

CO₂ CAPTURE AND SEQUESTRATION OPTIONS—IMPACT ON TURBOMACHINERY DESIGN

Originally Issued: June 2008

Updated: December 2008

Abstract—In today's climate of uncertainty about carbon dioxide (CO₂) emissions legislation, owners and power plant planners are evaluating the possibility of accommodating "add-on" carbon capture and sequestration (CCS) solutions in their current plant designs. The variety of CCS technologies under development makes the task very challenging. This paper discusses the more mature post-combustion CCS technologies, such as chemical absorption, and the associated equipment requirements in terms of layout, integration into the generating plant, and auxiliary power consumption. It also addresses supercritical coal-fired as well as combined cycle plants; evaluates plant configuration details and various operational scenarios; and discusses the issues related to balance-of-plant systems, including water treatment, availability, and redundancy criteria. The paper then presents several options for pre-combustion processes such as oxy-fuel combustion and integrated gasification combined cycle (IGCC) water-shift carbon monoxide (CO) conversion to CO₂. The impacts of several processes that only partially capture carbon are also evaluated from an engineering, procurement, and construction (EPC) contractor's perspective as plant designer and integrator. Finally, the paper presents several examples of studies in development by Bechtel in which a neutral but proactive technical approach was applied to achieve the best and most cost-effective solution.

Keywords—chemical looping, CO₂ capture, gas turbine, Graz cycle, oxy-fuel combustion, steam turbine, turbomachinery

INTRODUCTION

CO₂ Capture Options

In the past few years, the major thrust to lower greenhouse gases (GHG) emitted into the atmosphere has been directed toward increasing the thermal efficiency of plant equipment, in particular the turbomachinery. The other option for lowering GHG emissions is to capture the CO₂, a process associated with significant thermal efficiency losses. In the power generation industry, the most common CO₂ capture technologies fall under these categories:

- Post-combustion capture of CO₂ from the plant exhaust flue gases using chemical absorption.
- Capture of CO₂ before the combustion process. In this arrangement, the fuel is synthesis gas (syngas) containing mostly hydrogen and CO. The CO is converted to CO₂ in a water-shift reactor; then, the CO₂ is removed by physical absorbent and hydrogen (H₂) is used as fuel in the gas turbine.

- CO₂ capture from a number of different processes such as oxy-fuel combustion and chemical looping.

These technologies all have relatively low efficiency and high cost. Other than the post-combustion amine-based processes, all are in various stages of concept validation or small-scale demonstration. [1] The available CO₂ capture options are summarized in **Figure 1**.

Meaning of CO₂ Capture Ready

CO₂ capture and sequestration (CCS) from power generation sources will eventually be required in one form or another. Today the timing and the extent of regulations governing the process are only speculative. So far, none of the existing technologies has emerged as the dominant solution, and many new and innovative alternatives are in various stages of research, development, or testing. For plants in the planning or design stage, owners; engineering, procurement, and construction (EPC) contractors; and equipment suppliers are trying to determine which features need to be applied today for future CCS implementation.

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The “CO₂ capture ready” plant concept presents technical and commercial challenges.

ABBREVIATIONS, ACRONYMS, AND TERMS

AC	amine cooler	GT _{syn}	gas turbine burning syngas
AGR	acid gas removal	HHV	higher heating value
AQCS	air quality control systems	HP	high pressure
ASU	air separation unit	HPT	HP turbine
AZEP	advanced zero emission plant	HRSG	heat recovery steam generator
B&W	The Babcock & Wilcox Company	HTT	high-temperature turbine
CAR	ceramic auto-thermal recovery	HX	heat exchanger
CC	combined cycle	ICFB	internally CFB
CCS	carbon capture and sequestration	ID	induced draft
CEDF	Clean Environmental Development Facility	IP	intermediate pressure
CFB	circulating fluidized bed	IGCC	integrated gasification CC
CFD	computational fluid dynamics	ITM	ion transport membrane
CLC	chemical looping combustion	LP	low pressure
DOE	US Department of Energy	LPST	LP steam turbine
ENCAP	enhanced capture CO ₂ program	MEA	monoethanolamine
EPC	engineering, procurement, and construction	MPT	measuring point for mass, pressure, and temperature
F _g	the force exerted by gravity	Mwe	megawatt electrical
FG	flue gas	OTM	oxygen transport membrane
FGD	FG desulfurization	PC	pulverized coal
FGR	FG recirculation	ppm	parts per million
GHG	greenhouse gases	SCOC-CC	semi-closed oxy-fuel combustion CC
GJ	gigajoule, an SI unit of energy equal to 10 ⁹ joules	STG	steam turbine generator
GT _{H₂}	gas turbine burning hydrogen	syngas	synthesis gas
		USC	ultra-supercritical

In this context, the term “CO₂ capture ready” requires careful consideration. Beyond the technical challenges, the commercial investment in the specific features aimed at future CCS must be justified. Selecting a specific CCS technology poses a significant risk because the technology could become obsolete and result in a stranded asset. At this juncture, a pragmatic approach requires evaluating all known factors in existing carbon capture technologies, considering the additional space for the carbon capture facility, and laying out the plant to incorporate and modify existing hardware at a later date. This paper addresses the impact various methods of carbon capture have on the turbomachinery and the gas and steam turbines, focusing mainly on “add-on” features that do not require substantially modifying existing equipment. Because carbon capture is an energy-intensive process, the discussion also covers the impact on plant performance of large steam extractions for CO₂ capture processes and

the use of electrical power for CO₂ compression. Cost estimates of various technologies are not included, however, due to the high volatility of labor, material, and equipment prices.

BRIEF REVIEW OF CO₂ CAPTURE TECHNOLOGIES

Post-Combustion

The post-combustion capture of CO₂ from flue gases can be done by various methods: distillation, membranes, adsorption, and physical and chemical absorption. Absorption in chemical solvents such as amines is a proven technology performed consistently and reliably in many applications. It is used in natural gas sweetening and hydrogen production. The reaction between CO₂ and amines currently offers the most cost-effective solution for directly obtaining high-purity CO₂. [2]

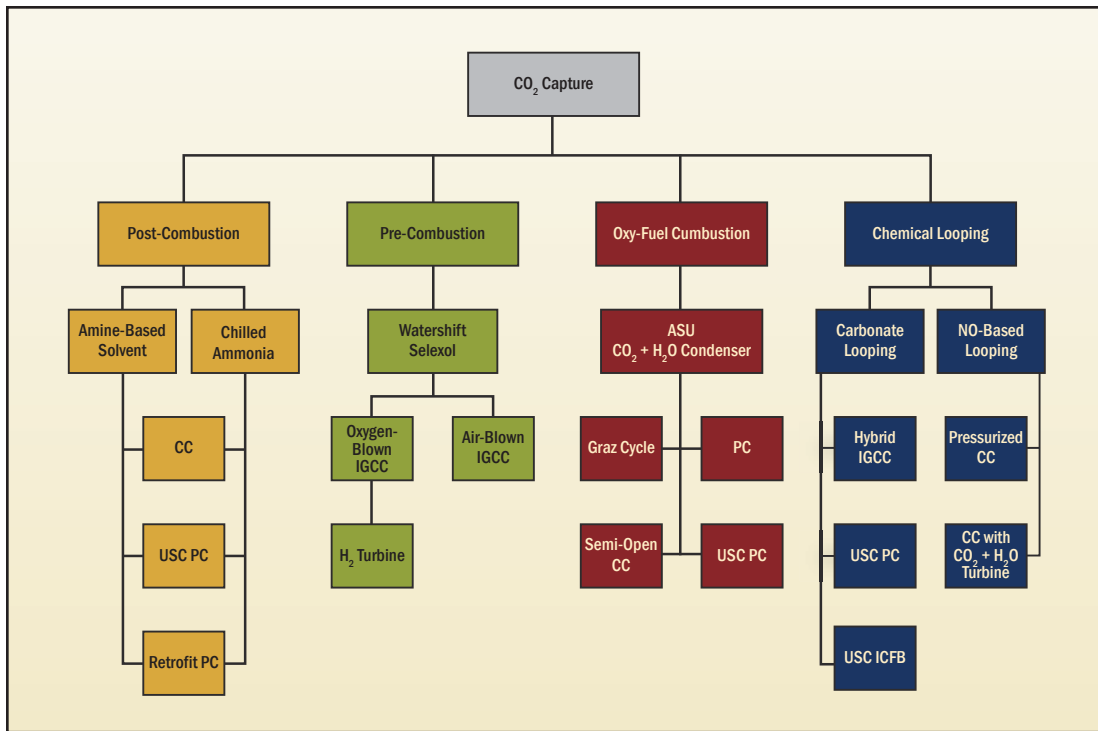


Figure 1. Available CO₂ Capture Options

In the post-combustion capture process, the flue gases from the power plant are cooled and treated to reduce particulates and sulfur oxide (SO_x) and nitrogen oxide (NO_x). Then, boosted by a fan to overcome pressure drops in the system, the flue gases pass through an absorber. A lean amine solution, typically monoethanolamine (MEA), counter-currently interacts with the flue gases to absorb the CO₂. The clean flue gases continue to the stack. The CO₂-rich amine solution is then pumped into a stripper (regenerator) to separate the amine from the CO₂. The energy to desorb the CO₂ from the solution is provided by steam. The CO₂-rich solution at the top of the stripper is condensed, and the CO₂ is sent for further drying and compression.

A schematic is given in Figure 2, and Table 1 summarizes the advantages and limitations of this process. Several commercial solvents are available. Fluor's Econamine FG(SM), using a 30% aqueous solution

of MEA solvent, is the most widely deployed process with more than 20 plants located in the United States, China, and India. Yet none of the plants capture CO₂ from coal-derived flue gas. KS-1 solvent produced by Mitsubishi Heavy Industries, Ltd., is in operation in four commercial-scale units capturing between 200 and 450 metric tons of CO₂ per day. The main effort in the development aims at lower heat of reaction, lower sensible heat duty, and lower heat of vaporization. Bechtel, in cooperation with HTC Purenergy, conducted an engineering study for a 420 MW gross power combined-cycle CCS system in Karsto, Norway, applying a proprietary solvent. See [3] for details on the solvent properties and regeneration process.

Post-Combustion Chilled Ammonia

Ammonia is the lowest form of amine. Like other amines it can absorb CO₂ at atmospheric

Table 1. Amine Scrubbing Advantages and Limitations

ADVANTAGES	LIMITATIONS
<ul style="list-style-type: none"> • Proven technology • Known chemical process • Ability to predict performance and solvent consumption 	<ul style="list-style-type: none"> • High energy consumption for solvent regeneration • High rate of process equipment corrosion • High solvent losses due to fast evaporation • High degradation in presence of oxygen

Amine scrubbing is a proven technology with known limitations.

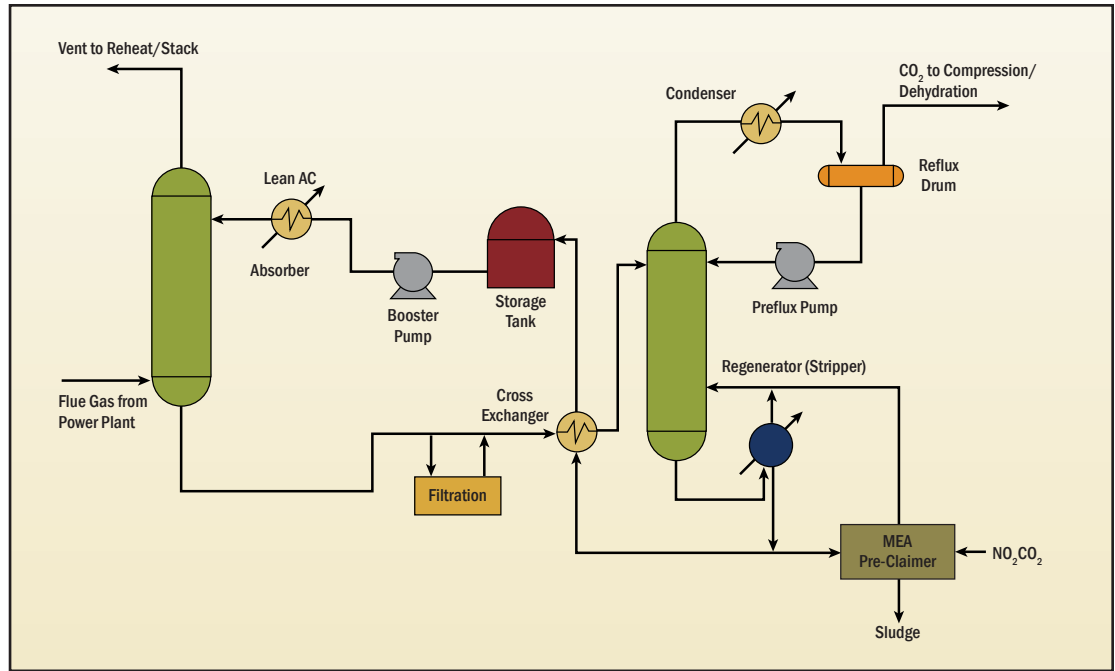


Figure 2. Post-Combustion Amine Process

pressure, but at a slower rate than that of MEA. The chilled ammonia system uses a CO₂ absorber similar to sulfur dioxide (SO₂) absorbers and is designed to operate with slurry.

The process requires the flue gas to be cooled before entering the cleanup system. The cooled flue gas flows upward, counter-current to a slurry containing a mix of dissolved and suspended ammonium carbonate (AC) and ammonium bicarbonate (ABC). More than 90% of the CO₂ from the flue gas is captured in the absorber. The CO₂-rich spent ammonia is regenerated under pressure to reduce the CO₂ liquefaction compression energy requirement. The remaining low concentration of ammonia in the clean flue gas is captured by cold-water wash and returned to the absorber. The clean flue gas, which now contains mainly nitrogen, excess oxygen, and a low concentration of CO₂, flows to the stack.

A schematic of this process is given in **Figure 3**, and **Table 2** summarizes the advantages and limitations of this process. Alstom owns the process rights. Several participants, including Alstom, have started tests on a sidestream pilot plant at the Pleasant Prairie Power Plant in Wisconsin. This pilot will be able to capture CO₂ emissions from a slipstream of less than 1% from one of the two boilers operating at the plant.

Additionally, a non-chilled ammonia scrubbing process is being planned by Powerspan Corp. for demonstration at FirstEnergy's Burger Power Station in Ohio.

CHEMICAL ELEMENTS

ABC	ammonium bicarbonate
AC	ammonium carbonate
Ar	argon
C	carbon
CaCO ₃	calcium carbonate
CaO	calcium oxide
CaS	calcium sulfide
CaSO ₄	calcium sulfate
CO	carbon monoxide
CO ₂	carbon dioxide
H ₂	hydrogen
H ₂ O	water
Hg	mercury
HX	hydrogen halide
Me	metal
MeO	metal oxide
N ₂	nitrogen gas
NG	natural gas
NH ₃	ammonia
NiO	nickel oxide
Ni	nickel
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxide
O ₂	oxygen
SO ₂	sulfur dioxide
SO _x	sulfur oxide

Table 2. Chilled Ammonia Advantages and Limitations

ADVANTAGES	LIMITATIONS
<ul style="list-style-type: none"> Compared to using amine, the regeneration energy is potentially lower. Applicable for new plants and for retrofit of existing coal-fired power plants. AC and ABC are stable over a wide range of temperatures. Solvent is oxygen and sulfur tolerant. The heat of the absorption reaction is lower. Potential to capture 90% of CO₂ emissions. 	<ul style="list-style-type: none"> Ammonia volatility can be an issue. Absorption rate is slower than that of MEA and requires as much as three times more packing to achieve same CO₂ removal performance. Several absorber vessels are required, increasing capital cost and affecting plant layout. Large-scale process experience is limited; experience should increase knowledge of feasibility.

*Chilled ammonia
is one
capture option.*

Pre-Combustion IGCC

The main advantage of IGCC pre-combustion CO₂ capture is that the amount of fluid to be processed is much smaller than for post-combustion capture at a coal-fired or combined cycle plant. For IGCC, only the syngas is treated, whereas for post combustion the entire exhaust flue gas flow must be processed. For oxygen-blown IGCC, the main syngas components are H₂ and CO, with some CO₂, steam, nitrogen gas (N₂), and traces of other elements.

The raw syngas produced by the gasifier must be cleaned of contaminants, including mercury, sulfur, and fluorides. The syngas chemical cleaning processes, acid gas removal (AGR)

such as Rectisol® or Selexol™, are able to remove a certain amount of CO₂. However, the actual conversion of the carbon monoxide (CO) into CO₂ and H₂ occurs in a water-shift process in which steam and syngas are mixed in the presence of a catalyst to convert the CO to CO₂ in an exothermic reaction. The shift stage can be integrated into the process either before (sour shift) or after (sweet shift) the sulfur removal stage. A CO₂ high-concentration capture (90%) will require two stages of shift in addition to the enhanced AGR. The fuel to be burned in the gas turbine is mainly H₂ with diluent. The amount of shift will determine the

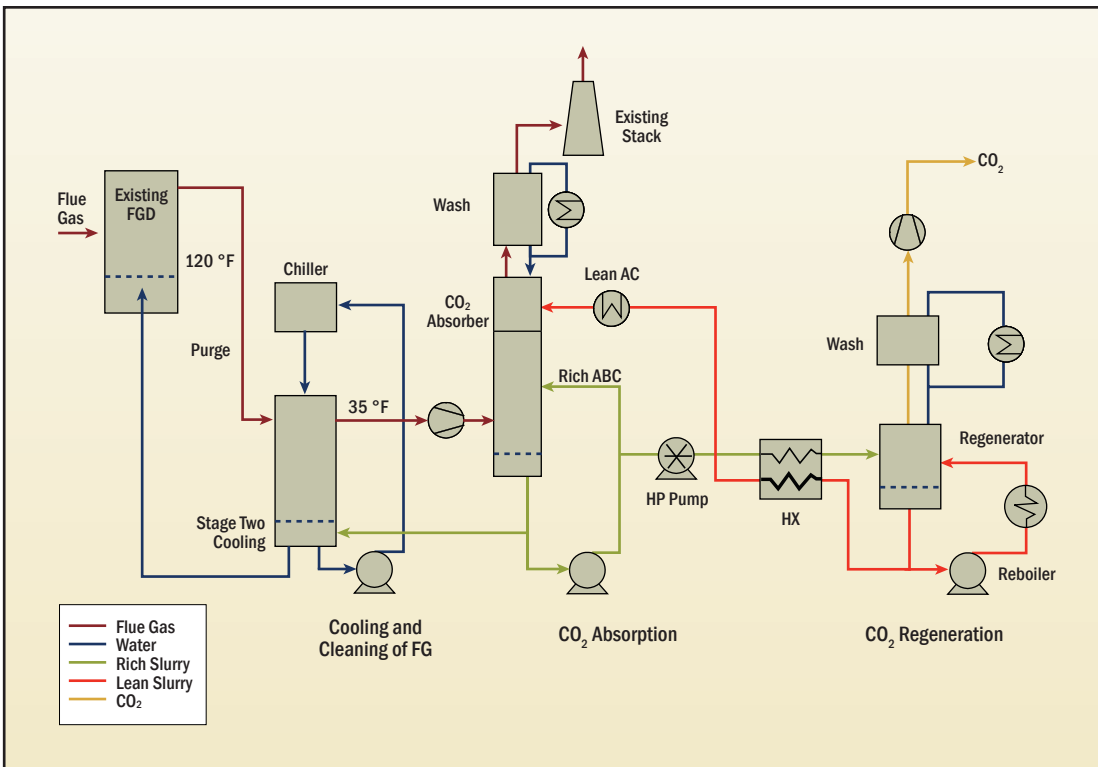


Figure 3. Chilled Ammonia Schematic [4]

concentration of H_2 , which could vary from 35% to 90%. A process schematic is shown in **Figure 4**.

Oxy-Fuel Combustion

In an oxy-fuel combustion-based power plant, oxygen rather than air is used to combust fuel, resulting in a highly pure CO_2 exhaust that can be captured at relatively low cost and sequestered. Often, the oxygen is mixed with flue gas to regulate burning, as well as to achieve a high CO_2 level in the flue gas. For the Rankine steam cycle, the volume of flue

gas leaving the boiler is considerably smaller than the conventional air-fired volume. The reasons for this difference are that N_2 in the air is not part of the flue gas and that the amount of flue gas is approximately 80% less for combustion with oxygen than with air. The flue gas consists primarily of CO_2 . The schematic is given in **Figure 5**, and **Table 3** summarizes the advantages and limitations of this process.

Theoretical and experimental research on this technology has intensified in the past 2 years. A 30 MWe oxy-fuel plant is under construction near Schwarze Pumpe, Germany,

Combustion using only oxygen results in highly pure CO_2 exhaust.

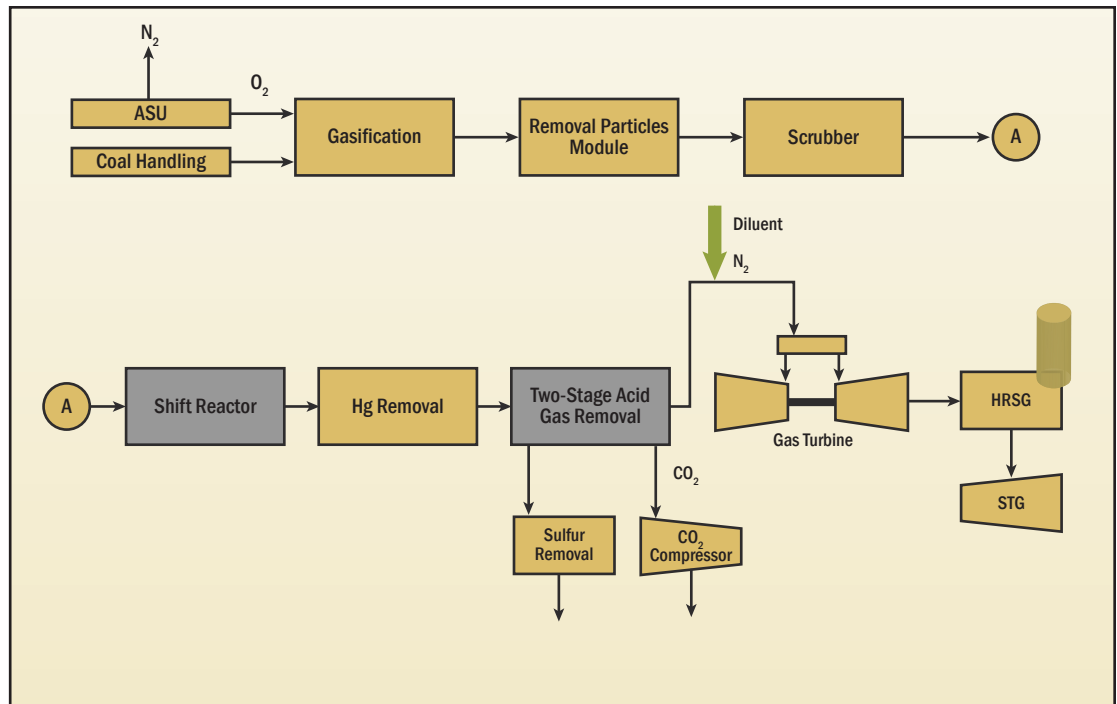


Figure 4. IGCC with Two-Stage Acid Gas Removal

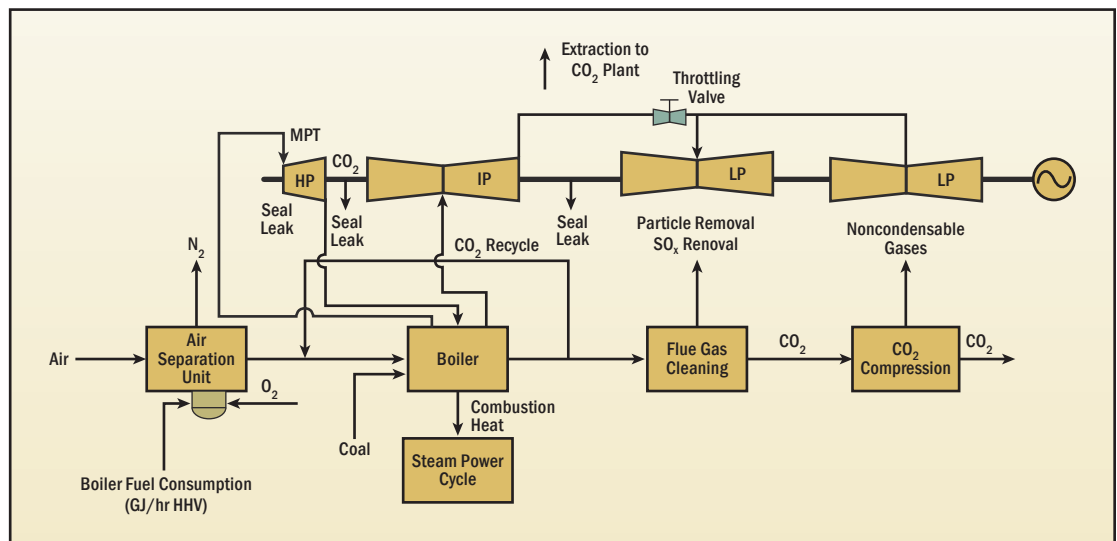


Figure 5. Oxy-Fuel Process Block Flow Diagram

Table 3. Oxy-Combustion Advantages and Limitations

ADVANTAGES	LIMITATIONS
<ul style="list-style-type: none"> • High concentration of CO₂ (80%) in flue gas may lower the cost of carbon capture. • Retrofit possibilities due to similar heat transfer rates; boiler can be used as oxygen or air blown. • 60% lower NO_x emissions, and lower mercury concentration in furnace backpass gas. • Amount of unburned Carbon (C) in ash reduced. • Char combustion rate increased. 	<ul style="list-style-type: none"> • Expensive ASU is typically a cryogenic air separation process with high energy demand (15%–20% of power output). • Due to air ingress, further cryogenic distillation is required after combustion to purify CO₂ in flue gas, which consumes additional energy. • Air infiltration into system is inevitable to a certain extent and is detrimental to process operation.

*Chemical looping
combustion
promises flue gas
free of N₂.*

to demonstrate the technology using an Alstom-supplied boiler. In the United States, the Babcock and Wilcox Company (B&W) and Air Liquide have converted B&W's 30 MW Clean Environment Development Facility (CEDF) in Alliance, Ohio, to an oxy-combustion system. IHI Corporation has a 1.2 MW pilot-scale testing facility in Japan.

The oxy-fuel combustion process uses an air separation unit (ASU), a device requiring high electricity consumption. To reduce the auxiliary load, new, less energy-intensive oxygen separation technologies are in development, including ion transport membrane (ITM), oxygen transport membrane (OTM), and BOC's ceramic auto-thermal recovery (CAR) oxygen production process.

Oxy-fuel combustion is also associated with promising combined cycles involving gas and steam turbines. [5] The Graz cycle and the semi-closed oxy-fuel combustion combined cycle are two examples now under theoretical investigation. The oxy-fuel combustion concept is applicable to a variety of fuels, including methane, syngas, and biomass gasification. In the Graz cycle, the working fluid following the combustion process is a mixture of steam (approximately 75%) and CO₂ (approximately 24%), with some small amounts of N₂ and O₂. The turbomachinery needed due to the unusual working fluid is discussed below. The expected cycle efficiency is in the range of 50%. A 50 MW oxy-fuel demonstration plant using methane fuel is being planned in Norway. In the United States, the Department of Energy (DOE), in cooperation with Siemens, has instituted a program to develop a high-temperature turbine for these types of plants. A pilot demonstration plant is expected to be operational in about 2015.

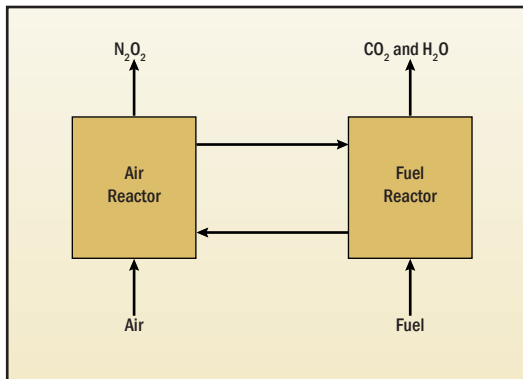


Figure 6. Generic CLC Process [6]

Chemical Looping

Chemical looping combustion (CLC) employs a circulating solid such as metal oxide or calcium oxide to carry oxygen from the combustion air to the fuel. Direct contact between the combustion air and fuel is avoided, and the flue gas is free of N₂. The metal oxide is reduced in a fuel reactor by a mixture of natural gas and steam and oxidized in an air reactor. The oxidation reaction is exothermic, and the resulting heat production in the air reactor is used to maintain the oxygen carrier particles at the high temperature necessary for the typically endothermic reaction in the fuel reactor. The fuel could be syngas from coal gasification, natural gas, or refinery gas.

The net heat evolved is the same as for normal combustion with direct contact. Because the fuel has no direct contact with air, the flue gas is free of N₂. The N₂-free flue gas contains moisture, SO_x, CO₂, and particulates. For coal fuel, after the particulates are removed by a baghouse and moisture is removed by cooling, the remaining gas is essentially high-purity CO₂. The high-purity CO₂ is compressed and cooled in stages to yield a liquid ready for sequestration. A schematic representation is given in **Figure 6**,

Table 4. Chemical Looping Advantages and Limitations

ADVANTAGES	LIMITATIONS
<ul style="list-style-type: none"> • No energy penalty for oxygen production and CO₂ separation. • No need for energy-intensive, high-cost ASU (assuming that coal gasification is not needed). • Potential exists for greater than 98% CO₂ capture. • Potential exists to use a variety of fuels (natural gas, coal, residual oil, etc.). • Possible to retrofit conventional air-blown CFB to CLC CFB with limited modifications. • Alstom bench scale tests suggest potential to meet ultra-clean low emissions targets, including CO₂ capture, at about the same cost and efficiency as today's power plants. 	<ul style="list-style-type: none"> • Most work performed to date has used methane as fuel; only limited studies with oxygen carriers used to react with coal or gasified coal. • Carbon deposition (formation of solid carbon) can occur. • For combustion of solid fuels, separate energy-intensive (due to use of ASU) gasification process is required. • Metal oxide must have high affinity for reaction with fuel but must not decompose at high temperatures or over a large number of cycles. • CO can be also produced; some mechanism to control it possible based on circulation rate. • Process has not been demonstrated on a large scale.

CCS plant components occupy a significant area.

and **Table 4** summarizes the advantages and limitations of this process.

Intensive academic research programs now under way are mainly concentrated on finding the appropriate metal oxides for different fuels. Alstom has completed engineering studies and bench-scale tests on the chemical looping process, and some pilot-scale process testing is proceeding. Chalmers' 10 kW CLC testing concluded the following for nickel (Ni)-based particles:

- No CO₂ is released from the air reactor.
- No significant carbon formation yields 100% CO₂ capture.
- Sand tests show low leakage from the air reactor to the fuel reactor: almost pure CO₂ is possible.
- 99.5% conversion of fuel occurs at 800 °C.

Because this method is still undergoing research, further details will not be discussed here.

CASES

This section discusses the impact of each CO₂ capture technology on the cycle, and particularly on the turbomachinery.

Coal-Fired Supercritical With Post-Combustion CCS

Power Plant Site Location, Available Space, and Other Requirements

Before discussing in detail the evaluation process of determining the impact on the turbomachinery, it is worthwhile to briefly mention the other implications of equipping a plant with a CCS system. Primarily, the suitability of the CO₂ sequestration site needs

to be considered. If the plant is situated far from an adequate geological storage location or an enhanced oil recovery site, the cost of constructing a pipeline and the additional loads for pumping CO₂ must be accounted for. Space requirements and plant layout should also be considered. By itself, the CO₂ capture hardware has a large footprint. For amine scrubbing, the CCS plant components (absorber, stripper, compression stations, and various cooling and storage tanks) occupy a significant area. The plant layout also has to accommodate large ducts for the flue gases, which need to be routed from the exit of the air quality control system (AQCS) block, between the induced-draft (ID) fan, to the amine scrubber without interfering with roads, buildings, and other infrastructure.

As discussed in greater detail below, large low-pressure (LP) pipes are needed to transfer the steam from the steam turbine generator (STG) to the amine scrubber, which requires pipe racks with adequate support. The entire balance of plant equipment must also be augmented to cater to the CCS requirements. The electrical system design for transformers, transmission cables, motor control centers, and other elements needs to be enhanced. Particularly when existing plants are being retrofitted with CCS capabilities, the ripple effect of adding a CO₂ plant requires detailed and careful review. One other consideration applies to the plant heat sink, which should be sized to allow the condenser and cooling tower to accommodate the additional steam when the post-combustion capture system is not in operation.

Steam Turbine Generator

A significant amount of steam is required for solvent regeneration. The steam consumption for

Table 5. Performance Comparison for Plants With and Without CO₂ CCS Capabilities

Performance Element	Without CCS	With CCS	Delta, %
Gross Power, MW	865	702	19
Net Power, MW	800	542	32.3
Steam Turbine Gross Power, MW	865	662	23.5
Auxiliary Loads, MW	65	160	145
Noncondensing Turbine, MW	N/A	40	N/A
Crossover Steam Extraction, % IP Exhaust Flow	0	62	N/A

a representative amine-based post-combustion capture system is shown in Table 5. Typical steam conditions are 3 bar and 270 °C. The amount of steam for 90% CO₂ recovery from the flue gas may be as high as 1.6 kg of steam for 1 kg of CO₂—more than 50% of the LP steam turbine flow. Therefore, it is imperative in all plant operational scenarios to consider the possibility that the CO₂ capture plant might not be able to receive part or all the extraction steam. This consideration is important in a case in which the steam turbine was permanently configured to operate with a reduced LP steam flow. Because venting such large quantities of steam is not an option in this case, any design must offer rapid configuration changes that allow the LP modules to operate under zero extraction conditions. The available options to extract the steam from the system are throttle LP,

floating-pressure LP, LP spool with clutched LP turbine, and backpressure turbine.

- **Throttle LP**—This configuration keeps the crossover pressure constant despite the large amount of steam extracted. The arrangement requires a throttling valve downstream of the solvent steam extraction point. Despite the significant throttling losses that occur, this setup offers flexibility to extract any amount of steam needed (i.e., for less than 90% CO₂ capture scenarios) and the capability to restore full power generation rapidly when the CO₂ capture system is not in operation. The throttling valves are commercially available for current LP crossover pipe sizes. A schematic is provided in Figure 7.
- **Floating-pressure LP**—In this arrangement, the turbine intermediate-pressure (IP) module must be designed to operate with a variable backpressure. When the CO₂ capture plant operates, the crossover pressure is lower. In this case, the last-stages loading of the LP module has increased and the exit losses are higher. For retrofits, the IP last stages can be replaced to match the desired operating conditions at both high and low steam flows, depending on the CO₂ capture steam demand. Obviously, additional valves in the extraction line and downstream of the extraction point in the crossover pipe facilitate operational control for the different steam flows required by variable CO₂ capture rates (e.g., 30%, 50%,

Steam for 90% CO₂ recovery may be more than 50% of the LP steam turbine flow.

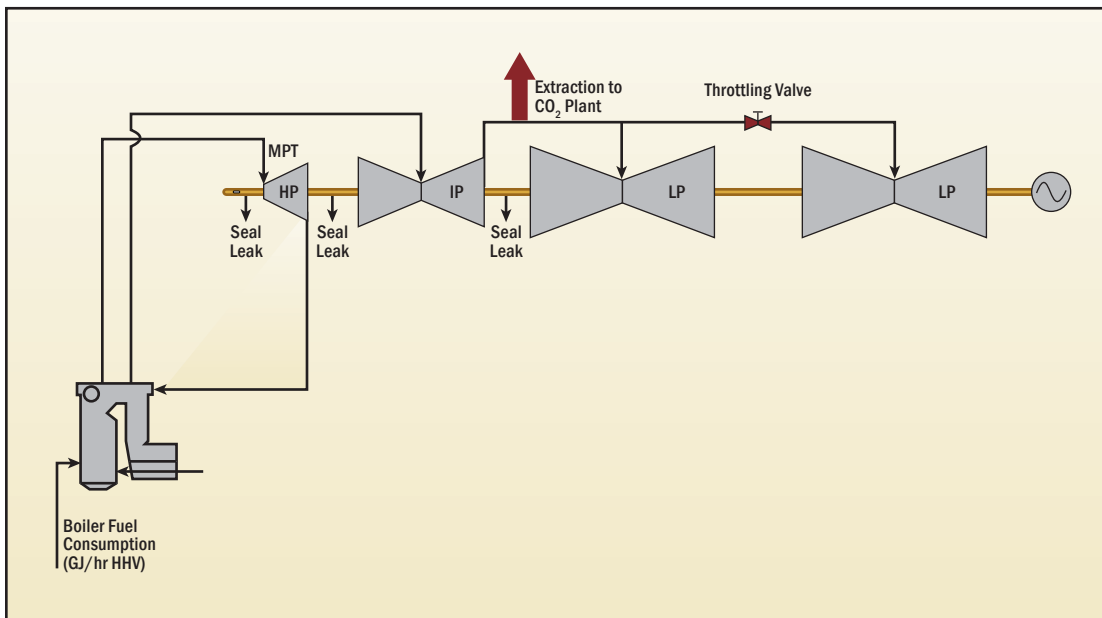


Figure 7. Throttling LP Turbine

90%) from the flue gas stream. A schematic is provided in Figure 8.

- LP spool with clutched LP turbine**— In this scheme, one of the LP modules is connected via a clutch to the generator in an arrangement similar to that used in a single shaft combined cycle in which a clutch is situated between the generator and the steam turbine. In this case, when the CO₂ capture plant is in operation, only one LP module is operating and the other is disconnected. The inlet flow and pressure of the operating LP module have to be designed to accommodate the steam conditions at the anticipated CO₂ capture levels.

This option is costly, requiring additional structural pedestals and a longer turbine hall, and offers little flexibility for various CO₂ capture rates. However, restoring the full capacity of the module when the CO₂ plant is not functional is not a complex activity. A schematic is provided in Figure 9. The LP module, which remains in operation, performs at the design conditions, thus achieving a higher efficiency than with other options. A variant of this arrangement could even operate without a clutch. In this setup, the second LP must rotate; thus, a minimum amount of steam flow (between 5% and 10% of the LP flow) must pass through this module to prevent

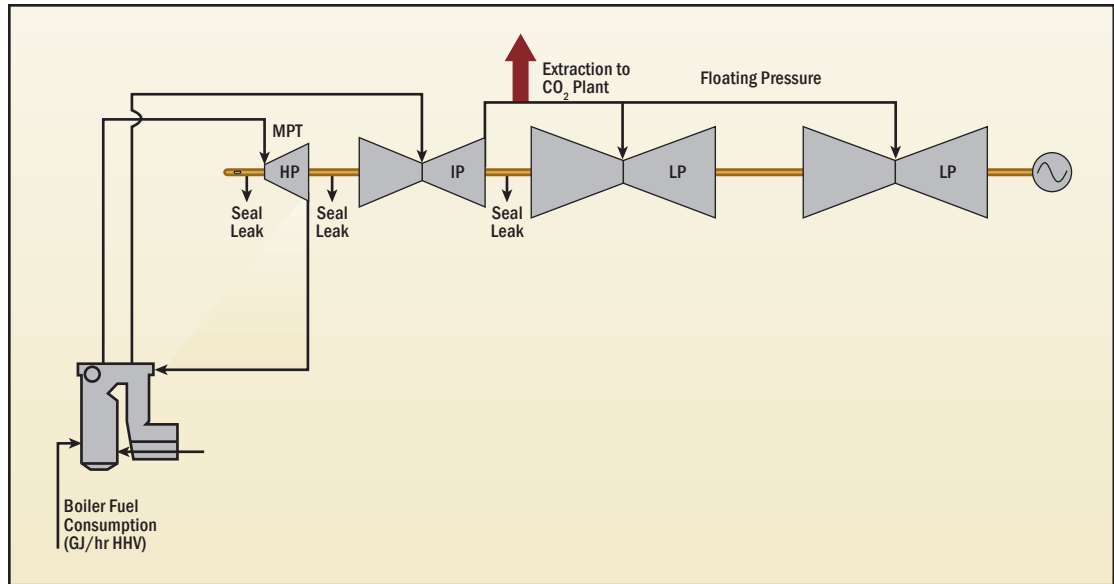


Figure 8. Floating-Pressure LP Turbine

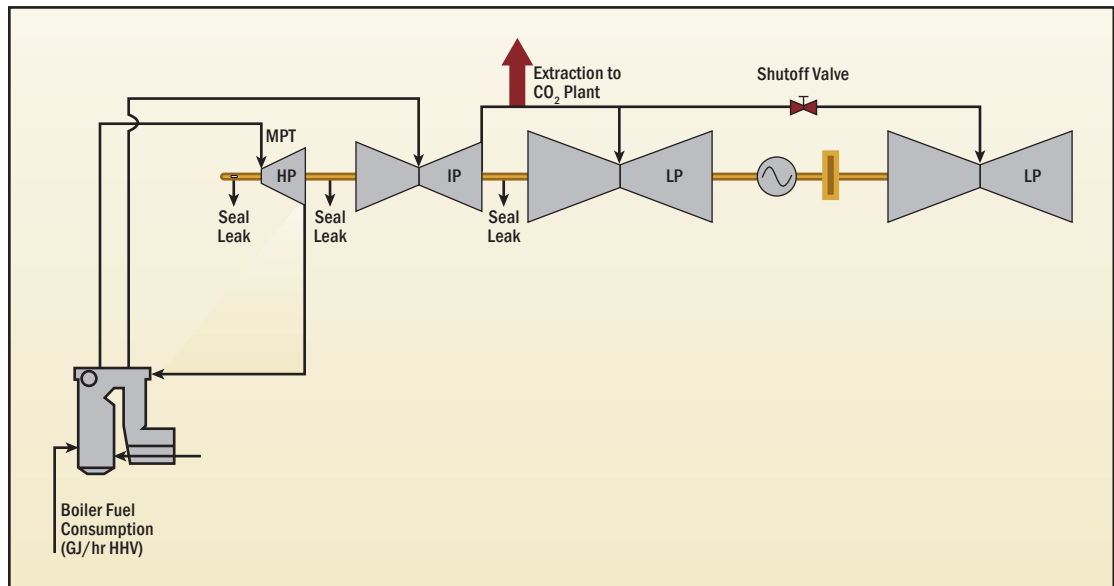


Figure 9. LP Spool with Clutched LP Turbine

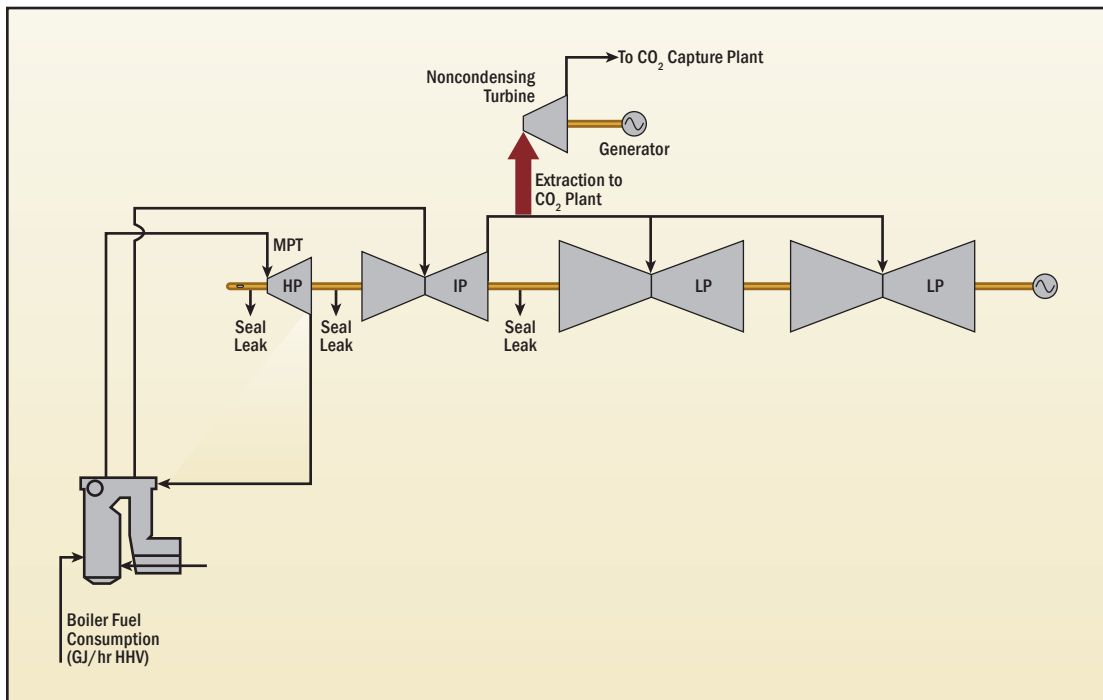


Figure 10. Additional Noncondensing Turbine

A backpressure turbine can produce power to reduce auxiliary loads.

overheating or mechanical vibrations under these minimal flow conditions. Extracting additional steam without producing real power is an added loss for the system. A more permanent solution for the second LP module is to replace the bladed rotor with a dummy. In this scenario, when the post-combustion capture is not operational, the steam cannot be returned to the cycle to produce power and must be either vented or condensed.

- **Backpressure turbine**—If the steam extraction for the post-combustion capture plant is taken from the IP/LP crossover pipe, the pressure and the temperature are too high for direct use in the sorbent regeneration process. One solution to exploit the available energy is to generate electric power through a noncondensing turbine, and use the power to reduce the auxiliary loads. A schematic is provided in **Figure 10**.

Table 5 offers an example of the impact of a CO₂ capture plant on the overall performance for a nominal 800 MW net power plant without post-combustion capture. It should be emphasized that each project must conduct its own evaluation based on specific site conditions, the selected capture technology, and type of sorbent used. Because each steam

turbine vendor has a different cycle design with dissimilar IP module exhaust pressures, the output power of the noncondensing turbine varies accordingly.

In the given example, it can be seen that the steam extraction for the post-combustion capture plant reduces the steam turbine output by almost 23%. Because of the post combustion capture plant, which in this example also contains the CO₂ compression section, the auxiliary loads increase by almost 95 MW. The noncondensing turbine produces 40 MW of power; without this turbine, the auxiliary loads would be even higher.

Summary of Options Impact

Figure 11 depicts the relative efficiency loss for each option. [7] This comparison of plant output does not account for the auxiliary power loss due to CO₂ compression loads. As expected, the setup with an additional noncondensing turbine offers the lowest power loss (7%), followed by the clutch arrangement, which has the least steam throttling and lowest LP turbine losses. However, both options require additional hardware or significant modifications to plant arrangement. For a retrofit, these alternatives require substantial pre-investment and site preparation.

Oxy-fuel combustion requires flue gas recirculation.

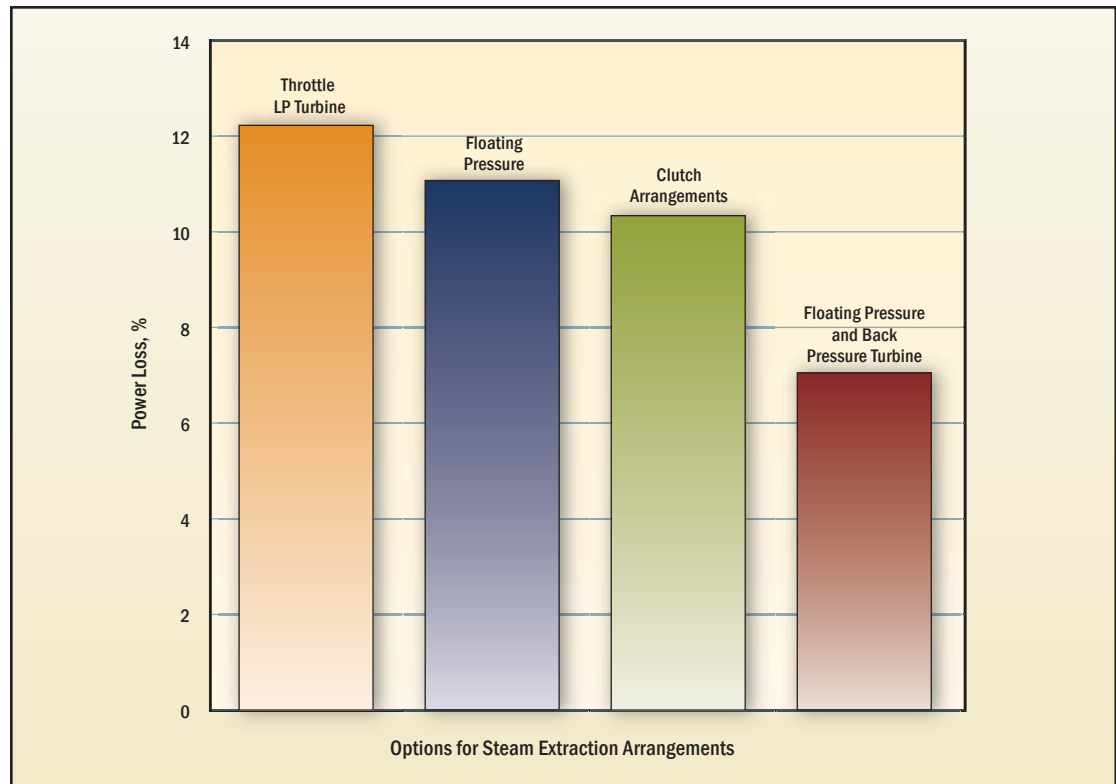


Figure 11. Power Loss for Various LP Turbine Arrangements

Steam Cycle Oxy-Fuel Combustion with Post-Combustion Capture System

Steam Cycle

- *Location, additional equipment, and space requirements*—As with the other CCS options, proximity to a CO₂ sequestration site should be considered for the oxy-fuel option, and adequate feasibility studies must be conducted. The distance from a geological storage location or an enhanced oil recovery site influences not only the plant's economics, but also its configuration and auxiliary power requirements. Compared to a conventional coal-fired plant, an oxy-fuel plant requires a number of new components besides the CO₂ capture hardware. Examples include an ASU, additional flue gas treatment modules, several heat exchangers to extract low heat, and fans and ducts for flue gas recirculation (FGR).

The optimal FGR ratio is still a topic of investigation. A commonly used value is 0.7, where zero is pure oxygen combustion with no recirculation. [8] Adequate space must be allocated not only for the equipment, but also for the interconnecting pipes, electrical cables, and controls. While SO₂ and other elements can be removed in the CO₂ capture plant, the quality of recirculation flue gas must be controlled in supplementary or modified

sulfur-removal devices to avoid long-term corrosion of the boiler. Another aspect to be considered is the increased cooling duty of the plant required by the ASU, flue gas condenser, and CO₂ compression unit. When the heat sink is a cooling tower, the plant layout needs to account for additional cells capable of coping with a larger cooling load than can be handled by a conventional plant without CCS.

- *Steam turbine generator*—In principle, the steam turbine configuration for this CCS option is the same as for a conventional steam plant without carbon capture. However, the cycle energy balance indicates that several sources of low-grade heat, such as the ASU and the CO₂ compressor, could be recovered, allowing substantial reduction in bleed flows for condensate and feedwater heating. As a result, there is an increased LP flow through the turbine. If the LP module last-stage blade system and generator are sized properly to handle the additional flow, the steam turbine gross power output increases. According to [7], the gross power output could be an estimated 4.5% or higher. This arrangement also yields a better efficiency, between 0.3 and 1.3 percentage points. Some LP steam extractions are required for oxygen preheating and the ASU plant dryers.

of CO₂ capture was arbitrarily set at 85%. There are many designer formulas for solvents, consisting of several primary, secondary, and tertiary amines including MEA and other reactive ingredients. Therefore, providing an absolute ratio of steam or electrical consumption per ton of CO₂ captured is not representative. **Figures 13 and 14** show how changing the target CO₂ percentage affects the steam and electricity required for capture and compression. It is assumed that the basis for evaluation is 95% CO₂ removal from the flue gas.

It can be seen that reducing the CO₂ capture rate from 95% to 80% reduces steam consumption by 20% and electricity consumption by 5%.

Impact on Gas Turbine

In a gas turbine, the nature of the premix combustion system decreases the concentration of CO₂ in the exhaust flue gas to half of that in a coal-fired boiler. Recirculating part of the exhaust gases achieves a higher CO₂ concentration. Among the thermal NO_x reduction techniques developed in recent decades, internal FGR is being used as a very effective method to lower peak flame temperatures. However, the FGR rate can only be increased to a certain value for stable operation. Particularly interesting to note for this mode of operation is the fact that the NO_x emission levels and combustion system acoustics are substantially improved.

However, the process could affect combustion stability and heat transfer properties. Theoretically, the amount of recirculated flow could be close to 40% of the exhaust gases. For CCS, FGR takes place at the compressor inlet. It should be noted that the amount of cooling necessary to bring the flue gases from exhaust conditions (at least 40 °C) to ambient temperature adds a substantial parasitic load. Due to the high sensitivity of gas turbine output to the compressor inlet temperature, a mixed stream of external air and recirculated gas above ambient temperature would certainly reduce the power generated. Large gas turbine manufacturers are conducting extensive studies not only on the operational impact of the FGR on various components, but also on the technical and economical optimization of the amount of recirculated flue gas.

IGCC with CCS

The main impact on IGCC with CCS is the use of H₂-rich fuel in the gas turbine. At 90% carbon capture, the expected hydrogen concentrations in the fuel may vary from 30%–78%. Hydrogen is an excellent fuel with a high heating value (52,000 Btu/lb). For comparison, natural gas has only 21,000 Btu/lb. The flame temperature is hotter (more NO_x), and flame propagation is faster, requiring modified combustor cooling schemes. The current proposal for an H₂ burner is based on the diffusion flame, which is more stable and less prone to combustion oscillations than the premix lean combustion flame. At this time, the state-of-the-art process for premix combustion of fuels with high H₂ concentrations (greater than 50%) is only in the experimental phase. The main unresolved issues continue to be premature ignition (flash-backs) and combustion noise.

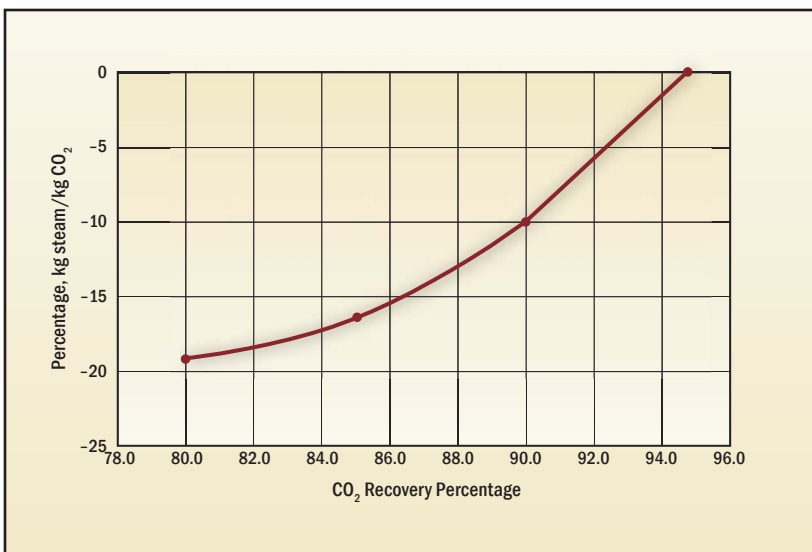


Figure 13. Steam Consumption at Various CO₂ Capture Rates

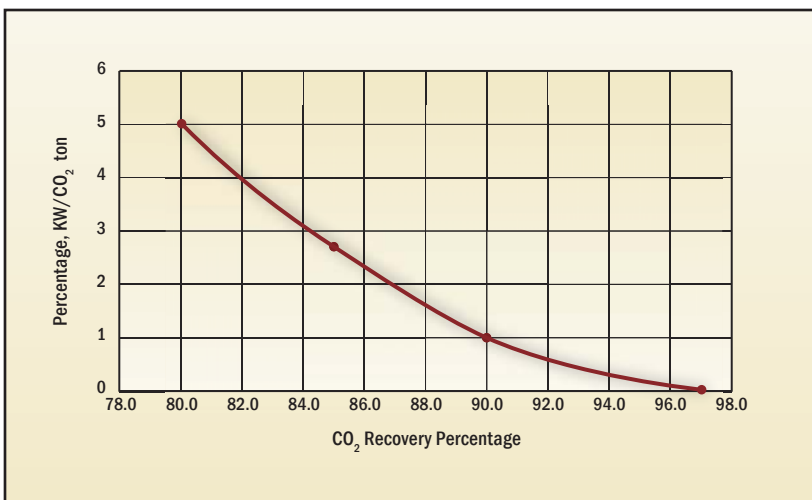


Figure 14. Electricity Consumption at Various CO₂ Capture Rates

In diffusion combustion, the H₂ is mixed with N₂ before entering the system. The N₂ dilution is used to meet the NO_x emission limit (15 ppm). Because the firing temperature of a gas turbine operating on H₂ is approximately 28 °C lower than that of a turbine operating with conventional IGCC syngas, the additional mass of the inert gas N₂ expanding in the turbine section helps compensate for the power loss associated with the lower firing temperature.

As discussed earlier, an IGCC with no CCS uses syngas, a fuel with much lower H₂ content and a significant amount of CO. The syngas combustion process has been known for many years and is used extensively in conventional IGCC applications using E- and F-class turbines. High H₂ operating experience indicates that in some process gas applications, the concentration of H₂ could be 60%–70% and even reach 90%. For example, GE reports [9] that an MS6000B gas turbine is burning refinery gas with a 70% H₂ concentration at the San Roque site in Cadiz, Spain, and that at the Daesan, Korea, site, the H₂ percentage can be as high as 95% for this model. The F-class operational experience indicates combustion with lower levels of H₂ concentration, about 44%. However, flame dynamics are such that combustion can occur safely only in the diffusion mode.

Despite the number of dilution additives (steam, N₂), current technology has high NO_x emissions. In diffusion mode, combustion of H₂-rich fuel is limited to 50% [10] to meet emissions targets and control flame stability. If N₂ is the dilution agent, then the percentage of H₂ cannot exceed 35%. The commonly used diluents are pure steam, pure N₂, and different mixtures of both. In Europe, many initiatives and research activities, such as the Enhanced Capture of CO₂ (ENCAP) program, aim at developing premix burners capable of burning high percentages of H₂.

The development of the burners is only the first step of the integration process. The impact on the combustion system, either annular or can, must also be evaluated. Major equipment suppliers, including GE, Siemens, and MHI, are conducting extensive combustion tests to demonstrate lower than 15 ppm NO_x. As part of the first phase of DOE's Advanced Hydrogen Turbine Development Program, Siemens investigated several promising premix combustion configurations for H₂ concentrations up to 60%.

There are also other differences between a gas turbine burning conventional syngas (GT_{syn}) and one burning fuel with a high concentration of H₂ (GT_{H2}). In order to maintain compressor pressure ratio, the first-stage turbine nozzle area must be sized properly to account for the differences between the larger flow of GT_{syn} and GT_{H2}. An increased percentage by volume of H₂ affects the life of the turbine hot sections as a result of the higher moisture content of the combustion products. [11] The GT_{H2} exhaust gas moisture content (12.4%) is higher than that of the GT_{syn} (8.4%); thus, the heat transfer properties and behavior of the hot gas path are different. More work is needed to redefine the computational fluid dynamics (CFD) boundary conditions and to conduct durability and life expectancy analyses.

Ultimately, the metal temperature increases due to the higher moisture content accompanying a higher H₂ content, resulting in a significant reduction of hot path component life. The practical solution recommended by gas turbine suppliers is to reduce the firing temperature, which reduces power output and efficiency. To protect the hot gas path components, the initial GT_{H2} firing temperature is approximately 28 °C less than that of a GT_{syn}. A relationship for the reduction of firing temperature as a function of H₂ percentage [11] is:

$$T_f = 13.312 \times (\text{volume \% H}_2)^{0.69} \quad (1)$$

In order to increase the firing temperature and reduce the NO_x emissions, several options are under investigation: new blade cooling concepts, advanced materials, high-temperature thermal barrier coating, and hybrid component design. The hybrid component is superior to a monolithic component, allowing expensive materials to be incorporated in the airfoils just in high-temperature areas. It is obvious that only intensive and continuous development efforts will make it possible to meet the ambitious goals set by DOE for IGCC plants with CCS capability: 2 ppm NO_x emissions, 3%–5% improved cycle efficiency, and capability to burn high-H₂ fuel.

Chemical Looping Combustion

Combined Cycle with Gaseous Fuel

- **Cycle configuration** – In CLC, the combustion occurs without any direct contact between the air and the fuel. As previously described, the CCS energy penalty is lower for CLC than for either pre- or post-combustion methods, because the CO₂ is not diluted with other combustion products. [12] A combined

ENCAP
aims at developing
premix burners
to burn
high H₂ fuel.

The gas turbine industry can convert existing products for CLC combined cycle.

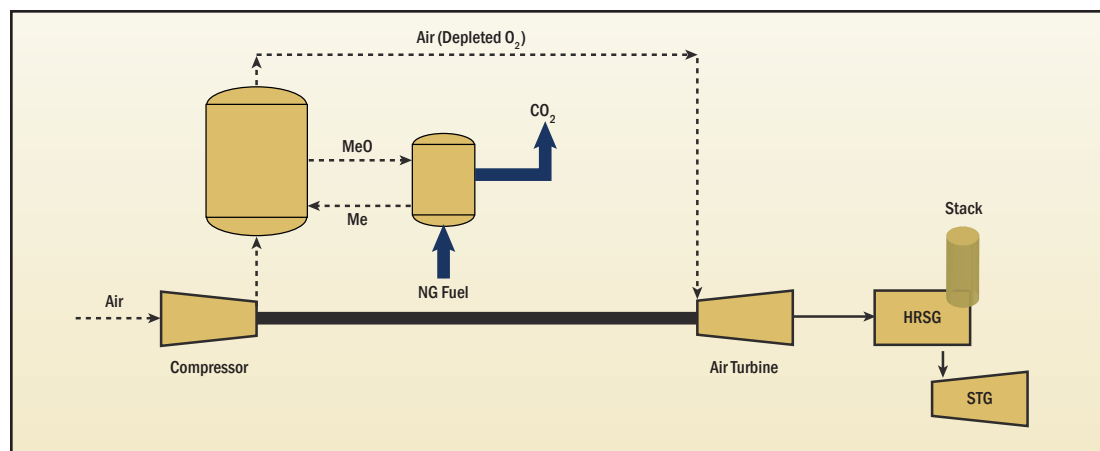


Figure 15. CLC in Combined Cycle Configuration

cycle with chemical looping is depicted in Figure 15. The principles of chemical looping were presented earlier in the paper (see Figure 6). This section provides details for a specific combined cycle application.

Pressurized air from the compressor enters the air reactor (oxidizer), where it reacts with the metal to create a metal oxide. This oxidation process is exothermic. The air (depleted oxygen) exiting the oxidizer at high temperature and pressure is available for further expansion in a turbine, to generate power. The air exiting the turbine passes through an HRSG, where its remaining energy is extracted for use in a conventional steam bottoming cycle. In the other system element, the fuel reactor, fuel, and metal oxide react to strip the metal from the O_2 to create a CO_2 - and H_2O -rich steam. This steam can be further expanded in a turbine and then condensed to separate the H_2O and the CO_2 . For this application, the most promising substance is NiO. The metal oxide requires an inert stabilizer to improve chemical reactivity and ensure mechanical stability.

- **Turbomachinery**—The gas turbine industry has sufficient technical knowledge to convert existing products for this application. The air compressor [12] has a moderate pressure ratio (18) and an air flow close to 800 kg/sec. The turbine inlet temperature is not above current gas turbine values (1,140 °C), and compressor bleed air can be used for cooling duty. The turbine exhaust temperature (500 °C) is typical for HRSG applications.

The steam bottoming cycle is no different from the one used in a conventional combined cycle. According to [12], a typical cycle efficiency, including CO_2 compression plant load, is close to 50%.

Better cycle efficiency can be achieved if the hot stream of CO_2 and steam exiting the fuel reactor passes through an additional turbine before being condensed. While cycle efficiency improves by 2%, this new turbine adds complexity and requires a full development program. An additional challenge facing the cycle is imposed by the requirement to maintain equal pressure at the exits of the two reactors under all operating conditions, to avoid gas leakages.

Steam Cycle with Solid Fuel

Intensive studies are being conducted to identify appropriate substances for the chemical looping process of solid fuels. One option is to use calcium sulfide and sulfate (CaS and $CaSO_4$) reactions in one reaction loop between the oxidizer and the reducer [13]. The fuel reactor (reducer) uses coal, steam, and calcium carbonate ($CaCO_3$) as input. The heat of the exothermic reaction in the oxidizer is transferred to steam and from there to a conventional steam cycle.

Another option (see [14]) uses calcium compounds to carry O_2 and heat between two reaction loops. The first loop uses $CaS/CaSO_4$ reactions to gasify the coal. In a water-shift reactor, CO is then combined with steam to generate CO_2 and H_2 . The second loop uses calcium oxide (CaO) and $CaCO_3$. Thermal energy is transferred from one loop to the other using bauxite as the heat transfer medium. In the final account, the products of the process are concentrated streams of CO_2 for sequestration and H_2 for consumption as fuel. An experimental pilot unit of this hybrid gasification and chemical looping is currently under development by the process owner, Alstom. A successful full scale demonstration of the process is expected in the 2016–2020 time frame.

Turbomachinery for the Cycle

In the first option, the steam generated by the process is used in a conventional steam turbine. However, the steam temperature and pressure values could exceed the current level of ultra supercritical steam turbine conditions. An additional concern is part load operation. The chemical looping process is not yet sufficiently developed to allow more detailed steam turbine design and operation.

In the second option, the turbomachinery is identical to that of an IGCC gas turbine using a highly concentrated stream of H₂ as the operating fuel. (A detailed discussion is provided in the previous section, IGCC with CCS.)

CO₂ Compression Issues

A typical CO₂ processing system includes compression, dehydration, and purification/liquefaction. As described earlier, this process is one of the major contributors to auxiliary power consumption and higher costs for the power plant.

The compression process [15] includes at least two compressors, intercoolers, water separators, dehydrators, and purifiers. The amount of impurities in the CO₂ stream has a major impact on the process. The presence of SO₂ and H₂O may decrease the amount of compression work, while the existence of N₂, O₂, and argon (Ar) may increase it. In the selection process, the intercooler temperature must be higher than the condensing temperature of the mixture. Additionally, CO₂ compression equipment requires stainless steel construction due to the presence of water vapors and potential corrosion.

A discussion of turbomachinery for CCS plants would not be complete without mentioning CO₂ compression technology. [16] The major effort in this area is dedicated to identifying processes capable of reducing power consumption, which represents 40% of the auxiliary loads. In some cases it represents 8%–12% of plant power output. [17]

For CO₂ compression applications, the traditional approach has been to use high-speed

reciprocating compressors. However, centrifugal compressors offer a challenging alternative: better efficiency, oil-free compression, and less maintenance. Given the importance of intercooling capability, it is worthwhile to mention an integral-gear design for centrifugal compressors that offers more flexibility for intercooling after each stage, optimization of flow coefficients due to selection of the most favorable rotating speed for each pair of impellers, and finally, a choice of drivers—either motors or steam/gas turbines.

A novel technology supported by DOE funding is the Ramgen supersonic shockwave CO₂ compressor. [17] Following a process similar to the one occurring in the air intake for aircraft engines at supersonic speeds, the device is able to achieve compression ratios of 10:1 in a single stage. With stage discharge temperatures of approximately 230 °C, the energy removed in the intercooler can be recovered and used in the solvent regeneration process. According to the details provided by Ramgen, 70% of the electrical input energy for compression can be recovered as useful heat. The second phase of this promising program will include detailed design specifications.

Thermal Performance Comparison

It is clear that the CCS processes discussed in this paper yield lower thermal efficiency than conventional systems without CCS. To quantify this phenomenon, the following examples are provided:

- *Chilled ammonia*—A study to evaluate the energy consumption and the cost of a full-scale CO₂ capture system was conducted by Alstom (see [4]) and the results were compared to those of a study of an MEA system performed by Parsons in 2000 and 2002 (see [4]). The base power plant is a supercritical pulverized coal (PC) boiler firing 333,542 lb/hr of Illinois No. 6 coal, operating at 40.5% net efficiency (at higher heating value [HHV]), and generating 462 MW of net power. Plant energy performance with and without CO₂ capture is summarized in **Table 7**.

Table 7. Chilled Ammonia Plant Energy Performance

Parameters	Supercritical PC Without CO ₂ Removal	SCPC With MEA CO ₂ Removal (Parsons Study) [4]	SCPC With NH ₃ CO ₂ Removal (Alstom Study) [4]
Net Power Output	462,058	329,524	421,717
Net Efficiency, % HHV	40.5	28.9	37.0

Post-combustion capture methods are most suitable for future capture-ready plants.

- *Oxy-fuel combustion*—Thermal performance is better for air-fired units than for oxy-combustion, as shown in **Table 8**. The unburned carbon content in fly ash is similar in both processes; however, additional coal needs to be burned for oxy-fuel combustion to achieve the same net output.

Table 8. Oxy-Fuel Combustion Thermal Performance

Process	Efficiency, % HHV
Air-Fired PC Boiler	39.1
Oxy-PC with CO ₂ Capture	29.9
Oxygen Transport Membrane Process with CO ₂ Capture	34.5

CONCLUSIONS

In anticipation of the future greenhouse gases regulations, the power industry has embarked on a major effort to develop alternative capture and compression technologies, mainly for CO₂. The proposed processes all require substantial amounts of energy, which negatively affects plant net power output and efficiency. This paper reviewed the current leading options and addressed their impacts on turbomachinery. Due to the uncertainties associated with CCS legislation, many developers, EPC contractors, and equipment manufacturers are looking at options to make plants currently in the design stage capture-ready, thus minimizing the future costs of CO₂ capture retrofits. Apart from the technical implications of various CO₂ capture processes, a collective effort of the engineering community should be devoted to inform and educate the public about the direct impact of the CCS on the electricity production and cost. For their part, by providing a long-term framework for CCS, policymakers could stimulate the deployment of low-carbon-footprint technologies and encourage the development of more cost-effective concepts.

Post-Combustion Capture Plants

The main impact on the steam turbine for either amine- or ammonia-based CCS technology is attributed to the large steam extractions needed for solvent regeneration. A range of solutions, standalone or in combination, is available to cope with various amounts of extracted steam. The options presented can be implemented with limited effect on steam turbine efficiencies. These post-combustion capture methods are the most suitable for

future capture-ready power plants, requiring minimal pre-investment for steam turbines and only a few later modifications. Current turbine designs and plant layouts can also accommodate more efficient future post-combustion CO₂ capture technologies as they become available. While the technical and economic penalties for CO₂ capture are high, post-combustion technology represents one of the most probable short-term solutions. The use of ammonia in place of traditional amines may eventually reduce the parasitic electrical and heat loads.

Oxy-Fuel Combustion Combined Cycles

Several cycles have shown theoretical promise of high efficiency. The use of unconventional working fluids demands extensive development efforts before any large-scale implementation can occur. This methodology does not lend itself to the concept of capture-ready because the turbomachinery is process specific. Under current legislative conditions and given the status of competitive technologies, a 2015 or 2020 implementation date is reasonable.

Other Methods

Other capture methods, such as chemical looping, are in the initial development or pilot demonstration stage. Their chances of being implemented in full-scale applications ultimately depend on future legislative and environmental policies. ■

TRADEMARKS

Econamine FG is a service mark of Fluor Corporation.

Rectisol is a registered trademark of Linde AG.

Selexol is a trademark owned by UOP LLC, a Honeywell Company.

ACKNOWLEDGMENTS

Justin Zachary wishes to express his gratitude to his co-author, Sara Titus, for preparing the background information on various CO₂ capture methods used in the development of this paper.

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The original version of this paper was presented at ASME Turbo Expo 2008, held June 9–13, 2008, in Berlin, Germany.

BIOGRAPHIES



Justin Zachary is currently assistant manager of technology for Bechtel Power Corporation. He oversees the technical assessment of major equipment used in Bechtel's power plants worldwide. Additionally, he is engaged in the evaluation and integration of integrated gasification combined cycle power island technologies. He also actively participates in Bechtel's CO₂ capture and sequestration studies, as well as the application of other advanced power generation technologies, including renewables.

Dr. Zachary has more than 30 years of experience with electric power generation technologies, particularly those involving the thermal design and testing of gas and steam turbines. He has special expertise in gas turbine performance, combustion, and emissions for simple and combined cycle plants worldwide. Before coming to Bechtel, he designed, engineered, and tested steam and gas turbine machinery while employed with Siemens Power Corporation and General Electric Company. He is a well-recognized international specialist in turbo-machinery and has authored more than 72 technical articles on this and related topics. He also owns patents in combustion control and advanced thermodynamic cycles.

Dr. Zachary is an ASME Fellow and a member of a number of ASME performance test code committees.

Dr. Zachary holds a PhD in Thermodynamics and Fluid Mechanics from Western University in Alberta, Canada. His MS degree in Thermal and Fluid Dynamics is from Tel-Aviv University, and his BS in Mechanical Engineering is from Technion – Israel Institute of Technology, Haifa, both in Israel.



Sara Titus is a mechanical engineer on the Edwardsport Integrated Gasification Combined Cycle project. In her 2 years with Bechtel Power, she has already contributed to a variety of projects as a control systems engineer, in nuclear operating plant services; a mechanical engineer, in the environmental group; and an air quality control systems engineer, in the fossil technology group.

Before her current position, Sara supported a front-end engineering and design study for a CO₂ test center in Norway. She was the responsible engineer for the test center's rich amine reclaimer and regenerator systems, and also helped to evaluate optional functionalities being considered for the project.

Earlier, Sara worked as a control systems engineer on nuclear power projects for the Tennessee Valley Authority (TVA) and Southern Nuclear Operating Company, where her duties included performing safety-related equipment qualification assessments and preparing design change packages. In addition, she worked on the Holcomb Station power plant expansion and the IGCC plant for American Electric Power.

Sara has authored several technical papers on the topic of CO₂ capture technologies and economics. Her most recent, "CO₂ Capture and Sequestration Option: Impact on Turbo Machinery," was presented at the ASME Turbo Expo conference in Berlin, Germany, in June 2008.

Sara holds MS and BS degrees in Chemical Engineering from the University of Maryland, Baltimore County, and is a member of the Society of Women Engineers, Women in Nuclear, and North American Young Generation Nuclear.