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Caveat
While the authors consider that the data and opinions in this report are sound, all parties must rely on their own judgement and skill when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of oil markets, CCS technology, and CO2-EOR specifically. The available data and models on sources and sinks are extremely limited and the analysis is therefore based on purely hypothetical scenarios. Any maps, tables and graphs are provided for high-level illustrative purposes only; no detailed location-specific studies have been carried out and no oil company has provided detailed decision-making inputs. All models are limited by the quality and completeness of input assumptions. “Over-analysis” of site-specific results is strongly discouraged. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report.

The views and judgements expressed here are the opinions of the authors and do not reflect those of Scottish Enterprise or the stakeholders consulted during the course of the project.
FOREWORD

The injection of Carbon Dioxide (CO\textsubscript{2}) to improve oil recovery levels is not new – it was first suggested by the academic community in the late 1970s and is of course already a well established process onshore in the United States. To date CO\textsubscript{2} Enhanced Oil Recovery (EOR) has not yet been applied in the United Kingdom Continental Shelf (UKCS) North Sea for a number of reasons, but chief amongst these is a lack of reliable large scale supply of CO\textsubscript{2}. However, with progress in Carbon Capture & Storage (CCS) demonstration and eventual commercial deployment over the coming years, there is likely to be an increasing supply of CO\textsubscript{2} for wide scale deployment of CO\textsubscript{2}-EOR. CCS is now recognised by UN, G8, EU, UK and Scotland as a key technology for limiting CO\textsubscript{2} emissions from the power and industrial sectors and numerous studies have indicated that the rollout of CCS around the North Sea region could play a significant role in providing low cost, low carbon and secure energy for the UK and Europe.

Scottish Enterprise believes that the skills and facilities required to deliver CO\textsubscript{2}-EOR exist in Scotland and that CO\textsubscript{2}-EOR can act as a positive economic driver for the delivery of CCS projects. We therefore commissioned this study to:

• assess the potential for CO\textsubscript{2} enhanced oil recovery in the UKCS;
• highlight the impacts of CO\textsubscript{2}-EOR on both the development of CCS and the broader Scottish economy;
• discuss barriers to deployment; and
• suggest actions that could be taken to maximise the possible economic impacts for Scotland from CO\textsubscript{2}-EOR.

The recently published industry led Oil & Gas strategy also highlighted enhanced/increased oil recovery as a key priority for the future of the Oil and Gas industry with the need to improve recovery rates as well as highlighting the opportunity of CCS more generally as a key area for the oil & gas supply chain.

Recognition of the potential of CO\textsubscript{2}-EOR in the North Sea is increasing: earlier this year, the UK government published a Roadmap with a vision for CCS deployment in UK which recognised the role of CO\textsubscript{2}-EOR within this. Submissions to the UK government CCS commercialisation programme and EU New Entrants Reserve (NER300) programme also include proposals which include CO\textsubscript{2}-EOR as a key element.

We hope that this report clearly demonstrates the opportunity to use CO\textsubscript{2} to help increase oil and gas recovery and the associated economic benefits in terms of jobs, investment and taxation, although of course a number of issues need to be addressed in order to realise these opportunities.

The report makes a number of recommendations in order to influence and support the development of CO\textsubscript{2}-EOR. We welcome these recommendations and are considering in detail how we can take these forward. Overall we hope that the report will help to inform the ongoing discussion at various levels of government and we will discuss the findings of this report with a number of groups and organisations including the UK government and our Industry Leadership Groups for both Oil and Gas and Thermal Generation and Carbon Capture and Storage.

David Rennie
Director, Oil & Gas Thermal Generation and CCS
Scottish Enterprise
Executive Summary

Recognising that the combination of Carbon Capture and Storage (CCS) with CO₂-Enhanced Oil Recovery (EOR) could bring positive impacts to the Scottish economy, Scottish Enterprise commissioned a team led by Element Energy and including Heriot Watt University and Dundas Consultants to examine the issues related to CO₂-EOR and quantify the economic impacts in Scotland.

Nineteen oilfields in the UK Continental Shelf (UKCS) may be technically attractive ‘anchor’ projects for CO₂-EOR. These have a combined potential incremental oil recovery of 2.5 billion barrels of oil, associated with storage in the region ca. 0.8 Gt CO₂. The uncertainty in these figures is at least +/- 50%. A cluster of large CO₂-EOR projects could contribute ca. 15% of UKCS oil production in 2030. Scenario modelling suggests that the highest rates of EOR deployment in the UKCS would bring £2.7 billion in Gross Value Added (GVA) to the Scottish economy, relative to a scenario where the oilfields are decommissioned. Supply chain opportunities for Scottish businesses would result in 5,300 person-years of employment (new or maintained) for projects initiated by the early 2030s.

Effective engagement of the Scottish supply chain with UKCS CO₂-EOR projects could double these GVA and employment figures. Domestic experience can then be leveraged to other potential CO₂-EOR markets in other sectors of the North Sea and internationally.

Financial modelling reveals that for several fields CO₂-EOR projects yield a positive Net Present Value (NPV) at current oil prices. Therefore EOR could be a driver towards the key outcome for the UK Government’s CCS commercialization programme to make power generation with CCS cost competitive with other large low carbon power generation technologies in the 2020s. The financial modelling identifies that the principal beneficiaries of a CO₂-EOR cluster in the North Sea would be the Governments of the UK, Norway and Denmark, as a result of the high taxes applied to the offshore industry. These tax receipts could in principle be offset against public subsidies for CCS, i.e. CO₂-EOR could be an enabler of CCS, although tax returns are highly sensitive to oil prices, reservoir performance, and number and choice of projects.

The commercial case for conventional oil companies to invest in CO₂-EOR is fragile. Since the collapse of the original BP DF1 Miller proposal, no UKCS oil operator has indicated strong, clear commitments to developing CO₂-EOR. This study has found numerous barriers and deeply-held scepticism as to the early commercial uptake of CO₂-EOR in the North Sea from a wide range of public and private stakeholders. CO₂-EOR has never before been carried out in the North Sea. Oil companies will factor in a range of uncertainties and first-of-a-kind risks.

Some stakeholders believe that commercial CO₂-EOR projects would only follow on the back of successful CCS demonstration, if oil prices remain high and if there is a reliable CO₂ supply directed towards a suitable oilfield. A wait-and-see approach to CO₂-EOR in the UKCS could however lead to missed opportunities for the UKCS, as most of the UK’s relevant oilfields are predicted to be decommissioned by the 2030s.

There are two proposals including CO₂-EOR in the North Sea in the EU’s New Entrant Reserve (NER300) programme for CCS demonstration. One of these (2Co Energy) has submitted a proposal for the use of CO₂-EOR in the UKCS in DECC’s CCS commercialization.

Even if an initial North Sea CO₂-EOR project is demonstrated in the 2010s, multiple barriers could jeopardise commercial viability of subsequent projects. These include weak incentives and uncertainties around CO₂ storage liabilities, oil price, oil recovery levels,
infrastructure requirements and costs, CO₂ supply, CO₂ storage capacity, and future regulation. High oil price is a positive driver of CO₂-EOR, but even at high oil prices, alternative investment opportunities may provide lower complexity and better risk-reward profiles for energy companies.

The uptake of CO₂-EOR in the 2020s in the North Sea will depend on many factors, including the levels of sustained policy support for CCS, oil prices, and stakeholder support. Since some of these drivers are outside of Scottish Enterprise’s control, a flexible strategy designed to influence key stakeholders is appropriate. The full report details five actions that Scottish Enterprise could take if it wishes to support CO₂-EOR. These are summarised below.

1. Support a “Champion” that can advocate a coherent view of CO₂-EOR requirements and opportunities to policymakers and other stakeholders.
2. Sponsor meetings, workshops and personnel exchanges to facilitate knowledge sharing between UKCS oilfield owners, engineers, policymakers, regulators and participants in ongoing CO₂ injection projects worldwide.
3. Leverage existing connections with the oil and gas supply chains to raise awareness of the supply chain opportunities for CO₂-EOR projects. This could include encouraging suppliers to participate in engineering studies for CO₂-EOR and/or providing funding for oil and gas industry suppliers to attend CCS networking events.
4. Support preparatory work for CO₂-EOR cluster development through a Task Force focussed on the needs of the relevant oil companies.
5. Facilitate continued co-operation, stability and consistency between the Scottish and UK Governments across the full suite of energy and climate policies relevant to CO₂-EOR deployment, especially in the event of constitutional change.

If adopted, these recommendations will maximise the CO₂-EOR opportunity, and position Scottish businesses to take full advantage of the economic benefits of CO₂-EOR.
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1 Introduction

Oil from the North Sea has been produced for more than four decades. Typical production is 50% of the oil in place below ground, although this varies from 10% through to 70%, depending on the particular field characteristics and production strategy.

The injection of CO\textsubscript{2} to improve oil recovery in the North Sea was first suggested by the academic community in the late 1970s. The process is well established onshore in the USA where CO\textsubscript{2}-EOR projects have been in operation for thirty years. Improved production can range from <5% to >20% of the original oil in place. To date, CO\textsubscript{2} EOR has not yet been applied in the North Sea, for a range of reasons but principally a lack of reliable large Mt/yr scale supplies of CO\textsubscript{2}.

The deployment of Carbon Capture and Storage (CCS) has been widely recognised as critical in the supply of the requisite amounts of CO\textsubscript{2}. CCS has been recognised by the UN, G8, EU, UK and Scotland as a key technology for limiting CO\textsubscript{2} emissions to atmosphere from the power and industrial sectors. Globally, CCS could provide up to 20% of CO\textsubscript{2} reduction in 2050 required to stabilise CO\textsubscript{2} emissions at 450 ppm, as part of a mix of technologies. If adopted this would imply a future cumulative global market valued in the trillions of dollars\textsuperscript{1}. Numerous studies indicate that roll out of CCS around the North Sea region could play a significant role in providing low cost, low carbon and secure energy for the UK and Europe\textsuperscript{2}. CCS can be implemented through a range of technical solutions, including different power and industrial sources, different capture technologies, a range of ship or pipeline transport solutions, and range of storage types including aquifer formations, depleted hydrocarbon fields and partially depleted oilfields when used in conjunction with CO\textsubscript{2}-enhanced oil recovery.

Earlier this year, the UK Department for Energy and Climate Change (DECC) published a Roadmap with a vision for CCS deployment in the UK. The vision explicitly includes capture from one or more clusters of power and industrial CO\textsubscript{2} sources with shared transport infrastructure for CO\textsubscript{2} storage in depleted hydrocarbon fields, aquifers and the combination of CO\textsubscript{2} storage in partially depleted oilfields with enhanced oil recovery (see Figure 1).

\textsuperscript{1} IEA CCS Roadmap (2009)
\textsuperscript{2} See for example Element Energy et al. (2010) One North Sea
DECC is currently evaluating submissions to its CCS commercialisation programme described in the Roadmap. The programme offers up to £1bn of capital support for CCS projects with ongoing revenue support through a Contract-for-Difference Feed-in Tariff for decarbonised electricity\(^4\). Based on public announcements, at least one bidder has identified CO\(_2\)-enhanced oil recovery in the UK sector of the North Sea as a key element in its proposal. If developed, this would imply that CO\(_2\)-EOR could begin operation in the UKCS in the period 2016-2020. Elsewhere in the North Sea, a proposal for CO\(_2\)-EOR in the Danish sector is being considered as part of the EU’s NER300 programme to support CCS demonstration.

Progress with CCS demonstration and eventual commercial deployment over the coming years should result in a significant supply of CO\(_2\) for wide scale deployment of CO\(_2\)-EOR.

Studies since 2000 have indicated that several billion barrels of additional oil could be recovered through CO\(_2\)-EOR in the North Sea region, providing CO\(_2\) storage capacity and potentially improving the economics of CCS roll-out. However there is currently limited public expression of interest from existing owners of North Sea oilfields and their service providers in developing CO\(_2\)-EOR projects.

Scottish Enterprise believes that the skills and facilities required to deliver CO\(_2\)-EOR exist in Scotland and that CO\(_2\)-EOR can act as a positive economic driver for the delivery CCS projects. Following competitive tender, in March 2012, Scottish Enterprise commissioned a team led by Element Energy with Dundas Consultants and Heriot Watt University to assess the potential for CO\(_2\)-enhanced oil recovery for Scotland, the impacts of CO\(_2\)-EOR on CCS projects and the broader Scottish economy, and actions that Scottish Enterprise could take to maximise the positive economic impacts from Scotland from CO\(_2\)-EOR.

\(^3\) DECC CCS Roadmap

\(^4\) These incentives are complemented by wider reforms of the GB electricity market including the introduction of a carbon price floor, capacity payment mechanism and emissions performance standards.
The project has produced a number of interim deliverables. These deliverables have been reviewed by Scottish Enterprise and with key stakeholders and accepted. The draft findings of the study were presented at the All Energy 2012 conference held recently in Aberdeen and at the Thermal generation & CCS Industry Leadership Group in Glasgow.

This report represents the final deliverable from the Element Energy-led study and is structured as follows:

Chapter Two describes the technical potential for CO₂-EOR in the North Sea.

Chapter Three introduces barriers to the growth of CO₂-EOR.

Chapter Four describes possible scenarios for CO₂-EOR development.

Chapter Five identifies Scottish supply chain opportunities.

Chapter Six describes the results of economic modelling CO₂-EOR and its economic and employment impacts.

Chapter Seven describes the potential actions to maximise the opportunity for Scotland.

This report is accompanied by a technical appendix which provides further detail on:

- the theoretical concepts around CO₂-EOR
- the database of CO₂-EOR potential
- the modelling of field economics and economic impacts for Scotland for different scenarios of CO₂ EOR uptake
2 Technical potential for CO$_2$-EOR

Enhanced oil recovery (EOR) methods are usually employed after other, more predictable conventional secondary recovery methods, such as pressure depletion and water-flooding, have been exhausted (Figure 2).^5

![Figure 2: Oil recovery processes](image)

As illustrated in Figure 3, tertiary EOR methods can be classified under four categories, which are gas injection, thermal, chemical and other methods.

Many reservoirs in the North Sea appear technically suitable for gas injection and several have in fact tested very positive for gas injection^6 (see Appendix). However, in addition to gas EOR, polymer flooding and low-salinity water injection could also be competitive EOR methods in the North Sea^7.

![Figure 3: Primary, secondary and tertiary recovery processes](image)

CO$_2$-EOR is one of several gas injection technologies that could be used to enhance oil production. Globally there are nearly 170 CO$_2$-EOR projects currently in operation. CO$_2$-

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^5 For a review, see for example, Tzimas et al. 2005 Enhanced Oil Recovery Using CO$_2$ in the European Energy System
^6 For further info see Awan, Teigland and Kleppe, SPE Reservoir Evaluation and Engineering (2008) 11 (3) 497-512
^7 Findings from DECC Pilot workstream on 23rd May 2012
^8 Adapted from Bai, B., EOR Performance and Modelling, Technology Focus, 2012
EOR can be classified into two categories, which are miscible and immiscible CO₂-EOR. The DECC Pilot Task Force has made provisional order-of-magnitude estimates of total UKCS recovery from different tertiary recovery approaches (see Table 1). Miscible CO₂ ranks highest.

Table 1: Estimated recovery from different EOR processes applied to North Sea oil and gas production (draft results identified by the DECC Pilot workstream on 23rd May 2012).

<table>
<thead>
<tr>
<th>Tertiary technology</th>
<th>EOR Process</th>
<th>Estimated Recovery (MMSTB or Million Stock Tank Barrels of Oil)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Injection</td>
<td>Miscible CO₂</td>
<td>5,700</td>
</tr>
<tr>
<td>Gas Injection</td>
<td>Miscible hydrocarbon flood</td>
<td>5,400</td>
</tr>
<tr>
<td>Gas Injection</td>
<td>Nitrogen and Flue Gas</td>
<td>500</td>
</tr>
<tr>
<td>Chemical</td>
<td>Surfactant/Polymer</td>
<td>4,800</td>
</tr>
<tr>
<td>Chemical</td>
<td>Colloid Dispersal Gel (CDG)</td>
<td>3,100</td>
</tr>
<tr>
<td>Chemical</td>
<td>Brightwater⁹</td>
<td>3,100</td>
</tr>
<tr>
<td>Chemical</td>
<td>Polymer</td>
<td>2,100</td>
</tr>
<tr>
<td>Thermal</td>
<td>In-situ Combustion</td>
<td>700</td>
</tr>
<tr>
<td>Thermal</td>
<td>Steam drive</td>
<td>600</td>
</tr>
<tr>
<td>Other</td>
<td>Low salinity water flood¹⁰</td>
<td>2,000</td>
</tr>
</tbody>
</table>

2.1 CO₂-EOR experience in North America

CO₂-EOR has been practised since the 1970s in North America as a means of extending onshore field lifetime after secondary production techniques (such as water flooding) have been exhausted.

Technical, HSE and regulatory standards, business models, and supply chains for CO₂-EOR in North America are therefore well established, reducing performance and regulatory risks. There is more than 3,000 miles of CO₂ pipeline network infrastructure, reducing CO₂ supply/demand risks. The experience provides a wealth of insights into how CCS with CO₂-EOR could be developed, although until very recently no attention was paid to permanently storing CO₂ underground as part of the EOR process.

Currently most of the CO₂ for North American fields mostly derives from natural sources and none currently derives from CO₂ captured at a fossil power station. All current CO₂ injection is onshore, with onshore CO₂ pipelines passing through sparsely populated and relatively flat terrains. Current peak CO₂ injection rates are in the region of 50 Mt/yr with

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⁹ http://www.nalco.com/applications/brightwater-technology.htm
¹⁰ http://www.uwyo.edu/eori/files/eorctab_jan09/buckley_mechanisms.pdf
incremental oil production approach 90 million barrels/year, although there are huge variations between individual fields in terms of performance\textsuperscript{11}. Even after CO\textsubscript{2} flooding, some oil still remains in reservoirs.

The underlying economic drivers for CO\textsubscript{2}-EOR in North America are driven by lower costs onshore (cheaper drilling costs, no need for offshore platforms), and a combination of tax incentives at State and Federal level since the 1970s\textsuperscript{12}. Finally, in contrast to the North Sea, where sea water will always be freely available, the economic potential for secondary recovery through water injection may be more limited in some onshore regions.

More recently, the use of CO\textsubscript{2} captured and transported from power and industrial sources to EOR fields has attracted substantial attention in North America, although the challenges in deployment should not be underestimated. Box A describes the North Dakota – Weyburn oilfield.

\begin{center}
\textbf{Case Study: The Weyburn-Midale Project}
\end{center}

As an example of a successful CO\textsubscript{2}-EOR project, the Weyburn-Midale project demonstrates full chain capture from an industrial source transported for EOR and permanent storage with extensive monitoring.

Following an initial test project in the 1990s, the project now involves capturing and compressing 3-5 MtCO\textsubscript{2}/yr from a gasification plant in North Dakota, transferring it across the US-Canada border by pipeline for injection in onshore oilfields in the Saskatchewan province, enhancing oil production by ca. 65%. The project employs may tens of CO\textsubscript{2} injector wells.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{Figure4.png}
\caption{Weyburn Oil Production 1955-2010\textsuperscript{1}}
\end{figure}

The project is a public-private partnership, including industry partners such as Apache Canada, Aramco Services, Cenovus Energy, Chevron, Dakota Gasification, OMV, Nexen, SaskPower, Schlumberger, Shell Canada and, government partners such as Alberta Innovates, IEA GHG R&D Programme, Natural Resources Canada, RITE, Saskatchewan Ministry of Energy and Resources, United States Department of Energy.

For more details see \url{http://www.ptrc.ca/weyburn_overview.php}

\textsuperscript{11} NETL, Carbon Dioxide Enhanced Oil Recovery, 2010
\textsuperscript{12} National Enhanced Oil Recovery Initiative (2012) Carbon dioxide enhanced oil recovery: A Critical domestic energy, economic, and environmental opportunity.
2.2 Offshore CO\textsubscript{2} Injection

Despite the absence of specific offshore CO\textsubscript{2}-EOR projects in the North Sea, there is significant UK and global experience relevant to offshore CO\textsubscript{2} injection:

- Since 1997, Statoil has been separating produced CO\textsubscript{2}/natural gas mixtures offshore and re-injecting CO\textsubscript{2} using deviated/horizontal wells into the Utsira aquifer in the North Sea at the Sleipner facility for long term storage.
- Further north, at Snøhvit, separated CO\textsubscript{2} is transported by offshore pipeline from the coast for injection using vertical wells into an aquifer.
- Off the coast of Brazil, Petrobras and partners are exploring a range of concepts for re-injection of produced CO\textsubscript{2} from the giant Lula oilfield and gasfields to boost production and lower the environmental impact. Brazilian environmental regulators have instructed Petrobras that the produced CO\textsubscript{2} must not be released to the atmosphere. As well as EOR, aquifer storage may also be explored. The water depths for the Lula field are in excess of 2km, so offshore floating production, storage and offloading (FPSO) vessels are used for separating and reinjecting the CO\textsubscript{2}. The reservoir itself is 5 km deep.
- There are hundreds of brine injection wells in the North Sea, and tens of wells for natural gas injection.

In terms of the reservoirs themselves, existing North Sea field owners and operators have an excellent understanding of their behaviour and production history under conventional conditions. The oil reservoirs are typically 1-4 km below ground, so that CO\textsubscript{2}/brine/oil flow models for oilfields which are onshore remain relevant for offshore configurations, even if the surface infrastructure requirements are substantially different.

2.3 Visions for CO\textsubscript{2}-EOR in the North Sea

Between 1999 and 2002, Sintef and the CENS project established an initial vision for an EOR system connecting multiple CO\textsubscript{2} sources with EOR fields in the UK, Norwegian and Danish sectors of the North Sea\textsuperscript{13}. Since then, multiple studies of CO\textsubscript{2}-EOR techno-economic potential have repeatedly confirmed intrinsically positive economics for a North Sea EOR system at high oil prices\textsuperscript{14}. These include UK, Norwegian, and Europe-wide analysis.

2.4 A database of candidate North Sea EOR fields

Heriot Watt’s in-house database of UK North Sea oilfields containing geological and other data appropriate for CO\textsubscript{2}-EOR screening was supplemented with similar data for oilfields in the Norwegian and Danish sectors of the North Sea. The database records field name, current operator, current equity distribution, quadrant/block, latitude and longitude of centroid, water depth, historical production start, close of production without EOR, final facilities abandonment, incremental oil produced under CO\textsubscript{2}-EOR, CO\textsubscript{2} storage potential under EOR conditions. The database (provided to Scottish Enterprise in Excel 2010 format) was prepared from standard published sources and online information.

\textsuperscript{13} www.co2.no/download.asp?DAFID=46&DAAlD=5

In terms of assessment methodology, the database records two “rule-of-thumb” approaches to estimating the theoretical incremental oil production from CO₂-EOR. If the standard approach of 10% STOOIP (Stock tank original oil in place, which is the total hydrocarbon content in an oil field) is considered, the total incremental oil production is 6,800 million barrels in the UK, Norwegian, and Danish fields in the database. This data is shown in Table 2.

However, the theoretical incremental oil production and CO₂ storage capacity for any given field has an uncertainty of at least ± 50%.

Table 2: Candidate EOR fields database in the North Sea (fields sorted by country then alphabetically).

<table>
<thead>
<tr>
<th>Country</th>
<th>Field Name</th>
<th>Incremental oil recovered Million barrels</th>
<th>Incremental CO₂ stored during EOR (MtCO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK</td>
<td>ALBA</td>
<td>119</td>
<td>39</td>
</tr>
<tr>
<td>UK</td>
<td>AUK</td>
<td>53</td>
<td>11</td>
</tr>
<tr>
<td>UK</td>
<td>BERYL</td>
<td>232</td>
<td>82</td>
</tr>
<tr>
<td>UK</td>
<td>BRAE</td>
<td>104</td>
<td>34</td>
</tr>
<tr>
<td>UK</td>
<td>BRENT</td>
<td>502</td>
<td>154</td>
</tr>
<tr>
<td>UK</td>
<td>BUZZARD</td>
<td>108</td>
<td>31</td>
</tr>
<tr>
<td>UK</td>
<td>CLAYMORE</td>
<td>144</td>
<td>46</td>
</tr>
<tr>
<td>UK</td>
<td>CLYDE</td>
<td>41</td>
<td>21</td>
</tr>
<tr>
<td>UK</td>
<td>CORMORANT</td>
<td>157</td>
<td>45</td>
</tr>
<tr>
<td>UK</td>
<td>DUNLIN</td>
<td>83</td>
<td>24</td>
</tr>
<tr>
<td>UK</td>
<td>FORTIES</td>
<td>420</td>
<td>80</td>
</tr>
<tr>
<td>UK</td>
<td>FULMAR</td>
<td>82</td>
<td>81</td>
</tr>
<tr>
<td>UK</td>
<td>JANICE</td>
<td>129</td>
<td>87</td>
</tr>
<tr>
<td>UK</td>
<td>MILLER</td>
<td>75</td>
<td>25</td>
</tr>
<tr>
<td>UK</td>
<td>NELSON</td>
<td>79</td>
<td>26</td>
</tr>
<tr>
<td>UK</td>
<td>NINIAN</td>
<td>292</td>
<td>94</td>
</tr>
<tr>
<td>UK</td>
<td>PIPER</td>
<td>140</td>
<td>20</td>
</tr>
<tr>
<td>UK</td>
<td>SCOTT</td>
<td>95</td>
<td>29</td>
</tr>
<tr>
<td>UK</td>
<td>TEAL</td>
<td>82</td>
<td>55</td>
</tr>
<tr>
<td>UK</td>
<td>THISTLE</td>
<td>82</td>
<td>22</td>
</tr>
<tr>
<td>UK/NO</td>
<td>MURCHISON</td>
<td>79</td>
<td>25</td>
</tr>
<tr>
<td>UK/NO</td>
<td>STATFJORD</td>
<td>635</td>
<td>236</td>
</tr>
<tr>
<td>NO</td>
<td>EKOFSK</td>
<td>710</td>
<td>221</td>
</tr>
<tr>
<td>NO</td>
<td>ELDFISK</td>
<td>210</td>
<td>36</td>
</tr>
<tr>
<td>NO</td>
<td>GULLFAKS</td>
<td>575</td>
<td>133</td>
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<td>NO</td>
<td>SNORRE</td>
<td>342</td>
<td>82</td>
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<tr>
<td>NO</td>
<td>TORDIS</td>
<td>94</td>
<td>22</td>
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<tr>
<td>NO</td>
<td>TROLL</td>
<td>393</td>
<td>90</td>
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<tr>
<td>NO</td>
<td>ULA</td>
<td>145</td>
<td>30</td>
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<tr>
<td>NO</td>
<td>VALHALL</td>
<td>229</td>
<td>51</td>
</tr>
<tr>
<td>NO</td>
<td>VIGDIS</td>
<td>92</td>
<td>37</td>
</tr>
<tr>
<td>DK</td>
<td>DAN</td>
<td>240</td>
<td>57</td>
</tr>
<tr>
<td>DK</td>
<td>HALFDAN</td>
<td>150</td>
<td>52</td>
</tr>
</tbody>
</table>

* Fields coloured in red may have known challenges with EOR implementation
Considering the database, there would be significant implementation challenges to CO$_2$-EOR at Statfjord and Brent, as these fields are depressurised, and the Miller field has been already decommissioned. Removal of the Miller, Brent and Statfjord fields reduces the overall technical potential in the database from 6,800 million barrels to 5,600 million barrels. Of the remaining fields, the three largest EOR candidates are Ekofisk and Gullfaks in the Norwegian sector and Forties in the UK sector.

Assuming 0.3t CO$_2$ stored per barrel of oil produced, the combined CO$_2$ storage capacity for the oilfields in the database would be approximately 2.1 GtCO$_2$, which would satisfy the storage requirement for 10 GW of coal power for 40 years (assuming a load factor of 75%). The overall CO$_2$ storage potential in oilfields represents only ca. 1% of the theoretical storage potential in the North Sea (ca. 100-300 Gt identified in the FP7 GeoCapacities project), most of the remainder lying in saline aquifer formations.

The realistic technical potential identified in this study for CO$_2$-EOR in the UKCS is an incremental ca. 2.4 billion barrels of oil, in ca. 19 anchor oilfields, with an additional ca. 3 billion barrels in ca. 11 anchor oilfields in the Norwegian and Danish sectors. Note that significant additional capacity may be available in other smaller fields (not listed in the Heriot-Watt database).

![Figure 5: Incremental oil potential of the candidate oil fields](image)

### 2.5 Technical uncertainties for CO$_2$-EOR

There are fundamental uncertainties around reservoir performance under CO$_2$-EOR conditions, and infrastructure required to deliver optimum performance. The oil and gas industry are experienced at managing these uncertainties at the levels of individual wells, platforms, fields and through careful management of portfolios of oilfields.

Some engineering and cost uncertainties were investigated through the 2008 SCCS-led study "CO$_2$ Storage around Scotland" and more recently through the publication of FEED
(Front end engineering design) studies for the Longannet-Goldeneye and the Kingsnorth-Hewett CCS projects.

In general, two interdependent uncertainties facing generic studies such as this are CO\textsubscript{2} and oil profiles over time, and the well configuration required to deliver these.

In quantitative terms, the reservoir uncertainties can be described as (i) the amount of additional oil recoverable (high quality reservoir models and data are required to narrow down uncertainties here); and (ii) the amount of CO\textsubscript{2} required to produce incremental oil and the amount of CO\textsubscript{2} that could be stored permanently.

Another unknown is the well infrastructure required for operation of the project. This could involve new CO\textsubscript{2} injection wells, new water injection wells, and new hydrocarbon production wells. However it is more likely that some of the existing wells could be re-used. This may involve some relining to make the wells CO\textsubscript{2}-resistant. In some cases old wells will need to be plugged and abandoned in a manner that allows long-term resistance to CO\textsubscript{2}.

The well design could be simple vertical wells or more complex wells such as deviated wells, horizontal wells or multilateral wells. The complex wells are more expensive but could provide higher performance for some reservoir types. The flow rates in wells could be as low as 0.1 Mt/yr/well up to a maximum of 4 Mt/yr/well. Flow rates in wells may change over time, e.g. as a function of pressure changes. Whereas onshore EOR injections can have hundreds of relatively cheap vertical producer wells, water injection wells and CO\textsubscript{2} injector wells, offshore experience for primary and secondary production suggests that fewer wells could be used.

These uncertainties can be narrowed (but not eliminated) through detailed reservoir simulation and FEED-level engineering using high quality data on the reservoirs and existing well and platform infrastructure available. In addition to these, other unknowns include the NPV and the risks of alternative options.

2.6 Critical assessment of data and assumptions

The North Sea presents novel technical challenges that challenge the relevance of “rules-of-thumb” developed in Texas for screening for CO\textsubscript{2}-EOR performance. The differences between the North Sea and Permian Basin geology (the location of the majority of the world’s CO\textsubscript{2}-EOR projects) are well understood by oil companies, engineering firms and CO\textsubscript{2}-EOR developers.

As well as being offshore, North Sea oilfields are found in deep sandstones with typically more fault blocks, steeply dipping beds, sweet oil with higher API, high permeability. In contrast many of the Permian Basin EOR projects (all onshore) target low API (i.e. heavier) oil in shallower horizontal, low permeability carbonates with limited faulting. Partly as a result of these differences, some stakeholders are nervous about the likely performance of CO\textsubscript{2}-EOR projects.

These differences pose a challenge to screening reservoirs for CO\textsubscript{2}-EOR relevance, but they do not imply that performance will necessarily be lower (or higher), although obviously the costs will be different as onshore projects are considerably cheaper than offshore projects.

As projects advance through stage gates, rules-of-thumb for basin-level screening are replaced with detailed numerical and engineering models based on high quality data. The costs for these studies can run into millions of pounds. However not all organisations will
have access to the data, models and know-how to understand EOR performance, which can lead to a reluctance to embrace the technology.

By way of comparison, despite these potentially more complex conditions, there is considerable success with secondary recovery in the North Sea. Of greater relevance, an example is the success of the miscible gas injection project at the Magnus field, in a faulted, tilted, sandstone reservoir with large well spacing and high permeability.

There are not many North Sea field-specific CO\textsubscript{2}-EOR techno-economic studies in the public domain that use high quality reservoir and cost data and models. Publicly available data are limited in reliability; not all data are available for all fields and “average” data may provide a distorted view of actual reservoir properties. Many studies have adopted screening criteria that may in fact be much less relevant in a North Sea context than in Texas (for the reasons highlighted in the Appendix). Therefore the number of fields, incremental oil production and storage capacities identified in the database may be significantly over-estimated or under-estimated.

Considering the reasons above, all stakeholders would benefit from a detailed, site-specific, up-to-date and widely available engineering study on the optimum configuration and performance for CO\textsubscript{2}-EOR projects and clusters (i.e. well design, well numbers, CO\textsubscript{2}/oil/water flows, CO\textsubscript{2} recycling). To narrow uncertainties over performance and costs, this engineering study should include both reservoir modelling, facilities engineering, and life-cycle environmental impact compared with alternatives.

The engineering solutions to adapt existing infrastructure (primarily wells and platforms), or to manage constant or growing streams of “fresh” captured CO\textsubscript{2} over time within an EOR context have not been well described and for maximum value, the engineering study should consider how CO\textsubscript{2} flows over time can be managed. This should lead to robust scenarios for the growth of a cluster involving multiple EOR fields.

By way of comparison, many stakeholders have found the recent FEED studies published by DECC for the Goldeneye and Hewett fields useful. Publicly available FEED studies ground expectations of equipment needs and costs, and eliminate information asymmetries that makes it difficult to build trust across parties within the CCS value chain. They help the supply chain identify the nature and scale of opportunities. However these information benefits come at a price. Shell’s FEED study for storage in Goldeneye required 77,000 person hours and cost £13m for the Longannet-Goldeneye project (out of a total FEED spend of nearly £40m before the competition was abandoned). The engineers involved had access to Shell’s very high quality reservoir data and models. It should be noted that FEED studies can become out-of-date within a few years, as project requirements or market prices change over time.\textsuperscript{15}

Smaller oil companies may find high opportunity costs for the internal resources required to develop a CO\textsubscript{2}-EOR project (cf. large companies like Shell), particularly for the power and capture components and interfaces.

2.7 Wider CO\textsubscript{2} storage capacity in the North Sea

The forthcoming ETI-sponsored UK Storage Appraisal Project provides the first comprehensive, transparent, and auditable assessment of UK offshore storage potential. It excludes CO\textsubscript{2}-EOR however.

\textsuperscript{15} DECC’s CCS commercialisation programme includes the potential for public subsidy of FEED studies. It is considered unlikely that an oil company would unilaterally pay for and then publish this information. This is partly because it could affect asset values substantially.
The study locates and identifies the capacities, risks, and economics for nearly 600 storage locations in the UK Continental Shelf. The combined theoretical CO\textsubscript{2} storage capacity from all depleted fields and aquifers is estimated at ca. 78 Gt, well in excess of UK needs under all foreseeable scenarios. Of this 68 Gt is found in aquifers.

However, the ultimately commercially deployable capacity may be significantly lower once technical suitability and cost of accessing the sites are considered. In the absence of CO\textsubscript{2}-EOR, hydrocarbon fields will not be available for storage until they have ceased production. For some aquifers it may take several years and £10s of millions of up-front expenditure in site appraisal before these can be developed for full-scale injection.

Given the long timeframes for site development, oilfields that have already commenced technical analysis of EOR may therefore significantly expand the theoretical potential for CO\textsubscript{2} storage in the Central North Sea in the near term.

Figure 6: Clustering of CO\textsubscript{2} storage locations in the Southern, Central and Northern North Sea, East Irish Sea. The figure also shows proximity of CO\textsubscript{2} storage locations and power/industrial sources\textsuperscript{16}

\textsuperscript{16} UK Storage Appraisal Project (in press), Image taken from DECC CCS Roadmap (2012)
3 Barriers for growth of CO$_2$-EOR in the North Sea

This chapter provides a brief description of the barriers for deploying the CO$_2$-EOR technical potential described above.

The main barriers to CO$_2$-EOR identified from stakeholders are:

(i) Challenges in matching CO$_2$ supply with demand (e.g. lack of a reliable supply of CO$_2$ within the tight window of opportunity before fields are decommissioned)

(ii) High project complexity – the need to create stakeholder networks across diverse industries, a high regulatory burden for CO$_2$ storage,

(iii) A wait-and-see approach from existing oil company owners and their service providers, partly as a result of scepticism over CCS policy, technology costs and performance, fragile EOR economics.

(iv) Weak financial incentives (project economics are discussed in Chapter 5)

Additional issues of concern include access to existing data, models, expertise and infrastructure and lack of active NGO support for CO$_2$-EOR.

3.1 Matching CO$_2$ supply with demand

CCS with CO$_2$-EOR involves several geographically specific investments in power stations, capture plants, pipelines, and oilfields. The EOR field will have an “optimal economic” CO$_2$ injection profile. The emitter/capture system will independently have an “optimal economic” CO$_2$ supply configuration. For early projects, developing optimal system wide CO$_2$ transfer may be challenging as partners need to match supply and demand for CO$_2$ over long and short timescales precisely. In some cases, views of what is optimal for any specific component or the system as a whole may change over time. In the case of a large integrated network with multiple sources and sinks the overall system “liquidity” ought to be higher, enabling easier management of changes in supply and demand at individual nodes in the network.

Over short timescales (e.g. within day), power stations may need to respond to electricity network supply and demand, implying a need for capture, transport, storage and EOR facilities to manage variable flows (including no-flow). Conversely, problems with individual wells are common in the oil and gas industry, but it would be a novel challenge for the electricity market if the requirements of CO$_2$ stores were to impact power generators.

Over medium timescales (e.g. months), all parties linked in a CCS chain will need to co-ordinate maintenance schedules. This will be in addition to standard co-ordination maintenance activities (e.g. within the electricity network or within a linked oil-import system).

Over long timescales (e.g. over years), CO$_2$ storage capacity may become limiting in any given field. There are very long lead-times for offshore infrastructure, implying plans to develop the “second” and “third” stores may need to be significantly progressed at the time that a new coal power station with full CCS is sanctioned.

17 Shipping-based solutions can be more flexible but still require specific locations for liquefaction and offshore loading facilities. Ship transport is also much more weather dependent than pipeline transport.

18 This would also be the case if multiple small storage only sites are considered or if a “single” store but with injection facilities dispersed over a large area were considered.
Long-term CO₂ storage capacity management will be less challenging for gas power stations, as the carbon intensity of gas is lower than for coal, and load factors for gas power stations are frequently lower than for coal (although this depends on the relative prices of gas and coal). However, the lower CO₂ supplies from gas power stations may not be attractive for oilfields if these result in very long project lifetimes. An additional potential complication is that in the late 2020s gas power stations with CCS may need to balance high levels of renewable electricity supply, implying CO₂ flows could become highly dependent on weather conditions (unless suitable buffering facilities were developed).¹⁹

Typically CO₂ injected “breaks through” to oil producing wells within a couple of years following first injection. The amount of CO₂ recycling at the oilfield will grow over time, limited by offshore recycling infrastructure capacity. Due to CO₂ co-production with oil, an individual EOR project will have a declining need for fresh captured CO₂ over time, possibly ceasing CO₂ import within ten years. It may be possible to extend oil production using purely recycled rather than fresh CO₂. Two alternative CO₂ injection and recycling scenarios are illustrated below – the upper diagram illustrates a project optimised to accept a steady stream of CO₂ for ten years. Thereafter recycling of CO₂ is used to increase oil production, although it may also be possible to cease oil production and simply store CO₂. In contrast the lower figure depicts a declining CO₂ acceptance rate, which is more analogous to projects in Texas which are currently optimised to minimise demand for CO₂ over time and instead maximise CO₂ recycling. The “base” oil refers to oil produced after CoP year.

Figure 7: Illustrative alternative theoretical CO₂ injection and recycling scenarios (data refer to simplified model of the Claymore field).

Once a project is operational, the value of fresh CO₂ for an oil company clearly decreases over time. In contrast, the power sector (or industrial emitter) is expected to face a growing financial incentive to store CO₂ due to the knock-on impacts of rising penalties from the ETS or carbon price floor.

The following strategies might be employed to maximise CO₂ storage within EOR projects:

- Injection locations within the reservoir and well design could seek to maximise long term CO₂ storage potential (rather than maximise oil production which has been the focus of EOR projects historically).
- Offshore production, injection and recycling infrastructure capacity can be phased over time (i.e. less capacity at the start, more capacity in later years). Alternatively, offshore production, injection and recycling infrastructure capacity can be sized at the project start to cope with requirements at the project end, i.e. in this case infrastructure would be under-utilised at the outset.
• Additional CO₂ injection wells could be installed at the platform, directing CO₂ into an alternate store (e.g. an aquifer which overlies or underlies the oilfield) from the same platform.
• As well as CO₂ transported for EOR, CO₂ can be directed to a CO₂ storage site developed elsewhere.
• A technically feasible alternative would be for the source to cease CO₂ capture, or vent captured CO₂ at some point along the chain – with appropriate penalties.

These options add additional costs and complexities onto the costs of CO₂-EOR relative to previous experience in west Texas. As such they create a more complex project critical path and first-of-a-kind risks than might be the case for ‘simple’ storage in a depleted hydrocarbon field or saline aquifer.

3.2 Timescales for decommissioning

The lack of CO₂ for the near future means that the UK cannot exploit its CO₂-EOR potential yet. However, late adoption of CO₂ capture will lead to missed opportunities for CO₂-EOR, as oil production infrastructure is decommissioned.

A good example is the Miller oilfield. This was proposed by SSE and BP for CO₂-EOR before UK CCS policy had been developed. The field has now been decommissioned and the costs for reinstalling the oil production equipment are expected to make CO₂-EOR prohibitively expensive.

Considering only Scottish EOR sinks, it is not possible to ensure all oilfields can be used as the timescales for field decommissioning and supply of CO₂ are poorly matched, if fields are only considered for CO₂-EOR at Close of Production (N.B. Earlier injection is possible). However, prudent planning could allow some of the oilfields with close of production dates between 2020 and 2030 to be deployed with CO₂-EOR.
### Table 3: Opportunities for CO₂ EOR, storage, capture and transport timescale until 2035 (list is not exhaustive)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New Anchor</strong></td>
<td>Up to 3 additional fields from</td>
<td>Up to 6 additional fields from</td>
<td>Additional fields from</td>
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<td>Claymore (UK)</td>
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<td>Brae (UK)</td>
<td>Piper (UK)</td>
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<td>Dan (DK)</td>
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<td></td>
<td>Brae (UK)</td>
<td>Claymore (UK)</td>
<td><em>small satellites</em></td>
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<td>Buzzard (UK)</td>
<td>Piper (UK)</td>
<td>(Additional Norwegian sector fields</td>
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<td>Gullfaks (NO)</td>
<td>available after 2045)</td>
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<td><strong>Storage only</strong></td>
<td>e.g. up to 4 additional depleted</td>
<td>e.g. up to 8 additional depleted</td>
<td>e.g. up to 20 additional depleted</td>
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<tr>
<td></td>
<td>gasfields, oilfields or aquifers</td>
<td>gasfields, oilfields or aquifers (more likely use a few large ones)</td>
<td>gasfields, oilfields or aquifers (more likely use a few large ones)</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Capture</strong></td>
<td>0-4 projects each 0.5-5 Mt/yr.</td>
<td>Up to 8 projects cumulative, each 0.5-5 Mt/yr</td>
<td>Up to 40 Mt/yr from Humber</td>
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<tr>
<td></td>
<td>e.g.</td>
<td>Up to 5 Mt/yr from Thames</td>
<td>Up to 20 Mt/yr from Tees</td>
</tr>
<tr>
<td></td>
<td>0-2 Mt/yr from Peterhead</td>
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<td>Up to 15 Mt/yr from Thames</td>
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<tr>
<td></td>
<td>0-5 Mt/yr from Netherlands</td>
<td></td>
<td>Up to 100 Mt/yr from continental Europe</td>
</tr>
<tr>
<td></td>
<td>0-2 Mt/yr from Montagard or Karslo</td>
<td></td>
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Moreover, as production declines at the oil fields, export infrastructure may be decommissioned or become too expensive for remaining production (e.g. Forties Pipeline System (FPS) – cessation notionally 2030).

CO₂ recycling requires a source of energy for compressors. Lack of availability of fuel or electrical power would create a barrier to EOR deployment. Many installations in UKCS are already fuel gas deficient and importing fuel gas to maintain operation. Continuation of gas supply from Norway is likely, given the general requirements for UK import.

The requirement for fuel gas favours EOR targets with connection to or in vicinity of Norway-UK gas transportation systems, although an offshore super grid may be a game-changer for power supply.

### 3.3 Engineering challenges

CO₂ injection scenarios to ensure maximal long-term geological storage for CO₂ will require different conceptual approaches to reservoir management than practised to date, leading to novel infrastructure designs.

Mixtures of CO₂ and brine will corrode carbon steel, implying existing materials may be unsuitable and more expensive alloys are required. So far there are few convenient reference projects indicating optimised offshore processing requirements – each developer needs to start from scratch and factor in higher contingencies for unexpected costs, and larger downside risks than might be the case for more conventional approaches to boosting recovery (or when CCS is considered mature).

It is essential to ascertain that reservoir rock will not be destabilised by contact with acid brine to the extent that injection wells are compromised (e.g. by mobilisation of fines leading to blocking of pores) or production wells become damaged (e.g. due to dissolution of minerals in the reservoir leading to precipitation of inorganic scales in the production tubing as fluid pressure is reduced). Also, after decommissioning, all of the wells will need to retain their integrity over long time frames if in contact with CO₂ or CO₂ saturated brine.

Because of the need for detailed modelling and infrastructure planning, a CO₂-EOR project requires a long lead time, with parallel but interdependent work streams on CO₂ supply, transport, and potentially buffer storage. Importantly there is a need for regular dialogue between reservoir engineers, topside facilities engineers, pipeline engineers, power engineers and chemical process engineers at all stages to avoid incompatibilities. Since this can take several years, during which time project plans can change and assets can change ownership, there will be a need to maintain technical competences.

In addition, oil production pilot projects are more expensive for offshore fields with respect to onshore oil fields (i.e. Texas); therefore core experiments are conducted prior to the offshore oil production. Several core samples are collected from the oil field and potential recovery processes (water, CO₂, etc.) are tested on these cores. This process can take a couple of months and is followed by detailed reservoir modelling. Core samples and existing models could be unrepresentative however for a specific reservoir. Therefore some uncertainties will persist after experimental analysis and modelling.

Furthermore, recognising that clusters of CO₂ sources onshore and CO₂ storage and EOR offshore are essential to minimising CO₂ transportation costs, there remains little consensus on the most appropriate investment choices for the UK and Europe in terms of offshore transmission infrastructure. Key choices include start/end and hub locations,
capacity, topology, pressure management, entry specification, phasing, role of shipping — all of these may impact the potential for CO\textsubscript{2}-EOR, as well as broader questions concerning the overall costs, risks and benefits of CCS.

The large uncertainties on CO\textsubscript{2} supply and storage capacities, and long lead times with high finance rates, make it very challenging for commercial investors seeking to “future-proof” infrastructure (e.g. through over-sizing pipelines).

A pre-FEED study could examine in more detail how infrastructure should be future-proofed for EOR, how CO\textsubscript{2} transmission and distribution pipeline networks for a cluster of EOR projects could grow over time, and how platform and well investments should be managed in the context of uncertainty over the timing, amounts and specification of CO\textsubscript{2} supplies. This would allow more informed debate on these issues, and improves the chance that demonstration-phase investments could contribute to larger roll-out, although this report recognises the challenges of linking this with the ambitious timetable for DECC’s CCS commercialisation programme.

There is little detail in the public domain on the number, design and positioning of CO\textsubscript{2} and oil wells, injection facilities, CO\textsubscript{2} recycling facilities, the potential for infrastructure reuse, or MMV costs for CO\textsubscript{2}-EOR projects. Also unclear are the needs to revisit previously abandoned wells. Nor is it clear to what extent these parameters might differ between sites. In the absence of FEED-quality data to the contrary, stakeholders may conclude EOR is too expensive — this could lead to missed opportunities.

### 3.4 Shared equity ownership of oilfields

Oil and gas companies, as a rule, have substantial expertise in drawing up commercial structures to optimise risk management and relatively few assets in the UKCS are licenced by a sole company. In general, licences are shared by several partner companies one of which (usually but not always) will be designated the “Operator”, the cost of development is generally shared between the partners, thus spreading risk and reward, and partner approval, often with voting along the lines of share ownership, will be required for substantial developments (such as EOR).

Considering multiple number of partners, commercial tensions between partners with different views on strategy could be expected for CO\textsubscript{2} EOR. The UK no longer has an equivalent of a national oil company to make nationally strategic or innovative investments. Indeed some field owners treat the UKCS as a “cash cow” to fund strategic investments elsewhere in the world. Many UKCS fields have shared equity partners with diverse characteristics, including

(i) Global reach, large balance sheet, ability to share technical experience, ability to absorb risk on specific projects;

(ii) Regional reach, late life asset management, limited access to specific technical/development expertise, ability to absorb risk is limited; and/or

(iii) New entrant company, no operated assets, highly leveraged, no appetite for CAPEX risk

The process to reach commercial agreement among these classes of oil companies for a given field could be protracted and/or a barrier to progress, especially if one partner has very little experience or interest in CO\textsubscript{2}-EOR.
3.5 High oil taxation

The oil and gas tax environment is complex and very different to that of most low carbon energy technologies and will be very different for CO₂-EOR projects compared with ‘conventional’ low carbon technology investments. The boundaries between oil and gas taxation and CCS taxation regimes may distort investment decisions, particularly in respect of decommissioning infrastructure. This applies to CCS as well as for CO₂-EOR.

The main issues are:

(i) The tax payments for an individual field can be opaque, which may create a challenge to accurate evaluation of CO₂-EOR economics by third parties.
(ii) The tax treatment of decommissioning, change of use, and future developments concerning brownfield developments, add to complexity.
(iii) Recent changes in oil tax levels have created a new instability in project returns - oilfield investors will now factor this into their financial models.
(iv) The levels of taxation are very high (up to 81%), reflecting the typically “supernormal” profits from conventional oil production. Current tax levels are set to minimise the economic rents for oil companies while maximising overall UKCS capital investment, but these do not factor in the market failures, added complexity, information asymmetries, and “public good” aspects of CO₂-EOR.
(v) Although field allowances are available for High Pressure High Temperature fields and fields developed West of Shetland, there are no specific tax benefits yet available for CO₂-EOR.
(vi) There does not appear to be an industry consensus on the preferred taxation structure to incentivise CO₂-EOR with permanent CO₂ storage whilst maintaining a level playing field for other oil production and CO₂ storage options.
Table 4: Oil taxation structure of the UK, Denmark and Norway

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<th>Tax</th>
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<th>Rate</th>
<th>Total Tax Rate (CT + SC)</th>
<th>Total Tax Rate (CT + SC + PRT)</th>
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<td>UK</td>
<td>Corporation Tax</td>
<td>30%</td>
<td>62%</td>
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<td></td>
<td>Supplementary Charge</td>
<td>32%</td>
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<td></td>
<td>PRT</td>
<td>50%</td>
<td>81%</td>
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<tr>
<td></td>
<td>Corporation Tax</td>
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<td>Special Tax</td>
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<tr>
<td>Norway</td>
<td>Corporation Tax</td>
<td>28%</td>
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<td>Special Tax</td>
<td>58%</td>
<td>78%</td>
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<tr>
<td>Denmark</td>
<td>Corporation Tax</td>
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<tr>
<td></td>
<td>52% Tax</td>
<td>52%</td>
<td>64%</td>
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3.6 Commercial, communication and cultural barriers

The development of a CO$_2$-EOR project coupled to a source with CO$_2$ capture and CO$_2$ transport is complex, and requires extensive dialogue between stakeholders over many years to build confidence. The stakeholders include direct project participants (i.e. the source, capture provider, transport provider, and oilfield), but also many other organisations (technology suppliers planning major investments, multiple Government departments, planners, HSE regulators, Environment Agency, large NGOs as well as dedicated groups concerned about specific project impacts, financiers, insurers, policymakers, and the advisors to all these stakeholders).

The engineering and commercial approaches differ substantially between power generation and oil production, so there is a significant potential for misunderstanding. Anecdotal evidence from stakeholder discussions includes differences in understanding the levels of approval or commitments in place, and how contingencies and “not to exceed” costs are treated in financial models and managed in practise. More generally, project partners and supply chains are frequently international, so that cross-cultural differences can also be a source of misunderstanding.

Publicly quoted companies typically use tightly controlled communication channels for the dissemination of potentially market sensitive information. This is particularly important for small or medium size oil companies as announcements around individual EOR projects have the potential to impact share price. Therefore communication is limited between these organisations and government, regulators, CO$_2$ sources, capture developers and transport providers on the potential availability of EOR. This makes planning of infrastructure for CCS with EOR difficult, risky and/or inefficient.

In contrast successful infrastructure development for other low carbon technologies or waste management solutions have involved frequent and high profile debates on competing visions and costs over many years. Sometimes this is because smaller private equity-backed developers can be flexible around announcements or changes of plan. Alternatively it is partly because electricity or waste markets are frequently economically tightly regulated, and decisions around individual projects are unlikely to change overall risk/reward profiles.

In addition, the cultural fit between the CO$_2$ storage agenda (essentially more similar to waste disposal than extraction of a valuable resource) and the CCS or CO$_2$-EOR agenda is challenging. Only a handful of the largest oil companies show a sustained agenda to support new technologies or the additional efforts associated with CO$_2$ reduction.

Taken together the commercial, communication, and cultural barriers may discourage or delay progress in advancing CCS projects through the various stage gates from concept to final investment decision. Even after project sanction, it is possible that decisions taken by a CCS project (for example a technical change such as CO$_2$ purity specification) may not be optimal from the system as a whole but instead reflect the inertia or risk profile of an individual partner within the CCS chain.

3.7 Permitting and regulatory barriers for CO$_2$-EOR

Subject to satisfying health, safety and environmental regulations, an oil company exploring conventional approaches to boosting oil recovery (waterfloods, in-fill drilling etc.)
need only submit an amended field development plan for approval by DECC’s oil and gas department (DECC EDU). In contrast for CO₂-EOR development the permitting and regulatory burden is considerably more complex and brings associated risks.

Not only will oil producers will initially need an amended field development plan (approved by DECC EDU) but the project will also require:

- a storage license (approved by DECC EDU)
- a storage lease (granted by the Crown Estate)\(^{20}\)
- a plethora of licenses and consents associated with power stations, capture plants, and pipeline infrastructure (potentially more than 50\(^{21}\)) which a full chain CCS project developer must acquire prior to, during, and upon closure of a CCS project, with a number of different regulators involved in granting the different licenses and consents.

The timescales for these are not well aligned. Some permits involve extensive consultation with a large and diverse list of potential statutory consultees. Investors will not sanction FID (Final Investment Decision) if the legal requirements are not fully met, and will be very unlikely to pass FID if any significant license or consent is outstanding across the entirety of the CCS chain (including if there is uncertainty around long-term liabilities post-project closure).

Importantly, for a single EOR project or a cluster involving a few capture plants, few pipelines and few EOR fields, failure to obtain a permit for each component could jeopardise the overall system. Cross-border CCS and/or EOR projects will pose additional regulatory challenges, although it should be possible to develop agreements similar to those for cross-border oil and gas infrastructure projects.

Similarly, developers must consider multiple existing regulatory frameworks including the EU CCS Directive, the EU ETS Directive, UK National Policy Statements in the Planning Act 2008. However the regulatory frameworks for CCS are evolving rapidly. This presents a regulatory risk for investors. Even if the regulations remain fairly stable (considered unlikely) there is uncertainty as to how regulations will be implemented by inexperienced regulators, how storage licenses will be awarded, and how eventual handover of a store back to the State would work in practice. The UK has yet to finalise regulatory frameworks and guidelines for the transition from hydrocarbon production to CO₂ storage, third party infrastructure and storage site access, and financial security arrangements. The EU CCS Directive itself will be reviewed in 2015 and changes to this could significantly affect the rollout of CCS.

Although the Energy Act 2008 provides for CCS and CO₂-EOR, “The Storage of Carbon Dioxide (Licensing) Regulations 2010” does not mention EOR explicitly. The accounting

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\(^{20}\) The Crown Estate will award first an Agreement for Lease, which is an exclusive time-limited option for a defined area of the seabed. Thereafter this can be converted, subject to agreement, to a lease which provides exclusive storage rights over a defined area of the seabed plus 3D subsurface formation for a defined volume or period (covering post-closure monitoring). I

\(^{21}\) See for example:  
http://www.decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/scottish_power/consents/consents.aspx and  
http://www.decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/e_on_feed_/environment_/environment_.aspx
position for CO₂ recycling in EOR operations is uncertain (impacting ETS credits and potential subsidies linked to CO₂ storage).\textsuperscript{22}

3.8 Liability issues

It will remain difficult for Management Boards to sanction major capital investments when the long-term liabilities to shareholders are unclear.

In brief, under the CCS Directive to avoid payments for CO₂ emissions under the ETS, CO₂ sources must demonstrate that the CO₂ is permanently stored. Storage sites (whether CO₂-EOR or ‘simple’ storage) must be licensed and must meet multiple stringent requirements around CO₂ monitoring and leakage. For the Goldeneye field, Shell estimated monitoring, measurement and verification (MMV) of storage could add up to £3/tCO₂ to storage costs, even before provision is made for consequential damage or potential remediation activities.

Under the Petroleum Act 1998, licensees are issued with a Section 29 notice, making them liable for decommissioning of existing infrastructure. Moreover, all current and former licensees are issued with a Section 34 notice under which they retain a liability in perpetuity. However it is not clear:

- When the best time and method to decommission infrastructure is given the need for long-term monitoring and potential site access.
- How to deal with infrastructure, e.g. that has already been abandoned (e.g. by others).
- What liabilities are (or should be) if wells have been abandoned in line with best practice but there is a hydrocarbon or CO₂ leak (either from the CO₂-EOR field or site in close proximity).
- How infrastructure decommissioning liability (and tax reliefs) should be apportioned between former licensees and new storage licensees.
- What site remediation activities would be required, and how much these would cost.
- In the event of catastrophic site failure for CO₂ storage (considered unlikely), would the oil companies be responsible for paying prevailing CO₂ prices (in addition to agreed rules on oil leak compensation).

3.9 Diverse KPIs for different stakeholders

The need to achieve diverse KPIs for different stakeholders poses a key barrier to the development of EOR projects and EOR clusters. The most important KPI for oil companies, and other investors, considering CO₂-EOR will be the project Net Present Value.

Whereas the largest multinational power and oil and gas companies have large and flexible resources, not all oil companies in the UKCS will necessarily be able to fund or be exposed to the high capital costs of CO₂ capture, onshore and offshore transport, and CO₂-EOR through cash and may need to raise finance from capital markets. They will also be unwilling to bear uncertain or unlimited long-term liabilities or provide financial securities in respect of storage.

\textsuperscript{22} The CCS Directive prohibits the use of interim storage (i.e. CO₂ stored in one reservoir subsequently transferred to other reservoirs), which may help balancing CO₂ flows for EOR projects, although no publicly announced EOR project to our knowledge explicitly requires this.
Additional KPIs assessed by oil companies when considering field investments relate to cash-flow, profitability and risk profiles and include CAPEX, OPEX, avoided abandonment costs, expected oil production, subsidies/tax structures and levels, price/volume relationship for CO₂, IRR and discounted profitability index (DPI), Value/Investment Ratio (VIR), Unit Development Cost (UDC) and Unit Technical Cost (UTC), Breakeven price (BEP), Return On Investment, Payback Period, Maximum exposure, Minimum economic field size (MEFS). A description of these terms is provided in the Appendix.

For sources of CO₂, providers of CO₂ capture and transport, the contracted volumes and tariffs (or revenues) for CO₂ storage from the EOR project will significantly affect cash-flow. The reliability of CO₂ supply and off-take will also be critical. In the case of insufficient CO₂ volume contracted, the stranded assets and exposure to carbon price will be a risk. These will be in addition to the intrinsic economics of their components to a CCS project.

For the UK Government, the primary KPIs include timely delivery of demonstration, level of subsidy required (net of taxes), the absolute project costs (inclusive of capture and transport), levels of CO₂ avoided, efficiency (on a £/tCO₂ avoided or £/MWh of decarbonised electricity), ability to advance CCS technology and support future CCS growth and cost reduction, contribution to electricity supply and energy security, overall economic impact (recognising the ability to develop supply chains), reducing risks of stranded assets, employment, global leadership, balance of trade, etc.

3.10 Lack of political support from most environmental NGOs for CO₂-EOR

The impacts from support or opposition for CCS and CO₂-EOR projects from environmental Non-Governmental Organisations (NGOs) should not be under-estimated. Whereas the UK and Scottish Governments have been able to count on the support of many environmental NGOs in their ambitions for energy efficiency programmes and renewable energy deployment, this should not be taken for granted for CCS linked to CO₂-EOR. Indeed some environmental NGOs have mounted high profile campaigns against projects with CCS potential in the UK so far (e.g. “Stop Kingsnorth” and “Say NO to Hunterston” campaigns), and in Europe (where local residents’ concerns on onshore CO₂ storage have been exploited to stop projects in Germany, the Netherlands and Denmark).

The environmental NGO community is heterogeneous, but common KPIs for NGOs would be overall environmental impact and strategic alignment with multiple policy objectives. Potential opposition from NGOs to projects creates reputational risk for project partners and investors. Concerns can be summarised as:

- Direct CO₂ emissions to atmosphere from unabated fossil power generation (e.g. if only part of the emissions from a new coal build are captured).
- Continued environmental and socio-economic impacts and imbalances from fossil fuel production and distribution.
- Downstream CO₂ emissions associated with combustion of produced oil.
- Crowding out of policy attention, infrastructure capacity, public subsidy and private capital that might otherwise be directed towards energy efficiency measures or renewable energy technologies.

23 One NGO has indicated a possible precondition for supporting CCS-EOR would be firm measures to reduce the dependence of the economy on oil.
- Consistency of logic for combining a climate mitigation technology with the increasing oil production, given that most oil is produced for combustion.
- In the short-term, under a cap-and-trade scheme, CO\textsubscript{2} reductions within the power (traded) sector may be counterbalanced by increased CO\textsubscript{2} emissions elsewhere.

A review of CCS and oil production life cycle carbon analyses studies identifies ambiguities and challenges in defining appropriate system boundaries to understand environmental impacts. To date there has been no independent, credible, and rigorous assessment of the relative environmental impacts or displacement potential for CO\textsubscript{2}-EOR in the North Sea compared with other marginal fossil fuel production technologies (shale gas, Arctic or deep water drilling etc.), therefore it is not possible to support or reject assertions based on this logic at this time. Nor has there been a full environmental impact comparison between alternative approaches to CO\textsubscript{2} storage.

Some contributing factors to overall carbon life cycle assessment for CCS/CO\textsubscript{2}-EOR are:

- Fuel choice for power station and its carbon intensity
- Power station efficiency
- Embodied carbon in power generation infrastructure
- Capture efficiency (typically 90\% of flue gas can be captured)
- Efficiency penalty for running capture equipment (typically 6-12\% reduction in efficiencies)
- Energy for compression/pumping for pipelines
- Energy for liquefaction/regasification for shipping
- Energy for offshore CO\textsubscript{2} recycling
- Subsurface CO\textsubscript{2} produced
- Embodied carbon in CCS infrastructure
- CO\textsubscript{2} recycled or vented
- CO\textsubscript{2} leakage from subsurface (e.g. through faults, old wells)
- Intrinsic carbon intensity of the oil (can vary between oils from different regions)
- Oil refining infrastructure
- Eventual emissions to atmosphere from use of refined oil (i.e. combustion vs. chemical, efficiencies)
- Embodied carbon in oil production and refining infrastructure

One KPI for NGOs will be project life cycle CO\textsubscript{2} emissions to atmosphere. However, determining the life cycle emissions of a CCS project including EOR requires a definition of appropriate boundary conditions for emissions to the atmosphere. However the lifecycle analysis boundaries can be broadened to include multiple sources, multiple transport mechanisms, multiple stores and CO\textsubscript{2}-EOR, and may also include CO\textsubscript{2} embodied in steel produced, and the life cycle CO\textsubscript{2} emission factors associated with oil (a carbon-rich fuel).

Importantly, accounting conventions assign CO\textsubscript{2} reduction to the power sector. Therefore to avoid confusion this should not be double counted as "green" oil production.

Considering only CO\textsubscript{2} capture from a new coal plant with "simple" storage in a depleted field or aquifer, CO\textsubscript{2} emissions in the flue gases can be reduced by potentially up to 90\%. However levels of actual CO\textsubscript{2} avoided will be lower to account for additional energy penalty for capture and compression, and consideration of what counterfactual energy sources are displaced within the electricity network (e.g. mix of gas, nuclear, renewables, etc.) which may change over time.
Alternatively, considering only the carbon impacts for oil production, the carbon intensity of crude oils has been estimated in the region 400-600 kg CO$_2$e/barrel. Of this the overwhelming contribution comes from combustion of refined products (<100 g/barrel from processing and refining). Average historical CO$_2$-EOR performance in Texas suggests 270-400 kgCO$_2$ is injected for every barrel of oil produced. The volumes of CO$_2$ emitted from downstream oil combustion are therefore comparable the volumes stored, although this is clearly highly sensitive to assumptions.

Figure 8: CO$_2$ emissions associated with a CCS project including CO$_2$-EOR.

As well as environmental NGOs, opposition to CCS investment (irrespective of whether this is linked to EOR) may in the future also come from groups anxious about impacts of the costs of climate mitigation being passed onto electricity consumers (notably reducing business competitiveness and increasing household energy bills).

3.11 Scepticism around early development of CO$_2$-EOR

The failure of the SSE/BP DF1 proposal for the Miller oilfield, and Norwegian projects combining CCS with EOR, has fuelled scepticism across a wide spectrum of stakeholders that large scale CCS with or without CO$_2$-EOR will be deployed commercially in the North Sea. There is considerable scepticism that any conventional oil company would sanction CO$_2$-EOR investment before CCS is considered “proven” and there are reliable supplies of CO$_2$. Therefore, many stakeholders, including oil companies and their supply chains, are adopting a wait-and-see approach to CO$_2$-EOR.

There is a danger however that lack of interest in CO$_2$-EOR could become a self-fulfilling prophecy. The limited focus to date on CO$_2$-EOR from policymakers stems partly from an apparent lack of strong policy recommendations from the oil industry. Overcoming this barrier would require advocacy in favour of rapid progress from the UK and other North Sea Governments in selecting CCS projects for demonstration, targetting transport...
infrastructure to be useful for oilfields, and providing clear policy support to underpin CO₂-EOR investments.

### 3.12 Constitutional change

Political uncertainty around future major constitutional change[^24] could, if not managed appropriately, lead to delays for power market investments and for oil and gas infrastructure. This threat could be mitigated by reassurance to industry of a continued high degree of co-operation between key stakeholders, notably the UK and Scottish Governments around energy and climate policies.

4 Scenarios for developing CO$_2$-EOR in the North Sea

This chapter reviews the main drivers for CO$_2$-EOR deployment and then considers how these might be translated into informative scenarios to provide insight for Scottish Enterprise on the likely order-of-magnitude of economic impacts.

The main drivers for CO$_2$-EOR in the North Sea will be:

- Funding for initial CCS demonstration in the 2010s
- Support for CCS deployment in the 2020s
- Oil prices
- A broad base with political support and co-operation across a diverse range of stakeholders.
- The costs, risks and benefits of CO$_2$-EOR vs. alternative investments (e.g. decommissioning, alternative recovery techniques, CO$_2$ storage).

4.1 Public funding for initial CCS demonstration in the 2010s

Recognising that CCS in the North Sea region could provide up to 8% of European decarbonisation needs in 2030 (with volumes transported up to 270 Mt CO$_2$/yr)\(^\text{25}\) the UK, Norway, Netherlands and EU have committed to supporting the development of full chain CCS involving CO$_2$ storage in the North Sea. With carbon prices in the EU ETS currently very low, this implies a need for public support for most of the additional costs of CCS.

The CCS programmes of the UK, Norway, Netherlands and EU have evolved considerably in recent years as public and private participants have understood project requirements, costs and risks more deeply. Significant progress has been made in the UK in developing a supportive economic and regulatory environment for CCS, although challenges remain.

The principle mechanism for EU funding is the NER300 competition. The European Investment Bank has now ranked CCS proposals for the first round of the NER300, and the EC and Member States are reviewing the assessments – a final decision is expected by the end of 2012. Three of the NER300 submissions indicated potential CO$_2$-EOR storage in the North Sea:

- 2Co Energy’s Don Valley Power Project, involving the construction of a new 900 MW (gross) IGCC coal power station with pre-combustion capture, onshore and offshore transport by pipeline to the Central North Sea for CO$_2$-enhanced oil recovery.\(^\text{26}\) This has recently been ranked first of all proposals by the EC\(^\text{27}\). The project involves work with National Grid, Samsung C&T, BOC/Linde, Foster Wheeler and BNP Paribas. 2Co is working on a study with Talisman Energy on options for CO$_2$ storage with EOR in the central North Sea.
- CO$_2$ capture from a refinery site (Air Liquide), cross-border transport by ship, for CO$_2$-enhanced oil recovery in Danish oilfields (Maersk Oil).
- Progressive Energy’s Tees Valley proposal involving the construction of a new IGCC coal power station with pre-combustion capture, onshore and offshore transport by pipeline to the Central North Sea for CO$_2$ storage using a combination of stores involving an aquifer and CO$_2$-enhanced oil recovery over the life of the project.

\(^{25}\) Element Energy et al. (2010) One North Sea

\(^{26}\) This project was formerly known as the Powerfuel Hatfield project.

\(^{27}\) http://ec.europa.eu/clima/funding/ner300/docs/2012071201_swd_ner300.pdf
Of these, 2Co Energy’s project has already benefitted from European Economic Recovery Programme funding of up to Eur185 million and leads the ranking of NER300 projects. With a collapse in carbon prices, several NER300 applicants withdrawing from the programme, and limited public monies among EU Member States for match funding, it is possible that 2-3 of the original 13 proposals may actually receive funding support under the NER300 competition.  

Figure 9 High level schematic for 2Co’s proposed Don Valley Power Project. (Figure not to scale).

In the UK, the Department for Energy and Climate Change has launched a new programme to fund CCS projects and supporting infrastructure to be operational between 2016 and 2020. Financing will be provided through a combination of a capital grant (up to £1 bn) and Contract-for-Difference Feed-in Tariff. Proposals have now been submitted and will be evaluated in Q3 2012, with a view to an award by October 2012. Contract negotiation will begin in Q4 2012. The Government is willing to support additional FEED studies. Both the 2Co and Progressive Energy proposals described above are included in the latest CCS competition. These will face stiff competition for funding from up to 16 UK interested parties, including for example:

- SSE/Shell/Petrofac proposal for post-combustion CO$_2$ capture at Peterhead gas power station with storage at the GoldenEye field.
- White Rose 426 MW (gross) oxyfuel CCS project at a new coal power station at Drax power station (Partners include Alstom, BOC and Drax)
- Captain Clean Energy Project, Summit Power/National Grid/Petrofac for a new IGCC power station at Grangemouth with CO$_2$ storage in the Moray Firth.

4.2 Support for CCS deployment in the 2020s

Clearly policy support for CCS deployment in the 2020s will depend on the success of initial CCS demonstration across a wide range of key performance indicators, not least

http://ec.europa.eu/clima/funding/ner300/docs/2012071201_swd_ner300.pdf
value for money. The direct budgets for CCS subsidies (including caps on feed-in tariffs) will dictate the pace of CCS development at least until the early 2020s.

Although funding levels for CCS in the 2020s are extremely uncertain (and for example will be linked to global climate agreements and macroeconomic indicators such as the health of the economy), numerous reports have sought to quantify levels for CCS in the UK and across Europe period to 2030 consistent with UK and global CO₂ stabilisation ambitions.

- The scenarios modelled for DECC’s Carbon Plan identify up to 10 GW power generation fitted with CCS by 2030, from both coal and gas sources, implying many tens of MtCO₂/yr. The CCSA, the industry trade association, has set out an ambition for 20 to 30 GW of CCS to be deployed in the UK by 2030.
- Element Energy’s “One North Sea” study identified CO₂ supply volumes directed from the UK, Norway, the Netherlands and Germany to the North Sea up to 30 Mt/yr in 2020. Looking ahead to 2030, a medium CO₂ supply of 35 Mt/yr was estimated, within a large range from <10 Mt/yr to 165 MtCO₂/yr.
- The SCCS/Arup CO₂ infrastructures study identifies low, mid and high CO₂ supply volumes across Europe of 50, 120 and 350 Mt/yr in 2030, although these scenarios do not explicitly consider CO₂-EOR.
- The European Commission’s Energy Roadmap 2050 identifies between 0.6% and 2.1% of gross electricity generation in 2030 will be supplied with fossil CCS with a maximum of ca. 120 GW CCS power in the 2030s\(^{29}\).
- The European Climate Foundation Power Perspectives 2030 study estimated 4 GW of power generation with CCS delivering 26-30 TWh in 2020. For 2030, Europe-wide capacity is estimated to be up to 38 GW of coal CCS and up to 16 GW gas CCS, delivering 231 TWh and 105 TWh in 2030 respectively.

### 4.3 Oil price

Previous studies have suggested that North Sea CO₂-EOR projects could only be competitive when real oil prices were sustained above $70-100/barrel. Until a few years ago, oil prices of $100 were well above most central oil price forecasts. However, as illustrated in Figure 10, the latest DECC forecasts are for central oil prices at $135/barrel, with a “low oil price scenario” at $75/barrel.

Oil prices are notoriously volatile, and future crashes in oil price cannot be ruled out. However, given these revised oil prices, the fundamental economics of North Sea CO₂-EOR are now more attractive than when ideas were originally proposed in the early 2000s.

Figure 10: Oil price forecasts

Periods of high oil price have historically been associated with higher offshore engineering costs for industry, supply chain bottlenecks and pricing models that relate to opportunity costs rather than production costs.

4.4 Political support and cross-stakeholder cooperation for CO₂-EOR

A high degree of support for CCS and CO₂-EOR from policymakers in Scotland, the UK and Europe, environmental NGOs, regulators, financiers, insurers, and, crucially, oil companies and their service providers, and technical, financial and legal advisors to all these stakeholders, will de-risk investments across the CCS and EOR value chains. This will reduce costs (of finance and potentially through improved project design) and accelerate the process of passing through project permitting and investment stage gates. CCS is highly capital intensive, so even small reductions in the cost of capital can produce significant reductions in overall project costs.

Examples for how the oil industry can assist with CO₂-EOR development are provided below:

4.4.1 Future-proofing and facilitating access to existing pipeline, platform and well infrastructure

CO₂ handling and recycling pose infrastructure challenges. CO₂ has distinct chemical properties and therefore metallurgical requirements, which may mean that some existing infrastructure will be unsuitable for re-use. The costs for upgrading existing infrastructure for CO₂-EOR require case-by-case assessment of infrastructure – as such existing operators will have much more insight than wider stakeholders.

If CO₂ supply does not match the timing of hydrocarbon production there could be a need for mothballing infrastructure. This applies to use of infrastructure for CO₂ storage or for CO₂-EOR. Mothballing could be expensive (e.g. in the region £10s of millions/yr opex/site). The alternative of complete removal and future reinstallation of oil production infrastructure, as well as new CO₂ infrastructure, is expected to be prohibitively expensive.
In addition to the platforms, North Sea has a large network of existing offshore pipelines connecting oil and gas fields with each other and the shoreline. As oil and gas fields deplete, some of these pipelines cease operation for hydrocarbon transport, and so could in principle become available for CO$_2$ transport (as was proposed for both the original DF1-Miller project and the more recent Longannet project).

However the need for appropriate locations, CO$_2$ volumes, metallurgy and phase behaviour of CO$_2$ will create significant limits on reuse potential. By the time CO$_2$ pipelines are required many of these pipelines could be 30-40+ years old, i.e. well beyond design life. In some cases the challenges of age could be partially managed by reducing pressure rating. For CO$_2$-EOR there will of course be a need for both CO$_2$ and oil transport infrastructure to be simultaneously available in the correct locations, increasing the complexity.

### 4.4.2 Access to high quality reservoir data and models

North Sea field owners and operators possess and use detailed datasets, models and know-how on the performance of individual reservoirs and design of topsides to optimise performance in the short and long term. When assets change ownership, models - and often key individuals - are transferred between companies. These data and models are typically regarded as valuable intellectual property as the quality of decision making improves considerably. The models can be used to estimate project values with a high degree of precision. An ability to draw on existing models and know-how around existing fields could significantly de-risk investments linked to a CO$_2$-EOR cluster. Individual developers and their due diligence advisors might obtain access to this information under commercial confidentiality, but the ability of the wider energy system community to comment critically on EOR investments is presently limited.

However, where owners/operators have limited interest in CO$_2$-EOR, no mechanisms currently exist to ensure that relevant data, models or know-how will be shared among the more diverse stakeholders required for a CO$_2$-EOR project/system to be developed. This creates an asymmetry in negotiating positions.

Owners of oil and gas-fields are frequently multi-national companies with portfolios carefully managed to ensure they meet their investor expectations for growth, income and risk. UKCS oil and gas field assets change ownership frequently, and particularly between “plateau” operation and when output starts to decline. Late life asset owners can bring innovative solutions to extend asset life, but in some cases assets are treated as “cash cows” to fund major investment elsewhere (not necessarily within the UKCS). These owners may not always have experience or a strategic interest in supporting CO$_2$-EOR.

Many fields have joint equity ownership among diverse partners. In these cases all partners would be expected to conduct due diligence to support any major investment decision, although typically one party would lead. Not all companies have the capacity to manage the additional complexity of CCS investment, needing to consider power generation, capture, and transport (onshore and offshore).

### 4.4.3 Commercial decisions on where to invest

In common with some of the renewable electricity generating technologies such as wind, wave and tidal power, CCS involves highly location-specific investments. Realistically CO$_2$ for EOR could be supplied from English, Scottish, Norwegian and EU sources, but appropriate transport infrastructure will need to be developed. The UK’s CO$_2$-EOR candidate oilfields are generally located more than 200 km from the east coast of the UK, implying pipeline capital costs in the region of several hundreds of millions of pounds. This
creates opportunities to future proof CCS investments to maximise future EOR application. Equally there is a risk that investments will be locked into configurations that inhibit optimum uptake of CO₂-EOR.

In the current market, decisions around investment are currently led by CCS demonstration project developers. The opinions of these stakeholders are mixed on the merits of ensuring CO₂ capture and transport infrastructure investments are future-proofed to maximise advantage for CO₂-EOR. Considering only EOR, the ideal transport infrastructure could be a limited number of tree and branch CO₂ trunk pipelines that can service multiple onshore sources and multiple offshore oilfields, supported by CO₂ transport by ship.

**Case Study: The Forties Pipeline System (FPS)**

This CO₂ infrastructure development scenario mirrors that of transporting oil from the North Sea fields to shore. The ‘Anchor field’ incurs the burden of the capital and operating costs from building and operating the pipeline. Oil “Anchor fields” included Brent and Forties, where production started in the 1970s (very few satellite fields were discovered at that stage). Subsequent users of the pipeline infrastructure do so usually on a third party basis by paying a tariff per unit volume transported.

The Forties Oil Pipeline System (‘FPS’) has developed into the most extensive oil transportation network in the North Sea. Over 70 fields (mostly UK, but including some Norwegian fields) now use the FPS. Forties is the ‘Anchor field’, with the FPS landfall being at Cruden Bay, north of Aberdeen. An onshore pipeline carries oil south to the Grangemouth refinery or Dalmeny tank farm. Oil is redelivered to users at the Hound Point loading jetties in the Firth of Forth. It is thought that the FPS operating costs are in the region of £90-100 million/year, including the offshore Main Oil Line pumps, Unity riser platform (allowing many third party fields access to the FPS); onshore pipeline, terminal, and export facilities. Total operating costs for the Forties field (including the FPS) are currently thought to be around £200 million/year.

The FPS does act as a blue-print of what has actually happened in the North Sea, based on a large ‘end field’ and subsequent third party use of an existing line. There are, in the UK, well-established precedents for the development of large-scale pipeline infrastructure and the commercial agreements for their use by multiple parties.

Tariffs for new fields wanting to use the FPS are published in line with the UK Infrastructure Code of Practice. Tariffs reflect the FPS’ historical and future capital costs and on-going operating costs. BP has the option to switch some existing (and new) FPS third party users from tariffs to a cost-sharing agreement from 2015 onwards.

**4.4.4 Attractive HSE, regulatory and economic environment**

A range of organisations worldwide and in the UK are already co-operating in working groups, Task Forces, and other consortia to resolve the HSE, regulatory, and economic barriers to CCS. At present there does not seem to be a coherent voice arguing the interests of potential EOR projects and their suppliers. Parties interested in promoting CO₂-EOR should ensure that these initiatives include the requirements for CO₂-EOR. This could include
infrastructure HSE challenges specific to CO\(_2\)-EOR
- regulations around infrastructure and liability sharing for CO\(_2\) storage and oil production
- economic incentives for CO\(_2\)-EOR such as tax reductions (c.f. high pressure high temperature fields)
- accurate framing and messaging about the lifecycle environmental impacts of CCS with CO\(_2\)-EOR

4.5 Alternative investment options

Oil companies typically manage a portfolio with many assets. Investments are made routinely on whether to extend, cease production or sell existing assets, trial new strategies for increasing performance from existing assets, or expand exploration, appraisal and production activities in new parts of the world.

High oil prices typically lead to extensions of economic life of existing projects. They also raise the number of competing options for new oil company investments – in the UKCS and globally.

Decommissioning costs for hydrocarbon fields can run from £10s to £1000s of millions for the largest fields (mainly related to platform decommissioning). CO\(_2\)-EOR offers an opportunity to delay these costs by extending the use of existing platforms.

The impacts of decommissioning are treated in the economic model, although it should be recognised that the full complexity around the tax treatment of decommissioning expenditure may not be captured.

CCS investors may find storage only projects more attractive than EOR projects - either because of lower costs, higher storage capacities, or being able to better integrate risk profiles (e.g. oil price uncertainty) within the overall project structure.

4.6 CO\(_2\)-EOR uptake scenarios

Given the diverse barriers and drivers for CCS and EOR summarised above, clearly a wide range of outcomes are possible in terms of EOR levels in the North Sea. Scenarios are frequently helpful to provide order-of-magnitude insights into how many oil fields can be exploited and under what conditions. Scenarios are used to provide insight and should not be treated as forecasts. Considering the opposite extremes:

- If a CCS demonstration project comprising EOR is successful in the 2010s, if oil prices are high, and if there is a large step increase in CCS policy support from Government, industry and NGOs, then a Very High EOR scenario in the North Sea could be developed and the levels of CO\(_2\) supply could satisfy the demands of at least 12 large fields and a few satellite fields developed over the period to the early 2030s.
- Conversely, lack of stakeholder support for CCS and CO\(_2\)-EOR, unsuccessful demonstration of CCS or CO\(_2\)-EOR, or a collapse in oil price, could lead to negligible uptake of CO\(_2\)-EOR in the North Sea. Clearly between these extremes, intermediate scenarios may be possible and may be more realistic.
Following stakeholder discussions and sensitivity analysis we have condensed the possible scenarios into four informative scenarios, which we call "No CO$_2$-EOR", "Go Slow CO$_2$-EOR", "Medium CO$_2$-EOR" and "Very High CO$_2$-EOR". These outcomes are illustrated in Figure 11 below as a function of CCS policy support (on the horizontal axis) and oil price (on the vertical axis).

**Figure 11: Scenarios for developing CO$_2$-EOR in the North Sea**

4.6.1 No CO$_2$-EOR uptake scenario

Scenarios with no CO$_2$-EOR projects in the North Sea region in the 2020s are entirely possible outcomes but are not discussed further in this study. Under these scenarios, the Scottish supply chain could benefit from alternative EOR technologies, CO$_2$ storage in depleted fields/aquifers, and/or oilfield decommissioning. These are outwith the scope of the present study$^{30}$.

4.6.2 Go Slow EOR scenario

In the Go Slow scenario, it is assumed that CO$_2$-EOR projects in the North Sea will emerge after one CCS demonstration project initially using storage in Phase I (2016-2020). Only a handful of CCS projects are commissioned in Europe before 2030. The first CO$_2$-EOR demonstration projects come on stream in Phase II (2021-2025) as an opportunistic investment. Further CO$_2$-EOR uptake is limited as oilfields are decommissioned.

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$^{30}$ CO$_2$-enhanced gas recovery (EGR) is not as mature as CO$_2$-EOR, and therefore is also outwith the scope of the present study but options for CO$_2$-EGR could be considered as part of analysis of the benefits of an offshore CO$_2$ network.
Figure 12: Illustrative fresh CO$_2$ injection and CO$_2$ supply in the “Go Slow” Scenario

Figure 13: Illustrative CO$_2$-enhanced oil production in the “Go Slow” Scenario
4.6.3 Medium CO₂-EOR uptake scenario

Following successful deployment of CO₂ storage in the North Sea in Phase I, an appropriately sized pipeline directed to an EOR sink, and significant experience of CO₂-EOR coupled to CCS elsewhere in the world (including onshore) may allow more rapid EOR deployment in the 2020s in the North Sea region.

In the event of more policy support or higher oil price, CO₂-EOR uptake is increased and includes five oilfields in UK, Norwegian and Danish sectors of the North Sea.

Figure 14: Illustrative fresh CO₂ injection and CO₂ supply in the “Medium” Scenario

Figure 15: Illustrative CO₂-enhanced oil production in the “Medium” Scenario
4.6.4 Very high CO₂-EOR uptake scenario

The scenario with highest CO₂-EOR levels corresponds to UK leadership on CCS, supported by other North Sea countries and the EU. This could occur if there was a combination of strong economic recovery (allowing projects to obtain public and private finance, and providing a backdrop of sustained high oil and CO₂ prices), strong global agreement on CO₂ reduction (which would justify developing an early lead in CCS technology and future-proofing infrastructure), high reservoir performance demonstrated in an EOR project developed in the 2010s.

In this scenario, there is a strong focus on maximising early oil recovery and a large availability of CO₂ storage options to buffer supply and demand mismatches. The first CO₂-EOR project is delivered successfully in the 2010s, allowing rapid scale up in the 2020s. Multiple CCS projects are commissioned supplying CO₂ from clusters of sources in Scotland, England and elsewhere in Europe using a mix of trunk pipelines and ships.

![Figure 16: Illustrative fresh CO₂ injection and CO₂ supply in the “Very High” scenario](image-url)
4.7 Scenarios for developing CO$_2$-EOR in the North Sea

Considering the issues that were raised before, several CO$_2$ supply and CO$_2$-EOR development scenarios were designed. For CO$_2$ supply, three scenarios are presented, which are go slow, medium and very high scenarios.

The locations, capacities and timing of trunk pipelines from shoreline hubs to oilfields will be a critical determinant of CCS and CO$_2$-EOR expansion. However there is no prevailing consensus for the optimal phasing, routing and capacity of any offshore transport network. The issues around pipeline choices have been extensively discussed before$^{31,32,33}$.

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$^{31}$ Element Energy et al. (2007) Report for the DTI on CO$_2$ pipeline infrastructure for the UK and Norway
$^{32}$ Element Energy et al (2009) CO$_2$ pipeline infrastructure, an analysis of global opportunities and challenges
5 The economic impacts from CO$_2$-EOR deployment

To estimate the impacts from CO$_2$-EOR in the North Sea, a techno-economic modelling approach was taken. The modelling approach allows examination of diverse factors including:

- The locations and plausible order-of-magnitude estimates for incremental oil production, COP dates, and CO$_2$ storage capacities from a database of potential CO$_2$-EOR oilfields in the North Sea.
- Incremental oil production and CO$_2$ recycling flows as a function of CO$_2$ injection and timing.
- Low, medium and high CO$_2$ supply scenarios
- Conventional and incremental oil production infrastructure and associated capex and opex for platforms, wells, recycling, compression equipment, and power
- Decommissioning costs
- Taxation (including existing PRT, SC, CT, decommissioning tax relief structures and hypothetical incentives for CO$_2$-EOR).
- Transfer prices for CO$_2$ reflect the price the oil company may pay (or be paid) for accepting CO$_2$ to either the transporter or the source.
- Estimates of the most likely work supply chain scenarios for Scottish businesses
- Historic Scottish oil industry multipliers linking turnover to GVA and jobs.
- Oil industry thresholds for KPIs such as EBIT, NPV after taxes, discounted profitability index, and oil produced.

![Economic model diagram](image)

In the absence of up-to-date, reliable, independent, transparent and publicly available reports on the infrastructure requirements and implied costs for CO$_2$-EOR in the North Sea, cluster studies must rely on high level analogies with the oil and gas industry and extrapolations of older studies. The completeness, relevance and therefore cost accuracy of these models is therefore uncertain.

The modelling combines the Heriot Watt database with Element Energy and Dundas Consultants’ in-house models for evaluating CO$_2$-EOR opportunities. The models have been extended to estimate employment and Gross Value Added in Scotland. This was
done using publicly available data provided by Scottish Enterprise. Components of the underlying economic model were confirmed as fit-for-purpose through peer review.

5.1 The cashflow for a single field

The undiscounted cashflow profile for a typical North Sea CO$_2$-EOR project is illustrated in Figure 19 below. The corresponding CO$_2$ and oil flows are shown below in Figure 20. The cashflow is characterised by £1bn+ up-front expenditure, ongoing costs potentially in the region £100m/yr, followed by a significant decommissioning cost (£100s of millions). The revenues from oil sales are expected to peak within a few years of beginning CO$_2$ injection, and thereafter decline gradually. Oil taxes make up a significant expenditure, although in the early years of operation, taxes can be offset using tax breaks for capital investment. The benefit from delayed decommissioning can be included as part of the cashflow.

![Illustrative undiscounted nominal cash-flow for a typical CO$_2$-EOR project](image)

**Figure 19:** Illustrative undiscounted nominal cash-flow for a typical CO$_2$-EOR project (the graph illustrates baseline assumptions applied to the Claymore field)
The modelling reveals that the oilfields in the database can provide positive NPVs under baseline conditions with oil prices at or above $70/bbl. For commercial developers projects must have a positive NPV after tax across a wide range of circumstances (including low oil price or reservoir underperformance), and with risk-adjusted profits comparable to or better than alternative investment opportunities.

Given the diversity of stakeholders, there is no “one-size-fits-all” KPI threshold that determines whether a project will go ahead. For this project we adopt a convenient oil industry benchmark, the Discounted Profitability Index. Projects with DPI greater than 0.3 at an oil price of $90/bbl (10% nominal discount rate), are normally commercially attractive for oil companies. First-of-a-kind projects would likely have a tougher DPI threshold, but to date there is little evidence to quantify any CCS-specific risk premium.

Importantly a sensitivity analysis reveals that EOR developers’ NPV is fragile to plausible variations in assumptions.

\[ \text{DPI} = \frac{\text{nominal NPV}}{\text{discounted nominal CAPEX}} \]
Figure 21: Illustrative sensitivity of project NPV to key inputs

Figure 21 shows considerable upside potential from the oilfield, as well as the downside risks. The data refer to the Claymore field under Medium scenario, i.e. $90/bbl, 10% discount rate, CO2 supplied free of charge. Oil recovery at 10% of STOIP, CO2 injection at 0.8 Mt/yr/well and base costs, tax at 62%. Base NPV = £200m, i.e. reductions below £200m will make the project loss-making.

If oilfield and capture project share ownership, then it may be possible that EOR profits could be used to offset the costs of capture and transport. Whereas DECC has indicated an openness to exploring the indexing of CfD FiT subsidies to gas prices for gas CCS projects, it may also be possible to structure reduced subsidies for CCS with EOR in the event of high oil prices (i.e. create capped returns for oil companies).

Whereas oil companies should be well placed to handle the majority of reservoir, construction and oil price risks described in the tornado diagrams, CO2-EOR brings a new risk related to the success or failure of the full project chain to be integrated on time. Despite best efforts of all parties, there may be delays onshore or offshore.

If EOR facility is developed but CO2 supply is delayed (either through problems with power generation, capture or transport infrastructure), then the returns from EOR economics could be wiped out. The graph below shows that a two year delay would bring the project discounted profitability index below 0.3, making it uncompetitive with alternative oil investments. A delay of five years in CO2 supply would wipe out project profits altogether.
Figure 22: The impacts of a delay in CO$_2$ supply on EOR project NPV and DPI
(Data shows the impacts for the Claymore field under Medium scenario assumptions)

Clearly the challenge is mirrored onshore. If CO$_2$ storage facilities are not ready in time for the power station, then it may be necessary to keep capture and transfer equipment idle or underutilised, as well as pay ETS payments for any CO$_2$ vented.

To manage these risks efficiently, all parties in a CCS value chain will have appropriate penalties for non-supply structured into contracts. This is standard practice in the energy sector. Where ownership of power station, capture plant, transport and EOR sink is spread amongst different organisations, the overall project costs will include risk premia from each of the underlying components. To date however, there is no clear view from industry as to the best risk allocation strategies for CCS. This is particularly challenging in the absence of national Governments seeking to take equity shares$^{35}$. 

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$^{35}$ National Government equity ownership of projects is considered for projects in Norway and the Middle East.
5.2 Economics of a cluster of fields

Following stakeholder discussions and analysis of multiple sensitivities, three EOR uptake scenarios, “Go Slow”, “Medium” and “Very High” were developed to help Scottish Enterprise understand plausible scenarios for CO₂-EOR development. The scenarios are not forecasts; rather they are views of how the world could develop that aid understanding.

Table 5: Quantitative description of EOR scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>EOR “Go Slow”</th>
<th>Medium EOR</th>
<th>“Very High” EOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of EOR projects modelled with start dates in</td>
<td>2</td>
<td>5</td>
<td>&gt;12</td>
</tr>
<tr>
<td>the period to 2016-2035</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak CO₂ supply for CO₂-EOR projects</td>
<td>Up to 12 Mt/yr</td>
<td>Up to 38 Mt/yr</td>
<td>Up to 120 Mt/yr</td>
</tr>
<tr>
<td>Cumulative fresh Mt CO₂</td>
<td>105</td>
<td>490</td>
<td>953</td>
</tr>
<tr>
<td>Cumulative recycled MtCO₂</td>
<td>259</td>
<td>1,239</td>
<td>854</td>
</tr>
<tr>
<td>Cumulative incremental EOR oil produced (million</td>
<td>300</td>
<td>1,356</td>
<td>2,807</td>
</tr>
<tr>
<td>barrels)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incremental base oil production (million barrels)</td>
<td>7</td>
<td>95</td>
<td>83</td>
</tr>
<tr>
<td>Cost of CO₂ supply for oil company £/t</td>
<td>£10/t</td>
<td>£0/t</td>
<td>-£10/t</td>
</tr>
<tr>
<td>(oilfield pays cost)</td>
<td></td>
<td></td>
<td>(Oilfield is paid to store CO₂)</td>
</tr>
<tr>
<td>Cost of CO₂ monitoring, liabilities etc.</td>
<td>£3/t</td>
<td>£2/t</td>
<td>£1/t</td>
</tr>
<tr>
<td>Tax breaks</td>
<td>PRT waiver only</td>
<td>PRT waiver only</td>
<td>PRT waiver Sliding scale Field Allowance capped at £10/barrel development cost.</td>
</tr>
</tbody>
</table>

To facilitate comparison between scenarios, reservoir performance, capital and operating costs the following “economic” inputs were held constant between scenarios:

- Oil price @ $90/barrel real (N.B. This is below DECC’s central oil price forecast but considered to be more relevant for oil company decision-making).
- Discount rate (10% nominal)
- Exchange rates (£1.16/€ and $1.6/£)
- Inflation (2.5%)
- Oil pipeline tariff (£2/barrel real)
- Payments for emitted CO₂ (DECC central scenario)
- Electricity purchase price (adapted from DECC central scenario)

The stacked bar chart in Figure 23 shows the resulting expenditure profiles emerging from the techno-economic modelling for the various scenarios. The cumulative discounted nominal costs are around £2bn, £7bn and £16bn in the Go Slow, Medium and Very High EOR scenarios, respectively. The graph confirms that under all scenarios, the biggest cost items for EOR relate to the construction and operation of platforms and wells, although this analysis excludes costs for pipelines and capture facilities.
These present an opportunity for Scottish supply chain activity, although one should note the order-of-magnitude uncertainty around the size of the EOR market and consider the market size in the context of current annual investment in the UKCS exceeding £10 bn/yr.

Table 6 illustrates the performance across a range of KPIs for the three scenarios. Considering only the UK fields, cumulative discounted nominal EBIT ranges from £0.7-13bn (at an oil price of $90/bbl), with developer NPV ranging from £0.2-4.7bn.
Table 6: Key Performance Indicators for EOR uptake scenarios (@$90/bbl)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Country</th>
<th>Cumulative EBIT (discounted at nominal 10%, excl. decomm.)</th>
<th>Cumulative Developers NPV (discounted at nominal 10%, post-tax and incl. decomm.)</th>
<th>PV of capex (discounted at nominal 10%)</th>
<th>Average discounted profitability</th>
<th>Average Unit Development Cost £/bbl</th>
<th>Incremental production / million barrels</th>
<th>Cumulative National Tax receipts (discounted at nominal 10%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Very High</strong></td>
<td>UK</td>
<td>£13 bn</td>
<td>£4.7 bn</td>
<td>£5.6 bn</td>
<td>0.84</td>
<td>£11</td>
<td>1,085</td>
<td>£8.9 bn</td>
</tr>
<tr>
<td></td>
<td>NO</td>
<td>£11 bn</td>
<td>£1.5 bn</td>
<td>£4.8 bn</td>
<td>0.32</td>
<td>£14</td>
<td>1,397</td>
<td>£9.9 bn</td>
</tr>
<tr>
<td></td>
<td>DK</td>
<td>£24 bn</td>
<td>£1.5 bn</td>
<td>£1.2 bn</td>
<td>1.24</td>
<td>£9</td>
<td>325</td>
<td>£3.2 bn</td>
</tr>
<tr>
<td></td>
<td>UK+NO+DK</td>
<td>£48 bn</td>
<td>£7.7 bn</td>
<td>£11.5 bn</td>
<td>0.67</td>
<td>£12</td>
<td>2,807</td>
<td>£22 bn</td>
</tr>
<tr>
<td><strong>Medium</strong></td>
<td>UK</td>
<td>£3.2 bn</td>
<td>£0.94 bn</td>
<td>£2.11 bn</td>
<td>0.45</td>
<td>£11</td>
<td>420</td>
<td>£2.5 bn</td>
</tr>
<tr>
<td></td>
<td>NO</td>
<td>£3.1 bn</td>
<td>£0.33 bn</td>
<td>£1.16 bn</td>
<td>0.29</td>
<td>£8</td>
<td>608</td>
<td>£2.8 bn</td>
</tr>
<tr>
<td></td>
<td>DK</td>
<td>£6.3 bn</td>
<td>£0.61 bn</td>
<td>£1.08 bn</td>
<td>0.56</td>
<td>£10</td>
<td>328</td>
<td>£1.8 bn</td>
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<tr>
<td></td>
<td>UK+NO+DK</td>
<td>£12.5 bn</td>
<td>£1.88 bn</td>
<td>£4.35 bn</td>
<td>0.43</td>
<td>£9</td>
<td>1,356</td>
<td>£7.1 bn</td>
</tr>
<tr>
<td><strong>Go Slow</strong></td>
<td>UK</td>
<td>£0.71 bn</td>
<td>£0.22 bn</td>
<td>£0.45 bn</td>
<td>0.5</td>
<td>£10</td>
<td>137</td>
<td>£0.56 bn</td>
</tr>
<tr>
<td></td>
<td>NO</td>
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<td>0</td>
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</tr>
<tr>
<td></td>
<td>DK</td>
<td>£0.71 bn</td>
<td>£0.15 bn</td>
<td>£0.50 bn</td>
<td>0.3</td>
<td>£9</td>
<td>163</td>
<td>£0.67 bn</td>
</tr>
<tr>
<td></td>
<td>UK+NO+DK</td>
<td>£1.42 bn</td>
<td>£0.38 bn</td>
<td>£0.95 bn</td>
<td>0.4</td>
<td>£10</td>
<td>300</td>
<td>£1.2 bn</td>
</tr>
</tbody>
</table>

As well as the oil companies, the Table shows that an important beneficiary from large scale CO₂-EOR development is the relevant national Government through increased tax receipts amounting to several billion pounds.

The tax receipts from EOR are of course highly sensitive to project EBIT and tax rate. The EBIT depends on many factors, not least the performance of reservoirs and oil prices. However in the event of high tax receipts from EOR projects, funding could be channelled to provide subsidies for capture and transport, or helping with broader national economic objectives. Conceptually the recycling of EOR tax receipts is shown in Figure 24.
According to one developer, the tax receipts from IGCC with CO₂-EOR make their proposed project competitive with unabated fossil power generation. Modelling carried out by the present authors confirmed this potential outcome in some scenarios (Data not shown). More generally a benefit equivalent to a reduction in levelised cost of generation of the order of £10s per MWh could be achieved if the profits and tax benefits from oil production were passed back to the power station. However the modelling also revealed the range of possible impacts from CO₂-EOR on power station economics is large. It is not clear that generators would wish to be exposed to the oil price and EOR performance risk. Conversely, the modelling also identified that the impact on CO₂-EOR economics (through CO₂ price and timing and amounts of CO₂ supply) from variable performance of power station with capture plant is also potentially large.

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Figure 24: Possible feedback from EOR projects in support of CCS development

![Diagram showing possible feedback from EOR projects in support of CCS development.](http://www.all-energy.co.uk/Userfiles/Image/1400_Lewis_Gillies_Gordon_B_Wed-23-May.pdf)
6 Supply chain impacts for CO₂-EOR

The overall size of the CO₂-EOR opportunity in the UKCS can be set in context. Based on the size, technical suitability and timing filters, this report identifies at least 12 large CO₂-EOR projects could be developed by 2030 in the North Sea region. Kemp suggests the numbers of producing hydrocarbon fields in the North Sea in 2030 will be up to 250, although the uncertainty is large and dependant primarily on oil price. Therefore in the Very High CO₂-EOR scenario, UKCS CO₂-EOR projects would amount to around 3-4% of total hydrocarbon fields by number in the UKCS in 2030. Clearly therefore any measures to support CO₂-EOR supply chains should form a part of wider programmes for the UKCS.

6.1 The importance of Anchor fields

Given that a number of these CO₂-EOR fields are in close geographical proximity, and that onshore CO₂ sources are also mostly clustered along the eastern side of the UK, there might be a few ‘anchor fields’ which receive CO₂ from shore via a pipeline or ship. CO₂ could then be distributed to other anchor fields and/or satellite projects within the ‘end field’ catchment area by spur pipelines e.g. in a hub-and-spoke arrangement.

A small number of CO₂ trunk pipelines running from shore to ‘end fields’ for use and distribution to other CO₂-EOR projects is likely to be a more efficient and cost-effective system than each field having its own dedicated CO₂ supply. However, this trunk pipeline and ‘end field’ scenario is likely to result in less supply chain work.

The CO₂ may have to be compressed when it arrives at an anchor field in order for it to be injected into the field’s reservoir. Compression is likely if existing pipelines (e.g. the Miller gas line) are re-used to transport CO₂. If new, purpose-built CO₂ pipelines are constructed they may be able to operate at sufficient pressure that re-compression at the field is not required before injection into the reservoir. The injection of CO₂ into Norway’s Snøhvit field is through onshore compression alone.

It is possible that liquid CO₂ could be transported to anchor fields by ship. This would require new liquefaction, storage, heating/compression infrastructure, at a shore terminal(s) and/or offshore. Again, ‘anchor fields’ might be developed with the facilities able to receive CO₂ from ships for compression and distribution to satellite fields for CO₂-EOR. Specialist CO₂ ships would have to be built and/or converted from an existing role.

Where offshore compression is required, it may be necessary to construct and install a new satellite platform to house the compressor. This may be easier and less technically challenging than trying to install CO₂ compression equipment on an existing platform which had not been designed for it (and there may not be any room on the existing platform for new compression facilities).

It is expected that new CO₂ injection wells will be needed on a field as part of a CO₂-EOR project, although other existing wells might be able to be re-engineered and re-completed as CO₂ wells. A new platform housing the CO₂ compression facilities might also be designed to operate as a well-head platform if additional well slots were required. If no temperature or pressure management was required, a subsea template could provide additional well slots.

6.2 Supply chain for CAPEX investments

The infrastructure required for CCS and CO\textsubscript{2}-EOR will provide opportunities for the supply chain (both in the UK and internationally) to bid for contracts. Excluding onshore power generation, capture and onshore distribution pipelines, this could include:

- Onshore compression at shoreline ‘terminal(s)’
- Offshore trunk CO\textsubscript{2} pipelines (new construction)
- Offshore trunk CO\textsubscript{2} pipelines (refurbishment / re-use of existing pipelines)
- CO\textsubscript{2} shipping (onshore terminal(s), ships, ‘end field’ facilities)
- Offshore CO\textsubscript{2} spur lines (from ‘end field’ to satellite CO\textsubscript{2}–EOR projects)
- Offshore CO\textsubscript{2} compression platforms
- Offshore CO\textsubscript{2} compressors
- Development drilling (CO\textsubscript{2} injection wells)
- Reworking of existing wells
- Operating supply chain (once CO\textsubscript{2}–EOR projects are on-stream)

6.2.1 CO\textsubscript{2} compression and pumping

Compressors and pumps are broadly similar to conventional equipment, but designed for the unique physical and chemical properties of CO\textsubscript{2}. Some Scottish companies provide pumps and compressors for the upstream industry and may be able to diversify into supplying CO\textsubscript{2} compressors and pumps. One issue may be the limited number of CO\textsubscript{2} compressors and pumps that may be required in the North Sea – may not make diversification attractive and/or viable. Significant competition comes from US suppliers such as KBR, which is responsible for the CO\textsubscript{2} compression and pipeline for the In Salah CO\textsubscript{2} injection project in Algeria and undertook FEED study for CO\textsubscript{2} removal at the Melkoya gas terminal in Norway; General Electric, which has extensive knowledge of dense phase pumping; and Willbros. US companies are likely to have a competitive advantage given extensive use of CO\textsubscript{2}-EOR in many fields in the US Permian Basin.

6.2.2 New CO\textsubscript{2} trunk pipelines to ‘end fields’ and spur pipelines to satellite CO\textsubscript{2}-EOR projects

Some pipeline engineering capacity for CO\textsubscript{2} lines may exist in Scotland, but likely to be a diversification from conventional oil and gas pipeline business. Significant competition exists including US engineering firms, as well as Norwegian firms Aker and Kvaerner. Scottish pipeline construction companies are near Wick (though more of a specialist in subsea pipeline bundles) and Leith (specialist pipeline coating company, although facility may close due to lack of pipeline demand in the North Sea).

6.2.3 Refurbishment / re-use of existing pipelines to transport CO\textsubscript{2}

Where it is feasible, refurbishment of pipelines could be a very cost-effective transportation solution, although the viability of the pipelines (e.g. the disused line from the abandoned Miller field to St Fergus and the original oil pipeline from Forties to Cruden Bay) to transport CO\textsubscript{2} is uncertain. It also requires a suitable CO\textsubscript{2}-EOR ‘end field’ to be located close to the offshore pipeline location. The Scottish supply chain should be able to participate in any inspection and refurbishment of existing lines and particularly with the construction of any new risers and ‘J tubes’ required connecting the pipelines to the ‘end fields’. However the workload associated with this will be at least an order-of-magnitude less than would be involved with a new pipeline.
6.2.4 CO₂ transport by ship

If shipping was to be used in the North Sea, harbour facilities for CO₂ loading would need to be constructed, together with CO₂ unloading facilities at the ‘end field’, which could be technically challenging. This work could provide opportunities for the Scottish supply sector. CO₂ ships would need to be procured or constructed, but this is unlikely to have a significant impact on the Scottish upstream supply sector. Yara, a Norwegian company, is currently the leading company in transporting CO₂ by ship. In 2010 Maersk Tankers announced that it was designing a CO₂ ship with Hyundai Heavy Industries and DNV. The potential for a CO₂ shipping hub at Peterhead is being studied separately by Scottish Enterprise.

6.2.5 Front End Engineering and Design for CO₂-EOR offshore platforms and facilities

FEED for CO₂-EOR should be a Scottish supply chain strength, diversifying from traditional upstream oil and gas engineering and design work. Some CO₂-EOR design work has been done for UKCS fields. A few Scottish companies are thought to have CO₂- EOR FEED capabilities and some experience. Strong competition will come from Norwegian contractors, Aker and Kvaener – both companies heavily involved in the CCS projects on Sleipner and Snøhvit in Norway. Given the “brownfield” nature of EOR, contractors already employed on existing platforms which require modifications for CO₂- EOR should be well-placed to compete for this work given their relationships with the platform operator and detailed engineering knowledge of the platform’s facilities. For example, PSN were involved in the BP Miller project design because they were the incumbent owner’s engineer.

6.2.6 CO₂ compression platform fabrication (and subsea wellheads)

Platform fabrication should be a UK and Scottish strength, with 17 yards in total of which 3 are in Scotland.38 The Scottish yards are Babcock Marine, Rosyth (fabricates subsea modules but no jacket experience); Burntisland Fabricators, Burntisland, Methil and Arnish (fabricates jackets, decks, topsides and modules); and Global Energy Group, Cromarty Firth (has the largest fabrication facilities in the UK having recently bought the Nigg facility). Other companies that may get involved in fabrication for the offshore industry include Merpro, Montrose (topsides and processing equipment) and ZE1, Shetland (modules and templates).

The Scottish fabrication sector should be able to compete for CO₂-EOR offshore platforms and facilities, but will face significant competition for contracts from other UK yards, European and Far Eastern contractors. Including Scottish platform suppliers in early engineering studies may improve supply chain opportunities later.

6.2.7 Development drilling for CO₂ injection wells

Development drilling is a routine activity in the North Sea, using fixed platform rigs on many established installations and mobile drilling rigs (semi-submersibles and jack-ups) where wells are required (for example on new wellhead jackets and subsea wells heads). Drilling of development wells for CO₂ injection will provide opportunities for the Scottish oil supply sector. The number of CO₂ wells for EOR is likely to be much smaller than for conventional oil and gas well drilling in the near term. Over the period to 2050, very high CCS scenarios could necessitate hundreds of wells for CO₂ storage (rather than EOR).

Experience developed in CO₂-EOR projects would be of direct relevance for CO₂ storage projects, and vice versa.

6.3 Supply chain for OPEX investments

6.3.1 Oil and gas OPEX

UK Continental Shelf OPEX was £7.0 billion in 2011, including all UK oil and gas fields (Oil and Gas UK, 2012 Annual Survey). According to Wood Mackenzie, UKCS 2012 OPEX is £6.2 billion, which excludes the general and admin costs that may be in the Oil and Gas UK estimates. Of the £6.2 billion, OPEX for fields in the Atlantic Margin, Northern North Sea and Central North Sea is £5.2 billion (84%). These fields are almost certainly going to have Scottish-based supply ports and a lot of Scottish-based service companies supplying the fields as a result.

6.3.2 CO₂-EOR OPEX

Fields suitable for CO₂-EOR are generally regarded as ‘late-life’ assets. Most of the potential CO₂-EOR ‘anchor projects’ which have been identified are fields which started up in the 1970s (Beryl, Claymore, Cormorant, Forties, Ninian etc.). Many of these fields consist of multi-platform developments, with some (if not all) of the platforms being permanently manned facilities. Direct operating costs for these fields (excluding any pipeline operating or tariff costs) are currently in the region of £80-100 million/year per field.

More recent fields, which are still regarded as potential CO₂-EOR anchor projects, include Scott (first production 1993) and Buzzard (2007). These are both multi-platform and manned developments, but with advances in platform design and technology, direct operating costs (excluding transportation tariffs) are around £70 million/year for each field. In comparison, a very recent field, Golden Eagle (development consent given 2011; first production in 2014) has direct operating costs expected to be £60 million/year (excluding transportation tariffs), with capital costs for a Production, Utilities and Quarters platform linked to a well-head platform of around £1,900 million.

Manned facilities are expensive to operate. Of the potential CO₂-EOR ‘anchor fields’, Beryl, Brent, Forties and Ninian each have offshore accommodation for around 600 to 700 people. With cost-saving and de-manning measures over the years, this accommodation is only likely to be close to fully-utilised during occasional periods of intense maintenance and/or refurbishment programmes. An active development/in-fill drilling campaign will also require a higher crew number to be on-board (although for newer platforms mobile drilling rigs may be brought in to do the development drilling). Generally, it is thought that crew levels are normally between 50-70% of accommodation capacity in these fields. Platform labour, supply vessels and helicopters are thought to account to 30-40% of total direct operating costs.

Operating the platform is thought to account for 40-50% of total direct operating costs. This includes platform utilities (power generation – a significant item; water/gas processing and injection – where it occurs); hydrocarbon processing (separating oil, gas and produced water etc); the safety systems (including stand-by vessels) needed to operate a platform in line with HSE requirements; and miscellaneous items (such as chemicals). Onshore support is thought to be around 20% of a field’s direct operating cost (general and administration costs; reservoir modelling; engineering support etc.).
Shell estimated that for the Goldeneye project, Measurement, Monitoring and Verification (MMV) costs for CO₂ storage would be in the range £3/tCO₂ stored, although the exact value may be site-specific.

As infrastructure has already developed in the North Sea, new developments are often “not normally manned” facilities or subsea systems in order to cut capital and operating costs. Not normally manned fields include Erskine (direct operating costs around £20 million/year, excluding transportation tariffs). A platform development is usually required where there is insufficient processing capacity on the ‘mother’ platform which controls the remote platform. Operational and maintenance work on the remote platform is done by workers commuting daily from the ‘mother’ platform. Temporary accommodation facilities are available in the remote platform if needed. CO₂ storage facilities (as distinct from EOR) are likely to be not normally manned and therefore have cheaper capex and opex than EOR fields.

Many mature fields in the North Sea do have spare processing capacity as their own production has declined. This allows satellite fields to be developed using cheap subsea systems tied-back to an existing platform which provides control, utilities (gas/water for injection if needed, chemicals) and processes the production stream. There are many examples of satellite fields being developed by subsea systems in the North Sea, including Bacchus (due on-stream in 2012 tied-back to the Forties Alpha platform; capital costs estimated to be just over £200 million; direct operating costs around £5 million/year, excluding tariffs for oil processing on the Forties platform and transportation through the Forties Pipeline System to shore).

It is estimated that somewhere between 60-80% of all the operating costs from UK North Sea oil fields is actually spent in the UK (including most labour, supply and stand-by vessels and helicopters). Operating expenditure on engineering work (such as compressor maintenance) is more discretionary, but UK-based companies should be well-placed to compete in this market.

A CO₂-EOR project would increase direct operating costs for an ‘anchor field’. Costs could include running CO₂ compressors onshore and offshore for transporting and injecting CO₂; maintenance of the CO₂ pipeline and CO₂ injection wells; and the running costs of a new wellhead / compression platform (if installed, this is likely to be bridge-linked to the main field platform). Little additional labour might be needed given the existing workforce – here the main opportunity from EOR is extending the employment of the existing workforce rather than “new” jobs.

The cost of buying the CO₂ may be an additional expense, although an equally possible scenario is that oilfields receive payments for storing CO₂.

For satellite CO₂-EOR projects, the main operating cost is likely to be the tariff payable to the anchor field for transportation of the CO₂ (with further tariffs possibly paid for offshore compression and processing the production stream including CO₂ if provided by the anchor field).

6.4 Procurement

Most of the operations, maintenance and drilling workforce on North Sea platforms are employed by contractors – there are relatively few employees from the oil company acting as the operator of the installation. Procurement by the service companies is very important to win these contracts (which are often of significant value).
Many operators will typically award contracts for all their platforms under an umbrella contract, rather than have individual contracts with service companies for each field. For example, in 2011 Talisman awarded Wood Group PSN a 5 year contract (with an option to extend for another 5 years) to provide operations and maintenance services on its 11 operated fields in the North Sea, plus the Flotta oil terminal. The contract is worth £90 million/year. In addition, Talisman extended Wood Group PSN’s engineering and modifications contract, worth £50 million/year, to end-2012. These contracts reflect Talisman’s working relationship with Wood Group PSN over the last 8 years. In 2011 Wood Group PSN also extended for 5 years a contract for operations, maintenance, engineering and construction with TAQA for its North Sea operated assets.

These contracts illustrate the strong position that successful, incumbent contractors are in to maintain their relationships with North Sea operating companies. Over time the incumbent service companies gain detailed knowledge of the platforms they are working on. This can be difficult for other service companies to compete against when the contracts are up for renewal.

With no CO2-EOR or CCS projects in the UK North Sea, the UK service companies have limited experience in this area (with the possible exception of the companies involved in the design work for the Miller and GoldenEye CO2 projects). UK service companies may face tough competition in the Front End Engineering and Design of CO2 facilities from Norwegian competitors such as Aker and Kvaerner (involved in the Sleipner and Snohvit CO2 projects in Norway) and US competitors such as KBR (involved in the In Salah CO2 project in Algeria).

However, once the CO2 facilities have been installed, there is little difference in operating and maintaining them compared to existing ‘non-CO2’ facilities on a platform (a CO2 compressor essentially uses the same equipment as a natural gas compressor, although some safety training will be required).

In the UK, contracts for capital projects (platforms, facilities, pipelines etc) and operating projects (platform operations, maintenance, supplies etc.) are open to competitive tender. This is supported by EU procurement rules and the UK government’s free market approach. The UK-based service companies have performed well, with perhaps 60-80% of UK North Sea operating costs being spent within the UK. The fabricators have found competition tougher, particularly on capital-intensive projects such as platform jacket and topsides fabrication; many of these recent contracts have gone to European or Asia Pacific fabrication yards.
6.5 Impacts of CO$_2$-EOR on the Scottish economy

The impacts on the Scottish economy from supply chain opportunities linked to CO$_2$-EOR were modelled using:

- The project capex and opex profiles over time
- Historical average Scottish shares of capex and opex in oil and gas project development in the UKCS and Norwegian and Danish sectors of the North Sea.
- Five-year average Scottish oil and gas industry GVA/turnover and employment/turnover ratios
- A Treasury Green Book public sector real discount rate

The economic modelling described was used to estimate most likely net present impacts on the Scottish economy from the supply chain for CO$_2$-EOR under the EOR Go Slow, Medium and Very High scenarios described previously.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Increase in Direct Output</th>
<th>Turnover for Scotland</th>
<th>Direct and Indirect GVA increase for Scotland</th>
<th>Direct and Indirect Employment in Scotland/ Person-years</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOR Go Slow</td>
<td>£1.1 bn</td>
<td>£0.5 bn</td>
<td>£0.3 bn</td>
<td>750</td>
</tr>
<tr>
<td>Medium</td>
<td>£4.5 bn</td>
<td>£1.8 bn</td>
<td>£1.1 bn</td>
<td>2,500</td>
</tr>
<tr>
<td>Very High EOR</td>
<td>£11.3 bn</td>
<td>£4.3 bn</td>
<td>£2.7 bn</td>
<td>5,300</td>
</tr>
</tbody>
</table>

Note that the estimates above reflect a conservative approach to estimating economic impact from EOR. The economic impacts in Scotland could be larger if:
i) Developers' turnover and oil profits are included (there is at present no guarantee that the resulting revenues would be spent in Scotland).

ii) Tax revenues from the oil company are invested in the Scottish economy.

iii) The Scottish supply chain targets CCS and CO₂-EOR opportunities.

iv) Investments linked to pipeline and onshore parts of the CCS value chain are included.

v) CO₂-EOR extends the life of linked assets that are supplied by Scottish businesses.

vi) Scottish businesses are able to supply CO₂-EOR projects in Norway and Denmark (N.B. This could easily double the supply chain impact opportunities).

vii) Scottish businesses are able to leverage experience with CO₂-EOR in the UKCS to compete in supplying CO₂-EOR projects elsewhere in the world.

On the other hand, these estimates assume a counterfactual of decommissioning of oilfields. They do not reflect displaced supply chain potential from CO₂ storage only operations. The supply chain for conventional CCS is outwith the scope of this study. Since storage only solutions could also involve Scottish businesses, the net impact on the supply chain from CO₂-EOR relative to CO₂ storage only would be much smaller.

The modelling predicts a “lumpy” profile for economic impacts and employment over time, due to bursts of activity related to construction of offshore EOR platforms and wells followed by steady operation until eventual decommissioning. The time profiles for undiscounted GVA and employment impacts are shown below in Figure 25 and Figure 26 respectively.

![Figure 25: Undiscounted GVA for Scotland in the three CO₂-EOR scenarios under base conditions.](image-url)
Total GVA and employment for Scotland is maximised in the very high scenario with £2.7 billion of GVA and 5,300 person-years of employment under base conditions. As illustrated in the above figures, GVA and employment reach a peak in 2019 due to increased level of construction in the end of second phase for the oil fields that start their operation in the third phase.

As shown in the following sensitivity graphs for the Very High EOR scenario, combinations of interventions to encourage CO2-EOR and boost Scotland’s share of supply chain capex or opex investment beyond current average practice could boost GVA by a further £3bn and employment by an additional 7,000 person-years, i.e. total Scottish supply chain impacts of ca. £6 bn in GVA terms and 12,000 person-years.

Facilitating the supply chain boost could be an opportunity for Scottish Enterprise. Given the scepticism towards CO2-EOR described earlier, if this is of interest, the priority would be first to ensure the Very High CO2-EOR scenario materialises through organising stakeholders and policy advocacy activities, followed by supply chain engagement.
6.6 Conclusions on supply chain impacts

The development of CO₂-EOR UK in the North Sea will have an incremental rather than revolutionary impact for the UK and/or Scottish offshore supply industry through a small number of high value and high profile projects.

A small number of offshore trunk pipelines may either be refurbished and/or constructed as green-field projects to transport CO₂ to ‘anchor fields’, using CO₂ for EOR and, importantly, distributing CO₂ to other projects within their catchment area. In time, further satellite developments may also use this infrastructure to access CO₂ for EOR. CO₂ may also be transported by ship.

This development scenario will require CO₂ compression at the beach; trunk pipeline refurbishment and/or construction; offshore CO₂ compression platforms at ‘end fields’; development drilling and/or recompletion of wells as CO₂ injectors; spur pipelines to other CO₂-EOR projects. These projects will all require Front End Engineering and Design work. This scenario provides the key CO₂-EOR projects for which the existing supply chain would be expected to compete.

A high level of international competition for key contracts is expected. US and Norwegian firms have proven experience in overall project FEED and construction and installation of key items such as CO₂ compressors. Diversification into this area for UK/Scottish companies should be straightforward – but may not be seen as a key priority given the (perceived) small number of CO₂-EOR projects likely to be approved. If a larger portfolio of CO₂-EOR projects could be shown as being feasible, supply chain motivation to diversify could be increased.

Construction of offshore platforms and subsea templates is an existing core skill for the Scottish and other UK service companies. However, competition from European and Far Eastern fabrication yards is already a significant threat to Scottish supply companies for current fabrication contracts and this is unlikely to change for any new platforms required as part of a CO₂-EOR development.
Once a CO₂-EOR project is operational, there is likely to be very modest additional work for the oil supply industry over and above the field operating without CO₂-EOR. There will be some additional inspection and maintenance work (e.g. on CO₂ compressors) and related facilities. If a CO₂-EOR field is classified as a CCS installation under the ETS, then it must comply with all the CCS Directive requirements. Therefore additional reservoir engineering, modelling and monitoring is also likely to be required, which Scottish companies could benefit from. The main benefit for the service companies may simply be that EOR allows the close-of-production date for the field to be delayed, maintaining the on-going supply chain that is needed to keep the field’s facilities operational for longer. Therefore, once a CO₂-EOR project is operational the main benefit to Scottish service companies may be from extending the field’s life through EOR.

Much of the existing Scottish supply chain for the upstream industry is relevant to both CO₂ storage and CO₂-EOR projects. Participation in CO₂-EOR projects may help Scottish businesses compete in wider international markets for CO₂ storage or CO₂-EOR, although competition could be fierce. There are some gaps in indigenous capabilities, but diversification could close these. The challenge for the Scottish supply industry is that competition is tough – both from (i) contractors with proven CO₂-EOR and/or CCS experience; and (ii) international fabricators gaining awards for jackets / decks / subsea structures due to cheaper costs and/or an integrated Front End Engineering and Design and Engineering Procurement and Installation Contracts. More generally, incumbent suppliers may be favoured, and direct experience of CO₂-EOR may be only a marginal, rather than decisive, factor in selection.

The competition is likely to exist at high oil prices (which are likely to increase the attraction of CO₂-EOR projects to oil companies operating suitable fields). However, high oil prices will also increase the attraction of other green-field (or brown-field) projects within an oil company’s international portfolio. Given the fiscal discipline on capital investment, some projects may get delayed in favour of others – which could mean that CO₂-EOR projects do not get approved. The supply chain ability to deliver projects may not be that relevant, unless it causes significant cost inflation due to lack of capacity. It is thought unlikely that this would be the case for CO₂-EOR projects.

The Scottish supply chain and upstream service companies need to be kept fully informed about the prospects for North Sea CO₂-EOR projects (including all countries, not just the UK). Given that competition is tough, and that actual projects (in the short term) are likely to be limited, market intelligence and building on strong relationships will be crucial. This will allow the Scottish supply chain to diversify where further capabilities and skills are required; and to compete strongly and as early as possible when CO₂-EOR contracts are offered.

The lack of certainty around CO₂-EOR uptake in the UKCS may result in the Scottish supply chain adopting a wait-and-see, i.e. reactive approach. Existing scepticism around CO₂-EOR market development may best be countered by sustained policies at national and international level that send a clear signal indicating a substantial future CO₂-EOR market in the UKCS and beyond.
7 Recommendations for Scottish Enterprise to maximise CO₂-EOR

1) Scottish Enterprise should support a Champion for CO₂-EOR

The preceding analysis identifies that CO₂-EOR could provide significant direct opportunities for Scotland and the UK as a whole, but that there are numerous and diverse obstacles to maximising the EOR potential within the tight window of opportunities available. Critically, high levels of CCS uptake are far from certain under present arrangements, and the added complexities and challenging risk/reward profile for CO₂-EOR projects are a difficult sell for the boards of commercial oil companies, and by implication their supply chains, at the present time.

It is the authors’ view that in the face of these diverse obstacles, a market-led approach with only current policy initiatives is unlikely to deliver the highest rates of CO₂-EOR. If the highest levels of CO₂-EOR uptake are seen as desirable by Scottish Enterprise, some near-term interventions may be necessary, given long lead times and a fairly limited window of opportunity.

Any public intervention must obviously focus on the specific market failures, such as information asymmetries, externalities such as the public goods associated with CO₂ storage that do not easily trickle down from incentives placed in the power market or ETS, and the potential long-term benefits to the economy from developing supply chain capabilities through domestic markets for export to international markets. Public intervention could also consider whether the existing fiscal regime for the offshore oil & gas sector acts as a barrier to CO₂-EOR uptake.

Most of these technical, economic, regulatory, logistical, commercial barriers lie outside of Scottish Enterprise’s immediate experience, resources, and ability to control. However, over the coming years, there will be numerous opportunities to shape the activities of the UK and Scottish Governments, the EU, oil companies, power and industrial sources, capture, and pipeline investments to maximise the likelihood that CO₂-EOR opportunities could be developed.

Existing support for CO₂-EOR is fragmented across multiple organisations, with no coherent message to policymakers as to what is required to maximise uptake. A lesson learnt from the development of CCS initiatives to date (including for example, ZEP in EU, the Scottish Carbon Capture & Storage consortium, Yorkshire Forward’s work on a Humber CCS network, work by the Rotterdam Climate Initiative, and the Tees Valley Process Industries CCS Initiative) is that over the timescale of a few years, dedicated, knowledgeable and energetic individuals, supported by public, private, NGO and academic stakeholders can significantly advance CCS opportunities beyond what the market might deliver “organically”. This study considers there would be an advantage in having a “Champion” charged with maximising the potential for CO₂-EOR.

For efficiency, any Scottish Enterprise initiative must leverage existing public or private initiatives – the role of the champion being to develop a set of coherent messages from the various workstreams rather than duplicating them.

Importantly, if jointly funded by the public sector and industry, these Champions are likely to garner more credibility and longevity than initiatives led solely by CO₂-EOR developers.

39 Useful initiatives for EOR include DECC Pilot, CCSA EOR working groups, ZEP, North Sea Basin Task Force.
As such Scottish Enterprise’s key opportunity is to act as an “honest broker” between potential partners in developing a CCS system with EOR, and influence the actions of wider stakeholders to ensure rapid and successful deployment.

Any EOR “champion” should command the respect from end-of-life field owners; have an excellent record of brokering deals in the energy sector, together with a deep understanding of CCS, reservoir engineering, offshore pipelines and facilities, commercial arrangements in the oil production, pipeline, power and waste sectors, and Scottish, UK and European energy and climate policies and decision making. Also, the shared response to Consultations from a CO$_2$-EOR Champion comprising a range of stakeholders would both reduce the burden for individual organisations and increase impact.

Finally, provision of a CO$_2$-EOR champion is well within Scottish Enterprise’s capabilities, having been deployed with some success in other sectors of the low carbon economy.

2) Scottish Enterprise should take the lead in facilitating knowledge sharing and co-operation across a wide range of stakeholders

To demystify and raise interest in CO$_2$-EOR, as well as to counter any disillusionment with CCS following the high profile failures of previous attempts, Scottish Enterprise should facilitate extensive knowledge sharing between North Sea oil industry stakeholders, and individuals and organisations involved in operational CO$_2$ injection projects in the US, Canada, Norway, Australia, Algeria and Brazil.

The precise approach taken should be tailored primarily to the knowledge or skills gaps of those oil companies with significant CO$_2$-EOR assets in the North Sea, and their supply chains. Potential gaps identified in the course of this study include reservoir engineering for miscible gas injection (particularly CO$_2$), materials selection and corrosion control with CO$_2$-rich fluids, design and operation of high pressure CO$_2$ pipelines, operation and maintenance of CO$_2$ injection facilities and wells.

It could involve workshops in Aberdeen, Stavanger and Houston, support for training or attending conferences, and staff exchange placements.

Suggested invitees for workshops include (i) the owners, operators and owners’ engineers, commercial leads and legal teams for all the CO$_2$-EOR oilfield candidates identified in this study; (ii) HM Government (including representatives from DECC’s oil and gas team and from OCCS; HM Treasury and BIS); (iii) CCS project developers (and participants in the power, industry, capture, onshore and offshore transport networks, storage, EOR) and their engineers and commercial teams; (iv) Trade associations (including CCSA and Oil and Gas UK); (v) International stakeholders (European Commission, European Investment Bank, interested MEPs, ZEP, Global CCS Institute); (vi) Interested parties within the North Sea Basin Task Force; (vii) experienced reservoir engineers, commercial leads and legal professionals from CO$_2$-EOR projects and pipelines internationally (e.g. Houston); (viii) contracts experts from the waste management industry; (ix) academics specialising in EOR and/or public perception; (x) companies that could participate in any CO$_2$-EOR supply chain opportunities; (xi) regulators and (xii) interested NGOs.

Scottish Enterprise should work with UK and international CCS conference promoters to ensure that more UKCS oil companies can become active participants within the CCS community.

Scottish Enterprise should also monitor developments in public perception of issues relevant to CCS with CO$_2$-EOR, assisting environmental NGOs, where appropriate, as they campaign to raise the awareness of climate change and scrutinise the impacts of
policies and measures by stakeholders. Scottish Enterprise has good experience of facilitating knowledge sharing, and is already well connected to many of the organisations listed.

3) Scottish Enterprise should raise awareness of the supply chain opportunities for CO\textsubscript{2}-EOR projects

Following previous market awareness raising opportunities, followed by high profile CCS project failures, there may be some apathy among suppliers in planning for CCS and CO\textsubscript{2}-EOR.

Scottish Enterprise could leverage its existing connections with the offshore supply chain to ensure relevant buyers and Scottish businesses have a deep understanding of the products and services required to deliver a CO\textsubscript{2}-EOR project. At the most basic level, this could be based on participation in any CO\textsubscript{2}-EOR Task Force or through facilitated workshops between buyers and suppliers.

However, given the novelty of offshore CO\textsubscript{2}-EOR for Scottish businesses, the highest quality information could be made available through a jointly-funded FEED study. Some of the larger suppliers of products and services for EOR projects may be able to provide support-in-kind for FEED studies, recognising this may provide a valuable reference project when competing for actual projects.

Any activities to ensure the Scottish supply chain is aware of the potential to participate in CO\textsubscript{2}-EOR projects in the UKCS or internationally should, of course, be carried out as part of and fully aligned with wider supply chain initiatives across CCS, and other technologies for boosting oil recovery.

4) Scottish Enterprise should provide constructive support for CO\textsubscript{2}-EOR cluster development through a Task Force focussed on the needs of the relevant oil companies

A CO\textsubscript{2}-EOR Task Force funded by Scottish Enterprise, oil industry and key suppliers could provide leadership, organisation and a forum for discussions for late-field oil companies who may be relevant in the development of a cluster of CO\textsubscript{2}-EOR projects.

The proposed Task Force could begin the long process of preparing for a future CO\textsubscript{2}-EOR market within the context of wider challenges for CCS deployment and EOR in the North Sea. The Task Force could examine, as it sees fit, issues such as:

- shared FEED studies for flexible offshore CO\textsubscript{2}-EOR infrastructure
- future-proofing of platforms and wells for CO\textsubscript{2}-EOR
- design specifications for CO\textsubscript{2} transport infrastructure
- understanding business models to allocate risks, costs and benefits with a CCS chain that includes CO\textsubscript{2}-EOR
- model contract agreements that can help speed the process through stage gates
- preferred levels and mechanisms for financial support for CO\textsubscript{2}-EOR, including taxation
- scenarios where incumbents in anchor EOR fields wish to pursue CO\textsubscript{2}-EOR as well as those where EOR development would need to involve third parties
- mutually acceptable mechanisms for the transfer or sharing of data, models, and know-how between potential partners within a CO\textsubscript{2}-EOR network.
- mutually acceptable mechanisms for providing access or liability sharing for assets and infrastructure between potential partners within a CO\textsubscript{2}-EOR network.
• developing appropriate regulatory frameworks for CO₂-EOR including transitions between different licensing systems.
• HSE issues specific to CO₂-EOR deployment in the North Sea

Importantly, the Task Force should leverage existing DECC-led PILOT, CCSA, NSBTF and ZEP EOR working groups that are tackling aspects of these questions.

5) Scottish Enterprise should facilitate continued co-operation between the Scottish and UK Governments across energy and climate policies relevant to CO₂-EOR

The UK and Scottish Government have shown significant co-operation over recent years in energy and climate policy, and all main political parties are committed to supporting CCS technology. This consistency has been welcomed by the majority of stakeholders.

Investments linked to CO₂-EOR projects will be typically major multi-billion pound investments intended to last decades, and are therefore challenged by major differences or changes or discontinuities in legal, regulatory and economic systems. Given the tight window of opportunity for CO₂-EOR, both UK and Scottish Governments will need to provide the industrial partners in CO₂-EOR with consistency of approach and some visibility of continuity for the power sector, oil and gas, and linked sectors in the event of any future constitutional change. This will help to avoid possible delays in investment or the use of high hurdle rates to account for the political/regulatory risks. Whilst outside of Scottish Enterprise’s direct control, Scottish Enterprise should ensure relevant organisations are made aware of potential issues flagged in respect of this issue by the proposed CO₂-EOR Champion/Task Force so these are managed in a timely manner.
8 APPENDIX

8.1 EOR methods

CO₂-EOR is only one of a range of methods currently deployed worldwide to extend recovery from oilfields. All current EOR methods are based on one or more of the following two principles:

- increasing the capillary number (reducing oil-water interfacial tension, which increases the mobility of the oil)
- and/or lowering the mobility ratio compared to their water-flood values

In practice, increasing the capillary number means reducing oil-water interfacial tension, which increases the mobility of the oil. The injectant mobility may be reduced by increasing water viscosity, reducing oil viscosity, reducing water permeability or all of the above, leading to a more efficient sweep process.

Globally there are nearly 170 CO₂-EOR projects underway, although other EOR techniques are used more widely. EOR projects on the UK Continental Shelf (UKCS) include two water-alternating gas (WAG), three miscible natural gas, and one immiscible gas.

![Figure 29: EOR projects globally](image-url)

40 Capillary number $N_c$ is used to represent the ratio between viscous and capillary forces in a two phase fluid system e.g. water displacing oil. The most commonly used form of the capillary number is $N_c = \frac{V}{\eta_0 \cos \theta}$ where $V$ is the apparent or superficial velocity of the displacing phase, $\eta_0$ is the Newtonian or dynamic viscosity of the displacing phase, $\theta$ is the interfacial tension between the displacing phase and the oil and $\theta$ is the upstream equilibrium contact angle.

41 Mobility ratio $M$ expresses the ratio of the mobility of the displacing phase to the mobility of the displaced phase. Again, in a two phase fluid system e.g. water displacing oil, $M = \frac{\lambda_w}{\lambda_o}$ where $\lambda_w$ is the mobility of water and $\lambda_o$ is the mobility of oil. Mobility of water $\lambda_w = k_w / \eta_w$ and mobility of oil $\lambda_o = k_o / \eta_o$ where $k_w$ is the effective or relative permeability to water in the presence of oil, $k_o$ is the effective or relative permeability to oil in the presence of water and $\eta_w, \eta_o$ are the water and oil viscosities respectively.

42 Adapted from Adasani, A.A. and Bai, B., 2011, Analysis of EOR projects and updated screening criteria.
8.1.1 Gas EOR methods

These methods are capillary number increasing methods. They are also called solvent flooding, miscible-gas flooding or simply gas flooding. The injectant can be dry gas, enriched gas (hydrocarbon miscible), CO$_2$, nitrogen or flue gas, or a combination of these.

Solvent methods recover oil by mass transfer. For some methods, the mass transfer of intermediate hydrocarbon components is from the crude to the solvent (vaporizing gas drive) and for others the transfer is from the solvent to the crude (condensing or rich gas drives). CO$_2$, nitrogen or flue gas methods are vaporizing gas drives and hydrocarbon miscible drives are the latter. In all cases it is the intermediate component, the component that is doing the transferring, that is key. If the reservoir pressure is high enough (or if there is sufficient intermediate content at the current pressure), the mass transfer will result in a mixture that is miscible with the crude, in which case the predominant recovery mechanism is a miscible displacement. In a miscible displacement, interfacial tension vanishes and capillary number becomes infinite. Failing this, the displacement will be immiscible.

Under favourable oil/reservoir conditions the oil and CO$_2$ can mix forming a single-phase liquid which enhances the ability of the oil to flow out of the reservoir. The primary reservoir condition for miscibility to occur is that the pressure must be greater than the minimum miscibility pressure (MMP) so that the CO$_2$ becomes fully mixed with the oil.

The incremental oil recovery with miscible CO$_2$-oil mix is often limited by the occurrences of unstable flow (viscous fingering), which may lead to early breakthrough of CO$_2$ if oil is by-passed. Consequently, the water-alternating-gas (WAG) technique has been used extensively in North America because the water sweep is usually more uniform and more sweep efficient.

On the other hand, an immiscible CO$_2$ displacement flood, where the MMP is not reached can still increase oil recovery in a low pressure reservoir with heavier oil. The mechanism here is that the CO$_2$ partially dissolves in the oil causing it to swell and reducing viscosity, although importantly it maintains reservoir pressure by creating an artificial gas cap which forces the oil down towards producing wells at the reservoir rim. In contrast to miscible projects which can be implemented at a small scale over a short time period (1 to 5 years), immiscible flood projects operate at the whole field scale and take longer to produce additional oil (up to 10 years).

Immiscible displacements are not as efficient as miscible displacements but may still recover oil by swelling, viscosity reduction, permeability increase, or pressure build up. CO$_2$ and enriched hydrocarbons tend to be miscible solvents; nitrogen and flue gas tend to be immiscible.

Miscible displacements in the laboratory result in nearly 100% ultimate oil recoveries. Field-scale displacements recover much less, primarily because the solvent tends to be more mobile than the oil/water mixtures they are displacing, which leads to by-passing of the solvent around or through the oil. Bypassing is the result of reservoir heterogeneity and viscous instability between two fluid fronts. Some types of heterogeneity can result in substantial mixing in the reservoir and a loss of miscibility.

They are deep enough to permit the high pressures required to attain miscibility and often contain sufficiently light and low viscosity oils, both characteristics that are ideal for miscible EOR. Not only do North Sea reservoirs appear amenable to gas EOR, but most (16 of the 18) have already been proven successful with natural gas injection (see Table...
The confidence in success is evidenced by the willingness of some operators to implement projects (six of the 18) even though the miscibility pressure cannot be attained. These projects were classified as immiscible. Nine of the 18 projects were classified as miscible, and three of the projects were unclassified according to miscibility (classed as solvent flooding). All projects were classed as successful with the exception of Ekofisk and Snorre A (CFB).

On the other hand, thermal EOR methods are less likely to be successful offshore than onshore because of the high well spacing encountered in the North Sea. Other technologies are in RD&D stage and are likely to be tested onshore before application offshore is considered.

Table 9: Examples of North Sea tertiary recovery tests

<table>
<thead>
<tr>
<th>Field</th>
<th>Operator</th>
<th>Country</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beryl</td>
<td>Exxon-Mobil</td>
<td>UK</td>
<td>HC Miscible</td>
</tr>
<tr>
<td>Brent</td>
<td>Shell</td>
<td>UK</td>
<td>HC Miscible</td>
</tr>
<tr>
<td>Alwyn North</td>
<td>Total</td>
<td>UK</td>
<td>HC Miscible</td>
</tr>
<tr>
<td>South Brae</td>
<td>Marathon</td>
<td>UK</td>
<td>HC WAG Miscible</td>
</tr>
<tr>
<td>Magnus</td>
<td>BP</td>
<td>UK</td>
<td>HC WAG Miscible</td>
</tr>
<tr>
<td>Ekofisk</td>
<td>ConocoPhillips</td>
<td>NO</td>
<td>HC Miscible</td>
</tr>
<tr>
<td>Statfjord</td>
<td>Statoil</td>
<td>NO</td>
<td>HC Miscible</td>
</tr>
<tr>
<td>Smorbukk South</td>
<td>Statoil</td>
<td>NO</td>
<td>HC Miscible</td>
</tr>
<tr>
<td>Snorre</td>
<td>Statoil</td>
<td>NO</td>
<td>HC WAG Miscible</td>
</tr>
<tr>
<td>Thistle</td>
<td>Lundin Oil</td>
<td>NO</td>
<td>HC WAG Immiscible</td>
</tr>
<tr>
<td>Gullfaks</td>
<td>Statoil</td>
<td>NO</td>
<td>HC WAG Immiscible</td>
</tr>
<tr>
<td>Brage</td>
<td>Norsk Hydro</td>
<td>NO</td>
<td>HC WAG Immiscible</td>
</tr>
<tr>
<td>Ekofisk</td>
<td>ConocoPhillips</td>
<td>NO</td>
<td>HC WAG Immiscible</td>
</tr>
<tr>
<td>Statfjord</td>
<td>Statoil</td>
<td>NO</td>
<td>HC WAG Immiscible</td>
</tr>
<tr>
<td>Oseberg</td>
<td>Norsk Hydro</td>
<td>NO</td>
<td>HC WAG Immiscible</td>
</tr>
<tr>
<td>Snorre A (CFB)</td>
<td>Norsk Hydro</td>
<td>NO</td>
<td>HC FAWAG</td>
</tr>
<tr>
<td>Snorre A (WFB)</td>
<td>Norsk Hydro</td>
<td>NO</td>
<td>HC FAWAG</td>
</tr>
<tr>
<td>Siri</td>
<td>Statoil</td>
<td>DK</td>
<td>HC SWAG</td>
</tr>
</tbody>
</table>

Water alternating gas injection

The bypassing can be eliminated or at least reduced by co-injection of water with the solvent (the WAG process), conducting the flood in a gravity stable mode and/or using foams to reduce the gas mobility. Most of the reported results have been on CO₂ solvent flooding in the US where ultimate recoveries of 12% of the original oil in place and utilization factors of 10 thousand cubic feet (Mcf) of solvent per incremental barrel of oil recovered are reported.

43 for further info see Awan, Teigland and Kleppe, SPE Reservoir Evaluation and Engineering (2008) 11 (3) 497-512
**Geographic distribution of CO$_2$-EOR**

From first application in the 1970s to date, the majority of CO$_2$-EOR projects worldwide have been implemented onshore in the North American oilfields. It is experience from these which provides the basis for most of the relevant guidelines that have been drawn up.

No projects have been deployed in the North Sea, although the Miller oilfield was recently considered for CO$_2$-EOR by BP and SSE. The plan was rejected, and the field is now being decommissioned. Most existing projects have utilised natural CO$_2$ transported over extensive long-distance pipeline networks, but new projects continue to come on stream utilising anthropogenic CO$_2$ as economic incentives and other imperatives for sequestration increase.

**Reservoir conditions for CO$_2$-EOR**

CO$_2$ has been injected in sandstone, limestone, dolomite, conglomerate, tripolite and unconsolidated sand formations, the majority being either sandstone or dolomite. CO$_2$-EOR has been implemented in reservoirs where previous production was most commonly by water-flooding, but also many by primary depletion, and occasionally by gas injection. Onshore field sizes vary from as small as 5 acres to as large as 50,000 acres, and may involve as few as 1 production well or as many as 1,000, and as few as 1 injection well to over 800 injection wells. Permeability values range from 1.5 mD to 3 D, porosities from 3 to 32%, depths from 1150 feet to almost 12,000 ft, temperatures from 82 °F to 257 °F, oil viscosities from 0.4 cP to 592 cP (for reference, water viscosity is usually in range 0.5 cP to 1 cP, depending on pressure, temperature and salinity), oil saturations at the start of CO$_2$ injection ranging from 24% to 89% (the lower end representing occasions when other recovery mechanisms have been used to their full extent, the higher end where CO$_2$-EOR has been deemed a viable alternative to the other recovery mechanisms, not an afterthought), oil saturations at the end of CO$_2$ injection ranging from 5% to 54% (the lower end representing very effective recovery, the higher end indicating that more than half of the OOIP remains unrecovered at the end of the project), and finally total additional recovery due to CO$_2$-EOR (however that is measured) ranging from 10 barrels of oil per day to over 29,500 barrels of oil per day in any given field. This last highest value is for one the largest of the fields, with over 500 injection wells, and where CO$_2$ injection was initiated when the oil saturation was a relatively high 78%.

Although at typical reservoir depths there may not be much to distinguish a subsurface geological formation offshore from one onshore, there are numerous differences between offshore and onshore hydrocarbon production projects, often driven by logistical considerations, and many of these apply to CO$_2$ injection also.

**Impacts from differences in well design and spacing**

Some of the differences between onshore and offshore CO$_2$-EOR processes are associated with the difference in the difficulty and the cost of drilling wells, where onshore drilling is generally much easier and cheaper. As a result, when wells are drilled offshore they tend to be bigger (larger diameter and/or longer completed interval in the target formation), targeting higher flow rates than onshore. However, fewer wells will generally be drilled offshore compared to onshore when draining an equivalent reservoir volume, and thus offshore wells will be spaced further apart.

The impacts for CO$_2$-EOR include the fact that for a well to be viable offshore, CO$_2$ will have to be delivered at a higher rate than for onshore wells, and it will be more difficult to handle incremental volumes of CO$_2$ in a modular fashion offshore. The impact of failure to
locate a suitable formation when drilling offshore is also greater due to the greater drilling costs involved. Lower well density offshore means that there is generally lower resolution of data to characterise formations, but also there are fewer potential leak sites.

Greater inter well spacing also means that the balance of forces during displacement will be different offshore compared to onshore. At very high velocities and/or short inter-well distances, gravity segregation is less pronounced. Gravity segregation will be most pronounced in fields which have large inter-well distances because there will be more time for buoyancy differences to take effect, and because fluid velocities in the inter-well regions will be lower due to the fact that flow to and from wells is radial, and thus the velocity reduces with the square of the distance from the well. Also, horizontal or deviated wells tend to have longer completion intervals, and hence lower fluid flow rates per foot of completion, leading again to lower velocities and greater gravity segregation. This gravity segregation reduces the sweep efficiency, and hence the potential ultimate recovery.

**Susceptibility of CO₂-EOR to weather and climatic conditions**

Land surface temperatures tend to vary much more than do seawater temperatures, and therefore there will be a lower impact of seasonal temperature variations when operating offshore. However, where transportation is not by pipeline, variations in climatic conditions will play out differently offshore and onshore (stormy weather preventing delivery of CO₂ by ship offshore, large snowfall disrupting delivery of CO₂ by truck, etc.)

### 8.1.2 Chemical EOR methods

These methods generally entail either increasing capillary number (micellar-polymer, caustic/alkaline flooding) or decreasing mobility ratio (polymer flooding). All are based on injecting one or more chemicals or brine with an altered composition into a reservoir to bring about the changes in fluid dynamics.

**Polymer EOR**

Polymer methods consist of injecting an aqueous phase (fresh-water or brine) into which has been dissolved a small amount of a polymeric thickening agent (usually concentrations are of order < 2,000 ppm). The thickening agent increases water viscosity and in some cases lowers the permeability to the phase to bring about the lowered mobility ratio. Polymer methods do not increase capillary number. Primarily because of low cost, there have been more polymer floods carried out than any other type of chemical EOR method. Polymer processes have historically recovered about 5% of the original oil in place and taken about 1 lbm of polymer to produce an incremental barrel of oil. Commodity price is clearly an important factor, with prices typically ranging from $1/lb to $4/lb, but being impacted by demand and by the oil price. Polymer EOR is actively being considered by a number of operators in the North Sea, to the extent that they are investing significantly in field specific testing. Thus polymer flooding represents significant competition to CO₂-EOR, and it is highly unlikely that any operator would consider both options given the technical challenges each poses individually, and also the challenge of identifying exactly how much incremental oil would be recovered compared to a base case business as usual (no EOR) scenario.

**Micellar-Polymer EOR**

Micellar-polymer (MP) methods are similar to the polymer method but with the addition of a surfactant to the injectant. The surfactant reduces oil-water interfacial tension making this method both a mobility ratio decreasing and a capillary number increasing process. MP processes recover about 15% of the original oil in place, but they are not economical at
low oil prices. At higher oil prices they still have to compete with other more established EOR methods, and are unlikely to be deployed in large offshore fields until good understanding is gained in smaller onshore fields, or fields where small area pilot testing is more practicable.

**Alkali EOR**

Caustic/alkaline methods are an attempt to use the interfacial tension lowering properties of natural surfactants that exist in many types of crude. Field experience is immature, but initial reports suggest that incremental oil can be recovered for 20-25 $/barrel. Again these face similar deployment issues to MP methods.

**Low salinity water flooding**

Low salinity water flooding (sometimes referred to as LoSal, which is a BP trademark), is increasingly being considered as an alternative to seawater injection. Water with a salinity varying between a few 10s of mg/l to 2000 mg/l (compare seawater which has a salinity of 35,000 mg/l, and some formation waters which can be saturated with salt at over 300,000 mg/l) is injected from the outset or part way through a water-flood project. The desired water salinity may be obtained from fresh water supplies (rivers or aquifers), or achieved by using available higher salinity water, such as seawater, and using reverse osmosis (RO) to desalinate. The mechanisms by which this increases oil recovery are not completely established, but it is evident that components that keep residual oil bound to the rock surfaces are disrupted, and the bonding weakened, and thus additional oil is mobilised. Low salinity water flooding may be the greatest competitor to offshore CO$_2$-EOR, since offshore water is readily available, and if investment is high for desalination plant to reduce residual oil saturations, then there will be less appetite to invest further in a possibly conflicting technology chasing a now smaller (lower residual oil saturation) target. (Typically $20$-$120$ million per $100,000$ barrels per day of water injection is spent on other similar technologies for altering water composition, where the variation in the cost is highly dependent on the footprint cost of the plant. Acidification of brine due to CO$_2$ injection would likely lead to dissolution of minerals, increasing salinity, and therefore counteract benefit of desalinated water injection.) One major oil operating company has made the decision to use low salinity water flooding as its water-flooding method of choice, not just because of the potential for increased recovery, which is very field specific, but because it also increases injectivity and reduces the risk of flow assurance problems such as inorganic scale deposition at production wells on injection water breakthrough; a business case has to be made each time low salinity water flooding is *not* chosen in a new field development where water-flooding will be implemented. Low salinity waterflooding may be considered in addition to polymer flooding, whereas it is unlikely that CO$_2$-EOR would be considered in combination with either of these techniques.

8.1.3 Thermal EOR methods

Thermal methods lower mobility ratio by decreasing oil viscosity. Since the effect of temperature is especially pronounced for viscous crudes, these methods are normally applied to heavy oils. This "niche" is actually quite large world-wide, consisting of more in-place hydrocarbon than light crudes.

An approximate classification of viscous crude oils based on reservoir conditions viscosity is as follows:
Table 10: Oil type vs. viscosity

<table>
<thead>
<tr>
<th>Oil type</th>
<th>Viscosity cp</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heavy crude</td>
<td>&lt;1,000</td>
</tr>
<tr>
<td>Tar sand</td>
<td>1,000 to 100,000</td>
</tr>
<tr>
<td>Bitumen or oil shale</td>
<td>100,000 to 1,000,000</td>
</tr>
</tbody>
</table>

Besides being aimed at viscous crudes, thermal methods will be successful if there is a rigorous heat management procedure in place. This means that heat losses are to be minimized as much as possible. Heat loss sources are:

1. Losses to rock and water - minimized by restricting application to reservoirs with small water saturation, large porosities or small shale content.
2. Losses to surface equipment - normally the smallest heat loss source, this is minimized by insulating surface lines and minimizing line length.
3. Losses to wellbores - minimizing wellbore heat loss is done by restricting application to shallow reservoirs. Heat loss in this manner can be controlled by insulating downhole tubulars, generating heat down hole, using in-situ combustion, injecting the steam at high rate or evacuating the production casing.
4. Losses to adjacent strata - minimizing this form of heat loss means minimizing the producing life of the field (normally done with small well spacing) or restricting application to thin reservoirs.

Cyclic Steam Stimulation

Cyclic steam stimulation (CSS) is also known as steam soak, or huff and puff. In this method steam is injected into a well bore out to a heated radius of a few tens of metres. Then the original steam injector is converted to a producer and a mixture of steam, hot water, and oil produced. CSS is the most common steam injection process today. Most of the time most of the wells are producers: there are no dedicated injectors. CSS is often used as a precursor to steam drive – see below.

Steam flooding

Steam drive, also known as steam flooding, is an EOR method whereby steam is injected into dedicated injection wells and the fluids driven to a separate set of producers. Combined CSS and steam drives often recover more than 50% of the original oil in place. This combination is the first commercial EOR process, having been used since the mid-1950s. Perhaps more than 2 billion barrels of oil have been produced in this manner to date.

In-situ combustion

The in-situ combustion process is an attempt to extend thermal recovery technology to deeper reservoirs and/or more viscous crudes. In recent years it has consisted of high-pressure air injection, with a fire front ignited in the reservoir and controlled by the rate of air injection. Ahead of the fire front the crude oil is heated and mobilised, whilst behind the front there will be a coke residue. In-situ combustion recovers 10-15% of the original oil in place.

Research in CO$_2$-EOR is showing the potential for increased recovery in heavier oils, but to date CO$_2$-EOR has not been implemented in fields where thermal recovery methods are used, and the highest viscosity oil in CO$_2$-EOR project is 257 cP.
8.1.4 CO₂-EOR method

Miscible EOR

As intimated, the miscibility of crude oil and supercritical CO₂ is a complex physical phenomenon involving both liquid and vapour phases. However under favourable oil/reservoir conditions the oil and CO₂ can mix forming a single-phase liquid which promotes the conditions noted above (viscosity reduction etc) enhancing the ability of the oil to flow out of the reservoir. The primary reservoir condition for miscibility to occur is that the pressure must be greater than the minimum miscibility pressure (MMP) so that the CO₂ becomes fully mixed with the oil.

At the MMP the CO₂ density is similar to that of the oil. MMP depends both on the composition of the crude oil, and the temperature and the purity of the CO₂ gas stream. A miscible CO₂ displacement flood can only be implemented where the current reservoir pressure is higher than the MMP. These conditions are typically found in North Sea oilfields at depths greater than about 700 m and are favoured by high CO₂ densities (e.g. 400 to 750 kg/m³ to achieve miscibility in the C5 to C30 hydrocarbons), low reservoir temperatures to maximise CO₂ density, light to medium crudes (i.e. lighter than 22°API) with relatively few aromatics and an absence of nitrogen, sulphur, SOx, NOx and other contaminants in the gas stream. The MMP for North Sea low sulphur light crudes is typically 180 to 250 bar.

The incremental oil recovery achieved by a miscible flood is often limited by the occurrences of unstable flow (viscous fingering) which may lead to early breakthrough with oil by-passed. For this reason the WAG technique is used because the water sweep is usually more uniform and more sweep efficient. Commonly with the process optimised for oil recovery, the CO₂ which breaks through is re-compressed and re-injected (saving the purchase of replacement gas). In a typical WAG project only around 20 to 25% of the injected CO₂ is retained in the reservoir.

Immiscible CO₂-EOR

An immiscible CO₂ displacement flood, where the MMP is not reached, can still increase oil recovery in a low pressure reservoir with heavier oil. The mechanism here is that the CO₂ partially dissolves in the oil causing it to swell and reducing viscosity, although importantly it also maintains reservoir pressure by creating an artificial gas cap which forces the oil down towards producing wells at the reservoir rim. In contrast to miscible projects which can be implemented at a small scale over a short time period (1 to 5 years), immiscible flood projects operate at the whole field scale and take longer to produce additional oil (up to 10 years). However, from the point of view of pure storage capacity, immiscible displacement operations are probably more attractive since they are limited only by the porosity of the reservoir rock and not the presence of residual fluids.

8.2 CO₂-EOR screening criteria

Many schemes have been proposed for the screening of oil reservoirs for miscible flood CO₂-EOR based on observations and empirical and modelling studies which have developed optimum reservoir parameters and associated weighting factors. The screening parameters considered in this study are summarised in Table 11, together with an indication of their effect – positive or negative – on reservoir potential for CO₂-EOR. The oilfield parameters considered can be separated into the oil properties and the reservoir properties.
Oil properties

The composition of the reservoir crude oil should comprise a high concentration of intermediate hydrocarbons with relatively few aromatics. Of primary importance, however, is the density and to a lesser extent, the viscosity of the oil. Various limits for these have been proposed with a lower limit on density of 22°API (~900 kg/m³) and viscosity less than 10 cP, which preferences medium to light crudes. An optimum figure for density has been suggested at 37°API (850 kg/m³) with viscosity in the range 1 – 2 cP. These figures favour miscible flood, but as noted above an immiscible flood of heavy oil may still be possible.

Figure 30: Variation of pure CO₂ density with depth

The trace with green triangle markers is for a “normal” pressure/thermal North Sea setting. The trace with red circle markers is for a normal pressure gradient but “high” thermal gradient (hot basin setting) and that with blue square markers is for a “high” pressure gradient but normal thermal gradient (saline aquifer conditions). It can be seen that higher temperatures at a given depth decrease density and a higher pressure gradient increases CO₂ density – and hence storage capacity. An important point to note from the plot is that after a certain depth threshold (~500 to 700 m) the density does not change significantly with increasing depth. This is important from storage considerations because although the pressure increases (and hence compression requirements) there is no advantage in terms of increasing density and hence storage capacity.

Relative saturation

The next area of screening conditions relates to the relative saturations of the reservoir fluids currently in place, and in particular the remaining oil saturation. This figure is associated with the production history of the reservoir – both due to oil and water flow and production. The initial oil saturation $S_{oi}$ in a reservoir may be of the order 80 – 90% and will decline at a rate dependent on production methods, e.g. water-flooding. It has been suggested that a relatively high remaining $S_{or}$ (35 – 40%) is best for CO₂-EOR with a porosity $\phi \times S_{or}$ product greater than 5%. Reservoirs with high ultimate recovery factors (such as are found in many North Sea fields) may not achieve this figure. Reservoir with low residual $S_{or}$ would probably not be suitable for CO₂-EOR on incremental oil recovery considerations alone.
**CO₂ breakthrough**

One of the main challenges in EOR projects can be the unfavourable reservoir characteristics, in terms of poor sweep efficiency leading to early breakthrough caused by the mobility contrast between resident and injected fluid or gravity induced gas segregation. Flow patterns controlled by heterogeneity and permeability must be considered for specific reservoir systems. Highly fractured reservoirs should be avoided due to the risk of early breakthrough of CO₂ at the production wells. Reservoirs with either very thick high permeability intervals, or thin very low permeability intervals can be poor candidates for CO₂ flooding. Values of permeability in the range 100 to 300 mD have been proposed as optimal.

**Permeability**

Permeability will also have another important effect on the reservoir injectivity – or ease with which fluids can be placed into the geologic formation per unit thickness. Injection is more difficult for viscous fluids and/or low permeability formations. Supercritical CO₂ has a very low viscosity compared to oil hence can usually be readily injected into formations with a wide range of permeabilities. A convenient measure of injectivity is the formation permeability thickness product \( k_h \) with values greater than \( 10^{-14} \) to \( 10^{-13} \) m³ usually considered acceptable.

**Aquifer-reservoir coupling**

Besides issues of heterogeneity and injectivity another structural feature which can have a bearing on CO₂-EOR potential is the aquifer-reservoir coupling. This is the characterization of the manner and magnitude by which any underlying water bodies influence the production of oil from the reservoir. Aquifers may or may not provide pressure support to the natural depletion of the reservoir, with a concomitant influx of water which may be produced from the wells over time. Typically aquifer drive may be “bottom-water” where the oil-water contact (OWC) is under the whole reservoir or “edge-water” where the OWC is only under part and this influences the pattern and timing of water breakthrough. A reservoir with strong aquifer support, which may result in high oil recovery, may not be a good target for CO₂ injection because of the need to displace the invaded water.
<table>
<thead>
<tr>
<th>Positive Indicators</th>
<th>Contra Indicators</th>
<th>Other remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil Properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Composition</td>
<td>High concentration of intermediate hydrocarbons especially C₅ to C₁₂, relatively few aromatics</td>
<td></td>
</tr>
<tr>
<td>Density ρ (*API gravity, kg/m³)</td>
<td>&gt; 22, 900 i.e. medium crude and lighter</td>
<td>&lt; 22 – consider immiscible CO₂ EOR, fill reservoir voidage if capacity is large</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt; 48 – extremely light oil such as condensate is not conducive to the development of multi-contact miscibility</td>
</tr>
<tr>
<td>Viscosity µ (mPa s ~ cP)</td>
<td>&lt; 10</td>
<td>&gt; 10, Consider immiscible CO₂ EOR</td>
</tr>
<tr>
<td><strong>Reservoir Properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth (m) ~ reservoir pressure</td>
<td>See above</td>
<td>Reservoirs at very great depth &gt; ~3500 m are likely to be considered uneconomic because of the higher CO₂ compression costs</td>
</tr>
<tr>
<td>Temperature</td>
<td>Reservoirs in regions with low geothermal gradients and ground temperatures</td>
<td>&gt; 121 °C limit proposed by US National Petroleum Council</td>
</tr>
<tr>
<td>Reservoir pressure - minimum miscibility pressure ratio P/MMP</td>
<td>Normally &gt; 1, but &gt; 0.95 may still be satisfactory.</td>
<td>CO₂ supercritical phase T &gt; 31.1 °C, P &gt; 7.38 MPa. CO₂ density decreases with increasing temperature</td>
</tr>
<tr>
<td>Original and current oil in place OOIP/COIP</td>
<td>MMP depends on oil composition – increases with temperature and gravity</td>
<td></td>
</tr>
<tr>
<td>Oil saturation-porosity product Sₒφ</td>
<td>≥ 0.05</td>
<td>Reserve estimates and production histories of both oil and water needed to make storage capacity estimates</td>
</tr>
<tr>
<td></td>
<td>&lt; 0.05</td>
<td>Consider filling reservoir voidage if</td>
</tr>
<tr>
<td>Positive Indicators</td>
<td>Contra Indicators</td>
<td>Other remarks</td>
</tr>
<tr>
<td>---------------------</td>
<td>------------------</td>
<td>--------------</td>
</tr>
<tr>
<td>volume of rock before EOR</td>
<td>capacity is large</td>
<td></td>
</tr>
</tbody>
</table>

**Reservoir Properties**

<table>
<thead>
<tr>
<th>Specific CO₂ (theoretical) storage capacity C (kg/m³)</th>
<th>&gt; 10</th>
<th>&lt; 10</th>
</tr>
</thead>
</table>

\[
C = \rho \left(1 - S_{or} - S_{wir}\right) + S_{wir} \phi C_s
\]

\( S_{or} \) residual oil saturation, \( S_{wir} \) irreducible water saturation, \( C_s \) specific water dissolution capacity

<table>
<thead>
<tr>
<th>Formation injectivity permeability-thickness product ( kh ) (m³)</th>
<th>( \geq 10^{-14} ) - ( 10^{-13} )</th>
<th>( &lt; 10^{-14} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>If ( kh ) is less, consider whether injectivity will be sufficient</td>
<td>Injectivity may be lost due to precipitates forming near the wellbore</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir heterogeneity</th>
<th>High heterogeneity improves extent of CO₂ flood invasion throughout the whole reservoir</th>
<th>Relatively homogeneous and high permeability formations allow lighter CO₂ to readily rise to the top of the reservoir bypassing oil</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High mobility paths (including faults) may cause early breakthrough. Steeply dipping beds may lead to reduced residence times.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Aquifer–reservoir coupling</th>
<th>Weak aquifer support increases storage capacity</th>
<th>Strong aquifer support reduces storage capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Difficult to assess – high oil recovery is usually indicative of strong aquifer support – WOR also indicator</td>
<td></td>
</tr>
</tbody>
</table>

| Seals | Adequate characterization of caprock, minimal formation damage | Areas prone to fault slippage |
8.3 Heriot Watt CO₂-EOR oil field database

Given the project resource constraints, a database was prepared by Heriot Watt naming the oilfields previously identified in public studies as candidates for CO₂-EOR, and identifying location and properties relevant to oil production and CO₂ storage.

For the UK fields the principle source of data was the recent SCCS study “CO₂ Storage around Scotland”, which identifies the largest EOR candidates.

These candidates were checked against Heriot-Watt’s existing database of UK North Sea oilfields containing geological and other data; appropriate for CO₂-EOR screening was supplemented with similar data for oilfields in the Norwegian and Danish sectors of the North Sea. The Heriot-Watt database had been assembled from standard published sources and was expanded using other sources, including online information.

The significant data for screening included:

- Oil gravity
- Oil viscosity
- Reservoir pressure
- Reservoir temperature
- Bubble point pressure
- STOOIP
- Oil URR
- Ultimate oil recovery factor (calculated)
- Porosity $\phi$
- Permeability $k$
- Oil saturation $S_o$
- Reservoir thickness $h$
- Original $S_o\phi$ (calculated)
- Injectivity indicator $kh$ (calculated)
- Drive mechanism

Complete data was not always available for all fields and most minor fields were eliminated due to lack of sufficient data. Where there were only some gaps in field data, some data was calculated using the following assumptions –

- Reservoir pressure from depth:
  pore pressure gradient 0.11 bar/m (0.486 psi/ft)

- Reservoir temperature from depth:
  geothermal gradient 5°C + 30 deg C/km

- Formation volume factor – assumed (average)
  UK fields 1.5, Norwegian & Danish fields 1.4

- STOOIP from URR - assumed
  Ultimate recovery factor (average) 40%.

The above suite of data (or derived data) was the best that could be extracted from the database in line with the screening criteria discussed above.
One particular difficulty with the assessments is the issue of reservoir pressure. Although initial reservoir pressure data is readily available (or may be estimated), current reservoir pressure information tends to be kept confidential by operators. For this reason, determining if reservoir pressure is above MMP and CO₂ flood is miscible or immiscible was not practical.

Each reservoir was then considered for assessment of CO₂-EOR potential based on the data above and the screening criteria, as carried out in the 2008 SCCS Scottish regional study. Any significant positive or contra potential indicators were noted in separate columns in the spreadsheet A “good prospect” might be achieved by one or more positive indicators and conversely a “poor prospect” by one or more contra indicators. An “average” prospect might be achieved by either a balance of positive or contra indicators or an absence of either i.e. no particular indicators for or against. Where inadequate or insufficient data was noted for a particular reservoir, no assessment of CO₂-EOR potential was made.

8.3.1 CO₂ Storage Capacity

The CO₂ storage capacities of the selected oil fields was taken from published literature and checked, where the necessary data were available, using the ‘direct replacement and the ‘CO₂-EOR’ calculation methods. The fields identified in the SCCS (2008) study only identified oilfields with a CO₂ storage capacity calculated by the direct replacement method greater than 50 Mt – therefore this filter was extended to Norwegian and Danish fields. As such the database only lists the largest relevant oilfields in the North Sea. The authors expect that there could be tens of fields in the North Sea which are relevant for CO₂-EOR but fall below this threshold, significantly increasing capacity and providing options for better source-sink matching.

Direct replacement method for estimating CO₂ storage capacity

The ‘direct replacement method’ is based on the assumption that the volume presently occupied by the recoverable hydrocarbons would be replaced by an equivalent volume of CO₂. This was calculated as the product of the ultimate recoverable reserves (URR) estimate for the field at reservoir conditions, and the density of CO₂ at reservoir conditions, and is expressed in millions of tonnes:

\[
\text{CO}_2 \text{ storage capacity (Mt) = } \left( \frac{\text{URR}_{\text{res,cond}} \times \text{CO}_2 \text{ density}_{\text{res,cond}}}{1000} \right)
\]

where \( \text{URR}_{\text{res,cond}} \) is the volume of recoverable oil in the reservoir in \( m^3 \) and \( \text{CO}_2 \text{ density}_{\text{res,cond}} \) is CO₂ density \( kg/m^3 \), both at reservoir conditions. \( \text{URR}_{\text{res,cond}} \) is calculated from URR at surface conditions by applying the formation volume factor, a factor that takes account of fluid shrinkage as it is brought to surface and gas comes out of solution, reducing the liquid volume.

CO₂ density was derived from a look up chart generated from data calculated by the online NIST Carbon Dioxide WebBook page.

The ‘direct replacement method’ is considered to be a maximum, and probably optimistic, amount of CO₂ that could be stored in an oil reservoir.

CO₂ storage capacity estimation under EOR conditions

A second method, the CO₂-EOR method, provides a more pessimistic estimate of CO₂ storage capacity. The method makes the assumption that the field is suitable for CO₂-EOR, although in some cases this will not be the case. This calculation assumes that an average of 10% of STOIIP (Stock Tank Oil Initially In Place) for the field would be
recovered using CO₂-EOR and that 0.33 tonnes of CO₂ would be required to produce 1 barrel of oil [1]. From these figures, a volume of CO₂ replacing a proportion of oil in a particular field is obtained.

\[
\text{CO}_2 \text{ storage capacity (Mt)} = (\text{STOIIP}/10) \times 0.33
\]

where \( \text{STOIIP}/10 \) = 10% of the Stock Tank Oil Initially In Place in barrels and 0.33 = tonnes of CO₂ injected to recover 1 barrel of oil.

### 8.3.2 Incremental Oil Recovery

The storage capacity and incremental oil recovery estimates in the database have been based on the conventional learning from North American projects of a ca. 10% additional recovery factor. Laboratory tests and reservoir modelling show that very high recovery efficiencies are possible in theory from CO₂-EOR. Under ideal conditions, laboratory core floods using high pressure CO₂ have recovered essentially all residual oil, and reservoir simulations have shown that with careful well placement and process design very high recoveries are possible. However actual field performance, with geologically complex reservoirs combined with unreliable performance information and control, has fallen short of this.

The causes of less than optimum performance of CO₂-EOR include the following:

1. Low injection volumes. Due to the high cost of CO₂ relative to oil prices and the inability to control the CO₂ flow through the reservoir, injected volumes were limited (typically 0.4 HCPV) and sweep efficiency restricted.
2. Poor sweep efficiency. Gravity override, viscous fingering and channelling in heterogeneous reservoirs can lead to limited contact with the residual oil.
3. Poor displacement efficiency with only a small portion of the residual oil mobilized often due to lack of effective miscibility.
4. Lack of CO₂ contact with the residual oil due to inefficient targeting, bypassing more highly saturated layers.
5. Poor operation management and control due to lack of real time process and performance data.
8.4 Comments on the Heriot-Watt database from Dundas Consultants

The incremental reserves that might be associated with an enhanced oil recovery project are the economic driver for any operator to consider such a project. The HW estimates were reported to be based upon a 10% of stock tank oil initially in place (STOIIP) (Method 1).

Estimates of incremental recovery based upon STOIIP are a reasonably common approach to providing high level guidance. One failing of this approach, however, which is particularly pertinent to the North Sea sector, is that it cannot take explicit account of any secondary recovery techniques that may already have taken place. For example, water injection is commonplace in North Sea oil production as a result of the high “embedded cost” in offshore installations compared to, for example, the relatively low cost developments on-shore in the USA where most CO₂ injection projects have taken place. That HW has chosen to use 10% rather than higher estimates reflects that this has been considered.

An alternative metric, though still only reasonable for “ball park” estimates, was proposed by Hughes as a basis for a similar screening study carried out under the auspices of the Scottish Centre for Carbon Capture and Storage (SCCS). Rather than a percentage of STOIIP, Hughes proposed that 1/6th of the remaining oil at the point of CO₂ injection might be recoverable (Method 2).

To compare a prediction based upon the “Hughes criteria” it was necessary to estimate the oil in place at the point of first CO₂ availability – notionally 2017, for example. Clearly, this involved a level of production profile prediction; given that production profiles are not generally available in the public domain. Historical production data are available however and so as a first step data for each of the UK fields were downloaded from the Department of Energy and Climate Change’s (DECC) website and included in an additional worksheet in the HW database (“UK Oil Fields Production”). By inspection, as all of the fields with the exception of Buzzard are mature, it may be seen that the annual production of oil is approximately a linear function of the cumulative production to that point, once the “development” phase of the field is complete.
Using this approach, then it was possible to estimate the continued production profile prior to EOR and consequently the incremental recovery based upon the alternative Hughes criteria. Note that this approach would also allow the estimation of incremental EOR at points in time other than the notional 2017 injection point. The results for the UK sector fields are shown in Table 12.

### Table 12: Alternative estimates of recovery for UK sector

<table>
<thead>
<tr>
<th>Field</th>
<th>HW MMboe</th>
<th>DC MMboe</th>
<th>DC Inc. Oil (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scott</td>
<td>94.6</td>
<td>87.2</td>
<td>9.2%</td>
</tr>
<tr>
<td>Claymore</td>
<td>143.9</td>
<td>140.1</td>
<td>9.7%</td>
</tr>
<tr>
<td>Buzzard</td>
<td>107.7</td>
<td>100.5</td>
<td>9.3%</td>
</tr>
<tr>
<td>Forties</td>
<td>419.6</td>
<td>241.4</td>
<td>5.8%</td>
</tr>
<tr>
<td>Beryl</td>
<td>232.2</td>
<td>247.0</td>
<td>10.6%</td>
</tr>
<tr>
<td>Thistle</td>
<td>82.4</td>
<td>67.5</td>
<td>8.2%</td>
</tr>
<tr>
<td>Ninian</td>
<td>292.0</td>
<td>283.6</td>
<td>9.7%</td>
</tr>
<tr>
<td>Piper</td>
<td>140.0</td>
<td>60.6</td>
<td>4.3%</td>
</tr>
<tr>
<td>Cormorant</td>
<td>156.8</td>
<td>139.6</td>
<td>8.9%</td>
</tr>
<tr>
<td>Dunlin</td>
<td>82.7</td>
<td>43.8</td>
<td>5.6%</td>
</tr>
<tr>
<td>Statfjord UK</td>
<td>NA</td>
<td>61.0</td>
<td>5.9%</td>
</tr>
<tr>
<td>Brent</td>
<td>501.5</td>
<td>468.4</td>
<td>9.3%</td>
</tr>
<tr>
<td>Murchison UK</td>
<td>79.0</td>
<td>75.6</td>
<td>9.6%</td>
</tr>
</tbody>
</table>

In general it may be seen that the alternative estimation method produces values only marginally lower than the 10% increment. The exceptions to this are fields such as Dunlin, for example, which are known to have exceptionally high recovery factors (48.5% is reported for Dunlin). On this basis, it is proposed that the HW estimates are defensible.

A similar exercise was carried out for the Scandinavian fields. As many of these have been producing for a shorter period than the UK sector fields the quality of the predicted profiles is somewhat lower. In general, the EOR increment at 2017 is aligned with the 10% estimate (7%-11%).
Table 13: Alternative estimates for recovery for Scandinavian fields

<table>
<thead>
<tr>
<th>Field</th>
<th>HW MMboe</th>
<th>DC MMboe</th>
<th>DC Inc. Oil (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ekofisk</td>
<td>710</td>
<td>511</td>
<td>7.2%</td>
</tr>
<tr>
<td>Statfjord</td>
<td>892</td>
<td>772</td>
<td>8.7%</td>
</tr>
<tr>
<td>Gullfaks</td>
<td>575</td>
<td>576</td>
<td>10.0%</td>
</tr>
<tr>
<td>Troll</td>
<td>393</td>
<td>404</td>
<td>10.3%</td>
</tr>
<tr>
<td>Snorre</td>
<td>342</td>
<td>314</td>
<td>9.9%</td>
</tr>
<tr>
<td>Valhall</td>
<td>229</td>
<td>259</td>
<td>11.3%</td>
</tr>
<tr>
<td>Vigdis</td>
<td>92</td>
<td>89</td>
<td>9.6%</td>
</tr>
<tr>
<td>Eldfisk</td>
<td>210</td>
<td>169</td>
<td>8.0%</td>
</tr>
<tr>
<td>Ula</td>
<td>145</td>
<td>153</td>
<td>10.6%</td>
</tr>
<tr>
<td>Tordis</td>
<td>94</td>
<td>96</td>
<td>10.2%</td>
</tr>
<tr>
<td>Dan</td>
<td>240</td>
<td>275</td>
<td>11.4%</td>
</tr>
<tr>
<td>Halfdan</td>
<td>150</td>
<td>165</td>
<td>10.9%</td>
</tr>
</tbody>
</table>

Cessation of Production Dates (Close of production – COP)

The HW database includes estimates of cessation of production (COP) dates which may be key in establishing scenarios related to the development of CO₂ EOR and associated infrastructure in the North Sea. Dundas Consultants are privy to COP data from a variety of industry sources; however, due to confidentiality or licencing issues, these data may not be used directly in output from this study.

An alternative means of estimating COP could be to estimate operating cost which, combined with an estimate of real terms oil price and production profile (as above) could be used to determine when the fields would become cash-flow negative. This could be a crude method of estimating COP and is reliant on two sources of estimate (production and OPEX). It has the advantage however of being related to oil price assumptions and being grounded in an approach that is relatively straightforward to present without access to proprietary data.

Based upon a flat RT oil price of $100/barrel and an exchange rate of 1.55$/£, the following may be derived:

Scott

The HW COP is given as 2015 implying an OPEX of around £80m/yr which would place this at the upper end of costs for a single platform. A lower assumption of (say) £60m/yr would move the COP to 2020. Other industry sources have suggested a COP for Scott of around 2020 which would seem consistent with the OPEX analysis.

Claymore

The HW COP is given as 2030 implying an OPEX of around £60m/yr which would place this at the mid-lower end of costs for a single platform. A higher assumption of (say) £70m/yr would move the COP to 2028. Other industry sources have suggested a COP for Claymore of around 2030 which would seem consistent with the OPEX analysis and the HW estimate.

Buzzard

The HW COP is given as 2025 implying an OPEX of around £50m/yr. However, given that the production history for Buzzard is relatively short, the OPEX method is not recommended for this field. Other industry sources concur with 2025 as a reasonable estimate for the Buzzard COP but there will be relatively more uncertainty in this estimate than others.
Forties
The Forties complex comprises four platforms, with shared services. Some savings might be expected for such an installation. The HW COP estimate is given as 2015 which would imply an OPEX per platform in excess of £150m/yr suggesting that the HW figure may be somewhat early. Using an estimate of £50m/yr/platform, the COP date would move to 2026 which is consistent with other industry sources. It is worth noting the decommissioning of the Forties system would be a major project in itself; were this to be scheduled for 2015, it is almost certain that information to that effect would be in the public domain (see Brent, below).

Beryl
The HW COP estimate is 2020 implying an OPEX of £70m/yr. This seems reasonable; a reduction to £50m/yr (for example) would extend the life to 2023 which is in line with expectations from other sources.

Thistle
The HW COP estimate is 2015 implying an OPEX of £67m/yr. This seems reasonable; a reduction to £50m/yr (for example) would extend the life to 2024. Cessation later than 2020 is believed to be more likely than 2015.

Ninian
The HW COP estimate is 2030 implying an OPEX of £35m/yr. This seems unreasonably low; a low estimate of £50m/yr (for example) would result in COP in 2026. Other sources suggest COP in 2020 with an implied OPEX of £85m/yr placing Ninian at the high end of the range of expected costs. It seems likely that a reasonable estimate of COP would be in the range 2022-2025.

Piper
The HW COP estimate is 2030 implying an OPEX of £21m/yr. However, it is known that the Piper platform plays host to a number of tie-back fields, notably Tweedsmuir. It is believed that OPEX sharing agreements with these other fields could see an extension of life towards the HW estimate.

Cormorant
The HW COP estimate is 2020, implying an OPEX of £70m/yr for each of the platforms (Cormorant Alpha and North Cormorant). This seems high, a lower estimate of £50m/yr/platform would see COP in 2024 which is more aligned with industry expectations.

Dunlin
The HW COP estimate is 2015, implying an OPEX of £95m/yr. A more reasonable estimate of £60m/yr would push the COP date out to 2021, in line with industry expectations.

Statfjord (UK)
The HW COP estimate of 2020 implies an OPEX of £60m/yr, aligned with industry expectations.
Brent

The Brent platforms (particularly Brent Delta) are the subject of extensive media coverage regarding Shell’s intention to begin decommissioning. Brent Delta has already reached COP and is seen as a template within the industry for the decommissioning process both because of the strategic nature of the Brent field and because of Shell’s position as a technology leader. Brent Alpha and Bravo are scheduled for COP in late 2013 with Brent Charlie in late 2014. The HW COP date of 2015 is therefore somewhat at odds with this but not greatly so. By way of comparison, an OPEX of £50m/yr/platform would imply cessation in 2012 providing some support to the approach.

Murchison (UK)

The HW COP date of 2020 would imply an OPEX of £25m/yr. A low-range estimate of £50m/yr would put COP around 2014, in line with industry expectations.

Ekofisk

The Ekofisk field has been developed through a complex combination of linked platforms. Originally targeted for development through pressure depletion only, with a correspondingly low recovery factor of c. 17%, secondary recovery programmes have improved this considerably. A large scale water flood programme has been underway since 1987 with an improvement in recovery factor to around 50% anticipated. The facilities have received press coverage due to the extraction activities causing sea bed subsidence in excess of 9m in the centre of the field. It is reported that the subsidence is expected to continue but at a slower pace.

The complexity of the field and infrastructure makes estimation of a COP date uncertain. The HW value of 2020 would be consistent with an OPEX per platform in excess of £100m/yr, which seems unlikely even accounting for higher operating costs in the Norwegian sector. A median OPEX of £60m/yr/platform results in an estimate of 2048 which is closer to industry estimates in excess of 2040.

Statfjord (NO)

Statfjord is produced over 3 integrated platforms. The HW estimate of 2030 seems late in comparison to an OPEX-based estimate of 2020 for £50m/yr/platform (assuming some joint development economies). Other industry sources would suggest around 2020 being more reasonable. It is worth noting that the Brent structure, one of the producing reservoirs, has been depressurised, secondary recovery in the form of water alternating gas (WAG) has already taken place, and artificial lift methods including electric submersible pumps (ESP) are being used. This accounts for low potential incremental recovery of c. 7%.

Gullfaks

The Gullfaks development also consists of 3 integrated platforms. The HW COP estimate of 2015 seems early compared with industry sources, suggesting around 2025. Based upon an average OPEX of £50m/yr/platform, a COP date of 2027 is predicted. However, the complexities of the development, including tie-back of a number of satellites and use as a transport hub make reasonable estimates difficult. Water injection, gas injection and WAG have all been used in Gullfaks. On balance, a COP data of around 2025 seems reasonable.
**Troll**

Troll is again a complex development consisting of a fixed wellhead and compression platform (Troll A) powered by electricity from land-based generation; a concrete floating and production facility (Troll B) and semi-submersible production and accommodation facility (Troll C). The HW COP of 2020 seems early compared to other sources suggesting as late as 2032. Estimation of OPEX in this case is complex but for comparison a median OPEX per platform of £50m/yr results in a COP estimate of 2028 suggesting that the HW may be overly conservative.

**Snorre**

Snorre consists of two facilities, Snorre A and Snorre B, a tension leg platform (TLP) and semi-submersible respectively. The HW estimate of COP is 2050 which aligns with statements from the operators to the effect that they are working on long term plans for the field (the “Snorre 2040” project) based on increased oil recovery. Other sources suggest COP may be as early as 2026 – this may reflect a risked view of the prospects for the 2040 project. A median OPEX per platform of £50m/yr results in an estimated COP of 2037.

**Valhall**

Valhall was originally developed using 3 production and accommodation facilities, a well head platform and an injection facility, all bridge linked. However, following subsidence in the field centre a new, shore-powered platform has been installed with the intention of prolonging production beyond 2040. The HW estimate of COP is 2020 – it is possible that this reflects the pre-redevelopment position. Based upon a single platform with associated OPEX of £60m/yr, field life is estimated to be economically feasible to 2050.

**Vigdis**

Vigdis is produced via series of subsea templates linked to Snorre A. The HW COP estimate of 2020 is earlier than other sources (around 2025). Estimation of OPEX for system is complex as it depends upon the tariffing/OPEX share agreement in place at Snorre A (note that Snorre A also provides water injection support). Arrangements for further secondary recovery include import of injection water from Statfjord. A notional £50m/yr would suggest Vigdis could continue producing until 2030 but clearly this is highly dependent upon the plans for field development.

**Eldfisk**

Eldfisk was developed using 3, bridge-linked platforms and a further water injection facility. It is planned to replace/augment some of the functions of these platforms with a new accommodation, wellhead and production facility, Eldfisk S (to which the Embla field, South of the development will be tied-back).

The HW COP estimate of 2015 seems inconsistent with this planned redevelopment activity. Other sources suggest a COP as late as 2045; on an OPEX basis life extension to 2050 is possible.

**Ula**

Ula is developed via 3 bridge linked platforms, including capacity for capacity for both water and gas injection (WAG has been used as a recovery strategy since 1998). The HW COP date of 2015 seems early compared to other sources (2028) and inconsistent with public statements made on the success of the WAG programme and agreements to purchase additional gas from neighbouring fields to see it continue.
Tordis
Tordis is produced as a subsea tie-back to Gullfaks C (including subsea separation). The HW COP estimate of 2020 is aligned with industry expectations and an OPEX of £50m/yr.

Dan
The Dan field is produced via a complex comprising 4 main production and accommodation platforms, 6 well head towers and two flare stacks. The HW COP estimate of 2020 is earlier than other sources. Based upon an estimate of well head tower OPEX being half of that of a production facility, an OPEX of £50m/yr/platform results in an OPEX based estimate of COP later than 2030.

Halfdan
Halfdan is again a complex, integrated development comprising a number of linked manned and unmanned structures. In addition, the field development is based upon the use of a pattern of alternating, parallel, horizontal injection and production wells to fracture the intervening structures and drive the oil in front of a continuous water flood. Similar patterns of aligned horizontal wells have been suggested for CO₂ EOR (e.g. for the Draugen development).

Historical production data are limited for Dan and Halfdan, which coupled with the complexity of the facilities, renders the OPEX estimation method of little use. Consequently, COP year of 2041 is used for both fields.
## 8.5 Economic Modelling

### 8.5.1 Key Performance Indicators

<table>
<thead>
<tr>
<th>Stakeholder</th>
<th>KPI</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil Company</strong></td>
<td>Nominal Costs and Revenues</td>
<td>Real cash flows (costs or revenues) can be adjusted to nominal values, using the rate of inflation($i$) and number of years($n$) with the following formula: $(\text{Real_value})\times(1+i)^n$</td>
</tr>
<tr>
<td></td>
<td>Discounted Costs and Revenues</td>
<td>Discounted cash flows or present values: future payments are discounted back to present or another year in order to reflect the time value of money</td>
</tr>
<tr>
<td></td>
<td>NPV</td>
<td>Net Present Value is the sum of the discounted (present) values of the individual cash flows of a project. Oil companies mostly use 10% discount rate on nominal cash flows.</td>
</tr>
<tr>
<td></td>
<td>IRR</td>
<td>Internal rate of return is used to measure and compare the profitability of investments. Many brownfield upstream opportunities are genuinely incremental and so cash flows can be “non-standard”. This can make the calculation of IRR tricky, misleading or even impossible.</td>
</tr>
<tr>
<td></td>
<td>DPI</td>
<td>Discounted profitability index is another KPI used by oil companies in order to assess the profitability of the projects. It is calculated by dividing NPV by the present value of CAPEX. Hurdle rate for DPI is usually 0.3.</td>
</tr>
<tr>
<td></td>
<td>VIR</td>
<td>Value investment (Profitability Index) ratio is similar to DPI; however, this time NPV is divided by undiscounted CAPEX.</td>
</tr>
<tr>
<td></td>
<td>Unit Development Cost</td>
<td>Total CAPEX/Total Oil Production ($/barrel or £/barrel). Commonly used but potentially misleading due to lack of discounting and no consideration of OPEX.</td>
</tr>
<tr>
<td></td>
<td>Unit Technical Cost</td>
<td>Unit Technical Cost; Discounted Technical Costs/Discounted Production $/barrel or £/barrel again but this time discounted and including all costs (CAPEX, OPEX, ABEX, Tariff etc.) less commonly used.</td>
</tr>
<tr>
<td><strong>Scottish Enterprise and Government</strong></td>
<td>Tax Revenues</td>
<td>NPV (3.5%) of all tax that is paid by the oil companies in the North Sea</td>
</tr>
<tr>
<td></td>
<td>EBIT</td>
<td>Intrinsic project economics before taxation</td>
</tr>
<tr>
<td></td>
<td>GVA</td>
<td>Gross value added is a measure in economics of the value of goods/services produced in a sector of an economy.</td>
</tr>
<tr>
<td></td>
<td>Total GVA</td>
<td>Overall GVA including direct (oil companies), indirect(suppliers) and induced(re-spent money on other goods) GVA.</td>
</tr>
<tr>
<td></td>
<td>Direct Employment</td>
<td>Direct employment(oil companies) caused by an increase in output or turnover of a sector/industry.</td>
</tr>
<tr>
<td></td>
<td>Total Employment</td>
<td>Total jobs including direct, indirect and induced.</td>
</tr>
</tbody>
</table>
### 8.5.2 Modelling inputs on CO$_2$-EOR project duration

Table 15: CO$_2$ flow and timeline assumptions in the scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Fresh CO$_2$ injection (years)</th>
<th>Further recycling only CO$_2$ injection (years)</th>
<th>Total EOR operation (years)</th>
<th>Fresh CO$_2$ injection profile</th>
</tr>
</thead>
<tbody>
<tr>
<td>Go Slow</td>
<td>10</td>
<td>10</td>
<td>20</td>
<td>Constant over time</td>
</tr>
<tr>
<td>Medium</td>
<td>10</td>
<td>10</td>
<td>20</td>
<td>Constant over time</td>
</tr>
<tr>
<td>Very High</td>
<td>10</td>
<td>0</td>
<td>10</td>
<td>Decreasing over time</td>
</tr>
</tbody>
</table>
### 8.5.3 Cost modelling assumptions

**Table 16: Assumptions and cost database**

<table>
<thead>
<tr>
<th>Cost</th>
<th>Base Value</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Well CAPEX</td>
<td>20</td>
<td>£million/well</td>
<td>New wells that are required for CO(_2) injection and oil production</td>
</tr>
<tr>
<td>Existing Well Re-use CAPEX</td>
<td>8</td>
<td>£million/well</td>
<td>Some of the existing wells can be upgraded in order to be used for CO(_2) injection or &quot;oil combined with CO(_2)&quot; production</td>
</tr>
<tr>
<td>Recycling Unit Capex</td>
<td>20</td>
<td>£million per Mt of peak CO(_2) recycling</td>
<td>Includes the CAPEX of recycling system and compressor.</td>
</tr>
<tr>
<td>Platform OPEX</td>
<td>5%</td>
<td>of platform CAPEX</td>
<td></td>
</tr>
<tr>
<td>Well OPEX</td>
<td>4%</td>
<td>of well CAPEX</td>
<td></td>
</tr>
<tr>
<td>Oil Field Base OPEX</td>
<td>50</td>
<td>£million/yr</td>
<td>Oil field's base OPEX without CO(_2)-EOR (due to business-as-usual operations, existing platform, other infrastructure, etc.)</td>
</tr>
<tr>
<td>Fresh CO(_2) Transfer/Purchase Cost</td>
<td>-£10 to £10</td>
<td>£/tonne of CO(_2)</td>
<td>Oil fields may need to pay for the fresh CO(_2) that is supplied from the power plants. The oil companies may need to pay for the CO(_2); however, this price is highly uncertain. CO(_2) price could be 0 or could be even negative, which means that power plants may have to pay for the CO(_2) stored in an oil field.</td>
</tr>
<tr>
<td>Planning Cost</td>
<td>5%</td>
<td>of total CAPEX</td>
<td>Including planning and FEED costs</td>
</tr>
<tr>
<td>Decommissioning Unit Cost (ABEX Unit Cost)</td>
<td>0.4</td>
<td>£/barrel (OOIP)</td>
<td>Decommissioning costs are highly uncertain; however, it is known that Miller oil field decommissioning cost is around £300 million. Dividing that cost by Miller's original oil in place value gives 0.4 £/barrel of unit cost. Decommissioning costs of other oil fields were estimated proportional to their OOIP amounts.</td>
</tr>
<tr>
<td>Incremental decommissioning cost of EOR</td>
<td>15%</td>
<td>of total CAPEX</td>
<td>Due to new platform, wells and other infrastructure, CO(_2)-EOR increases the decommissioning cost of an oil field.</td>
</tr>
</tbody>
</table>
8.5.4 Commodity Price Assumptions

Figure 32: Commodity price scenarios
8.5.5 Impacts from the supply chain on the Scottish economy

The North Sea oil and gas industry continues to provide a source of wealth creation, employment and tax receipts for Scotland and across the UK. The GVA for Scotland from the oil and gas industry is £15.3 billion (15% of total GVA) and UK Government oil and gas tax revenues exceed £8 billion. Also, ca. 440,000 jobs across the UK were supported by the oil and gas industry in 2010, while 45% of oil and gas industry jobs are in Scotland.\textsuperscript{44, 45}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{oil_gas Employment in the UK.png}
\caption{Oil and gas employment in the UK\textsuperscript{17}}
\end{figure}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{oil_gas Employment distribution by region.png}
\caption{Oil and gas employment distribution in the UK\textsuperscript{17}}
\end{figure}

\textsuperscript{44} HMRC, Statistics of Government revenues from UK oil and gas production, 2011
\textsuperscript{45} Oil & Gas UK, 2011 Economic Report, 2011
Figure 35: Contribution of CO$_2$-EOR projects in the UKCS$^{46}$

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$^{46}$ Kemp, A.G. and Stephen, L., 2010, The Long Term Prospects for Activity in the UK Continental Shelf  
http://homepages.abdn.ac.uk/e.phimister/pages/acreef/acreef%20papers/nsp-119.pdf
### 8.5.6 CO₂ supply assumptions

**Table 17: CO₂ supply scenarios until 2035**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2016-20</th>
<th>2021-25</th>
<th>2026-30</th>
<th>2031-35</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Very High Scenario (Mt/yr)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UK Scotland</td>
<td>0</td>
<td>3</td>
<td>7</td>
<td>10</td>
</tr>
<tr>
<td>UK NE England</td>
<td>0</td>
<td>5</td>
<td>5</td>
<td>14</td>
</tr>
<tr>
<td>UK Yorkshire</td>
<td>5</td>
<td>10</td>
<td>17</td>
<td>24</td>
</tr>
<tr>
<td>UK Thames</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>12</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0</td>
<td>8</td>
<td>14</td>
<td>22</td>
</tr>
<tr>
<td>Denmark</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td>6</td>
</tr>
<tr>
<td>Norway</td>
<td>0</td>
<td>4</td>
<td>4</td>
<td>8</td>
</tr>
<tr>
<td>Germany</td>
<td>0</td>
<td>0</td>
<td>10</td>
<td>60</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Medium Scenario (Mt/yr)</th>
<th>2016-20</th>
<th>2021-25</th>
<th>2026-30</th>
<th>2031-35</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK Scotland</td>
<td>0</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>UK NE England</td>
<td>0</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>UK Yorkshire</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>UK Thames</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0</td>
<td>4</td>
<td>7</td>
<td>10</td>
</tr>
<tr>
<td>Denmark</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Norway</td>
<td>0</td>
<td>2</td>
<td>2</td>
<td>5</td>
</tr>
<tr>
<td>Germany</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Go Slow Scenario (Mt/yr)</th>
<th>2016-20</th>
<th>2021-25</th>
<th>2026-30</th>
<th>2031-35</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK Scotland</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>UK NE England</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>UK Yorkshire</td>
<td>0</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>UK Thames</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0</td>
<td>2</td>
<td>2</td>
<td>5</td>
</tr>
<tr>
<td>Denmark</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Norway</td>
<td>0</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Germany</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
8.5.7 Details of the EOR Go Slow scenario

Figure 36: CO₂-EOR network for “Go Slow” scenario

Figure 37: Go Slow scenario cost breakdown
Table 18: KPI for fields under Go Slow scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Oilfield</th>
<th>Nominal NPV pre-tax and excl. Decom. / £million</th>
<th>Nominal NPV after tax / £million</th>
<th>PV of CAPEX after tax / £bbl</th>
<th>Discounted Profitability index after tax / (DPN)</th>
<th>Value Investment Ratio (VIR)</th>
<th>Unit Development Cost / £bbl</th>
<th>Unit Technical Cost / £bbl</th>
<th>Incremental Oil Production / Million barrels</th>
<th>Nominal Discounted Total Tax / £billion (nominal 10%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK</td>
<td>Claymore</td>
<td>£709</td>
<td>£222</td>
<td>£1.60</td>
<td>£447</td>
<td>0.50</td>
<td>0.16</td>
<td>£9.80</td>
<td>£56.59</td>
<td>137</td>
</tr>
<tr>
<td>DK</td>
<td>Dan</td>
<td>£781</td>
<td>£153</td>
<td>£9.90</td>
<td>£503</td>
<td>0.30</td>
<td>0.10</td>
<td>£9.47</td>
<td>£58.21</td>
<td>163</td>
</tr>
</tbody>
</table>

Figure 38: Go Slow scenario project sensitivity
8.5.8 Details of the Medium CO$_2$-EOR scenario

**Phase I** (2016-2020)
- **Ninian**: 4 Mt/yr
- **UK Sink**: 2 Mt/yr
- **Norway Sink**: 2 Mt/yr

**Phase II** (2021-2025)
- **Ninian**: 5 Mt/yr
- **UK Sink**: 4 Mt/yr
- **Norway Sink**: 4 Mt/yr

**Phase III** (2026-2030)
- **Claymore**: 2 Mt/yr
- **Ninian**: 5 Mt/yr
- **UK Sink**: 4 Mt/yr
- **Norway Sink**: 7 Mt/yr

**Phase IV** (2031-2035)
- **Claymore**: 5 Mt/yr
- **Ekofisk**: 3 Mt/yr
- **Halfdan Dan**: 5 Mt/yr
- **Ninian**: 5 Mt/yr
- **UK Sink**: 4 Mt/yr
- **Norway Sink**: 10 Mt/yr
Figure 39: CO₂-EOR network for “Medium” scenario

![Diagram of CO₂-EOR network for Medium scenario with cost breakdown]

Costs (£million, nominal, discounted, 10%)

- CO₂ Insurance and Monitoring Cost
- Offshore Fuel Cost
- Oil Transport Cost
- Emission Cost
- Fresh CO₂ Cost
- Incremental OPEX
- Base OPEX
- Recycling CAPEX
- Well CAPEX
- Platform CAPEX
- Planning Cost

Figure 40: Medium scenario cost breakdown

Table 19: KPI for fields under Medium scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Oilfield</th>
<th>Nominal NPV pre-tax and exc.</th>
<th>Nominal NPV after tax/£milion</th>
<th>Nominal NPV per barrel after tax/£/bbl</th>
<th>PV of CAPEX/£milion</th>
<th>Discounted NPV Index after tax (DP)</th>
<th>Value Investment Ratio (VIR)</th>
<th>Unit Development Cost/£/bbl</th>
<th>Unit Technical Cost/£/bbl</th>
<th>Incremental Oil Production/£ion barrels</th>
<th>Nominal Discounted Total Tax/£ion</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK</td>
<td>Ninian</td>
<td>£2.293</td>
<td>£867</td>
<td>£2.30</td>
<td>£1,612</td>
<td>0.41</td>
<td>0.21</td>
<td>£10.68</td>
<td>£46.47</td>
<td>281</td>
<td>£1.8</td>
</tr>
<tr>
<td></td>
<td>Claymore</td>
<td>£897</td>
<td>£284</td>
<td>£2.00</td>
<td>£497</td>
<td>0.57</td>
<td>0.19</td>
<td>£10.54</td>
<td>£48.66</td>
<td>139</td>
<td>£0.7</td>
</tr>
<tr>
<td>NO</td>
<td>Ekofisk</td>
<td>£3,081</td>
<td>£334</td>
<td>£0.50</td>
<td>£1,159</td>
<td>0.29</td>
<td>0.06</td>
<td>£8.39</td>
<td>£45.81</td>
<td>508</td>
<td>£2.8</td>
</tr>
<tr>
<td>DK</td>
<td>Halfdan</td>
<td>£1,115</td>
<td>£300</td>
<td>£1.80</td>
<td>£517</td>
<td>0.58</td>
<td>0.19</td>
<td>£9.63</td>
<td>£43.72</td>
<td>157</td>
<td>£0.9</td>
</tr>
<tr>
<td></td>
<td>Dan</td>
<td>£1,201</td>
<td>£307</td>
<td>£1.80</td>
<td>£583</td>
<td>0.54</td>
<td>0.18</td>
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Figure 41: Medium scenario project sensitivity
8.5.9 Details of the Very High CO$_2$-EOR Scenario

Figure 42: CO$_2$-EOR network for very high scenario
Figure 43: Very High scenario cost breakdown
Table 20: KPI table for fields under “Very High EOR” scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Oil field</th>
<th>Nominal NPV* pre-tax and excl. Decommissioning (£million)</th>
<th>Nominal NPV* after tax (£million)</th>
<th>Nominal NPV* per barrel after tax (£/barrel)</th>
<th>PV* of CAPEX (£million)</th>
<th>Discounted Profitability Index after tax (DPI)</th>
<th>Value Investment Ratio (VIR)</th>
<th>Unit Development Cost (£/barrel)</th>
<th>Unit Technical Cost (£/barrel)</th>
<th>Incremental Oil Production (Million barrels)</th>
<th>Nominal Discounted Total Tax** (£billion)</th>
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<tr>
<td>UK</td>
<td>Scott</td>
<td>£1,649</td>
<td>£586</td>
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<td>£817</td>
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<td>0.22</td>
<td>£12.49</td>
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<td>Beryl</td>
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* NPV and PV of CAPEX are discounted by 10%

** Tax is discounted by 3.5% (public)
Figure 44: Very High scenario project sensitivity