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Carbon Capture and Storage

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Abstract: Rapid industrialization and sudden growth of population around the globe from the 18th century onwards ultimately led to the uncontrolled growth of manufacturing and energy producing industries. To make processes economical industries side lined the environment which began showing its effects from the past 50 years. Ever since Global Warming (commonly attributed to the unhealthy quantities of greenhouse gasses) starting to take up the centre stage, environmentalist and chemical engineers around the globe felt the need to reinvent our industrial processes to balance economy with environmental health. Through the medium of this report we intend to highlight yet another essential need of the hour that not only has the potential to reverse the damage of high carbon release by industries but also maintain economics of plant operation. Although Carbon capture is already a subject that is in study by scientists and engineers around the globe we intend to contribute and understand its plausibility using technology and simulation as a tool to facilitate better understanding of Co2 extraction from flue gasses.

I. INTRODUCTION

CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing or from flue gas discharged. It can also be applied to the combustion of biomass-based fuels and in certain industrial processes, such as the production of hydrogen, ammonia, iron and steel, or cement.

Capturing CO2 involves separating the CO2 from some other gases. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a very long time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions.

The capture and storage of carbon dioxide is a technically feasible method of making deep reductions in CO2 emissions from sources such as those mentioned above. Although it can be implemented mainly by applying known technology developed for other purposes, its potential role in tackling climate change was not recognized as early as some other mitigation options. In recent years, the technical literature on this field has expanded rapidly. Recognizing the need for a broad approach to assessing mitigation options, the potential importance of issues relating to CO2 capture and storage and the extensive literature on other options.

CO2 is emitted principally from the burning of fossil fuels, both in large combustion units such as those used for electric power generation and in smaller, distributed sources such as automobile engines and furnaces used in residential and commercial buildings. CO2 emissions also result from some industrial and resource extraction processes, as well as from the burning of forests during land clearance. CCS would most likely be applied to large point sources of CO2, such as power plants or large industrial processes.

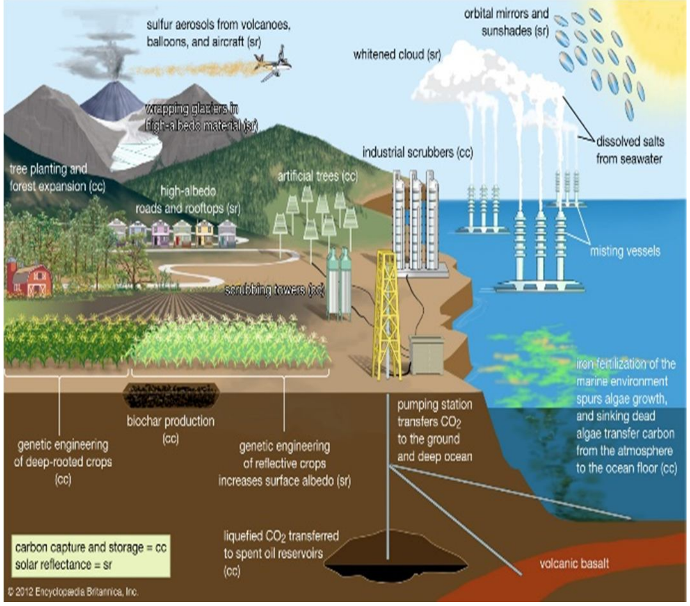


Fig. 1. Carbon Capture and Storage Overview

A. Storage Mechanism Of Captured Carbon

While Carbon Capture technology is still in the research phase in our country several facilities both in and outside of India are currently working on this technology and optimizing solutions to the challenges that arise in scaling this technology to the larger scale wherein the effect of introducing this technology will have the potential to bring about monumental impact.

Carbon storage and transport processes form the basis of the feasibility report of this technology or any related technology for that matter as ineffective transport and utilization/storage can further undo the positive impact that this technology can have for the environment.

There are various storage and transportation mechanisms that are currently under review for the carbon capture model some of which are as follows.

Pipelines are preferred for transporting large amounts of CO2 for distances up to around 1,000 km. For amounts smaller than a few million tonnes of CO2 per year or for larger distances overseas, the use of ships, where applicable, could be economically more attractive. Pipeline transport of CO2 operates as a mature market technology (in the USA, over 2,500 km of pipelines transport more than 40 MtCO2 per year). In most gas pipelines, compressors at the upstream end drive the flow, but some pipelines need intermediate compressor stations. Dry CO2 is not corrosive to pipelines, even if the CO2 contains contaminants. Where the CO2 contains moisture, it is removed from the CO2 stream to prevent corrosion and to avoid the costs of constructing pipelines of corrosion resistant material. Shipping of CO2, analogous to shipping of liquefied petroleum gases, is economically feasible under specific conditions but is currently carried out on a small scale due to limited demand. CO2 can also be carried by rail and road tankers, but it is unlikely that these could be attractive options for large-scale CO2 transportation. Storage of CO2 in deep, onshore or offshore geological formations (Geological Storage) uses many of the same technologies that have been developed by the oil and gas industry and has been proven to be economically feasible under specific conditions for oil and gas fields and saline formations, but not yet for storage in unminable coal beds (see Figure 2)

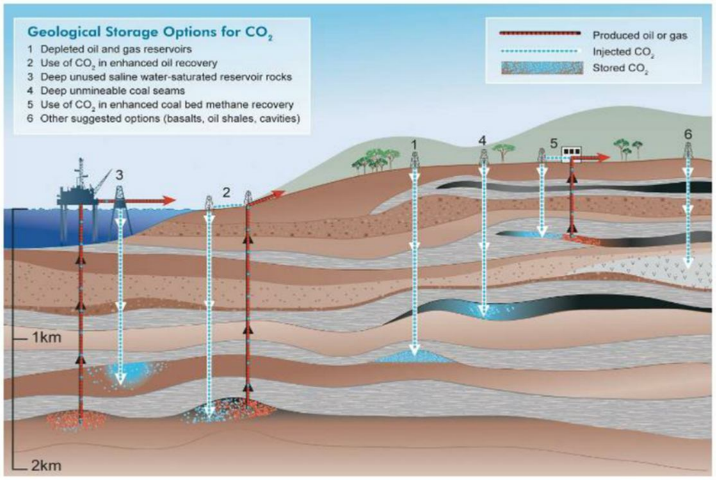


Figure .2 Geological Storage Options

If CO2 is injected into suitable saline formations or oil or gas fields, at depths below 800m, various physical and geochemical trapping mechanisms would prevent it from migrating to the surface. In general, an essential physical trapping mechanism is the presence of a caprock10. Coal bed storage may take place at shallower depths and relies on the adsorption of CO2 on the coal, but the technical feasibility largely depends on the permeability of the coal bed. The combination of CO2 storage with Enhanced Oil Recovery (EOR11) or, potentially, Enhanced Coal Bed Methane recovery (ECBM) could lead to additional revenues from the oil or gas recovery. Well-drilling technology, injection technology, computer simulation of storage reservoir performance and monitoring methods from existing applications are being developed further for utilization in the design and operation of geological storage projects. Three industrial scale storage projects are in operation:

1) The Sleipner project in an offshore saline formation in Norway,
2) The Weyburn EOR project in Canada, and
3) The In Salah project in a gas field in Algeria.
4) Others are planned

Ocean storage potentially could be done in two ways: by injecting and dissolving CO2 into the water column (typically below 1,000 meters) via a fixed pipeline or a moving ship, or by depositing it via a fixed pipeline or an offshore platform onto the sea floor at depths below 3,000 m, where CO2 is denser than water and is expected to form a "lake" that would delay dissolution of CO2 into the surrounding environment (see Figure 3). Ocean storage and its ecological impacts are still in the research phase.

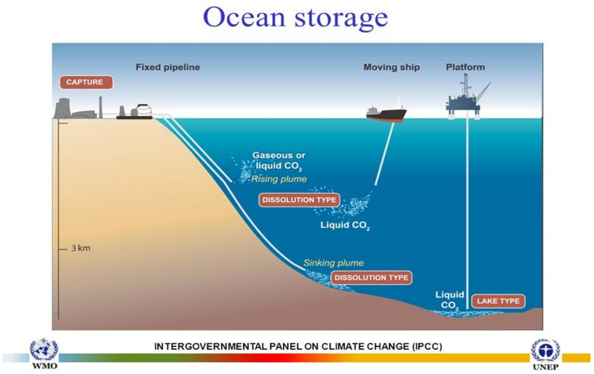
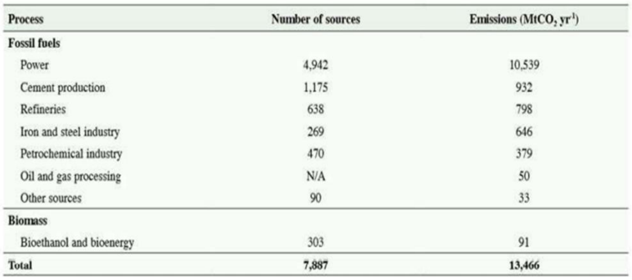


Figure 3. Ocean Storage Options

II. CURRENT CO2 SOURCES

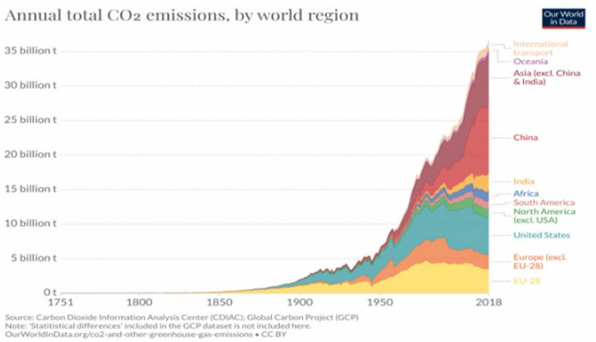
To assess the potential of CCS as an option for reducing global CO2 emissions, the current global geographical relationship between large stationary CO2 emission sources and their proximity to potential storage sites has been examined. CO2 emissions in the residential, commercial and transportation sectors have not been considered in this analysis because these emission sources are individually small and often mobile, and therefore unsuitable for capture and storage. The discussion here also includes an analysis of potential future sources of CO2 based on several scenarios of future global energy use and emissions over the next century.

Globally, emissions of CO2 from fossil-fuel use in the year 2000 totalled about 23.5 GtCO2 yr-1 (6 GtC yr-1). Of this, close to 60% was attributed to large (>0.1 MtCO2 yr-1) stationary emission sources (see Table 1).



Process	Number of sources	Emissions (MtCO$_2$ yr^{1})
Fossil fuels		
Power	4,942	10,539
Cement production	1,175	932
Refineries	638	798
Iron and steel industry	269	646
Petrochemical industry	470	379
Oil and gas processing	N/A	50
Other sources	90	33
Biomass		
Bioethanol and bioenergy	303	91
Total	**7,887**	**13,466**

Table-1 : Industries with CO2 emissions of more than 0.1 Mt per year



Source: Carbon Dioxide Information Analysis Center (CDIAC); Global Carbon Project (GCP)
Note: 'Statitistical differences' included in the GCP dataset is not included here.
OurWorldInData.org/co2-and-other-greenhouse-gas-emissions • CC BY

1) The above interactive chart shows the breakdown of global CO2 emissions by region.
2) We see that until well into the 20th century, the global emissions were dominated by Europe and the United States. In 1900, more than 90% of emissions were produced in Europe or the US; even by 1950, they accounted for more than 85% of emissions each year.

But in recent decades this has changed significantly.

In the 2nd half of 20th century, we see a significant rise in emissions in the rest of the world, particularly across Asia, and most notably, China.

The US & Europe now account for just under one-third of emissions.

III. FUTURE EMISSION SOURCES

The future emissions of CO2 are projected on the basis of six illustrative scenarios in which global CO2 emissions range from 29 to 44 GtCO2 (8–12 GtC) per year in 2020, and from 23 to 84 GtCO2 (6–23 GtC) per year in 2050. It is projected that the number of CO2 emission sources from the electric power and industrial sectors will increase significantly until 2050, mainly in South and East Asia. By contrast, the number of such sources in Europe may decrease slightly. The proportion of sources with high and low CO2 content will be a function of the size and rate of introduction of plants employing gasification or liquefaction of fossil fuels to produce hydrogen, or other liquid and gaseous products. The greater the number of these plants, the greater the number of sources with high CO2 concentrations technically suitable for capture. The projected potential of CO2 capture associated with the above emission ranges has been estimated at an annual 2.6 to 4.9 GtCO2 by 2020 (0.7–1.3 GtC) and 4.7 to 37.5 GtCO2 by 2050 (1.3–10 GtC). These numbers correspond to 9–12%, and 21–45% of global CO2 emissions in 2020 and 2050, respectively. The emission and capture ranges reflect the inherent uncertainties of scenario and modelling analyses, and the technical limitations of applying CCS. These scenarios only take into account CO2 capture from fossil fuels, and not from biomass sources. However, emissions from large scale biomass conversion facilities could also be technically suitable for capture.

The potential development of low-carbon energy carriers is relevant to the future number and size of large, stationary CO2 sources with high concentrations. Scenarios also suggest that large-scale production of low-carbon energy carriers such as electricity or hydrogen could, within several decades, begin displacing the fossil fuels currently used by small, distributed sources in residential and commercial buildings and in the transportation sector (see Section 8). These energy carriers could be produced from fossil fuels and/or biomass in large plants that would generate large point sources of CO2 (power plants or plants similar to current plants producing hydrogen from natural gas). These sources would be suitable for CO2 capture. Such applications of CCS could reduce dispersed CO2 emissions from transport and from distributed energy supply systems. At present, however, it is difficult to project the likely number, size, or geographical distribution of the sources associated with such developments

IV. CARBON CAPTURE METHODS

Carbon capture has actually been in use for years. The oil and gas industries have used carbon capture for decades as a way to enhance oil and gas recovery. Only recently have we started thinking about capturing carbon for environmental reasons. Currently, most research focuses on carbon capture at fossil fuel-powered energy plants, the source of the majority of man-made CO2 emissions. Many of these power plants rely on coal to create energy, and the burning of coal emits CO2 into the atmosphere. Some researchers envision a future where all new power plants employ carbon capture.

Three processes for CO2 capture have been classified which are as follows:-

A. Post Combustion Capture

In this process, CO2 is removed from the flue gas produced after combustion of the fuel. A schematic of post-combustion capture is presented in Figure-4

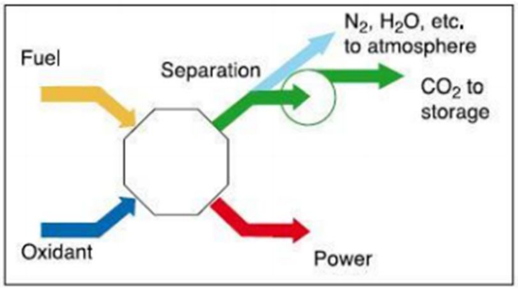


Figure-4 : Post combustion capture

With post-combustion -carbon capture, the CO2 is grabbed after the fossil fuel is burned. The burning of fossil fuels- produces something called flue gases, which include CO2, water vapor, sulfur dioxides and nitrogen oxides. In a post-combustion process, CO2 is separated and captured from the flue gases that result from the combustion of fossil fuel. This process is currently in use 16 to remove CO2 from natural gas. The biggest benefit to using this process is that it allows us to retrofit older power plants, by adding a "filter" that helps trap the CO2 as it travels up a chimney or smokestack. This filter is actually a solvent that absorbs carbon dioxide. The solvent can later be heated, which will release water vapor and leave behind a concentrated stream of CO2.- Postcombustion carbon capture can prevent 80 to 90 percent of a power plant's carbon emissions from entering the atmosphere. But the post-combustion process requires a lot of energy to compress the gas enough for transport.

B. *Pre Combustion Capture*

In this process, carbon content of the fuel is reduced before combustion so as to produce pure CO2 on combustion. Figure-5 given below presents a schematic of precombustion decarbonization.

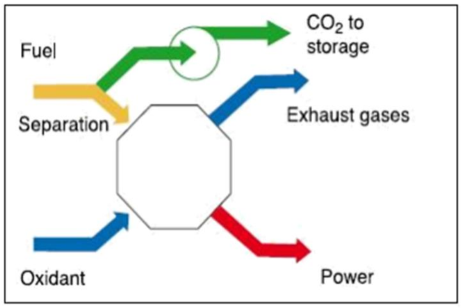


Figure-5: Pre-combustion capture

With precombustion carbon capture,- CO2 is trapped before the fossil fuel is burned. That means the CO2 is trapped before it's diluted by other flue gases. Coal, oil or natural gas is heated in pure oxygen, resulting in a mix of carbon monoxide and hydrogen. This mix is then treated in a catalytic converter with steam, which then produces more hyd-rogen, along with carbon dioxide. These gases are fed into the bottom of a flask. The gases in the flask will naturally begin to rise, so a chemical called amine is poured into the top. The amine binds with the CO2, falling to the bottom of the flask. The hydrogen continues rising, up and out of the flask. Next, the amine/CO2 17 mixt-ure is heated. The CO2 rises to the top for collection, and the amine drops to the bottom for reuse. The excess hydrogen also can be used for other energy production processes. Precombustion carbon capture is already in use for natural gas, and provides a much higher concentration of CO2 than post-combustion. The precombustion process is lower in cost, but it's not a retrofit for older power plant generators. As with post-combustion, precombustion carbon capture can prevent 80 to 90 percent of a power plant's emissions from entering the atmosphere

C. *Oxyfuel Combustion*

Here instead of air, combustion is taken place in the presence of oxygen which prevents dilution of CO2 with other gases.

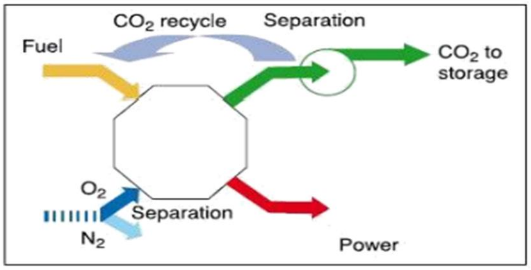


Figure 6: Oxyfuel Combustion Capture

With oxy-fuel combustion carbon capture, the power plant burns fossil fuel in oxygen. This results in a gas mixture comprising mostly steam and CO2. The steam and carbon dioxide are separated by cooling and compressing the gas stream. The oxygen required for this technique increases costs, but researchers are developing new techniques in hopes of bringing this cost down. Oxy-fuel combustion can prevent 90 percent of a power plant's emissions from entering the atmosphere.

V. SOLVENT SELECTION

Among the wide portfolio of CCS technologies, Physical and Chemical absorption are considered the most close-to-market approaches to be applied at industrial scale.

Physical absorption is based on the CO2 solubility into the solution without chemical reaction which is based on Henry's law and hence high CO2 partial pressures and low-temperatures are highly recommended for its application. **Chemical absorption** is based on the reaction between CO2 and specific compounds—solvents— that lead to form a weak bond between CO2and the solvent. Chemical absorption occurs indeed at low CO2 partial pressure.

Main constrains limiting its deployment:

1) The huge volume of gas to be treated,
2) The low CO2 concentration in the flue gas,
3) The presence of trace components such as NOx, SO2 and particulate matter which degrade the solvents.

A. *Chemical Absorption Solvent*

1) *Conventional Amine-based Solvents:* The amine-based chemical absorption process has been used for CO2 and H2S removal—acid gas removal—from gas-treating plants since 1950s and are considered to be by far the most developed CO2 capture process. CO2 is absorbed typically using amines to form a soluble carbonate salt. The absorber operates below 60°C and ambient pressure. This reaction is reversible and the CO2 can be released by heating the solution with the carbonate salt in a separate stripping column. The CO2 stripping occurs at 120°C and pressures ranging between 1.8 and 3 bar.

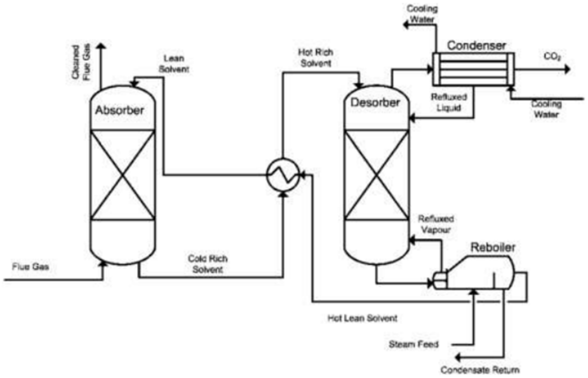


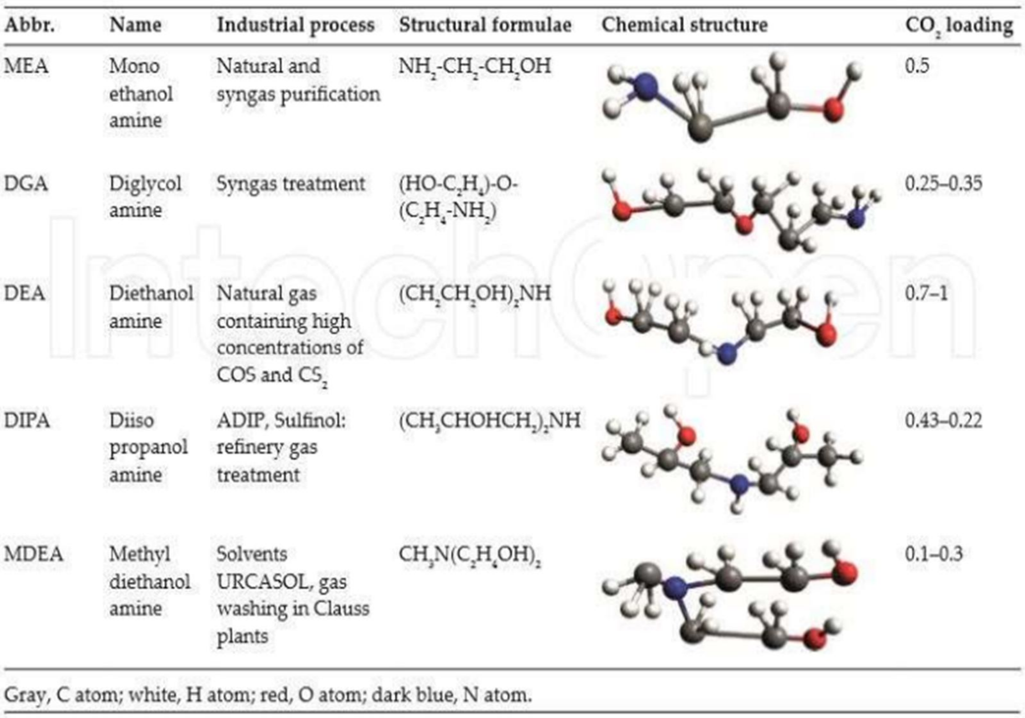
Figure 7: Simplified diagram of a conventional acid gas removal process using chemical absorption

The alkanolamines are volatile, cheap and safe to handle compounds and are commonly classified by the degree of substitution on the central nitrogen; a single substitution denoting a primary amine; a double substitution, a secondary amine; and a triple substitution, a tertiary amine. Each of the above-mentioned alkanolamines has at least one hydroxyl group and one amino group. In general, the hydroxyl group serves to reduce vapour pressure and increases the solubility in water, while the amine group provides the necessary alkalinity in aqueous solutions to promote the reaction with acid gases. Therefore, the molecular structures of primary and secondary amines are the non-fully substituted alkanolamines and they have hydrogen atoms at the non-substituted valent sites on the central nitrogen, whereas the tertiary amines are fully substituted on the central nitrogen. This structural characteristic plays an important role in the acid gas removal capabilities of the various treating solvents.

a) Primary alkanolamines such as --**monoethanolamine** (MEA) and **diglycolamine** (DGA), provide high chemical reactivity, favored kinetics, medium-to-low absorption capacity and acceptable stability. **Monoethanolamine** (MEA), the first-generation and the most well-known amine-based absorbent, is highlighted by its high chemical reactivity with CO2 and low cost.
b) Secondary alkanolamines such as **diethanolamine** (DEA) and **diisopropanolamine** (DIPA), which have a hydrogen atom directly bonded to the nitrogen, shows intermediate properties compared to primary amines and they are considered as an alternative to MEA.
c) Tertiary amines such as **triethanolamine** (TEA) or **methyldiethanolamine** (MDEA), that are characterized by having a high equivalent weight, which causes a low absorption capacity, low reactivity and high stability.

The main issues that amine-based chemical absorption has to address to be applied as industrial scale for carbon dioxide emission mitigation are:

- High energy consumption during the solvent regeneration.
- Corrosion requires the use of both inhibitors and resistant materials in their application.
- Scale up from actual (800 t/day) to required (8000 t/day) CO2 capacity.
- Degradation in the presence of O2, SOx and other impurities such as particles, HCl, HF and Hg.

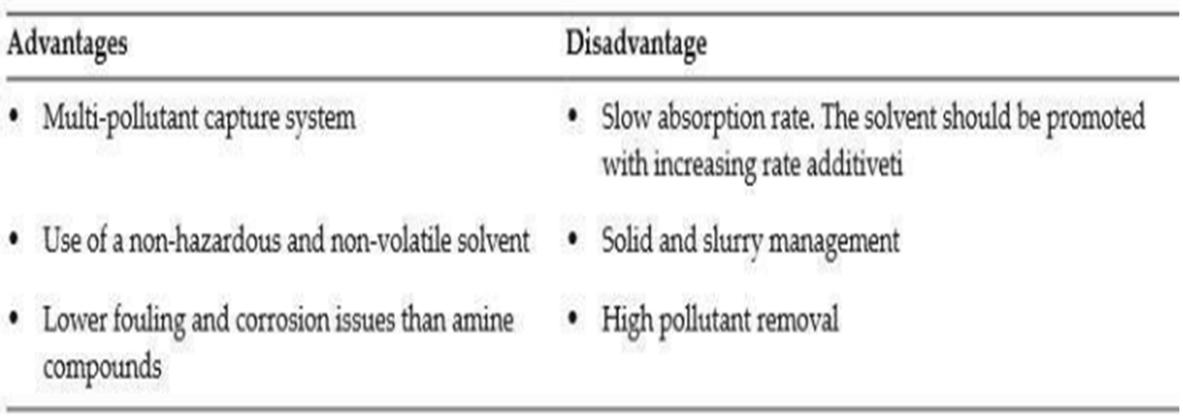


Abbr.	Name	Industrial process	Structural formulae	Chemical structure	CO_2 loading
MEA	Mono ethanol amine	Natural and syngas purification	NH_2-CH_2-CH_2OH		0.5
DGA	Diglycol amine	Syngas treatment	(HO-C_2H_4)-O-(C_2H_4-NH_2)		0.25–0.35
DEA	Diethanol amine	Natural gas containing high concentrations of COS and CS_2	$(CH_2CH_2OH)_2NH$		0.7–1
DIPA	Diiso propanol amine	ADIP, Sulfinol: refinery gas treatment	$(CH_3CHOHCH_2)_2NH$		0.43–0.22
MDEA	Methyl diethanol amine	Solvents URCASOL, gas washing in Clauss plants	$CH_3N(C_2H_4OH)_2$		0.1–0.3

Gray, C atom; white, H atom; red, O atom; dark blue, N atom.

Table-2: Most commonly amines used in acid gas treatment

2) *Non Amine Based Solvents:* Non-amine-based solvents are called to those chemical solvents which do not integrate an amine group in their structure molecular. The most relevant solvent proposed as an alternative to the conventional amine-based solvents is the sodium carbonate (Na2CO3). About 30% p/p sodium carbonate slurry is used to provide a basic environment in which CO2 is absorbed as bicarbonate followed by sodium bicarbonate formation. The NaHCO3 precipitation enhances the bicarbonate formation and, hence, the CO2 capture capacity of the solvent is improved.



Advantages	Disadvantage
• Multi-pollutant capture system	• Slow absorption rate. The solvent should be promoted with increasing rate additiveti
• Use of a non-hazardous and non-volatile solvent	• Solid and slurry management
• Lower fouling and corrosion issues than amine compounds	• High pollutant removal

Table-3: Advantages and disadvantages of CCS based on chemical absorption using Na2CO3

B. Physical Absorption Solvents

Physical absorption processes are highly recommended to separate CO2 in pre-combustion processes that commonly operate at elevate CO2 partial pressure. Physical solvents are able to selectively capture CO2 in contact with a gas stream without a chemical reaction occurring. As it was indicated in the introduction section, the high partial pressures of CO2 and low temperatures are desirable to obtain an optimized performance of the physical absorption process in terms of absorption rates and solubility equilibrium of CO2. Then, the rich (CO2 loaded) solvent is regenerated.

PROCESS	ADVANTAGES	DISADVANTAGES
Selexo	• Non-thermal solvent regeneration. • Non-corrosive solvent. • Dry gas leaves from the absorber.	• Most efficient at elevated pressures.
Rectisol	• Non-foaming solvent.	• High Refrigeration cost.
Ipexol-2	• High chemical and thermal stability • Non-corrosive solvent	• High capital costs • Amalgams formation at low T
Fluor	• High CO2 solubility • Non-thermal regeneration • Simple operation • Non-corrosive solvent	• High solvent circulation rates • Expensive solvent
Purisol	• Non-foaming solvent	• High Compression Cost

Table-4: Advantages and Disadvantages of Common Solvents

VI. METHYLDIETHANOLAMINE

As there are three alkyl groups present in MDEA, the reaction between CO2 and MDEA is hindered. Therefore, CO2 dissolves in H2O first to form carbonic acid (H2CO3), and then carbonic acid reacts with amine. The following reaction takes place:

$CO_2 + H_2O + MDEA \leftrightarrow MDEAH^{+} HCO_3^{-}$

Nowadays aqueous solutions of MEA are used mainly. The major advantages of MEA are: large reactivity, cheap, and less capacity for absorption of hydrocarbons. The main disadvantages of MEA are: High corrosiveness of MEA which increases by temperature, large heat of reaction with CO2 and H2S results in large energy requirements for the regeneration of solvent and subsequently the total cost for the process is raised, relatively large vapour pressure which sees amine losses through vaporization.

Though MDEA is costlier than MEA, but it has lower rate of reaction with CO2 as compared to other amines which makes it suitable to use in various industries.

The main reactions taking place in CO2-MDEA-H2O system are as follows:

Water dissociation equilibrium:
$2H_2O \leftrightarrow H_3O^{+} + OH^{-}$

Bicarbonate formation equilibrium:
$CO_2 + 2H_2O \leftrightarrow H_3O^{+} + HCO_3^{-}$

Carbonate formation equilibrium:
$H_2O + HCO_3^{-} \leftrightarrow H_3O^{+} + CO_3^{2-}$

MDEA protonation equilibrium:
$H_3O^{+} + MDEA \leftrightarrow H_2O + MDEA^{+}$

VII. SIMULATION OF MDEA SYSTEM USING DWSIM

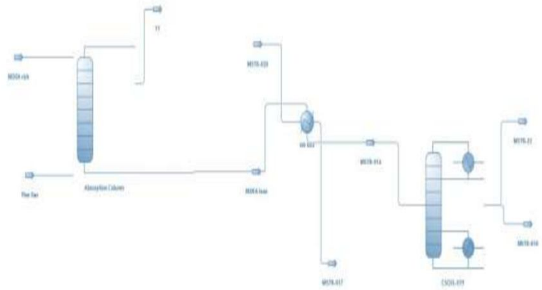


Figure-8: DWSIM Simulation of CO2 capture using MDEA

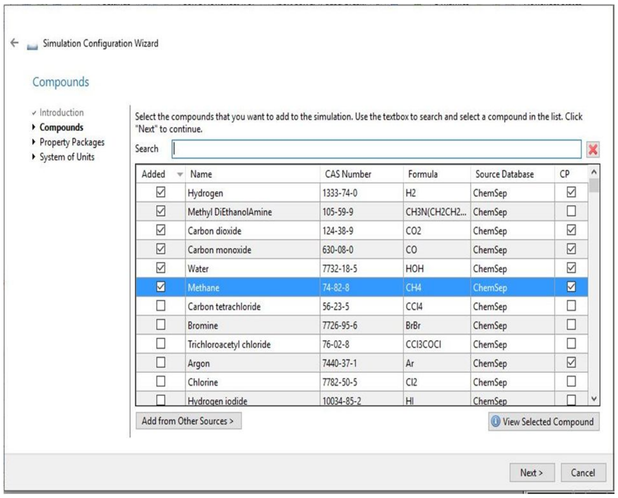
DWSIM is an open source simulation software that is widely used for simulating chemical processes to a certain level of accuracy. Using DWSIM any unit operation or a combination of various operations that result in a process can be simulated and results can be estimated which may be used as evidences to judge the feasibility of the process in question.

One of the most widely used methods of carbon capture is through absorption in MDEA solvent.

Using a sample flue gas concentrated with a certain amount of Co2 we simulated a flowsheet in the following steps to indicate the efficiency with which an MDEA rich solution can absorb the co2 from the stream of gases in the given flue gas system.

A. Procedures For Developing The Flowsheet

1) After providing the project title and name of the account, first the different components were selected as shown below.



Simulation Configuration Wizard

Compounds

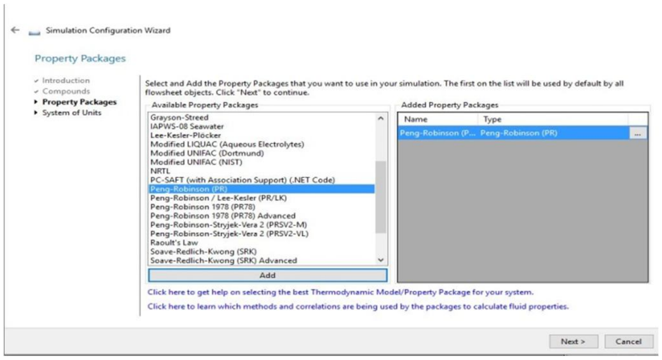
- ✓ Introduction
- **Compounds**
- Property Packages
- System of Units

Select the compounds that you want to add to the simulation. Use the textbox to search and select a compound in the list. Click "Next" to continue.

Search

Added	Name	CAS Number	Formula	Source Database	CP
☑	Hydrogen	1333-74-0	H2	ChemSep	☑
☑	Methyl DiEthanolAmine	105-59-9	CH3N(CH2CH2...	ChemSep	☐
☑	Carbon dioxide	124-38-9	CO2	ChemSep	☑
☑	Carbon monoxide	630-08-0	CO	ChemSep	☑
☑	Water	7732-18-5	HOH	ChemSep	☑
☑	Methane	74-82-8	CH4	ChemSep	☑
☐	Carbon tetrachloride	56-23-5	CCl4	ChemSep	☐
☐	Bromine	7726-95-6	BrBr	ChemSep	☐
☐	Trichloroacetyl chloride	76-02-8	CCl3COCl	ChemSep	☐
☐	Argon	7440-37-1	Ar	ChemSep	☑
☐	Chlorine	7782-50-5	Cl2	ChemSep	☐
☐	Hydrogen iodide	10034-85-2	HI	ChemSep	☐

2) After Selecting the Components, from the set of the given property Packages, we add the Peng Robinson Package



Simulation Configuration Wizard

Property Packages

- ✓ Introduction
- ✓ Compounds
- **Property Packages**
- System of Units

Select and Add the Property Packages that you want to use in your simulation. The first on the list will be used by default by all flowsheet objects. Click "Next" to continue.

Available Property Packages

- Grayson-Streed
- IAPWS-08 Seawater
- Lee-Kesler-Plöcker
- Modified LIQUAC (Aqueous Electrolytes)
- Modified UNIFAC (Dortmund)
- Modified UNIFAC (NIST)
- NRTL
- PC-SAFT (with Association Support) (.NET Code)
- Peng-Robinson (PR)
- Peng-Robinson / Lee-Kesler (PR/LK)
- Peng-Robinson 1978 (PR78)
- Peng-Robinson 1978 (PR78) Advanced
- Peng-Robinson-Stryjek-Vera 2 (PRSV2-M)
- Peng-Robinson-Stryjek-Vera 2 (PRSV2-VL)
- Raoult's Law
- Soave-Redlich-Kwong (SRK)
- Soave-Redlich-Kwong (SRK) Advanced

Added Property Packages

Name	Type
Peng-Robinson (P...	Peng-Robinson (PR)

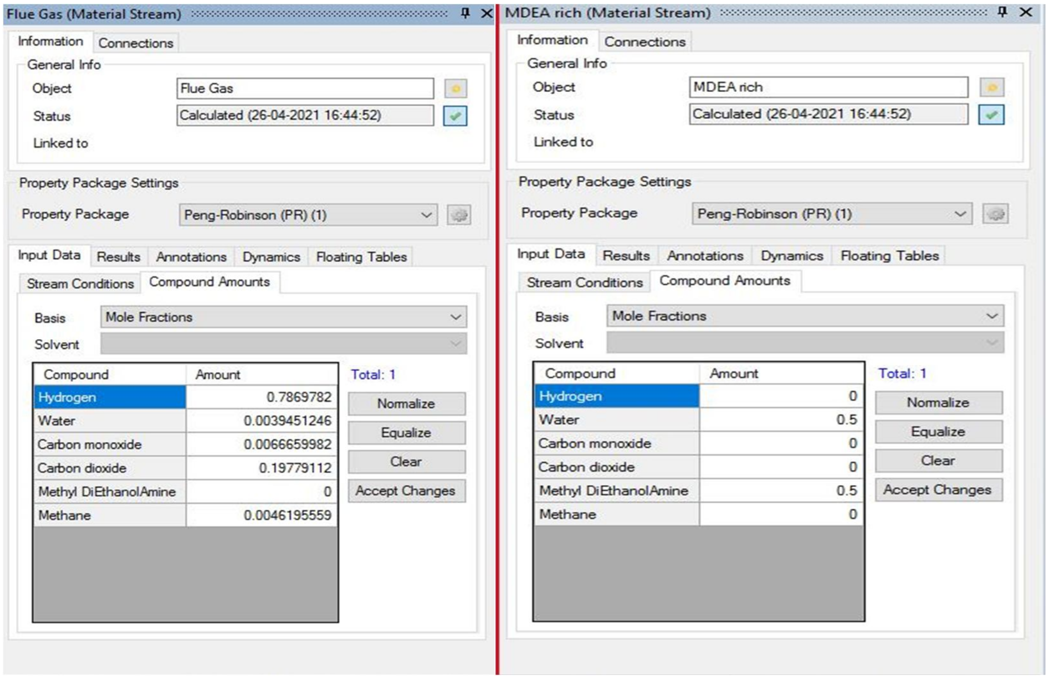
Click here to get help on selecting the best Thermodynamic Model/Property Package for your system.

Click here to learn which methods and correlations are being used by the packages to calculate fluid properties.

3) After adding the Property Package, we finally change The System of units to SI.

4) Next, we introduce our two input Streams – Flue Gas and the Solvent Stream. The Flue gas was initially fed to the Absorption Column at a temperature and pressure of 310 K and 1600 kPa respectively. MDEA was then fed at 298 K with a pressure of 1600 kPa and with a flow rate of 185kg/s.

5) The Composition of the Respective Feed Streams are then specified.



Flue Gas (Material Stream)

Object: Flue Gas
Status: Calculated (26-04-2021 16:44:52)
Linked to
Property Package: Peng-Robinson (PR) (1)
Basis: Mole Fractions
Solvent

Compound	Amount
Hydrogen	0.7869782
Water	0.0039451246
Carbon monoxide	0.0066659982
Carbon dioxide	0.19779112
Methyl DiEthanolAmine	0
Methane	0.0046195559

Total: 1

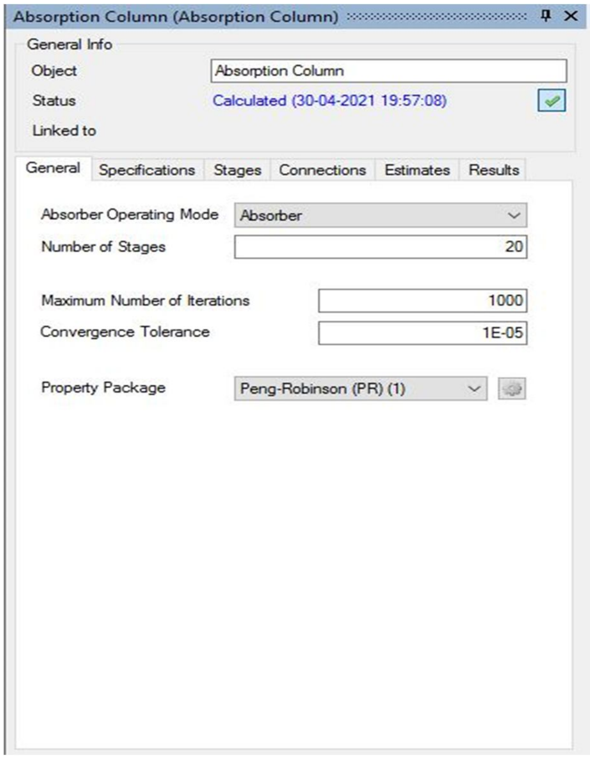
MDEA rich (Material Stream)

Object: MDEA rich
Status: Calculated (26-04-2021 16:44:52)
Linked to
Property Package: Peng-Robinson (PR) (1)
Basis: Mole Fractions
Solvent

Compound	Amount
Hydrogen	0
Water	0.5
Carbon monoxide	0
Carbon dioxide	0
Methyl DiEthanolAmine	0.5
Methane	0

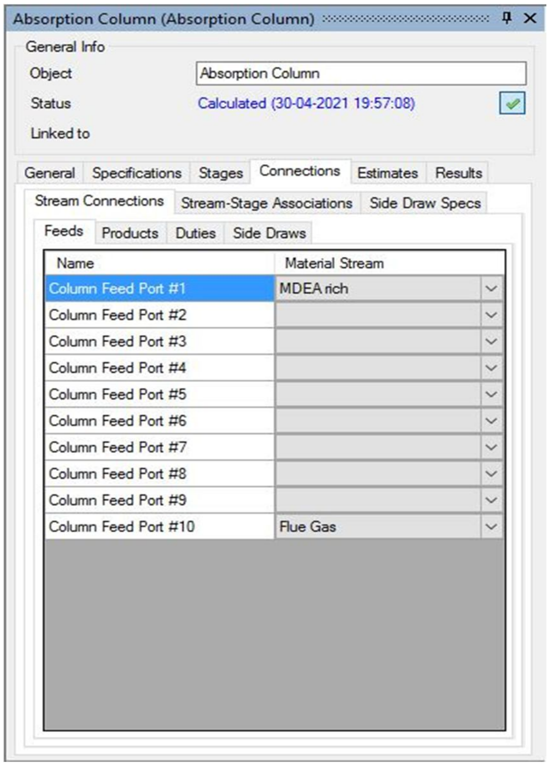
Total: 1

6) After the streams were successful specified, next the Streams are connected to the Absorption Column. And the required Specifications are filled up.



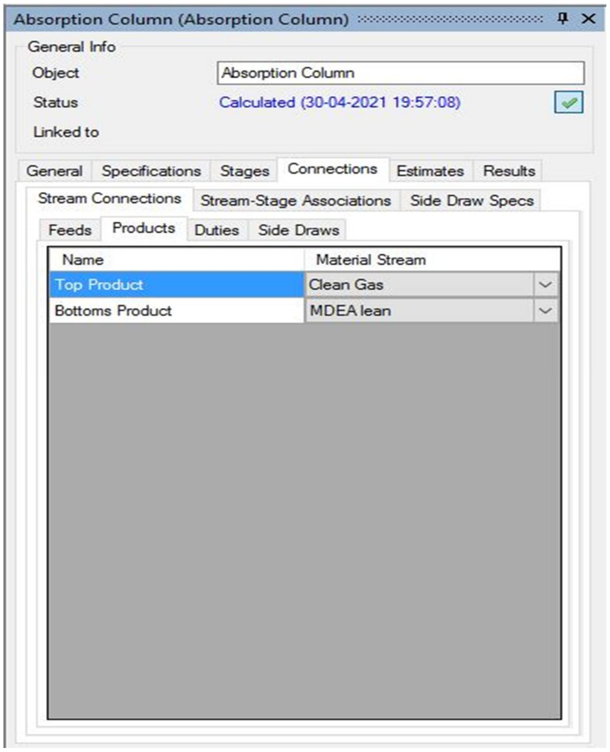
Absorption Column (Absorption Column)

Object: Absorption Column
Status: Calculated (30-04-2021 19:57:08)
Linked to
Absorber Operating Mode: Absorber
Number of Stages: 20
Maximum Number of Iterations: 1000
Convergence Tolerance: 1E-05
Property Package: Peng-Robinson (PR) (1)



Object: Absorption Column
Status: Calculated (30-04-2021 19:57:08)
Linked to

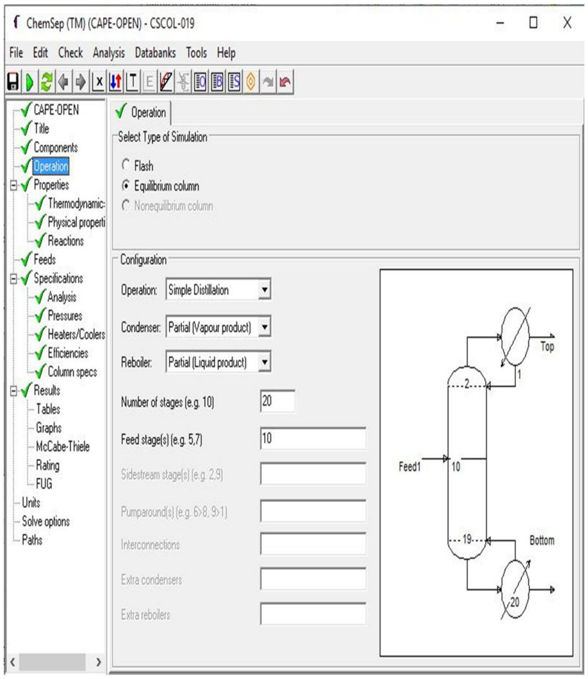
Name	Material Stream
Column Feed Port #1	MDEA rich
Column Feed Port #2	
Column Feed Port #3	
Column Feed Port #4	
Column Feed Port #5	
Column Feed Port #6	
Column Feed Port #7	
Column Feed Port #8	
Column Feed Port #9	
Column Feed Port #10	Flue Gas



Object: Absorption Column
Status: Calculated (30-04-2021 19:57:08)
Linked to

Name	Material Stream
Top Product	Clean Gas
Bottoms Product	MDEA lean

7) We see 2 Product streams coming out of the Absorption Column – The Clean Gas and The MDEA Lean stream. The Clean Gas stream is the Flue Gas Stream from which maximum Carbon dioxide and Carbon monoxide are absorbed. The MDEA Lean stream comprises MDEA-CO2-H20 Complex.
8) The MDEA lean stream is Preheated before it is fed to the Desorber.
9) The Heated MDEA Lean stream is then fed to the Desorber, Where CO2 and MDEA are separated.



Select Type of Simulation
○ Flash
● Equilibrium column
○ Nonequilibrium column

Configuration
Operation: Simple Distillation
Condenser: Partial (Vapour product)
Reboiler: Partial (Liquid product)
Number of stages (e.g. 10): 20
Feed stage(s) (e.g. 5,7): 10
Sidestream stage(s) (e.g. 2,9):
Pumparound(s) (e.g. 6>8, 9>1):
Interconnections:
Extra condensers:
Extra reboilers:

B. Results & Discussion

After the initial run we found the CO_2 conversion to be 99.78 %.

	Flue Gas	Clean Gas	Captured CO_2		
Amount of CO_2 *(Mol/s)*	83.78590	0.18083	83.60490		

Since these values Correspond to a Computerized Simulation, we can expect that Experimental Values shall deviate as a result of unaccounted disturbances.

VIII. ANALYSIS OF POSSIBLE LOGISTICAL HAZARDS

Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1,000 years. For well-selected, designed and managed geological storage sites, the vast majority of the CO2 will gradually be immobilized by various trapping mechanisms and, in that case, could be retained for up to millions of years. Because of these mechanisms, storage could become more secure over longer timeframes. Release of CO2 from ocean storage would be gradual over hundreds of years.

Ocean tracer data and model calculations indicate that, in the case of ocean storage, depending on the depth of injection and the location, the fraction retained is 65–100% after 100 years and 30– 85% after 500 years (a lower percentage for injection at a depth of 1,000 m, a higher percentage at 3,000 m) In the case of mineral carbonation, the CO2 stored would not be released to the atmosphere.

If continuous leakage of CO2 occurs, it could, at least in part, offset the benefits of CCS for mitigating climate change. Studies conducted to address the question of how to deal with nonpermanent storage are based on different approaches: the value of delaying emissions, cost minimization of a specified mitigation scenario or allowable future emissions in the context of an assumed stabilization of atmospheric greenhouse gas concentrations.

Some of these studies allow future leakage to be compensated by additional reductions in emissions; the results depend on assumptions regarding the future cost of reductions, discount rates, the amount of CO2 stored and the atmospheric concentration stabilization level assumed. In other studies, compensation is not seen as an option because of political and institutional uncertainties, and the analysis focuses on limitations set by the assumed stabilization level and the amount stored.

While specific results of the range of studies vary with the methods and assumptions made, all studies imply that, if CCS is to be acceptable as a mitigation measure, there must be an upper limit to the amount of leakage that can take place.

In CCS operations it is likely that CO2 will be handled close to, or above, its critical pressure (73.82 bar) where many of its properties are similar to that of a liquid. In this state it is often referred to as 'dense phase', whereas above critical temperature (31.04°C) and pressure it is referred to as 'supercritical'. Significant hazards associated with dense phase or supercritical CO2 arise when pressure falls suddenly or is lost completely.

CO2 is not currently defined as a dangerous substance under the Control of Major Accident Hazards Regulations 1999 (COMAH) or as a dangerous fluid under the Pipelines Safety Regulations 1996 (PSR). In June 2011 HSE published Assessment of the major hazard potential of Carbon Dioxide PDF. This report concluded that CO2, based on the evidence available at that time, has major accident hazard potential if released at, or above, its critical pressure. However, where the risks are properly controlled the likelihood of a major hazard incident is expected to be very low, as in other similar processes in the energy, chemical and pipeline industries.

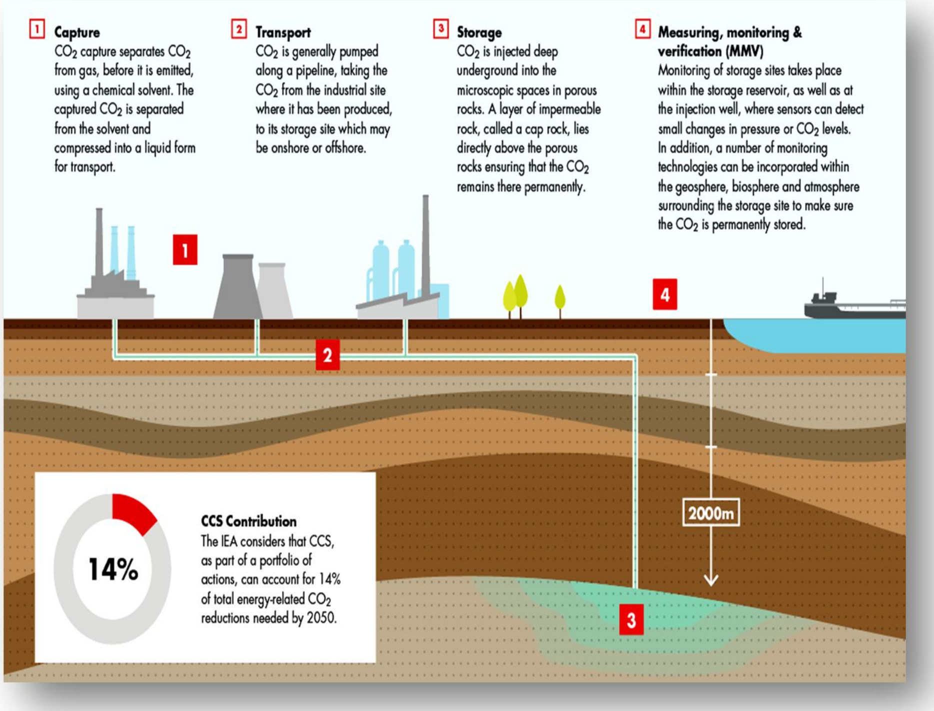
In particular the following issues require further research and validation:

1) Modelling releases and dispersion
2) Separation distances
3) Design and operation of plant and pipelines.

IX. LIMITATIONS OF SIMULATION

1) DWSIM being open sourced, free to use software is very efficient in handling simple processes.
2) It is impossible to create a model in the software which gives 100% industry level outputs. Thus, we were forced to use a "lumped parameter" approach throughout the simulation for simplicity purposes.
3) DWSIM supports very limited library sources, inefficient enough of providing proper compound data due to which it was very difficult to get and import the information regarding the structures and properties of the various compounds, thus making it difficult for us to simulate proper compound-based reactions involved in the process.

A. Summarizing CCS Process Diagramatically



1 Capture
CO_2 capture separates CO_2 from gas, before it is emitted, using a chemical solvent. The captured CO_2 is separated from the solvent and compressed into a liquid form for transport.

2 Transport
CO_2 is generally pumped along a pipeline, taking the CO_2 from the industrial site where it has been produced, to its storage site which may be onshore or offshore.

3 Storage
CO_2 is injected deep underground into the microscopic spaces in porous rocks. A layer of impermeable rock, called a cap rock, lies directly above the porous rocks ensuring that the CO_2 remains there permanently.

4 Measuring, monitoring & verification (MMV)
Monitoring of storage sites takes place within the storage reservoir, as well as at the injection well, where sensors can detect small changes in pressure or CO_2 levels. In addition, a number of monitoring technologies can be incorporated within the geosphere, biosphere and atmosphere surrounding the storage site to make sure the CO_2 is permanently stored.

CCS Contribution
The IEA considers that CCS, as part of a portfolio of actions, can account for 14% of total energy-related CO_2 reductions needed by 2050.

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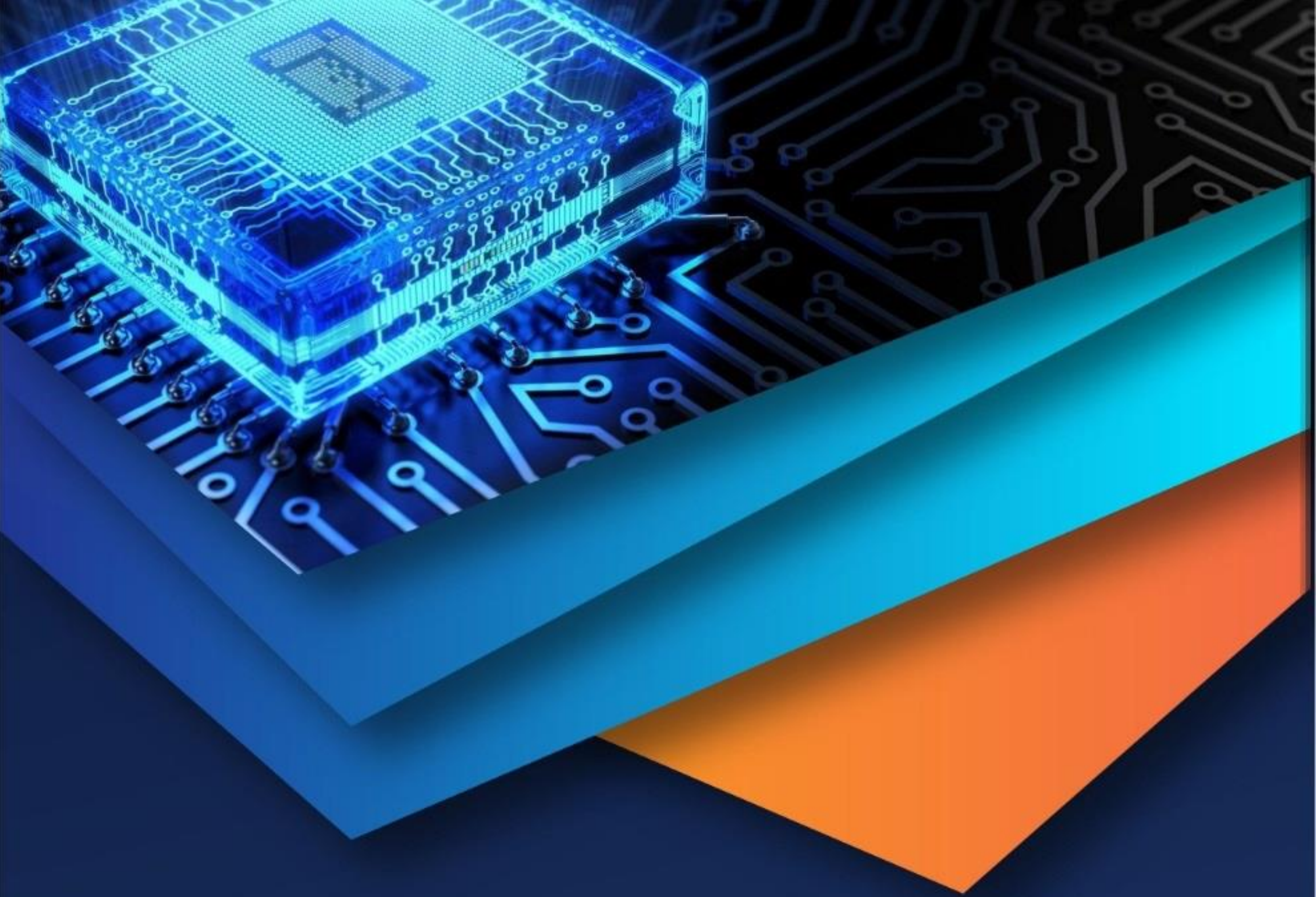

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