

CO₂ Emission Abatement on a Natural Gas Liquid Processing Plant using Chemical Adsorption Technology: A Review

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Abstract— In this paper, a review of the impacts of a typical natural gas liquid processing plant on the environment is presented. It reviews the main processing units, the unit operation equipment and the possible emissions from these units to the environment. An analysis of the Environmental Impact Assessment is also presented. The review proffers a solution by proffering mitigation of the main pollutant, carbon dioxide, using the chemical adsorption method. Additionally, a brief evaluation of the technical and economic impacts of the proffered Mitigation technology is also presented.

Index Terms — EIA, Greenhouse gases, Ozone Layer, Emissions, Pollutants, Natural Gas, Crude Oil, Fossil Fuels

1 INTRODUCTION

Environmental concerns, depleting conventional oil reserves, increasing world energy demands, huge reserves and technological advances has led to development of energy sources such as natural gas that is considered to be more environmentally friendlier in comparison to conventional oil and other fossil fuels [1]. The superior environmental qualities of natural gas over coal or crude oil are that emissions of sulphur dioxide are negligible or that the levels of nitrous oxide and carbon dioxide emissions are lower. This helps to reduce problems of acid rain, ozone layer, and greenhouse gases [1]. However, even though natural gas is considered to be cleaner than other fossil fuels, its exploration, and production and its subsequent usage emits pollutants that have several adverse environmental impacts. This essay will seek to review the possible control technologies available in handling the main important pollutant emitted and the mechanisms involved in its generation.

1.1 Process Description of a Typical Natural Gas Liquid Processing Plant

Figure 1 Gas which is collected under pressure from underground reservoirs via group of adjacent wells goes to the mixer, from this collection point, the gas is sent to the separator where it is purified by removing the free liquid water and natural gas condensate (associated with the crude in the reservoir which the gas came in contact). Water contained in a natural gas stream may cause hydrate formation, these hydrates form when a gas or liquid containing free water experiences specific temperature and pressure conditions, hence the need for its removal. The condensate is a valuable by-product which is transported to a petroleum refinery while the wastewater is disposed of by either re-injecting it to the reservoir to stabilize the reservoir pressure or discharging it to the sea after treating to meet environmental standards (depending on the regulatory agency in country of operation).

Waste water, condensate and gas physical separation is done in a separator (pressure vessels that separate a mixed phase stream) by one or more of these three principles namely momentum, gravity settling, and coalescing; however, the

fluid phases must be immiscible and have different densities for separation to occur [1]. Gravity segregation is the main force that accomplishes the separation, which means the heaviest fluid settles to the bottom and the lightest fluid rises to the top [1]. The raw gas is then transported to a gas processing plant where further purification is carried out.

The amine gas treatment is done at this stage; it involves the use of various alkanols referred to as amines to remove hydrogen sulphide (H₂S) and carbon dioxide (CO₂) from the raw gases. The process is commonly referred to as acid gas removal and gas sweetening [2]. A typical amine gas treating process consists of an absorber unit and a regenerator unit as well as accessory equipment. In the absorber, the down flowing amine solution absorbs H₂S and CO₂ from the up flowing sour gas to produce a sweetened gas stream as a product and an amine solution rich in the absorbed acid gases. The acid gases removed from the amine treatment stage are sent to the sulphur recovery unit where the hydrogen sulphide is converted to sulphur. This is achieved through a process called the Claus process.

In the Claus process, hydrogen sulphide reacts with oxygen to yield elemental sulphur and water. The feed gas (acid gases) is first burned in the furnace using air, the hot reaction product gas, containing gaseous sulphur, is used to produce steam in a boiler (called a waste heat boiler) which results in cooling the gases. The gas is then further cooled and condensed in a heat exchanger while producing additional steam. The condensed liquid sulphur is separated from the remaining unreacted gas in the outlet end of the condenser and sent to product storage. The remaining product in this stage is called the tail gas which is sent to the Tail Gas Treatment Unit (TGTU) for further processing and recycling of sulphur. The final residue gases in the TGTU process is sent to the incinerator where it is burnt off as waste gas.

After gas sweetening, the next gas processing stage is the removal of water vapour; to ensure that a reasonable amount of water is removed in order to check hydrate formation.

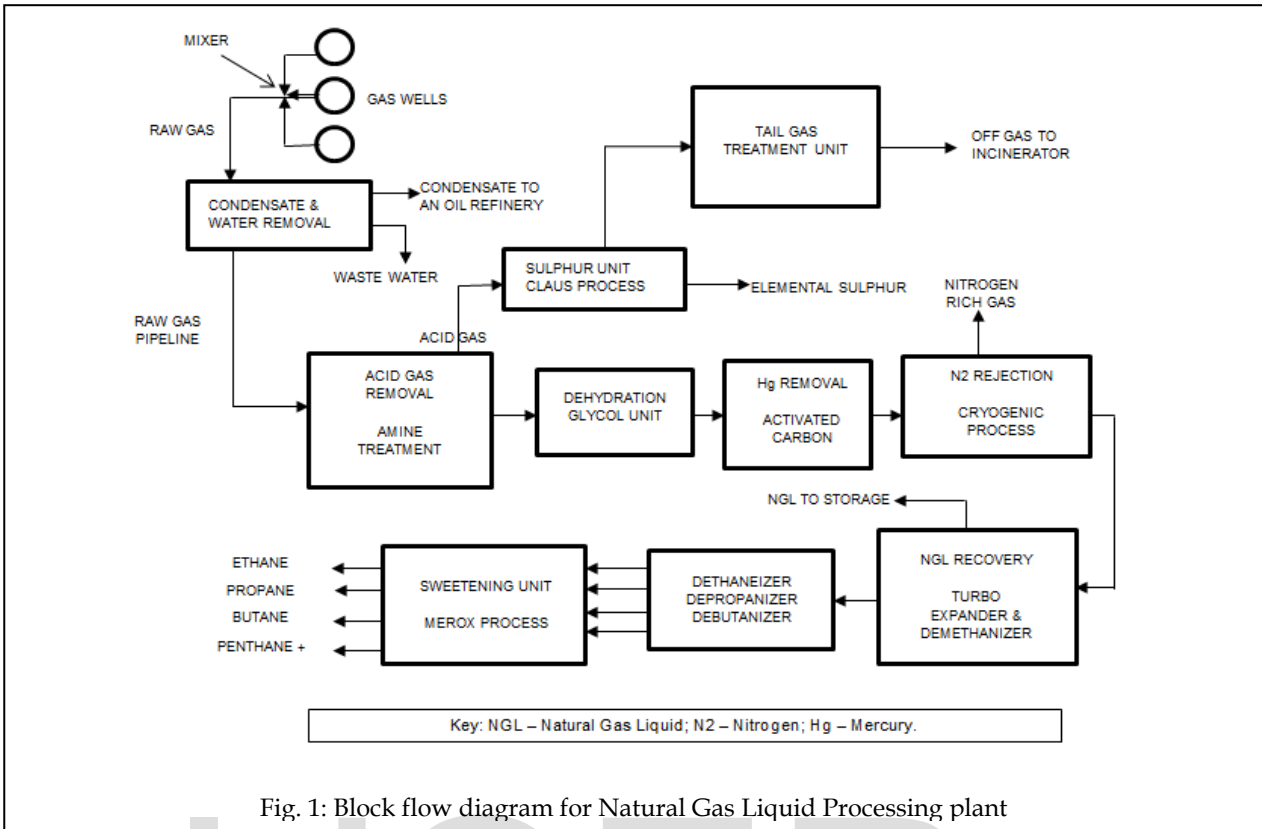


Fig. 1: Block flow diagram for Natural Gas Liquid Processing plant

Table 1: Block flow diagram for Natural Gas Liquid Processing plant

	Receptor/Resource	Impact	Pathway	Extent	Mitigation
Emissions from vents in the glycol dehydration treatment unit.	Human population	Increased respiratory disease incidence.	Ingestion of airborne H ₂ S and NO _x can cause asphyxiation while benzene and NO _x are both carcinogenic.	Local	Discourage the use of unit operation equipment designed with vents.
	Plant population	Direct damage. Increased mortality. Secondary ecological impacts.	NO _x and SO _x acidification of rain and soil	Local to regional	Same as above
	Atmospheric CO ₂ levels	Climate change (temperature and weather patterns). Secondary and tertiary impacts on social and natural systems	CO ₂ Contribution to greenhouse effect	Global	CO ₂ Capture and storage, Eliminate vents from process equipment.
Wastewater from the gas-liquid separator and the glycol dehydration unit	Sea water quality	Potential reduction in the quality of water available in the sea where the effluent will be discharged.	Disposal of wastewater to sea. Wastewater after treatment usually contains small quantity of VOCs & Oil	Local to regional	Reinjection of wastewater to reservoir from which it was produced. Complete treatment of wastewater to remove oil and VOCs.
	Marine life	Potential reduction. Secondary and community impacts	Same as above	Local to regional	Same as above
	Depletion of O ₂ level in sea water.	Depletes O ₂ in water thereby killing marine life.	The airborne N ₂ in VOCs can feed algal blooms in coastal waters. Can spur algal blooms, releasing toxins.	Local to regional	Same as above
Emissions from the Tail Gas Treatment Unit (TGTU)	Human population.	SO ₂ when emitted into the atmosphere can aggravate existing respiratory disease in humans and contribute to its development.	SO ₂ emission to the atmosphere during flaring of waste gas.	Local to regional	Elimination of flares. Incinerating waste gas.
	Human and Plant population	Harmful to a variety of flora including forage, forest, fibre, and cereal crops as well as many vegetable crops. Noise from flare can cause hearing problems, while smoke can cause asphyxiation and increased asthmatic attack),	Noise, smog and waste heat from waste gas flaring	Local to regional	Same as above.

This can be achieved by the use of ethylene glycol (glycol injection) systems as an absorption mechanism to remove water and other solids from the gas stream. Alternatively, adsorption dehydration may be used, utilizing dry-bed dehydrators towers, which contain desiccants such as silica gel and activated alumina, to perform the extraction [3]. The Tri-ethylene Glycol (TEG) process will be explained here because of its vast

the wet gas stream in what is called the 'contactor' [4]. The glycol solution absorbs water in the wet gas. Once absorption takes place, the solid particles in the gas become denser and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only

the water out of the solution. The difference in boiling point between the water vapour and the glycol solution is a factor used to remove water from the glycol solution, allowing it to be reused in the dehydration process [4]. After the removal of water vapour, the next stage entails the removal of Hg, which is done using the adsorption process shown in Fig.1.

The adsorption process makes use of the activated carbon. In this process, activated carbon, often impregnated with iodine or sulfur, is widely used to trap mercury in the gas. Nitrogen is also removed using the cryogenic process. This process involves using low temperature distillation to remove the Nitrogen.

The next stage involves the recovering of the natural gas liquids (NGL). This also involves the use of another cryogenic (low temperature distillation) process involving expansion of the gas through a turbo-expander followed by distillation in a de-methanizing fractionating column. The residue gas from the NGL recovery section is the desired product which is piped to storage.

The recovered NGL stream is processed through a fractionation train consisting of three distillation towers in series: namely a de-ethanizer, a de-propanizer and a debutanizer. The overhead product for this three fractionating column are ethane, propane and normal & iso-butane respectively. The bottom products for the de-ethanizer serve as the feed for the de-propanizer. Also, the bottom product for the de-propanizer serves as the feed for debutanizer. The recovered streams of propane, butanes and C_5^+ (Pentanes and higher alkanes) are each "sweetened", and along with the recovered ethane, are the final NGL by-products from the gas processing plant [4].

2 SOURCES OF EMISSIONS AND ENVIRONMENTAL IMPACTS

In order to have a clearer picture of the sources of emissions and the subsequent environmental impacts, it will be necessary to identify the primary constituent of natural gas which is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane (C_2H_6) and various isomers of propane (C_3H_8), butane (C_4H_{10}), and pentane (C_5H_{12}), as well as trace amounts of higher boiling hydrocarbons up to octane (C_8H_{18}). Non-hydrocarbon gases, such as CO_2 , Mercury (Hg), hydrogen sulphide (H_2S), nitrogen (N_2), and water vapour (H_2O), may also be present [5]. Emissions from a Natural Gas Processing plant as it is with any other industrial plant can be either point or non-point sources. Point sources are emissions that exit stacks and flares and, thus, can be monitored and treated. Nonpoint sources are fugitive emissions that are difficult to locate and capture [1]. Fugitive emissions may occur in NGL Plant from, valves, pipe connections, shutdown maintenance etc. Our emphasis here will be on point source emissions.

Figure The sources of emissions in a typical natural gas processing plant include;

1. Gas-liquid separator
2. Amine treatment unit (gas sweetening)
3. Glycol dehydration unit
4. Sulphur recovery unit
5. Tail gas treatment unit

2.1 Gas-Liquid Separator

The effluent from the gas-liquid separator unit is a liquid effluent emission called wastewater. Wastewater is usually oily and contains volatile organic compounds [6], thus its disposal to sea may result to reduction in water quality and may adversely affect marine life. Airborne N_2 in the VOCs enhances growth of choking aquatic vegetation or phytoplankton (e.g. algal blooms) disrupts normal functioning of the ecosystem, causing a variety of problems such as a lack of oxygen in the water, needed for fish and shellfish to survive.

2.2 Amine Treatment Unit (Gas Sweetening)

The absorbers and regenerators used in the treatment unit require power and fuels are burnt to generate this power, typical emissions for this combustion process include the gaseous effluent emissions which consists of NO_x (oxides of nitrogen with an indirect warming effects on the atmosphere by the production of tropospheric O_3), carbon monoxide (CO) (which have indirect warming effects on the atmosphere by producing tropospheric O_3 and CO_2 , as well as a reduction in tropospheric OH), and CO_2 (Carbon dioxide a major greenhouse gas which affects the earth by direct warming effect due to absorption of long-wave, terrestrial radiation). Process wastes (which include spent catalyst and absorbents for this unit) though relatively small in natural gas refining can have adverse environmental impact if not safely disposed of. These wastes are known to be contaminated by trace amounts of hydrocarbons [6]. Its impacts on the environment includes; contaminating agricultural land, threats to aquatic lives (if disposed into sea) and air emissions (hydrocarbons getting oxidized by air to yield greenhouse gases such as CO_2). Noise emissions are also inherent in this unit; this pose direct negative impacts on human lives such as hearing loss and general discomfort.

2.3 Glycol Dehydration Unit

The glycol dehydration unit which is used to further remove water from the gas streams is usually recovered by vaporizing the water in the solution while leaving behind glycol that can be reused in the dehydration unit. Regeneration of the glycol solutions used for dehydrating natural gas can release significant quantities of benzene, toluene, ethyl-benzene and xylene, as well as a wide range of less toxic organics [6]. Glycol dehydrator vent streams, if present, will be a source of air emission in the natural gas processing plant. The air pollutants that will be emitted from the vent streams include volatile organic compounds, CO; which have indirect warming effects on the atmosphere by producing tropospheric O_3 and CO_2 , as well as a reduction in tropospheric OH, NO_x ; whose indirect effect is in the production of tropospheric O_3 , CO_2 and CH_4 ; both of which are greenhouse gases. Generally, emissions from the glycol unit can cause harm to humans (CO and NO_x can cause asphyxiation while benzene and NO_x are both carcinogenic), harm to the environment (short exposure to high concentration of NO_2 can cause severe injury to leaves thereby reducing growth rates and production capabilities of plants) and marine lives (by the deposition of material in precipitation through rain, dew or snow into sea water). Table 1 shows the main emissions units in an NGL plant, receptor/resource of emission, impact, pathway, extent mitigations.

2.4 Sulphur Recovery Unit (Claus Process)

Claus process is used to recover sulphur from hydrogen sulphide. Emissions from this process include; CO, CO₂, SO₂ and liquid sulphur, these emissions can cause harm to both humans and the environment as stated in the glycol dehydration unit. The sulphur recovery unit also generates process waste from the spent catalyst and adsorbents which can have adverse effect on land when disposed of. Particulates from the reaction furnace affect the atmospheric air which may result to discomfort, irritation and an increase in the likelihood of asthmatic attacks in humans. In the environments, particulates from the sulphur recovery unit can affect the vegetation due to increase absorption of radiant energy. Noise pollution is also a factor in this unit and basically they emanate from the prime movers that power the furnace, reboilers and other accessory equipment.

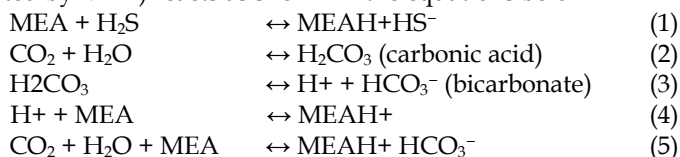
2.5 Tail Gas Treatment Unit

The tail gas treatment unit (TGTU) releases both gaseous and liquid effluent as well as particulates. During combustion of the waste gas in the flue gas stack or incinerator, gaseous emissions such as SO₂ and CO₂, are emitted to the atmosphere. SO₂ when emitted into the atmosphere can aggravate existing respiratory disease in humans and contribute to its development [7], it contributes to various types of smog that occur in industrialized nations [8]. SO₂ is also harmful to a variety of flora including forage, forest, fibre, and cereal crops as well as many vegetable crops. Noise, waste heat, odour and smoke from this flare also have adverse effects on humans (noise can cause hearing problems, while smoke can cause asphyxiation and increased asthmatic attack), and the environment (damage to the chlorophyll as a result of which plants suffer a condition equivalent to anaemia in animals, abnormalities in growth rate and a destruction of mechanisms and parts of the plants). In a NGL processing plant, the main pollutant called the acid gas consists of H₂S and CO₂, H₂S is usually converted completely to elemental sulphur, this leaves us with CO₂ as the main pollutant from the natural gas processing plant [4].

2.5.1 CO₂: The main Important Pollutant and Mechanisms of its Generation.

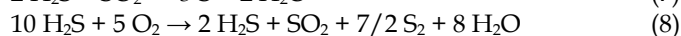
CO₂ is the main pollutant emitted as a result of the processing of natural gas [4]. It is produced together with the gas in the gas well. CO₂ is emitted to the atmosphere in an NGL processing plant through the flue gas stack during incineration or flaring of the waste gas from the tail gas treatment unit. Other sources include process vent emissions in the glycol dehydration unit and the process furnaces and boilers.

Natural gas typically contains about 1-2% by volume of CO₂ [1], but might get as high as 65% as in LaBarge gas field in Wyoming. CO₂, together with H₂S are known as acid gas and they are generally undesirable because they are corrosive and cause safety concerns. During gas sweetening, the amine (denoted by MEA) reacts as shown in the equations below



This acid-base reaction occurs with any of the alkanol-amines, regardless of the amine structure, but the reaction is not as rapid as that of H₂S, because the carbonic acid dissociation step to the bicarbonate is relatively slow [9], as a result, some of the CO₂ being sent to the sulphur recovery unit with the products. At the sulphur recovery unit the main emphasis is the recovery of sulphur from gaseous H₂S. While H₂S is taken off in this process, its side reaction yields additional CO₂ as stated in the equation of reaction.

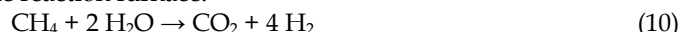
Thermal step (two-thirds of the H₂S is converted to sulphur):



Catalytic step (Further conversion of H₂S and SO₂ to Sulphur):



The trace amounts of CH₄ that accompanied the acid gas to the Claus process react with water to yield CO₂ and also the catalyst used in the Claus process also hydrolyses the carbonyl sulphide (COS) and carbon disulphide (CS₂) that is formed in the reaction furnace:



At the TGTU, the waste gas is further treated to convert any remaining H₂S to sulphur and the effluent from this unit is burnt off in the flue gas stack as well as a release of the CO₂ gases into the atmosphere as gaseous pollutants.

2.5.2 Environmental Impacts of Carbon Dioxide (CO₂)

CO₂ is a major greenhouse gas, when ranked by their contribution to the greenhouse effect; the second most important is CO₂ which contribute about 9-26% [10]. The effects of CO₂ emission in the environment include;

Humans: Human beings will be affected by increased CO₂ emission in the atmosphere by exposure to climate change through changing weather patterns (temperature, precipitation, sea-level rise and more frequent extreme events) and indirectly through changes in water, air and food quality and changes in ecosystems, agriculture, industry and settlements and the economy [11]. Specific health impacts includes; malnutrition, extreme events (such as heat waves, floods and weather disasters, and fires), infectious disease vectors (such as dengue and malaria) and cold waves in countries such as the UK [11 and references therein].

Environment: Impacts of CO₂ emissions on the environment include; possible extinctions of some freshwater ecosystems, marine ecosystems and biodiversity (e.g. by melting sea ice, affecting algae that grow on its underside), terrestrial ecosystems and biodiversity [12] [13]. Temperature rise, a major fall out of CO₂ to the atmosphere can also lead to serious regional impact to the coastal land around due to sea level rise.

3 CONTROL TECHNOLOGIES FOR CO₂ CAPTURE.

Generally, the control of CO₂ emission can be grouped into; post combustion, pre-combustion, oxy-fuel combustion and industrial process as shown below.

The CO₂ capture technologies available for the control of CO₂ emissions include;

- Liquid solvent based technologies
- Solid adsorbent based technologies
- Membrane separators
- Cryogenic systems
- Oxy-fuel

3.2 Liquid Solvent Based Technologies

This involves the use of either a physical or a chemical solvent for CO₂ capture and separation from gas streams. In physical solvents, there is CO₂ does not react with the solvent; the solubility of CO₂ in the solvent is a function of pressure, temperature and the solvent used, an example is the Morphisorb Process. The advantage of the physical solvent method is the avoidance of energy penalties associated with solvent regeneration as the CO₂ is dissolved, to a lower pressure at which it is collected [14] and its limitation lies in the fact that it is only suitable for applications where CO₂ is present at high partial pressure. Chemical based solvents, the CO₂ reacts with the solvent and is chemically bound requiring considerable amount of energy to reverse the process and release the CO₂, and example is the Monoethanolamine (MEA). It is more effective method and removes CO₂ at a wide range of concentrations and temperature. This method has a low tolerance for SO_x and NO_x [15].

3.2 Solid Adsorbent Based Technologies

In order to eliminate the extra energy used in vaporisation of water in the liquid solvent based technologies, solid adsorbents are being developed worldwide to ensure that CO₂ capture can be more energy efficient. An example is the RTI Process which involves the reaction of CO₂ with sodium carbonate, a reaction that is reversible at 2000C [15].

3.3 Membrane Separators

This method is developed to reduce cost by eliminating the large and costly unit operation equipment such as packed columns contacting towers as well as increasing the handling capacity of the flue gas to be treated; example is the Kvaerner Process. Membranes have 1000 times more surface area per unit volume compared to packed columns [16]. This method also reduces the carbon footprint of the CO₂ capture unit.

3.4 Cryogenic Systems

This systems aims to eliminate the problem of CO₂ separation, since the main method used, the cryogenic process, is best suited for high pressure streams with relatively high CO₂ concentrations. Its major drawback occurs is often when other condensable gases (e.g. water) are present in the stream. A novel approach is the US based SIMTECHE process [16].

3.5 Oxy-fuel

This entails the burning of the waste gas can in pure oxygen rather than in air. This result in a higher combustion temperature and when CO₂ capture is not required it is inherently more expensive, but when CO₂ capture is required, it gives the advantage of an exhaust stream composed almost exclusively of CO₂ and steam. CO₂ can be captured simply and cheaply by condensing the steam.

4 SELECTION AND FUNDAMENTALS OF THE MOST APPROPRIATE TECHNOLOGY

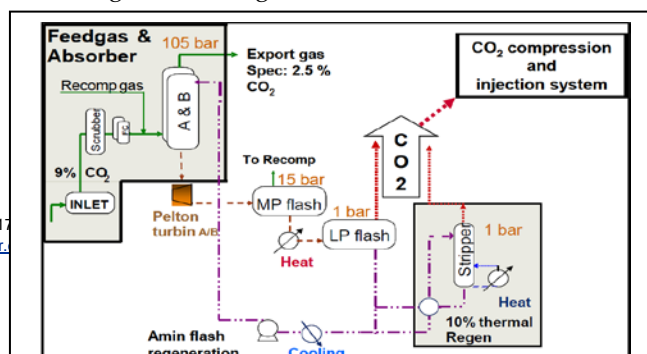
Among the various technologies available for the capture of CO₂, they are advantages and disadvantages for using each method, this together with the concentration and the pressure of CO₂ are the factors considered in selecting a viable technology for CO₂ capture.

Although the technology used in the Oxy-fuel combustion CO₂ capture is much simpler its disadvantage lies in the high cost of oxygen production, currently, large scale cryogenic air-separation for oxygen production consumes around 0.3 kWh/m³ of low pressure oxygen [17]. Cryogenic systems are used for streams containing high CO₂ volumetric concentrations (typically >90%) [18 and references therein], this technology is impractical with relatively small concentrations of CO₂. The membrane separators is in the development stages for CO₂ capture [19] [20], it is also limited by the quality of separation because the selectivity of a single membrane is usually insufficient to separate out CO₂ to the purity level required for most uses and therefore, multistage processing is usually required, incurring considerable complexity, energy consumption and capital cost [21] [15]. Solid adsorbent based technologies have the problem of low selectivity of adsorbent molecules and it also requires a low level of contaminants in the gas stream [18]. Water vapour has also been found to be a problem with some adsorption systems as polar adsorbents such as silica gel, alumina-silicates and zeolites have a very high affinity for water and will preferentially absorb water molecules leaving behind CO₂ [21]. Liquid solvent based technologies which include the physical and chemical absorption, physical absorption offers several advantages such as less energy requirement for solvent regeneration than chemical solvents [22] [23] and it requires little or no solvent since it is organic solvent [21] Since physical absorption depends on Henry's law (It is temperature and pressure dependent with absorption occurring at high pressures and low temperatures), the process is only viable at high partial pressures of CO₂ (i.e. high concentrations) [23], [24].

Hence, the selected technology for the CO₂ capture is the chemical absorption using amine; amine is chosen because of its low operating cost [1] and technically because most of the existing natural gas companies are conversant with the amine treatment unit [2] [8] [21] since it is a unit used in gas sweetening.

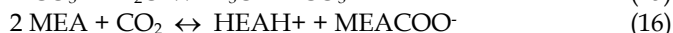
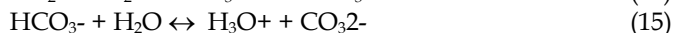
4.1 Fundamentals of the Chemical Adsorption Technology used in CO₂ Capture in a Typical Natural Gas Processing Plant.

A typical amine gas treatment unit consists of an absorber, a stripping column and accessory equipment such as pumps, reboilers, heat exchangers, condensers etc., as shown in Fig. 2 below. The gas from the gas well is sent to an absorber unit



through the bottom while alkanolamine (amine-water solution) is fed into the absorber from the top, the absorber is kept at a temperature range of 60-70°C and a pressure of 1-1.7 atm.

The alkanolamine flows downward with the aid of gravity displacing the gas in the process, when both the gas and alkanolamine makes contact; the amine through weak chemical bonding absorbs the CO₂ and some hydrocarbons. In the case of Mono-ethanolamine (MEA), the aqueous reactions for the production of the carbamate ion (HCO₃⁻) are [12] [25] [26]



CO₂-removal efficiency of the absorber depends on flow rates, temperature, pressure, gas composition, amine concentration and absorber design [27] [12]. The CO₂ free gas is collected at the top of the absorber for further processing while the CO₂ - rich amine solution is collected at the bottom of the absorber column and sent to the first of two flash drums, working at 15 bar the hydrocarbons are separated from the CO₂ - amine solution rich solution. On leaving the first flash drum, the CO₂ - amine stream is heated in a heat exchanger before it enters the second flash drum. In the second flash drum, the amine is depressurized to about 1.2 bar and the CO₂ is collected at the top of the drum, about 10% of the semi-lean liquid amine which still contains residual CO₂ is sent to the stripping column for thermal regeneration. Operating at about 120 °C, CO₂ is stripped off by steam in the stripping column. The regenerated amine is mixed with the semi lean amine and pumped back to the absorber column for a new regeneration cycle. The process achieves CO₂ of over 95% purity [28].

After CO₂ capture, they exist many storage methods depending on what is best suitable for the company; in the gas industry, CO₂ can be stored in the reservoir to stabilize the reservoir pressure due to the depletion of its content (oil or gas) from production, it can be used for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) etc.

5 EXAMPLES OF APPLICATIONS OF CO₂ CAPTURE IN NATURAL GAS PROCESSING INDUSTRY

StatoilHydro is a large oil and gas operator in the Norwegian sector of the North Sea. Discovered in 1974, the daily gas export exported as at 2009 was million cubic metres, along with this was the unwelcomed high content of CO₂ in the gas. 9% CO₂ in the well gas was to be reduced to sales gas maximum specifications of 2.5% [29]. When Sleipner Vest field came into operation in October 1996, it registered two world firsts: the installation of a large-scale offshore CO₂ extraction plant at the Sleipner Treatment platform; and the facilities for

injection from the Sleipner A platform, about 1 million tonnes of compressed CO₂ have been injected annually. The injected CO₂ is now in a dense phase and has physical properties like a liquid [30].

With stringent legislation by government, CO₂ tax emissions, CO₂ role in enhanced oil and gas recovery and the growing need to save the earth from eminent disaster due to global warming, oil and gas processing companies are beginning to embrace CO₂ capture and sequestration. Examples of companies that have towed this line include; StatoilHydro, British Petroleum (BP), Sonatrach, Gaz de France, Anadarko Petroleum, ExxonMobil.

5.1 StatoilHydro

StatoilHydro is a large oil and gas operator in the Norwegian sector of the North Sea. Discovered in 1974, the daily gas export exported as at 2009 was million cubic metres, along with this was the unwelcomed high content of CO₂ in the gas. 9% CO₂ in the well gas was to be reduced to sales gas maximum specifications of 2.5% [29]. When Sleipner Vest field came into operation in October 1996, it registered two world firsts: the installation of a large-scale offshore CO₂ extraction plant at the Sleipner Treatment platform; and the facilities for injection from the Sleipner A platform, about 1 million tonnes of compressed CO₂ have been injected annually. The injected CO₂ is now in a dense phase and has physical properties like a liquid [30].

5.2 StatoilHydro Jonit Venture

StatoilHydro and its joint ventures partners (Total, Gaz de France, Amerada, Hess and RWE Dea) operate the Snohvit field outside Northern Norway. The field which came on-stream in 2007 produces natural gas with concentrations of 5-8% [30]. Its production capacity is about 5.7 billion cubic metres of natural gas per year at optimal production. The CO₂ content has to be reduced to less than 50 parts per million (ppm) to avoid CO₂ freeze out in the LNG process. Thus 700 000 tonnes of CO₂ will be captured per year. The CO₂ is captured by amine absorption.

5.3 British Petroleum/StatoilHydro/Sonatrach

British Petroleum in joint venture with StatoilHydro and Sonatrach, an Algerian state owned Oil and Gas Company jointly run the In Salah Gas Company. The company produces about 9 billion cubic metres of market-ready gas from fields located in the desert of Central Algeria. In Salah gas fields, CO₂ concentration produced from the natural gas wells is between 1-10% and a reduction to a level of no more than 0.3% before supplying it to customers is required. The gas fields contain CO₂ with concentration. To achieve its production rate of 9 billion cubic metres of market ready gas, the capture and storage of 1.2 million tonnes of CO₂ annually is necessary. The CO₂ is stripped off from the gas stream using an amine process and injected into 3 wells in a saline formation surrounding one of the gas fields - Krechba at 1800 m depth (StatoilHydro CCS, 2010).

5.4 Gaz de France

Gaz de France is a state owned French company with oper-

ations in countries such as Netherlands, United Kingdom, Ivory Coast etc. In the Netherlands, Gaz de France is currently re-injecting CO₂ into an offshore and a nearly depleted natural gas field. The gas produced at the K12-B gas field located in the Dutch sector of the North Sea contains CO₂ of concentration 13%. In order to meet export pipeline specifications, CO₂ is removed from produced gas and re-injected. The injection began in May 2004. It is the first site ever where CO₂ was reinjected into the same reservoir it was produced. Since 2004, nearly 60,000 tonnes of CO₂ has been reinjected [31].

5.5 ExxonMobil/Anadarko Petroleum

ExxonMobil operates the LaBarge gas field which came on-stream in 1986, in southwest Wyoming. The gas which contains the lowest hydrocarbon content natural gas commercially produced in the world has a CO₂ concentration of 65%. The gas is processed at the Shute Creek Treating Facility (SCTF), about 400,000 tonnes of CO₂ captured at SCTF is reinjected into a carefully selected section of the same reservoir from which it was produced per year. Currently ExxonMobil provides 4 to 5 million tonnes of CO₂ for Enhanced Oil Recovery (EOR) [32]. Expansion project is underway to increase CO₂ capture in the field to 7 to 8 million by the end of 2010. Anadarko Petroleum, operators of the salt creek oil field buys some of the CO₂ produced at ExxonMobil's LaBarge field. To date, it has injected over 181 billion cubic feet of CO₂ into the field in its EOR and in the process sequester the CO₂ [33].

6 TECHNICAL AND ECONOMIC IMPACTS

There are various technical and economic issues associated with CO₂ Capture and Storage (CCS). In the next few years if CCS technologies are to be developed in time for their potential to be realised, significant technology development and deployment efforts are necessary and must be accompanied by the simultaneous rather than the sequential development of legal, regulatory and policy frameworks and enabled by public awareness and acceptance [17]. The technical and economic impacts of CCS include;

6.1 Technical Impact of CCS

The technical impacts associated with CO₂ NGL processing plants include;

1. Monitoring and Verification: Long term assurance monitoring through; soil and atmospheric measurements to confirm non leakage/seepage of injected CO₂ of the CO₂ reinjected into reservoirs is needed. Hydrogeological monitoring to ensure leakages of CO₂ into the overlying aquifers is prevented. This data will take a long time to acquire and validate but CCS is relatively new field [34].
2. Storage Integrity Monitoring: This will be required to monitor the predicted behaviour of the CO₂. Injected CO₂ plume will be in order to validate migration paths, migration times, shape and geomechanical integrity of the reservoir. This will help in the long term understanding of the storage risk such as leakage into portable water aquifers, leakage to surface through wells and leakage to surface from reservoirs [35].
3. Volatility and Degradation of amine solution: Due to the

volatile nature of amine, they are often losses of amine in the system. When the amine catalyst used in CO₂ adsorption degrades, it will be need replacement, the degraded amine will constitute a contaminants to the receptors which it will be disposed off. Additionally, amine-CO₂ solution is often very corrosive and poses a major problem to the stripping column.

4. Carbon footprints: The carbon footprint of the entire plant tends to increase due to the increase energy requirements that will be needed to run the CO₂ Capture plant. Increased emissions from the power plants that run the reboilers, absorbers, pumps etc, are examples of how CO₂ capture can lead to even more emissions in a plant.
5. Constraints from existing wells: The size of the depleted existing wells is not big enough to accommodate CO₂ storage from other industries.
6. Hydrate formation: The formation of hydrates in the pipeline transporting CO₂ for storage is another problem facing its sequestration as well as storage in ocean [18].
7. Acidification of sea water: CO₂ stored in the ocean might lead to the acidification of sea water.
8. Risk: A research on risk quantification is required to ensure that the risk involved with CCS is fully understood.
9. Process Integration/Size of the CCS Unit: A major challenge that is likely to face the NGL processing industry will be that of scaling down the size of the CCS unit to ensure that it is compact and lighter as much as possible to be mounted on offshore installations.

6.2 Economic Impact of CCS

Except for few companies who use the CO₂ captured in CCS for EOR and EGR, Investments in CCS will only be attractive for NGL companies if they are incentives available. Current fiscal and regulatory climate is not favourable for industries to capture and store their CO₂ emissions, as CCS reduces efficiency, adds costs and lowers energy output [36].

According to the European Commission, firms will be charged a minimum tax per metric tons of carbon dioxide emission at a suggested rate of € 4 to € 30 per ton of CO₂ [37]. The CCS unit at the Sleipner Vest field will be used for economic analysis based on the proposed CO₂ emission tax in order to explain the economic implications.

The annual operating cost of the plant ranges from € 5.5 million at inception to € 1.1 million at present [28]

Cost of Project,

$$CP = \text{€ } 220 \text{ million}$$

Average cost of annual operation,

$$CA = (5.5 + 1.1)/2 = \text{€ } 3.3 \text{ million}$$

Average CO₂ tax rate,

$$CTR = (4 + 30)/2 = \text{€ } 17$$

Quantity of CO₂ captured,

$$C_{co2} = 1 \text{ million tonnes per year.}$$

Neglecting cash depreciation and decommissioning cost, for a twenty year project life, Total project cost,

$$TP = 220 \times (17 \times 20) = \text{€ } 14,080 \text{ million}$$

If CO₂ was emitted rather than being captured, then; the total CO₂ tax is given by:

$$CT = CTR \times C_{co2} \times \text{Project life} = 17 \times 1 \times 20 = \text{€ } 340 \text{ million}$$

From the above analysis it is seen that it will be more eco-

nomical for StatoilHydro to pay the emission tax if implemented rather than capture CO₂, hence, the need for a financial regulatory framework for CCS. The constraints as stated in this example can be overcome by government support in the form of tax credits and other incentives. Public-private partnerships have been formed to address this problem but most of the projects have been cancelled or scaled back due to lack of funds.

Financing CO₂ Transport: A major challenge affecting wide-scale utilization of CCS is the need to finance infrastructure required for transport of large volume of CO₂ from capture site to storage site. Developments of a central or shared CO₂ transport system will cut CSS cost and generate efficiency on a system basis. Since the cost for this kind of network is likely to exceed the budgets of individual CCS project, governments may need to play pivotal role in its construction [17].

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