A REPORT ON

ECONOMIC VIABILITY OF CARBON CAPTURE AND STORAGE IN ENHANCED OIL RECOVERY

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By

HARSH JOSHI (R040205023)

UTTAM KUMAR SINHA (R010205055)

Under the supervision of
Dr. B.P. PANDEY
Dean Emeritus, Professor of Eminence

UNIVERSITY OF PETROLEUM AND ENERGY STUDIES
DEHRADUN, UTTARAKHAND

UNIVERSITY OF PETROLEUM & ENERGY STUDIES
(ISO 9001:2000 Certified)

CERTIFICATE

This is to certify that the work contained in this thesis titled "ECONOMIC VIABILITY OF CARBON CAPTURE AND STORAGE IN ENHANCED OIL RECOVERY" has been carried out by Harsh Joshi and Uttam Kumar Shina under my supervision and has not been submitted elsewhere for a degree.

11.05.09

Dr. B.P.Pandey
Dean Emeritus & Professor of Eminence

Corporate Office:
Hydrocarbons Education & Research Society
3rd Floor, PHD House,
4/2 Siri Institutional Area
August Kranti Marg, New Delhi - 110 016 India
Ph.: +91-11-41730151-53 Fax : +91-11-41730154

Main Campus:
Energy Acres,
PO Bidholi Via Prem Nagar,
Dehradun - 248 007 (Uttarakhand), India
Ph.: +91-135-2102690-91, 2694201/ 203/ 208
Fax: +91-135-2694204

Regional Centre (NCR) :
SCO, 9-12, Sector-14,
Gurgaon 122 007
(Haryana), India.
Ph: +91-124-4540 300
Fax: +91-124-4540 330

Regional Centre (Rajahmundry):
GIET, NH 5, Velugubanda,
Rajahmundry - 533 294,
East Godavari Dist., (Andhra Pradesh), India
Tel: +91-883-2484811/ 855
Fax: +91-883-2484822

Email: info@upes.ac.in URL: www.upes.ac.in

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HARSH JOSHI
&
UTTAM KUMAR SINHA
(B.Tech, Applied Petroleum Engineering)
University of Petroleum & Energy Studies
Dehradun

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2 EOR- Enhanced oil recovery

3 NO_X- Nitrogen Oxides

4 Mt- Metric Tonnes

5 Bbl- Barrel

6 MEA- Monoethanolamine

7 ECBM- Enhanced Coal Bed Methane

ABSTRACT

Carbon Capture and Storage is a new and advanced technology supporting Enhanced oil recovery. Capturing atmospheric carbon and storing it is based on simple processes. Injection of it will enhance the process of oil recovery. Checking of the operational and processing cost against the price of total recovered oil will prove the economic viability of the project.

In this report we have discussed different ways of capturing Carbon dioxide, storing and transporting it .We also found some new techniques which have not yet been introduced but will be used in near future.

We have studied and derived an equation from which we can find the optimum CO_2 injection so that the risk of leakage is minimum or negligible.

In this report we have also discussed economic viability of CCS coupled with EOR. In this we have taken into account all the prices involved in CCS consisting of capture cost, storage cost , transportation cost and injection cost and compared it with the returns which we will get from the extra oil produced due to carbon injection and revenue generated by reducing the CO_2 emissions from the environment. Thus we found the ideal price of Oil for which CCS implementation will be economic viable for today's CO_2 price.

Then we studied the condition of CCS in India and found that at present CCS can not be implemented in India due to some barriers. Then we studied about places where CCS has been practiced and implemented successfully and giving huge returns along with reducing emissions and where there is a future probability which are being explored like in Norway.

INTRODUCTION: Carbon capture and storage (CCS) is an approach to mitigate global warming by capturing carbon dioxide (CO_2) from large sources such as fossil fuel power plants and permanently storing it away from the atmosphere. To achieve a desired atmospheric CO2 concentration, world emissions should be no more than 7,700 Mt CO2 by the year 2100. However, under business as usual (BAU) conditions, emissions are projected to increase to more than 72,000 Mt CO2 by 2100. So large amounts of abatement and sequestration need to occur and very quickly. CCS has been estimated to have the theoretical potential to sequester an amazing 3,000,000 Mt CO2 in the U.S. alone. In a world with abundant coal reserves, a dependence on fossil fuels and a greater demand for energy, achieving a safe level of CO2 is an impossible scenario in the absence of immediate and serious mitigation measures like CCS.

Although CO_2 has been injected into geological formations for various purposes, the long term storage of CO_2 to be used in EOR is a new concept. EOR involves injecting CO_2 to pressurize oil reservoirs in order to facilitate extraction of additional oil. Basically, CO2 is useful for EOR because it is miscible with oil and has a fairly efficient sweep throughout the reservoir. CO2 is the primary component of EOR because it is miscible with oil, meaning that it lowers the viscosity and allows the oil to flow easier, thereby increasing production. It has the lowest pressure to achieve desired results. Other gases, such as oxygen or nitrogen are rarely, if ever, used because unwanted chemical reactions occur with their use. The CO2 changes the oil properties such that it flows more easily and has a fairly efficient sweep throughout the reservoir.CCS EOR is unique from traditional EOR practices because there is an ideological shift from CO2 usage in traditional EOR operations. CCS EOR would involve using the greatest amount of CO2 possible, rather than the least amount, as occurs in traditional EOR. Unlike traditional EOR, CCS EOR has dual purpose of long-term CO2 sequestration and enhanced oil production. In traditional EOR, there was no need to address long-term management, monitoring, verification, and liability aspects, unlike CCS EOR. CCS EOR would also mean that project developers would buy anthropogenic ally produced CO2 rather than the cheapest available (which is often naturally occurring CO2). The issues of crediting, monitoring, verification, and liability for long-term storage are also integral parts of CCS EOR. Traditional EOR practices operate under state and/or national guidelines set for oil operations. These guidelines have generally been formed for 30 - 40 operational well years, have well abandonment requirements, and do not require the type of long-term monitoring and measuring procedures that are necessary with CCS EOR.

EOR can potentially recover an additional 6-15% of the original oil in place, and thereby increase total production from an oil reservoir by 10-30%.

Geologic CCS is a technique that consists of capturing and separating carbon dioxide (CO2) from point sources such as fossil fuel power plants, condensing it to a liquid with pressure and density, transporting it through pipelines, injecting it into suitable geologic storage facilities, and finally providing monitoring and verification of its sequestration.

Four kinds of geologic reservoirs have the potential to store and sequester CO2:

1.) Deep saline formations,

2.) Oil wells for enhanced oil recovery (EOR) ,

3.) Depleted oil and gas reservoirs,

4.) Unmineable coal seams .

Once injected, the CO2 does not remain as a 'bubble' or a 'pool' underneath the earth's surface. Rather, it is usually injected as a supercritical fluid and absorbs into the surrounding pore space made of rocks, minerals, and water. Eventually, it is reincorporated into the carbon cycle through rock absorption and mineral carbonation.

Thus, proper site selection and characterization is extremely important. It involves an assessment of pore space and permeability, among other things. Measuring the amount of CO2, monitoring it, and verifying that it stays underground and has not leaked is also a long-term yet critical part of the CCS process. A mathematical formula to find the leak-off rate will be discussed later in this report.

Like any industrial operation, there are local human and environmental risks associated with accidents, leaks, and other unforeseen circumstances.CO2 leakage can be abrupt or gradual.

<u>Human:</u> A sudden burst of large amounts of CO2 would pose a threat to human health, but only if the concentration is more .It is also important to remember that CO2 is a naturally occurring gas, is something humans breathe in and out every day, and is harmful only in high enough concentrations.

<u>Environmental:</u> Elevated concentrations from leaks could be a detriment to plants, subsurface animals, and possibly contaminate groundwater.

However, proper site for storage and operations produce projects that are no more risky than common industrial operations such as underground natural gas storage or oil production. Accident risks associated with pipeline transport are low and are comparable to those associated with existing hydrocarbon pipeline. Observations from analogues suggest that the fraction of CO2 retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years.

CHAPTER 1: WHAT IS CARBON CAPTURE AND STORAGE(CCS)

Sources of Carbon Capture: These are fossil fuel power plants, fuel processing plants and large-scale industrial processing plants. However No applications of carbon capture in large (500 MW) power plants.

Economic Considerations:

➢ Costs:

- CO_2 commodity cost
- Transport and compression infrastructure
- Energy budget for capture, compression and transport-energy costs rising-*regardless for brine or EOR*
- Purity at separation for EOR requirements-higher purity requirement means greater separation expense
- Surface infrastructure costs
- Subsurface infrastructure costs
- Monitoring, measuring and verification for sequestration
- Regulatory compliance for EOR and Sequestration
- Legal costs-perfecting surface and sub-surface lease and pore space ownership

➢ Value Returns:

- Crude oil value-quality and transport to market
- Carbon credit generation if applicable
- Geologic asset value—increasing provable producible reserves and confirmed pore space valuation for sequestration.

CHAPTER 2: CO₂ CAPTURE SYSTEMS

There are mainly four types of CO2 capture systems. These are:

Post-combustion(often amine absorber)

Acidic gases like CO2 dissolve in amine solution (aqueous) at atmospheric pressure and around 60C. (exothermic process).
CO2 is driven out from the amines by reducing pressure, increasing
temperature or steam desorption at 120 to 130C. Amines then recycled.
Widely used under reducing conditions and at high partial pressures, e.g. for H2S and/or CO2 removal from oil refinery gases, natural gas or coal gas.
Under oxidizing conditions, SO2, NOx and especially oxygen react with amines causing solvent loss. The products can be acidic and/or toxic.
Proprietary additives protect amines from oxidation and materials from
corrosion, but still sensitive to SO2 and NOx. Little public information on how well additives protect amines from flue gas oxygen.
Post-combustion capture presents fewer risks to boiler operation

Gaps: Post Combustion:

- Cost: only small scale at present, large scale to expensive
- Temperature & amine performance: Savings in reducing heat of exhaust stream, Amine stability, reduced regeneration from less amine loss and wastage
- Alternative absorption processes: Chemical (Amine) and physical Surface adsorption, also gap in improving the efficiency of CO2 captured.
- Size of equipment: compact adsorpants and increased surface area with high mass transfer. Also minimizing amine carry over in flue gas. Using different materials, such as semi-permeable types, can improved mass transfer process
    - Absorber technology
    - Membrane materials
- Energy requirements
    - Waste heat recovery (WHR)
    - Compression
    - Amine conditioning/recovery

Pre-combustion(gasification)

Gasification produces CO_2, CO, H_2 and H_20.
Water gas shift to CO_2 and hydrogen well proven in other industries.
$CO + H_20 = CO_2 + H_2$
Shift and CO_2 removal carried out at high pressures, high partial pressures and under reducing conditions.
So IGCC is expensive and complex but the marginal cost of adding CO_2 capture is less than combustion.

Gaps: Pre Combustion:

- Cost: There is no large scale system in use today for the concomitant production of Hydrogen as a fuel and CO_2 capture.
- Hydrogen manufacture processes: develop less energy intensive processes, such as the shift phase reaction from CO to CO_2 with H_2 removal in one step. Also making H_2 at pressure to reduce compression and power costs.
    - New processes to reduce cost and improve efficiency at scale
    - Integrating Syngas production with CO_2 capture
- Size of equipment: challenge is upscale of technology, although development of compact reformer is still appropriate for part of the overall process.
    - Can we scale up what works on small scale?
- Energy requirements: New innovative process design required

Oxyfuel: Liquefaction plant separates oxygen from air (80% nitrogen). Fuel is burnt in oxygen + recycled flue gas to control temperature. Flue gas is mainly water + CO2 which should be a relatively easy mixture to separate. Applicable to boilers and to GTs but the latter need more extensive design modifications. Air separation plants use a lot of power. Novel proposals using near-flame membranes to provide combustion oxygen are a long way from commercial demonstration. Manufacturers offering oxy-fuel plant on "commercial terms", i.e. cost-plus with government or buyer accepting delivery and performance risk. What are the flame stability and radiative properties of combustion with the high CO2 (and perhaps water) partial pressures? Recycling increases SOx partial pressures.

Gaps: Oxyfuel:

- Cost: Cost of O_2 production. If combined with gas turbines is likely to require new turbine design and materials
- Temperature of process: High combustion temps require specialized materials for process equipment like, boilers, heaters and if used with Turbines.
- Process efficiency
    - Integration with pre-and post combustion processes for CO_2 Capture. In post-combustion, add O_2 to combustion process. This may require expensive conversion costs.
    - Pre-combustion use of gasification with oxygen, might allow integration of the H_2 and O_2 generation process at improved efficiency
- Energy requirements: Improvements in energy efficiency and power requirements is required.

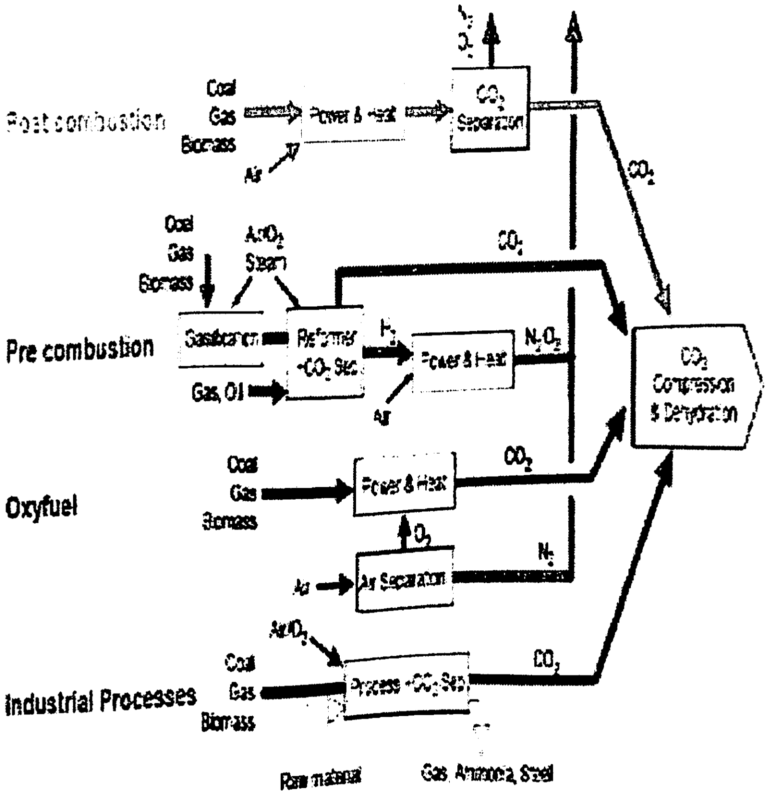
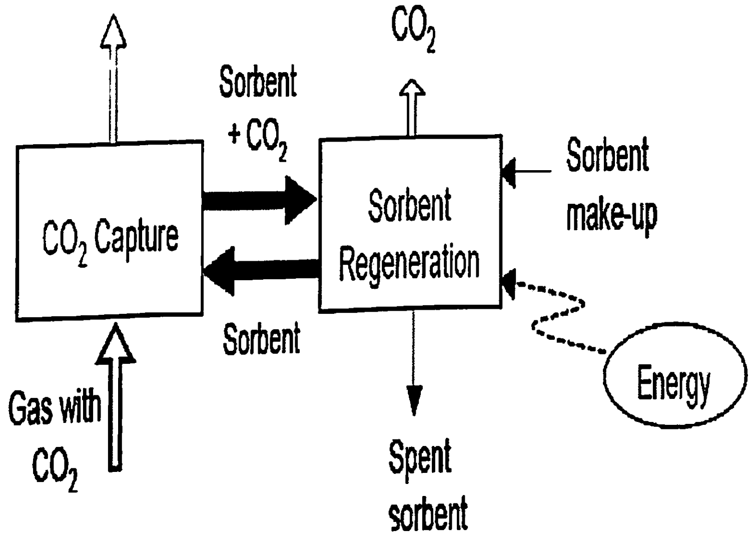


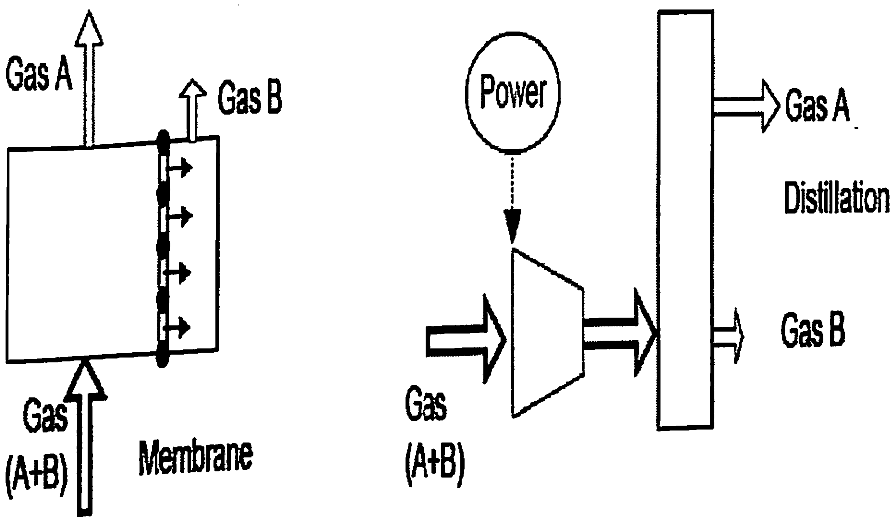
Figure 1: CO_2 Capture Processes

CO_2 Separation Processes: Separation processes are as follows:

1. Separation with solvents;
2. Separation with a membrane;
3. Separation by cryogenic distillation.



a) Separation with sorbents/solvents



b) Separation with a membrane *c) Separation by cryogenic distillation*

Figure 2: Types of separation processes

CHAPTER 3: CO_2 STORAGE

There are many types of CO2 storage. A few are discussed here:

Geologic: Injection of CO2 as a liquid or supercritical fluid underground in permeable geological formations. It has a mature market in the form of EOR.

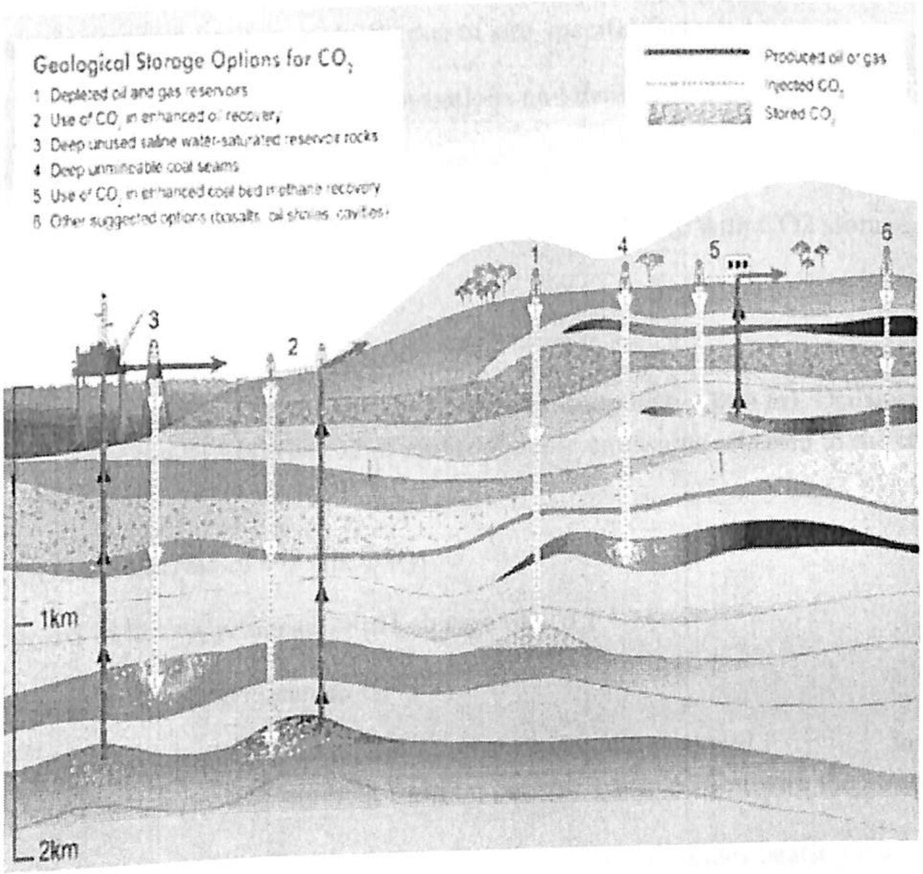


figure 3: Types of storages

Storage Capacity: Capacity estimates involve high degree of uncertainty, but no reliable quantification of this uncertainty available. Oil and gas reservoir capacity not available for CO2 storage until hydrocarbons are depleted. Assuming an economic potential for CCS in the order of 200 to 2,000 GtCO2 for the next century, it is virtually certain (probability 99%) that there is 200 GtCO2of geological storage capacity worldwide.

Table 1: Reservoir capacity

Reservoir type	Lower Estimate(GtCO2)	Upper estimate(GtCO2)
Oil and gas fields	675	900

Unmineable coal seams	3-15	200
Deep saline formations	1000	uncertain

Cost of Geologic storage: Large variability due to site-specific factors.

- 0.5 – 10 US$/tCO2 for storage in saline formations and depleted oil and gas reservoirs
- 0.1 – 0.3 US$/tCO2 for monitoring
- 1- 16 US$/tCO2 net benefits for enhanced oil production onshore with CO2 storage, including costs of geological storage

Ocean: Injection of CO2 as a liquid into the deep ocean(depths > 1,000 m). Oceans have taken up 500 GtCO2 of the total 1,300 GtCO2 of anthropogenic emissions released to the atmosphere over the last 200 years

- Current CO2 uptake rate of ~ 7 GtCO2/yr
- CO2 is stored in the upper ocean -> pH change of ~ 0.1
- No pH change in the deep ocean so far
- There is no physical limit to the amount of CO2 that could be stored in the ocean; the amount stored will depend in the long-term on oceanic equilibration with the atmosphere.

Mineral Carbonation: Chemical reaction of CO2 with metal oxides bearing material to form chemically stable carbonates. Reaction of CO2 with metal oxide bearing materials to form insoluble carbonates

$Mg_2SiO_4 + 2CO_2 \rightarrow 2MgCO_3 + SiO_2$ +89 KJmol-1CO2 $Mg_3Si_2O_5(OH)_4 + 3CO_2 \rightarrow 3MgCO_3 + 2SiO_2 + 2H_2O$ +64 kJmol- $CaSiO_3 + CO_2 \rightarrow CaCO_3 + SiO_2$ +90 kJmol-1CO2

Carbonation of metal oxides occurs natural (weathering of silicate rocks) but on geological time scales. The goal in mineral carbonation is to accelerate this process .Magnesium, calcium silicate rocks (basalt) are ideal source material. Theoretical storage capacity of magnesium silicates is 0.55 kgCO2/kg of rock; worldwide magnesium silicate resources exceed the requirements to neutralize all CO2 emissions from worldwide coal resources.

Mineral Carbonation Reaction Scheme: Direct gas–solid reaction at suitable temperature and pressures -> too slow and only feasible at higher pressure and temperature. Single or multi step wet processing:

- suspending fine grained material in acidic aqueous solution

- dissolution of mineral phases and subsequent release of Mg and Ca ions, which react with dissolved carbonic acid to form magnesium and calcium carbonates,

- requires pre-treatment of fine grained material to accelerate process

- 1.6 – 3.7 tonnes of silicates per tonne of CO2 required

- 2.6 – 4.7 tonnes of material for disposal per tonne of CO2 stored as carbonates.

Cost of Mineral Carbonation and Hurdles to Overcome: 50 – 100 US$/tCO2 for the wet carbonation process of natural silicates (includes costs for additional energy requirements).

One new technology for CO2 storage is:

CO2 Accelerated Concrete Curing:

It is a CCS application in which CO2 is stored within Precast Concrete. It is advantageous in following ways:

- Profitable
- 30-50% Plant Energy Savings
- Carbon Taxes Savings.

➢ **Physical Properties:**
  - Rapid Strength Development
  - No Shrinkage Cracking
  - Low Permeability

➢ CCS Improvements:
  - CO2 Stored as Solid Limestone
  - Heat and H20 only by-products
  - 60t CO2 per 1000t Concrete
  - >500 Mt CO2/yr Globally.

Scientific principles:

$$\left.\begin{array}{l} C_3S(\text{alite}) + 3H^+ \leftrightarrow \mathbf{3Ca^{2+}} + SiO_2 + 3OH^- \\ C_2S(\text{belite}) + 2H^+ \leftrightarrow \mathbf{2Ca^{2+}} + SiO_2 + 2OH^- \\ Ca(OH)_2 \leftrightarrow \mathbf{Ca^{2+}} + 2OH^- \end{array}\right\} \begin{array}{c} \textit{Dissolution} \\ \text{(Ca supply)} \end{array}$$

$$+$$

$$\left.\begin{array}{l} CO_2\ (g) \Rightarrow CO_2\ (aq) \\ CO_2\ (aq) + H_2O \Rightarrow H_2CO_3\ (aq) \\ H_2CO_3\ (aq) \Rightarrow HCO_3^-\ (aq) + H^+ \\ HCO_3^-\ (aq) \Rightarrow CO_3^{2-}\ (aq) + H^+ \end{array}\right\} \begin{array}{c} \textit{Carbonate} \\ \textit{Dissociation} \\ (CO_3\ \text{supply}) \end{array}$$

$$=$$

$$\left.\begin{array}{l} Ca^{2+}\ aq) + CO_3^{2-}\ (aq) \Rightarrow CaCO_3\ (s)\ \text{(Limestone)} \end{array}\right\} \begin{array}{c} \textit{Precipitation} \\ (CO_2\ \text{storage}) \end{array}$$

Organic liquid CO_2 capture agents with high gravimetric CO_2 capacity: There is a new class of CO_2 binding organic liquid that chemically captures and release CO_2 much more efficiently than aqueous alkanolamine systems. Mixtures of organic alcohols and amidine bases reversibly bind CO_2 chemically as liquid amidinium alkyl carbonates. The free energy of CO_2 binding in these organic systems is very small. These CO_2 capturing agents do not require an added solvent because they are liquid, and therefore have high CO_2 capacities of up to 19% by weight for neat systems, and slightly less when dissolved in acetonitrile. The rate of CO_2 uptake and release by these organic systems is limited by the rate of dissolution of CO_2 into and out of the liquid phase. Gas absorption is selective for CO_2 in both concentrated and dilute gas streams.

What does it need for a successful implementation?

- Acceleration of the overall rate of process, especially the dissolution rate of magnesium and calcium silicate minerals
- Decrease of energy penalty
- Complete recovery of all chemical species involved in process

- Reducing overall costs

Cost of CO2 Captured =

(Total capital x Capital charge factor + Fixed operating cost)/(Plant capture capacity x utilization factor+ Variable operating cost)

Characteristics of CO_2 Source that would Impact on Costs

- Concentration of the CO2 in the waste gas stream
- Other impurities in the gas stream
- Temperature and pressure of the gas stream
- Quantities of the waste gas stream.

Parameters that Influence the Economics of the Capture Process:

- Fuel type and cost,
- Fraction of the CO2 to be captured (recovery factor),
- Final CO2 purity and export pressure,
- Ambient temperature including cooling water temperature,
- Plant size and utilization factor,
- Project life time and construction period,
- Return on capital and operating costs,

Comparison between Proposed storage methods:

Table 2: Comparison between Proposed storage methods

Geologic	Relative inexpensive (8 – 10 $/tCO2) Technology is existing Uncertainty in reservoir integrity Unknown local and regional risks (leakage, water pollution) Legal issues – long-term liability
Ocean	Large storage capacity Long residence time Huge environmental impact – change in ocean chemistry –harm to marine organisms Legal issues
Mineral	Large storage capacity

carbonation	Permanent and environmentally benign storage Expensive Huge deposits of cheap waste material

Pipeline is the main source of transportation of carbon dioxide, so if we reduce the overall cost of pipeline we can reduce the initial investment cost of transportation or we will have to use ships for transportation which require large operational cost.

Factors Influencing the Cost of Pipeline:

- Throughput,
- Length of pipeline,
- Type of terrain,
- River crossing,
- Country/region regulations with regard to pipelines,
- Pipeline inlet pressure,
- Booster stations,
- Pipe diameter.

Pipelining Cost - An Example (western Canada)

Pipeline throughput: 2 MMt/year

Pipeline length 100 km; pipeline diameter: 12 inches

Pipeline construction cost: US $ 36.0 MM

Annual capital Charges: $ 4,610,000 (12% return, 25 yrs life)

Annual operating cost: $ 400,000

Total: $ 5,010,000

Cost of CO2 transport: $ 2.5/tonne over 100 km

If distance is 400 km, cost of transport = $ 10/tonne

Distance from CO2 source is a key economic factor

CHAPTER 4: USE OF CCS IN EOR

In terms of dynamic miscibility, carbon dioxide display s properties similar to those of the intermediates . (C2toC6) of the hydrocarbon chain. It's action considerably decreases capillary forces. It is more or less miscible with the oil in place, and with the gas and water.

Moreover, CO2, which dissolves in the oil, also increases the volume of the oil considerably (20to100%) and significantly lowers its viscosity. This is also valid for heavy oils, even if CO2 is not miscible with them

Thus CO2 offers an advantage compared to C2 to C6 for medium-pressure reservoirs. This is because the miscibility pressure is lower, generally between 130 and 200 bar (instead of higher than >250 bar for C2 to C6).

This process, which appears promising, is very often limited by the high cost of the product.

Surface Facilities for CO2 – EOR

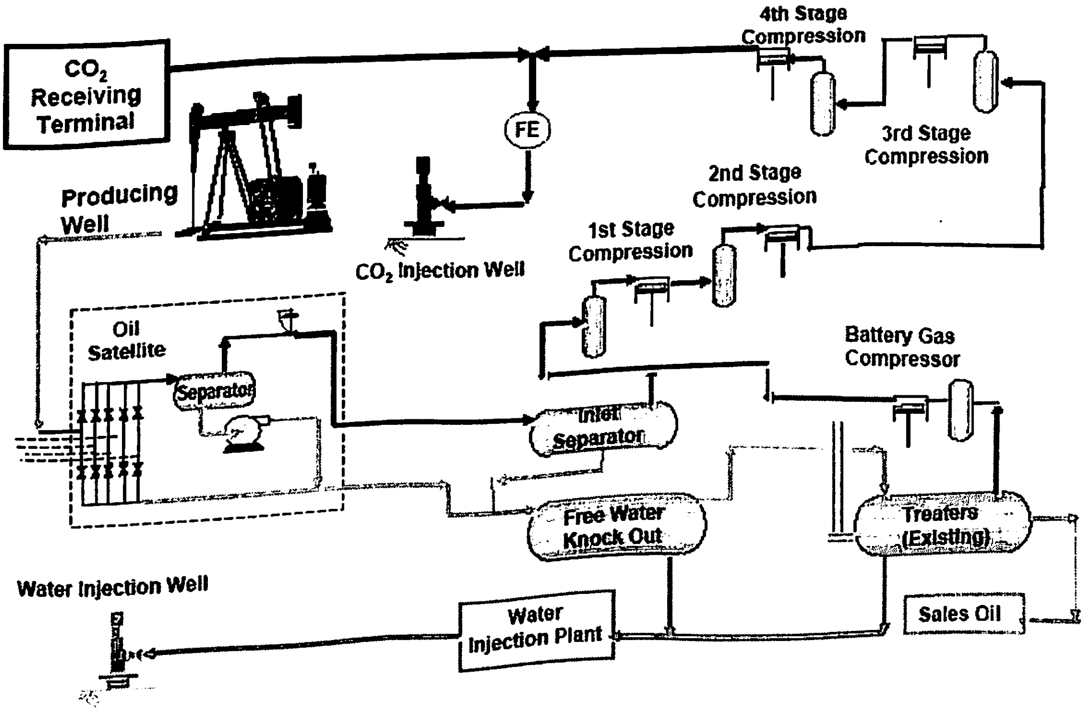


Figure 4: Surface Facilities for CO2 – EOR

CO_2 Recycle Technologies for EOR

Ryan-Holmes process – uses distillative separations to remove CO2 and H2S with propane or butane as additive (in a number of variations, 2, 3 or 4 column design)

Benfield process - hot potassium carbonate

Amine process – MEA

Influence Diagram of Uncertainties for EOR Strategy:

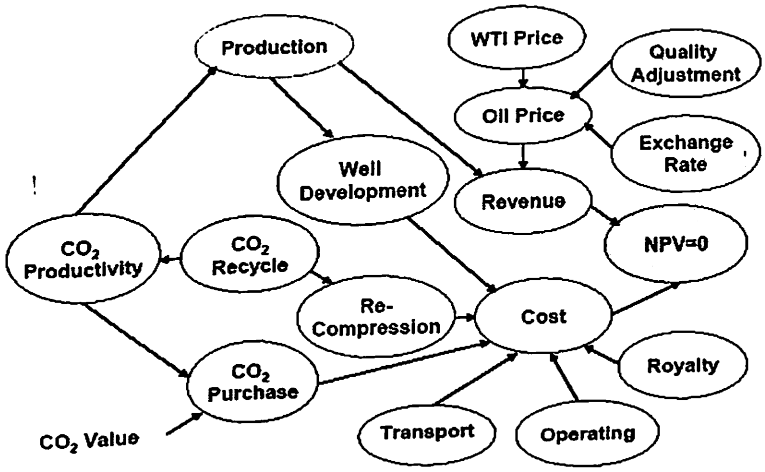


Figure 5: Influence Diagram of Uncertainties for EOR Strategy

Cost of different parameters used in EOR (as given by ONGC for GS-3 and GS-4 sand of Gandhar oil field in Gujarat):

Table 3: Cost of different parameters used in EOR

	GS-3	GS-4
WTI Oil Price ($/b)	30.00	45.00
Price after Discount. ($/b)	0.00	-1.00
CO2 Productivity (MCF/b)	2.67	8.00
CO2 Recycle Ratio relative to CO2 purchased	0.82	1.00
Recompression Cost ($/MCF)	0.5	0.6
Pipelining Cost ($/b)	1.00	1.50
Field Development Cost ($/b)	4.50	6.50
Operating Cost ($/b)	6.50	7.50
Royalty ($/b)	6.00	9.00

Findings from the EOR Example shown above:

1. The most important parameters are CO2 productivity and oil prices.
2. The CO2 affordable price ranged from - $ 1/t to > 100/t for the GS-3 sand.
3. Under the “most likely” case (GS-4), the value of CO2was $ 35 /t of CO2 for EOR (the GS-4 oil price was $ 45/BBL).

So we find that there is a potential gap between the available price and the affordable price.

#CO2 Capture $ 40/t

#CO2 Transport $ 10/t

#Delivered Price of CO2 $ 50/t and

#Affordable price to pay $ 35/t

So we introduce a concept of Carbon trading in which companies get revenues from govt. and international organizations for reducing carbon emissions which help in mitigating global warming. This is done under *Kyoto protocol. The price, or prices, of the Kyoto Protocol permits will determine whether or not geological carbon storage will be a competitive option.

*(This Protocol states that reductions should primarily be achieved through domestic action, and thus the use of the mechanisms should be “supplemental to domestic action”. Parties to the Kyoto Protocol have committed themselves to reducing their greenhouse gas emissions. The Protocol also establishes three so-called flexibility mechanisms that Parties to the Protocol may use to help them comply with their commitments: emissions trading, Joint Implementation and the Clean Development Mechanism (CDM), and each mechanism has its own type of permit.)

Establishing a Storage Project

Site Characterization: evaluate geology, local and regional hydrogeology; identify leakage pathways.

Assessing Risk of Leakage*: predict movement of CO2 over time and locations where leakage might occur.

Monitoring*[#]*: Ensure that an adequate monitoring plan is in place.

#Gaps in Storage Monitoring:

- Cost: Currently 4D seismic is used to monitor CO2 in the reservoir. This is very expensive and requires multiple surveys to verify position of CO2. Additionally some reservoirs are not easily picked up on seismic, as it is a function of the types of geology surrounding the reservoir.
- HSE Risk Assessment Methodology: At this time, no one is looking at this problem from the HSE Risk Assessment Methodology view point. But it is an important aspect given that industry will have the responsibility to demonstrate that CO2 geologic storage is safe. A risk assessment methodology provides a basis from which to do this and one that is a widely recognized procedure to understand risk and mitigation strategies, plus costs.
    - Leakage
    - Contamination
    - Mitigation
- Long term monitoring standards and tools: Long term methods need to address the time frame they might be required to be used in. This is likely to be different from monitoring an oil field which might have a 15 or 20 year life time.
- Verification: Verification could be important in a world where carbon trading, Clean development Mechanisms or carbon offsets are used as mechanisms to reduce GHG (Green house gases) emissions.

Reporting: Report CO2 injected and emissions from storage site.

CHAPTER 5: OPTIMAL CCS, CARBON CAPTURE AND STORAGE

Here we will develop an equation to find the percent value of risk involved due to leakage in storing CO2 .

The total present value of CO2 storage minus CCS costs=

$$\int_{0}^{\infty} e^{-rt}\left(k_1 u + k_2 u^2 + f_1 x + f_2 x^2\right) dt$$

Here;

.r= Discounting Factor

u= Controlled CCS level

x=The total storage level of CO2.

And , $$dx = \left(u - Lx - S\right) dt + \sigma x\, dz$$

Where,

.dx= change of CO2 storage level due to leakage.

L and S are constants to find expected CO2 leakage.

The CO_2 storage level is to some extent affected by stochastic leakage and other stochastic events.

.dZ = change of level due to stochastic events

Now applying ;

The Hamilton-Jacobi-Bellman Equation equation with optimized control:

$$0 = Z = e^{-rt}\left(k_1 u + k_2 u^2 + f_1 x + f_2 x^2\right) + V_x\left(u - Lx - S\right) + \frac{1}{2} V_{xx} \sigma^2 x^2 + V_t$$

Differentiating *with respect to the control, u:*

$$\frac{\partial Z}{\partial u} = e^{-rt}\left(k_1 + 2k_2 u\right) + V_x = 0$$

Differentiating again ***with respect to the control:***

$$\frac{\partial^2 Z}{\partial u^2} = 2k_2 e^{-rt}\,\frac{V_x e^{rt} + k_1}{-2k_2}$$

Therefore;

Input the optimal control in the Hamilton-Jacobi-Bellman equation:

$$0=Z=e^{-rt}\left(k_1\left[\frac{V_x e^{rt}+k_1}{-2k_2}\right]+k_2\left[\frac{V_x e^{rt}+k_1}{-2k_2}\right]^2+f_1x+f_2x^2\right)+V_x\left(\left[\frac{V_x e^{rt}+k_1}{-2k_2}\right]-Lx-S\right)+\frac{1}{2}V_{xx}\sigma^2x^2+V_t$$

Let us consider:

$$V(x,t) = e^{-rt}\left(a + bx + cx^2\right)$$

Now, the partial derivatives can be determined by:

$$V_x = e^{-rt}\left(b + 2cx\right)$$

$$V_{xx} = e^{-rt}\left(2c\right)$$

$$V_t = -re^{-rt}\left(a + bx + cx^2\right)$$

Therefore the Hamilton-Jacobi-Bellman equation after putting the values of derivatives:

$$\begin{aligned}0 = &-\frac{k_1}{2k_2}V_x - \frac{e^{-rt}k_1^2}{2k_2} + \frac{e^{-rt}}{4k_2}\left(V_x e^{rt} + k_1\right)^2 + e^{-rt}\left(f_1x + f_2x^2\right)\\ &-\frac{e^{rt}}{2k_2}\left(V_x\right)^2 - \frac{k_1}{2k_2}V_x - LxV_x - SV_x + \frac{1}{2}V_{xx}\sigma^2x^2 + V_t\end{aligned}$$

$$\begin{aligned}0 = &-\frac{k_1}{2k_2}e^{-rt}(b+2cx)-\frac{e^{-rt}k_1^{\,2}}{2k_2}+\frac{e^{-rt}}{4k_2}\left(e^{-rt}(b+2cx)e^{rt}+k_1\right)^2+e^{-rt}\left(f_1x+f_2x^2\right)\\ &-\frac{e^{rt}}{2k_2}\left(e^{-rt}(b+2cx)\right)^2-\frac{k_1}{2k_2}e^{-rt}(b+2cx)-Lxe^{-rt}(b+2cx)-Se^{-rt}(b+2cx)\\ &+\frac{1}{2}e^{-rt}(2c)\sigma^2x^2-re^{-rt}\left(a+bx+cx^2\right)\end{aligned}$$

$$\begin{aligned}0 = &-\frac{k_1}{2k_2}(b+2cx)-\frac{k_1^{\,2}}{2k_2}+\frac{1}{4k_2}(b+2cx+k_1)^2+\left(f_1x+f_2x^2\right)\\ &-\frac{1}{2k_2}(b+2cx)^2-\frac{k_1}{2k_2}(b+2cx)-Lx(b+2cx)-S(b+2cx)\\ &+\frac{1}{2}(2c)\sigma^2x^2-r\left(a+bx+cx^2\right)\end{aligned}$$

$$\begin{aligned}0 = &-\frac{k_1}{2k_2}b-\frac{k_1}{k_2}cx-\frac{k_1^{\,2}}{2k_2}+\frac{1}{4k_2}\left(b^2+4c^2x^2+k_1^{\,2}+4bcx+2k_1b+4k_1cx\right)\\ &+f_1x+f_2x^2\\ &-\frac{1}{2k_2}\left(b^2+4bcx+4c^2x^2\right)-\frac{k_1}{2k_2}b-\frac{k_1}{k_2}cx-Lbx-2Lcx^2-Sb-2Scx\\ &+c\sigma^2x^2-ra-rbx-rcx^2\end{aligned}$$

$$\begin{aligned}0 = &-\frac{k_1}{2k_2}b-\frac{k_1}{k_2}cx-\frac{k_1^{\,2}}{2k_2}+\frac{1}{4k_2}b^2+\frac{1}{k_2}c^2x^2+\frac{k_1^{\,2}}{4k_2}+\frac{1}{k_2}bcx+\frac{k_1}{2k_2}b+\frac{k_1}{k_2}cx\\ &+f_1x+f_2x^2-\frac{1}{2k_2}b^2-\frac{2}{k_2}bcx-\frac{2}{k_2}c^2x^2-\frac{k_1}{2k_2}b-\frac{k_1}{k_2}cx-Lbx-2Lcx^2-Sb-2Scx\\ &+c\sigma^2x^2-ra-rbx-rcx^2\end{aligned}$$

$$\begin{aligned}0 = &\left[-\frac{k_1}{2k_2}b-\frac{k_1^{\,2}}{2k_2}+\frac{1}{4k_2}b^2+\frac{k_1^{\,2}}{4k_2}+\frac{k_1}{2k_2}b-\frac{1}{2k_2}b^2-\frac{k_1}{2k_2}b-Sb-ra\right]\\ &+\left[-\frac{k_1}{k_2}c+\frac{1}{k_2}bc+\frac{k_1}{k_2}c+f_1-\frac{2}{k_2}bc-\frac{k_1}{k_2}c-Lb-2Sc-rb\right]x\\ &+\left[\frac{1}{k_2}c^2+f_2-\frac{2}{k_2}c^2-2Lc+c\sigma^2-rc\right]x^2\end{aligned}$$

$$
\begin{aligned}
0 = {} & \left[\left(-\frac{k_1^2}{4k_2} - ra\right) + \left(-\frac{k_1}{2k_2} - S\right)b + \left(+\frac{1}{4k_2} - \frac{1}{2k_2}\right)b^2\right] \\
& + \left[\frac{1}{k_2}bc + f_1 - \frac{2}{k_2}bc - \frac{k_1}{k_2}c - Lb - 2Sc - rb\right]x \\
& + \left[f_2 - \frac{1}{k_2}c^2 - 2Lc + c\sigma^2 - rc\right]x^2
\end{aligned}
$$

This function must be zero for all values of x:

$$
\begin{aligned}
0 = {} & \left[\left(-\frac{k_1^2}{4k_2} - ra\right) + \left(-\frac{k_1}{2k_2} - S\right)b + \left(+\frac{1}{4k_2} - \frac{1}{2k_2}\right)b^2\right] \\
& + \left[\frac{1}{k_2}bc + f_1 - \frac{2}{k_2}bc - \frac{k_1}{k_2}c - Lb - 2Sc - rb\right]x \\
& + \left[f_2 - \frac{1}{k_2}c^2 - 2Lc + c\sigma^2 - rc\right]x^2
\end{aligned}
$$

Therefore, each factor must be equal to zero.

Determination of the objective function parameters:

Determination of the parameter of the second order term of the function:

$$\left(\left[f_2 - \frac{1}{k_2}c^2 - 2Lc + c\sigma^2 - rc\right] = 0\right) \rightarrow$$

$$-\frac{1}{k_2}c^2 + \left(-2L + \sigma^2 - r\right)c + f_2 = 0$$

$$c^2 + \left(\frac{2L + r - \sigma^2}{k_2}\right)c - \frac{f_2}{k_2} = 0$$

$$c_1 = -\left(\frac{2L + r - \sigma^2}{2k_2}\right) + \sqrt{\left(\frac{2L + r - \sigma^2}{2k_2}\right)^2 + \frac{f_2}{k_2}}$$

$$c_2 = -\left(\frac{2L + r - \sigma^2}{2k_2}\right) - \sqrt{\left(\frac{2L + r - \sigma^2}{2k_2}\right)^2 + \frac{f_2}{k_2}}$$

$$\left\{\frac{f_2}{k_2} > 0 \quad \wedge \quad c < 0\right\} \rightarrow c = c_2$$

$$c = -\left(\frac{2L + r - \sigma^2}{2k_2}\right) - \sqrt{\left(\frac{2L + r - \sigma^2}{2k_2}\right)^2 + \frac{f_2}{k_2}}$$

Determination of the parameter of the first order term of the function, taking the already determined parameter of the second order term into account:

$$\left(\left[\frac{1}{k_2}bc+f_1-\frac{2}{k_2}bc-\frac{k_1}{k_2}c-Lb-2Sc-rb\right]=0\right)\to$$

$$\left[-\frac{1}{k_2}c-L-r\right]b+f_1-\frac{k_1}{k_2}c-2Sc=0$$

$$\left[-\frac{1}{k_2}c-L-r\right]b=\frac{k_1}{k_2}c+2Sc-f_1$$

$$b=\frac{\frac{k_1}{k_2}c+2Sc-f_1}{-\frac{1}{k_2}c-L-r}$$

$$b=\frac{f_1-\frac{k_1}{k_2}c-2Sc}{\frac{1}{k_2}c+L+r}$$

$$b=\frac{f_1-\left(2S+\frac{k_1}{k_2}\right)c}{\frac{1}{k_2}c+L+r}$$

$$b=\frac{f_1-\left(2S+\frac{k_1}{k_2}\right)c}{\frac{1}{k_2}c+L+r}$$

Determination of the constant of the objective function, taking the already determined parameter of the first order term into account:

$$\left(\left[\left(-\frac{k_1^2}{4k_2}-ra\right)+\left(-\frac{k_1}{2k_2}-S\right)b+\left(+\frac{1}{4k_2}-\frac{1}{2k_2}\right)b^2\right]=0\right)\rightarrow$$

$$-\frac{k_1^2}{4k_2}+\left(-\frac{k_1}{2k_2}-S\right)b+\left(+\frac{1}{4k_2}-\frac{1}{2k_2}\right)b^2=ra$$

$$a=\frac{\left(-\frac{k_1}{2k_2}-S\right)b+\left(+\frac{1}{4k_2}-\frac{1}{2k_2}\right)b^2-\frac{k_1^2}{4k_2}}{r}$$

$$a=\frac{\left(-\frac{k_1}{2k_2}-S\right)b+\left(+\frac{1}{4k_2}-\frac{1}{2k_2}\right)b^2-\frac{k_1^2}{4k_2}}{r}$$

Optimal function:

$$V(x,t)=e^{-rt}\left(a+bx+cx^2\right)$$

$$c=-\left(\frac{2L+r-\sigma^2}{2k_2}\right)-\sqrt{\left(\frac{2L+r-\sigma^2}{2k_2}\right)^2+\frac{f_2}{k_2}}$$

$$b=\frac{f_1-\left(2S+\frac{k_1}{k_2}\right)c}{\frac{1}{k_2}c+L+r}$$

$$a=\frac{\left(-\frac{k_1}{2k_2}-S\right)b+\left(+\frac{1}{4k_2}-\frac{1}{2k_2}\right)b^2-\frac{k_1^2}{4k_2}}{r}$$

Optimal control:

$$u = \frac{V_x e^{rt} + k_1}{-2k_2}$$

$$u = \frac{\left[e^{-rt}\left(b + 2cx\right)\right] e^{rt} + k_1}{-2k_2}$$

$$u = \frac{b + k_1 + 2cx}{-2k_2}$$

$$u = \frac{b + k_1}{-2k_2} - \frac{c}{k_2} x$$

A mathematical approach to optimal CCS control has been developed that can handle risk.

Possible leakage is an important issue that has to be carefully investigated in the future.

It is important that the future management decisions are based on a decision model consistent with the structure of this model and that the parameter values are carefully estimated before practical management decisions are calculated.

CHAPTER 6: CASE STUDIES

Potential for CCS in India: Opportunities and Barriers

Overview of India's Energy Sector

Table 4: Domestic coal availability

Fuels	2001	2036
Coking coal (million tonnes)	27	50
Non-coking coal (million tonnes)	299	550
Lignite (million tonnes)	25	50

Table 5: Natural gas availability(in MMSCMD)

	2006	2011	2016	2021	2026
Domestic availability	84	123	125	125	125
LNG import	25	65	95	125	135
Transport pipelines					
Iran-Pakistan-India	0	30	90	90	90
Myanmar-India	0	0	30	30	30
Total Imports	25	95	215	245	255
TOTAL	109	218	340	370	380

Fuel Import in 2031:

Coal import: 1438 MT ~4 times of consumption in 2001

Import dependency: 78%

Oil import: 680 MT

Import dependency: 93%

Gas import: 93 BCM

Import dependency: 67%

GHG mitigation potential – Scenario Analysis:

CO2 Emissions by Fuels
(BAU):

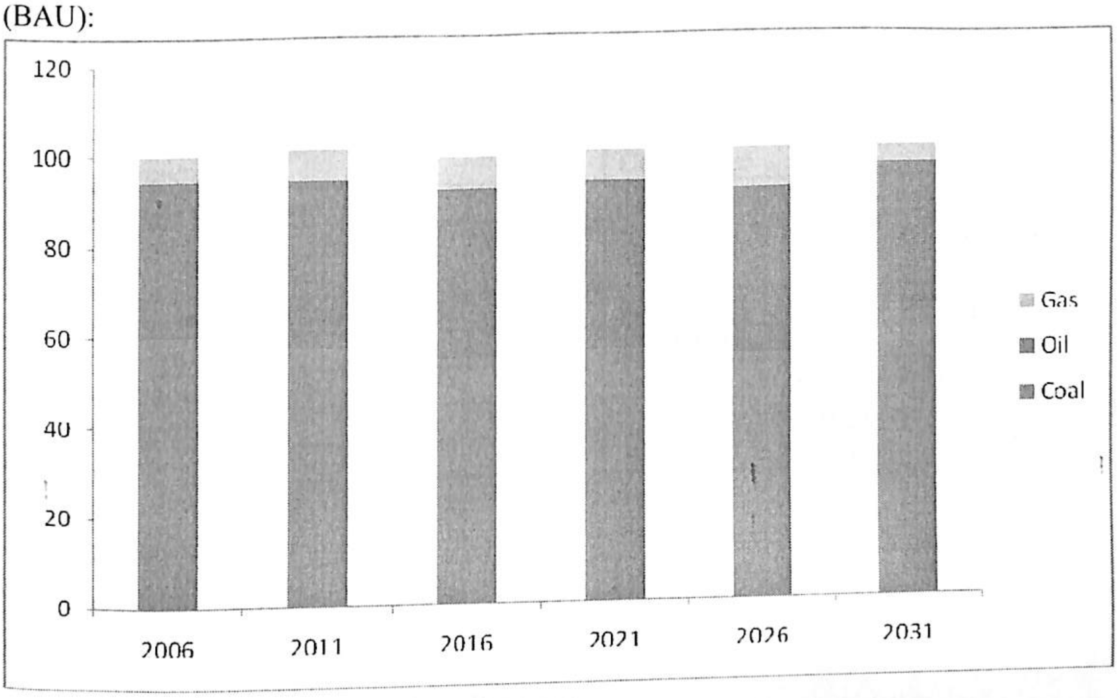


Figure 6: GHG mitigation potential – Scenario Analysis

Power sector presents the greatest opportunity to implement CCS.

GHG mitigation scenarios at various CO2 Prices (without CCS):

Table 6: various CO2 Prices

Scenario	2001	2011	2021	2031
BAU	917	1663	3332	7261
$5/ tonnes	917	1457	2495	5067
$10/tones	917	1400	2472	4989
$20/tonnes	917	1383	2412	4972

Geological CO2 Storage Potential:

Estimated CO2 storage potential in:

⍰ Deep saline reservoirs (on and off shore) estimates ~360 GtCO2

⍰ Depleted oil and gas wells estimates ~ 7 GtCO2

⍰ Un-mineable coal seams 5 GtCO2

- Volcanic rock 200 GtCO2

Cost implications:

Cost Range of CCS components:

Table 7: Cost Range of CCS components

CCS component	Cost range
Capture from power plant	15- 75 US $/ mt. CO2 net captured
Capture from gas processing or NH3 production	5 – 55 US $/ mt. CO2 net captured
Capture from industrial sources	25 –55 US $/ mt. CO2 net captured
Transportation	1–8 US $/mt.CO2
Geological storage	0.5 – 8 US $/mt. (injected)
Ocean storage	5 – 30 US $/mt. (injected)
Mineral carbonation	50 – 100 US $/mt. (net mitigated)

Current CCS Activities in India

- India is a member of CSLF & IEA GHG R&D Program.
- It is participating in the Future Gen Program.
- The Government of India has plans to invest in CCS related activities in the XI & XII Five Plan (report of the working group on R&D for the energy sector).
- Institute of Reservoir Studies is carrying out CO2 capture and EOR field studies in Gujarat.
- NGRI is testing the feasibility of storing CO2 in basalt formation.

Barriers to CCS;

1) __Financial Barriers:__

- High capital costs (30 to 40% increase)
- Higher Energy penalty (O&M)

2) __Institutional barrier__

- Does not fit in the overall goal of meeting the millennium development goals.
- Non-productive expenditure.
- Does not contribute to sustainable development.

3) ***Technical Barriers***:

⍰ Yet to be commercially demonstrated in large point sources of CO2

⍰ Capture technologies are not standard for all large point sources (ex: power plant & cement plant)

⍰ Sinks and their capacities to yet be identified

⍰ Many parts of India are seismically active – issue of permanenance

⍰ EOR/ECBM/EGR potential yet to be established in India

⍰ Potential & cost for sequestering in depleted oil & gas wells yet to be determined (off-shore and on-shore)

⍰ Mapping and matching of sinks and sources for optimization of cost to be done.

Other Barriers:

1) Storage (leakage – safety; leakage-carbon accounting).
2) Acceptance – general public is unaware of CCS.
3) Regulatory: no international standards as yet.

⍰ EC established national standards to allow CCS for European Trading

4) Financial: Lack of business architecture; Storage business does not exist.

World scenarios:

So we found that at present CCS is not economical feasible in India. Now we will study about different places in world where CCS has been quiet successful.CCS has been at present most successful in three places apart from many places where it is in planning or initial stage.

CCS in Norway:

In Norway currently there are two CCS schemes in operation at SLEIPNER and SNOWHIT LNG project. SLEIPNER has removed millions of tones of CO_2 from natural gas which is being reinjected during EOR. By doing this company saved huge money from being paid as tax. The extracted CO_2 has been injected into the water-bearing Upper Miocene Utsira formation located at a depth of 1000 meters above the Sleipner reservoir and is overlain by an 80 meters thick shale cap rock. The Utsira formation forms an elongated sand-body about 450 kms and 90 kms wide. The thickness reaches a maximum of 250-300 m, and has an estimated capacity of several billion tonnes of CO_2.

In 2000, the Sleipner scheme was demonstrated to be a success as seismic surveys, which can clearly identify denser CO_2 solution in the aquifer, showed that the injected gas had remained in-situ without leaking trapped by the integrity of the overlying seal.

A second CCS scheme in Norway is currently being developed at the Snohvit LNG project. The processing facilities will remove CO_2 prior to the natural gas entering the liquefaction plant. Water will then be removed from the CO_2. At the Snohvit field, the Tubaen formation will be used to store the CO_2. The formation lies beneath the gas-bearing strata and is capped by 75-125m of thick impermeable shale. It is expected that 0.75 million tonnes of CO_2 will be reinjected per annum.

To stimulate the development of a CCS industry, a value-chain requires to be put in place to commercialize the generation and storage of CO_2. The principle behind the generation and storage of CO_2. The Principle behind creating value-chain involves the power station paying for the capture and transportation of CO_2 to the storage site. There, the field operator would pay a tariff to the power station to receive the CO_2 which is funded by the revenue from additional oil production.

An analysis of a coupled enhanced oil recovery (EOR) and Carbon Capture & Sequestration (CCS) project in a mature oil reservoir:

A coupled EOR and CCS project is defined as follows:

CO2 is injected into the reservoir until original reservoir pressure is attained (that is, more CO2 would be injected than in a conventional EOR-only project)

Reservoir is not in contact with an aquifer nor has been flooded for tertiary oil recovery.

It is for both Carbonate and sandstones:

Table 8: Comparison between carbonate and sandstone

	Carbonates	Sandstone
Permeability Distribution	Layered	Stochastic
Vertical to Horizontal permeability ratio	.01	.1
Average Porosity, Fraction	.11	.23
Reservoir Temperature, ^0F	110	150
Remaining oil saturation before flooding	0.58	0.33
Remaining oil saturation after flooding	0.31	0.18

***Continuous CO2injection method**

Table 9: Various cost components

Symbol	Factor	Low	Medium	High
A	Oil price, $\bbl	20	40	60
B	CO_2 price, $\mscf	1	3	4
C	Flood performance, mscf\ bbl	7	12	20
D	Drilling Cost			
E	Operational Cost Operating Cost$mm/month Recycle Cost $/mscf	 .0192 0.56	 .024 0.7	 .029 0.84
F	Discount Rate, %	0.1	0.15	0.20

Capture and Compression Costs:

CO_2source is nominal 500 MWe conventional coal-fired power plant Compression to 152 bars delivered on injection site.

Total capture cost is estimated as 45 $/t (or 2.6 $/mscf)

Transportation Costs:

CO_2 is transported from sources at 200-400 miles far from reservoirs; 0.5-1.2 $/mscf of CO_2

Economics of a 450 Mile CO2 Pipeline:

30" Pipeline

- Free Flow Capacity – 650 MMcf/d
- Capacity w/ 1 Pump Station – 880 MMcf/d
- Annual Pump Station Expense (w/o repl. costs or power substation) - $7 MM

26" Pipeline

- Free Flow Capacity – 450 MMcf/d
- Capacity w/ 3 Pump Stations – 800 MMcf/d
- Annual Pump Station Expense (w/o repl. costs or power substation) - $19 MM

24" Pipeline

- Free Flow Capacity – 370 MMcf/d
- Capacity w/ 5 Pump Stations – 800MMcf/d

- Annual Pump Station Expense (w/o repl. costs or power substation) - $31 MM

Compression Capital Costs:

Stated Conditions

- 15 psig Suction to 2100 psig Discharge
- 3 - 5800 T/d Compressors
- Purchase Cost - $30 MM
- Installation Cost - $30 MM (based on general construction and installation costs)
- Total Cost - $60 MM
- Total Power Requirement – 82.8 MW

Higher Suction Pressure

- 50 psig Suction to 2100 psig Discharge
- Purchase Costs - $22.5 MM
- Total Costs - $45 MM
- Total Power Requirement – 45 MW

Total Amortized Cost ($/Mcf):

Amortization Schedule

- 20 and 30 Years
- Solved for Lowest Cost per Mcf Delivered to the EOR Project
- 800 MMcf/d from Day 1
- Two Year Construction Timetable
- Total Capital - $750 M – (24" Pipeline)

Components of Costs – Stated Conditions (15 psig)

- Capital Recovery - $0.475/Mcf

- Operating Costs of Pipeline and Booster Stations - $0.146/Mcf
- Total Costs - $0.621/Mcf
- Excludes Costs of Power to Compress CO2
- Excludes Cost for CO2

***The Costs of Capture is the same whether the Emitter Chooses to Ultimately Inject into a Pipeline or Inject into Saline Reservoirs.CO2 Pipelines Operate at Pressures > 2000 psi. Injection Pressures for Saline Reservoir Injection will most likely be > 2000 psi.**

Single Gasification Project Emitting 200 MMcf/d of CO2

30 Year Life

Total CO2 Emissions – 2.2 Tcf of CO2

For ABC field having reservoir geometry:

16,000' Underground

Reservoir Pressure - +/- 11,000 psi

Areal Extent - 5,500 acres

Average Thickness - 300'

Storage Capacity will be Approx. – 3 Tcf

Now:

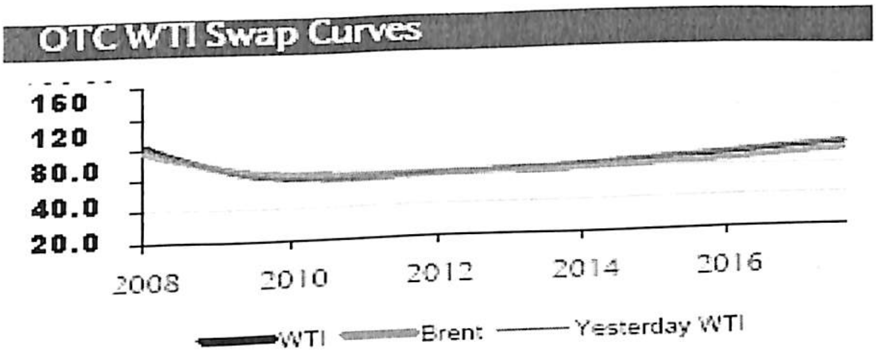


Figure 7: WTI Swap curves

10 year WTI/Brent Oil price ~$80.00/bbl. Value of CO2 created by oil price.

In US rule of thumb: 1000 cubic ft of CO2 is valued as 3.0% of bbl of oil value- $80. X 3.0% = 2.40/mcf,

Hence ,*Implied value* delivered to wellhead: 17.4 X 2.40 = $41.76/US ton.

One US ton (17,400 cubic feet) will produce ~2.5 bbls of oil

#Crude oil quality, field characteristics, distance to/from markets will influence

CHAPTER 7: MODELING OF CARBON CAPTURE AND STORAGE

Capture of CO_2

Coal Power Plant:

Specification: 500 MW

Coal used per day:

Fuel consumption= 0.2-0.3 gm/unit power generated.

Power generated= 500MW

So coal used per day= 100000- 150000 kg.

or 100-150 tonnes/day.

Carbon-dioxide produced per day:

Now in a genuine coal power plant, 0.16 million tonnes of coal produces 8000 to 10000 tonnes of CO_2.

So 150 tonnes of Coal will produce 9 tonnes of CO_2 per day.

Carbon capturing from flue gas:

Composition of Flue Gas:

Nitrogen: 78-80%
CO_2 : 10-12%
Oxygen: 2-3%
SO_2 : 180-250 ppm
CO : 70-110 ppm
NO_2 : 50-70 ppm

Flue gas treatment:

We pass the flue gas coming out of boiler from a water cooling apparatus to reduce its temperature.

Liquefaction of the flue gas:

Boiling point of CO_2= -55^0C

Melting point of CO_2= -78^0C

So in between -55^0C and -78^0C, CO_2 is in liquid state.

Boiling point of SO_2= -10^0C.

Melting point of SO_2= -75.5^0C

So in between -10^0C and -75.5^0C, SO_2 is in liquid state

Boiling point of N_2= -195^0C.

Boiling point and melting point of $NO_X < -100^0C$

Boiling point of O_2= -218^0C.

Liquefaction process will be done by **BHP Nitrogen Expander Process.**

On reaching a temperature of -78^0C, both CO_2 and SO_2 will be liquefied.

They are simply taken by a pipeline for further treatment.

Remaining flue gas consists mainly of N_2 and very small amount of O_2.

This Nitrogen is further utilized in the liquefaction process.

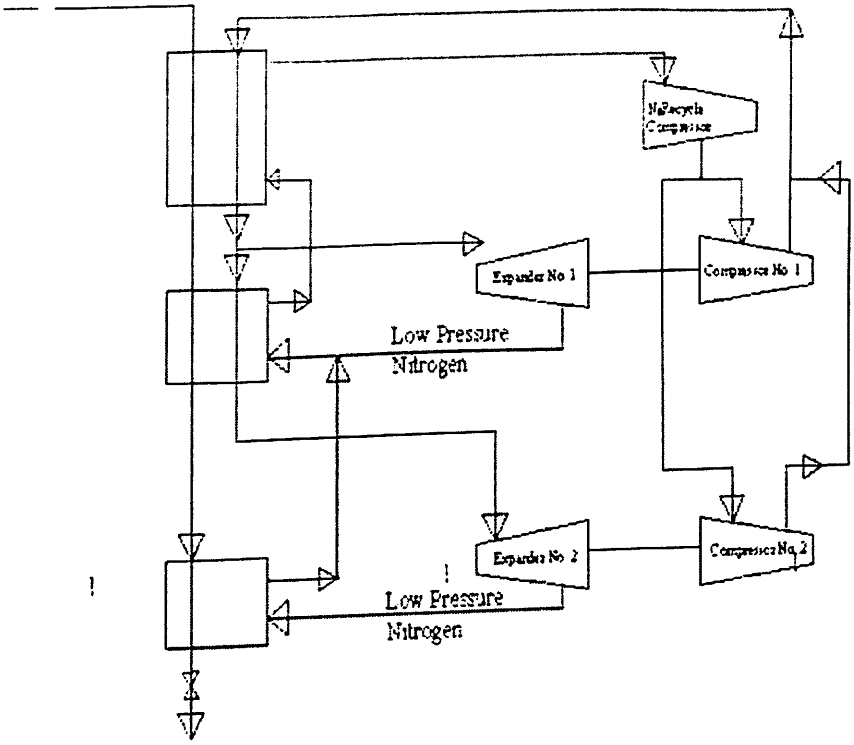


Figure 8: Liquefaction of flue gas

Treatment of liquefied CO_2 and SO_2:

It is brought back to the normal temperature.

Doing so will change its form from liquid to gas.

Further reduction of SO_2:

Solubility of CO_2 in water: 90ml/100ml water

Solubility of SO_2 in water: 6.43ml/100ml water

Now by flushing the gaseous mixture with a flush of water will further reduce the sulphur content from the gaseous mixture as solubility of SO_2 is very much less than that of CO_2.So for a fixed amount of water CO2 dissolved will be approximately 15 times more than the amount of SO2 dissolved. As concentration of SO2 in flue gas is very less, water flushing will reduce it further and brings it within permissible limits that can be sent to the refineries.

Next step is to dehydrate the above zone and bring the water content below 50 PPM. Dehydration is done by using MOLECULAR SIEVES.

This is done because now the captured carbon is transported through pipeline for storage. So in order to meet the pipeline specification dehydration is done. Else CO_2 will form Carbonic Acid (H_2CO_3) in presence of water.

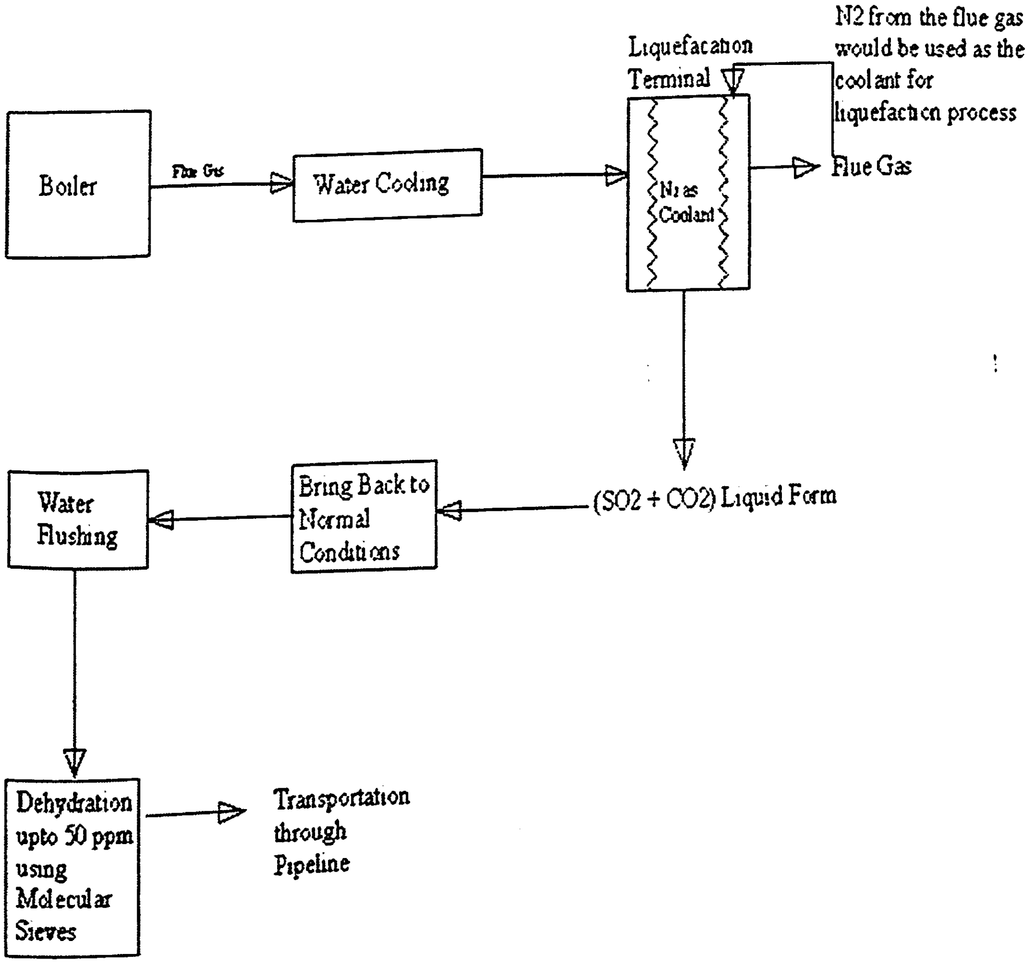


Figure 9: CO2 capture through physical processes

Transportation of Captured Carbon:

Specifications:

- 12 inch diameter pipeline.
- 100 km in length.
- Normal Steel pipeline.
- Zigzagged instead of straight pipeline to provide allowance for thermal expansion.

Cathodic protection is installed to protect the pipeline from external corrosion.

Operating Pressure:

Operating pressure for a carbon carrying pipeline is about **7.4 -21 MPa.**

(Because CO2 flow is in single phase at the above pressure range, for varying temperature. So we don't have to maintain the temperature of pipeline all the time for single phase flow)

Now carbon being transported per day will be:

9 tonnes per day from above calculation,

Or 9000 kg per day,

Or 9000000/1.98 lit/day or CO_2. [Density of CO_2=1.98gm/cm3].

Or $4.5*10^6$ lit/day.

So, we have to select dimensions of pipeline so that it should have the capacity equal to or greater than $4.5*10^6$lit/day. So we take a 12" pipeline which will have the capacity of $7.3*10^6$lit (greater than required)

Selection of Compressor:

As the desired operating pressure is between **7.4 MPa-21 MPa,** So the compressor should deliver a pressure of about 80-240 bar.

[7.4 MPa= 7.4*106 Pa

= 74.6 atm

= 74.6*1.013 bar

~ 80 bars.

Similarly 21 MPa is equal to 230 bars.]

So the pressure range is between 80 to 230 bars. Selecting 150 bars as the operating pressure for the compressor would do the job.

We select a Reciprocating compressor, having 3 stages of compression and delivering 150 bars of compressed CO2.

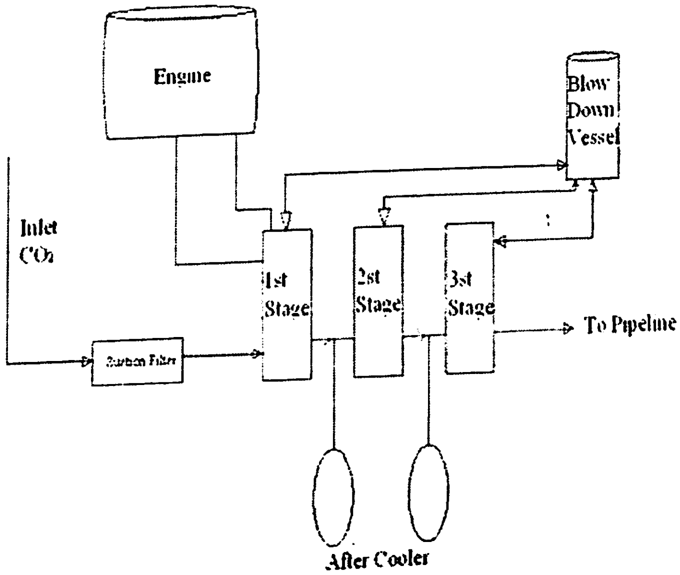


Figure 10: Reciprocating compressor

In between the 100 km pipeline there will be **3 Booster Compressors.**

Now the compressed CO2 would be finally delivered to the other compressor for injecting it to the storage.

So working condition of pipeline are:

Operating pressure= 7.4 – 21 MPa

Operating temperature = Can vary from room temperature

Gas Composition:

1) CO2= 99.9966%

2) SO2=0.0033%

Maximum flow rate=7.3*10^6 lit

Some pipeline design considerations:

1) CO2 is an acid gas and will react with water to form carbonic acid. Carbonic acid corrosion is a formidable challenge and consideration for facilities that process CO_2 should be taken such as corrosion-resistant stainless steels provided with erosion protection may have to be used.
2) CO_2 should be approximately free from water and liquid hydrocarbon as Water, hydrocarbons and CO2, beyond forming corrosive carbonic acid, may combine to form hydrates that could plug the system

Compressor at the start of pipeline: Three stage , single engine compressor.

1) Suction Pressure= Atmospheric pressure
2) Discharge pressure=Operating pressure of pipeline= 150bar (Assumed between operating pressure range)

Some compressor design considerations:

1) The high pressure ratio compression of CO_2 results in significant heat of compression. Both upstream and interstage cooling are desirable because less energy is required to boost the pressure of a cool gas.

Booster Compressor: For a 100km pipeline we are taking 3 booster compressors with following specifications:

1st booster compressor:

1) Suction pressure=125 bar
2) Discharge pressure=145 bar

2nd booster compressor:

1) Suction pressure=120 bar
2) Discharge pressure=140 bar

3rd booster compressor:

1) Suction pressure=115 bar
2) Discharge pressure=135 bar.

Storage of Captured Carbon: CO_2 is stored in depleted oil and gas reservoirs by injecting it through wells from where production has been stopped and the well is abandoned. For this we just need a compressor which can inject CO_2 coming from pipeline to the wellhead of injection well.

Parameters involved in successful geological storage:

1) **Type of storage-** Storage in depleted oil and gas reservoirs as it can lead to enhanced oil recovery if needed in future.
2) **Injection depth-** CO_2 will be injected at depths below 0.8km as CO2 increases in density with depth and becomes a supercritical fluid below 0.8km. Supercritical fluids take up much less space and diffuse better than either gases or ordinary liquids through the tiny pore spaces in storage rocks.
3) **Trapping mechanism-** Generally the trapping mechanism are stratigraphic trapping or structural trapping or a combination of two. In stratigraphic trapping cap rock coupled with impermeable rocks form a closed container to trap the CO_2. In structural trapping, impermeable rocks shifted by a fault in strata hold CO_2 in place.
4) **Injection Pressure-** Let the injection pressure is P_i. Assuming reservoir pressure at depth below 0.8km. We know that generally a pressure gradient of 0.43psi/ft is there in the reservoir, so for 0.8 km(2600ft), reservoir pressure will be 1118psi and will keep on increasing with depth. We are taking reservoir pressure at 2600ft.

   So, assuming it a hollow vertical cylinder, difference between injection pressure and reservoir pressure will be equal to product of density of CO_2, gravitational acceleration and depth of injection.

   $P_i - 1118 = \rho_{CO_2} * g * depth$

   So, $P_i = 1118 + (1.98*16.018/12^3)*(9.8*0.3*12)*(2600*12)$

   $= 1118 + 2020 = 3138 psi$

   So, $P_i = 213.5$ bar

Now for compressor used in injecting CO_2 has following specification:

1) Suction pressure=135 bar
2) Discharge pressure=213.5 bar.

CO_2 in enhanced oil recovery:

Miscible CO_2 EOR can increase the recovery of original oil in place by 8-20 %.CO_2, at high pressure and reservoir temperature, mixes with the oil to form a low viscosity, low surface tension fluid that can be more easily displaced. Additionally, CO2 has the capability of invading zones not previously invaded by water, as well as releasing and reducing trapped oil. The critical consideration is that in miscible displacements the residual oil saturation, that is, the oil left after being miscible contacted with CO2, is reduced nearly to zero.

CO_2 EOR Technical Aspects:

1) Miscibility: Flooding a reservoir with CO2 can occur either miscible or immiscibly. Miscible CO2 displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition

2) Generally, the injected CO2 content is in the range **92 to 97%.**

Well Design and Mechanical Integrity:

Oil and gas wells have existed for almost 150 years, since the time of Drake's first efforts in Pennsylvania in 1859. As well technology has evolved over the decades, trade and professional organizations such as the American Petroleum Institute (API), the American Society of Mechanical Engineers (ASME), the National Association of Corrosion Engineers (NACE), and others, have and continue to evaluate and catalogue the technical requirements and associated best design and operational practices into formal engineering standards and recommended practices.
To assure clarity, precise definitions of the major physical elements that comprise the wellbore and mechanical completion of a CO2 injection well are presented below.

1) Upstream Metering and Piping Runs. This section runs from the individual water and CO2 field distribution systems to the well. It contains: control valves, pressure sensors, metering equipment, and both check and isolation valves and blinds. Depending on operator preference, separate CO2 and water meter/piping runs may be used, each connecting individually to flanges on the Christmas tree, or the lines may be commoned and a single metering/piping run used with a single connection to the Christmas tree.

2) Christmas tree: The assembly of valves, spools, pressure gauges and chokes fitted to the wellhead of a completed well to control production. Christmas trees are available in a wide range of sizes and configurations, such as low or high pressure capacity and single or multiple completion capacity.

3) Wellhead: The surface termination of a wellbore that incorporates facilities for installing casing hangers during the well construction phase. The wellhead also incorporates a means of hanging the production (and injection) tubing and installing the Christmas tree and surface flow control facilities in preparation for the production phase of the well.

4) Casing: Steel pipe cemented in place during the construction process to stabilize the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or cross flow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment and down hole production equipment, such as the drilling blowout preventer (BOP) or production packer. Casing is available in a range of sizes and material grades.

5) Tubing:

a) Production: A wellbore tubular used to produce reservoir fluids. Production tubing is assembled with other completion components to make up the production string. The production tubing selected for any completion should be compatible with the wellbore geometry, reservoir production characteristics and the reservoir fluids.

b) Injection: A wellbore tubular used to inject fluid in the reservoir. Injection tubing is assembled with other completion components to make up the injection string. The injection tubing selected for any completion should be compatible with the wellbore geometry, reservoir production characteristics and the reservoir fluids.

6) Liner: Any string of casing in which the top does not extend to the surface but instead is suspended from inside the previous casing string. Many conventional well designs include a production liner set across the reservoir interval. This reduces the cost of completing the well and allows some flexibility in the design of the completion in the upper wellbore, such as when the fluid characteristics make it beneficial to increase the diameter of the conduit and components.

7) Packer: A down hole device used in almost every completion to isolate the annulus from the production conduit, enabling controlled production, injection or treatment. A typical packer assembly incorporates a means of securing the packer against the casing or liner wall, such as a slip arrangement, and a means of creating a reliable hydraulic seal to isolate the annulus, typically by means of an expandable elastomeric element. Packers are classified by application, setting method and retrievability.

Cost of CCS and Economic Viability:

Leakage of CO_2 to the surface:

$$u = \frac{b + k_1}{-2k_2} - \frac{c}{k_2}x$$

u= Controlled CCS level

x= Total storage level of CO_2

This implies that for a fixed discount rate as Total storage level of CO_2 increases, controlled CCS level decreases. Here we are taking oceanic storage with a depth of more than 800m as total storage level. Now assuming values of all the constants involved in the above equation:

- r = .05
- k1 = -100
- k2 = -1
- f1 = 200
- f2 = -.1
- L = .2

S = 0

We get

u(x) = 612 – 0.163x

Now, x=800m

So, u(x) =481.6m.

So, we find that after storing CO_2 upto a depth of 800 m , due to leakage the controlled level of CO_2 is 481.6m.

Now, we find the volume of CO_2 that can be stored in an area of 5000 acres in an oceanic storage is 5000*481.6*3.33=8018640 acre-ft.

Now 1 acre-ft= 43560sq. Ft

So, 8018640sq.ft=0.349 Tcf of stored CO_2 will be present if we store CO_2 under an area of 5000 acres and a depth of 800m in an oceanic storage.

Now from sources 17400 cu. ft will produce ~2.5bbls of Oil

So 1 cu.ft will produce $\sim 1.4*10^{-4}$ bbls of oil

So 0.349Tcf of stored CO_2 will produce $0.488*10^{8}$ bbls of Oil.

According to current oil price of 54 \$/bbl, the total revenue generated by recovered oil produced is **2.6 billion \$.**

Economic Viability of this CCS project in EOR:

Capture cost = 2.6\$/mcf

Transportation cost through pipeline=1.2\$/mcf

Operating cost of pipeline=0.621\$/mcf

Injection Cost=0.3\$/mcf

Total cost=4.721\$/mcf

Now Volume of CO_2 stored $=0.349*10^{9}$mcf

So total CCS cost is **1.64billion\$**

So, net profit for using CCS in EOR in a single field will be 0.96billion\$. So we can say that this hypothetical project will be economically viable to implement.

CHAPTER 8: CONCLUSIONS

1)CCS technically proven and safe

2)Will be one of several elements in meeting the global climate challenge

3)Enormous potential –broader acceptance necessary

4) Value chain concepts necessary

5)Need commercial incentives

6)Coupled EOR and CCS projects are unlikely to be initiated in a low oil price environment unless some form of CO2 credit is provided

7) It appears clear that any design of a CO2 credit scheme should include differentials based on reservoir characteristics, CO2 injection method, and the configuration of wells.

8) Enhanced Oil Recovery is the Lowest Cost Option for Sequestering CO2 for emissions today and for the foreseeable future. It provides an Economic Solution for CCS and provides additional quantities of domestic oil production. The only CCS method that produces an economic benefit and social benefits and the only CCS method that can be utilized now.

9) CO2 located closer to existing CO_2 pipeline infrastructure will have a considerable cost advantage. It is no different than natural gas production as the closer natural gas is to the user the higher the price it receives.

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