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Amine Based CO_2 Capture from Gas Turbines

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Abstract

The CO_2 Capture Project (CCP) is a joint project of eight major energy companies, developing a wide range of CO_2 capture technologies to significantly reduce the cost of capturing and storing CO_2.

A feasibility study has been carried out to examine post combustion CO_2 capture from eleven simple cycle gas turbines using best available technology. The paper presents the findings of the study and examines the complex issues of retrofitting an amine-based capture facility onto existing gas processing plant located on the Alaskan North Slope.

The facility, designed to capture 1.78 million tonnes per year of CO_2, produces a high pressure, high purity product stream suitable for delivery to an enhanced oil recovery project. The paper highlights the benefits and the key challenges to be addressed by anyone considering post combustion capture of CO_2 at industrial scale and in an environmentally challenging location.

Introduction

The CO_2 Capture Project (CCP) is a joint project of eight major energy companies who are working to reduce significantly the cost of capturing and storing CO_2. The CCP is developing a wide range of CO_2 capture technologies, classified within the generic groupings of post-combustion, oxyfuel and pre-combustion decarbonisation.

A feasibility study has been carried out to examine post combustion CO_2 capture from eleven simple cycle gas turbines using today's best available technology. The study will provide one of four baselines, against which new and improved technologies for CO_2 capture will subsequently be assessed.

The CCP selected amine scrubbing as the best available technology for post combustion CO_2 capture and they requested Fluor to use their proprietary Econamine FG^{SM} process to produce a baseline process design and cost estimate. The Econamine FG^{SM} technology uses MEA scrubbing with chemical inhibitors to counter the effects of corrosion caused by oxygen in the flue gas. The process is well developed and has been widely used at a relatively smaller scale to produce high purity CO_2 for the food industry and feedstock for urea and methanol plants. However the process has never been implemented at a scale that is envisaged for the current feasibility study.

CO_2 Capture Scenario

The CO_2 capture scenario described in this paper is based upon BP's Central Gas Facility (CGF) at Prudhoe Bay, located on the North Slope in Alaska. The CGF employs a range of simple cycle gas turbines providing various mechanical shaft power duties including, for example, re-injection compression and process refrigeration. The objective of the study is to provide a detailed process design and cost estimate for a retrofit CO_2 capture facility, designed to capture the majority of the CO_2 currently emitted in the flue gases from eleven of these turbines, using a commercially proven amine based process (Fluor's Econamine FG^{SM}).

The resulting capture plant facility is designed to deliver 1.78 million tonnes per year of CO_2 (equivalent to around 5,200 tonnes per day), representing around 85% of the total CO_2 emitted by the selected turbines on an annual basis. The anticipated sink for the CO_2 is a potential Enhanced Oil Recovery (EOR) project on the North Slope, requiring the CO_2 from the turbine sources to be separated from other constituents in the flue gas prior to compression, to produce a high pressure, high purity CO_2 product stream.

The number and type of gas turbines selected for CO_2 capture in the study are listed below in Table 1.

Table 1: Number and Type of Gas Turbines selected for CO_2 Capture

Turbine Type	Number
General Electric Frame 6-1B	4
General Electric Frame 5-2B	3
Rolls Royce RB-211C	4

Process Overview

The CO_2 capture plant consists of the process equipment and supporting utility systems required to recover CO_2 from turbine flue gases. Figure 1 shows the main component blocks of the process schematically. The turbines utilise associated natural gas as a fuel, resulting in a flue gas that contains only dilute levels of CO_2 (around 3.3 mol% amongst other combustion products). The CO_2 is removed from the flue gases using Fluor's proprietary Econamine FG^{SM} solvent. It is subsequently regenerated from the solvent, dehydrated and compressed. The product is dry and of high purity and pressure (>99.9 vol. % CO_2 and 50 ppmv H_2O at 220 barg), suitable for use as a miscible injectant in a potential Enhanced Oil Recovery project.

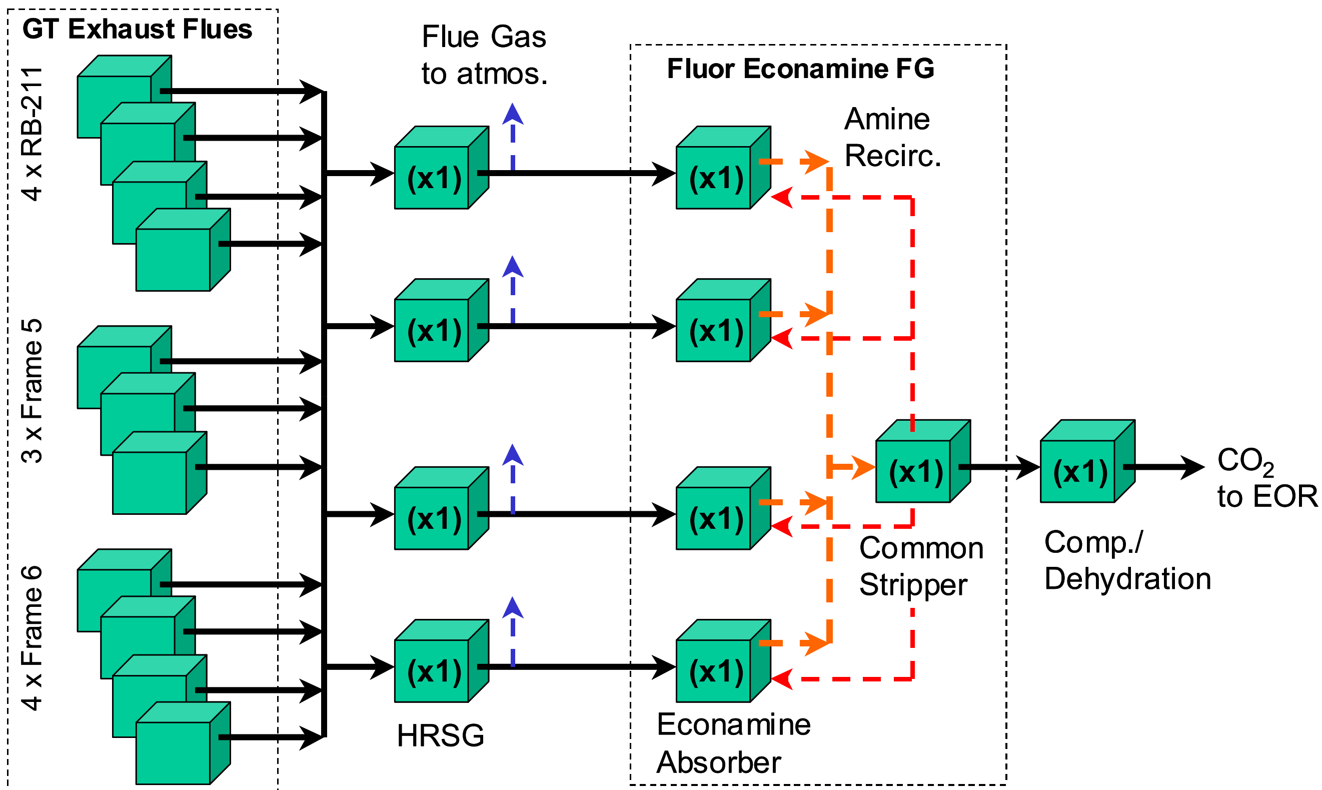
At the start of the study, it was quickly determined that the most cost effective configuration for the CO_2 capture plant involved maximising the size of the absorption trains. It was found that the size of each train was limited by the largest commercially available Heat Recovery Steam Generator (HRSG) and by the largest Absorber diameter that can be built with confidence. On this basis, the flue gases from the gas turbines are combined and fed to four identical absorption trains. Each absorption train contains a HRSG, a Direct Contact Cooler (DCC), a blower and an Econamine FG^{SM} absorber, complete with its associated heat exchangers, filters and pumps.

Regeneration of the Econamine FG^{SM} solvent takes place in a single stripping system, common to all four absorption trains. The stripping system includes a common stripper, a reclaimer, an amine filtration package, the associated heat exchangers and pumps and a solvent storage facility.

In its present configuration, the facility only utilises a small proportion of the heat energy available from simple cycle gas turbine exhaust (available at almost 500°C), by recovering heat through a single waste heat recovery unit connected to one of the Frame 5 turbines. The specification of new heat recovery steam generators to each proposed absorption train can satisfy two key process requirements, allowing essential pre-cooling of the turbine flue gases before they enter the absorption system whilst meeting the full energy demands of the capture plant.

Given the large scale of the proposed capture plant, the cost of providing virtually all of the other supporting utility systems have been included in the study, as existing infrastructure would be unable to accommodate the additional requirements of the new facilities.

Figure 1: Block diagram of the Gas Gathering, Capture and Product Treatment System



The facility is essentially self-sufficient in terms of energy and all utilities except treated seawater (used to generate boiler feed water for the HRSGs and general process water). During normal operation, the specification of a steam turbine generator allows the CO_2 plant to produce enough electricity to satisfy its own power demands, whilst exporting excess power to the local grid. It is envisaged that this excess power could be used to displace power generation elsewhere on the facility.

Process Description

The flue gases from several turbines are commingled before entering the HRSG, where the flue gases are cooled to a temperature that has a safe margin over its dewpoint. The heat available from the flue gas is used to raise three levels of steam, with each HRSG designed to recover around 140 MW of heat from the incoming flue gas. High pressure steam is used to generate electricity via a steam turbine power generator before subsequently being used as motive steam for the CO_2 product compressors. Intermediate pressure steam is used to provide heat to the stripper reboiler and the amine reclaiming system. Low pressure steam is used to provide deaeration for the boiler feed water. In addition to raising steam, a heating coil in the HRSG is used to further recover energy, for space heating of both new and existing modules at the CGF.

The partly cooled flue gases then flow to the DCC, where they are quenched. The DCC circulating water is cooled and filtered, providing a means of removing particulates that may be present in the flue gas stream. After leaving the DCC, the cooled flue gas is passed into a blower to maintain the required pressure in the inlet flue gas ducts and to ensure proper distribution of flue gases between the four absorption trains.

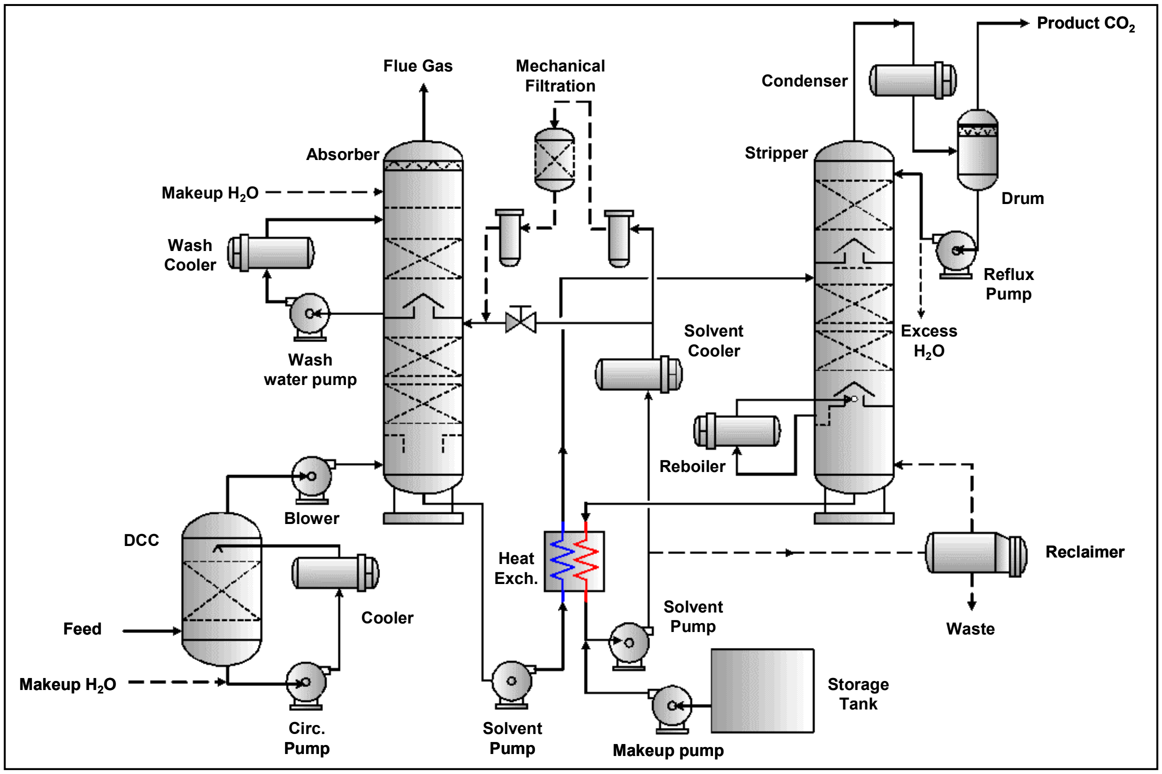
On exiting the blower, the flue gas enters the absorption column where it is counter-currently contacted with the Econamine FG^{SM} solution. CO_2 is absorbed from the flue gas stream as it passes up the column, before passing out through the top section of the absorber, which provides a wash for the gases before venting to atmosphere, ensuring that less than 1 ppmv of entrained solvent is emitted to atmosphere.

CO_2 is absorbed into the lean solvent, with the solvent circulation rate controlled by measuring the amount of CO_2 in the lean solvent feed to the absorber. The CO_2 rich solvent leaves the absorber and is sent for generation in the stripping system, where heat is provided to reversibly release the CO_2 from solution using four kettle type reboilers. A wash section at the top of the stripper ensures that a minimal amount of entrained and vaporized solvent leaves the column in the product CO_2 stream.

To maintain an efficient operation, a reclaimer is operated in parallel to the reboilers (as an intermittent batch process) to limit the build up of heat stable salts in the lean solvent, thereby reducing solvent losses over time. Additionally, a small percentage of the lean solvent returning to the absorbers is continuously filtered via a carbon bed to remove solids and other degradation products.

After leaving the top of the stripper, the CO_2 stream is compressed in a five stage centrifugal compressor, powered by a condensing steam turbine drive. Between the third and fourth stage, the CO_2 is dehydrated using a proprietary dehydration system, to ensure that the moisture content of the stream at the final export pressure of 220 bar(g) is sufficiently low for transportation via the export pipeline. Figure 2 shows the Econamine FG^{SM} process schematically.

Figure 2: Schematic Layout of the Econamine FG^{SM} Process



Site Layout Considerations

The gas turbines at the Central Gas Facility are physically arranged in reasonably close proximity to one another, occupying an existing plot of around 400 m length by 200 m width. The harsh climatic environment of the Alaskan North Slope required a decision to be made early on in the study regarding the modularisation of the CO_2 capture equipment. Modularisation of the new plant provides three key benefits:

- An opportunity to minimise the high cost of installation labour in the field;
- The relative ease of transportation of process equipment to the site;
- A means for enclosing and winterising the process equipment for the ease of operation.

The construction strategy for the study is based on prefabricating the process and utility modules at Anchorage, Alaska and then transporting these modules to the Prudhoe Bay site via two sea-lifts. The four absorption trains and all supporting process equipment (stripping system, product compression, dehydration and utility plant) required in the capture facility are therefore strategically arranged in seven large sized modules with interconnecting pipe racks. The key limiting factors for each process module are:

- its overall size, dictated by both the available plot space and the maximum dimensions of the sea-lift barge;
- its weight, set by the sea-lift and road based transportation requirements.

Table 2 summarises the allocation of different process units to each module.

Table 2: Process Unit Allocation to Modules

Process Unit	Module Number
Heat Recovery Steam Generator (HRSG), Direct Contact Cooler (DCC), Blower, Absorber (Train 1)	1
HRSG, DCC, Blower, Absorber (Train 2)	2
HRSG, DCC, Blower, Absorber (Train 3)	3
HRSG, DCC, Blower, Absorber (Train 4)	4
Power Generation – Steam Turbine, CO_2 Compression & Dehydration, Plant Air, Instrument Air & Nitrogen System	5
Solvent Stripping & Reclaiming	6
Solvent Storage & Make-up, Glycol Circulation & Storage, Seawater Treatment & Waste Storage	7

In addition to the process modules, approximately eighteen pipe-way modules and sixty ductwork modules are required to connect the gas turbines and the process and utility systems together. The decision to modularise the capture plant, together with limitations imposed by the availability of transport routes to the Alaskan North Slope has a significant impact on the project schedule, estimated during the study to take a total of 57 months, with the first two trains being available for start-up after 45 months and an additional 12 months for the remaining 2 trains.

Utility Plants

Retrofitting a post combustion capture process of this scale requires the provision of significant utility systems to meet the needs of the CO_2 capture plant. Table 3 summarises the design capacities of the various utility systems required.

Table 3: Utility Plant Design Capacities

Utility	Design Capacity	Comments
HP Steam	602 Te/hr	Motive force for CO_2 compressor; Steam turbine for power generation
IP Steam	119 Te/hr	Stripper reboiler (combined with IP steam from Steam Turbine)
LP Steam	28 Te/hr	-
Cooling Medium	32,300 m^3/hr	-
Heating medium	2,310 m^3/hr	-
Sea water supply	125 m^3/hr	Compensating for steam blow down, solvent water balance and reverse osmosis unit waste
Demineralised Water	43 m^3/hr	-
Plant Air	643 Nm^3/hr	-
Instrument Air	965 Nm^3/hr	-
Nitrogen	80 Nm^3/hr	-

The steam turbine produces 69 MW(e) net of electrical power. After internal distribution of power to various process users on the CO_2 capture plant, a balance of 18 MW(e) is available for export to the local grid.

Environmental Emissions

There are a series of waste streams associated with the operation of the plant. Table 4 summarises these emissions.

The most notable emission from the CO_2 capture plant (apart from the balance of the treated flue gas components) is the reclaimer waste stream. The reclaimer produces around 5,000 tonnes per year of material, which is anticipated to require disposal. The reclaimer waste will contain a mixture of organic and inorganic compounds, typically including higher molecular weight nitrogen compounds, sodium salts and other metal salts.

The overall purpose of the capture plant is to reduce CO_2 emissions to atmosphere by capturing the CO_2 for subsequent storage. Whilst the amount of CO_2 targeted for capture equates to a total of 1.78 million tonnes of CO_2.per annum, the quantity of CO_2 emissions avoided is slightly higher than this, as the 18 MW(e) of electricity exported to the local grid from the steam turbine could be used to offset gas turbine generated power produced elsewhere on the facility.

If it is assumed that the exported power can displace essentially one Frame 5 gas turbine, a further 98,000 tonnes per annum of CO_2 emissions can be credited to the CO_2 capture plant. Hence, the total quantity of CO_2 avoided on an annual basis rises to 1.88 million tonnes per annum.

Table 4: Capture Plant Emissions

Type	Type of Emission	Average Rate	Frequency
Gas	Flue Gas from Absorbers (per train)	1,073,000 m^3/h	Continuous
Gas	Vent from Nitrogen generation package	322 Nm^3/h	Intermittent
Gas	Steam vent from intermittent blow down drum	Normally no flow	
Gas	Moisture vent from dehydration package	Small	Continuous
Liquid	Boiler drum blow down	15 m^3/h	Continuous
Liquid	Excess water from stripper reflux	Normally no flow	Intermittent
Liquid	Reject water from water treatment system	55 m^3/h	Continuous
Liquid	Reclaimer waste	100 metric tonnes/ week	Intermittent
Liquid	Filter backwash	Normally no flow	Intermittent
Solid	Spent carbon from amine filter package	63,500 kg	Once every 6 months
Solid	Disposable filter cartridges	Infrequent	Intermittent

Cost of Carbon Dioxide Capture

Tables 5 and 6 provide a break down of the total capital cost and annual operating costs associated with the proposed CO_2 capture plant.

Table 5: Capital Costs

Capture Plant Cost	Millions US$
Direct Field Cost - Process Modules (Off site)	705
Direct Field Cost - Process Modules (at North Slope)	252
Indirects	116
Home Office Costs	161
Other (start up support, owner's costs etc.)	149
Contingency (at 20%)	277
Total:	**1,660**

Table 6: Annual Operating Costs

Capture Plant Cost	Millions US$/yr
Chemicals	12.4
Maintenance (Materials & Labour)	24.9
Labour	2.2
Overheads	21.5
Insurance & Taxes	16.6
Total:	**77.7**

An indicative assessment places the likely cost of CO_2 capture from the facility (expressed as US$/tonne of CO_2 captured) at around $137/tonne (or $130/tonne of CO_2 avoided). These figures include elements of annualised capital and operating costs. The authors believe that the figures accurately reflect the potential costs of retrofitting capture technology at a location with a very harsh working environment. Some of the reasons why the cost of capture on the North Slope is so high are listed below:

- An execution strategy to cope with a two to three month annual construction window;
- A prolonged schedule of 57 months due to limited sea-lifts;
- A very high labor field cost;

- Construction strategy based on super modules weighing approximately 10,000 Te each;
- A very dilute feed gas with an average of concentration of only 3.3% CO_2 by volume;
- Multiple sources of low density gas (at 550°C) led to large collection ducts;
- A design for severe cold weather conditions mandated a costly glycol cooling system;
- Lack of fresh water resulted in an expensive water supply system that included an RO unit.

Had a less climatically challenging location been selected as the basis for this study, these costs would almost certainly be significantly reduced.

Conclusions

The present study has demonstrated that, despite the unprecedented scale, the post combustion capture of 5,200 Te/d of carbon dioxide from several gas turbines operating at BP's Central Gas Facility on the Alaskan North Slope is technically feasible, using today's best available technology.

The size of process equipment and the associated infrastructure required to support the capture plant would have a significant impact on the existing complex. The study has both highlighted and gone on to assess the cost impacts of a wide range of issues, some of which are generic to any post combustion capture scenario, but several of which are specific to the harsh environmental conditions presented by the Alaskan climate.

The capture plant produces a high purity, high pressure stream of 5,200 tonnes per day CO_2 (equivalent to 1.78 million tonnes per annum), suitable for use with an Enhanced Oil Recovery project or as an injectant stream for storage of CO_2 in a depleted reservoir or deep saline formation and in doing so, allows credit to be taken for an additional 98,000 tonnes per annum of CO_2 as a result of local electricity export.

Costs have been derived which, together with similar studies on other CO_2 capture scenarios (not reported here), will form the basis for comparison with future technology developments and will allow the participant companies of the CO_2 Capture Project to assess the cost reduction opportunities available from such developments.