The Sustainable Option of Power from Fossil Fuels with Carbon Capture and Storage: An Overview of State-of-the-Art Technology

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Abstract To limit the global rise in temperature to 1.5–2 °C, considerable reductions in greenhouse gas emissions, especially CO_2, are needed—challenging because of the continuous increases in energy demand and the large contribution from fossil fuels. Gas-fired power plants will be a significant part of power generation over the next few decades, and whilst CO_2 emissions are significantly lower than for coal, they must still be addressed to lower carbon intensity. This can be achieved through carbon capture and storage (CCS) as a key enabling technology. This chapter aims to summarize the key research on state-of-the-art gas turbine technologies for enhanced post-combustion capture and oxy-turbine gas-CCS cycles, including the technical challenges and opportunities. For post-combustion systems, supplementary firing, humidification, exhaust gas recirculation and selective exhaust gas recirculation will be assessed, which outline the CO_2 increases and electrical efficiencies achievable when considering the capture penalty. An alternative to post-combustion capture is the use of oxy-turbine cycles, where the relative merits are assessed. Lastly, this chapter discusses the impacts of the technical, policy, financial and social challenges on scaling-up these technologies for full-chain commercial-level deployment. Overcoming these will be a necessity to enable CCS to decarbonize energy for a sustainable future.

Keywords Carbon capture and storage · CCS · Natural gas · Gas-CCS
Post-combustion capture · Oxy-turbine cycles

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1 Introduction

The global energy demand is expected to increase significantly in the near future as a result of economic growth and population increases worldwide, with the power sector predicted to account for 47% of the total primary energy consumption by 2035 [1]. Current predictions indicate that more than half of the electricity demand will be provided by fossil fuels in the next few decades [1, 2], therefore making it challenging to achieve the necessary reductions in CO_2 emissions to tackle climate change [3]. It is clear that any efficiency improvements and the current trend to switch to less carbon-intensive fossil fuels (i.e. natural gas) will contribute to lowering the amount of CO_2 emitted into the atmosphere. However, these alone are not enough to achieve the profound emission cuts required to keep global average temperature rises below 1.5–2 °C, and further actions are thus required [1–3]. No stand-alone solution is possible for this purpose, but the integration of several options will be key to ensure a transition to a fully integrated, low-carbon economy. This includes both efficiency improvements and fuel switching, as mentioned above, but also an increase in the share of nuclear and renewable energy, as well as the use of CO_2 capture and storage (CCS) technologies [4].

In this decarbonization context, carbon capture and storage is expected to play an important role within the solution portfolio, accounting for up to 14% of the total cumulative effort in CO_2 emissions reduction through to 2050 [4]. The importance of CCS relies on its ability to decouple CO_2 emissions from fossil fuel sources, thus securing the supply of an increased energy demand whilst still attaining the CO_2 emission targets associated with the most demanding scenarios [4]. It has a large importance in the industrial sector (such as, cement, iron and steel, chemical and refinery plants), where CCS is one of the few options that can provide substantial cuts in CO_2 emissions here. CCS is also relevant in the power sector, where flexible, reliable, fossil-fuelled backup utilities are widely required in spite of the increasing penetration of renewables (which are inherently intermittent), in order to guarantee the security of supply and ensure a precise match between the instantaneous electricity generation and demand at all times. Although the high costs are at present a limiting factor to deployment, further advantages of CCS could come from an economic perspective, as it can contribute to limiting the mid- and long-term costs of the transition towards a sustainable, low-carbon model. This is the case of the electricity sector, where it has been estimated that excluding CCS from the solution portfolio will increase investment costs by 40% if the same CO_2 reduction targets are to be achieved [4].

Focusing on the power sector, large efforts have been initially devoted to the development of CCS technologies for coal applications. However, coal is very carbon-intensive and a move towards fuels with a lower carbon footprint will mean that CCS technologies will also have to be utilized with these other resources. This is the case of natural gas, which has experienced rapid growth in the last few decades due to its lower carbon emissions per unit of energy generated (less than 400 kg/MWh vs. approximately 800 kg/MWh for coal), in addition to the more flexible operation and lower capital costs of gas-fired systems with respect to coal-fired power plants [4]. Given the increasing importance of those systems [1, 2], this chapter aims to discuss the implementation of CCS in natural gas-fired power plants, with a focus on the capture step. For this purpose, a summary of the different capture systems and the current status of CCS commercialization are covered in Sects. 1.1 and 1.2, respectively. Moreover, Sect. 2 is dedicated to adapting post- and oxy-combustion capture options to best suit natural gas combustion, focusing on state-of-the-art technologies and discussing the main technical challenges. Pre-combustion systems using natural gas are not considered in detail herein due to the less attractive economics at present, although alternatives are currently being studied to improve the competitiveness of these systems [5, 6]. Political, financial and social factors affecting the deployment of CCS are also commented on in Sect. 3, where a final discussion on the opportunities of these systems is included. The conclusions of this chapter are then presented in the last section.

1.1 Overview of Carbon Capture Systems

Carbon capture and storage technologies aim to separate the CO_2 generated from industrial processes and generate a CO_2-concentrated stream that can be then purified, compressed and permanently stored. The CO_2 capture stage is key in CCS systems, as it is responsible for reducing the CO_2 emissions of a specific process and accounts for the largest cost share of the entire CCS chain (i.e. capture, transportation and storage) [7, 8]. Three systems can be distinguished depending on where the separation step happens, namely post-combustion, oxy-combustion and pre-combustion capture [7]. These are briefly discussed here.

Post-combustion systems separate the CO_2 contained in a gaseous stream (i.e. the flue gas) as a result of a fossil fuel or biomass combustion process, leading to a CO_2-rich stream that can be ultimately stored. This separation step can be carried out using solvents, solid sorbents, membranes or cryogenic processes. Post-combustion technologies are suitable for its implementation in existing plants (retrofitting), as they are placed downstream of the plant thus hardly affecting the production process.

Oxy-combustion systems burn the fuel using an oxygen-rich flow instead of air. A gaseous stream that mainly contains CO_2 and H_2O is obtained after combustion, leading to a CO_2-rich flow after water condensation. Therefore, the gas separation stage takes place in this system before combustion, i.e. O_2 separation from N_2 in air. Cryogenic methods are often considered for this purpose, although the use of chemical looping combustion systems or membranes has been proposed to reduce the often high energy penalty and costs.

Pre-combustion processes separate CO_2 prior to combustion. In these systems, a CO/H_2 stream (syngas) is produced after gasification or reforming of the fuel using air or oxygen and/or steam. The syngas then undergoes a water–gas shift reaction, where the CO reacts with steam to obtain a CO_2/H_2 mixture. The CO_2 is then separated by physical absorption or using some of the post-combustion processes referred to above, leading to a highly concentrated H_2 flow that can be used as energy source.

The systems discussed above are mainly focused on energy generation processes. Nevertheless, an area of great importance is CO_2 capture from industrial sources (e.g. in the cement or the iron and steel industry). Separation of CO_2 from industrial gas streams has been routinely carried out with purposes different from CCS, such as to reduce the CO_2 content in natural gas or to separate CO_2 from H_2 during ammonia production [7]. Nevertheless, the study of technologies aimed at capturing CO_2 from a range of industrial sources has received increasing attention recently, as it is one of the few options to achieve deep cuts in CO_2 emissions in these systems.

1.2 *Current Status of Commercial CCS Deployment in the Power Sector: Carbon Capture from Coal*

A number of large-scale CCS projects with individual CO_2 capture capacities in the range of 0.4–8.4 $MtCO_2$/yr are currently operational [9]. Many of them are related to CO_2 separation in the natural gas processing industry, but there are dedicated projects in the power generation sector as well. Others are also related to industrial sectors like the iron and steel industry and the production of fertilizers, synthetic natural gas, hydrogen and ethanol [9]. The resulting CO_2 stream is employed for enhanced oil recovery (EOR) in most of these projects, as this is an economic driver for the development of CO_2 capture initiatives in some regions (e.g. USA and Canada). Nevertheless, there are also CCS projects that target the geological storage of CO_2. Some have been running for several years, thus injecting considerable amounts of CO_2 underground and providing valuable information for control and monitoring purposes (see, for example, the ongoing Sleipner, Weyburn-Midale and Snøvit projects [9] and the In Salah project (injection suspended in 2011) [10].

In the power sector, the recent deployments of full-chain CCS demonstrations have primarily focused on coal-fired generation as mentioned in Sect. 1, with two fully operational plants at large scale coming online in the past few years. This is the case of Boundary Dam, which was the first power station in the world to implement the technology at scale [11]. In this project, located in Saskatchewan (Canada), one of the units (139 MW) of the existing power plant was retrofitted with post-combustion CO_2 capture at 90% efficiency using the Shell CANSOLV's combined CO_2 and SO_2 capture process, with a capture capacity of 1 $MtCO_2$/yr [12]. It became operational in 2014, and the captured CO_2 is mainly transported via pipeline to be used for EOR in the Weyburn oil field [12], although a small fraction is taken for geological storage under the framework of the Aquistore project [13]. More recently, Petra Nova in the USA has become the largest post-combustion carbon capture plant worldwide. It also uses solvent-based technologies—specifically, a proprietary KS-1 solvent—and can capture up to 1.4 $MtCO_2$/yr with $\sim 90\%$ efficiency from a slipstream (equivalent to 240 MW) of flue gas from the associated coal-fired power plant. The CO_2 is then used for EOR purposes at the West Ranch oil field [14].

The projects mentioned above show that CCS in the power sector is already a reality. These are important assets for the future of CCS, providing valuable information and operational experience that can be employed to optimize these processes and reduce risks, uncertainties and costs for future plants. Nevertheless, more projects are required at demonstration and commercial scale to prove and optimize the more mature and also novel emerging capture technologies from a variety of sources and gain additional knowledge. To this end, further potential CCS projects at large scale are at different stages of development, including capture projects dedicated to the industrial sector, as well as post-, pre- and oxy-combustion options for power generation [9]. Current and future demonstration activities are essential to reduce the costs of CO_2 capture, improve system performance and gain confidence in the entire CCS chain, which could facilitate a more rapid deployment of CCS in the near future if adequate policies and incentives are in place. This is discussed in detail in Sect. 3.

2 Carbon Capture from Natural Gas-Fired Power Plants: Gas-CCS

Widespread deployment of carbon capture and storage in gas-fired power plants (gas-CCS) requires adaptation of the capture technologies and/or the turbomachinery and other process units to the specific characteristics of these systems. This section focuses on post- and oxy-combustion gas-CCS applications, highlighting the main challenges and opportunities with a view to its commercial deployment.

2.1 Post-combustion CO_2 Capture

Conventional gas-fired power plants use very high excess air ratios to limit the temperature in the combustion chamber and protect the gas turbine from damage occurring when working at very high inlet temperatures. This operating strategy results in large flows of flue gas with a CO_2 content of just 3–4 vol%—much lower than that of coal-fired power plants (around 12–15 vol% CO_2)—which negatively affects the performance of any CO_2 capture process placed downstream [15, 16]. As a result, coupling post-combustion carbon capture systems with gas-fired plants is particularly challenging, and large capture reactors are required to cope with the increased flows, which should also capture CO_2 efficiently under restricted driving force conditions. Therefore, higher penalties and capture costs can be expected in gas-CCS systems [15, 16]. In addition, the flue gas also contains large amounts of oxygen (of the order of 12–13 vol%), which can increase oxidative solvent degradation in those systems using amines as the capture technology [17], thus increasing operating costs. A number of options have been proposed in order to enhance the CO_2 content in the flue gases generated in gas-fired systems, which lead to lower oxygen levels and can also reduce the flue gas flow to be treated in some cases. These therefore have a range of benefits for the capture system, as they can potentially reduce the size, energy penalty and costs associated with the post-combustion plant. These are:

- Supplementary firing
- Humidification
- Exhaust gas recirculation
- Selective exhaust gas recirculation.

These schemes are explained in detail in Sects. 2.1.1, 2.1.2 and 2.1.3. The discussion in these sections is mainly focused on the use of amine scrubbing (usually employing monoethanolamine (MEA) as the solvent) in gas-CCS systems, especially in terms of electrical efficiencies, as they are the most mature post-combustion capture systems as indicated in Sect. 1.2, and much information is available on these systems. Nevertheless, it is important to highlight that all post-combustion capture technologies could potentially benefit from the increase in the flue gas CO_2 content attained through the gas turbine configurations described in the next sections.

In addition to the specific characteristics of the flue gas to be treated, further challenges of gas-CCS systems are related to the need for flexible operation of the post-combustion CO_2 capture plant. Gas-fired power plants have the ability to quickly respond to changes in demand and are often employed for backup purposes at varying loads [18]. Therefore, any capture plant coupled to these systems will also need to operate flexibly, exhibiting reliable and effective performance under a wide range of conditions. Dynamic operation of capture systems is not fully understood at the moment for any of the capture technologies proposed in the literature, and it is currently an active R&D area. Another topic of research is related to process optimization and intensification. There is still scope for specific improvements in the capture systems for all of the proposed technologies, with large efforts devoted to finding new optimized configurations that can improve the energy penalties and costs of these systems. However, it is important to point out that alternative layouts can often lead to increased complexity/costs of the power plant and/or the capture system, and their effects on the overall performance of the integrated plants and their flexibility should be carefully evaluated, especially for gas-fired systems.

2.1.1 Supplementary Firing

Supplementary firing consists of burning additional fuel downstream the gas turbine (see Fig. 1) by taking advantage of the high oxygen content remaining in the exhaust gas of gas-fired systems (around 12–13 vol% O_2 as discussed in Sect. 2.1). This option was initially proposed to increase the power output of natural gas combined cycle (NGCC) systems during periods of peak electricity demand, since extra power can be generated in the steam cycle as a result of the higher temperature of the flue gas entering the heat recovery steam generator (HRSG) after the supplementary firing stage [19]. This idea can be also exploited to compensate for the adverse effect of ambient conditions on gas turbines (e.g. an increase in ambient temperature), which reduce the power output of the plant [20]. Additionally, supplementary firing has been investigated for gas-CCS applications because of its associated benefits, namely (i) a higher CO_2 content in the flue gas, which increases the driving force in the CO_2 capture stage; (ii) a reduction in the flue gas O_2 concentration, which can lead to lower rates of solvent degradation in amine CO_2 capture systems; (iii) a decrease in NOx emissions; and (iv) the potential use of biomass in the supplementary firing unit, which can lead to a further reduction in CO_2 emissions linked to the concept of negative emissions [15, 16, 21–25]. Moreover, some authors have claimed that further advantages can be obtained if the power plant is designed to continuously operate under supplementary firing conditions, as the flue gas flowrate arriving at the capture plant could be reduced with respect to that of a reference NGCC plant (without supplementary firing) with the same power output [24], thus reducing the cost of the downstream CO_2 capture system.

NGCC plants using supplementary firing are available at commercial scale—see, for example [26]. However, there are specific challenges and limitations that need to be considered when coupling those systems with CCS. This is certainly the case of the maximum CO_2 increase that can be achieved in the flue gas as a result of supplementary firing, which is related to the energy consumption in the post-combustion capture system (see [16] for amine scrubbing plants) and depends on the amount of fuel that can be burnt in this stage. This is usually limited by material considerations, i.e. by the maximum temperature of the flue gas at the inlet

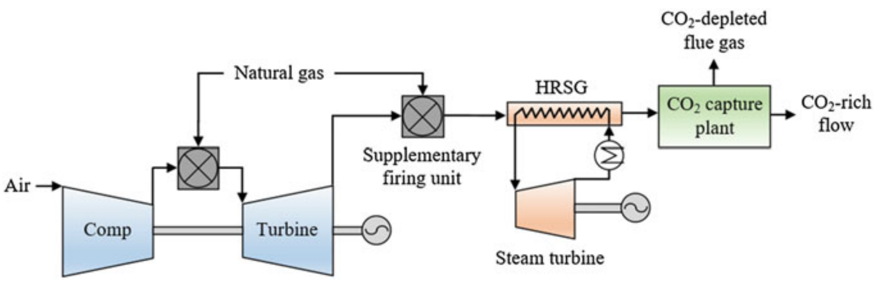


Fig. 1 Representation of a natural gas combined cycle with supplementary firing and CO_2 capture

of the HRSG. A limit of 800 °C is often considered [24, 27], but higher temperatures can be employed if insulated casings (up to 900 °C) or water-cooled furnaces (up to 1300 °C) are employed in the HRSG [28]. Concentrations around 7 vol% CO_2 can be achieved assuming the supplementary firing process operates at ~1300 °C, although this can theoretically increase up to ~11 vol% CO_2 under stoichiometric conditions (which imply much higher temperatures) [16]. Alternatively, sequential supplementary firing can be used, thus allowing for high CO_2 concentrations in the flue gas whilst keeping temperatures in the HRSG at moderate values [24]. In this case, the supplementary fuel is distributed into a number of firing stages throughout the HRSG, as opposed to the system seen in Fig. 1. As a result, the flue gas achieves a more limited temperature increase in each stage, and therefore, more supplementary fuel can be burnt (leading to higher CO_2 concentration) without compromising material performance. The maximum flow of fuel that can be burnt is then limited by the flue gas oxygen concentration in the last firing stages. Concentrations close to 11 vol% CO_2 have been calculated at the inlet of the absorber reactor in NGCC systems using sequential supplementary firing with maximum temperatures in the HRSG of 820 °C, assuming complete and stable combustion can be performed at very low oxygen levels in the last firing stage (around 1 vol% O_2 at the exit of the last stage) [24].

Moreover, the use of supplementary firing can increase the mass flowrate of the flue gas to be treated in the capture plant in those cases where no exhaust gas condensation is applied, thus offsetting the benefits of an increased CO_2 concentration [16, 25]. Another important limitation is the associated reduction in the net electrical efficiency of the power plant, as the fuel fed to the supplementary firing unit is only used to produce power in the Rankine steam cycle, unlike the main fuel stream. This cycle is less efficient than the combined Rankine and Brayton cycles, which together with the higher temperature difference in the HRSG results in a reduced efficiency [25]. Therefore, the potential benefits of supplementary firing in CO_2 capture applications depend on two opposite effects that impact the overall system efficiency: the efficiency loss in the power plant versus the decrease in the energy consumption of the capture process as a result of the higher flue gas CO_2 content. This has been studied in NGCC power plants that make use of a supplementary firing stage and incorporate an amine CO_2 capture plant downstream (MEA-based). Electrical efficiencies between 42 and 48% have been calculated for these systems, which can be up to 7–8 net percentage points lower than those of a NGCC without supplementary firing coupled to an amine capture plant [16, 24]. Similar trends were also reported in a recent study that investigates the use of supplementary firing in NGCC plants with CO_2 capture in order to compensate for the power reduction experienced by these systems when the ambient temperature increases [29]. Results obtained also indicate a substantial efficiency drop of around 5 net percentage points with respect to the system without supplementary firing [29]. The efficiency drop associated with the system of Fig. 1 can be partially compensated with the use of supercritical steam cycles in the HRSG [16, 24]. Nevertheless, this comes at the expense of a more complex system, thus affecting its cost and flexibility [25, 30].

More complex supplementary firing configurations have been evaluated for its application in NGCC plants equipped with amine scrubbing CO_2 capture in order to investigate further performance improvements [25]. One of these options consists of the use of supplementary firing together with exhaust gas reheating, which can raise the electrical efficiency by 15% compared to the conventional supplementary firing case, but the CO_2 concentration is also reduced [25]. Another alternative is based on combining supplementary firing and exhaust gas recirculation, the latter of which is explained in detail in Sect. 2.1.3. In this case, the effect on efficiency is more moderate ($\sim$4% increase with respect to the conventional supplementary firing configuration), but it largely reduces the mass flow and increases the CO_2 content of the flue gas, which will reduce the costs of the CO_2 capture plant. However, there is a substantial decrease in the oxygen available in the supplementary firing stages [25]. The use of a NGCC system that incorporates supplementary firing, exhaust gas reheating and recirculation, as well as a supercritical HRSG design, has also been analysed, leading to an efficiency penalty of just $\sim$3 net percentage points with respect to the NGCC system without CO_2 capture [25]. Nonetheless, it is important to highlight that the alternative configurations mentioned here have substantially more complex process schemes than that of Fig. 1. Therefore, this has implications in terms of operational flexibility and costs, as discussed in Sect. 2.1, which are sensitive areas for power plants incorporating CCS systems and should be carefully evaluated.

2.1.2 Humidification of Gas Turbine Cycles

Humidified turbines introduce moisture to a conventional gas turbine cycle so that the working fluid is changed from air to an air–H_2O mix. Such systems have previously been utilized to: (i) improve electrical efficiencies, since the mass flowrate of working fluid through the turbine is increased whilst keeping the compressor power unchanged (moisture is added after compression), therefore increasing the power output [31–39], and (ii) to control emissions, particularly of NOx, as peak flame temperatures in the primary combustion zone are reduced by the higher heat capacity of the working fluid [16, 35, 40, 41]. Furthermore, humidification has also been reported to improve the specific output [42] and specific work [43].

More recently, humidified turbine cycles have been evaluated as a means of augmenting the CO_2 level in the exhaust to aid carbon capture. Humidified cycles increase the CO_2 content of the flue gas, since the moisture replaces some of the air and can be condensed out [16, 40, 44]. The amount of CO_2 augmentation, however, depends on a range of factors related to the various operating parameters/conditions, but mainly on the degree of humidification. This water–air ratio is also a key defining parameter for efficiency improvements [16]. Various maximum CO_2 concentrations have been reported for the flue gas generated in humidified gas turbine cycles—although often these are around 5 vol% [16, 45]. This is equivalent to an increase in the flue gas CO_2 content of $\sim$25–30%, which could enable large reductions in the reboiler duty of amine capture systems [16, 46]. As the degree of humidification or water–air ratio is such an important parameter, the moisture addition needs to be finely balanced, even though the amount of water/steam required to achieve performance improvements is often substantial. High water–fuel ratios are often needed, but at such levels, increases in emissions relating to incomplete combustion are found—specifically CO and unburned hydrocarbons due to the lower oxygen availability and reduced system temperatures in the primary combustion zone [16, 47]. Takahashi et al. [42] state that each system has a different optimal point for efficiency maximization, which is often in the region of 12–14 vol% of moisture inclusion in the inlet oxidizer (water/air ratio)—this has been corroborated by Li et al. [16]. Others have suggested that much lower levels of humidification in the region of 5–6 vol% are sufficient [32, 33, 48].

Wet turbine cycles are classified depending on the way the moisture is introduced, and there are a range of possible configurations. Methods exist for both the injection of water in its liquid form, either directly or with evaporative cycles using humidification towers, and as steam [40]. Humid air turbines (HAT) and steam injected gas turbines (STIG) are considered in turn below. These are recuperative cycles that recover the heat to use again, which means the efficiency and outputs are increased, whilst the specific investment costs decrease [40, 49]. This can be beneficial to mitigate, at least in part, some of the energy penalty caused by adding carbon capture to an electricity generation process. Part-load performance is also better than that of a combined cycle [40], and as a result, they are classed as higher performance gas turbine technologies.

Humid air turbine systems, also referred to as evaporative gas turbines (EvGT), utilize a saturator or humidification tower to add moisture downstream of the compressor [44, 50], as shown in Fig. 2 in its simplest configuration. The inclusion of heat recovery components (e.g. an economizer) means that the thermal energy in the flue gases and in the compressor outlet gas can be recovered by using it to heat and evaporate water, which is then used to saturate the air exiting the compressor. This gives a single phase mixture, which can be further heated with the heat recovered from the turbine exit stream before entering the combustor, as depicted in Fig. 2 [49]. By recovering and reusing this heat, considerably higher thermal efficiencies can be achieved for a specific system. Moreover, the increased mass flow of the working fluid through the turbine (due to the addition of moisture to the air) results in a higher specific power output and greater electrical efficiencies, as the power consumption in the compressor remains unchanged [44, 51–53]. This is equivalent to arguing that the compressor power demand decreases in HAT systems with respect to a non-humidified gas turbine if the same power output is to be achieved, since humidification occurs after the compressor [44, 54, 55]. HAT systems can achieve maximum electrical efficiencies in the region of 50–52% [35, 56, 57], and decrease significantly with the addition of a post-combustion capture system downstream, to $\sim$42% using a MEA-based scrubbing plant [16]. HAT systems can start up faster and have a higher availability than non-humidified combined cycles and could therefore play a valuable role in a future with significant amounts of intermittent renewables in the grid mix [58].

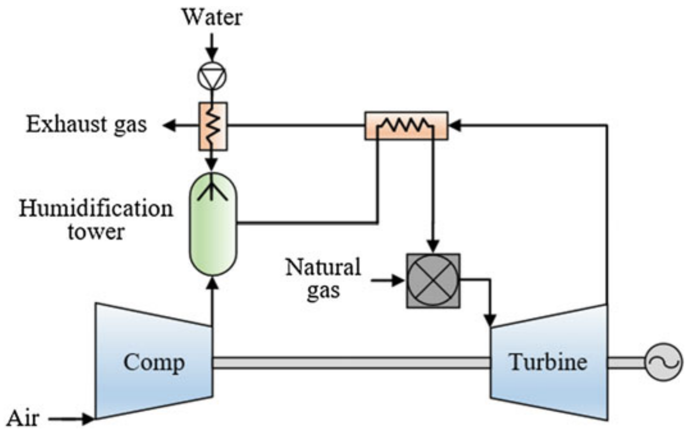


Fig. 2 Schematic of a humidified gas turbine operating under HAT conditions

Another humidification option is based on steam injected gas turbine systems. These integrate a HRSG, where the heat contained in the flue gas is recovered to generate steam after the turbine, which is then injected into the combustion chamber, as delineated in Fig. 3 [40, 51–53]. Additional recuperation can be included by heating the compressed air prior to combustion [52]. As in the case of HAT cycles, a fraction of the air is replaced by steam, which increases the mass flowrate of the working fluid through the turbine without increasing the power consumption in the compressor, thus leading to higher electrical efficiencies [40, 51, 53]. For STIGs in combined cycles, a single HRSG can be used, with a bleed-off to feed steam to the combustor. Horlock [52] reports that the work output of the turbine increases linearly with the quantity of the steam injected, and the optimum steam quantity corresponds to the maximum steam exit temperature, along with the minimum pinch point temperature difference. This also has limitations based on the compressor surge and maximum steam flowrate [59]. STIG cycles typically have much lower electrical efficiencies than HAT systems by comparison—which peak at up to 48%, but are generally lower at around 37–41% [16, 31, 53, 60–62]. This, together with the limited increase in the CO_2 content that can be achieved in the flue gas, makes the option of coupling STIG systems with post-combustion CO_2 capture unattractive. Advances and modifications to standard STIGs can further improve performance up to 50% though [51].

In addition to these two main modifications (HAT and STIG), a range of other more complex cycles and altered configurations have been proposed. These include, but are not limited to, the inclusion of an inverted Brayton cycle, integrated bottoming cycles, recuperative heating of the flue gas after the condenser, part-flow evaporative gas turbines, recuperated and intercooled-recuperated cycles, semi-closed humidified cycles, multi-effect thermal vapour compression, chemically recuperated cycles, spray intercooling/aftercooling, humid air water injected turbines and regenerated water injected cycles, as well as CHENG, FLECS,

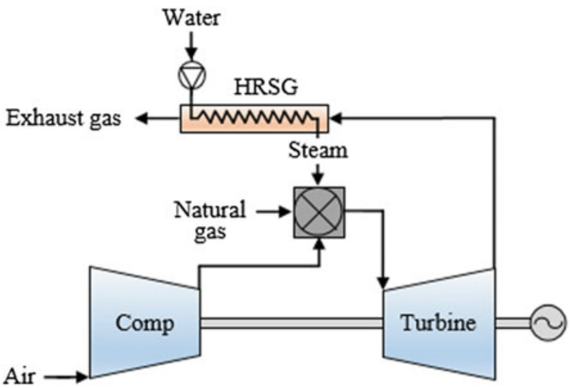


Fig. 3 Schematic of a humidified gas turbine operating under STIG conditions

REVAP and advanced-HAT turbines [35, 38, 42, 43, 57, 61–65]. Hybrid systems have also been considered, which primarily focus on the integration of low-carbon energy sources, such as renewables (solar and biomass) or fuel cells into humidified systems [66–70]. Whilst these have shown a range of additional benefits to the traditional humidification technologies, such as further improvements in efficiency, their considerable complexity can substantially increase the costs and reduce the flexibility of such systems, and are therefore not considered viable at present.

Moreover, there are a number of common issues with humidified gas turbines cycles. Water consumption for all 'wet' gas turbine cycles can be problematic, specifically adding significant cost. Water utilization rates for STIG designs though can be up to three times greater than for HAT systems [37, 49]. Condensing out the moisture from the flue gas to reuse is vital to ensure the operational costs are not excessive. Choosing the most appropriate condenser can have significant impacts on the plant footprint and costs [71]. However, reusing the water can also lead to problems. Demineralization of the recycled water is often required to stop build-up of species that can cause deposition and corrosion within the system [35, 47]. Furthermore, extra components are required for all these systems to achieve the humidification. These, and the necessary ancillary equipment, add notably to their complexity as well as their costs. Minimizing the moisture inclusion in the cycle is therefore necessary in terms of water consumption, but there are other reasons to ensure an optimal moisture–air ratio is used: (i) excessive moisture addition lowers the oxygen content of the oxidizer stream and can negatively impact flame stability, and (ii) excess water in the outlet flue gas stream can further dilute the solvent used for amine scrubbing carbon capture, increasing the reboiler duty [16, 56]. Moreover, modifications are sometimes required to the gas turbine system components, which have to cope with a mismatch in the compressor and turbine flows. Increases in the pressure ratio are often needed in optimized humidified systems, and thus, higher-grade materials could be needed [51, 53]. Additionally, blade cooling optimization may also be required, which presents new opportunities (or challenges!) in the field of blade and disc cooling architecture [72].

The general consensus then is that gas turbine humidification can result in considerable performance benefits when looking at the gas turbine itself (no CO_2 capture); however, the improvements in performance are more pronounced for systems operating with HAT than STIG. Nevertheless, these systems can only provide a limited increase in the CO_2 content of the flue gas (up to ~ 5 vol%), and the calculated electrical efficiencies when coupled with amine-based capture technologies are lower than those of other available options (e.g. a conventional NGCC using amine scrubbing for CO_2 capture with or without exhaust gas recirculation or supplementary firing) [16]. This limits the interest of humidified turbine cycles for gas-CCS applications.

2.1.3 Exhaust Gas Recirculation and Selective Exhaust Gas Recirculation

Both exhaust gas recirculation (EGR) and selective exhaust gas recirculation (S-EGR) can increase the CO_2 partial pressure in the turbine flue gases that are sent to the post-combustion capture plant by concentrating the CO_2 into a smaller flowrate of gas. In the EGR case depicted in Fig. 4, this is achieved by recirculating a proportion of the flue gases back to the compressor after passing through a flue gas cooler and a water knockout unit [73]. The recirculated flow contributes to control temperatures in the combustor and replaces a fraction of the inlet air, thus reducing the exhaust flowrate and increasing the back-end CO_2 levels, which facilitates effective post-combustion capture in a plant with a reduced size and energy penalty. Several studies report that using EGR decreases the volumetric flue gas flowrate by an equivalent amount [18, 74–77]—e.g. the flue gas flow can be halved by using recirculation ratios of $\sim 50\%$. At this level, the CO_2 content in the flue gas increases from ~ 4 to ~ 8 vol% CO_2, with the specific reboiler duty of an associated MEA capture plant decreasing by $\sim 8\%$ [77]. Other benefits can also be found when deploying EGR into gas-CCS systems. NOx reductions have been extensively reported for EGR operation [16, 78–81]. Whilst this is primarily due to the decrease in the peak combustion and flame temperatures [82], since the CO_2 has a higher heat capacity, the reduced oxygen availability may also play a role [77].

Despite the beneficial impacts of EGR, there are also limitations, as considered herein. The recirculation ratio is the defining parameter for the CO_2 increase [16], which is related to the efficiency gains attained in the NGCC plant with CO_2 capture. The overall consensus on EGR from both experimental and theoretical studies is that EGR ratios of 40% are the most ideal, although an absolute maximum recirculation rate, which is under much debate, of 50% could be used with small system modifications [83].

This key defining factor needs to be chosen carefully to ensure that the maximum potential CO_2 concentration is achieved, with minimal negative consequences, such as increases in other emissions resulting from combustion instabilities due to oxygen depletion in the oxidizer and/or lower peak temperatures. The recirculation ratios reported vary widely, although typical maximum EGR

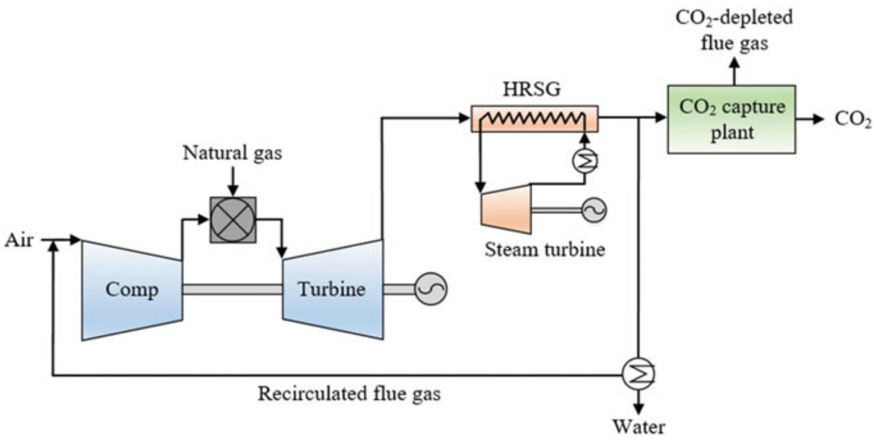


Fig. 4 Schematic of a gas turbine operating with exhaust gas recirculation

ratios employed are usually in the region of 35–40%, leading to up to 6.5 vol% CO_2 in the resulting flue gas [16]. At these values, the oxygen concentration at the inlet of the combustor is of $\sim$16–17 vol%, which ensures stable combustion and low emissions [84, 85] without the need for major combustor redesign [16, 73, 75, 84]. High overall electrical efficiency of the NGCC (above 50%) using EGR at those levels and with CO_2 capture (amine-based) has also been reported, reducing the energy penalty associated with the amine scrubbing system by 0.3–0.7 net percentage points with respect to an equivalent system without EGR [18, 75, 77]. Others though, such as Peeters et al. [83], Evulet et al. [80] and Li et al. [77], have reported higher optimal EGR ratios of up to 50%, suggesting this is where the electrical efficiency peaks. Whilst this is able to increase the CO_2 content of the flue gas further, up to $\sim$8 vol% [76, 80, 84, 85], as indicated above, issues associated with depleted oxygen conditions in the combustor can start to arise, such as instabilities in combustion and in the flame, resulting in poor burnout [77]. This is due to the narrower flame stability limits when combusting in an air–CO_2 environment [84]. In extreme cases, where the EGR ratio is too high, this can even lead to lean blowout [81]. EGR ratios of 60% result in excess oxygen of just around 1 vol%, with the O_2 content of the oxidizer less than 10 vol% [16]. These combustion and flame instabilities, as well as the limited O_2 availability in the combustor at high EGR ratios, can increase pollutant formation, in particular CO and unburned hydrocarbons [76–78, 83, 85–87]. At low air–fuel ratios and altered oxidizer compositions, variations in heat transfer, reductions in temperatures and slower chemical kinetic reaction rates also result in more incomplete combustion [84, 85].

The techno-economics of such configurations has also been considered [18, 75]. As well as benefitting the efficiency, EGR is advantageous for the economics. A more compact design is possible for the absorber by the use of EGR because of the reduced gas flowrates with a higher CO_2 content, thus lowering the capital costs of the capture unit [18, 75]. Although carbon capture significantly increases the overall costs of power generation, the integration of EGR can lower these compared to a standard gas turbine facility with CCS. Therefore, EGR can reduce the cost of electricity of an NGCC with an amine-based capture system from $84.3/MWh (no EGR) to $81.9/MWh (EGR), leading to a cost of CO_2 avoided ~9% lower than without EGR [75].

In addition to conventional EGR, more recent studies have started to look at selective EGR (S-EGR), where a fraction of the CO_2 from the flue gas is selectively recycled (not all the other species), which mitigates some of the drawbacks explored above [79, 88–91]. These configurations use a membrane (or another CO_2 separating device, such as a rotary wheel [90]), where the combustion air flows counter-currently with the flue gas (richer in CO_2 due to S-EGR). The CO_2 passes through the CO_2-selective membrane and enriches the oxidant before going to the compressor, with this CO_2 separation mainly driven by the difference in partial pressure between the permeate and retentate streams (without the need for energy consumption due to compression/vacuum) [88]. As a result, such studies consider higher levels of CO_2 in the inlet stream to the capture plant than EGR systems. Nevertheless, the final CO_2 concentration attained in the flue gas depends on the individual capture efficiencies of the capture plant and the selective membrane.

Series configurations, where all the flue gas is treated in the capture plant and subsequently in the CO_2 separator (as outlined in Fig. 5a), can result in CO_2 concentrations in the flue gas of up to 13–14 vol% if the capture plant and the selective membrane (or CO_2 separator) operate at ~30 and ~95% capture efficiency, respectively, to ensure an overall CO_2 capture efficiency of ~90% [88, 90]. However, higher CO_2 levels (well above 20 vol%) can be attained if the selective membrane is forced to work at increased CO_2 separation efficiencies [88, 92]. For parallel arrangements, where the flue gas is split into two streams that go to the CO_2 separator and CO_2 capture plant (shown in Fig. 5b), flue gas CO_2 levels in excess of 18 vol% have been reported if the capture plant and the CO_2 selective separator are able to operate at very high capture efficiencies between 96 and 98% [88, 90]. However, they diminish to around 8 vol% CO_2 if these individual capture efficiencies are of 95% [89]—with an overall capture efficiency of 90% in all cases.

As can be seen, parallel configurations require high capture efficiencies in both the CO_2 separator and the CO_2 capture plant to ensure overall capture rates remain high, whereas for the series design, capture efficiencies in the capture unit can be considerably lower, whilst still maintaining high overall levels of capture [88]. If these are balanced successfully, potential capital and operational cost savings (CAPEX and OPEX) in the capture unit can be achieved, due to (i) the higher CO_2 content in the flue gas and (ii) the greatly reduced size of the capture plant, due to the significantly lower volumetric flue gas flowrates [88–90]. However, the overall efficiency and cost benefits of a parallel S-EGR plant regarding the integrated gas-CCS system (not just the capture plant) are very sensitive to the auxiliary energy consumption and the costs associated with the selective membrane [89]. There also is potential here for process intensification and improvements in the overall cycle efficiency.

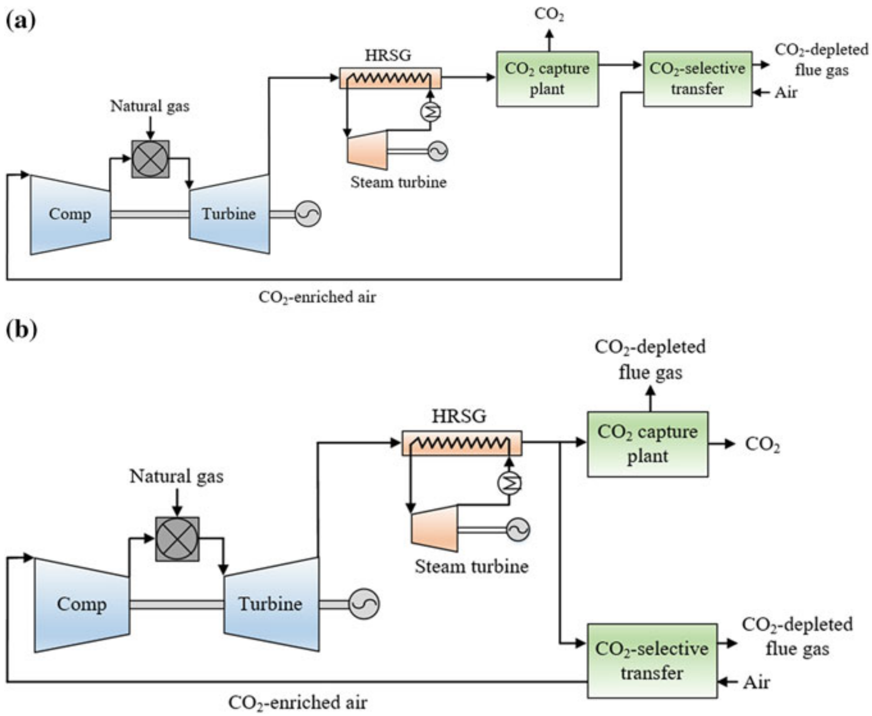


Fig. 5 Schematics of gas turbines operating with selective exhaust gas recirculation, showing (**a**) the series configuration and (**b**) the parallel configuration

Moreover, the use of S-EGR increases the CO_2 and reduces the O_2 content in the inlet oxidizer, which can have detrimental impacts on combustion performance and therefore emissions release. This is particularly true for unburned and incompletely combusted species, like CO and unburned hydrocarbons, as with EGR [79, 91]. These emissions are caused by flame instabilities and the reduction in flame temperatures. If the level of O_2 in the combustor becomes too low and the instabilities too great, blow-off and flame extinction can occur, which would necessitate changes to the operating regime—notably the air–fuel ratio to allow stable combustion [91]—and/or combustor redesigns to avoid those effects. Ensuring sufficient oxygen availability in the combustor is key for S-EGR, as with EGR above. However, with S-EGR, much more CO_2 can be recirculated without approaching stoichiometric conditions [88].

At present, preliminary economic analyses suggest that such configurations would still be more costly than a simple EGR system. Whilst the CO_2 capture system would cost less, other plant systems, namely the selective membrane set-up, would increase the total plant costs and therefore negatively impact on the cost of electricity according to a recent analysis of the parallel configuration [89]. The effect of the auxiliary consumption in S-EGR systems could also be substantial

[89]. Nevertheless, S-EGR configurations could show better competitiveness against conventional NGCCs coupled with amine capture plants only (without EGR or S-EGR) [88, 89, 92]. Additional cost reductions for membranes in the future though can help in this area and are likely to be due to material advancements. Improvements in CO_2 permeance, and to a lesser extent CO_2 selectivity, will reduce the costs of the selective membrane and also make the units much more compact and should thus be explored [88].

2.1.4 Comparison of Advanced Cycles

A brief comparison of the benefits and potential of the cycles discussed above is carried out in this section. According to the discussion in Sects. 2.1.1, 2.1.2 and 2.1.3, simple humidified cycles, without the complexities of the bottoming cycle, are seen to cost less than other system modifications; however, the least benefits are observed for these when coupled with CCS systems [16, 45]. This is because they offer lower levels of electrical efficiency than any of the other gas-fired power plant configurations with CO_2 capture (around 9 net percentage points lower than NGCCs using MEA scrubbing), and thus, these seem a less attractive option for gas-CCS applications [16]. NGCC power plants incorporating supplementary firing and amine scrubbing for CO_2 capture can achieve higher concentrations of CO_2 in the flue gas than EGR configurations, depending on the maximum combustion temperature allowed, but their electrical efficiency is lower [16]. The use of NGCCs with EGR and amine capture systems generally shows the greatest electrical efficiency when compared to supplementary firing, humidified gas-fired plants [16] and conventional NGCC schemes with amine scrubbing [18, 75]. The economics of the EGR option in NGCCs with an amine capture plant is also better compared to conventional NGCC+amine systems, in terms of CAPEX, cost of electricity and CO_2 avoided [18, 75]. However, careful design of the exhaust recycle control system is required to avoid affecting the turbine performance (back-pressure) [18]. Moreover, the impacts of EGR on turbomachinery when targeting moderate EGR ratios appear to be fairly manageable [16, 76]. Finally, S-EGR options have the potential to significantly increase the CO_2 content in the flue gas, and they could be competitive against conventional NGCC+MEA plants [88–90, 92]. The performance and economics of these systems are very sensitive to the assumptions considered though [89], and the effects of the CO_2-rich working fluid on the turbomachinery should be considered [92]. S-EGR systems are under study and further benefits against EGR are still under discussion [89, 90].

2.2 *Oxy-Turbine Cycles*

Oxy-combustion gas turbines burn the fuel using an oxygen-rich flow instead of air in the combustion chamber, thus leading to a flue gas that contains nearly pure CO_2

after H_2O condensation (see Sect. 1.1). The oxygen used as oxidizer is usually supplied by an air separation unit (ASU), which delivers a high-purity O_2 stream after separation from air. Combustion in oxy-fired systems takes place at close to stoichiometric conditions to minimize the costs and energy penalty associated with the ASU, as well as the requirements for subsequent purification of the CO_2-rich stream prior to storage or use (EOR). Under these conditions, extremely high temperatures can be achieved in the combustor, and therefore, these systems usually employ recycled CO_2 or water in order to control combustion temperatures. As a result, oxy-fired gas turbine cycles are often classified as CO_2- or water-based cycles. These differ depending on the main component in the working fluid, i.e. CO_2 (semi-closed oxy-combustion combined cycle (SCOC-CC), MATIANT cycle and NET Power/Allam cycle) or H_2O (CES and Graz cycles) [93, 94]. In addition to these configurations (which make use of an ASU), alternative cycles have been proposed incorporating O_2 separation from air by means of high-temperature membranes (AZEP and ZEITMOP cycles). Chemical looping combustion of gaseous fuels has also been proposed, where oxygen from air is transferred to oxidize the fuel using an oxygen carrier. However, substantial development of these systems is required to achieve efficiencies competitive with NGCCs, requiring the use of pressurized fluidized beds and high temperatures [5, 95, 96].

A summary of the main oxy-cycles investigated so far is shown in Table 1, which has been recently published by the International Energy Agency [93]. This presents the cycle efficiency (used as a performance indicator), together with the degree of development of key components for each cycle, which allows the classification of the systems on the basis of their current potential [93].

As can be seen in Table 1, the most promising cycles are the semi-closed oxy-combustion combined cycle, the NET Power/Allam cycle, as well as the Graz and CES water-based cycles [93, 94]. Therefore, these will be described in Sects. 2.2.1, 2.1.2, 2.1.3 and 2.2.4.

Table 1 Summary of the main oxy-fired gas turbine cycles (adapted from [93])

Cycle	Efficiency (%)	Efficiency score	Development index penalty	Total cycle score
SCOC-CC	45–49[a]	7	1	6
MATIANT	40–49	7	4	3
E-MATIANT	46–47	7	2	5
NET Power/Allam cycle	55–59	10	4	6
CES	45–50	8	2	6
Graz	49–54	9	2	7
AZEP	49–53	9	6	3
ZEITMOP	46–51	8	9	−1

[a]Maximum value according to [94]

2.2.1 Semi-closed Oxy-Combustion Combined Cycle

The semi-closed oxy-combustion combined cycle is represented in Fig. 6. In this system, a recycle stream that contains mainly CO_2 is compressed and sent to the combustion chamber, where natural gas is combusted using oxygen from an ASU. The resulting flue gas at elevated temperature and pressure is expanded in the gas turbine to generate electricity. The hot gases leaving the turbine are subsequently fed to the HRSG, thus recovering heat in a steam cycle to generate additional electricity. Water is then knocked out from the flue gas stream that exits the HRSG—composed of CO_2 and H_2O mainly—after cooling, leading to a highly CO_2-concentrated flow. Most of this stream will be recycled back to the compressor to initiate a new cycle, whereas the remaining fraction is taken to the compression and purification unit before finally being stored or used (i.e. EOR) [15, 73, 93, 94].

The configuration of the SCOC-CC cycle of Fig. 6 is similar to that of air-combustion NGCCs, but using a CO_2-rich stream as the working fluid in the gas turbine. No major design changes are expected in the HRSG with respect to conventional combined cycles, whereas the gas turbine section (compressor, combustor and turbine) requires some modifications to accommodate the new characteristics of the working fluid [93, 94]. This is the case of the lower specific heat ratio of CO_2 compared to air, which requires SCOC-CC systems to operate with higher pressure ratios of around 30–40 (for a turbine inlet temperature of 1300–1400 °C) to achieve optimum cycle efficiencies in the range of 45–49%, as shown in Table 1 [93, 94]. Considerations related to cooling of the turbine blades and the optimum temperature of the recycled CO_2-rich stream are also important when designing SCOC-CC systems [93, 94].

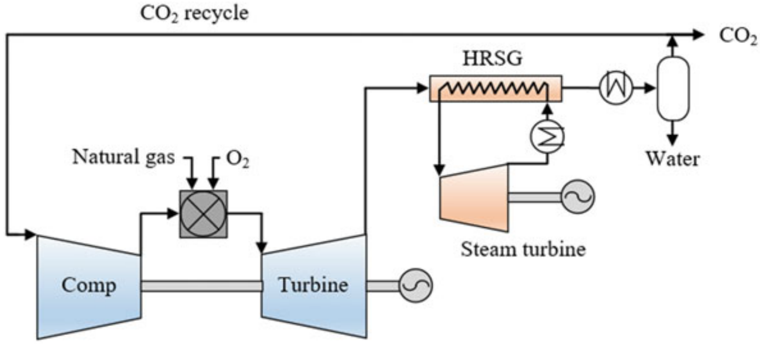


Fig. 6 Schematic representation of the semi-closed oxy-combustion combined cycle

2.2.2 NET Power/Allam Cycle

The NET power cycle, also named the Allam cycle, is represented in Fig. 7. It characterizes by using supercritical CO_2 as the working fluid in a semi-closed, recuperated Brayton cycle that employs a single gas turbine operating at high pressure (inlet pressure ~300 bar) and low pressure ratio (~10) [97, 98]. The turbine is driven by the CO_2-rich flue gas generated in the high-pressure combustor, where natural gas is burnt under oxy-firing conditions at close to 1100–1200 °C [98]. After expanding in the turbine, the flue gas enters an economizer heat exchanger where heat is recovered and transferred to the recycled high-pressure CO_2 stream before it enters the combustor. The low-temperature flue gas that exits the economizer is further cooled to near ambient conditions, and water is separated and taken out of the cycle. The resulting CO_2-rich stream is then initially compressed in an intercooled compressor, followed by subsequent cooling and pumping steps (up to ~300 bar). A fraction of this flow exits the system (at ~100 bar) [97]. The remaining CO_2 is heated in the economizer up to 700–750 °C prior to entering the combustor.

The main benefit of the Allam cycle is the very high efficiencies that can be achieved, which are between 55 and 59% (see Table 1) with nearly zero CO_2 emissions. Additional advantages include compact designs and reduced footprint, as well as predicted competitive costs with respect to other capture options [97, 98]. There are, however, a number of challenges related to the operating conditions in the cycle. This is the case of the turbine design, which has characteristics of both steam and gas turbines due to its high pressure and temperature of operation. The combustor also requires a novel design due to the high pressures and the working

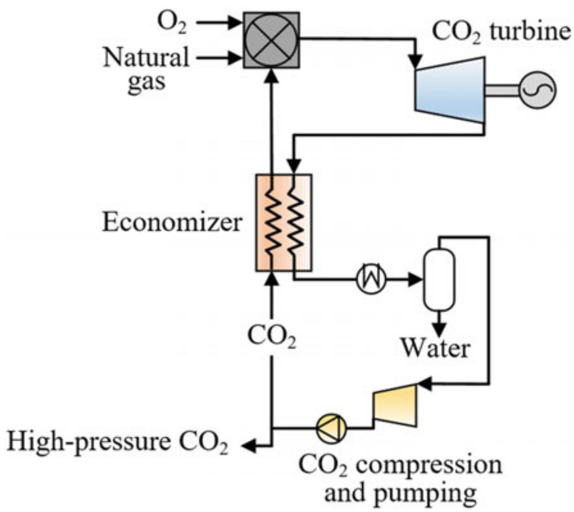


Fig. 7 Representation of the Allam cycle

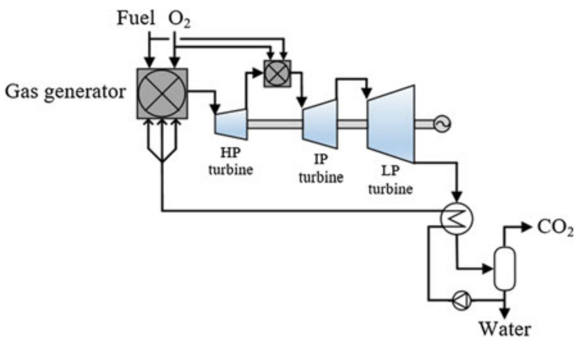
fluid employed, and it has been recently tested at reduced scale during a limited time of operation [99]. Moreover, the economizer heat exchanger is a key part of the cycle that requires development and careful design, as it needs to cope with large flows of CO_2 and substantially different pressures and temperatures [93, 94, 97, 98]. Nevertheless, rapid progress is being made in all these areas [97], and a 50 MW_{th} demonstration plant is being built in La Porte, Texas, to continue these investigations. This plant will test the performance of the key components mentioned above and the process itself, thus allowing valuable operational experience to be gained and providing essential information for the development of the technology [97].

2.2.3 CES Cycle

The CES cycle uses steam as the main working fluid, as depicted in Fig. 8 following the configuration presented by Anderson et al. [100]. In this scheme, natural gas is combusted using oxygen from an ASU in the gas generator, which operates at 50–100 bar. Liquid water is injected and evaporated in the combustor to control temperature, leading to a flue gas with around 90% steam content. This flue gas is expanded in a high-pressure turbine that operates with a pressure ratio of ~5, and it is further reheated in a second oxy-fired gas combustor. The temperatures considered for the reheating stage are between 760 and 1760 °C, depending on the development stage of the subsequent intermediate-pressure turbine (first, second and third generation turbines have been anticipated) [101]. After final expansion in a low-pressure turbine, the flue gas is sent to a vacuum condenser. A CO_2-rich stream is then recovered for storage/use (i.e. EOR) purposes, and water is pumped, preheated (using heat from the flue gas that leaves the low-pressure turbine) and sent back to the gas generator.

The efficiency of the CES cycle is highly dependent on the temperature at the inlet of the intermediate-pressure turbine, with values close to 50% for the more advanced designs [93, 94]. Therefore, a major technical challenge is the design of the intermediate-pressure turbine capable of working under very high inlet

Fig. 8 Representation of the CES cycle



temperatures with a steam-rich flow [102]. Less challenging is the design of the high- and low-pressure turbines due to the much more limited temperatures of operation [93, 94, 101, 102]. Tests have been performed at the 20 and 200 MW_{th} scale to reduce the uncertainties associated with the gas generator equipment [103].

2.2.4 Graz Cycle

The S-Graz cycle, a high-efficiency modification of the Graz cycle that uses a steam-rich working fluid, is represented in Fig. 9. In this system, natural gas is burnt at ~40 bar in an oxy-fired combustor that uses two streams with high steam concentrations to moderate temperature [104, 105]. The flue gas leaving the combustor is expanded in a high-temperature turbine to atmospheric pressure and passed through a HRSG. A fraction of the cooled gas is expanded in a low-pressure turbine to vacuum conditions and sent to a condenser, where CO_2 is separated from steam and is then further compressed and subsequently stored. The condensed water is then pumped and taken to the HRSG, thus recovering heat from the flue gas exiting the high-temperature turbine and generating steam at high pressure and temperature (~180 bar and 550 °C) [93]. This stream is then expanded in a high-pressure turbine to ~40 bar and enters the combustor to control temperature (a fraction is also used to cool the high-temperature turbine). The remaining fraction of the flue gas exiting the HRSG is also used to limit temperatures in the combustor after passing through an intercooled compressor [104, 105]. This configuration has been further improved in the modified S-Graz cycle, where condensation takes place at higher pressure [104].

The Graz cycle can achieve efficiencies up to 54% (see Table 1), using a combustor that operates at 40–50 bar and 1400–1500 °C [93, 94, 105, 106]. The main limitation of this cycle is the need for a new design suitable for the high-temperature turbine, capable of withstanding corrosion and operating at very high temperatures similar to steam turbines and moderate pressures close to gas turbines [93, 94].

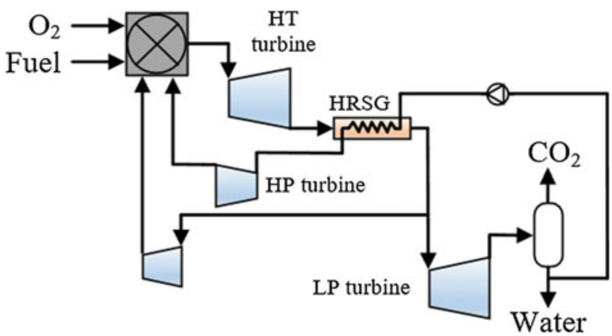


Fig. 9 Representation of the S-Graz cycle

3 Scaling-up: Deployment at a Commercial Scale and the Challenges of Decarbonization

The challenges of decarbonization via gas-CCS at a commercial level are not just technical and policy based but also financial—which are all interconnected and heavily dependent on each other. As the technologies develop, are scaled up and become more commercially viable, the economic aspects should also become more favourable, and therefore, extensive policy support will be required to bring them from the brink of commercialization to actual full-scale deployment. All these aspects need to be addressed in order to derisk the market and allow gas-CCS to be deployed, whether these are integrated into new builds or retrofitted into existing infrastructure. Much of the policy and financial aspects considered herein apply to the CCS industry as a whole and are not necessarily specific issues to deploying just gas-based power with carbon capture. These various barriers are therefore examined in the wider context of CCS, as well as for gas-CCS specifically.

One of the key challenges that covers all of these aspects—technical, political and financial—is the potentially disruptive nature of CCS technologies to the power and industry sectors [107]. To implement carbon capture is not an easy task, neither for new-built plant nor considering retrofits. Developing these to higher levels of technology maturity and commercial readiness and producing the supporting regulatory and policy frameworks to surround this will go a long way to convincing companies that not only is the technology sound, but is also vital.

3.1 Technical Aspects

Technology developments are needed to ensure that the optimized options and configurations of gas-CCS plants are ready to be utilized reliably at the large-scale, centralized facilities. Furthermore, knowledge transfer from demonstration projects and their vast operational experience will go a long way to contribute to the commercial-scale deployment of these technologies. The technical challenges for different NGCC options have been highlighted throughout the previous sections. Advances in the key areas will alleviate some of the issues currently seen with demonstrating these technologies and scaling them up for deployment at a commercial scale. This includes material advancements and developments for many configurations, including humidification, EGR and S-EGR, as well as the selective membranes that are often used with the latter. Comparative studies of the different options considered in Sect. 2.1 have shown that whilst all these pursue improvements in the overall electrical efficiency of the power plant with CCS, not all of these options would necessarily be suitable for up-scaling—although the reasons for these are not always technical. NGCC systems incorporating humidification and CCS, for example, have been shown not to be competitive against other options in terms of electrical efficiency (see Sect. 2.1). However, they may be better suited to other applications at a smaller scale where NGCCs are not an option [51, 53, 108], providing a CCS hub and cluster approach is followed. This leaves the other configurations—EGR/S-EGR and supplementary firing—to be considered for implementation in full-scale commercial plants with CCS. In fact, supplementary firing is already used at such scales, and thus, other considerations are needed to evaluate in detail its compatibility with CCS, related to the reduction in process efficiency, as discussed in Sect. 2.1.1. The limited data availability, however, for some of these options, especially S-EGR for enhanced carbon capture, at both pilot or larger scales, means that at present it is difficult to consider which may be preferable in terms of scaling-up and developing to a commercial level of deployment. Consequently, these require much research into all aspects of the technology to advance their progress from pilot-scale testing through to full-scale demonstrations.

Moreover, the progress in the development and understanding of the different capture technologies itself is a key. The technology readiness levels of these vary widely, from those more mature (e.g. post-combustion amine scrubbing) to others that only exist as a concept or at very small scales. It is important to continue the optimization of the more mature technologies, but equally essential is the development of second and third generation technologies. This could potentially improve the energy penalties, costs and environmental aspects of the mature systems, and find different application niches. Nevertheless, up-scaling any technology is fairly challenging and scaling factors are vast. Scaling-up from laboratory to pilot scale often involves factors of 10 or more, and when pilot to full, commercial-scale systems are considered, these factors can be in the order of thousands to tens of thousands [109]. Whilst the risks are high when it comes to dramatically increasing the size of the technology process, these up-scaling risks can be notably reduced through comprehensive process designing and extensive modelling, which all need to be reinforced by in-depth laboratory and pilot-scale experiments, in particular for the most key controlling parameters. This is true for both the operation of individual system components and the complete integrated plant [109]. Moreover, optimization and process intensification will need to be tailored specifically for individual deployments, with a view for flexible operation.

3.2 Policy Challenges

Technical developments in this area are required to inform policy and regulation on natural gas utilization and CCS applications in the future, especially where these are integrated into gas-CCS systems. Strong policy drivers and regulatory framework development are much needed to create a favourable CCS market and facilitate its deployment in all forms, across power and industry, not just with natural gas [110]. There appears to be a ‘chicken and egg’ situation in this regard though—with full-chain demonstration projects at scale being required to gain policy acceptance for CCS [111], whilst full policy support being needed to diminish the risks and get to large-scale projects in the first place. Which will come first? There is need for risk minimization, and thus, policies where governments can underpin investment will be of great benefit to getting 'first of a kind' projects of the ground. Whilst this is already happening for coal, mainly on the North American continent (such as at Petra Nova [112] and Boundary Dam [11], considered in Sect. 1.2), there has been considerably less interest in natural gas. Often the technologies cannot be used directly, and other sectors and disciplines further afield may have to be looked to, in order to gain the knowledge and experience required to develop the relevant integrated system infrastructure. In the UK, for example, the 'buy, not build' mentality means that it is not developing its own technologies specifically for the UK market, as the requisite policy framework is currently still not in place. Furthermore, it is a necessity for the relevant policies to be stable and developed over time with the technologies as their deployment progresses—only this can build the long-term confidence required for this industry. An established and secure policy environment, among other factors, is essential to ensure the future of the emerging CCS sector.

Other gas emissions than CO_2 have been successfully minimized due to extensive legislation being passed to limit their release. Technologies were developed and then deployed on all qualifying plants to ensure environmental safeguarding and regulatory bodies were formed to monitor this. As more technology was developed and deployed, the costs were reduced (learning curve)—many similar stories can be found for technologies in all industry sectors. Dealing with CO_2 emissions, however, is especially challenging and costly (not only at a capture level, but also for the transportation and storage stages). Therefore, the progress from feasibility studies and laboratory-/pilot-scale demonstrations of the basic principles for proof of concept to full-scale, full-chain commercial CCS operation is taking a significant period of time—highlighting the complexities of the technologies and the surrounding issues.

Industries are needed, and expected, to take the knowledge and technical developments to the next stage, by providing business-level and business-led development. However, if the necessary incentives, directives and regulations are not in place, this will be increasingly difficult to achieve. The inconsistent and conflicting messages coming from government in this respect, with regard to the policy disconnect, are making this increasingly difficult. This is most notably in the UK with the cancellation of yet another CCS demonstration competition [113]. It is not just the *policy*, but also the *politics* that play a role here—recognizing that climate change mitigation is vital and that CCS options can have an important contribution is one thing, but actually developing the political willingness to invest and form pertinent policy support and specific regulations is another, and not yet forthcoming [114]. The UK, however, is not the only country to abandon or postpone projects, with many examples across the rest of Europe and North America particularly, where once-promising projects have been cancelled or remain dormant [115]. In Europe, an effective policy structure to encourage the commercialization of CCS still remains elusive after years of stagnation in the industry [116]. CO_2 emissions do not have borders, and therefore, the policy framework cannot either—connectivity here between the national and international is imperative.

Policy instruments need to be clear in their aims and objectives, and be broad enough to comprehensively regulate all aspects of CCS. This will need to look at not only the technologies and financial aspects, but also strategic procedures for permitting, liability and monitoring activities by the relevant competent authority [110]. The temporal issues with consistently postponing the decision-making on CCS—or 'kicking the can down the road' as Karimi [117] terms it—are just delaying the inevitable, whatever that might be.

A greater awareness and general public support should also be gained through continued dissemination, and therefore, also hopefully public (and private!) investment and acceptance could be attained [114]. CCS remains largely unknown in the public domain, and consequently, effective communication, engagement and outreach are essential to demonstrate to the general population that CCS is a needed and safe technology—especially in geographical areas that may be directly impacted by its implementation and where extensive phased consultations will likely be compulsory [111, 118].

Even though public acceptability is something that may not be considered as an essential requirement for CCS advancement and deployment, corporate perception is something that cannot be ignored. Braunreiter and Bennett [107] and Karimi [117] report that there is a lack of interest among key stakeholders as fossil fuel companies have not shown a great deal of interest in CCS. They are the most likely 'consumers' of the technology though, and as something that will inform and thus directly influence their decision-making on CCS investment, their views need to be taken into account. Business models and strategies in this area will need to be developed with input from the relevant policy-making bodies. Kapetaki and Scowcroft [119] assessed the risks and enablers for CCS demonstration project business models. Whilst the financial implications are by far the most dominant factor, a range of other aspects play a key role and are often impacted by the overall economics. They suggest that the efficiency of permitting processes, protracted stakeholder engagement and clarity of regulatory frameworks, considered in detail further along in this section, are all needed to deliver a successful project [119]. Worldwide government engagement with academia and industry for knowledge sharing is hence vital. And this appears to be one of the best ways to engage, along with taking advantage of previous 'lessons learned' from other projects, nationally and internationally [120].

3.3 Financial Issues

The financial implications of integrating CCS into natural gas power plants and also the wider context can only lessen over time if the above issues are addressed. The technical challenges need to be overcome (and are currently being extensively researched), and policy is certainly required for it to become more favourable for investment to enable the widespread deployment of such technologies. However, it would seem that costs (or perceived costs) are the primary driver of both development and deployment, and therefore, to get this fledging industry off the ground, funding and other incentives (both financial and non-financial) may be needed [116]. Coordination is required between different financing schemes, particularly those operating on different regional, national and international levels—greater connectivity and complementarity are essential to incentivize interest and thus investment [110]. It is to be expected that subsidies will be needed for many if not all of the early CCS plants [121].

Further to this, the deployment of post-combustion CCS and other capture systems is required to demonstrate the technologies, and this will also lead to notably reductions in overall costs, as the majority of the derisking processes will have already been undertaken for an 'n^{th} of a kind' plant. Cost reductions here arise through analysing the real-world experience of planning and building an actual project and then using it to identify the potential improvements and key cost saving opportunities [111]. Economies of scale will also be imperative to minimize implementation costs over time, especially when it comes to geological storage of CO_2.

Temporal aspects of both projects and policies have a part in defining the way forward [117]. Though renewables (including wind, geothermal, solar, biomass and waste) are experiencing continued rapid growth rates [122], the delays, postponements and cancellations in developing and deploying CCS mean that there is a much reduced prospect of achieving our 2050 greenhouse gas emissions reductions.

In the UK, reports such as that of the Parliamentary Advisory Group on CCS [113] have stated that although the use of carbon capture technologies is vital to ensure the lowest cost of decarbonization, a system of economic regulation is still needed. This means that in addition to the regulatory framework considered above, an economic framework is also required to aid deployment. These need to be in place as soon as possible to enable CCS technologies to be used in the near future. Most decarbonization scenarios for the UK do not have unabated gas power still on the grid in the future (by 2050), and thus, any new builds will need to have CCS integrated at this stage, or at least be capture-ready when they are built [113]. Without this, they are susceptible to becoming stranded assets with a limited life, especially if/when carbon pricing comes into force and emission limits are more severe. Moreover here, investment in new gas power is inherently risky at this point with the deficiencies in current CCS and climate policy [113]. This is making it increasingly difficult to form and maintain a dedicated CCS industry. The cost of the overall system is as much dependent on the gas price as it is for the CCS technology [123]. Carbon pricing will also have significant impacts of all aspects of CCS deployment, and this CO_2 tax could be used to incentivize investment on the technologies [110], especially for natural gas with its lower inherent carbon intensity than coal.

3.4 Additional Considerations

In the broader context, gas-CCS should more likely be deployed where domestic natural gas resources are used. This protects investments, allowing the continued use of the resources to generate power whilst still addressing the energy trilemma issues [114]. However, it is the Middle East, Europe and Eurasia which account for almost 75% of proven reserves [122], and although there are some gas-CCS projects in these areas, they are not yet at the scale they are required to be [115]. Demands for natural gas in the global primary energy consumption remain high and are increasing, whilst the use of oil and coal is declining and is predicted to continue to do so [122]. Overall, it can be seen that many of the technical, political and financial issues of implementing carbon capture are not just specific to gas. Developing a transport and storage infrastructure that is fully integrated with all sources of CO_2 will invariably do much to enable the deployment of CCS technologies with natural gas, as it will for coal and industrial CO_2 capture. Moreover, derisking investments, specifically the areas that others do not want to, needs to be considered strategically by governments to ensure their climate targets are met.

Billson and Pourkashanian [116] outline the three main issues that have arisen in Europe in particular and have resulted in the current situation for CCS deployment in general. This essentially summarizes much of the previous discussion. These are: (i) poor engagement and communication of the key message to the relevant stakeholders; (ii) a market that compels industry to depend on government funding and subsidies, which results in considerable vulnerabilities to political forces, as seen with the UK commercialization programme; and (iii) governments not willing to help in financing the initial CCS projects, which does nothing to bolster industrial support [116].

It is only by addressing all of the various challenges—the technological, policy and financial issues considered above—that we can get to a point where the deployment of these technologies on a large scale is both feasible and favourable. Focusing on just one of these will not be sufficient. Whilst many aspects of these systems have been demonstrated, often at scale, integrating these different components to form a full-chain gas-CCS system will be the only way to start to derisk investment. Combining carbon capture with fossil fuel-based energy can realize a number of benefits in decarbonizing the power sector, which will clearly be needed to meet the climate change targets for emissions limits. Much research is still evidently required here though to make this a reality and for gas-CCS to 'catch-up' with the developments in capture from coal.

4 Conclusions

With global energy demand increasing and the power sector needing to be rapidly decarbonized, disruptive technologies, such as carbon capture, will be required. This can enable energy to be produced within the confines of the energy trilemma—of being sustainable, secure and affordable. This is the case of power generation using natural gas as a fuel, which although significantly less carbon intense that coal still necessitates profound emission cuts. Considerable efforts have been seen for coal-CCS, and substantial knowledge and experience have been and are still being gained in this sector. Nevertheless, these CCS technologies will need to be adapted and optimized to be used with gas-fired plants.

Post-combustion systems for CO_2 capture are at present the most developed and advanced, with several operational plants online. However, separating the CO_2 from the flue gas of a NGCC is difficult and costly without further adaptations. High excess air ratios used in gas-fired systems result in large flows of flue gas with low CO_2 and high O_2 levels that can negatively affect downstream capture performance. A range of options have been proposed to enhance the CO_2 content generated by gas-fired systems to ensure high capture efficiencies are achieved with potentially reduced energy penalties and cost—supplementary firing, humidified turbine cycles, EGR and S-EGR have been discussed in this chapter.

Promising oxy-combustion gas turbine systems are also being researched, still requiring significant developments. These include SCOC-CC, NET Power/Allam, CES and Graz cycles, amongst others. It is the NET Power/Allam cycle which at present results in the highest achievable efficiencies, using supercritical CO_2 as the working fluid. Although the compact designs and reduced plant footprint are favourable, the challenges related to the extreme operating conditions need addressing and further technology development is required—ongoing at present.

Particularly important for gas-fired power plants is the need to be flexible in order to balance a grid with increasing proportions of intermittent renewables. Therefore, any gas-CCS option will also need to be flexible by definition. At a more general level, the technical barriers to the large-scale implementation of CCS require knowledge transfer between the existing infrastructure to enable the scale-up, demonstration and commercial roll-out of these options. The lessons learned from these are needed to support and be supported by the regulatory framework to deliver the strong policy drivers and the consequent favourable CCS market that are required by industry. Risk minimization through the underpinning of investments will certainly be essential to getting 'first of a kind' projects of the ground. Greater engagement with key industry stakeholders, and to a lesser extent, also the public, will also go a long way to facilitating the wider-scale utilization of CCS on a scale to help in mitigating climate change. However, to achieve this, conflicting and inconsistent government messages need to be prevented, to allow projects to develop, rather than be abandoned, postponed or cancelled altogether. The financial challenges can only lessen over time if the technology and policy issues are overcome. Investment needs to be incentivized, but this must be coordinated on regional, national and international levels. Other factors, as well as the technology and commercial readiness levels, effect the costs; these are also impacted by economies of scale, carbon pricing/tax, '1st of a kind' versus 'n^{th} of a kind' plants and a system of economic regulation, which is invariably is still needed. This is a prerequisite for a dedicated CCS industry to mature and become sustainable.

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