more of the heat can be extracted from the source than with a pure working fluid. ORC uses organic working fluids with low boiling points, instead of steam, to recover heat from a lower temperature heat source. Both Kalina cycle and ORC have found applications in areas such as waste heat recovery, geothermal, solar thermal and biomass power plants and can potentially be integrated, as a bottoming cycle, with a steam Rankine cycle to improve the net plant efficiency of a steam power plant.

Goswami cycle is a novel thermodynamic cycle that uses a binary mixture to produce power and refrigeration simultaneously in one loop. It is suitable as a bottoming cycle using waste heat from conventional power cycles or as an independent cycle using low temperature sources such as solar and geothermal energy. It is currently under development.

10.5 Combined cycles

Steam Rankine cycles can be combined with topping and/or bottoming cycles to form combined thermodynamic cycles to improve efficiency. Various topping cycles using different working fluid have been proposed and evaluated. However, most of the recent work was academic research.

Addition of a Kalina cycle or ROC as a bottoming cycle to conventional steam power plants to improve overall plant efficiency has been proposed and evaluated. The thermodynamic analyses indicated that the combined cycle efficiency could be higher than a corresponding standalone Rankine cycle but the increase was moderate. Work is needed to determine the technical viability of such combined cycles and to determine if the benefits from the efficiency gains can justify the increased costs and system complexity.

10.6 Chemical looping combustion

CLC is an indirect form of combustion in which an oxygen-containing solid material, typically a metal oxide, supplies the oxygen to a fuel, and the spent oxygen 'carrier' is separately regenerated by air at high temperature. As there is no direct contact between air and fuel, CLC produces a stream of CO_2 and water vapour from which the CO_2 can be readily recovered eliminating the need for additional energy intensive CO_2 separation. CLC also minimises NOx formation.

Extensive research has been performed on CLC in the last decade with respect to oxygen carrier development, reaction kinetics, reactor design, system efficiencies, and prototype testing.

Several CLC processes fuelled by coal derived syngas or by coal are under development. In addition, several chemical looping coal gasification processes are being developed that provide flexibility to produce electricity, H_2 or syngas and to integrate with alternative power cycles such as fuel cells. Depending on the type of process chosen, various chemical looping based power plant configurations have been proposed and studied. Recent studies all indicate that compared with PCC and oxy-PCC plants with carbon capture, chemical looping based power plants could achieve higher efficiency, high carbon capture rate with considerably lower energy penalty for carbon capture and lower costs. If CLC can be successfully developed into practical systems and commercialised, they may revolutionise the coal-based power generation.

Despite the extensive research on CLC in recent and the advances that have been made, there are still a number of issues that require further investigation. For example, development of oxygen carriers with high reactivity and stability is still one of the challenges for CLC.

10.7 Solar-coal hybrid power plants

Recently, there have been several solar boost coal power projects that integrate solar energy with coal power system. Solar thermal energy can be used to produce high pressure, high temperature steam, which is then used to supplement the coal power steam cycle to reduce the consumption of coal in the production of electric power at the plant. The solar generated steam can be directly used to drive the steam turbine, or to replace the steam extracted from turbine for feedwater heating. Alternatively, the solar thermal energy is used to preheat the combustion air.

Off-shelf technologies are used in solar-coal hybrid power systems so no technology development work is needed. This approach can help utility companies to generate more renewable power with significant cost savings. The emissions of CO_2 and other air pollutants are reduced as a result of reduced coal use. Solar-coal hybrid plants can be new constructions, as well as the addition of solar fields to existing coal plants. More work is needed to find the most effective way to integrate the solar energy with coal power.

Coal will continue to play an important role in the global power generation. If the technologies for alternative power generation systems can be developed into practical systems, they could ultimately have a significant impact on coal-based power generation.

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