TÍTULO / TITLE: Offshore CO_2 enhanced oil recovery with CCS programs

FORUM: F06 – IOR / EOR – maximising the development of mature fields

KEY WORDS**:** Offshore, CO_2, Enhanced Oil Recovery, Carbon Capture and Storage

ABSTRACT (máx. 300 palabras):

CO_2 can be an effective EOR agent and is the dominant anthropogenic greenhouse gas driving global warming. Capturing CO_2 for EOR projects can maximize hydrocarbon recovery and help provide a possible bridge to a lower carbon emissions future, by adding value through EOR production and field life extension, and providing long term storage post-EOR operations.

Offshore use of CO_2 for enhanced oil recovery is in its infancy, but, with the adoption of carbon capture and storage to decarbonize fossil-fuelled power generation, there is a time-critical opportunity to add value to the CCS chain by adopting and maturing offshore CO_2-EOR.

In shallow water oil fields in a mature stage, with their strong natural water driver, high (40% to 60%) recovery of original oil in-place can be already achieved, leaving a much smaller target for CO_2-EOR. Furthermore, when there is low content of CO_2 in the associated gas, unless CCS programs are carried out in order to supply sufficient CO_2, other advanced EOR technologies such as low-salinity water injection or deep reservoir flow diversion, with higher reservoir sweep and oil displacement efficiencies at this moment may be preferred to economically target these reduced volumes of residual oil and push recovery factors up to 70%.

In deep-water oil fields, which entail higher cost wells and more complex facilities, higher oil recoveries than currently offered are also required to become economically viable using CO_2-EOR. However, in contrast with shallow water oil fields, the primary/secondary oil recovery efficiencies in deep water fields are considerably lower, providing a larger residual oil target using CO_2-EOR.

CCS programs with offshore storage to abate emissions from power generation or associated gas may now become a reality; especially after the COP21 and Major Oil companies asking for a carbon policy (as the one in Norway) to be applied worldwide.

Nomenclature

Bcfd	Billion cubic feet per day
BIGCC	Biomass Integrated Gasification Combined-Cycle
CCS	Carbon Capture and Storage
CRA	Corrosion Resistant Alloy
EOR	Enhanced Oil Recovery
ETS	Emissions Trading System
FAWAG	Foam Assisted Water-Alternating-Gas
FPSO	Floating Production Storage and Offloading unit
IGCC	Integrated Gasification Combined-Cycle
IRCC	Integrated Renewables Combined-Cycle
Mbpd	Million barrels per day
Mcfd	Million cubic feet per day
OOIP	Original Oil-In-Place
RST	Reservoir Saturation Tool
Stb	Stock tank barrel
SWAG	Simultaneous Water-Alternating-Gas
UNFCCC	United Nations Framework – Convention on climate change
WAG	Water-Alternating-Gas

Introduction

The twenty-first session of the Conference of the Parties (COP) and the eleventh session of the Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol (CMP) took place from 30 November to 11 December 2015, in Paris, France. The final text can be found in ref. [6]. According to the organizing committee at the outset of the talks, the expected key result was an agreement to set a goal of limiting global warming to less than 2 degrees Celsius (°C) compared to pre-industrial levels.

The year ended with what may become the most important element of all, Article 6 of the Paris Agreement. While this doesn't mention carbon pricing at all, it nevertheless provides fertile ground for its development through international trade of allowances and various other carbon related instruments. It also seeks to create a new global mechanism to underpin emissions reductions and promote sustainable development. Nonetheless, the ambitious goal of the Paris Agreement will need much wider and faster uptake of carbon pricing policy than is apparent from the charts below.

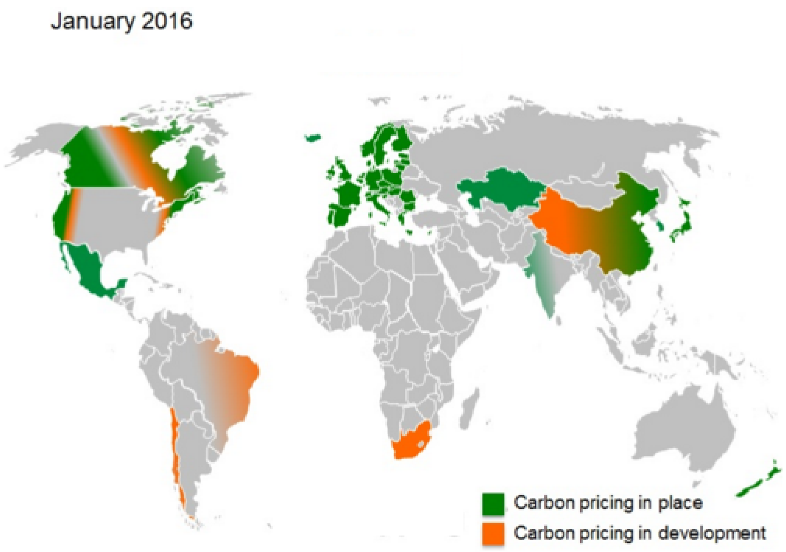

Figure 1: Countries with carbon policies in place or in development as of January 2016 (ref. [1])

Carbon capture and storage (CCS), through a suite of technologies, separates and captures CO_2 from power and industrial sources, then transports the CO_2 to a suitable site for injection into deep underground formations for permanent storage. CCS makes possible the strong reduction of net CO_2 emissions from fossil-fuelled power plants and industrial processes, providing a protection strategy for power plants that would otherwise be decommissioned, mothballed or suffer reduced operations in a carbon-constrained world. CCS may then become a potential source of CO_2 for enhanced oil recovery. This process is presented throughout the following paper.

The CCS opportunity

Background

The International Energy Agency (IEA) in its 450 Scenario1 (see ref. [2]), states that CCS is increasingly adopted from around the mid-2020s, with deployment accelerating in the 2030s and capturing around 5.1 Gt of CO_2 emissions per year by 2040 (nearly triple India's energy sector emissions today). Over the period 2015 to 2040, about 52 Gt of CO_2 emissions are captured. This involves a massive increase in CCS deployment over the 13 large-scale projects in operation today, which capture a total of about 27 Mt CO_2 per year (though only 5.6 Mt CO_2 at present is being stored with full monitoring and verification). To date, CCS investments are being made in sectors in which costs are relatively manageable (e.g. natural gas processing or refining) and where the captured CO_2 has a valuable application, such as for enhanced oil recovery. Widespread deployment will require moving well beyond these boundaries.

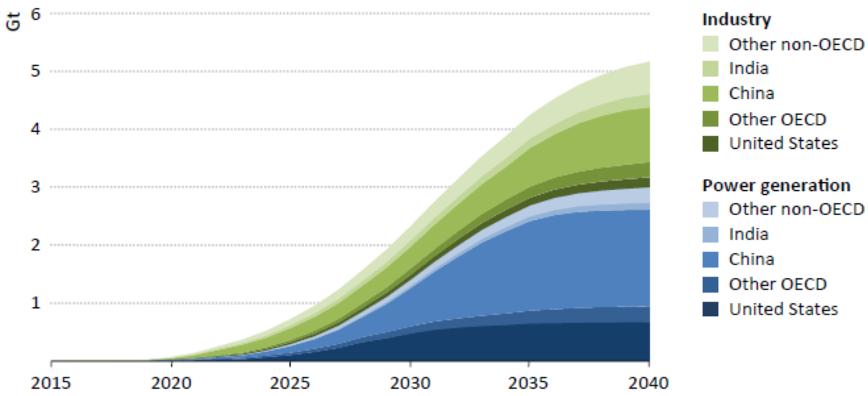

Figure 2: CO_2 captured in IEA's 450 Scenario by sector and region (ref. [2])

Note: Industry includes the following sectors: steel, cement (energy- and process-related), chemicals and paper production; oil refining; coal-to-liquids, gas-to-liquids and natural gas processing.

With the given carbon pricing or other policy measures to incentivise low-carbon operations, equipping coal or gas-fired power plants with CCS can be a commercially sound investment, allowing them to operate for more hours. The retrofit of existing plants with CCS can provide plants with a new lease on life as low-carbon generators, which could be particularly important in countries like China that already have a large fleet of coal- and gas-fired power plants and where coal prices are anticipated to remain relatively low.

Countries and companies with revenue streams from the extraction and processing of fossil fuels thus have a clear interest in supporting the development and deployment of CCS.

Both public and private sector actors can foster wider adoption of CCS technology. The priority is demonstration with large, focused and direct financial support. No trade-off between subsidizing CCS or other low carbon technologies should be made before the end of the demonstration phase that will define

[1] The IEA's 450 Scenario in ref. [2] depicts a pathway to the 2 °C climate goal that can be achieved by fostering technologies that are close to becoming available at commercial scale.

the real economic potential of CCS. UNFCCC countries have acknowledged that following the precautionary principle, uncertainty is not a reason for inaction. If by 2020, demonstration projects do not prove as promising as expected, governments will be able to readjust their incentive programs.

Carbon Capture processes

Four main capture processes exist: three for power or industrial plants (pre-, post- and oxy-combustion), and one for natural gas processing.

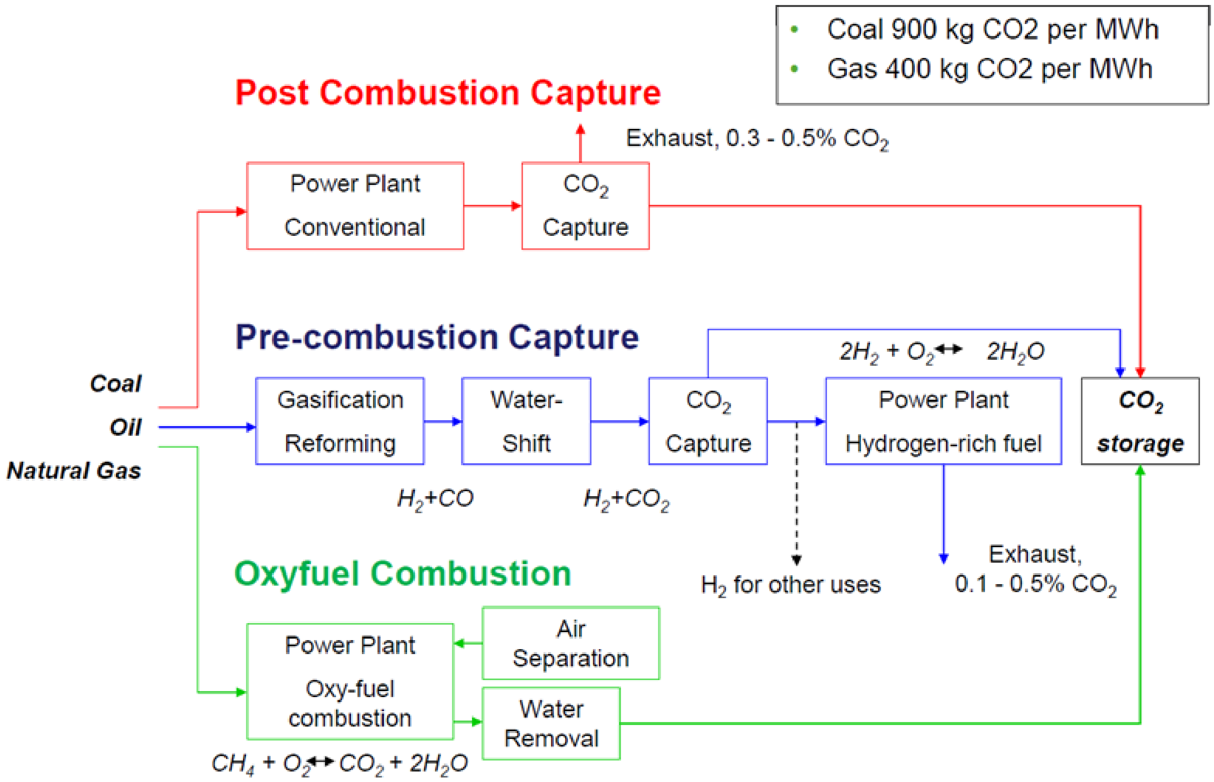

Figure 3: Capture options for power or industrial plants (~90%)

<u>Post-combustion</u>

Thermal power plants burn fuel with air to produce heat and emit flue gases that generally consist of a hot gas at standard pressure with 80% N_2, 10% CO_2, some oxygen, vapor and other pollutants (NOx, etc.). The CO_2 is then separated from the flue gases with various methods. The main hurdle is to separate CO_2 from N_2, which stays inert along the whole reaction. Most CO_2/N_2 separation systems today are using amine-based solvents. Additional drying, purification and compression are required before transportation (Figure 4).

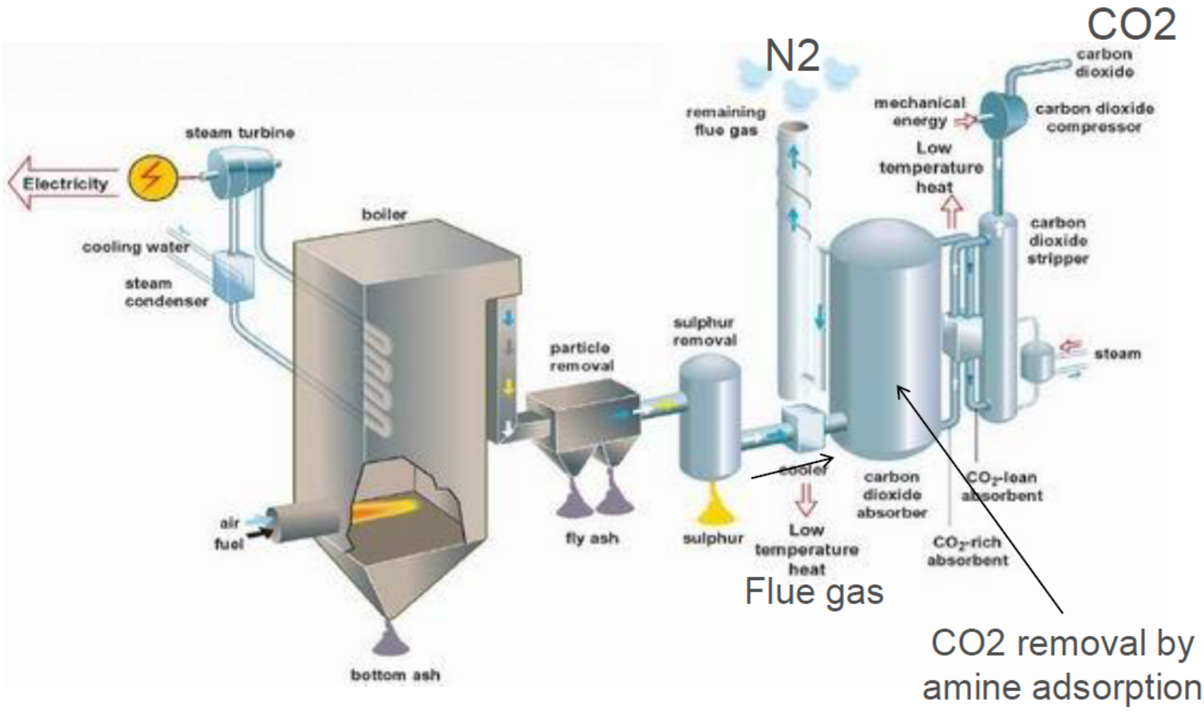

Figure 4: Schematic of Post Combustion Capture Plant (ref. [4])

Post-combustion systems are the most mature capture technology, and are expected to be retrofitted to modern and efficient thermal power plant: supercritical pulverized coal (SPC) and natural gas combined-cycle (NGCC). But it can virtually be retrofitted to almost any existing plant with large and steady source of CO_2, by adding the capture process to the exhaust gas circuit. Post-combustion is the only system that does not require an additional oxygen production plant. However, the process is still highly inefficient, given the low partial pressure of CO_2 in the flue gas. Energy requirement with existing amine-based solvent developed for non-CCS purpose are about 4.5GJ/tCO_2 capture, decreasing plant efficiency by 25%. Therefore, new and more efficient solvent are being demonstrated at pilot scale, but no commercial scale power plant with solvents-based post combustion have been built yet.

Oxy-combustion

Thermal power plant burners are modified to burn fuel with nearly pure oxygen instead of air - which contains only 21% of O_2. As a result, CO_2 concentration in flue gas varies between 80% and 98%, mixed with vapor, resulting in a stream almost ready to transport. Additional drying, purification and compression are also needed before transportation. Extremely high temperature is reached when fuel and pure oxygen are combusted, so flue gas needs to be partially recycled to cool down the burner, modified to resist higher temperature (see Figure 5).

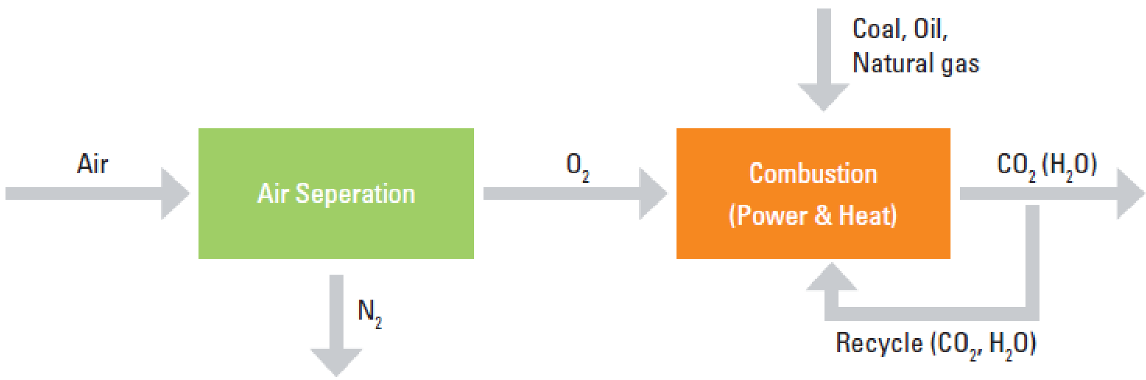

Figure 5: Oxy-combustion process

However, the main hurdle is the very large stream of pure oxygen needed for the oxy-combustion: Various O_2/N_2 separation systems exist but the main technology used today – cryogenic air separation units (ASUs), based on distillation at low temperature – is energy intensive. Another important issue is the insufficient purity of CO_2 in flue gases, which happened to be a matter of prime importance in early demonstration projects. Overall, the efficiency of the system is theoretically better than in post-combustion, but oxy-combustion is the less mature process for power generation. Oxy-firing process is being studied for steelmaking within the Ultra-Low CO_2 Steel Making (ULCOS) consortium of western European steel producers. In power generation, it has been proven at pilot scale (Total Lacq and Vattenfall Schwarze Pumpe) but remains to be demonstrated at large scale. One major challenge is to create such a massive flow of pure oxygen at reasonable costs.

Pre-combustion

The pre-combustion process regroups all industrial processes that transform hydrocarbon sources (coal, oil, gas or biomass) to generate synthesis gas (syngas) (hydrogen, carbon monoxide and dioxide) as an intermediate step.

Syngas is a strategic building block that can be used to produce a wide range of products (Figure 6). It can be transformed into liquid hydrocarbon, or hydrogen: another high energy content fuel that can be burn to produce electricity or heat, used to enrich industrial products into higher valued ones ('upgrading' of fossil fuel in refineries, producing ammonia for the fertilizing industry, etc.), or more marginally used to produce electricity directly in fuel cells. The syngas process has been in use for more than 50 years and is considered mature.

The advantage of this capture system is that the separation of CO_2 from H_2 is easier than from flue gas: concentration (17-38%) and partial pressure of CO_2 is much higher (typically 8bar) than in flue gases (0.1bar), allowing various gas separation methods that cannot be currently applied to post-combustion, and that are more efficient. Pressure swing adsorption (PSA) is the system of choice today, but CO_2/N_2 membranes, efficient only at high pressure, could potentially reduce drastically costs of separation.

CO_2 is removed from syngas (previously shifted with vapor), and the remaining H_2 is burned in hydrogen turbine to produce electricity without CO_2 in the flue gases:

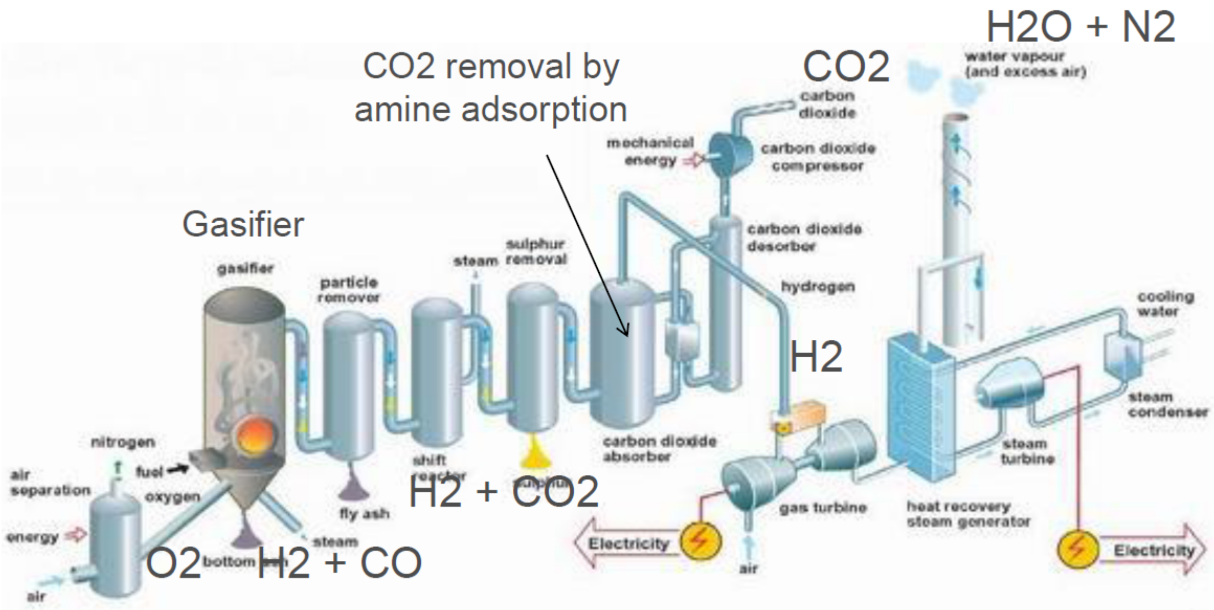

Figure 6: Schematic of Pre-combustion Capture Plant (ref. [4])

Integrated gasification combined-cycle (IGCC) remains much more expensive than conventional plant because of their complexity. They need, for instance, an air separation unit, although three times smaller than for oxy-combustion power plants. IGCC facilities are generally ‘CCS ready’, providing additional drying, purification and compression.

Ultimately, the syngas process with CCS could be applied to many sectors:

- Power Generation (IGCC from coal, IRCC from natural gas, BIGCC from biomass)
- Second generation biofuels (BtL or Biomass to Liquid)
- Synthetic liquid fuels from natural gas (GtL, Gas to Liquids) or coal (CtL, Coal to Liquids), the latter having an extremely high carbon footprint without CCS
- Synthetic natural gas (SNG)
- Chemical production (Ammonia NH_3)
- In Refineries, 5-20% of CO_2 emissions come from production of hydrogen, and demand is increasing with new regulations for higher quality fuels from lower quality crude.
- Furthermore, hydrogen fuel offers the flexibility to design pre-combustion power plant with mixed output, selling both electricity (during the day) and hydrogen byproducts like ammonia (at night).

<u>Natural gas sweetening</u>

About half of the raw natural gas produced worldwide contains more than 4% CO_2 by volume, which is above specifications for its transport (2% for pipelines). Natural gas processing facilities includes a ‘gas sweetening’ step which separate and remove CO_2. It is the lowest cost opportunity to create a large flow of CO_2 ready to be stored: CO_2 flow rate can be very high, separation is inherent to the process of natural gas production, and operates at already high pressure, reducing further cost of compression. The first large-scale integrated CCS projects were gas processing facilities, and CO_2/CH_4 separation system is already commercialized and mature.

Enhanced Oil Recovery

Background

Oil production is separated into three phases: primary, secondary and tertiary, the latter also being known as Enhanced Oil Recovery (EOR). Primary oil recovery is limited to hydrocarbons that naturally rise to the surface, or those that use artificial lift devices. Secondary recovery employs water and gas injection, displacing the oil and driving it to the surface. According to the Institute for 21st Century Energy (U.S. Chamber of Commerce) in ref. [8], utilizing these two methods of production can leave up to 50% of the oil in the reservoir.

The way to further increase oil production is through the tertiary recovery method or EOR. Although more expensive to employ on a field, EOR can increase production up to a maximum of 70% recovery. The following figure shows an example of the different recovery percentages reaching a maximum of 55%.

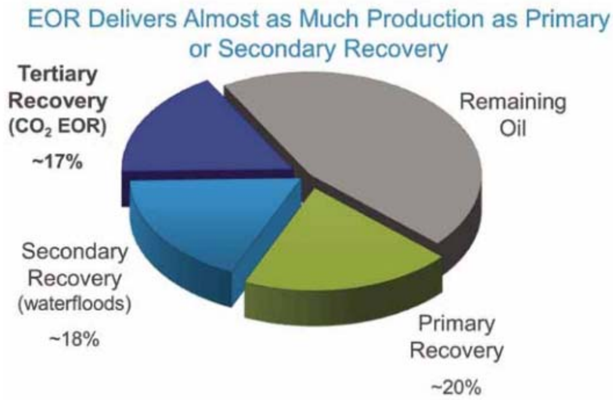

Figure 7: Example of approximate recovery factors shown for onshore U.S. (ref. [8])

Used in fields that exhibit heavy oil, poor permeability and irregular fault lines, EOR can entail changing the actual properties of the hydrocarbons, which further distinguishes this phase of recovery from the secondary recovery method. While water flooding and gas injection during the secondary recovery method are used to push the oil through the reservoir, EOR applies steam or gas to change the makeup of the reservoir.

Whether it is used after both primary and secondary recovery have been exhausted or at the initial stage of production, EOR enhances oil displacement in the reservoir.

EOR techniques

There are three main types of EOR, including thermal recovery, chemical flooding and gas injection. Since it increases the cost of development alongside the hydrocarbons brought to the surface, producers do not use EOR on all reservoirs. The economics of the development equation must make sense. Therefore, each field must be well evaluated to determine which type of EOR will work best on the reservoir. This is done through reservoir characterization, screening, scoping, and reservoir modeling and simulation.

Thermal Recovery

Thermal recovery introduces heat to the reservoir to reduce the viscosity of the oil. Many times, steam is applied to the reservoir, thinning the oil and enhancing its ability to flow. First applied in Venezuela in the 1960s, thermal recovery now accounts for more than 50% of applied EOR in the US, as stated in ref. [8].

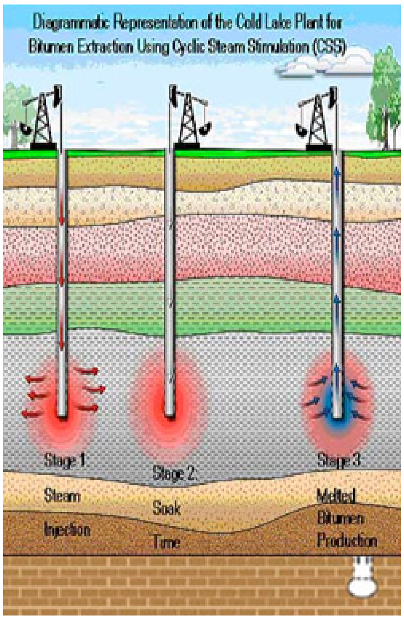

Figure 8: Thermal Recovery

Chemical Injection

Chemical injection EOR helps to free trapped oil within the reservoir. This method introduces long-chained molecules called polymers into the reservoir to increase the efficiency of water-flooding or to boost the effectiveness of surfactants, which are cleansers that help lower surface tension that inhibits the flow of oil through the reservoir. Less than 1% of all EOR methods presently utilized in the US consist of chemical injections.

Gas Injection

Gas injection used as a tertiary method of recovery involves injecting natural gas, nitrogen or carbon dioxide into the reservoir. The gases can either expand and push gases through the reservoir, or mix with or dissolve within the oil, decreasing viscosity and increasing flow. Nearly half of the EOR employed in the US is a form of gas injection according to ref. [8].

Carbon dioxide EOR (CO_2-EOR) is the method that is gaining the most popularity. While initial CO_2-EOR developments used naturally occurring carbon dioxide deposits, technologies have been developed to inject CO_2 created as byproducts from industrial purposes.

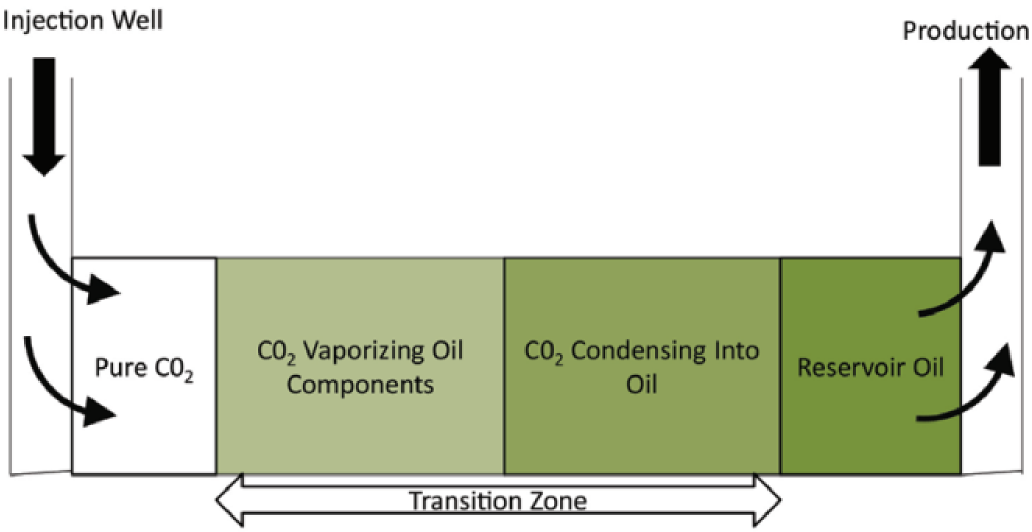

Figure 9: The schematic of the CO_2 miscible process showing the transition zone between the injection and production well

First employed in the US in the early 1970s in Texas, CO_2-EOR is being successfully used in the oil fields of the Permian Basin of West Texas, the Gulf Coast, the Rockies, and basically all over the world as depicted in Figure 10. Moreover, it is expected to become even more widely spread in the near future.

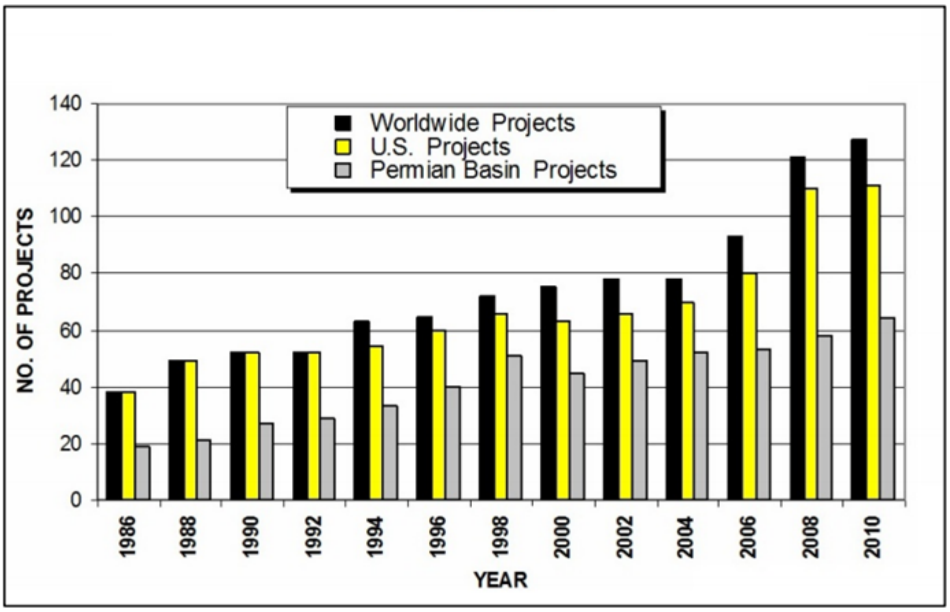

Figure 10: Active CO_2-EOR project counts (1986-2010) (ref. [15])

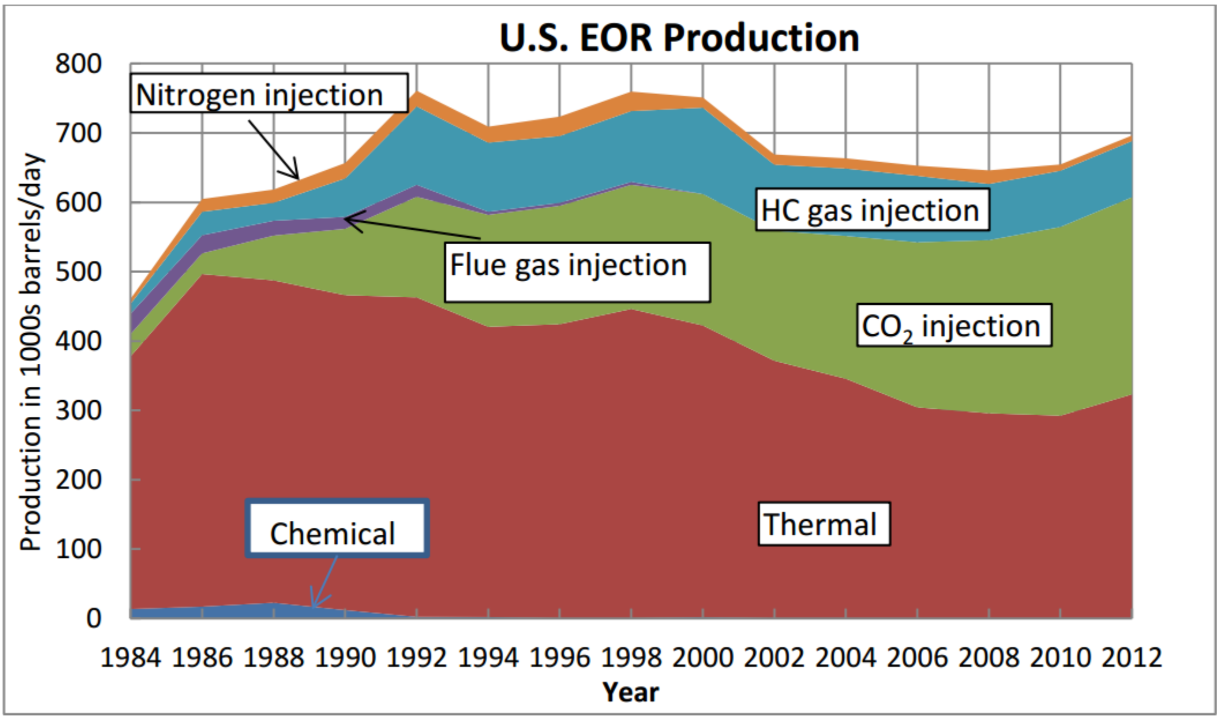

Figure 11: U. S. EOR Production by type (1984-2012) (ref. [16])

<u>Other EOR applications</u>

Other EOR applications gaining acceptance are low-salinity water flooding, which is expected to increase recovery by nearly 20%, and well stimulation, which is a relatively low-cost solution because it can be employed to single wells (rather than the whole reservoir).

Offshore CO_2-EOR Current Applications

General

Although EOR applications are predominantly employed today onshore, technologies are being developed to expand the reach of EOR to offshore applications. Challenges that presently exist for offshore EOR include economics of the development; the weight, space and power limitations of retrofitting existing offshore facilities; and fewer wells that are more widely spaced contributing to displacement, sweep and lag time.

Currently, the application of EOR is being considered for a number of offshore developments. With successful subsea processing (for mature fields) and secondary recovery methods employed in offshore environments through water and gas injection, the technologies to apply EOR methods is quickly nearing.

As such, the success of using CO_2-EOR in onshore oil fields inspires operators to consider using CO_2-EOR in offshore oil fields. The international pursuit of offshore EOR is somewhat active, as illustrated by the following five active or planned international offshore CO_2-EOR projects:

1. Offshore Brazil, Pre-Salt Layer (ref. [9])
2. North Sea, Draugen/Heidrun Oil Fields (ref. [17])
3. Offshore Abu Dhabi, Persian Gulf Oil Fields (ref. [12])
4. Offshore Vietnam, Rang Dong Oil Field (only offshore EOR application using anthropogenic CO_2) (ref. [18])
5. Offshore Malaysia, Dulang Oil Field (ref. [11])

CO_2-EOR Offshore Brazil – The Pre-salt Layer

Background

Brazil's Pre-Salt area is currently the international pioneer in pursuing deep water offshore CO_2-EOR. The Lula Field is a super-giant deep water oil field located in the Santos Basin of Brazil.

According to ref. [9], given the innovative strategies being pursued by Petrobras, the Lula Field serves as a most valuable case study of using early application of advanced CO_2-EOR technology to optimize the development of a major offshore oil field. Significant preparation steps taken at Lula, as discussed further in this section of the report, include: intensive reservoir characterization, testing of alternative enhanced oil recovery options, and rigorous monitoring of pilot flood performance. Lula was discovered by Petrobras in 2006 in ultra-deep waters, between 1650 and 2,200 meters (5,400 and 7,200 feet), approximately 180 miles south-east of Rio de Janeiro. Lula's carbonate reservoir is overlain by a thick 1,800 meters (6,000 feet) salt column and holds moderately light, 28-30 °API oil with a high solution gas-oil ratio. The associated gas in the reservoir contains 8% to 15% of CO_2.

First oil year	Unit name	Operator	Country	Owner
2011	FPSO Cidade de Angra dos Reis MV22 (Pilot 1)	Petrobras	Brazil	Modec
2012	FPSO Cidade de Sao Paulo MV23 (Pilot 2)	Petrobras	Brazil	Modec
2013	FPSO Cidade de Paraty (Pilot 3)	Petrobras	Brazil	SBM
2014	FPSO Cidade de Ilhabela (Pilot 4)	Petrobras	Brazil	SBM
2014	FPSO Cidade de Mangaratiba MV24 (Pilot 5)	Petrobras	Brazil	Modec
2015	FPSO Cidade de Itaguai MV26 (Pilot 6)	Petrobras	Brazil	Modec
2015	FPSO Cidade de Marica (Pilot 7)	Petrobras	Brazil	SBM
2016	FPSO Cidade de Saquerema (Pilot 8)	Petrobras	Brazil	SBM
2016	FPSO Cidade de Caraguatatuba MV27 (Pilot 9)	Petrobras	Brazil	Modec

Table 1: FPSO units with CO_2 re-injection on the pre-salt layer offshore Brazil

Pre-Salt CO_2-EOR highlights

- *Early Implementation of CO_2-EOR*

According to ref. [9], Petrobras implemented a series of short-term EOR pilots at Lula with the intention of developing the entire field using CO_2-EOR, if the CO_2 pilot was successful. According to Petrobras, early implementation of CO_2-EOR would improve capital efficiency as it frees the operator from having to subsequently retrofit production systems and find platform space for CO_2 recycling. Early implementation of CO_2-EOR would also preclude halting operations and shutting-in oil production when undertaking CO_2-EOR later in the oil field's life.

- *Deepwater CO_2-EOR Technology*

The technology deployed by Petrobras for Lula mirrors the methodology and design used in ARI's deep water CO_2-EOR resource assessment modeling. Similar to Petrobras, ARI (ref. [10]) uses a hub and spoke model to service multiple fields with subsea completions. Both Lula and ARI's offshore CO_2-EOR design utilize intelligent well completions, dynamic down hole monitoring, tracer injections and extensive CO_2 recycling.

Figure 12: CO_2 compression topside module on FPSO at the Lula field – Heaviest module aboard

- *Reservoir Characterization and Phased Development*

Petrobras is following a phased development of the Lula Field, allowing for its field development and EOR strategy to evolve as reservoir characterization and performance data improve. Importantly, the company uses Extended Well Tests (EWTs) to define reservoir connectivity and other key characteristics, and a phased development program to formulate their EOR strategy without waiting for results from the operation of a water flood.

- *Choosing a Recovery Method at an early stage*

Petrobras decided early in its field development cycle not to vent the CO_2 produced at Lula, but to use this gas for miscible CO_2-EOR. In addition, the high CO_2 content present in the associated gas dictated that corrosion resistant alloys be used in all production wells enabling a CO_2-EOR flood to use existing wells and infrastructure without major refurbishment.

- *First Development Phase*

The first Lula EOR pilot consisted of one injection and one production well. In April 2011, Petrobras began injecting produced reservoir gas into the oil field at a rate of 35 Mcfd. After six months of gas re-injection, the hydrocarbon gas was separated from the CO_2 in the FPSO's membrane processing system and transported onshore for sale. The separated CO_2 was then re-injected into the reservoir at a rate of 12.3 Mcfd. A horizontal well was drilled in Q1 2012 and WAG injection, utilizing water and the high CO_2 concentration gas, commenced in the second half of 2012. The Lula EOR pilot included one gas injector, two WAG injectors, and multiple producers. Ultimately, as shown in Table 1, a range of pre-salt fields are using CO_2 injection.

Figure 13: Third generation[2] FPSO Cidade de Ilhabela on its way to the oil field

The major takeaway from the Lula field case study is that early implementation of CO_2-EOR should be considered for giant, newly-discovered deep water offshore fields. As demonstrated by Petrobras, phased development, reservoir simulation and dynamic data acquisition, instead of waiting on the field's water flood performance, can be used to define how oil recovery will respond to CO_2-EOR.

CO_2-EOR North Sea

Background

Enhanced oil recovery using gas injection is not a new concept for North Sea oil fields. Many projects have been conducted to date including EOR projects in major oil fields such as Brent, Ekofisk and Stratfjord (see Table 2). However, these EOR projects have used hydrocarbon gas as the miscible agent instead of CO_2.

[2] Third generation FPSO's means that topsides are complex and heavier than 20,000t partially due to the CO_2 processing system

First oil year	Field	Operator	Country	EOR Type
1971	Ekofisk	Conoco-Phillips	NORWAY	HC Miscible[3]
1971	Ekofisk	Conoco-Phillips	NORWAY	HC WAG Immiscible
1976	Beryl	Apache North Sea	UK	HC Miscible
1976	Brent	Shell	UK	HC Miscible[4]
1978	Thistle	Lundin Oil	NORWAY	HC WAG Immiscible
1979	Statfjord	Statoil	NORWAY	HC Miscible
1979	Stratfjord	Statoil	NORWAY	HC WAG Immiscible
1983	South Brae	Marathon	UK	HC WAG Miscible
1983	Magnus	BP	UK	HC WAG Miscible
1986	Gullfaks	Statoil	NORWAY	HC WAG Immiscible
1987	Alwyn North	Total	UK	HC Miscible
1992[5]	Snorre	Statoil	NORWAY	HC WAG Miscible
1992	Snorre A (CFB)	Norsk Hydro	NORWAY	HC FAWAG
1992	Snorre A (WFB)	Norsk Hydro	NORWAY	HC FAWAG
1993	Brage	Norsk Hydro	NORWAY	HC WAG Immiscible
1999	Smorbukk South	Statoil	NORWAY	HC Miscible
1999	Oseberg	Norsk Hydro	NORWAY	HC WAG Immiscible
1999	Siri	Statoil	DENMARK	HC SWAG[6]

Table 2: Some of North Sea EOR experiences

Today, North Sea oil field operators are interested in substituting CO_2 for natural gas as the injectant for EOR. A number of factors, including opportunities to sell the hydrocarbon gas and interest in capturing and storing CO_2 from power plants, are currently being considered for combining CO_2-EOR and CO_2 storage in the oil fields of the North Sea.

CO_2-EOR Projects for North Sea Oil Recovery and CO_2 Storage

A number of CO_2-based enhanced oil recovery projects have been considered for the North Sea, transporting the CO_2 from onshore power plants to offshore oil fields, including:

- **Draugen and Heidrun Oil Fields**. In 2006, Shell and Statoil announced plans for capture of CO_2 from onshore power generation with transport and injection of the CO_2 into two Norwegian sector offshore oil fields. Both companies had good technical and management pedigrees for implementing the project. Shell pioneered using CO_2 for EOR in the 1970s and Statoil was the first to store CO_2 offshore at the Sleipner field in the 1990s. At the time, the project would have been the world's largest offshore CO_2-EOR operation.
  After completing a technical study, the operator estimated that CO_2 flooding at Draugen would provide only modest volumes of additional oil recovery and, without incentives or financial support

[3] Not currently operational
[4] In blowdown phase; not EOR project
[5] The Norwegian carbon tax was introduced in 1991
[6] Principally a gas-storage project

for CO_2 capture, the modest additional oil would not justify the cost of storing CO_2 with CO_2-EOR. The CO_2-EOR project required retrofitting production wells, drilling six new subsea wells to target the flanks of the oil field, and building a CO_2 pipeline. In addition, the platform (and thus oil production) needed to be shut down for a year, further increasing the financial impact of the project.

Although the Draugen Project was deemed to not be commercially viable, Shell and Statoil did determine that it was technically feasible. Today's environment, with current low oil prices, still make future CO_2-EOR projects in North Sea oil fields economically uncertain, despite the improvement of CO_2-EOR technology and the incentives to capture CO_2.

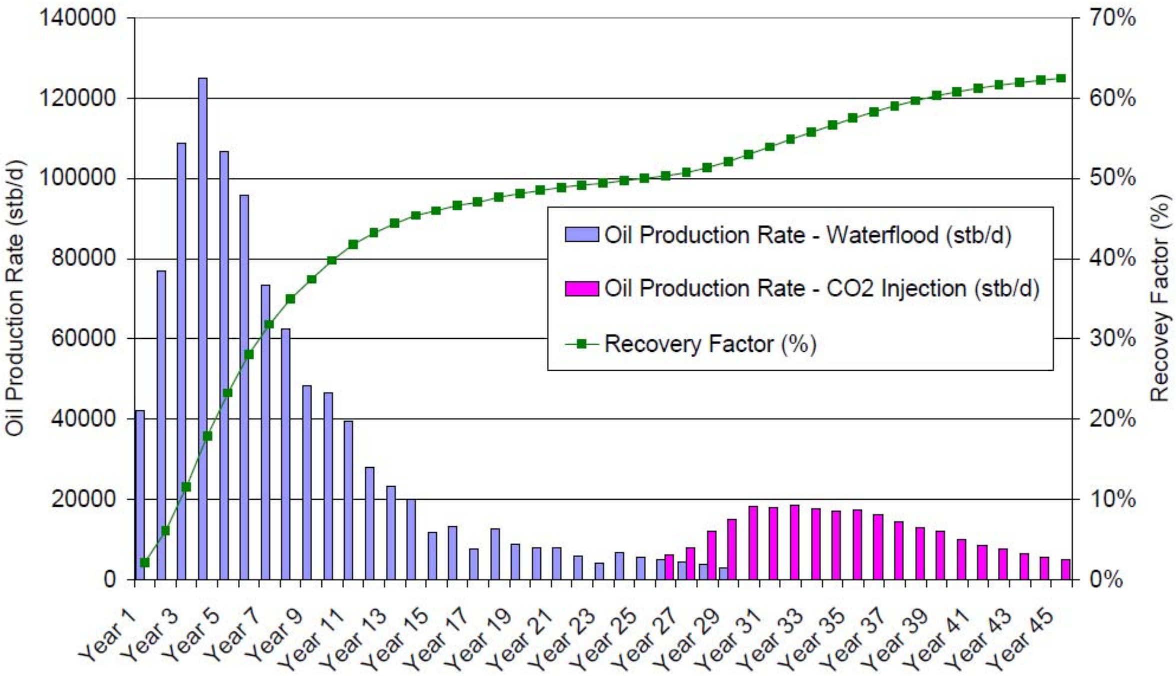

Figure 14: Typical CO_2-EOR Response in North Sea Oil Field

- **Don Valley Project.** The recently formed company, 2Co Energy, proposed an innovative CO_2-EOR project involving capturing CO_2 from the Don Valley IGCC power plant and transporting the CO_2 300 km offshore to improve oil recovery and store CO_2 in two mature oil fields in the Central North Sea. Two offshore storage options were studied: the potential use of Talisman Energy Ltd's central North Sea oil fields for enhanced oil recovery (EOR), as well as deep saline formations in the southern North Sea. The offshore EOR/Storage feasibility study was completed as well as the final decision to use the saline storage site known as 5/42. In the summer of 2013 drilling appraisal was undertaken on this site. Initially, the Don Valley Project was named by NER300[7]

7 According to the EU Emissions Trading System provisions for CCS schemes, in order to provide further incentives for the development of CCS projects, the Revised ETS Directive provides that up to 300 million EUAs (EU Allowance Unit of one tonne

(the new entrants' reserve), a €4.4 billion fund created by the European Commission to finance low carbon technologies, as a top prospect. However, the UK government did not pledge financial support for the project, making the project ineligible for NER300 funding. The UK government cited the Don Valley Project's £5 billion price tag including (£1 billion for offshore facilities, £3 billion for the power plant with CO_2 capture) as a main reason for their decision. 2Co is currently studying the economic feasibility of moving forward without governmental funding.

- **Miller Oil Field**. BP had defined a program to capture CO_2 from the Peter head gas-fired power station, storing the CO_2 with CO_2-EOR in the Miller offshore oil field. The project failed to receive government support and the Miller oil field is now abandoned.
- **Danish Oil Fields**. Maersk Oil submitted a plan to the EU for capturing of CO_2 from an oil refinery and transporting the CO_2, by ship, to oil fields in the Danish sector of the North Sea. This project is currently also on hold.
- **Tees Valley**. Progressive Energy also submitted a proposal to the EU involving the construction of a new IGCC power station with pipeline transportation of the captured CO_2 to Central North Sea oil fields for CO_2-EOR. This project is currently also on hold.

CO_2-EOR Offshore Abu Dhabi

The Marine Operating Unit of Abu Dhabi National Oil Company (ADNOC) has begun to examine the viability of injecting CO_2 into its offshore fields to improve oil recovery. Currently about 5 Bcfd of natural gas is injected to enhance oil recovery from the Abu Dhabi oil fields and ADNOC is looking to replace the hydrocarbon gas injection with CO_2.

In 2010, ADNOC initiated a feasibility study to determine the commercial viability of CO_2 flooding in the low permeability Lower Zakum field off the coast of Abu Dhabi. Talks are underway between ADNOC and Masdar, an Abu Dhabi renewable energy technology company, to capture 800,000 metric tons of CO_2 per year from a steel plant in Mussafah, UAE and use this CO_2 for enhanced oil recovery. ADNOC then completed a successful two year CO_2-EOR pilot in the onshore Rumaitha field (injecting 1.2 Mcfd). The company plans to build upon its onshore EOR experience to implement CO_2-EOR in its offshore Persian Gulf oil fields to help achieve its goal of increasing oil production to 3.5 Mbpd from its current level of 2.8 Mbpd.

In October 2014, the Dubai-based Dodsal group won a Dh450 million contract to build a CO_2 compression facility and a 50-kilometre pipeline. Abu Dhabi also has rising local demand for gas and would like to replace its use in the energy sector with CO_2 to free it up for commercial uses. The emirate has one of the world's highest carbon footprints and would like to cut its emissions.

According to ref. [12], the Abu Dhabi CCS project completion is set for Q2 of 2016.

CO_2-EOR Offshore Vietnam

The only offshore CO_2-EOR application using anthropogenic CO_2 is in Rang Dong field, offshore Vietnam.

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ofCO_2) in the new entrants' reserve (NER) were made available until 31 December 2015 to help stimulate the construction and operation of up to 12 CCS demonstration projects

In 2007, a Joint Venture with Vietnam Oil and Gas Group (PETROVIETNAM), Japan Vietnam Petroleum Co., Ltd. (JVPC), and Japan Oil, Gas and Metals National Corporation (JOGMEC) completed a feasibility study that indicated that CO_2 injection into the oil fields in the South China Sea would increase oil recovery efficiency by 6.4% of oil initially in place compared with water flooding with a utilization efficiency of 3.4 incremental barrels per tonne of CO_2 injected (5.55 Mscf/stb) and would therefore provide storage for CO_2. To confirm the feasibility study's findings, the companies conducted a small scale CO_2 injection pilot test in June 2011. The pilot test consisted of a CO_2-EOR "Huff 'n' Puff" operation in the Rang Dong oil field, located 135 miles south-east of Vung Tau in Block 15-2 of the Cuu Long Basin. The pilot project was operated by JVPC with support from PETROVIETNAM and funding from JOGMEC.

The CO_2 was trucked by road to VungTau (163 tonnes) from a fertilizer plant near Hanoi. Then it was transported by ship to the Rang Dong oil field.

In 2012, the companies declared the pilot test had successfully confirmed the main objectives of the pilot – adequate CO_2 injectivity and increased oil production.

Three stage treatment:

- Establish pre-test flow rate then log saturation profile (RST)
- Inject CO_2 (111 tonnes) over 7 hours, leave to 'soak' then log
- Flow well then log

The following facts were observed:

- Bottom-Hole Pressure ~3300 psia
- Minimum Miscible Pressure ~2980 psia
- Swelling and viscosity reduction mechanisms observed
- Oil rate increased from 950 to 1500 stb/d
- Water cut reduced from 50-60% to near zero
- 214 incremental stb of oil
- Utilization 1.9 incremental stb per tonne of CO_2 (or 9.8 Mscf/stb)
- Pre and post injection logging indicates saturation reduction

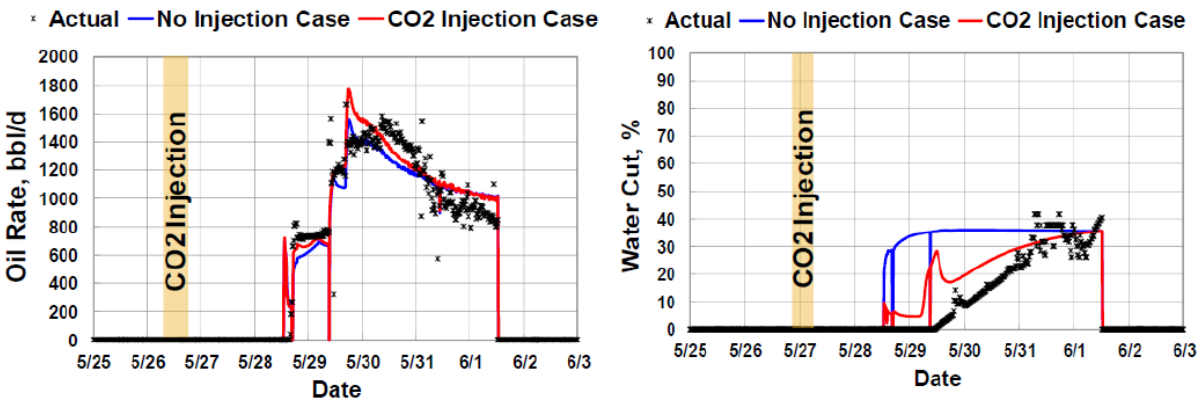


Figure 15: Rang Dong Oil field CO_2-EOR data (ref. [18])

CO_2-EOR Offshore Malaysia

Petronas publicly announced that two-thirds of the country's original oil in-place of 17 billion barrels is at risk of being stranded (after completion of primary/secondary recovery) without implementation of advanced EOR (see ref. [11]).

Based on this, starting in November of 2002, Petronas initiated a four year CO_2-EOR pilot in the Dulang oil field. The oil field is located 130 km offshore from Terengganu, eastern Malaysia, in 250 feet of water. The offshore oil field is one of Malaysia's largest with 1.1 billion barrels of OOIP and an estimated primary/secondary recovery of 328 million barrels, including the use of water injection to combat falling reservoir pressure. The field's produced gas contains a high concentration of CO_2 (>50 percent).

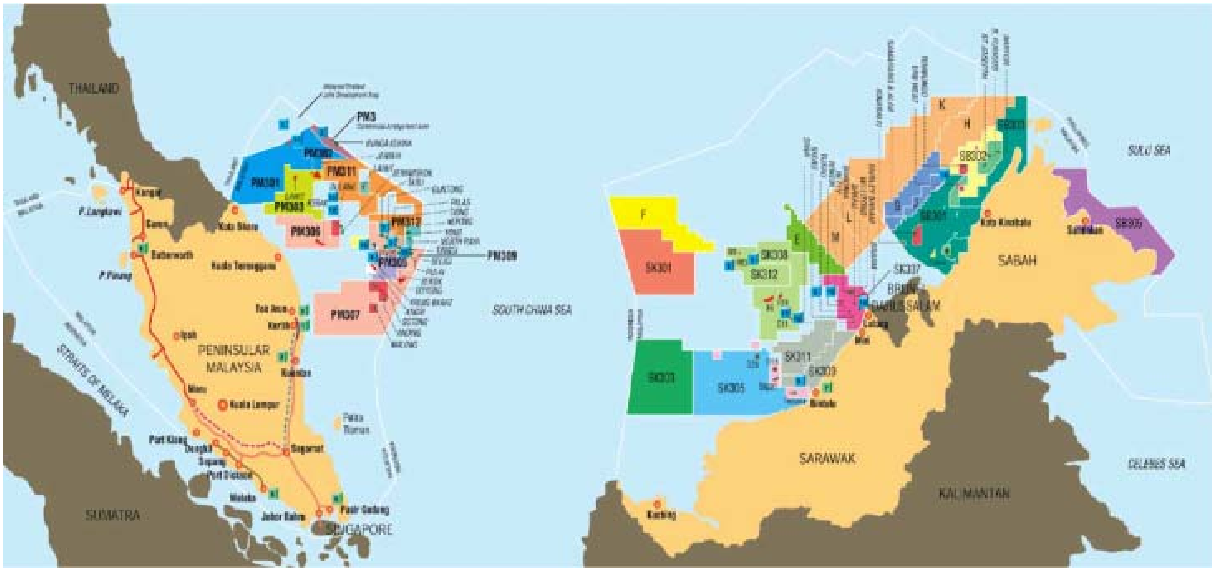


Figure 16: Offshore oil fields, Malaysia

Petronas determined that Dulang's initial reservoir pressure was nearly 1,000 psig below minimum miscibility pressure (MMP), ruling out miscible or near-miscible gas injection. As such, the company decided to conduct a pilot immiscible water-alternating-gas (IWAG) flood that would re-inject the CO_2-rich produced gas back into the reservoir. The EOR pilot consisted of 3 producers and 3 injectors in the S3 Block of the Dulang Field. Petronas injected 4 Mcfd of CO_2 and 3.5 Mbpd of water in cycles lasting 3 months each.

After four years of operation, the IWAG EOR Pilot was terminated in 2006 and deemed a success by Petronas. The operator concluded that the offshore IWAG EOR Pilot was operationally manageable, significantly increased oil production, and reduced the water cut. Field wide application of an IWAG flood was recommended, but has yet to be implemented.

More recently, Petronas signed two new production sharing contracts (PSCs) in 2011 with Shell Malaysia for evaluating thirteen EOR projects offshore Sarawak and Sabah, looking to increase average oil recovery in the fields from 36 percent of OOIP to 50 percent of OOIP, according to Shell.

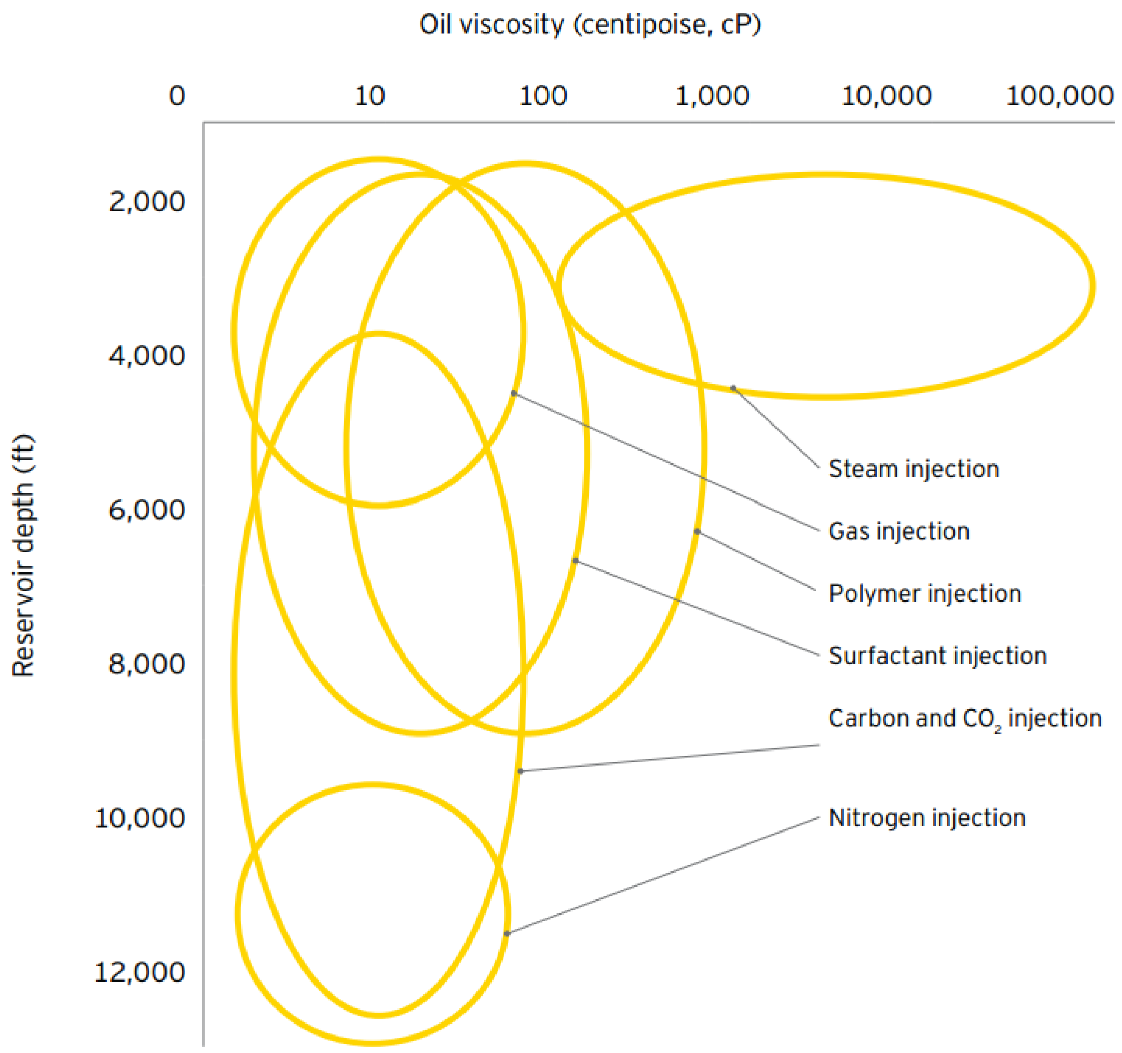
Offshore CO_2-EOR Opportunities

CO_2 EOR Challenges

Based on the information exposed above, it can be stated that the offshore CO_2-EOR Offshore faces the following challenges:

Project viability

Implementing an EOR project is a long and complex process given the advanced nature of the techniques as well as the uncertain nature of the tertiary production phase.



Source: Enhanced Oil Recovery (EOR) Report, Royal Dutch Shell.

Figure 17: EOR methods and related technical factors (ref. [13])

Method	Density (kg/cubic m)	Remaining recoverable reserves (% of initial recoverable reserves)	Rock type	Depth (m)	Permeability (mD)	Temperature (°C)	Expected extra ORF (%)
Nitrogen injection	>850	>40	Carbon	>2,000	190	–	n/a
Hydrocarbon injection	>904	>30	Carbon	>1,350	–	–	20 – 40
CO_2 injection	>904	>20	Carbon	>700	–	–	5 – 25
Polymer injection	>966	>70	Sand	<3,000	>10	<95	5 – 30
Surfactant injection	>946	>35	Sand	<3,000	>10	<95	5 – 30
Thermal/combustion under rapid oxidation	>1,000	>50	Sand	>50	>50	>40	n/a
Thermal/steam injection	>1,014	>40	Sand	<1,500	>200	–	10 – 60

Source: International Energy Agency.

Table 3: Criteria governing the potential use of an EOR method (ref. [13])

Regarding CO_2 injection, there is a limited CO_2 supply at present except for fields where CO_2 amounts in associated gas are high enough (Lula field, Brazil). However significant quantities are likely to become available on 5-10 year timescale (i.e. early to mid-2020's) especially after COP21 in Paris whose measures are to be implemented from 2020 onwards.

In terms of brownfield opportunities the secondary recovery factor in shallow waters is already quite high (even up to 60%) therefore the target is smaller and may not be suitable if CO_2-EOR modules are not put in place before fields become too mature. All in all, existing facilities are usually incompatible with high CO_2 content in fluids (corrosion issues, etc.), and there is limited room for additional weight or space for new facilities.

Implementation (Capital Expenditure)

Offshore CO_2-EOR entails some capital expenditures compared to onshore, which need to be considered:

- CO_2 reception facilities and controls (compression modules, etc.)
- Flow lines to injectors (CO_2 and water) and control valves
- Gas/liquid separation facilities capable of handling high content CO_2 in produced fluids
- Separation of CO_2 and hydrocarbon gas (or just separate enough for fuel gas)
- Dehydration and compression of produced gas for reinjection (increasing CO_2 content in produced gas)

- Start-up CO_2 pumps
- Production well tubing needs to be replaced with CRA materials (to deal with produced CO_2)
- Baseline measurements for subsequent monitoring

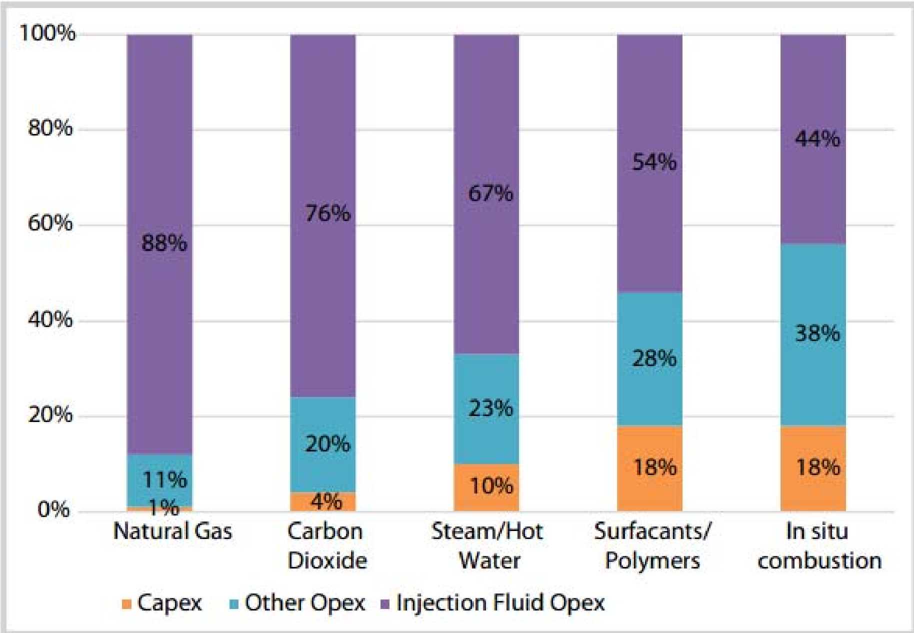


Figure 18: EOR cost components (ref. [14])

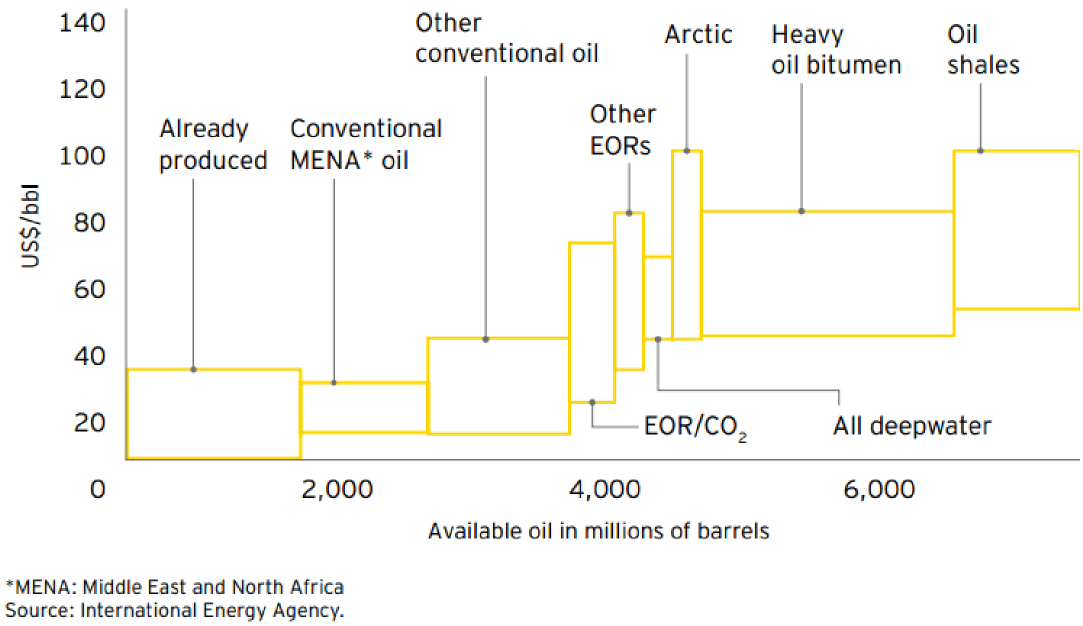


Figure 19: Typical oil production costs (ref. [13])

Offshore CO_2-EOR next steps

Four important "next steps" could help the offshore industry address the above key challenges:

1. *Royalty Reductions*

Royalty reductions for storing CO_2 with EOR in shallow and deep water oil fields could serve as incentive for accelerated application of CO_2-EOR technology. This is the case, for instance, on the Norwegian Continental Shelf where a carbon tax (upper cap of approximately $58[8] per tonne of equivalent CO_2) is levied from all the Oil and Gas activities.

2. *Flagship Offshore CO_2-EOR Projects*

Nothing beats "learning-by-doing". So there is an urgent need for offshore CO_2-EOR projects in regions where nothing has been done yet. The focus would be on learning and cost reductions with the results shared with the offshore industry.

3. *Advanced Subsea Technology for mature fields*

There is need for continued sponsorship of research for improving subsea technologies essential for deep water CO_2-EOR. Especially for brownfield projects where there are weight, space and power limitations.

4. *Affordable CO_2 supplies*

The offshore CO_2-EOR industry would benefit greatly from investments in advanced CO_2 capture technologies that reduce the cost of capturing CO_2 emissions and expand the supply of CO_2.

Conclusion

So, what the future holds for offshore CO_2-EOR and CCS is controversial considering the current scenario (low oil price, inexistent offshore carbon policies and availability of other EOR techniques with higher recovery factors). The Major Oil and Gas companies' position (see letter from June 2015 in ref. [5]) and the resolution from the COP21 held in Paris in December 2015 (ref. [6]) suggests that different carbon pricing measures might be applied worldwide in the medium/long term (2020 onwards); meaning that fossil fuels (even natural gas) would eventually need to be backed by CCS technologies which can lead to a potential need for CO_2 offshore storage and thus trigger offshore CO_2-EOR.

The following text is extracted from the EU's Energy Roadmap 2050 in ref. [3]:

*"If carbon capture and storage (CCS) is available and applied on a large scale, gas may become a low-carbon technology, but without CCS, the long-term role of gas may be limited to a flexible backup and balancing capacity where renewable energy supplies are variable. For all fossil fuels, **carbon capture and storage will have to be applied from around 2030 onwards** in the power sector in order to reach the decarbonisation targets. CCS is also an important option for decarbonisation of several heavy industries and combined with biomass could deliver 'carbon negative' values. The future of CCS crucially depends on public acceptance and adequate carbon prices; it needs to be sufficiently demonstrated on a*

[8] Upper cap of the Norwegian carbon tax is NOK500 being approximately USD58 as of February 2016

large scale and investment in the technology ensured in this decade, and then deployed from 2020, in order to be feasible for widespread use by 2030"

The International Energy Agency (IEA) in ref. [2] provides the following information for CO_2 abatement considering their 450 Scenario.

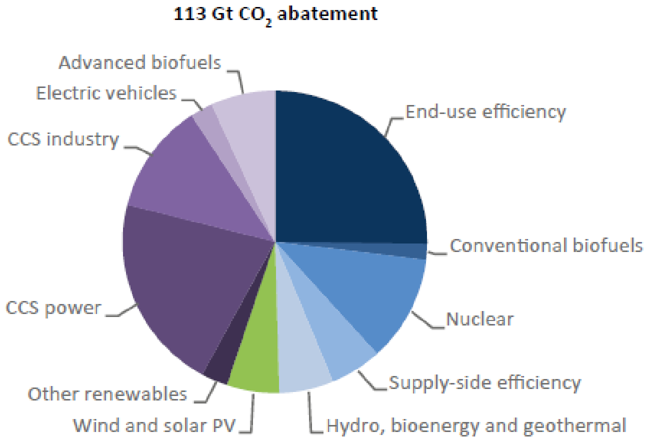


Figure 20: Global cumulative CO_2 emissions reductions by measure 2015-2040 (ref. [2])

In terms of offshore CO_2-EOR, it seems that it may provide a viable path for the future, provided that:

- Supply of CO_2 is (in all probability) developed from national CCS programs
- Initial CCS projects are planned for storage only, but proximity and availability of CO_2 provide opportunities for EOR initially possible in the smaller/medium sized fields
- Offshore reservoirs are found a safe place to store the capture CO_2 after field abandonment
- If successful and prompt installation, redevelopment of mature fields may occur
- CO_2-EOR decisions are made at an early stage of concept development for newly discovered fields
- New specialist CO_2 operators emerge
- Once EOR phase is complete there is still some extra opportunity to store additional CO_2
- Adjustment of carbon pricing regime takes place to make offshore EOR economic
- Regulation around CO_2 storage (over and above Oil & Gas regulations) does not become a significant burden

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