REGIONAL ASSESSMENT OF THE ECONOMIC BARRIERS TO CO2 ENHANCED OIL RECOVERY IN THE NORTH SEA, RUSSIA AND GCC STATES

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Regional Assessments of the Economic Barriers to CO_2 Enhanced Oil Recovery in the North Sea, Russia and GCC States
(IEA/CON/14/222)

Key Messages

- Approximately 95% of all CO_2 EOR activity takes place in the U.S., and in 2010, CO_2 EOR projects were producing approximately 300,000 barrels of oil per day, close to 4% of total U.S. oil production. To achieve this quantity of oil, approximately 60Mt of CO_2, is injected annually into oil fields.
- The widespread success of CO_2 EOR in the U.S. could potentially be extended to other petroleum provinces around the world where it is technically and economically feasible. CO_2 EOR also offers the prospect of providing a commercial driver to develop and expand CO_2 storage and even CCUS.
- The main factor that will drive potential of CO_2 EOR uptake is the prevailing price of oil. The injection rate, capital expenditure (CAPEX), operational costs (OPEX) and tax incentives are of secondary importance.
- Investment in CO_2 EOR is highly constrained by the volatility of the price of oil. For EOR projects to remain profitable over their operational life the cost of supplied CO_2 supplied needs to fluctuate. One example from this study, based on the North Sea, shows that the cost of CO_2 could be ~35 €/tonne if the price of oil reached US$150/bbl but it would need to drop to ~2 €/tonne if the price of oil fell to US$50/bbl. In an onshore Middle East location CO_2 could be supplied at a higher cost (€8.2/tonne) at this oil price.
- Offshore production relies on fewer deviated wells with less spatial coverage of producing areas which is less advantageous for CO_2 EOR compared with onshore 5 or 9 spot closely-spaced injection and production well configurations commonly used in North America. This configuration provides a higher density and control for EOR operations.
- Experience with CO_2 EOR shows that the projected incremental recovery ranges from 7% to 23% of Original Oil in Place (OOIP). Estimates for CO_2 EOR recovery rates for the North Sea range from 4 – 18%.
- Based on previous estimates of suitable fields, and a 3 barrel/tonne of CO_2 recovery rate, the estimated incremental oil potential for the Norwegian sector could be 3,535 M barrels that would require 1,180 M tonnes of CO_2. In the UK sector an additional 2,520 M barrels could be recovered with 840 M tonnes of CO_2.
- The main factors that currently inhibit investment in offshore CO_2 EOR are the upfront investment costs, loss of oil production during work-overs and lack of significant CO_2 volumes.
- There is growing interest in CO_2 EOR in the Middle East. The Abu Dhabi National Oil Company (ADNOC) has implemented a CO_2 EOR pilot project into its Rumaitha oilfield and Saudi Aramco launched the Uthmaniyah CO_2 EOR demonstration project in July 2015.
- It is recommended that IEAGHG should conduct a follow up review of actual CO_2 EOR projects in Middle East and proposed projects in China (Offshore Guangdong Province) including the longer-term transition and/or incorporation of storage accounting / infrastructure development. An active watching brief should be maintained and when substantial information released its significance should be reported.
- A Review should also be conducted when North Sea developments reach an advanced stage particularly the deployment of subsea separation and injection systems and platform modification related to CO_2 EOR.

Background to the study

The use of CO_2 for enhanced oil recovery has been recognized as an effective technology for tertiary oil production. The first commercial CO_2 EOR project started in 1972 at the SACROC oil field, which straddles the border of west Texas and southeastern New Mexico. Approximately 20% comes from anthropogenic sources with the remainder sourced from natural fields. It has also been advocated for the North Sea, but economic conditions, particularly for offshore locations have to date, not been favourable. The objective of this study is to explore the economic conditions that would be necessary for a CO_2 EOR project in the North Sea and in the Middle East.

Traditional oil production can recover up to 20-40% of the original oil in place (OOIP). The application of an EOR technique, typically performed towards what is normally perceived to be the end of the life of an oilfield, can increase the cumulative recovery by an additional 5-15%. The investment decision for a CO_2 EOR project hinges on key factors relating to geological site suitability, capital and operational costs. A number of identified success factors for the well-established CO_2 EOR industry in the U.S. are listed below:

- Depth and oil composition can enable CO_2 to form miscibility lowering viscosity
- There is sufficient unrecovered oil after primary and secondary recovery (usually water flooding)
- There is sufficient access to a reliable supply of CO_2
- Operator knowledge and experience can be applied
- Tax incentives to promote profitable implementation

The use of CO_2 for EOR does invariably lead to some permanent retention in producing fields, but in the longer term there is potential to use the technology to develop a storage infrastructure on the back of commercial or incentivized EOR. One of the main reasons for the limited use of CO_2 EOR outside the US is the lack of a CO_2 supply network. The development of a CO_2 pipeline network in the 1970s and 1980s benefited from oil price control exemption and tax incentives designed to boost US domestic oil supply[1].

An assessment of the suitability of over 50 of the world's largest oil producing basins strongly suggests that considerable technical potential exists for conducting CO_2 EOR in oil fields in multiple geographical regions outside the U.S., particularly in the Middle East, Russia and, to a lesser extent, in the North Sea region of Europe. In light of this, it seems prudent to assess the possible barriers to implementation which focus on the prevailing economic and regulatory conditions in certain regions.

Scope of work

This report, compiled by the Dutch research organization, TNO, comprises of a literature review of ongoing and potential CO_2 EOR activities in the North Sea region, GCC countries and Russia, and two CO_2 EOR case studies. Current oil production trends and geological suitability have been reviewed to assess the potential of CO_2 EOR, and its future. A key part of this task was to compile and review the existing economic feasibility studies that have been conducted for each of the regions concerned, with an emphasis on the assumptions that have been applied to existing economic assessments of CO_2 EOR. These assumptions have been used within the case study modelling exercise. The literature review also highlights specific challenges for the future progression of CO_2 EOR.

To reflect how site-specific conditions might affect CO_2 EOR, two case studies, one offshore and one onshore, have been produced based on accurate contemporary cost data for CAPEX, OPEX and the cost of CO_2. In each case, a discounted cash flow analysis has been applied to calculate the NPV and the Internal Rate of Return (IRR) to determine the economic viability and identify which parameters have the greatest effect on economic viability. TNO's ECCO Tool has been used to generate each analysis and the impact of each parameter. The ECCO Tool is a software program designed to evaluate quantitatively the post-tax economics of CCS projects for each of the various mutually dependent

[1] CRS Report for Congress, Carbon Dioxide (CO2) Pipelines for Carbon Sequestration: Emerging Policy Issues, April 19, 2007.

factors along the CCS value chain. The ECCO tool can be used for studying the economic feasibility of CCS projects to be evaluated by commercial companies under different external and contractual conditions. The tool integrates cost engineering, transport and well/reservoir physics, planning, including the impact of contracts and physics on the sizing and timing of CAPEX and OPEX, and full post-tax economics. The ECCO Tool also provides maximum price, or 'gate-fee', that a CO_2 EOR can pay for a tonne of CO_2 at the well-head for an economically viable project. Each case study includes a sensitivity analysis to determine how different parameters affect the economic viability of a CO_2 EOR project.

Findings of the Study

North Sea

North Sea reservoirs have been assessed extensively for CO_2 EOR opportunities, but, so far, no projects have been implemented. In the Norwegian sector, several fields have been investigated, particularly Draugen, Grane, Oseberg East, Brage, Heidrun, Volve and Gullfaks. In the UK, The Miller and Forties oil fields and a number of others have been assessed for CO_2 EOR, but none have proved to be economically viable. Despite the extensive and successful track-record of CO_2 EOR in the US there are some formidable challenges with offshore implementation into a mature region like the North Sea. In North America 5 or 9 spot closely-spaced injection and production well configurations are commonly used providing higher density and control for EOR operations. Offshore production relies on fewer deviated wells with less spatial coverage of producing areas.

Not all fields in the North Sea are suitable for this EOR technology. For example the Statfjord and Brent fields are unsuitable because they have been depressurised.

The increased oil recovery rate from CO_2 EOR is dependent on reservoir properties, oil recovery rates of preceding recovery methods and the EOR strategy. Experience with CO_2 EOR shows that the projected incremental recovery ranges from 7% to 23% of Original Oil in Place (OOIP). Estimates for CO_2 EOR recovery rates for the North Sea range from 4 – 18%. A figure of 10% was adopted for the case study models. Previous studies have assumed a recovery rate of between 1-3 barrels/tonne of CO_2 injected[2,3]. Based on previous estimates of suitable fields, and a 3 barrel/tonne of CO_2 recovery rate, the estimated incremental oil potential for the Norwegian sector could be 3,535 M barrels that would require 1,180 M tonnes of CO_2. In the UK sector an additional 2,520 M barrels could be recovered with 840 M tonnes of CO_2.

One of the main barriers to the adoption of CO_2 EOR in the North Sea is the economic penalty caused by lost production over long shut-down times when platforms are modified with additional process equipment (pipes and vessels) and corrosion resistance. Other factors include:

- Timescales for decommissioning (example: when an oilfield is decommissioned, the cost of reinstalling the oil production for EOR is too expensive)
- Limited space and weight margins at the platforms, and high costs associated with close-down in connection with modifications of the platform
- Engineering challenges caused by a mixture of CO_2 and brine which will corrode carbon steel and will demand more expensive corrosion resistant alloys. The engineering of corrosion management is well developed and includes many technologies, including corrosion inhibition additives, cathodic protection with sacrificial electrodes, and various specifications for different

[2] SCCS, 2015 Enhanced oil recovery in the North Sea: Securing a low carbon future for the UK.

[3] Hill, B, Hovorka S and Melzer S, GHGT-11. Geologic carbon storage through enhanced oil recovery "Energy Procedia 37 (2013) 6808 – 6830

parts of the wells in contact with wet CO_2, such as coatings as well as metals such as chrome steel.

- Shared equity ownership of oil fields
- High oil taxation
- Commercial, communication and cultural barriers
- Liability issues
- Diverse KPIs for different stakeholders
- Lack of political support from most environmental NGOs for CO_2 EOR
- Scepticism around early development of CO_2 EOR
- The lack of an established CO_2 supply network either via pipeline or tanker.

Several previous studies have concluded that CO_2 EOR in the North Sea is possible and that there is a considerable potential, however there are significant hurdles. The main factors are the upfront investment costs, loss of oil production during work over and lack of significant CO_2 volumes. Development of the CO_2 EOR supply chain is a major hurdle, which includes platform work overs, CO_2 capture plants, transport infrastructure, and the possible development of a permanent storage site (relief site) for the CO_2. Presently, the economic situation in Europe coupled with the very low EU-ETS CO_2 price (approximately 8 €/tonne CO_2), and an unclear political framework, does little to trigger the much needed large-scale implementation of CCS from the industrial and power sectors.

Both Norway and UK have a relatively high oil tax. The oil tax is 50-75% for UK and 78% for Norway, but there is an investment allowance of 62.5% for Supplementary Charge (see foot note)[4]. It is conceivable that at very low oil prices these rates might change but not necessarily favourably for incentivising investment in CO2 EOR.

In a previous example, the BIGCO2 project in 2009, the economic and capacity potential of the North Sea was studied. A techno-economic model was developed for a network consisting of 18 Norwegian and 30 UK oil fields. The project lifetime was set to 40 years with a discount rate of 7%. The case study was based on an infrastructure where CO_2 was collected from sources in Europe, and gathered in Emden (Germany) and Aberdeen (UK). From there, CO_2 was delivered by pipeline to the Ekofisk area and further to the Tampen area. The annual volumes of CO_2 injected were estimated to 178 Mt. After CO_2 breakthrough, the CO_2 produced with the oil was separated out and reinjected. CO_2 was injected into the oil reservoirs as long as the cash flow was positive. The results of this exercise are summarised in Table 1 assuming an oil price of US $80/barrel. The associated breakeven cost for CO_2 is US$44/tonne delivered.

Table 1 BIGCO2 Project Estimate of stored CO_2 in the North Sea due to EOR operations

Item	**Value**	**Unit**
Total oil produced	4,706	Million Sm^3
Total oil recovery factor	60.6	% HCPV
EOR oil	682	Million Sm^3
Incremental oil recovery factor	8.8	% HCPV
Total stored CO_2	7,254	Mt
CO_2 stored in oil reservoirs	2,284	Mt
Total investment costs	58,234	Million USD
Total operation costs, excluded CO_2 purchase	2,858	Million USD/year

[4] In the UK sector of the North Sea the Supplementary Charge is an additional charge on a company's ring fenced profits. This charge only applies to companies involved in the exploration for, and production of, oil and gas in the UK and on the UK Continental Shelf

Although the current economic situation does not favour CCS, there is political support for offshore CO_2 storage in some countries bordering the North Sea. The technology is seen as a potential stepping stone towards full-scale CCS. CO_2 EOR is currently the only utilization option that can offset a considerable amount of CO_2, in addition to plain storage.

Some other innovations may aid the future development by offering flexibility and cost reduction in CO_2 supply. Ship transport has recently seen an increased interest. It is flexible, which is important in a start-up phase. For smaller volumes, longer distances and a limited number of years, ship transport is more cost efficient than pipeline transport. Another option is subsea processing installations which are currently under development and are expected to significantly decrease the lost production due to a reduction in the time for rebuilding the process equipment, as well as investment cost of CO_2 EOR. Conversion of decommissioned CO_2 EOR oil fields to CO_2 storage projects could also provide delayed decommissioning costs for platforms etc. and even additional revenue after the EOR operations.

Russia

Russia is the second largest oil producer after Saudi Arabia. In 2014 the country's share of global production was 12.7%. However, many of the largest Western Siberian fields have been in decline which has encouraged some Russian oil companies to invest in EOR to sustain current levels of production. The potential for CO_2 is hampered by the lack of climate change mitigation or carbon management policy. Moreover there are no specific policies to develop CCS despite being the world's fourth largest CO_2 emitter.

A range of EOR technologies have been applied to boost production levels with the exception of CO_2 EOR. In the past, there have been trials with CO_2 enhanced production in Russian oil fields. There are reports on large scale pilot tests conducted in the 1980s, using CO_2 from petrochemical plants. Cumulative injected volumes ranged from about 50,000 tonnes to more than 750,000 tonnes of CO_2 that were injected into the Radaevskoye, Kozlovskoye, Sergeevskoye and Elabuzhskoye oil pools. Additional oil volumes in the order of 12% were obtained. The projects faced problems in terms of sufficient CO_2 supply and corrosion of the pipelines and equipment. Despite the relative success in terms of additional oil recovered, these pilots have not led to larger-scale EOR projects with CO_2.

Countries of the Gulf Co-operation Council

The Gulf Co-operation Council (GCC) was established in 1981 to develop intergovernmental and economic union between Arab states that surround the Persian Gulf. Collectively the region is responsible for approximately a quarter of global oil production. With continued production from mature fields there is widespread use of EOR techniques particularly the use of injecting natural gas to reduce the viscosity of oil, although there is an increasing demand for natural gas for power generation and as a petrochemical feedstock. Consequently, there is growing interest in CO_2 for EOR. Some estimates have calculated that as much as 141 billion barrels could be recovered from Saudi Arabia alone.

A previous screening study to assess the suitability of Middle Eastern oil for CO_2 EOR has suggested that out of 48 reservoirs screened in GCC countries 32 would be suitable candidates for the recovery technique. Oil reservoirs in both Saudi Arabia and the UAE are overwhelmingly suitable for CO_2 EOR applications, with approximately 90% of the oil fields suitable in each country. Table 2 summarises the total number of suitable reservoirs for CO_2 EOR by country.

Table 2 Number of suitable fields for CO_2 EOR by GCC Country

Country	No. of reservoirs assessed	No. of reservoirs meeting suitability criteria
Bahrain	2	0
Kuwait	5	4
Oman	11	4
Qatar	10	6
Saudi Arabia	9	8
United Arab Emirates	11	10
Total	**48**	**32**

There are several large point sources of CO_2 throughout the GCC region which is clearly evident from Figure 1. However, although quite abundant across the region the concentration of CO_2 in flue gases from combine cycle gas-fired power stations is ~3-4%. CO_2 from this source is estimated to be US$80/tonne. At this price CO_2 EOR would only be viable at sustained high oil process. Data from 2007 identified only two possible ‘high purity’ sources in the region generating 13 Mt/year.

Figure 1. Location of large point sources of CO2 (≥ 0.5 Mt/year) in the GCC region.

A single economic evaluation of CO_2 EOR in a GCC has been completed using generic cost components for capture, transport and injection of CO_2. The study used a ‘typical’ Middle Eastern sandstone reservoir. The CO_2 source was a large CCGT power plant with the ability to deliver up to 2.5 Mt CO_2 via an 80 km by 30 inch pipeline to the target reservoir. The costs of CO_2 capture from the CCGT assumed as US$38 tonne. Due to the considerable infrastructure needed, the total operational and capital expenditure for the project over 35 years (oil production commenced after 5 year construction) was considerable, at approximately US$7 billion (2010).

The results of the economic evaluation were positive, with an overall recovery rate of 58% (OOIP). Based on a constant oil price of US$75, and a 15% discount rate, the NPV at the end of the project was calculated as US$3.77 billion. The report also includes an extensive sensitivity analysis, which amongst a range of outcomes, highlights the sensitivity of the prevailing oil price and the effect on the NPV of the project. Specifically, a 50% increase in oil prices increased the NPV of the project by 89%.

The two key factors that will drive potential uptake are the cost of CO_2 and the prevailing price of oil. A previous analysis of the proportionate influence of these two factors is summarized in Figure 2. The relationship depicted in this graph clearly shows that low CO_2 prices and high oil process provide the most favourable economic conditions for CO_2 EOR. It is also clear that high CO_2 prices has the most negative impact on the economic productivity of original oil in place (OOIP).

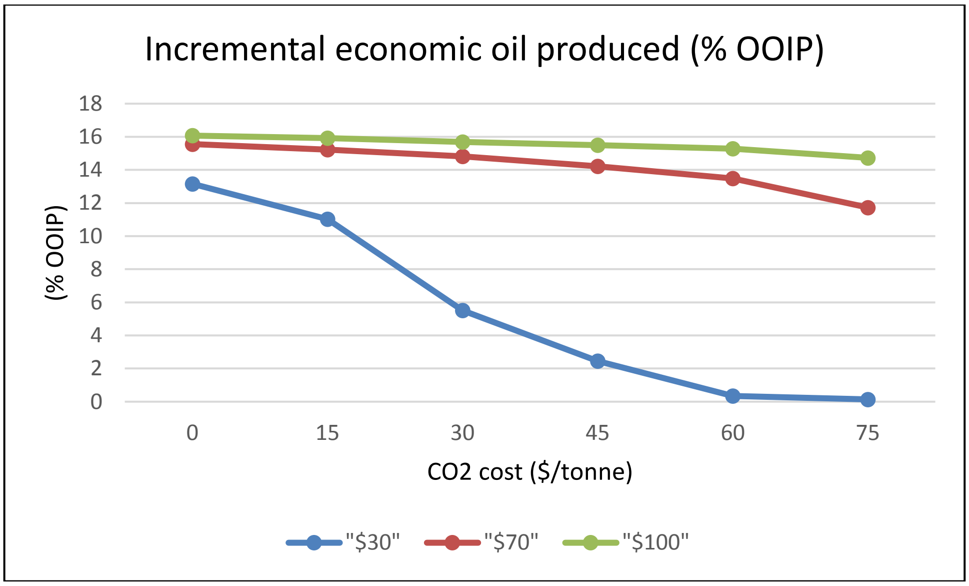

Figure 2 Influence of Oil Price and the cost of CO_2 on economic oil production

There is growing interest in CO_2 EOR in the Middle East. The Abu Dhabi National Oil Company (ADNOC) has implemented a CO_2 EOR pilot project into its Rumaitha oilfield. The trail achieved a 5-7% increase in oil production rate prior to CO_2 breakthrough. Saudi Aramco launched the Uthmaniyah CO_2 EOR demonstration project in July 2015. 0.8 Mt of captured CO_2 is transported 70 km by pipeline for injection. There are 4 injection wells, 2 observation wells and 4 production wells.

Case studies

To test how site-specific conditions might affect the economic feasibility of CO_2 EOR projects, two case studies based on a North Sea and a Middle East scenario were constructed. These case studies were developed using TNO’s ECCO tool using contemporary cost data for CAPEX and OPEX. The ECCO Tool is a programme designed to quantitatively evaluate the post-tax economics of CCS projects taking account of the key parameters that are integral to each project. These case studies were developed to test two important questions: what is the maximum CO_2 wellhead price for an economically feasible EOR project in the North Sea and the Middle East; and what is the effect of the different parameters on the CO_2 wellhead price?

In each case a discounted cash flow analysis is applied to calculate the Net Present Value (NPV) and the Internal Rate of Return (IRR). Each case study includes a sensitivity analysis to determine how the key parameters affect the economic viability of the CO_2 EOR project. These models assume a 30 year life for each project. Unfortunately due to the volatile political climate in Europe it was not possible to gain access to information on the Russian oil industry. Commercial confidentiality also constrained access consequently these case studies have been devised using assumptions that are representative of reservoir characteristics in each region. CAPEX and OPEX have been taken from a Zero Emissions Platform (ZEP) study in 2011. The IRR for the North Sea was 12% and 25% for the GCC region to reflect different market dynamics of the two regions. A 0% rate of tax has been assumed for GCC countries as the vast majority of oil production is controlled by national oil companies.

The base scenario in the North Sea provides a maximum CO_2 price at the well-head of €18/tonne, with a range between €1.9/tonne and €34/tonne. The sensitivity analysis indicates that the prevailing oil price and the injection rate have the highest sensitivity on the IRR. The pressure in the box model assumes a constant flow of CO_2 during EOR. A higher injection rate will lead to a higher production rate this explains the high sensitivity on the IRR. Increasing the injection rate, from 5 Mt/yr in the base case to 9 Mt in the upside case also has a positive effect on the maximum gate fee. With a higher injection rate, the operation facilities (like compressor, injection wells) are more optimally utilized compared to a low injection rate which results in costs savings and allows a higher CO_2 price to be paid.

In the case of the North Sea a 12% IRR can only be achieved if all conditions in case study can be met over the technical life of the project (i.e. 30 years and that operational parameters remain within the boundaries defined in the case study). For example, with a high price of oil at US$150/bbl a 12% IRR could be sustained with a higher price for CO_2 (~35 €/tonne). Similarly at US$50/bbl CO_2 would have to be ~2 €/tonne to sustain a 12% IRR. Therefore for a project to remain profitable (assuming a consistent 12% IRR) the delivered CO_2 price would need to be adjusted with a fluctuating oil price.

The inference of the 'tornado' diagram (Figure 3) implies that increasing incremental oil production (STOIIP) through CO_2-EOR would benefit from a lower price for CO_2, (upside) but increasing the injection rate is also positively beneficial (upside) and should therefore result in higher EOR recovery. This implies that increasing CO_2-EOR production through a higher injection rate also requires a reduction in the price of CO_2 to maintain the 12% IRR. The inference from the 'tornado' diagram is that a higher price for CO_2 can be tolerated if the price of oil, or injection rate, is increased but increasing production from CO_2-EOR only benefits from a decrease in the price of CO_2 for incremental production.

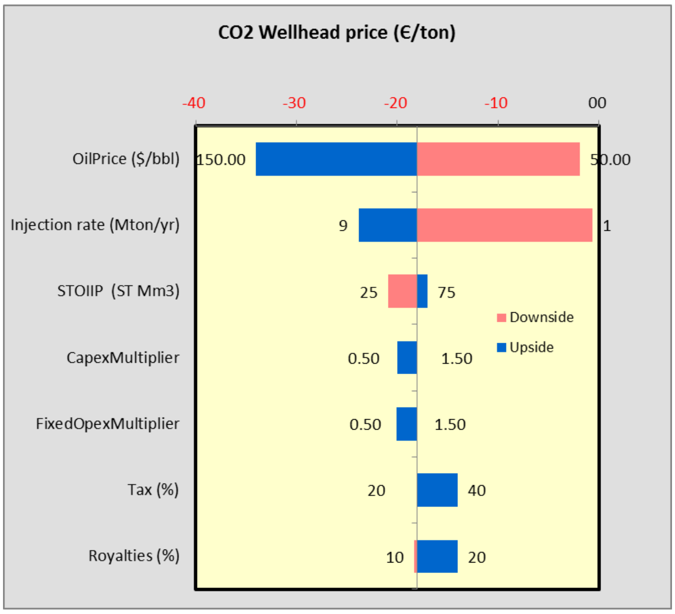

Figure 3 Sensitivity analysis of the North Sea case study

The base scenario in the GCC region (Figure 4) provides a maximum CO_2 price at the well-head of €21/tonne, with a range between €8.2/tonne and €48.1/tonne. An increased injection rate has the same impact as in the North Sea. Higher injection rates profit from the economy of scale and the oil operator is able to accept a higher CO_2 price at the wellhead. The lower CAPEX and OPEX of the onshore operations, and the exclusion of taxation and royalties on the additional incremental oil produced, allow higher CO_2 prices to be paid at the wellhead across the range. The higher required IRR at 25% reduces the difference in the CO_2 wellhead prices between the North Sea and GCC region.

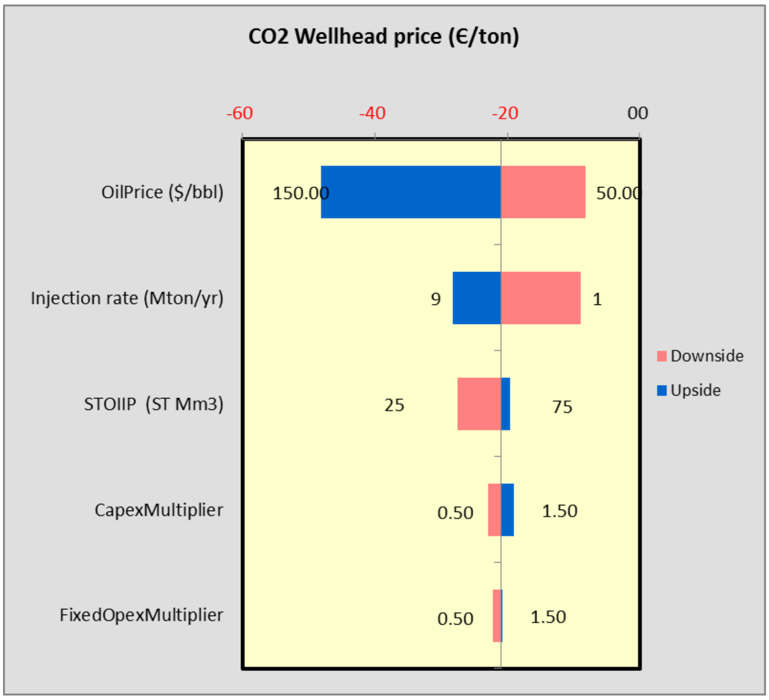

Figure 4 Sensitivity analysis of the GCC case study

Expert Review Comments

- This a well-conceived and well executed study that attempts to integrate a number of different studies and run some consistent economic scenarios to illuminate the value and barrier to CO_2 EOR in several highly prospective parts to the world. The broad conclusions seem reasonable and are well justified. It is unfortunate, but not unexpected, that detailed industry input into the modelling for Russia and GCC was not given.
- At times the approach is overly precise on calculations in the absence of data, and not clear enough on the weaknesses and uncertainties in the approach, given the lack of CO_2 EOR development and experience in the three chosen regions.
- In the case of the North Sea, the report has the opportunity to build upon considerable work from the UK, Norway, and Europe. The review of the current status in the Gulf Cooperation Council region is much better, reflecting the status quo and high level of interest in CO_2 EOR in this part of the world in recent years. In all three regions, the assumptions relating to oil price could be better justified, with perhaps an overemphasis on a $100/bbl scenario.
- There is some uncertainty/incorrect understanding of the concept and importance of recycle CO_2 for EOR, which is different than most other types of secondary and tertiary recovery. In all CO_2 EOR operations, CO_2 is produced with the oil and water. The oil, water and CO_2 must be separated, and the CO_2 compressed from atmospheric pressure. The reuse of produced CO_2 is considered essential for all existent CO_2 EOR projects in order to process more of the reservoir.
- A constant incremental recovery efficiency to CO_2 EOR has been assumed, but changing the STOIIP, does not give a true indiction of this impact. This is an important factor that should be considered, since any set of conditions that support the economic feasibility of CO_2 EOR projects will depend on the potential incremental production from CO_2 EOR.

Conclusions

- In the Norwegian sector, several fields have been investigated, particularly Draugen, Grane, Oseberg East, Brage, Heidrun, Volve and Gullfaks. In the UK, The Miller and Forties oil fields and a number of others have been assessed for CO_2 EOR, but none have proved to be economically viable.
- Based on previous estimates of suitable fields, and a 3 barrel/tonne of CO_2 recovery rate, the estimated incremental oil potential for the Norwegian sector could be 3,535 M barrels that would require 1,180 M tonnes of CO_2. In the UK sector an additional 2,520 M barrels could be recovered with 840 M tonnes of CO_2.
- One of the main barriers to the adoption of CO_2 EOR in the North Sea is the economic penalty caused by lost production over long shut-down times when platforms are modified with additional process equipment (pipes and vessels) and corrosion resistance.
- The two key factors that will drive potential uptake are the cost of CO_2 and the prevailing price of oil.
- Both case studies conducted as part of this study clearly show that the oil price and the injection rate are the two predominant factors that influence the CO_2 wellhead price.
- The most significant barriers to the uptake of CO_2 EOR in all three regions investigated are the high cost of CO_2 supply. The high capital costs of offshore infrastructure, high taxation and lack of fiscal incentives are added disincentives for development in the North Sea.
- There is growing interest in CO_2 EOR in the Middle East. The Abu Dhabi National Oil Company (ADNOC) has implemented a CO_2 EOR pilot project into its Rumaitha oilfield and Saudi Aramco launched the Uthmaniyah CO_2 EOR demonstration project in July 2015.

Barriers to CO_2 EOR Deployment

Experience from North America clearly demonstrates that the use of CO_2 for EOR can be technically proficient and commercially viable. The widespread use of the technology has led to the development of an efficient pipeline supply which now includes anthropogenic sources. All three regions investigated in this study are suitable candidates for CO_2 EOR and would benefit from US and Canadian experience, however significant barriers remain. These include:

The North Sea
- High capital costs of offshore infrastructure
- High cost of CO_2 supply
- High taxation of oil revenue
- No specific fiscal incentive for CO_2 EOR operations
- Limited climate policy for CO_2 storage

GCC States
- Limited knowledge of natural CO_2 accumulations
- High cost of CO_2 supply (mainly gas power plants)
- State-owned oil and gas system limits commercial risk-taking for EOR?
- No climate policy for CO_2 storage

Russia
- Limited knowledge of natural CO_2 accumulations
- Large distances between CO_2 sources and oil-producing areas
- High cost of CO_2 supply

- Taxation system not adjusted for mature fields with EOR operations
- No climate policy for CO_2 storage

Recommendations

- Conduct a follow up review of actual CO_2 EOR projects in Middle East and proposed projects in China (Offshore Guangdong Provence) including the longer-term transition and/or incorporation of storage accounting / infrastructure development. Keep an active watching brief and wait until there is substantial information released.
- Review the EOR-MRV example in Texas by Occidental.
- Review in detail when North Sea developments reach an advanced stage particularly the deployment of subsea separation and injection systems and platform modification related to CO_2 EOR.

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TNO report

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Regional assessment of the economic barriers to carbon dioxide enhanced oil recovery in the North Sea, Russia and GCC States

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Summary

CO_2 enhanced oil recovery (EOR) combined with long-term CO_2 storage with adequate monitoring systems, has the potential to reduce CO_2 emissions from power and industrial sources, while preserving the profitable lifetimes of maturing oil fields. CO_2 EOR can increase the rate of incremental oil recovery by between 5% and 15% of the original oil in place. Despite this prospect, CO_2 EOR has only been implemented on a large scale onshore in the USA. In Europe, CO_2 EOR is an established practice in Hungary, with feasibility projects completed in Croatia.

Globally, there are many maturing oil-producing basins in, for example, the North Sea, Russia and the region of Gulf Cooperation Council (GCC), where this technique is being considered by relevant stakeholders, although is yet to be implemented on an industrial scale. Investigating the reasons why CO_2 EOR is not progressing, or progressing slowly in certain regions, can help inform national and international policy makers with decision making concerning climate policy and energy security.

This report comprises the results of a project which has been designed to evaluate the effect of individual cost components on the overall economic efficiency of CO_2 enhanced oil recovery operations. Based on existing literature, attempts have also been made to understand whether significant differences exist in the cost structure of potential CO_2 EOR projects across regions, namely, the North Sea, in countries of the GCC, and Russia. A set of hypothetical case studies have been developed to test a modeling approach to identify the maximum wellhead CO_2 price that an EOR operator can pay, based on a set of regional specific geological and financial assumptions. From the work completed, an overview of the key hurdles to CO_2 EOR projects in the three regions of interest are presented.

With regards to individual cost components, insufficient reliable data could be retrieved to be able to compare capital and operating costs between the North Sea, the GCC region and Russia. One economic evaluation was available in open literature regarding CO_2 EOR at a typical Middle Eastern oil field, however the cost data for each components were derived from international literature, and thus do not provide insights into regional differences. It can be assumed that capital costs for pipelines and wells for comparable projects in different regions may be similar as engineering procurement and constructions (EPC) services and equipment are generally provided by international firms.

Regional case studies combining geological and economic modeling were developed for the North Sea and the GCC region, and in all of the economic evaluations, the assumed oil price during the lifetime of the EOR project has the greatest overall effect on the project Net Present Value (NPV). The stock tank oil-initially-in-place (STOIIP), CAPEX, and OPEX have declining levels of impact on the NPV, in the order given. At a base case oil price of $100, maximum 'gate fee'[1] prices were €18/tonne and €21/tonne of CO_2 in the North Sea and GCC region case study, respectively. However at lower oil prices of $50, currently seen on world markets, this results in very low gate fee prices at €2 and €8 in the same regions, respectively.

[1] The gate fee price represents the cost of the CO_2 the operator must pay when it reaches the injection well (i.e. at the end of the delivery pipeline).

Based on the results of this exercise, low oil prices provide no economic basis for conducting CO_2 EOR in the North Sea. Even in the North Sea base case, additional revenue potentially in the form of EU ETS credits would likely be needed for a financially sound business case. In the GCC case study, the base case gate fee of €21/tonne could be sufficient to cover CO_2 delivery from some low-cost industrial or gas processing sources, should they be present and sufficient for CO_2 EOR operations.

The key hurdles to CO_2 EOR for each region considered are provided below:

The North Sea

- Limited natural accumulations of CO_2
- High capital costs of offshore infrastructure
- High cost of CO_2 supply
- High taxation of oil revenue
- No specific fiscal incentive for CO_2 EOR operations
- Limited climate policy for CO_2 storage

GCC States

- Limited knowledge of natural CO_2 accumulations
- High cost of CO_2 supply (mainly gas power plants)
- State-owned oil and gas system limits commercial risk-taking for EOR
- No climate policy for CO_2 storage

Russia

- Limited knowledge of natural CO_2 accumulations
- Large distances between CO_2 sources and oil-producing areas
- High cost of CO_2 supply
- Taxation system not adjusted for mature fields with EOR operations
- No climate policy for CO_2 storage

In all three of the regions covered in this report there is considerable technical potential to implement CO_2 EOR projects. North Sea oil production has been in considerable decline for a number of years, and the GCC region and Russia appear to have a growing reliance on maturing oil fields and require new EOR technologies to support current production rates. Pilot CO_2 EOR projects in the GCC region have been successful, and a full scale project with an injection rate of 0.8 Mt/yr has started in 2015. In the North Sea and Russia, however, the outlook for CO_2 EOR looks less promising.

One of the key hurdles reported for North Sea CO_2 EOR projects, is the investment required for the modification of platform and installations, and the lost revenue during modification. In all regions, CO_2 EOR activities can be regulated under existing oil and gas regulation, and regulatory uncertainty is not assumed to constitute a barrier to the broader deployment of the technique. However, if the CO_2 EOR is combined with long-term storage and coupled with an incentive (i.e. carbon credits), additional CCS regulation in certain jurisdictions could have a cost impact on CO_2 EOR projects combined with CO_2 storage. Russia could adjust its fiscal policy towards oil and gas revenue to reflect to higher costs of extracting oil from harder-to-recover oil fields, which require additional investment in enhanced oil recovery techniques. Certain countries, for example the UK, recently reduced petroleum revenue taxation to support continued production in mature fields.

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1 Background

Since the emergence of CO_2 capture and storage (CCS) as a potentially critical climate change mitigation technology, many proponents of the technology have highlighted existing CO_2 enhanced oil recovery (EOR) operations in various parts of the world, particularly in the U.S. The objective for such attention, has been to emphasize that the technology and knowhow to capture, transport and inject CO_2 into the subsurface has been available since the 1970's. The first commercial CO_2 EOR project started in 1972 at the SACROC oil field, which straddles the border of west Texas and southeastern New Mexico.

Although many existing CO_2 projects utilize CO_2 from natural geological sources or high-purity industrial streams, the world's largest CCS demonstration project within the power industry, the Boundary Dam Carbon Capture Project in Saskatchewan, Canada, captures CO_2 from a coal-fired power plant for use in an enhanced oil recovery project. The capture of CO_2 for use to produce more fossils fuels to be burnt has led to recent criticism by some NGOs (Greenpeace 2015), particularly as scientific research indicates that by including the combustions emission of additional oil produced, net carbon emissions could occur from such projects (Jaramillo, P., et.al , 2009). Others argue that CO_2 EOR can help support the investment in infrastructure needed for 'true' CCS projects, which can greatly reduce global CO_2 emissions while contributing to energy security (IEA, 2014).

Traditional oil production can recover up to 20-40% of the original oil in place (OOIP) (Tzimas, A. et.al., 2005). The application of an EOR technique, typically performed towards what is normally perceived to be the end of the life of an oilfield, can increase the cumulative recovery by an additional 5-15% (Tzimas, A. et.al., 2005). The investment decision for a CO_2 EOR project hinges on key factors relating to geological site suitability, capital and operational costs. A number of identified success factors for the well-established CO_2 EOR industry in the U.S. are listed below.

- Depth and oil composition can enable CO_2 to form miscibility to lower viscosity[2]
- There is sufficient unrecovered oil after primary and secondary recovery (usually water flooding)
- There is sufficient access to a reliable supply of CO_2
- Operator knowledge and experience can be applied
- Tax incentives to promote profitable implementation

Approximately 95% of all CO_2 EOR activity takes place in the U.S., and in 2010, CO_2 EOR projects were producing approximately 300,000 barrels of oil per day, close to 4% of total U.S. oil production (Tzimas, A. et.al., 2005). To achieve this, approximately 60Mt of CO_2, is injected annually into oil fields, with approximately 20% coming from anthropogenic sources (Tzimas, A. et.al., 2005). On recognition of the success of CO_2 EOR in the U.S., it can be questioned why this process is not taking place at a large scale in other oil-producing regions of the world. An assessment of

[2] Conditions where CO_2 and oil are miscible usually increase oil recovery; miscibility is favored by higher pressure and for lighter oils.

the suitability of over 50 of the world's largest oil producing basins (Godec, M. 2011) strongly suggests that considerable technical potential exists for conducting CO_2 EOR in oil fields in multiple geographical regions outside the U.S., particularly in the Middle East, Russia and, to a lesser extent, in the North Sea region of Europe. In light of this, it seems prudent to assess the possible barriers to implementation which focus on the prevailing economic and regulatory conditions in certain regions.

1.1 Cost components of EOR projects

The economic viability of an EOR project can be ascertained by calculating the Net Present Value (NPV) of a project, based on the capital investment (CAPEX), the operation cost (OPEX), the price of CO_2 used and the price of oil, scale of reserves and duration of the project. The price of CO_2 will be derived from the capital and operational expenditures required to deliver the CO_2 to the wellhead and, thus, can be considerable if a dedicated capture plant with pipeline or ship is to be built from an anthropogenic source. In regions with incentives (e.g. a carbon price) for CCS, the profit margin of the project can be increased to favor investment. The investment required to undertake CO_2 EOR in an oil field will also take into consideration the expectant costs and benefits of other EOR techniques, such as polymer flooding.

Other considerable capital costs which may be relevant relate to the infrastructure at the field, such as additional wells, platforms (if offshore), topside modifications to the oil production system, construction of the separation and compression equipment, downtime of existing facility and missed production, planning and engineering costs, and decommissioning. OPEX is clearly related to the fuel, power and the maintenance of equipment necessary for operation at each phase of the delivery and injection of the CO_2. There may also be costs related to the transportation of additional oil produced, compensating for CO_2 emissions if applicable, and the costs of complying with environment and health regulations. Potentially, if the CO_2 EOR project is combined with a regulated CO_2 storage project, where financial incentives for long-term storage are available, monitoring equipment, verification work and financial assurances may represent further costs.

On the opposite side of the financial decision, the expected additional incremental oil to be produced (calculated using the areal sweep efficiency as a function of the displaceable hydrocarbon pore volume) and the prevailing oil price will infer the expected returns of the project, minus any tax and/royalties that are applicable. In the U.S., the use of CO_2 for enhanced oil recovery is subsidized by a tax credit of $10/tonne of CO_2 through a Federal CCS Policy, the U.S. Code 45Q - Tax Credit for Carbon Dioxide Sequestration, that also offers $20/tonne of CO_2 stored for project that stores CO_2 without EOR (IEAGHG, 2009). However, this fund is limited and many EOR operators do not take advantage of it. In the 28 Member States of the European Union (EU), CO_2 enhanced oil recovery is an applicable mitigation technology in the EU Emission Trading Scheme, whereby carbon offsets are generated for each tonne of CO_2 used for EOR and permanently stored in accordance with specific monitoring and reporting guidelines. At the time of writing, spot prices for tradeable EU carbon offsets[3] on the carbon market were approximately €8 (DECC, 2015a). Such regional schemes can improve the economic viability of EOR projects, but may also require

[3] Officially – European Union Allowances (EUA) can either be held within the organization to offset emissions, or traded on the carbon market.

additional monitoring, stewardship and financial liability commitments, which is the case in the EU.

1.2 Objectives

This report comprises the results of a project conducted by TNO (The Netherlands) and Tel-Tek (Norway), on behalf on the IEA GHG (UK), which has been designed evaluate the effect of individual costs components on the overall economic efficiency of CO_2 enhanced oil recovery operations. Attempts have also been made to understand whether significant differences exist in the cost structure of potential CO_2 EOR projects across regions, namely, the North Sea, in countries of the Gulf Cooperation Council, and Russia. The outcome of the project has been to outline a set of conditions that support the economic feasibility of CO_2 EOR projects, conducting a series of sensitivity analysis on oil price, injection rates, CAPEX, OPEX, stock tank oil-initially-in-place (STOIIP) and taxation of oil revenue.

1.3 Report overview

This report comprises of a literature review of ongoing and potential CO_2 EOR activities in the North Sea region, GCC countries and Russia, and a set of CO_2 EOR case studies, followed by a number of key observations and recommendations for supporting CO_2 EOR activities, as part of efforts to prevent human-induced climate change. Further detail on the individual report components are provided below.

- In Sections 2, 3 and 4, **a literature review** of CO_2 EOR potential and previous economic evaluations conducted in the regions of the North Sea, Russia and the GCC region are presented, respectively. Current oil production trends and geological suitability are reviewed to assess the strategic importance and expected potential of CO_2 EOR, and outline any existing or planned activities. Where possible, existing recovery rates that are currently achieved are documented. A key part of this task is to compile and review existing economic feasibility studies that have been conducted for each of the regions concerned, with a particular focus on the assumptions that have been applied to existing economic assessments of CO_2 EOR. These assumptions may be used within the case study modelling exercises. The literature review also highlights regional specific challenges for CO_2 EOR projects to move forward.

- Section 5 includes **a set of case studies** that have been developed using TNO's ECCO Tool. The ECCO Tool is a software program designed to evaluate quantitatively the post-tax economics of CCS projects for each of the various mutually dependent actors along the CCS value chain. The ECCO tool can be used for studying the economic feasibility of CCS projects to be evaluated by commercial companies under different external conditions and contractual constructions. The tool integrates cost engineering, transport and well/reservoir physics, planning, including the impact of contracts and physics on the sizing and timing of CAPEX and OPEX, and full post-tax economics.

To reflect how site-specific conditions might affect CO_2 EOR, two case studies, one offshore and one onshore, have been produced based on accurate contemporary cost data for CAPEX, OPEX and the cost of CO_2. In each case, a discounted cash flow analysis is applied to calculate the NPV and the Internal Rate of Return (IRR) to determine the economic viability and identify which parameters have the greatest effect on economic viability. The ECCO Tool also provides maximum price, or 'gate-fee', that a CO_2 EOR can pay for a tonne of CO_2 at the well-head for an economically viable project. Each case study includes a sensitivity analysis to determine how a number of key parameter affects the economic viability of the CO_2 EOR project.

- Section 6 provides **key observations and recommendations,** based on the literature review and case studies, which broadly outline the technical and economic potential of CO_2 EOR for both maintaining oil production and reducing CO_2 emissions in each of the three regions concerned. The perceived hurdles to CO_2 EOR projects moving forward, and policy, regulatory and technical recommendations to overcome such barriers are given.

2 The North Sea region

2.1 North Sea

After the Groningen gas discovery, the North Sea area caught strong international interest. In the very south of the North Sea, British sector, major gas discoveries were made in 1965, 1966, 1967 and 1968. The first discovery in the Norwegian sector was the Ekofisk field in 1969. In the following years, more fields were discovered offshore. The oil production peaked around the year 2000. The number of new large discoveries has declined, with the largest in the last five years being the Johan Sverdrup field. Figure 1 and Figure 2 show the historical oil production for the Norwegian and the UK sector of the North Sea.

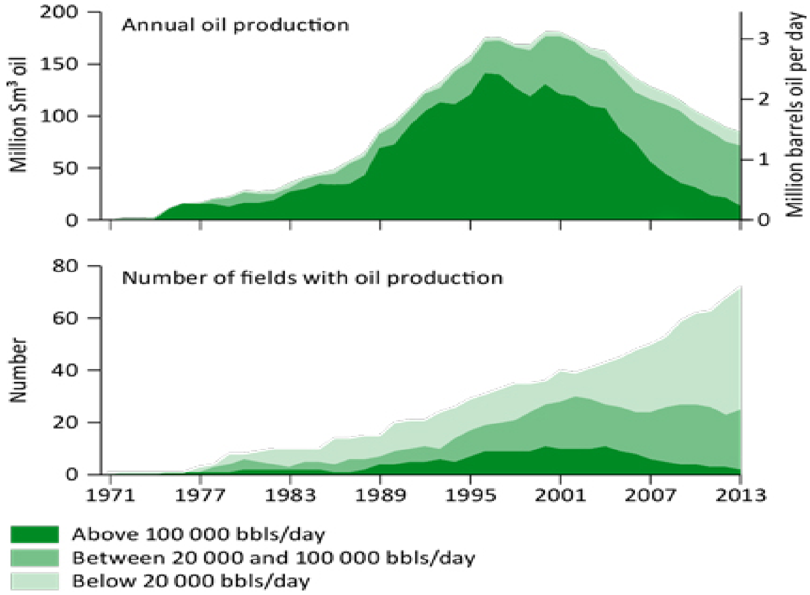


Figure 1: Historical oil production in the Norwegian North Sea (NPD, 2014a).

Figure 2: Historical oil production from the UK continental shelf (DECC, 2015a).

2.2 Current status of the North Sea oil fields

2.2.1 Norwegian oil fields

The Norwegian Petroleum Directorate (NPD) regularly releases reports on the status of the Norwegian oil fields. The latest report was released in April 2014 and prepared in the autumn of 2013 (NPD, 2014a) and gave an overview of recent developments and future plans for the Norwegian petroleum activities. The key points were:

- The remaining resources are estimated to be 3.9 billion Sm^3. Of these, a little over 2 billion Sm^3 were proven quantities.
- 4.3 billion Sm^3 of oil has already been sold and delivered.
- Thirteen fields are under development, and two of these are located outside the North Sea. Six of the fields under development were discovered between 1974 and 1992.

The NPD continuously update the information on the 25 largest oil producing fields (NPD, 2014b). The numbers, as of December 31st 2014, are provided in Figure 3. The figure shows the distribution between produced oil, remaining oil reserves and the resources that are expected to remain in the reservoir after the field has been closed down.

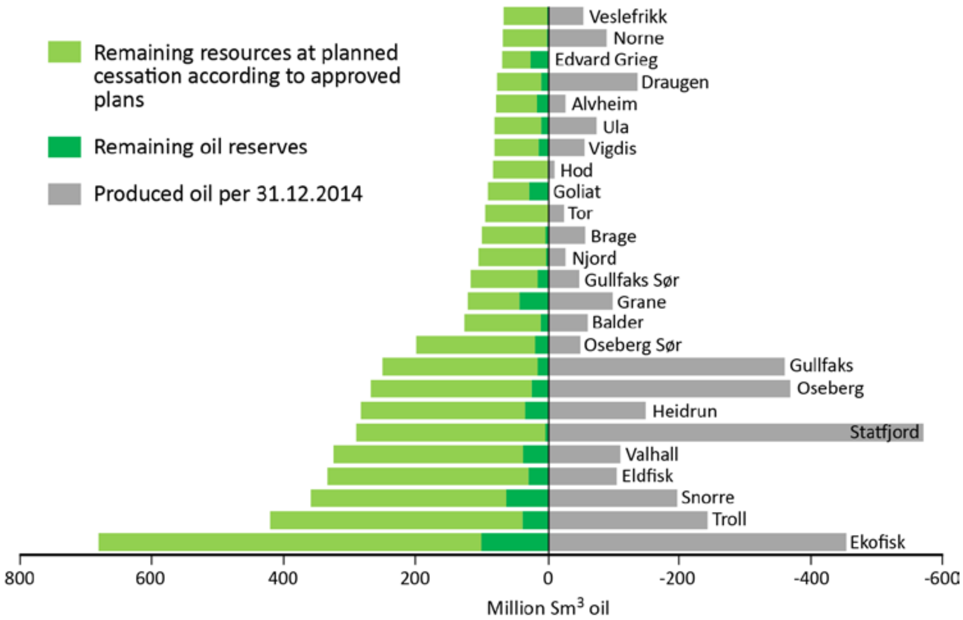


Figure 3: Current status of Norwegian oil fields [NPD, 2014b].

In Table 1, key numbers for selected oil fields are provided. The numbers are as of December 31st 2015 (NPD, 2014b).

Table 1: Key numbers in million Sm^3 for selected oil fields (NPD, 2014b).

Oil field	Produced oil per 31.12.2014	Remaining oil reserves	Remaining resources at planned cessation according to approved plans	Original oil in place (OOIP)	Recovery rate as of 31.12.2014*	Expected recovery rate after planned cessation*
Ekofisk	453	101	580	1134	40%	49%
Troll	242	39	382	664	36%	42%
Snorre	196	64	296	556	35%	47%
Eldfisk	104	29	305	439	24%	31%
Valhall	110	39	287	435	25%	34%
Statfjord	569	5	286	860	66%	67%
Heidrun	148	35	249	432	34%	42%
Oseberg	368	25	244	637	58%	62%
Gullfaks	359	16	235	610	59%	61%
Oseberg sør	48	20	180	248	20%	27%
Gullfaks sør	47	16	101	164	29%	38%
Vigdis	56	15	67	138	41%	51%
Ula	73	11	71	155	47%	54%

*The recovery rates are calculated here based on the data provided in (NPD, 2014b).

According to the Norwegian Ministry of Petroleum and Energy, the average recovery factor from Norwegian oil fields was around 40% in 1995 and 46% in 2014 (Ministry of Petroleum and Energy, 2014). This recovery factor is expected to increase in the coming years due to implementation of new recovery technologies. With every project that is realized on a specific field, the light green column in Figure 3 will be reduced for this field. Several of the largest fields are in their tail production and any extension of the lifetime of the field could potentially be very profitable. This is partially due to the increased oil recovery rate, but also because a longer lifetime increases the possibility of discovering new fields that can utilize the same infrastructure and thereby reduce the investment cost of the new field.

2.2.2 UK oil fields

The Department of Energy and Climate Change (DECC) manages the data regarding oil and gas fields in the UK sector of the North Sea. Such data includes production history, income, expenditure on exploration, spills, remaining reserves and approvals. Production data is updated monthly on an oil field basis. Yearly reports on remaining reserves and predicted ultimate recovery are provided. The most recent numbers are 2014 estimates, which were reported in 2015 (DECC, 2015b). Probable reserves from fields that are in production or under development are 630 Mt oil, of which 374 Mt are proven. An additional 98 Mt are deemed probable from significant discoveries where plans are being developed. In Table 2 the oil produced from a select number of oil fields is presented. For historical production data for all fields in the UK sector, the reader is referred to (DECC, 2015a).

Table 2: Oil produced per 31.12.2014 for a select number of oil fields in million bbl (DECC, 2015a).

Oil field	Produced oil per 31.12.2014
Alba	457
Auk	158
Beryl	829
Brae	590
Brent	1,951
Buzzard	508
Claymore	607
Clyde	441
Cormorant	661
Dunlin	405
Forties	2,718
Fulmar	553
Janice	56
Miller	339
Nelson	449
Ninian	1,224
Piper	1,032
Scott	416
Teal	64
Thistle	441
Murchinson	302

No information about the OOIP and expected recovery rates has been found.

2.3 Ongoing CO_2 EOR and storage activities

2.3.1 CO_2 EOR activities

North Sea reservoirs have been assessed extensively for CO_2 EOR opportunities, but, so far, no projects have been implemented. In the Norwegian sector, several fields have been investigated, and the fields Draugen, Grane, Oseberg East, Brage, Heidrun, Volve and Gullfaks have had the most focus. There are technical challenges, like limited space and weight margins at the platforms, and high costs associated with close-down in connection with modifications of the platform (CSLF, 2013a). In the UK, The Miller and Forties oil fields and a number of others have been assessed for CO_2 EOR, but none have proved to be economically viable. The hurdles towards implementation of CO_2 EOR in the North Sea are discussed in more detail in Section 2.4.

EOR using water and natural gas (water alternating gas injection, WAG) is normal procedure on most oil fields in the North Sea; it has been ongoing since 1998 and 2002 in the Ula and Magnus fields, respectively. Experience from these operations can be useful for initiating CO_2 EOR. The use of EOR technologies, other than water and natural gas injection, i.e. CO2, has been extensively studied by the Norwegian Petroleum Directorate (NPD). In January 2015, they reported considerable potential in several fields, but the results of specific oil fields are not publicly available. Aker Solutions together with Statoil reported a study on CO_2 EOR on a field in the Norwegian North Sea (no field name given) in January 2015 with significant increased oil volumes but at negative NPV by today's circumstances. Microbial EOR is implemented at one field (Norne) in order to mobilise the immobile oil (NPD, 2014a).

In the United States, CO_2 has been utilized for EOR for decades and is considered to be a mature technology (Bachu, S., 2013). CO_2 stripped from methane gas at gas processing plants (Val Verde Basin gas fields) was the first CO_2 source in the 1970's and since then has been a significant and increasing CO_2 resource in the Permian Basin. Gas processing is the main source of CO_2 for new projects in the Northern Rockies (e.g. La Barge, Lost Cabin plants) and transported to oilfields. The CO_2 is usually supplied from naturally occurring CO_2 reservoirs, and transported to oil fields by pipelines. Recently, as more focus has been put on climate change, the need to reduce CO_2 emissions to the atmosphere has been brought to attention. A CO_2 capture plant has recently been installed on Unit 3 at SaskPower's Boundary Dam coal fired power plant in Canada. Here, the CO_2 is mainly to be used for EOR in the Weyburn oil field (around 20 Mt), with the rest to be permanently stored (less than 1 Mt) (Stéphenne K., 2014). The CO_2 EOR operations in North America have been limited to onshore activities. In the U.S., implementation of CO_2 EOR offshore in the Gulf of Mexico is being evaluated. Other countries are also looking into offshore CO_2 EOR, with the most prominent being Brazil, United Arab Emirates (UAE), Vietnam and Malaysia (Malone, T. et.al., 2014).

Other countries also have had many years of experience with CO_2 EOR on land: Hungary, Croatia, Poland, Turkey and Brazil. Lula field has been injecting 0.7 Mtpa since 2013. Brazil, UAE, Vietnam and Malaysia are also looking into offshore CO_2 EOR (Malone, T. et.al., 2014).

2.3.2 CO_2 storage activities

Even if some permanent storage of CO_2 projects have been executed, it is not yet common practice, and in the Norwegian shelf, only two full-scale projects are currently in operation: one in the North Sea and one in the Barents Sea (MIT, 2015a, NPD, 2014c).

- Sleipner West – offshore the west coast of Norway, the natural gas produced contains a higher concentration (4 – 9%) of CO_2 than the export specifications allow (2.5%). The CO_2 is removed from the gas on the offshore platform and pumped into the Utsira Formation (a saline aquifer, 800 – 1,000 m below the seabed). The injection of CO_2 started in 1996 and has an annual injection rate of 0.9 Mt CO_2.
- Snøhvit – offshore northern Norway, the natural gas containing 5 – 8% CO_2 is transported to an onshore facility where the CO_2 is removed before liquefying the natural gas. The CO_2 is still transported by pipeline to a subsea installation into the Tubåen Formation (a saline aquifer, 2300 m below the seabed). The downhole injection interval has been changed. The injection started up in 2008, with an annual injection rate of 0.7 Mt CO_2. In 2011, the CO_2 injection was moved to the Stø Formation due to observed unacceptably slow injection rates associated with pressure increase in the Tubåen Formation, giving concerns in the long term.

2.4 Potential for EOR

There are several differences between North American (US and Canada) CO_2 EOR projects and potential North Sea projects (NPD, 2014c). In Table 3, the differences are summarized.

Table 3: Reservoir Differences between North America and North Sea oil fields (Tzimas A. et al., 2005) .

	North America	North Sea
Reservoir type	Carbonate	Sandstone
Permeability	Low (typically < 20 mD)	High (typically > 500 mD)
Reservoir depth	Low	High
Well productivity	Low	High
Well spacing	Low	High
Stratigraphy	Less faulted Horizontal beds	Fault blocks Steeply dipping beds
Oil type	Sour and sweet 28 – 42 API	Predominantly sweet High API

North Sea reservoirs are located at a greater depth, which results in higher temperatures and pressures compared to the North American reservoirs. Regardless, it is expected that the density of the injected supercritical CO_2 will be the same in both cases as the higher pressure will balance the higher temperature. From this, it can be assumed that similar amounts of CO_2 are needed for EOR projects in North American and the North Sea. The increased depth of the North Sea reservoirs also increases the miscibility.

In North America, the most common well patterns are 5 or 9 spot closely-spaced injection and production wells. For North Sea projects, a line drive pattern is more likely (Tzimas A. et al., 2005). Offshore wells are considerably more costly than onshore wells, and it is therefore probable that the number of wells will be far less, in the tens or even less, than what is currently the norm for onshore EOR projects, where hundreds of injection wells are not uncommon for one project. The distance between the wells is also expected to differ significantly. The well costs are anticipated to be a considerable cost factor and the placement of the wells must be carefully considered based on an EOR strategy that is tailor-made for a specific oilfield.

The increased oil recovery rate due to CO_2 EOR is dependent on reservoir properties, oil recovery rate of the preceding recovery methods (primary and secondary), and the EOR strategy. Experience with CO_2 EOR shows that the projected incremental recovery of oil ranges from 7 to 23% of OOIP (Stéphenne, K., 2014). The CO_2 EOR OOIP recovery rate is expected to be lower for North Sea oil fields compared to North American ones. The main reason for this is the considerably higher recovery rates from primary and secondary production (35 – 55%, some fields even have recovery rates above 60%) (Tzimas A. et al., 2005). In Tzimas A. et al., 2005, reservoir modelling of North Sea oil fields was performed. The modelling resulted in a CO_2 EOR recovery rate of 4% of OOIP in a low recovery regime. In the high recovery regime, the rate was increased to 9% of OOIP for miscible projects in the North Sea. A recovery rate of 18% was assumed by the IEA GHG (Godec, M. 2011) for UK and

Norwegian oil fields. In another study of CO_2 EOR in the North Sea, an incremental oil recovery rate of 8.8% was used (Pershad H., et al., 2012). The incremental oil production from CO_2 EOR was estimated for a number of oil fields (Norwegian, Danish and UK) at 10% of the OOIP (STB) (American Petroleum Institute, 2007).

There are distinct differences between UK and Norwegian production. Notably, UK fields have gone through primary and secondary production, with lower recovery factors, whereas Norwegian fields tend to have been developed with improved oil recovery (IOR) techniques from the start, resulting in higher recovery factors. This difference makes UK fields a better prospect than Norwegian fields that are at high depletion already. Estimating the potential for incremental oil recovery from CO_2 EOR for the oil fields in the North Sea is challenging and will vary from field to field. A rough estimate for a selection of oil fields is provided in the next section in order to give an idea of the potential. An EOR strategy needs to be developed for each oilfield in order to reduce the uncertainty and to identify the individual potential.

2.4.1 Norwegian oil fields

The potential for incremental oil recovery due to CO_2 EOR is estimated based on the field data from Table 1 and an assumed incremental oil recovery of 10% of OOIP. The results are given in Table 4. In Holt T., et al., (2009) it was reported that Statfjord is unsuitable for CO_2 EOR, as the field has been depressurized. This field is therefore removed from Table 4.

Table 4: Potential for incremental oil recovery for a selection of Norwegian oil fields in million Sm^3.

Oil field	Produced oil per 31.12.2014	Remaining oil reserves	Remaining resources at planned cessation according to approved plans	Original oil in place (OOIP)	Incremental oil recovery due to CO_2 EOR
Ekofisk	453	101	580	1134	113
Troll	242	39	382	664	66
Snorre	196	64	296	556	56
Eldfisk	104	29	305	439	44
Valhall	110	39	287	435	44
Heidrun	148	35	249	432	43
Oseberg	368	25	244	637	64
Gullfaks	359	16	235	610	61
Oseberg sør	48	20	180	248	25
Gullfaks sør	47	16	101	164	16
Vigdis	56	15	67	138	14
Ula	73	11	71	155	16
Total					**562**

2.4.2 UK oil fields

Estimating the potential for the UK oil fields is not performed here, due to the limited availability of data. The results are, therefore, based on the work performed in (Kemp A.G., Sola Kasim A., 2012). An incremental oil recovery of 10% of OOIP was assumed. The potential for incremental oil production due to CO_2 EOR, as reported by Tzimas A. et al., (2005) is given in Table 5. These numbers have a ± 50% uncertainty. The oil fields Brent and Miller were considered to be unsuited for CO_2 EOR and, therefore, are not included in Table 5. Brent has been depressurized and the Miller field has already been decommissioned. Miller could be reopened with new technology, and the oil and gas pipelines would have had to be kept in a form suitable for further use.

Table 5: Potential incremental oil production due to CO_2 EOR for a select number of UK oil fields in million bbl (Kemp A.G., Sola Kasim A., 2012)

Oil field	Incremental oil recovered
Alba	119
Auk	53
Beryl	232
Brae	104
Buzzard	108
Claymore	144
Clyde	41
Cormorant	157
Dunlin	83
Forties	420
Fulmar	82
Janice	129
Nelson	79
Ninian	292
Piper	140
Scott	95
Teal	82
Thistle	82
Murchinson	79
Total	**2,521**

2.4.3 CO_2 storage potential due to CO_2 EOR

Generally it can be said that the more CO_2 that is injected into the reservoir, the higher the oil recovery rate will be. The increased oil production rate must be weighed against the cost of purchasing the CO_2 and the cost of infrastructure and energy needs for increased rates of recycling. The CO_2 requirement per barrel of incremental oil in Tzimas A. et al., (2005) was assumed to be 0.33 tonne. In NPD (2014c), a minimum, maximum and a most likely value, 1.6, 2.6 and 1.8 bbl/tonne CO_2, respectively, were used in a study of the UK sector of the North Sea. In other studies

(SCCS, 2015b) and (Hill, B., et.al., 2013), 1-3 bbl/tonne CO2 injected is assumed as typical injection factors, with sensitivities up to 5 bbl/tonne CO2 injected.
Assuming that 3 bbl of oil is produced for every tonne of CO_2 injected, the total CO_2 injected is then roughly estimated to be for

- Norwegian fields (Table 4) – The incremental oil potential is estimated to 3,535 million bbl, which gives a CO_2 amount of 1,180 Mt CO_2,
- UK fields (Table 5) – The incremental oil potential is estimated to 2,520 million bbl, giving a CO_2 amount of 840 Mt CO_2.

In Meltzer S., (2012) it is reported that 90 – 95% of the fresh CO_2 supplied to CO_2 EOR projects is being retained in the reservoir and the processing units, as these are connected in a closed loop, while [63] reports losses less than 0.5%. Any leakage is expected to be minimal, and mainly related to short and infrequent power outages during reconditioning of the CO_2 and CO_2 migration from the reservoir. The following equation can be used to calculate the amount of CO_2 stored after the CO_2 EOR project has been plugged and abandoned (Meltzer S., 2012):

$$CO_2\ storage\ (\%) = \frac{Total\ CO_2\ injected - \ CO_2\ produced - \ CO_2 losses}{Purchased\ CO_2 injected}$$

Another factor that affects the CO_2 supply and storage potential is CO_2 breakthrough. After some time, CO_2 will be produced together with the oil. This CO_2 must then be separated out and reinjected to the reservoir. According to the American Petroleum Institute, (2007), the U.S. experiences show that on average 40% of the injected CO_2 can be expected to be produced with the oil. In (Klokk Ø., 2010), where a CO_2 value chain on the Norwegian Continental Shelf was considered, a CO_2 recycling rate of 75% (of CO_2 injected) was assumed.

There is also potential for additional storage of CO_2 in the oilfield reservoir after the oil production has ceased. The potential is reservoir specific, and careful considerations regarding the reservoir integrity is needed for such a continued operations.

2.5 Hurdles to CO_2 EOR

There is considerable experience with CO_2 EOR in the U.S., proving that the technology is economically beneficial. However, the challenge is to transfer this experience to other regions in the world. Direct transfer is difficult due to differences in geological conditions, CO_2 infrastructure, and economic conditions. Compared to potential North Sea projects, the North American projects have benefited from

- being onshore (no weight or area restrictions, less stringent on number of injection wells, better climate conditions, less complex overall operation),
- having naturally occurring pure CO_2 relatively easily accessible (low cost of CO_2), and
- having higher oil production potential due to the somewhat lower recovery efficiency from primary and secondary production compared to North Sea fields.

Barriers for growth of CO_2 EOR in the North Sea are mainly economic due to lost production over long shut-down times when making process equipment (pipes and vessels) corrosion resistant. Other factors were identified in (Pershad H., et al., 2012) and the bullet list below is a direct transcript:

- *“Timescales for decommissioning (example: when an oilfield is decommissioned, the cost of reinstalling the oil production for EOR is too expensive)*
- *Engineering challenges (Mixture of CO_2 and brine will corrode carbon steel-maybe more expensive alloys are more suitable. The engineering of corrosion management is well developed and includes many technologies, including additive corrosion inhibition chemicals, cathodic protection with sacrificial electrodes, and various specifications for different parts of the wells in contact with wet CO_2, such as coatings as well as metals such as chrome steel)*
- *Shared equity ownership of oil fields*
- *High oil taxation*
- *Commercial, communication and cultural barriers*
- *Liability issues*
- *Diverse KPIs for different stakeholders*
- *Lack of political support from most environmental NGOs for CO_2 EOR*
- *Scepticism around early development of CO_2 EOR*
- *Constitutional change”*

Several studies regarding CO_2 EOR in the North Sea have been conducted. Generally, the conclusion from these studies is that injection of CO_2 for enhanced oil recovery is possible and that there is a considerable potential, however there are significant hurdles. The main ones are the upfront investment costs, loss of oil production during work over and lack of significant CO_2 volumes (Cavanagh A., Ringrose P., 2014). Development of the CO_2 EOR supply chain is a major hurdle, which include the platform work over(s), CO_2 capture plant(s), transport infrastructure, and the possible development of a permanent storage site (relief site) for the CO_2.

The lack of access to sufficient volumes of CO_2 is another main concern. Presently, the economic situation in Europe coupled with the very low EU-ETS CO_2 quota price (approximately 8 €/tonne CO_2) cited earlier in this report as 8 Euros (Section 1.1 Cost Components) and an unclear political framework does little to trigger the much needed large-scale implementation of CCS from the industrial and power sectors. Several full-scale capture demonstration projects were planned in Europe in 2007-2008, but most of these have either been terminated or put on hold due to lack of a commercial business case. Currently, there are only a few full-scale projects still under development. Two are from the “Strategic UK Storage Appraisal Project” run by the UK DECC, where the projects Peterhead and White Rose were in the competition until it was withdrawn by the British government in autumn of 2015. Another project is the ROAD project in the Netherlands.

In addition, there is going to be a gap between the cost of capture (minimum sales price of CO_2 for a viable business capture side) and the value of CO_2 when purchased, as perceived by the different stakeholders. Emitters will want to sell their CO_2 at a price that is likely to be higher than what oil field owners are going to be willing to pay.

The oil price is one of the more important factors that heavily influence the economics of an EOR project. Likewise, the issue of cost of oil not recovered during construction, However, it is not clear whether a low or high oil price is beneficial for CO_2 EOR projects. A relatively low oil price is beneficial in the construction phase to reduce the revenue loss from lost oil production if it is a tail-end retrofit case. While a low oil price in the production phase also leads to less value of the incremental oil from the CO_2 EOR. A high oil price is disadvantageous to EOR projects as the revenue loss during the construction phase is likely to be considerable and give the project a negative NPV. Literature & studies based on U.S. CO_2 EOR indicate greatest returns on investment & overall profit occur at high oil prices. The current oil price is at an historical low, less than 50 $/bbl in August 2015.

Both Norway and UK have a relatively high oil tax. According to (SCCS, 2015a), the oil tax is 50-75% for UK and 78% for Norway, but there is an investment allowance of 62.5% for Supplementary Charge. This reduces the effective rate considerably, to as low as 30% rather than 50% on many fields, and 54.5% rather than 67.5 % on very old fields. While other low carbon energy projects are likely to get tax reduction or even no taxation, CO_2 EOR operations are likely to have a high taxation (ZEP, 2011). With the recent fall in oil price, the UK and Norway oil tax level has been in discussion by government and industry. The signals from the Norwegian government were no change in the short term, while the UK government seemed to prepare for a tax cut (Offshore Aberdeen, 2015).

2.6 Economics of CO_2 EOR

A number of studies have been conducted over the years where the economics of CO_2 EOR projects are included, and some of these are highlighted in this chapter. The difficulty however, when attempting to systemize the results, is the difference in assumptions and baselines for each study. Differences include, but are not limited to, single field or a cluster of fields, operational window, scope, future scenarios, and combination with permanent storage of CO_2. The studies show that under certain assumptions, specific projects can be beneficial from a cost perspective.

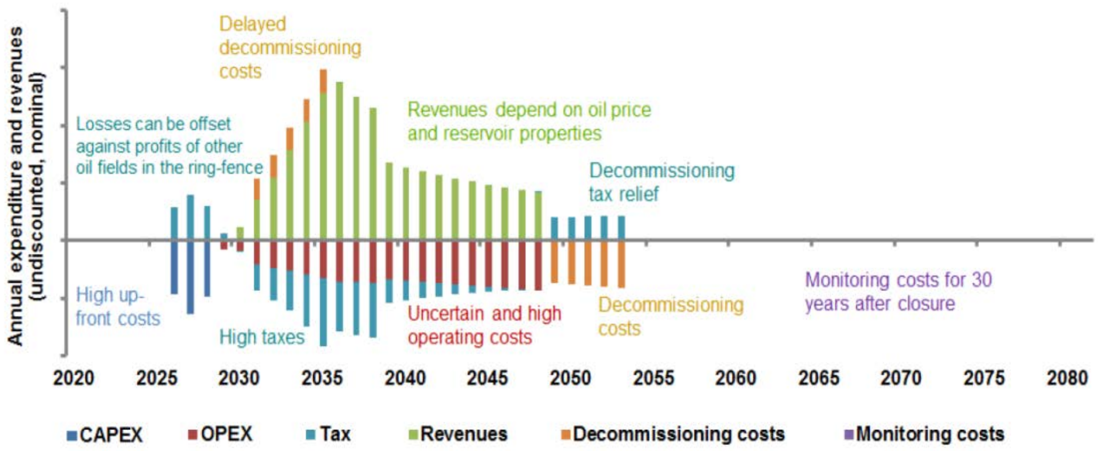


Figure 4: Illustrated cash flow of a CO_2 EOR investment .(Pershad, H. et.al., 2014)

In (Pershad H., et al., 2014) and (Pershad H., et al., 2012) key input parameters and main cost drivers are identified. Many of these are site/field specific, which makes it challenging to provide general cost data for CO_2 EOR in the North Sea. In (Pershad H., et al., 2014) the cash flow of a CO_2 EOR investment was illustrated (see Figure

4). The figure shows all phases of a CO_2 EOR project and the associated costs and revenues. The cash flow of a CO_2 EOR project is highly site specific. Key input parameters are, but not limited to, field capacity, well injection rate, liability transfer costs, interest rate, well depth, well completion costs and number of observation and exploration wells.

The lost revenue due to lost production during time for rebuilding will be highly site dependent. Newer platforms with corrosion resistant materials may have a short time as old tightly packed process units with plain carbon steel could be prone to a satellite processing platform or ship/barge. It is rather difficult to generalize this lost revenue. The main other cost components of CO_2 EOR projects were identified by (Pershad H., et al., 2012) to be

- Planning cost
- CAPEX
  - o Platform modification
  - o Well
  - o Recycling of CO_2 (including separation and compression units)
- OPEX
  - o Base
  - o Incremental due to CO_2 EOR (separation and compression of CO2.
- Fresh CO_2 cost
- CO_2 emission cost
- Oil transport cost
- Offshore fuel cost
- CO_2 insurance and monitoring cost

In the BIGCO2 project from 2009 (Holt T., et al., 2009), the economic and capacity potential of the North Sea was studied. A techno economic model was developed for a network consisting of 18 Norwegian and 30 UK oil fields. The project lifetime was set to 40 years with a discount rate of 7%. The case study was based on an infrastructure where CO_2 was collected from sources in Europe, and gathered in Emden (Germany) and Aberdeen (UK). From there, CO_2 was delivered by pipeline to the Ekofisk area and further to the Tampen area. The annual volumes of CO_2 injected were estimated to 178 Mt. After CO_2 breakthrough, the CO_2 produced with the oil was separated out and reinjected. Resulting in a gradual reduction of the fresh CO_2 volumes injected, and the excess CO_2 was to be injected in aquifers nearby. CO_2 was injected into the oil reservoirs as long as the cash flow was positive. The economic parameters and the key results are summarized in Table 6 and Table 7, respectively.

Table 6: Economic parameters used in (Holt T., et al., 2009).

Economic parameters	Value	Unit
Costs of new injection wells	30	Mill.USD/well
Modification of oil production system	400	USD/(bbl/day)(*)
Engineering/contingency costs	25/25	% equipment cost
Operating costs	5	% of equipment cost
Energy compressor	0.17	USD/kWh
CO_2 transport cost	6.0	USD/tonne
Aquifer deposition costs	4.0	USD/tonne

*This investment cost is field dependent and is calculated from the plateau oil production rate of the field.

Table 7: Summarized key results of (Holt T., et al., 2009) assuming an oil price of 80 $/bbl.

Item	Value	Unit
Total oil produced	4,706	Million Sm^3
Total oil recovery factor	60.6	% HCPV
EOR oil	682	Million Sm^3
Incremental oil recovery factor	8.8	% HCPV
Total stored CO_2	7,254	Mt
CO_2 stored in oil reservoirs	2,284	Mt
Total investment costs	58,234	Million USD
Total operation costs, excluded CO_2 purchase	2,858	Million USD/year

The net present value (NPV) and the CO2 breakeven cost is calculated. For the above estimation, with the assumption that the oil price is 80 $/bbl, the associated breakeven CO_2 cost is 44 $/tonne delivered.

In a study from 2005 (Tzimas A. et al., 2005), 81 active oil fields in the UK, Norwegian and Danish sectors were considered for CO_2 EOR. Of these, 15 were selected for a preliminary economic evaluation as standalone projects. It was assumed that the stored CO_2 was credited and resulted in an income to the project. Another assumption was that taxations were not included. The main cost assumptions are rendered in Table 8.

Table 8: The main cost assumptions (Tzimas A. et al., 2005) (2004/2005 numbers).

Item	Value	Unit
Topside modifications	2	€/bbl of incremental oil
Drilling of new wells*	1.75	M€/km
Reconfiguration of old wells*	0.5	M€/well
Operation and maintenance	7.5 10	€/bbl (oil production) €/tonne CO_2 (CO_2 injection after the end of EOR)
Decommissioning	250 - 450	M€ (depending on the platform size)
CO_2 cost at power plant gate	25.5	€/tonne
Transport cost of CO_2	1 - 3	€c/tonne km
Discount rate	10%	

*An equal number of new and old wells were assumed.

A study from 2007, requested by the “North Sea Basin Task Force”, looked at a potential CO_2 EOR scenario in the North Sea (Pershad H., et al., 2007). Key assumptions were high oil price, low cost CO_2 available, and that CO_2 EOR is preferable to other EOR technologies. In this study, the following numbers were used for well drilling and platform costs:

- Well drilling costs (including the horizontal component of drilling)
    - Fixed cost per well (shallow water) - £5.6m
    - Fixed cost per well (deep water) - £8.3m
    - Drilling cost (shallow water, shallow reservoir) – 2 600 £/m

    - Drilling cost (shallow water, deep reservoir) – 3 640 £/m
    - Drilling cost (deep water, shallow reservoir) – 4 400 £/m
    - Drilling cost (deep water, deep reservoir) – 6 600 £/m
- EOR platform costs
    - Shallow water
        - CAPEX - £140m
        - OPEX – 10% of CAPEX
    - Deep water
        - CAPEX - £280m
        - OPEX - 10% of CAPEX

In another study, (Kemp A.G., Sola Kasim A., 2012) from 2013, the economics of CO_2 EOR cluster development for UK oil fields were investigated. Key investment variables were identified and divided into physical and financial data, and these are rendered in Table 9 and Table 10, respectively.

Table 9: Key physical data identified for CO_2 EOR in (Kemp A.G., Sola Kasim A., 2012).

Physical data	
Distance to:	Backbone pipeline (km), or Onshore CO_2 hub (km)
Reserves	OOIP (mmbbls) Produced oil to date (mmbbls) COP (cessation of production) date (without EOR)
Water-related	Water depth (m) Water cut (%)
Wells	No. of existing injectors No. of existing producers No. of injectors modified for EOR Well capacity (Mt CO_2/year)
CO_2 injection	Volume of CO_2 EOR purchased (Mt CO_2/year) Volume of CO_2 recycled (Mt CO_2/year) Volume of hydrocarbon gas produces (Mt CO_2/year) Volume of CO_2 injected (Mt CO_2/year)
Production	Injection-output ratio (tCO_2/bbl) EOR oil production (mmbbls/year) Volume of CO_2 emissions infield

Table 10: Key financial data identified for CO_2 EOR in (Kemp A.G., Sola Kasim A., 2012).

Financial data, CAPEX	
Infrastructure investment	Pipeline investment (£m) Well rework (£m) Surface facility (£m)
Injector capital	(£m)
Recycle system	(£m)
Monitoring	(£m)
Financial data, OPEX	
Cost of purchased CO_2	(£m)
Recycle cost	(£m)

Purchase of CO_2 allowances (EU-ETS)	(£m)
Other incremental O&M	(£m)
Financial data, revenues	
Oil price	($/bbl)
CO_2 sequestration fees	(£m)

A number of different scenarios were studied and cost estimated. The benefits from clustering, the effect of the oil price, CO_2 price, and tax effects were studied in regard to the profitability of the EOR projects. Specific cost data were adopted from (Pershad H., et al., 2007).

In (Pershad H., et al., 2012) from 2013, 19 oil fields on the UK Continental Shelf were considered as potential anchor projects for CO_2 EOR. Combined, the potential incremental oil recovery could be 2.5 billion bbls of oil. Three CO_2 EOR scenarios were modeled, slow, medium and very high implementation, representing 2, 5 and more than 12 projects, respectively. Some of the assumptions made are dependent on the CO_2 EOR implementation scenarios. One such assumption is the cost of CO_2, in the slow scenario the cost is assumed to be £10/tonne, for the medium it is £0/tonne, and in the very high, it is assumed that the oil company gets paid £10/tonne for storing the CO_2. The CO_2 injection rate is 0.8 Mt/year/well. In Table 11, the assumptions are summarized.

Table 11: The main cost assumptions (Pershad H., et al., 2012).

Item	Value	Unit
Oil price	90	$/bbl
New well CAPEX	20	£m/well (for both CO_2 injection and oil production
Existing well re-use CAPEX	8	£m/well
Recycling unit CAPEX	20	£m
Platform OPEX	5	% of platform CAPEX*
Well OPEX	4	% of well CAPEX
Oilfield base OPEX	50	£m/year
Planning cost	5	% of total CAPEX (including FEED costs)
Decommissioning unit cost (Abex unit cost)	0.4	£/bbl (OOIP)
Incremental decommissioning cost of EOR	15	% of total CAPEX
Discount rate	10	% (nominal)

*Platform CAPEX is dependent on the platform infrastructure already in place at the oilfield studied.

2.7 Legal aspects

A CO_2 EOR project entails that CO_2 is injected into an oil reservoir to increase the oil production. From each injected batch of CO_2, around 50% will be produced back with the oil. All such CO_2 produced with the oil is expected to be recycled and reinjected into the reservoir. Except for minor diffuse leaks, eventually all imported CO_2 will be injected and stored in the reservoir. At the end of the oil production period, the oil field is decommissioned. The change from an oil production project to a CO_2 storage project also makes storage laws and regulations valid.

In order to have a successful implementation of CO_2 EOR in the North Sea, the legal and regulatory framework must be clear and predictable. In recent years changes have been made to the legal and regulatory frameworks, both on an international and EU level, to accommodate for the implementation of CCS operations (SCCS, 2013). CO_2 EOR operation has had less focus, as the main concern has been permanent storage of CO_2. In the text below, some of the findings from the work performed in (SCCS, 2013) regarding the legal status of CO_2 EOR are presented. The consensus is that the combination of CO_2 EOR and permanent storage challenges the existing framework and demands legal clarification with relevant authorities.

Both national (UK and Norwegian) and international laws are relevant in regard to the implementation of CO_2 EOR projects in the North Sea. There are two international marine conventions that could potentially be relevant. These are the London Protocol and the OSPAR Convention. According to (SCCS, 2015a), neither of the conventions is likely to apply to any CO_2 EOR projects. However, any storage project following the EOR project must comply with the London Protocol, which under special conditions explicitly allows CO2 storage under the ocean bottom.

EOR seems to only be affected by the EU CCS Directive if it is combined with storage of CO_2. However, the text in the Preamble to the Directive is open for interpretation. In (SCCS, 2013), it is stated that a strict interpretation of the Directive could limit the combination of CO_2 EOR and storage considerably. It is recommended in (SCCS, 2013), that this is readdressed in future revisions of the Directive.

CCS operations are subjected to the EU ETS and a CO_2 emitter that captures and transports the CO_2 in a pipeline to permanent storage have no issues regarding CO_2 accounting. This is not the case for pure CO_2 EOR projects. There are also accounting issues when ship transport is used instead of pipelines. According to (SCCS, 2015a), the reasoning behind such an exclusion of ships is not clear and should be amended in future revisions. As with all other activities under ETS there must exist a Measurement and Reporting Guideline (MRG) regulating the activity. An MRG for ship transport is lacking today but could be developed with relevant EU Commission authorities when the need is there.

2.8 New developments

- While the current economic situation does not favour CCS, there is political support for offshore CO_2 storage in the countries bordering the North Sea.
- Offshore CO_2 EOR is seen as a potential stepping stone towards full-scale CCS.
- CO_2 EOR is currently the only utilization option that can offset a considerable amount of $CO_{2,}$ in addition to plain storage.
- Ship transport has recently seen increased interest. It is flexible, which is important in a start-up phase. For smaller volumes, longer distances and a limited number of years, ship transport is more cost efficient than pipeline transport.
- Research that focuses on offshore offloading (local buffering) is ongoing, where room for optimization is possible.

- Subsea processing installations are currently under development and are expected to significantly decrease the lost production due to time for rebuilding the process equipment, as well as investment cost of CO_2 EOR.
- Conversion of decommissioned CO_2 EOR oil fields to CO_2 storage projects can provide delayed decommissioning costs for platforms etc. and even additional revenue after the EOR operations.

2.9 Outlook

The nature of the oil fields in the North Sea makes them suitable for CO_2 EOR, and the potential for incremental oil recovery is considerable. A number of studies have been conducted that look into the economics of CO_2 EOR projects in the North Sea. The assumptions that provide the basis for the economic evaluations vary from study to study, making it difficult to identify clear trends. However, the consensus is that under certain assumptions, specific projects can be beneficial from a cost perspective. A common economic baseline would be beneficial, but still a significant portion of the cost elements are site/field specific.

The lack of access to sufficient volumes of CO_2 is one of the main concerns. Short-term availability of CO_2 around the North Sea is limited. Several full-scale capture demonstration projects were planned in Europe in the early 2000, but most of these have either been terminated or put on hold due to lack of financial security. Currently, there are few full-scale projects still under development. Two are from the “Strategic UK Storage Appraisal Project” run by the UK DECC where, the projects Peterhead and White Rose are still in the competition. Another project is the ROAD project in the Netherlands. These projects are the only likely sources of CO_2 in the next 5 - 10 years, as any CO_2 available in 10 years will almost certainly come from projects that are under planning today. This is due to the long lead time of CCS projects. Based on the current activity, the potential CO_2 volumes that could be made available in the short term are limited.

3 Russia

3.1 Background

In 2014, the Russian Federation held a share of 12.7% of total global oil production, just 0.2% behind Saudi Arabia, and 0.4% more than the U.S. Daily oil production in 2014 was just over 10800 thousand bbl/day (BP, 2015). On reflection of Figure 5, production has increased by approximately 10% since 2005, however the total proven reserves has taken a sharp decline in recent years. The reserves to production ratio in 2014 was 26.1. The rise on oil production in the recent decades is attributed to primarily enhanced oil recovery techniques, however not specifically CO_2 EOR.

Since peaking at approximately 11500 thousand bbl/day in the late 1980's, oil production in Russia dropped to around 6000 thousand bbl/day in the mid-1990's (BP, 2015). New technologies such as hydraulic fracturing and horizontal well drilling are understood to be enabling Russia to continue to boost production in many maturing oils fields. West Siberia is Russia's main oil producing region, accounting for almost two-thirds of Russia's total production. Many of the largest Western Siberian fields have been in decline, although new applications of existing technologies have boosted recovery rates. Both LUKoil and TNK-BP, the second and third-largest oil producing companies in Russia, are using multi-zone hydraulic fracturing to support production at several oil fields in Western Siberia (Institute for Energy Research, 2012).

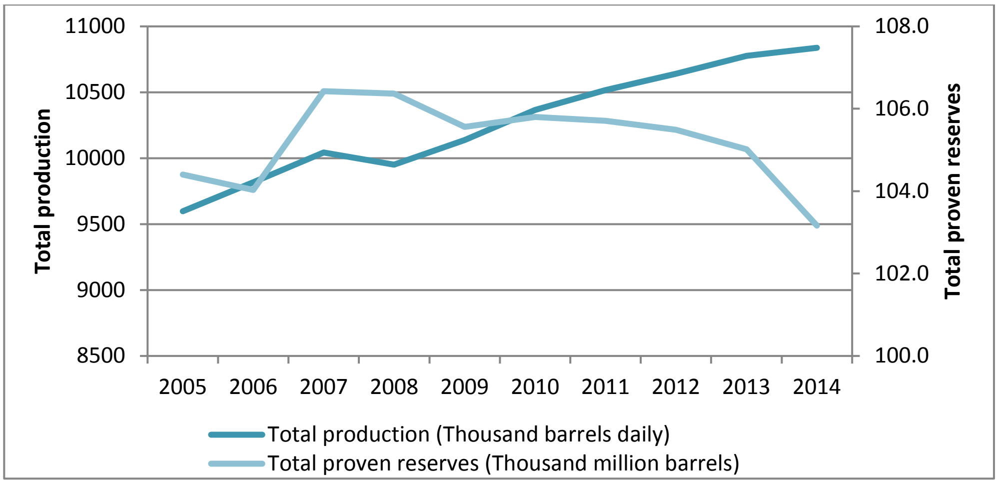


Figure 5: Total daily oil production and total proven reserves in Russia in 2014 (BP, 2015).

In terms of production forecast, analysts speculate that the year on year growth of production experienced since 2008 may soon start to taper off, as operators may not be able to offset declining production rates at mature fields with new production at greenfield sites (Ernst & Young, 2013). However, current international sanctions and low oil prices mean that attributing any expected decline in production to operational constraints is indeed speculative. Evidence suggests that the fraction of easily recoverable oil, as a part of Russia's inventory of recoverable reserves, is steadily dropping, with reserves held as heavy and viscous oil, held in tight reservoirs and held in deposits below the gas cap now making up close to 50% of total recoverable reserves. Figure 6 depicts the trend of reduction in easily recoverable reserves over the last years. Also visible is the simultaneous reduction in the oil recovery factor, a measure that represents the percent of the original in place that is technically recoverable from Russian oil fields, which has dropped by 10% since the 1960's (Ernst & Young, 2013).

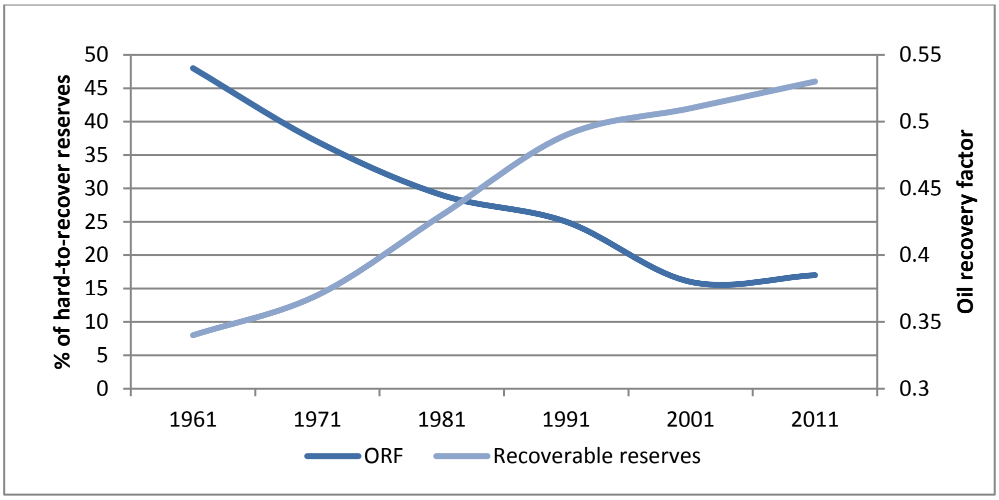


Figure 6: Hard-to-recover reserves as a percentage of total reserves in Russia from 1961 to 2011, and the change in oil recovery factor[4] of Russian oil fields during the same period (Ernst & Young, 2013).

Enhanced oil recovery techniques, including CO_2 EOR, are expected to be vital for sustaining the current levels oil production in Russia until 2030 and beyond (Ernst & Young, 2013).

3.2 CO_2 emissions in Russia

Russia is the fourth largest emitter of CO_2 globally, after China, the U.S. and India, and its responsible for roughly 5% of global emissions. Figure 7 shows a general upward trend in CO_2 emissions since the turn of the century. Russia has a particularly weak climate policy, and its recent pledge to the UNFCCC for emission reductions up to 2030, allows emissions to rise further to 2030, and therefore requires no energy efficiency or carbon management policies for the energy or industrial sectors (Climate Action Tracker, 2015). There are no specific policies in Russia to accelerate the deployment of carbon capture and storage technologies. CCS does have, however, considerable potential in the country given that 70% of the power capacity is fossil fuel based (Climate Action Tracker, 2015).

[4] The oil recovery factor (ORF) is equal to the estimate of recoverable oil (ERO) divided by the estimate of in place oil (EIPO).

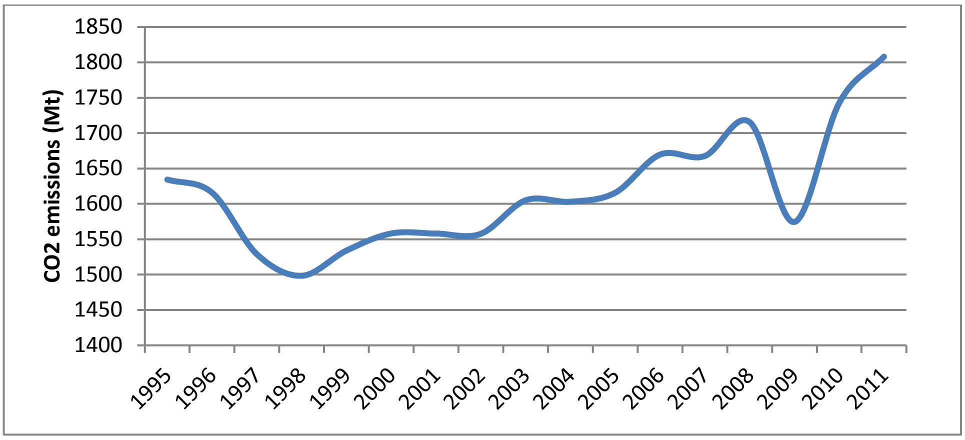


Figure 7: Carbon dioxide emissions from the burning of fossil fuels and the manufacture of cement in Russia from 1995 until 2011 (World Bank, 2015).

3.3 Current EOR projects

According to Ernst & Young (2013) there are a range of EOR projects including thermal, hydraulic, chemical and various combined methods to enhance the production, but there are currently no EOR pilot projects in Russia that use CO_2. In the past, there have been, however, trials with CO_2 enhanced production in Russia oil fields. There are reports on large scale pilot tests conducted in the 1980s, using CO_2 from petrochemical plants. Cumulative injected volumes ranging from about 50,000 tonne CO_2 to more than 750,000 tonne CO_2 were injected into the Radaevskoye, Kozlovskoye, Sergeevskoye and Elabuzhskoye oil pools, and additional oil volumes up to the order of 12% were obtained. The projects faced problems in terms of sufficient CO_2 supply and corrosion of the pipelines and equipment used to transport CO_2. Despite the relative success in terms of additional oil recovered, these pilots have not led to larger-scale EOR projects with CO_2.

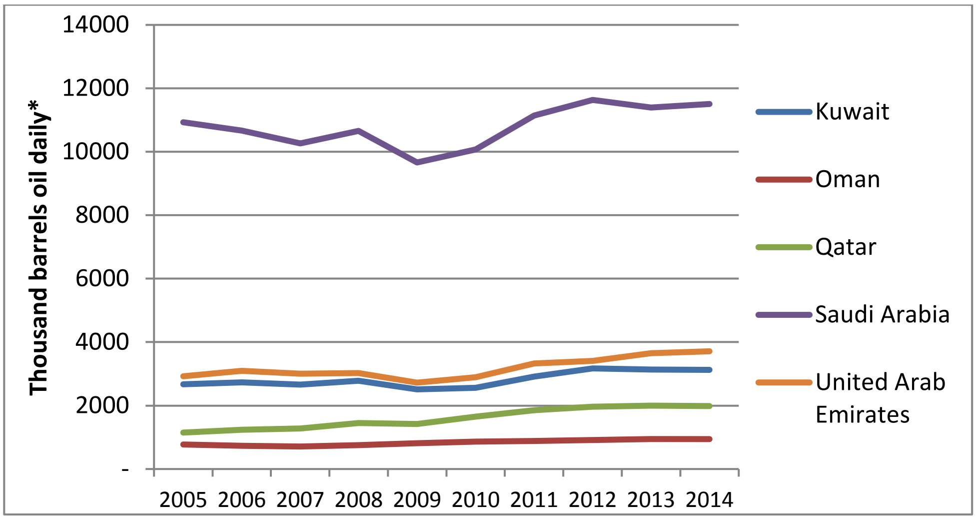
3.4 Outlook

Evidence shown above would suggest that Russia is likely to have to invest considerably in enhanced oil recovery techniques to maintain current levels of oil production from maturing fields. It seems however, that other forms of EOR appear more promising, primarily because the delivery of CO_2 to the remote locations in West Siberia which produce approximately 70% of Russian oil are too costly. The lack of an ambitious climate policy in the country offers no incentive to combine CO_2 EOR with long-term CO_2 storage. Finally, Ernst & Young (2013) states that the current tax regime on mineral xtraction in Russia is not conducive to encourage investments in EOR techniques by oil operators. The tax levied from oil producers is based on revenues, rather than financial results, and therefore makes no distinction for oil produced using more expensive EOR techniques or by conventional oil production.

4 Countries of the Gulf Cooperation Council

4.1 Oil production in the GCC region

Established in 1981, the Gulf Cooperation Council (GCC) is a regional intergovernmental and economic union between the Arab States of the Persian Gulf, namely Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates. The region includes a number of major oil and gas producing nations, and together in 2014, the region was responsible for approximately a quarter of the total global oil production, just over half of which is produced by the largest oil producing country globally, Saudi Arabia. Particularly Qatar and the United Arab Emirates have seen continued year on year growth of oil production since 2015 (Figure 8). The same region also boasts about 30% of global proven oil reserves (BP, 2015).



* Includes crude oil, tight oil, oil sands and NGLs (the liquid content of natural gas where this is recovered separately).

Figure 8: Oil production trends in GCC states since 2005 (BP, 2015).

Export earnings from oil production in GCC countries contribute between about 80% to 90% of state budgets, and therefore there is considerable importance for the states to both maintain production and market share, as well as diversify their economies to reduce economic vulnerability (Hvidt, M, 2013).

Despite the fact that Saudi Arabia has one of the highest claimed global reserves to production (R/P) ratio of around 64 years (BP, 2015), some of the largest and most important fields in the country, such as the Ghawar and Safaniya fields are expected to be in production decline. The largest producing oil field in Kuwait, the Burgan field, has also been producing since the 1950's, and the production rate continues to decline from its peak in the early 1970's (Sorkhabi, R, 2012). As with the majority of Middle Eastern oil producing nations, field specific data is not publically available, and a reduction in the production rate could be due to other factors beyond technical capacity.

Secondary recovery techniques such as water flooding, steam and natural gas injection have been commonplace activities in many GCC countries already for a number of years. In recent years, CO_2 EOR has emerged as the potential method for boosting production in the region.

Despite onshore CO_2 EOR having been utilized on a large scale to boost oil production in the United States since the 1980's, with other CO_2 EOR projects taking place in Trinidad, Turkey and Brazil, the exploration of CO_2 injection as a tertiary recovery method appears to have occurred relatively late in the history of oil production in GCC countries. Sufficient oil production rates, and a lack of natural sources of CO_2 could be assumed to be possible reasons for this. In fact, recent interest for CO_2 EOR in the Gulf region appears to have coincided with the emergence of the concept of large scale carbon capture and storage, with the primary goal of reducing emissions from power and industrial CO_2 sources to reduce the threat of global climate change.

4.2 CO_2 emissions and point sources in the GCC

In parallel to the rapid economic development brought about by the export of oil and gas, GCC countries have also seen their CO_2 emissions increased significantly. Electricity generation capacity, primarily gas and oil-fired power plants, has had to rise considerably to meet the needs of individuals and industry. The geography of the region means that considerable power is needed for cooling and for the operation of water desalination plants. According to World Bank indicators, all of the GCC countries are positioned within the top 11 of countries with the highest CO_2 emissions per capita (World Bank, 2015). GCC countries are responsible for approximately 8% of global CO_2 emissions (IEA, 2012).

Table 12: CO_2 emissions (2010) in GCC countries and % change since 1990 (IEA, 2012)]

	Bahrain	Kuwait	Oman	Qatar	Saudi Arabia	UAE	GCC countries	World
CO_2 emissions (Mt CO_2, 2010)	24	87	40	47	446	154	798.2	30,276
% change 1990-2010	102	204	293	362	180	197	190	44

Five of the GCC governments ratified the UNFCCC Kyoto Protocol in 2005, with Bahrain ratifying in 2006, indicating that the respective governments recognize human induced climate change as a problem. Although none of the GCC countries have binding reduction targets for greenhouse gas emissions, or made any pledges for reductions under climate agreements, the group has invested in renewable energy projects, primarily solar power, and established a network of clean energy research institutes. In their national communications to the UNFCCC, Kuwait, Saudi Arabia and the United Arab Emirates highlight CCS as a key technology focus to achieve national CO_2 reductions in line with economic development goals.

Exploring CCS, particularly in combination with CO_2 EOR, may have benefits in terms of energy security for GCC countries. As a form of tertiary oil recovery, Bahrain, Qatar and the UAE regularly inject natural gas to reduce the viscosity of oil and increase its displacement and eventual recovery. The UAE is the largest user of natural gas, which, according to Lecarpentier, et.al. (2012) re-injected approximately 25% of total natural gas produced in 2011 to enhance the production of oil. But with increasing demand for gas by petrochemical industries, other energy intensive industries and power generation, in addition to export commitments, a number of countries in the GCC are facing gas supply shortages. Therefore by replacing the injection of natural gas with CO_2 to enhance oil recovery, valuable supplies of natural gas can become available. Increased availability of natural gas in the GCC may also have climate benefits, as certain members such as Oman and the UAE are currently planning to build coal-fired power plants to meet electricity demand despite having no known indigenous coal reserves (Meed Projects, 2015).

4.3 CO_2 EOR potential in GCC countries

The theoretical potential for CO_2 EOR is represented by the amount of additional barrels of oil that can be produced based on the understanding of existing field properties, assuming no financial restraints such as the price of oil or CO_2. Given the sheer amount of field data required (both reserves and field properties), and the level of confidentiality of such data in GCC countries, publically available figures of EOR potential in most regions are limited to high-level estimates.

Advanced Resources International [6] provide estimates of technical CO_2 EOR potential for 54 of the largest oil basins in the world, based on generic field properties from U.S. field analogues. A global maximum theoretical CO_2 EOR potential of 470 billion barrels of additional oil was calculated, of which 141 billion barrels are located in Saudi Arabia, 28 billion barrels in the UAE and 1.5 billion barrels in Oman. These estimates represent considerable gains in additional oil, with the potential to add an additional 50%, 28% and 25% to the current total proven reserves to each of the three countries, respectively (BP, 2015). The figures presented here are also relatively consistent with information published in Manaar (2015) which estimates that EOR techniques (including both steam and CO_2 injection) can increase the total recoverable reserves of GCC countries by approximately one-third. Care must be taken with such figures however, as they are not based on specific field data.

An initial screening study has been completed to assess the suitability of Middle Eastern oil reservoirs for CO_2 EOR application (Algharaib, M, 2013). The properties of 107 (48 located in GCC countries) reservoirs were crosschecked against a set of well-known criteria for CO_2 EOR suitability, based on worldwide experience[5]. Of all the reservoirs evaluated in GCC countries, 67% were deemed as being suitable for CO_2 EOR. Table 13 summarizes the results for the GCC countries assessed. According to the study, oil reservoirs in both Saudi Arabia and the UAE are overwhelmingly suitable for CO_2 EOR applications, with approximately 90% of the oil fields suitable in each country.

[5] The criteria included reservoir temperature and depth, miscibility pressure, oil density, oil viscosity, current oil saturation.

Table 13: An assessment of a number of main oil reservoirs in GCC countries and their expect suitability for CO_2 EOR (Algharaib, M, 2013)

Country	No. of reservoirs assessed	No. of reservoirs meeting suitability criteria
Bahrain	2	0
Kuwait	5	4
Oman	11	4
Qatar	10	6
Saudi Arabia	9	8
United Arab Emirates	11	10
Total	**48**	**32**

Although it can be said with some confidence that CO_2 EOR can have a clear role in supporting oil production in maturing fields in GCC countries, the key question is whether it is economically feasible to implement EOR projects. All EOR projects will require additional investment to install the required infrastructure to deliver and inject the CO_2 in to the field. Two key economic factors are the cost of CO_2 and the prevailing price of oil. Table 14, shows the economic incremental oil recovery potential in the U.S. as a function of the crude oil price and the delivered CO_2 cost. These calculations are based on an average CO_2/oil ratio of 30% by mass [6]

Table 14: The effect of CO_2 cost and the oil price on the incremental economic oil produced as a fraction of original oil in place based on a hypothetical U.S. oil field [6]

Incremental economic oil produced (% OOIP)			
CO_2 cost at well ($/metric tonne)	Oil price ($ per Barrel)		
	$30	*$70*	*$100*
$ -	13.16%	15.56%	16.07%
$15.00	11.03%	15.22%	15.92%
$30.00	5.51%	14.82%	15.69%
$45.00	2.46%	14.21%	15.50%
$60.00	0.35%	13.48%	15.28%
$75.00	0.14%	11.73%	14.73%

Clearly, low CO_2 prices and high oil prices provide the best economics for CO_2 EOR. The data also shows that the negative impact of high CO_2 prices on economic productivity of original oil-in-place recovered is less pronounced at high oil prices. The primary costs components of CO_2 are clearly the costs of acquiring the CO_2 (either from natural sources or industrial installations), and transporting the CO_2 to the well. The U.S. CO_2 EOR industry managed to flourish with cheap sources of natural CO_2, and also with industrial sources (ethanol, ammonia and gas processing plants), with CO_2 available for less than $25 per tonne. With natural sources becoming depleted, the cost of CO_2 in the U.S. is currently rising (Meltzer S., 2012).

4.4 Potential CO_2 sources

It is currently unclear whether there are significant natural sources of CO_2 in the GCC region. Natural accumulation of CO_2 can occur through many geological processes (Baines, S.J., Worden, R.H., 2004), and it cannot be ruled out that such accumulations could be present, however no information regarding this could be found. Other low cost CO_2 sources can be supplied from industrial processes that release CO_2 in a concentrated form, primarily through the upgrading of field gas, reformation of natural gas to produce hydrogen, or from ethylene oxide production.

There is limited available data on specific CO_2 sources in GCC countries, making it difficult to identify possible 'high purity' CO_2 sources in the region. Data from 2007 (GeoGreen, 2012) identified just 13 Mt per year of potential 'high purity' CO_2 in the Middle East region. Two sources were identified within the GCC region Figure 9. Point sources of anthropogenic CO_2 in the GCC are dominated by emissions from natural gas power plants. Data on CO_2 emissions from specific power plants across the world have been estimated in the CARMA database (CARMA, 2015), and this data has been incorporated into the map below. Figure 9 provides the locations of all power production facilities across the GCC region that have annual CO_2 emissions of 0.5 Mt or above.

Figure 9: Locations of large point sources of CO_2 (≥ 0.5 Mt/yr) in the GCC region (CARMA, 2015), and the approximate location of two high-purity sources in Saudi Arabia (GeoGreen, 2012)

Although quite abundant across the region, the concentration of CO_2 in the flue gases, typically combined cycle natural gas (NGCC) power plants, is generally between 3-4% by volume (IEAGHG, 2002). The removal of CO_2 from the flue gases of NGCC power plants will require considerable additional energy, capital and operating costs. The energy efficiency of a NGCC with capture is reduced by approximately 15%[6], and the costs per tonne of CO_2 estimated at $80 (NETL, 2013). With reference to Table 14 above, utilizing CO_2 captured from natural gas-fired power plants therefore will only be financially viable during periods of sustained high oil prices.

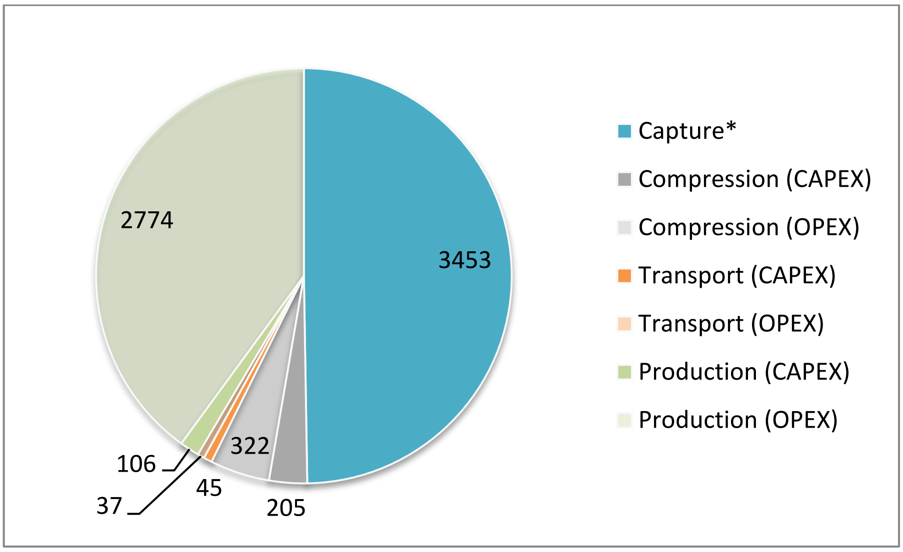
[6] HHV basis

4.5 Economic potential

Very little information or data on current oil reserves, current field conditions or oil production prices concerning GCC countries is available in the public domain. Attaining a regional specific view of economic viability and cost drivers of the GCC region is difficult, and most existing studies use informed assumptions for field conditions and estimations for cost components based on international prices.

One such economic evaluation of CO_2 EOR has been completed in (Algharaib, M & Al-Soof, 2012), which used generic cost components for capture, transport and injection of CO_2, into an oil field with the constraints of a 'typical' Middle Eastern sandstone reservoir[7]. The CO_2 source was a large natural gas combined cycle (NGCC) power plant with the ability to deliver up to 2.5 Mt CO_2 via an 80 km by 30 inch pipeline to the target reservoir. The costs of CO_2 capture from the NGCC were assumed as US$38 based on (David, J, 2000). Due to the considerable infrastructure needed, the total operational and capital expenditure[8] for the project over 35 years (oil production commenced after 5 year construction) was considerable, at approximately US$7 billion (2010).

Figure 10, provides a breakdown of the total cost of the four primary cost components of a hypothetical CO_2 EOR project in a Middle Eastern sandstone reservoir. The costs of capture (CAPEX and OPEX) is clearly the largest cost component, with the OPEX of the production activities, mainly CO_2 recycling/treatment and regulator field activities, the second largest cost component of the project.



**Due to the methodology to derive the capture cost used, no individual numbers were available for CAPEX and OPEX.*

Figure 10: A breakdown of the total cost of the four primary cost components of a hypothetical CO_2 EOR project in a Middle Eastern sandstone reservoir, with a 5 year construction period and 30 year operation period (million US$ 2010). Based on (Algharaib, M & Al-Soof, 2012).

[7] The hypothetical field was 2,500 m deep, has a porosity of 20%, and a thickness of 45 m. The reservoir extends laterally for 35,300 acres, with a temperature and pressure of 83°C and 250 bar. Oil saturation is 40%, with residual oil saturation from core experiments is 8%. Absolute viscosity is 0.6 cp and a formation volume factor of 1.45 bbl/STB.
[8] Capital expenditure depreciation linearly over 12 years.

The results of the economic evaluation are positive, with an overall recovery rate of 58%[9] (OOIP). Based on a constant oil price of US$75, and a 15% discount rate, the NPV at the end of the project was calculated as US$3.77 billion. The report also includes an extensive sensitivity analysis, which amongst a range of outcomes, highlights the sensitivity of the prevailing oil price and the effect on the NPV of the project. Specifically, a 50% increase in oil prices increased the NPV of the project by 89%.

The hypothetical example explained above suggests that, based on informed assumptions regarding the performance and costs of a CO_2 EOR in a hypothetical field, a large scale project can be highly economically viable. However the considerable capital costs required for CO_2 capture highlight the long-term investments necessary for CO_2 EOR when no low cost natural or anthropogenic sources of CO_2 are available.

4.6 Current CCS and CO_2 EOR activities in GCC countries

Given the huge theoretical potential for CO_2 enhanced oil recovery, a number of GCC countries have implemented pilot projects and are planning demonstration projects in the region. In 2009, the Abu Dhabi Company for Onshore Oil Operations (ADCO), in collaboration with the Abu Dhabi National Oil Company (ADNOC), Masdar[10], and a group of industry stakeholders, implemented the first CO_2 EOR pilot project in the GCC region. The project involved injecting around 60 tonnes of CO_2 per day, delivered by truck, into a heterogeneous carbonate reservoir which is part of the ADNOC Rumaitha oilfield. The pilot project was designed to assess CO_2 injectivity into the reservoir, examine asphaltene deposition during injection, assess CO_2 breakthrough time and sweep efficiency, and identify issues with relation to surface facilities and well integrity.

According to Al Basry, et.al., (2011) the CO_2 EOR pilot project in Abu Dhabi, which ran for 14 months, was successful for the parties involved in building experience in the design, implementation, operation and monitoring of CO_2 EOR operations in the region. In terms of sweep efficiency, CO_2 breakthrough was detected in a producer well 60 days after the commencement of injection, with the producer well positioned 70 meters from the injection well. Furthermore, a 5-7% increase in oil production rate prior to CO_2 breakthrough was achieved.

Almost in line with the CO_2 EOR pilot testing project in Abu Dhabi, plans were announced to build a hydrogen-fueled power plant combined with CO_2 capture, and a capture plant at a steel production facility. Together the projects would have captured a combined total of approximately 2.5 Mt CO_2 per year, however the hydrogen project ‘Hydrogen Power Abu Dhabi’ (HPAD) has been put on hold indefinitely. The Emirates Steel Industry Carbon Capture and Usage Project (ESI CCUS), involves the planned capture of 0.8 Mt CO_2 per year from a direct reduced iron (DRI) steel plant in Mussafeh, UAE (MIT, 2015b).

[9] The performance prediction is based on the Stalkup module (Green, D.W, & White, G.P, 1998).
[10] Masdar is an organization established in 2006 to advance the clean energy industry in Abu Dhabi.

The feasibility of CO_2 EOR in the Middle East region is demonstrated by the proposed development of the world's first CO_2 capture project in an iron and steel plant, which started the construction phase in 2014. The project is located in the UAE. The total volume of CO_2 captured will be transported annually to the Rumaitha oil field for EOR. In November 2013, ADNOC and Masdar formalized a joint venture agreement and awarded the Dodsal Group with a US$122.5 million EPC contract to build the CO_2 dehydration and compression facility at the Emirates Steel factory and the 45 kilometer pipeline to the Rumaitha oil fields. Capture and injection of CO_2 is planned for 2016 (MIT, 2015b).

In Saudi Arabia, Saudi Aramco has also officially started a demonstration project for CO_2 EOR (July 2015). The Uthmaniyah CO_2 EOR Project is a large-scale project, located in the Eastern Province of Saudi Arabia, whereby 0.8 Mt CO_2 captured from a natural gas processing plant is transported 70 km by pipeline for injection and storage into the Uthmaniyah Field, a development area which is part of the giant Ghawar field. The objectives of the project are to, assess the incremental oil recovery after water flooding, estimate the amount of storage of CO_2 and identify the risks, uncertainties and operational concerns (CSLF, 2013b). The project is also understood to be testing a range of CO_2 monitoring technologies. The project infrastructure, in addition to the pipeline, consists of 4 injection wells, 2 observation wells and 4 productions wells (MIT, 2015b).

4.7 Regulatory environment in GCC countries

CO_2 EOR activities are generally able to be regulated under legislation used to control oil and gas exploration and production. In all GCC countries, state owned enterprises dominate and have full concessions of all oil and gas production, and to a large extent, downstream refining and petrochemical sectors. State-owned operators are generally self-regulating and comply with the highest standards relating to risk management, health and safety (Al-Saleh YM, et. al., 2012). It is not expected that a lack of national regulation poses a key hurdle to the development of CO2 EOR projects in GCC countries. From a policy perspective, none of the members of the GCC has shown intention to introduce incentives, or penalties, to encourage the reduction of CO_2 from large industrial sources in the region (Luomi, M, 2014).

The inclusion of CCS as an approved technology as part of the UNFCCC Clean Development Mechanism has been strongly supported in the UNFCCC negotiations by most GCC states since the mid-2000s (Luomi, M, 2014). In 2010, CCS was made eligible within the Clean Development Mechanism (CDM), which would in essence provide a financial incentive to undertake CO_2 storage projects to generate carbon offsets that could be sold on the carbon market. However, with no additional legally binding climate commitments having been made by developed nations since the Kyoto Protocol climate agreement entered into force in 2005, the price for certified emission reductions (CERs) generated by registered CDM projects has plummeted from a peak of US$20 in 2008, to below US$1 in 2015. Therefore whereas having CCS included in the CDM has a symbolic value as the mitigation potential of the technology has been recognized, the CDM cannot currently be considered a viable route for co-financing any form of CO_2 storage project.

4.8 Outlook

The year 2015 has witnessed the initiation of the first large scale CO_2 EOR projects in the GCC region, in Saudi Arabia, which could be followed by further CO_2 EOR projects in the UAE in 2016. Beyond these projects, assuming they are implemented, further investment in CO_2 EOR will be dependent on whether oil prices reach levels that are sufficiently high, for example close to US$100, to offset the considerable capital and operational costs needed. In the near-team, towards 2020, there seem to be few incentives stemming from global climate policy, that can help co-finance the capture of CO_2 in the GCC region and therefore lower the costs of CO_2 EOR.

5 Case studies

To reflect how site-specific conditions might affect the economic feasibility of CO_2 EOR projects, two case studies, the North Sea and Middle East have been developed based on accurate contemporary cost data for CAPEX and OPEX for hypothetical production scenarios. The case studies have been developed using TNO's ECCO Tool (Loeve, D. et.al., 2013, Nøkleby, P.H., 2015). The ECCO Tool is a software program designed to evaluate quantitatively the post-tax economics of CCS projects for each of the various mutually dependent actors along the CCS value chain. The ECCO tool can be used for studying the economic feasibility of CCS projects to be evaluated by commercial companies under different external conditions and contractual constructions. The tool integrates cost engineering, transport and well/reservoir physics, planning including the impact of contracts and physics on the sizing and timing of capex and opex, and full post-tax economics.

The case studies were developed to shed light on two important research questions:

- What is the maximum CO_2 wellhead price for an economically feasible EOR project in the North Sea and Middle East?
- What is the effect of different parameters[11] on the CO_2 wellhead price?

The subsurface EOR module of the ECCO tool is used to estimate the CO_2 wellhead price (Reuters, 2014). In each case a discounted cash flow analysis is applied to calculate the NPV and the Internal Rate of Return (IRR) to determine the economic viability, and identify which parameters have the greatest effect on economic viability. The ECCO Tool also provides maximum price or 'gate fee', that a CO_2 EOR operator can pay for a tonne of CO_2 at the well-head for an economically viable project. Each case study includes a sensitivity analysis to determine how a number of key parameter affects the economic viability of the CO_2 EOR project. The economic viability is a specific minimum internal rate of return depending on the region of the operator.

5.1 Methodology

The following 2-step procedure is used to estimate the CO_2 wellhead price:

1. Based on a box model, normalized production and injection curves are derived (so-called type curves);
2. These type curves are used in the ECCO tool (a techno-economic evaluation tool) to derive the wellhead price, including a sensitivity analysis.

A quarter of a five-spot model injection and production pattern was used to create the so called type curves upon which the production and CO_2 storage performance can be assessed over the lifetime of the project. Figure 11 is a diagram of the five-spot production/injection pattern applied to the box model.

[11] The parameters include STOIIP, oil price, injection rate, CAPEX multiplier, OPEX multipliers and tax.

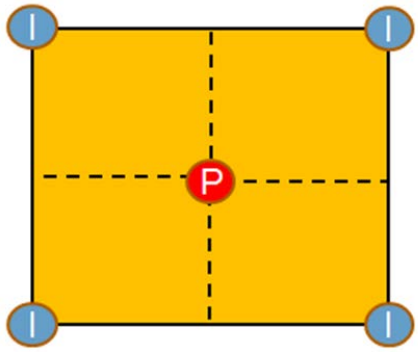


Figure 11: Five-spot injection/production pattern

The production scenario this box model field consists of three phases. Phase 1 is primary oil production by pressure depletion over a period of 4 years. Phase 2 is secondary production whereby the pressure is maintained by water injection for a period of 23 years. In phase 3 the EOR operations start, with an baseline scenario of 27 WAG (water alternating gas) cycles which consist of 208 days of CO_2 injection followed by 104 days of water injection. The modelling assumes CO_2 EOR operations will continue for a period of 30 years. A type curve of the cumulative production as a percentage of the hydrocarbon pore volume is presented in Figure 12. The results of the type curve are then carried over to the ECCO tool as the production data for the techno economic analysis.

The ECCO tool is then constrained by the target IRR (see below), which enables the retrieval of the maximum gate fee per tonne of CO_2 that can be paid in each respective scenario. A sensitivity analysis is calculated to assess the impact of individual cost components of the economic feasibility of each case study.

5.2 Data sources and limitations

To provide the most useful and representative overview of current oil production operations with potential CO_2 EOR applications in the three regions examined, determined actions were taken to interact with oil production operators in the respective areas. Furthermore, it was intended that three regional case studies would be developed which each reflect different regional geological conditions, and use cost data that is representative of the region. Unfortunately, due to political and confidentiality restraints, little primary information on regional specific field conditions and cost components could be ascertained for the GCC region and Russia.

Despite not having access to regional data, two hypothetical case studies, North Sea and the GCC region, have been devised using assumptions for reservoir characteristics which can be considered as representative for both Middle East and North Sea. An overview can be found in Table 15.

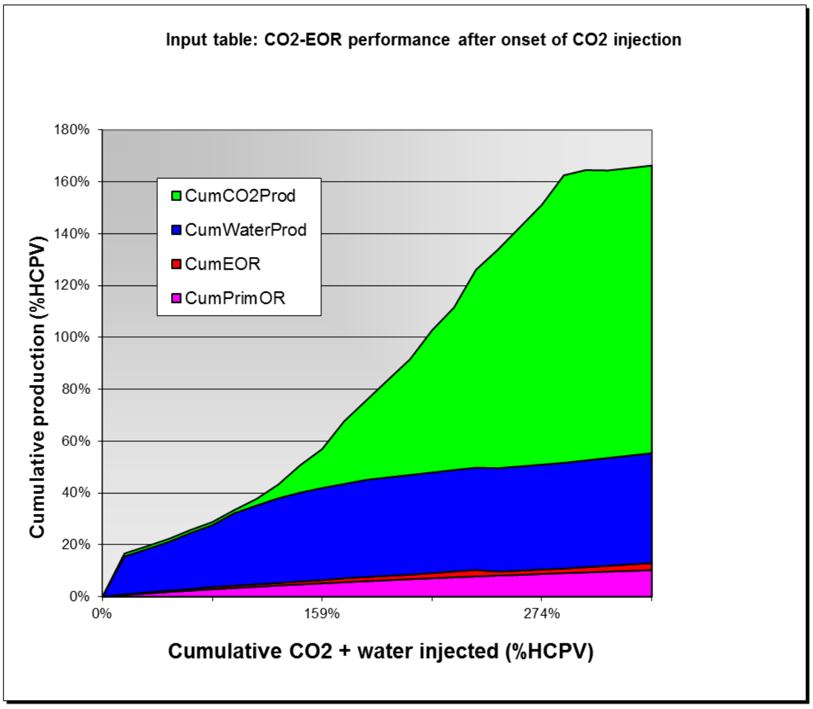


Figure 12: Type curve of cumulative production after CO_2 WAG injection . Where: CumCO2Prod is the cumulative CO_2 production, CumWaterProd is the cumulative water production CumEOR is the cumulative EOR production, CumPrimOR is the cumulative primary oil production and HCPV is the hydrocarbon pore volume.

Table 15: Input parameters for reservoir characteristics of the box model

Property	Value
Dimensions (L×B×H)	800 m x800 m x70 m
Porosity	0.09 (homogeneous)
Permeability (horizontal; vertical)	100 mDarcy;10 mDarcy (laterally homogenous)

CAPEX and OPEX data have been taken from work by ZEP (2011), which includes costs for CO_2 EOR operations both in onshore and offshore European settings. The case studies use the CAPEX and OPEX data applicable for offshore EOR operations for the North Sea case study, and data applicable for onshore EOR operations for the GCC region case study.

In addition to different cost data between the GCC region and North Sea case studies, different target internal rate of returns were applied (see section 5.1) for the North Sea (12%) to the GCC region (25%), to reflect the different market dynamics of the two regions. Furthermore, in the North Sea scenario a tax rate and royalties are included in the modelling, in the GCC region however the royalties and taxes are set to 0%. The 0% rate for tax and royalties in the GCC system reflects the fact that the vast majority of oil production is conducted by national oil companies (NOCs). Defining a standard UK tax rate is challenging due to the tiered level tax system, however the figures used in this modelling scenario could be representative of a maturing field which is applicable receive a level of tax relief to allow EOR to commence.

Table 16: Cost assumptions used.

Prices and indices	Unit	*North Sea*	*GCC region*
Crude oil sales price (constant during lifetime)	\$/bbl	100.00	100.00
Gas sales (wellhead) price (constant during lifetime)	€/sm^3	0.45	0.45
Capex multiplier	1	1.00	1.00
Fixed opex multiplier	1	1.00	1.00
Business economic data			
Discount rate	1/y	8.0%	8.0%
IRR (North Sea/Middle East)	1	12%	25.0%
Well and field-related costs			
Drilling & completion capex per well (onshore/offshore)	M€/well	15.00	7.5
Workover cost per well (opex)	M€/well	0.80	0.80
Average time between workovers for a well	Y	4	4
Well opex	M€/well/y	0.35	0.35
Operational costs			
Variable opex CO_2 injection	€/t	1.300	1.300
Variable opex produced oil	€/STm^3	35.000	35.000
Variable opex produced water	€/STm^3	1.000	1.000
Variable opex produced gas	€/sm^3	0.143	0.143
Variable opex re-produced CO_2	€/t	0.75	0.75
Fixed opex (ZEP)	M€/y	4.00	2.00
Cost of venting CO_2	€/t	0	0
Capital costs			
Initial Capex (ZEP) onshore	M€	27	27
Initial Capex (ZEP) offshore	M€	56	56
Field abandonment capex - fraction cum capex	1	12.0%	12.0%
Royalty and fiscal parameters			
Royalty rate as fraction of HC sales	1	13.5%	n/a
Tax rate	1	31.5%	n/a
Tax depreciation method		straight-line	n/a
Tax number of depreciation years	Y	11	n/a

5.3 Results: The North Sea Scenario

The base scenario in the North Sea provides a maximum CO_2 price at the well-head of €18/tonne, with a range between €1.9/tonne and €34/tonne. The sensitivity analysis, in line with existing literature, indicates that the prevailing oil price has an overwhelming effect on the maximum gate fee. Increasing the injection rate, from 5 Mt/yr in the base case to 9 Mt in the upside case also has a positive effect on the maximum gate fee. With a higher injection rate, the operation facilities (like compressor, injection wells) are more optimally utilized compared to a low injection rate which results in costs savings and allows a higher CO_2 price to be paid.

The results also show that the amount of STOIIP has an inverse effect on the maximum CO_2 gate fee. This is because the incremental EOR oil production is relatively smaller in larger fields compared to smaller ones. Because of the ratio CO_2/water injected and the EOR oil produced becomes less favorable for the same amount of CO_2/water injected (which is smaller number expressed in %HCPV, see type curve). So the revenue becomes higher mainly because primary oil production is higher, but the incremental EOR oil production is smaller and therefore the operator needs a lower CO_2 price at the wellhead in order to maintain the 12% IRR.

Table 17: Results of the North Sea case study

Variable	*Downside*	*Upside*	*Base case*	*Downside*	*Upside*	*Base Case*
OilPrice ($/bbl)	-2	-34	-18.	50.00	150.00	100.00
Injection rate (Mton/yr)	-1	-24	-18.	1.0	9.0	5.0
STOIIP (ST Mm3)	-21	-17	-18.	25	75	50
CapexMultiplier	-19	-20	-18.	0.50	1.50	1.00
FixedOpexMultiplier	-19	-20	-18.	0.50	1.50	1.00
Tax	-18	-14	-18.	20.00	40.00	30.00
Royalties	-18	-14	-18.	10.00	15.00	20.00

5.4 Results: The GCC Region Scenario

The base scenario in the GCC region provides a maximum CO_2 price at the wellhead of €21/tonne, with a range between €8.2/tonne and €48.1/tonne. Increase injection rate has the same impact as in the North Sea. Higher injection rates profits from the economy of scale and the oil operator is able to accept an higher CO_2 price at the wellhead. The lower CAPEX and OPEX of the onshore operations, and the exclusion of taxation and royalties on the additional incremental oil produced, allow higher CO_2 prices to be paid at the wellhead across the range. The higher required IRR at 25% reduces the difference in the CO_2 wellhead prices between the North Sea and GCC region.

Table 18: Results of the GCC Region case study

Variable	*Downside*	*Upside*	*Base Case*	*Downside*	*Upside*	*Base Case*
OilPrice ($/bbl)	-8	-48	-21	50.00	150.00	100.00
Injection rate (Mton/yr)	-9	-28	-21	1.0	9.0	5.0
STOIIP (ST Mm3)	-28	-20	-21	25	75	50
CapexMultiplier	-23	-19	-21	0.50	1.50	1.00
FixedOpexMultiplier	-22	-21	-21	0.50	1.50	1.00

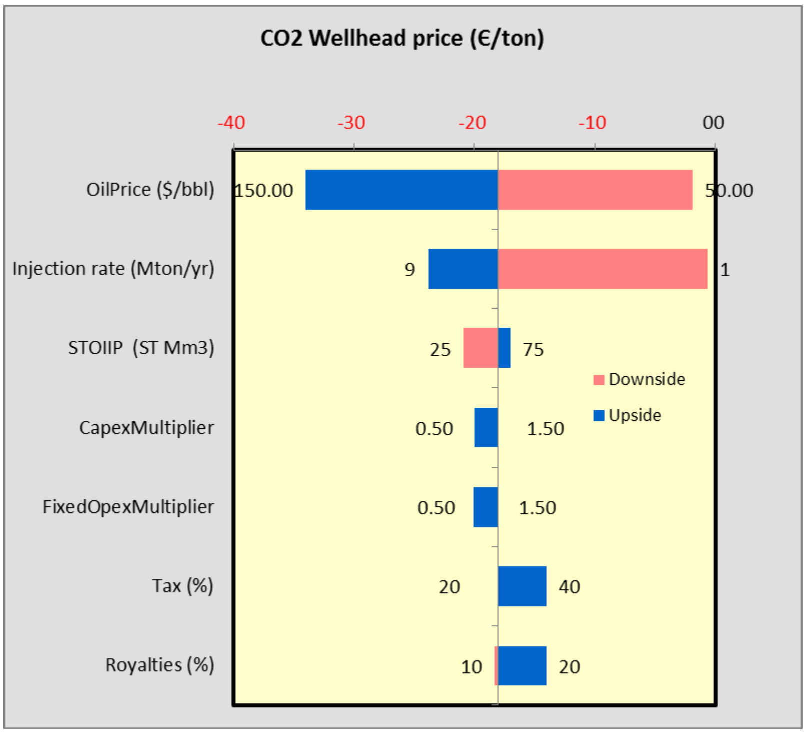


Figure 13: Sensitivity analysis of the North Sea case study

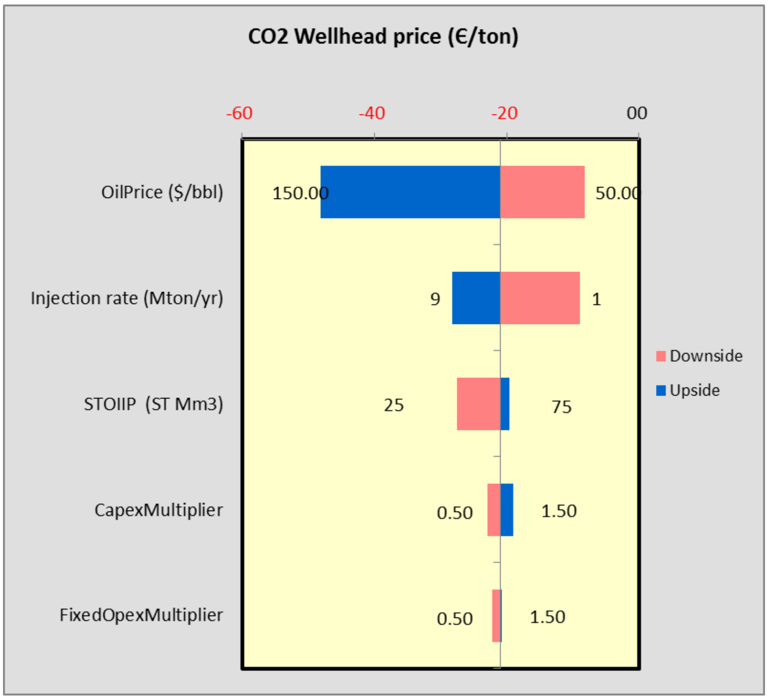


Figure 14: Sensitivity analysis of the GCC case study

6 Summary

6.1 Economic feasibility of EOR projects

Information was available regarding economic studies that have been completed in the North Sea. The assumptions that provide the basis for the economic evaluations vary from study to study, making it difficult to identify clear trends. However, the consensus is that under certain assumptions, specific projects can be beneficial from a cost perspective.

With regards to the maximum gate fee that an EOR operator can pay for CO_2 at the wellhead, case studies have been developed specifically for this project using the best available data combined with expert judgement for the assumptions used. Regional case studies were developed for the North Sea and the GCC region, and in all of the economic evaluations, the assumed oil price during the lifetime of the EOR project has the greatest overall effect on the NPV. The STOIIP, CAPEX, and OPEX have declining levels of impact on the NPV in the order given.

At a base case oil price of $100, maximum gate fee prices were €18/tonne and €21/tonne of CO_2 in the North Sea and GCC region case study, respectively. However at lower oil prices of $50, currently seen on world markets, this results in very low gate fee prices at €1.9 and €8.2 in the same regions, respectively. This result is consistent with the current challenges faced by U.S. CO_2 EOR operators, and thus based on this study, such low oil prices provide no economic basis for conducting CO_2 EOR in the North Sea. Even in the North Sea base case, additional revenue potentially in the form of EU ETS credits would likely be needed for a financially sound business case. In the GCC case study, the base case gate fee of €21/tonne could be sufficient to cover CO_2 delivery from some low-cost industrial or gas processing sources.

In terms of cost components, insufficient reliable data could be retrieved to be able to compare capital and operating costs between the North Sea, the GCC region and Russia. One economic evaluation was available in open literature regarding CO_2 EOR at a typical Middle Eastern oil field, however the cost data for each components were derived from international literature, and thus do not provide insights into regional difference. It can be assumed that capital costs for pipelines and wells for comparable projects in different regions may be similar as EPC services and equipment are generally provided by international firms.

6.2 Main hurdles to CO_2 EOR

In all three of the regions covered in this report there is considerable potential to implement CO_2 EOR projects. North Sea oil production has been in considerable decline for a number of years, and the GCC region and Russia appear to have a growing reliance on maturing oil fields and require new EOR technologies to support current production rates. Pilot CO_2 EOR projects in the GCC region have been successful, and a full scale project with an injection rate of 0.8 Mt has started in 2015. In the North Sea and Russia, however, the outlook for CO_2 EOR looks less promising.

Indeed, on reflection of the successful CO_2 EOR industry in the U.S., a number of clear hurdles to EOR are apparent in the three regions focused on in this report. These main barriers are presented below:

The North Sea

- Limited natural accumulations of CO_2
- High capital costs of offshore infrastructure
- High cost of CO_2 supply
- High taxation of oil revenue
- No specific fiscal incentive for CO_2 EOR operations
- Limited climate policy for CO_2 storage

GCC States

- Limited knowledge of natural CO_2 accumulations
- High cost of CO_2 supply (mainly gas power plants)
- State-owned oil and gas system limits commercial risk-taking for EOR
- No climate policy for CO_2 storage

Russia

- Limited knowledge of natural CO_2 accumulations
- Large distances between CO_2 sources and oil-producing areas
- High cost of CO_2 supply
- Taxation system not adjusted for mature fields with EOR operations
- No climate policy for CO_2 storage

6.3 Advancing CO_2 EOR through sub-sea technology

One of the key hurdles reported for North Sea CO_2 EOR projects, is the investment required for the modification of platform and installations, and the lost revenue during modification. By moving equipment required to separate and condition the CO_2 to the sea floor, modifications to the platform can be minimized. Recent development of subsea processing offers an increasing number of new concepts and opportunities. Subsea processing systems and equipment such as separators, heat exchangers and pumps have been qualified and are in use in a subsea environment today. In 2015, a subsea compressor will be installed at the Åsgard field on the Norwegian Continental Shelf (Nøkleby, P.H., 2015). A subsea compressor unit might be a key component in an arrangement for treating a CO_2-rich well stream.

By exploiting the opportunities the subsea process systems offer, it can be technically feasible to arrange a subsea-based well stream process train, which could provide separation of the high concentration CO_2 well stream and reinject the compressed or liquefied CO_2 to the reservoir or into a nearby aquifer. Alternatively, the compressed CO_2 could be pumped to an adjacent oil reservoir for CO_2 flooding. Although a complete stabilization of the oil phase at the seabed is not seen as commercially realistic, it is regarded as technically feasible for bulk separation of CO_2 at the sea floor by, for example, selective membranes or other separation concepts.

6.4 Regulatory and policy options to promote CO_2 EOR

In all regions, CO_2 EOR activities can be regulated under existing oil and gas regulation, and regulatory uncertainty is not assumed to constitute a barrier to the broader deployment of the technique. However, if the CO_2 EOR is combined with long-term storage, coupled with an incentive (i.e. carbon credits), additional CCS regulation certain jurisdictions could have a cost impact on CO_2 EOR projects combined with CO_2 storage.

With regards to policy, there are of course possible actions that the governments of regions could do to stimulate CO_2 EOR. Russia could adjust its fiscal policy towards oil and gas revenue, to reflect to higher costs of extracting oil from harder-to-recover oil fields which require additional investment in enhanced oil recovery techniques. For example in 2012, the UK government introduced tax allowances for operators investing in mature oil fields, which successfully managed to increase investment in exploration in the North Sea (Reuters, 2014).

The U.S. approach of providing tax relief to companies injecting CO_2 for EOR is not applicable to GCC States, given that all oil and gas production is either fully or partly state owned. Introducing a carbon tax to encourage the capture of CO_2 in Russia and GCC states does not seem a feasible option at present, as neither region have progressive climate policies.

In December at the United Nations Climate Change Conference, COP 21, an agreement was made by all 196 parties calling for zero net anthropogenic greenhouse gas emissions to be reached during the second half of the 21st century. Furthermore in the adopted version of the Paris Agreement, the parties will also "pursue efforts to" limit the temperature increase to 1.5 °C, which will require zero emissions sometime between 2030 and 2050. This agreement must transcend into additional policies to curb CO_2 emissions, which could provide some incentives for the broad deployment of CCS technologies, potentially combined with EOR.

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