PROSPECTS FOR CO_2-EOR IN THE UKCS

The UK's hydrocarbon industry has made a significant contribution to UK GDP over the last fifty years. However, the basin is mature and is expected to see major decommissioning over the next 10-15 years. The remaining oil reserves could be significantly improved by greater use of enhanced oil recovery. Several techniques could be applied, of which CO_2-EOR is one. It is a mature technology and has been used onshore in the USA for 40 years, where it has benefited from large natural sources of CO_2. Applied in the UK, it could provide valuable storage space for carbon emissions.

An un-risked technical potential across the UKCS oil fields identified a resource of up to 6 billion barrels of additional oil, with storage for over 1 billion tonnes of CO_2. However, CO_2-EOR is, as yet, untested at scale offshore, where it faces greater technical, commercial and economic risks, some of which are hard to quantify. Less than a tenth of the un-risked potential is likely to be economic[1]. The main factors affecting the economics of CO_2-EOR are oil price, cost of CO_2 supplied, reservoir performance, capital expenditure and the fiscal regime. These risks will need to be mitigated if projects are to proceed.

The additional oil that could be extracted has the potential to provide substantial, taxable oil revenues, extending the life of the oil fields for up to 15 years. It could also offer additional, secure CO_2 storage at a lower cost than other options, thereby reducing demand on the Levy Control Framework from CCS, and the overall cost of transition to a low carbon energy system. Delivering it will require addressing commercial interactions between the parties in the supply chain which are currently not clearly understood, particularly how to finance the back-up stores needed to manage the CO_2 flows for EOR projects.

Conclusions

Oil reserves in the North Sea could potentially be increased by up to 10% by injecting carbon dioxide as part of a miscible gas injection enhanced oil recovery scheme (CO_2-EOR)[2]. CO_2-EOR also provides the opportunity to stimulate the development of CCS, reducing the cost of achieving the UK's energy and carbon targets.

With some of the best and largest CO_2 storage assets in Europe, the transformation of the North Sea could provide opportunities to manage carbon emissions from neighbouring states over a long period. The Central North Sea offers the only realistic location for CO_2-EOR, but opening up this potential is dependent on developing a supply of CO_2.

Early development of several capture projects is essential to supply the volumes of CO_2 necessary for CO_2-EOR. In return, CO_2-EOR could provide CCS projects with a secure, lower-cost CO_2 storage option. Delivering the CO_2 for EOR will have a significant bearing on the development of a CO_2 transport network in the North Sea, and the location of CO_2 storage sites. By providing secure, early storage and stimulating a CO_2 transport network CO_2-EOR could accelerate the development of CCS.

[1] 68 Million tonnes DECC March 2015
[2] Proven and possible oil reserves amount to 648 million tonnes DECC, March 2013

The maturity of most North Sea oil fields means there is a narrow time window in which to deploy CO_2-EOR, with the potential incremental oil recovered declining from about 500 million barrels to 100 million barrels between 2025 and 2030, if no supply of CO_2 is available. Thereafter, fields would have to be redeveloped: while not unfeasible, the potential risks and costs mean they would not be considered for a first or early project.

Implementing CO_2-EOR offshore is very challenging and carries additional operational, commercial and financial risks. Much of it is either sub-economic or marginal and would require an improved oil price, without intervention. Modifications to the fiscal regime applied to each of the fields could improve the economics of EOR extraction.

A first CO_2-EOR project might be able to proceed if both the capture projects proposed on power stations in Scotland went ahead along with capturing industrial emissions. Expansion beyond the first CO_2-EOR project would almost certainly require additional supplies of CO_2 from capture plants in Teesside, Humber or Europe, in order to deliver the volumes required.

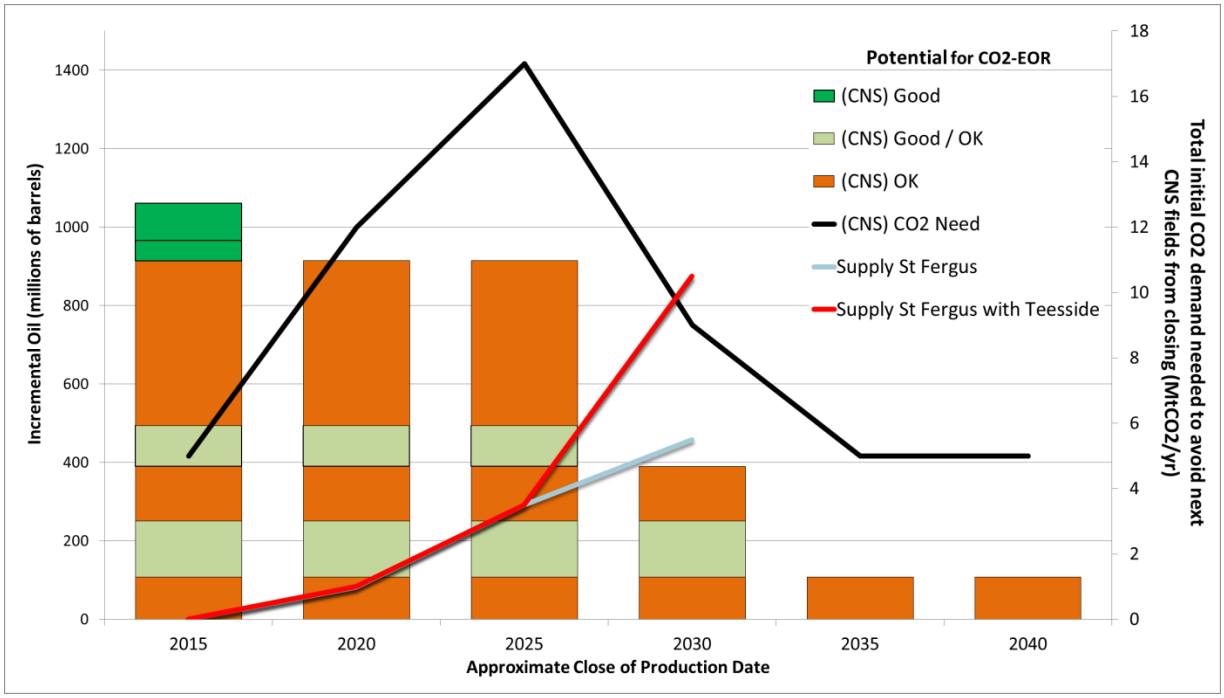

Figure 1 Potential (un-risked) oil recovery from leading candidate fields based on anticipated cessation of production dates. Two-thirds of the potential oil is in fields that could close by late 2020's. Split by field, location and suitability for CO2-EOR. Black line indicates initial CO2 supply required to keep open CNS fields due to close that year. Red and pale blue lines show CO_2 supply from Teesside and St Fergus on a Cautious CCS scenario. CO_2 supply to NNS is unlikely in timeframe[3].

Building a pipeline from Teesside or Humber would open up new potential CO_2 storage sites in the CNS, which are larger and may be cheaper to develop. Depleted oil fields in the CNS should also be included as they are already well characterised and could be available sooner than deep saline aquifer storage sites. If a pipeline is not built to deliver CO_2 for EOR then it may be several decades before it is needed for CCS, and would depend on whether the UK develops an industry accepting and storing European CO_2.

[3] SCCS 2009, Senergy 2013

The development of CO_2-EOR will need to engage with the public at an early stage and clearly demonstrate how the carbon reductions are achieved. It will need to balance the benefits of stimulating CCS, improving the chances of achieving the carbon targets at a lower cost, increasing energy security and the wider economy against the difference in emissions from extracting domestic oil and imports.

Recommendations

CO_2-EOR could deliver around 500 million barrels of additional oil, extending the life of the oil fields and importantly, providing secure, well understood, low-cost storage space for CO_2 from CCS developments. However, the window of opportunity to achieve this is narrow – a sufficient supply of CO_2 is not expected to be available until mid-2020s, and all but one of the best CO_2-EOR candidate fields are expected to cease production by 2030. Redeveloping fields is likely to be prohibitively expensive.

Realising the potential benefits is dependent on building multiple CCS capture projects and a pipeline network that can supply CO_2 to the Central North Sea by 2025-2030.

A significant opportunity exists in the North Sea to help maximise the economic return by extending the life of the existing oil fields and develop a world-leading off-shore CO_2 storage industry.

Realising this requires a plan that coordinates the dual opportunities.

1. **If the benefits of CO_2-EOR are to be realised then a coordinated plan is needed for the North Sea that brings the different sectors and industries together for the extraction of oil and the development of CCS and a CO_2 transport network.**
    a. A CO_2 network in the North Sea led by CCS alone is likely to be very different to one that includes CO_2-EOR. CCS and oil development need to be considered together to avoid unnecessary expense.
    b. A CO_2 pipeline network in the North Sea opens the opportunity for a new industry able to accept CO_2 from neighbouring countries.
2. **Policy decisions made over next two years on Phase 1 and Phase 2 of CCS will determine the likelihood of CO_2-EOR developing in the UK.**
    a. The time window for CO_2-EOR is narrow as most suitable oil field are expected to cease production by 2030. Intervention is required to build an off-shore CO_2 supply before decommissioning decisions are taken. Developing capture projects is a priority. Any delays will reduce the opportunity.
    b. Both CCS Commercialisation projects under consideration by DECC should be supported as early as possible to start building the CO_2 supply infrastructure and develop learning about CCS.
    c. Final Investment Decisions on early Phase 2 capture projects will need to be made by 2017, with an agreement on CfD, if the projects are to deliver CO_2 by the mid-2020s.
    d. Industrial carbon emissions could enhance the CO_2 supply but they need support to deploy capture technologies, in the same way that CfDs help finance power stations.
    e. Suitable storage, in depleted hydrocarbon fields, particularly oil, and deep saline aquifers need to be commercially de-risked to enable Phase 2 capture to proceed.

3 **Extracting oil with CO_2-EOR is relatively expensive and carries higher risks and is likely to require modifications to the tax regime to attract the investment. This should be offset by an evaluation of the wider economic impacts including building a supply chain, jobs and the transition to a low-carbon energy system.**
   a. The tax regime for CO_2-EOR projects needs to recognise the higher commercial and economic risks of extracting the additional oil.
   b. An early CO_2-EOR project is essential to understand the supply chain risks and costs and the technical challenges.
      i. Early projects carry greater risk and therefore require additional incentives.
      ii. Field maturity means a subsequent project might have to run in parallel to the first. As a result it will carry similar risks to the first project.
      iii. Further projects will need to be addressed on a field by field basis.

4 **Commercial models need to be developed for the interactions between CO_2 emitters, transporters and CO_2-EOR developers. Developing an early CO_2 transport network will reduce the risks and therefore cost for emitters, storage developers and CO_2 users.**
   a. A CO_2 transport company would reduce the commercial and counter-party risks for emitters and storage developers. A publicly supported network company would enable the early pipeline network to be designed to accommodate future requirements.
   b. A 'Market Maker' model would manage the interactions between emitters, storage developers and CO_2-EOR developers, reducing their risks and allowing accelerated deployment.
      i. It would also reduce the risk of cross-subsidy between energy and oil industry through CfD calculations.

5 **Additional actions**
   a. The status of CO_2-EOR in the EU CCS Directive needs to be defined, in order to determine compliance requirements and the long-term storage liabilities.
   b. Decommissioning tax arrangements need to be defined for infrastructure that has been repurposed for CO_2, particularly where a field qualifies for PRT.
   c. The cost of redeveloping fields for CO_2-EOR after cessation-of-production needs to be better understood.
   d. Abandonment and decommissioning of wells and associated infrastructure needs to consider the potential for future redevelopment.

Next Steps

- Approval of both CCS Commercialisation projects and a focus on early Phase 2 capture projects so they can progress to FEED and be commissioned by the mid-2020s.
- Oil and gas and CCS industries to work together to develop long-term vision for North Sea development, informed by detailed modelling work.
- Modelling of CO_2 flows between potential sources and sinks.
  - A national CO_2 network company could undertake long-term forecasting of the potential emitters, sinks and users.
  - Modelling would provide a more detailed understanding of the CO_2 flows, particularly for early projects, where a CO_2 network with multiple emitters is not in place. This would help ensure a consistent and reliable supply of CO_2 and to

understand the interactions between the multiple sources of CO_2, different types of store and the demand from EOR.

- Clear understanding of the greenhouse gas emissions from the development and operation of the system. This will be important for establishing public acceptance of EOR.
- Identification of storage, including aquifers and depleted oil and gas fields, to enable Phase 2 CCS. Location informed by CO_2 flow modelling work.
- Licencing arrangements for oil fields under EU CCS Directive to be clarified.

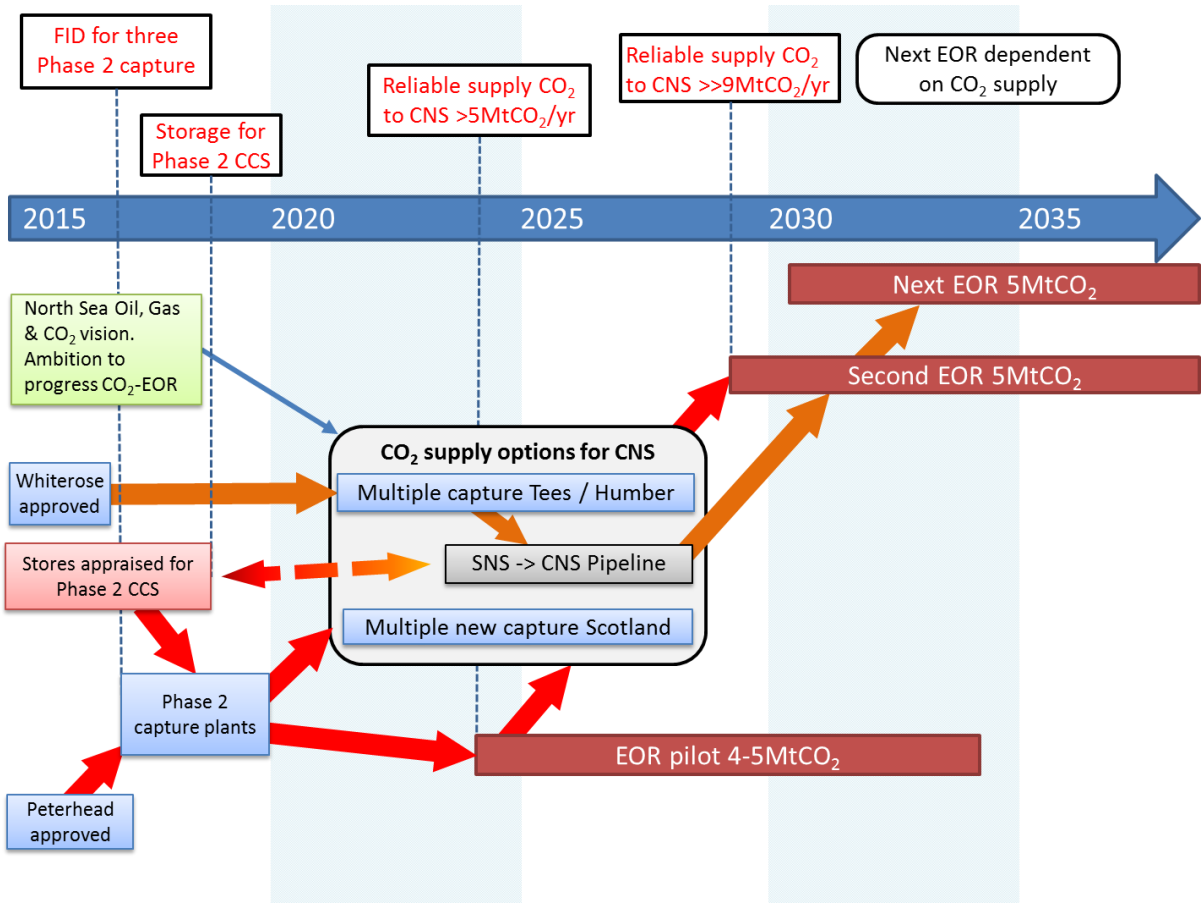

Figure 2 Critical stages and timeline for the delivery of early EOR projects, showing dependencies. Red lines show critical path, but uncertainties around delivering a reliable supply for second EOR project by late 2020s means orange path should also be considered. Note a decision on pipeline development has a significant bearing on the location of new store appraisals.

Contents

Steering Group

Angus Gillespie (Chair)	Shell
Peter Emery	Drax
Tony Espie	BP
Steven Fogg	Atkins
Paul Freeman	OCCS, DECC
Ward Goldthorpe	Crown Estate
Julien Hailstone	Nexen
Andy Leonard	OGUK
David Rennie	Scottish Ent
Paul Sullivan	National Grid
Jonathan Thomas	OGA
Tassos Vlassopoulos	GE

Thanks also to the following for their contributions

Russell Cooper, Brian Allison, Jason Golder, Chris Bryceland, Faraz Ahmad and Dave Puckett who all attended or deputised at Steering Group meetings.

And also for their detailed technical input: Owain Tucker, Stephen Goodyear, Peter Whitton, Stuart Haszeldine, Christoph Balzar, John Regan, Willie Reid, Kath Mansfield, Daryon Shahbahrami, Harsh Pershad, David Hughes, Graeme Sweeney, Luke Warren and Theo Mitchell.

1 Introduction

Despite studies showing potentially favourable outcomes for using CO_2 for Enhanced Oil Recovery (CO_2-EOR) in the UK, no project has yet been taken forward[4]. CO_2-EOR in the UK is dependent on Carbon Capture and Storage (CCS) and in return could offer lower cost, well-understood storage locations that may not need the same amount of appraisal time and development costs as deep saline aquifers[5].

Onshore CO_2-EOR is a mature technology, and has been used in the USA for 40 years expanding to over 140 projects producing about 6% of domestic US oil production, using about 70 $MtCO_2$/yr, mostly extracted from natural geological sources[6]. In 2014 CO_2 captured from SaskPower's Boundary Dam coal-fired power station in Canada was added to the supply, providing revenue for the power station and an additional source of CO_2 at a time of increasing demand.

Only a handful of EOR projects have progressed successfully in the North Sea to date, with one, Magnus, contributing to 40% of its annual production by 2010[7]. Shortage of economically available hydrocarbon gas for injection has constrained further projects, and the UK has no geological sources of CO_2. The UK has also successfully pioneered other offshore EOR techniques, including polymer EOR and low salinity water injection.

The Wood Review highlights the need for the oil industry to be encouraged to invest in EOR schemes to avoid leaving significant value behind and to extend the life of the offshore industry and jobs, whilst bolstering UK energy security[8]. Most assessments of the potential of CO_2-EOR in the UK Continental Shelf (UKCS) are un-risked and based on CO_2 being available now. The realistically achievable figure is likely to be substantially lower than the 2-3 billion barrels of additional oil identified[9], with over a third in the Central North Sea (CNS)[10].

Around two thirds of this potential oil recovery and CO_2 storage is in oil fields that will cease production by the late 2020s. Once fields cease production it is uncertain as to the feasibility and cost of reopening them.

Significant opportunities are presented by stewardship of the UK's remaining hydrocarbon reserves and the transition to a CO_2 storage industry, which could require infrastructure on a scale similar to the current oil and gas industry. Revenue from the additional oil production could offset some of the costs of developing CCS. Furthermore, CCS could save tens of billions of pounds from the annual cost of low carbon energy by 2040[11].

To achieve any of this will require addressing some significant challenges technically, economically and commercially. There is as yet no supply of CO_2; with decisions on the first capture projects are due in the next 18 months. The market for CCS is still in development and new business models and

[4] REF ZEP 2014?
[5] ZEP 2014
[6] 300,000 barrels per day, ETI 2015
[7] Senergy 2013
[8] Wood Review 2014
[9] Senergy 2013 High level screening of un-risked technical potential of CO_2-EOR
[10] 700 - 1,600 million barrels, storing 340-800 $MtCO_2$
[11] ETI March 2015

commercial arrangements will be needed. Attracting the necessary industrial investment in the North Sea, needs to be compared to other more profitable options elsewhere, globally.

Public acceptance will also be important. Using CCS to extract more oil via CO_2-EOR in a carbon constrained world may not appear logical. If the incentives needed to encourage the use of existing facilities to extract oil are to be acceptable, CO_2-EOR will have to demonstrate that the additional environmental benefits and carbon intensity of the oil production are better than the alternative operations that are being explored[12].

Aims of the report

This project reviews the current state of play in the development of carbon capture, CO_2 transport and storage and the use of CO_2 for EOR. It seeks to understand the role of CO_2-EOR and how it interacts with the development of CCS and to understand the risks and market failures that are preventing progress being made.

With significant decisions due to be made over the next 18 months on the first UK CCS projects and on the next spending review, it is vital that the impact of these on the future development of CCS and the offshore oil industry are understood. This report makes proposals for how to realise these opportunities, highlighting the issues that need addressing and how the risks across the various industrial sectors involved could be addressed.

[12] SCCS 2014b

2 Characteristics of CO_2-EOR

Decisions to undertake EOR are based on technical and commercial factors based on the field geology and economics. At a national level it has the potential to increase oil recovery and extend the life of the industry and, in the case of CO_2-EOR, the potential to store CO_2. The choice of technique is determined by the characteristics of each field, availability of injectant and the economics.

EOR is referred to as the third ('tertiary') stage of oil recovery, where oil that does not flow readily from the reservoirs requires more advanced techniques to extract it. As much as 15% of the original oil in place could be recovered, yielding additional revenue. However, extraction costs for each barrel are higher than primary and secondary extraction. External incentives are therefore likely to be needed, particularly for early projects.

2.1 Introduction to EOR and when CO_2 is a preferred flood

Early, high-level assessments of UK oil fields, using the SENEOR EOR screening tool, suggested that CO_2-EOR could be utilised in a wide range fields, accessing about 5.7 billion barrels (Figure 3), about 5-15% of original oil in place (OOIP)[13], of which 2 billion barrels in the CNS. Other processes, including low salinity, polymer or surfactant injection, could yield about 3-15% of OOIP.

EOR is a technically challenging process. Experience from around the world suggests the realistically achievable CO_2-EOR potential is likely to be around 10% of the technical potential suggested by SENEOR, due to the physical and chemical characteristics of each field.

The supply of injectant is a major barrier to development of any EOR project. Analysis by DECC of sources of stranded gas suitable for injection concluded there was insufficient volume to make a full scale project viable. CO_2 could become available at low cost, if CCS was developed at sufficient scale.

	EOR Process	Potential (Billion barrels)
Gas	Miscible CO_2	5.7
	Miscible Hydrocarbon	5.4
Chemicals	Surfactant + Polymer	4.8
	Polymer	2.1
	Colloid Dispersal Gel	3.1
	Bright Water	3.1
	Low Salinity Water	2.0
Heat	In-Situ Combustion	0.7
	Steam	0.6

Figure 3 Potential volumes of oil recovered by different EOR options across the UKCS. Source PILOT 2012, DECC SENEOR Tool

TEXT BOX: EOR

EOR is regarded as the third, or tertiary, stage of oil recovery and usually follows initial pressure depletion (primary recovery) and water flood (secondary recovery).

[13] Thomas J 2012 Presentation to 33rd IEAEOR Symposium August 2012

More than half of the original oil is left dispersed across the reservoir after water flood. EOR typically uses a chemical injectant that interacts with the remaining oil to make it flow more easily, increasing overall oil recovery by 3-15% of the original oil in place. A variety of injectants and techniques can be used that interact with the oil in various ways and spread differently through the reservoir. The choice of EOR technology will depend on availability of injectant, the characteristics of the reservoir and the costs and economics of each field.

Alternating CO_2 injection and water flood, a process called Water-Alternating-Gas (WAG), can improve the efficiency of the oil mobilisation process. Separation of the injectant from the produced oil can be more complex than for a water flood. The choice of process and the amount of CO_2 injected will depend on the reservoir geology and how the remaining oil is dispersed across the field.

Figure 4 illustrates the increase in oil recovery following CO_2 injection. After CO_2 injection it takes time before oil recovery increases, as the CO_2 moves through the field mobilising an oil bank. EOR is more expensive than secondary recovery techniques such as water floods and tax incentives in Texas have enabled the additional oil to be extracted.

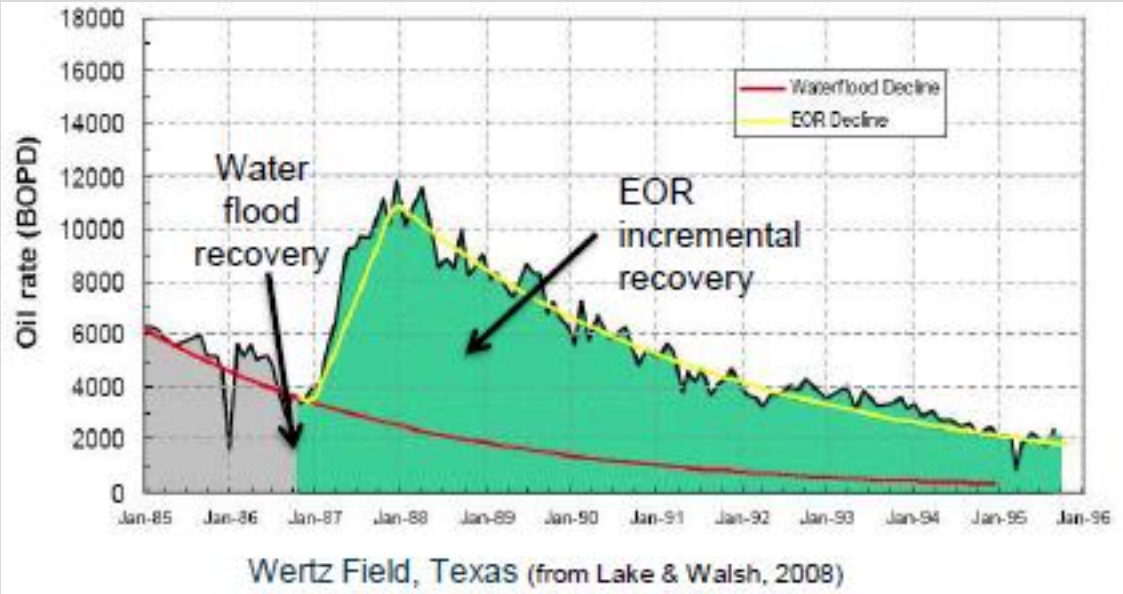

Figure 4 Example of CO2-EOR from Texas showing incremental oil recovery from CO_2 injection compared to water flood.. Typical recovery is 2.5-3.5 barrels per tonne of CO_2 i.e. 0.35-0.5 tonnes oil per tonne of CO_2[14].

TEXT BOX: INJECTION PROFILES

The initial injection volume estimated for possible UK projects vary from 1-2MtCO_2/yr to 5-10 MtCO_2/yr. Once the initial flood of CO_2 eventually breaks through at the oil production wells, it is separated and recycled, reducing demand for imported CO_2. Figure 4 illustrates a possible scenario for a CO_2-EOR field where the CO_2 recovery rate increases to the point where it can meet the injection demands. Thereafter, demand may be occasional as the CO_2 disperses within the reservoir and becoming unavailable for recycling.

[14] Source 2Co presentation 2013

A typical field would recycle the CO_2 as much as three times. In the US where the CO_2 has to be purchased the volumes of fresh CO_2 used are lower.

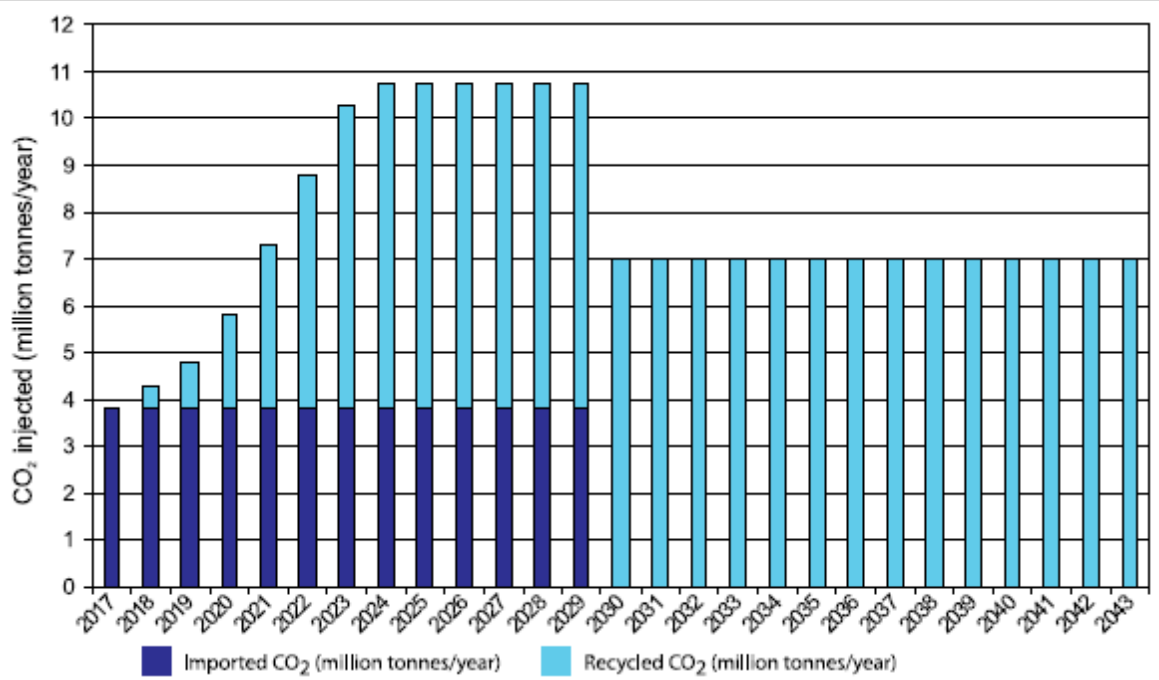

Figure 4 Estimated CO_2 injection and recycle gas injection profiles for the Claymore Field. There is some uncertainty about how quickly (Source SCCS 2009)

2.2 Onshore versus offshore CO_2-EOR

Offshore CO_2-EOR is much more complex, both technically and economically than onshore. Onshore CO_2-EOR is a mature technology developing in the US due to natural, geological sources of CO_2. Wells are easier and cheaper to drill allowing smaller well spacing in regular patterns providing better sweep control. Processing facilities, for separation of CO_2 and oil and compression for reinjection, are also not constrained by space.

Fewer injection wells, offshore, means the distance to extraction points will be further, making managing the CO_2 flood harder, but also delaying how quickly the mobilised oil bank reaches the production well: this may be between 1-2 years or as high as 6-10 years from initial CO_2 injection. With substantial upfront costs any delay in revenue impacts on the project's NPV.

The amount of oil that could be recovered rangeS between 6 and 10% for North Sea reservoirs; requiring about 1 tonne of CO_2 for every 0.2- 0.45 tonnes (1.6–3.3 barrels) of additional oil.

Adjacent fields may be able to share facilities, as a cluster, to reduce infrastructure costs, particularly for CO_2 separation and re-compression re-injection after recycling[15]. Offshore hubs such as the Goldeneye platform (part of the Peterhead project) could also be developed to reduce costs.

The first offshore CO_2-EOR projects will provide valuable learning on how to address the technical, operational and financial risks, but will be more expensive and therefore require additional

[15] DECC 2013, Senergy 2013, EE 2014, SCCS 2014a

incentives. The scale of the reconfiguration of an oil platform to take this additional equipment means that the first 'pilot' project is in effect a full scale operation[16].

TEXT BOX: Metalurgy

Access to water means offshore fields often use water floods. If water is present in the extracted fluids then the production well for CO_2-EOR will need to be designed or refurbished to cope with the carbonic acid created when CO_2 mixes with water. The extent of the investment required will depend on the individual fields and wells and the type of alloy metal currently in place. It is likely that the tubing in many of the production wells will need replacing.

2.3 Carbon emissions from a CO_2-EOR system

An important aspect of developing CO_2-EOR is understanding the carbon emissions from the system, which will be important for public acceptability. This includes ensuring that the CO_2 delivered remains stored in the field to allow credits to be gained but also accounting for the emissions for additional energy input to extract the oil, which includes the recycling of the CO_2. This additional energy input means that the carbon intensity of oil from offshore CO_2-EOR is higher than extraction by conventional means[17]. Concern may also be raised that compared to CCS – with storage only – CO_2-EOR is producing more oil, and would therefore increase the UK's carbon emissions. However, this domestically produced oil needs to be compared to the carbon intensity of oil that would otherwise be imported.

Compared to other forms of oil extraction the carbon intensity of oil from CO_2-EOR in the UKCS is estimated to be about 129-135kgCO_{2e}/bbl; higher than conventional oil, but lower than unconventional recovery techniques (analysis range from 40-135kgCO_{2e}/bbl[18,19]). *[FIGURES SUBJECT TO REVIEW]*. This 'penalty' needs to be set against the benefits of accelerating CCS, the consequent reduction in decarbonisation of the energy system and the wider economic benefits to the UK and energy security.

Evidence suggests that a majority of the CO_2 taken from the capture source will be sealed into the oil reservoir, although small quantities may be lost through leaks during transportation, injection and processing. Little data is available on the exact amounts, as yet, but analysis suggests 0-1% of the original CO_2 taken from the emitter[20], while US experience suggest this may be as high as 2%[21].

In some fields it may be possible to store additional CO_2 in the reservoir by continuing to inject after oil production has declined. However, the feasibility and capacity to store additional CO_2 would depend on the field characteristics. In an open aquifer oil reservoir, careful injection could displace the water allowing additional CO_2 to be stored. In a closed reservoir, additional CO_2 would increase the pressure unless water is extracted, which would require treatment to remove any oil and CO_2 before disposal.

---

[16] Miscible hydrocarbon gas may be injected into the field to test the geology and the viability of a reservoir, as the rig already has equipment to separate these gases from the oil.
[17] SCCS 2014
[18] SCCS 2014 *Carbon Accounting for CO_2EOR,* Nov 2014
[19] EC JRC Dec 2005
[20] NETL
[21] SCCS 2014

3 CO_2-EOR in a UK context

For CCS projects the priority is confirming the storage. For CO_2-EOR it is about securing the supply. Without sufficient volume of CO_2 to enable the recovery of enough oil to cover the additional costs and risks of an EOR project, projects will not come forwards. Most of the best candidate fields are due to close by 2030, setting a timeframe for the delivery of CO_2, beyond which field redevelopment will raise costs.

The Central North Sea provides the most promising opportunity for CO_2-EOR, but there is uncertainty about whether enough CO_2 could be captured locally in time to keep the best candidate fields open. Delays could mean that only a couple of fields are developed. With most capture projects expected around Teesside and the Humber, it is likely that a pipeline will be needed to deliver additional CO_2 in order to maximise the opportunity from CO_2-EOR.

3.1 The amount of CO_2 captured by 2030 and 2050

The amount of CO_2 captured and where will depend on how quickly capture plants are deployed in the power sector and the incentives available for capturing industrial carbon emissions. Estimates for CCS power plants in 2030 range from 4 to 12 GW (12 – 60 $MtCO_2$/yr), or lower if nuclear replaces fossil fuels[22]. By 2050 between 13 and 40GW of CCS could be required, producing between 50 and 130 $MtCO_2$/yr[23]. A further 5 to 20 $MtCO_2$/yr could be captured from industry by 2050[24], concentrated in a few locations, in particular Teesside and Grangemouth.

3.2 Where we are now

Two projects are being considered by DECC's CCS Commercialisation Competition, White Rose and Peterhead, with the intention of this first Phase of CCS being operational by 2020. Other projects are awaiting the outcome of the initial round and are likely to be considered for early Phase 2 CCS[25].

Peterhead plans to capture about 1$MtCO_2$/yr for 10-15 years from a 385MWe gas power plant, transporting via a refurbished gas pipeline to the depleted gas field at Goldeneye in the CNS. White Rose would take 2$MtCO_2$/yr from a new 448MWe oxy-fuel power plant at Drax to the Bunter sandstone aquifer in the SNS via an oversized pipeline from Humberside. Once operating it may take 2-3 years to prove technically and commercially, with the CO_2 unlikely to be available for CO_2-EOR.

Goldeneye is located close to a number of fields that could have good potential for CO_2-EOR. The additional storage capacity in the gas field means it could act as a balancing store for these projects. There are no suitable CO_2-EOR projects in the vicinity of the Bunter Aquifer.

Other proposals that were considered for the competition include Teesside, which could lead to a cluster of industry and power capture projects. Don Valley, which completed a FEED study for a new IGCC plant connected to aquifers in the SNS, via the Humber.

In Scotland, Summit Power's Caledonian Clean Energy Project could provide 3.8 $MtCO_2$/yr by the mid-2020s to the Goldeneye hub. A reserve project on DECC's CCS Commercialisation programme it

[22] TSDG 2014 Report of workshop in May 2014
[23] ETI 2015
[24] Element Energy 2014 CCS Hub
[25] DECC CCS Roadmap 2012

is undertaking a £4.2 million feasibility study into industrial capture. A subsequent IGCC project in Grangemouth could add 4 $MtCO_2$/yr, with the potential to include industrial capture schemes.

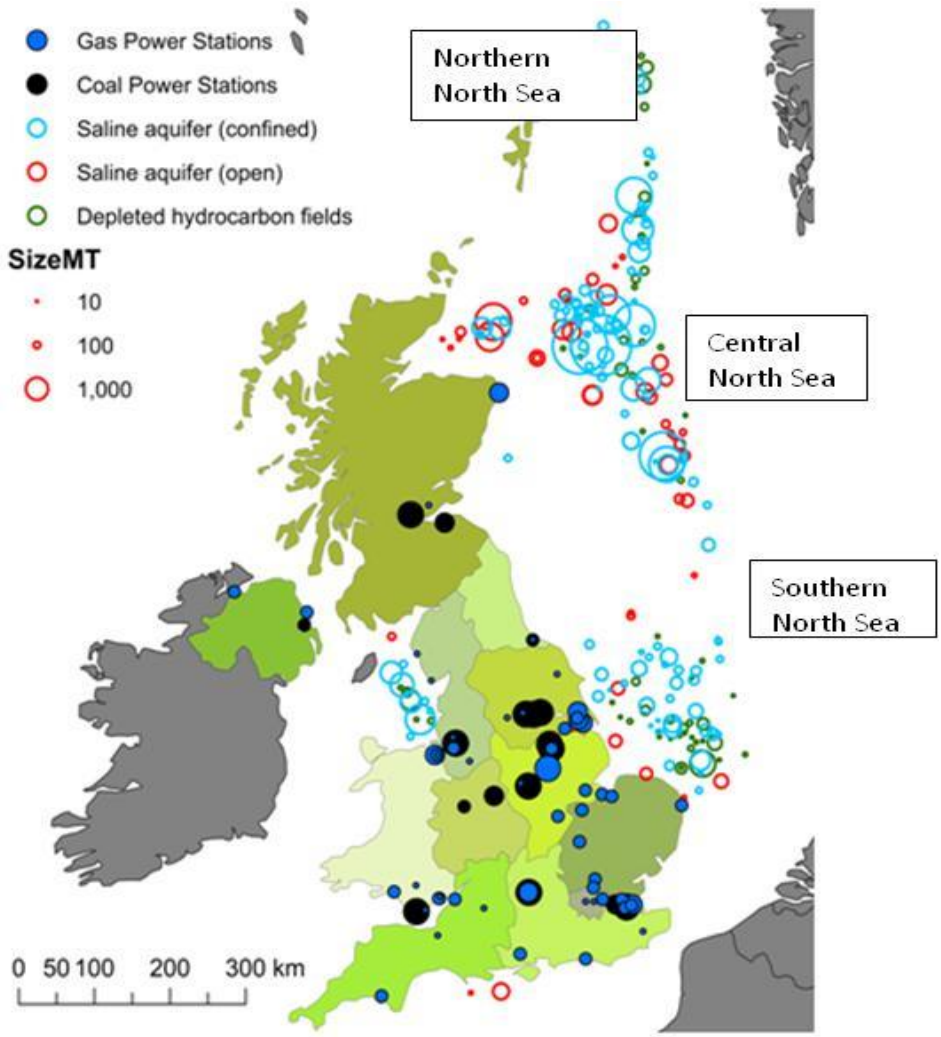

Figure 5 Location and size, in 2013, of power generation sources of CO_2 from the UK and of potential sinks[26]. Industrial sources of CO_2, are not marked, but could provide consistent supplies, albeit at smaller volumes. The location and volumes of these sources might change by 2030 as the low carbon energy system develops[27].

3.3 Geographic location

Where the CO_2 is produced is important as a majority of the emissions by 2030 are expected from North-East of England[28]. Most of the current oil activity in the Central and Northern North Sea is accessed through St Fergus. Uncertainty around the supply though St Fergus by 2030 (Figure 6) suggests that additional CO_2 may be needed from either Teesside or Humber.

Humberside is expected to utilise stores in the Southern North Sea, which may reach 35$MtCO_2$/yr by 2050[29]. Teesside emissions could go to aquifers in the SNS or a longer pipeline to the CNS, subject to suitable storage being available.

[26] ETI 2015
[27] Source www.co2stored.co.uk using ETI emissions data
[28] ETI Analysis
[29] Element Energy 2013

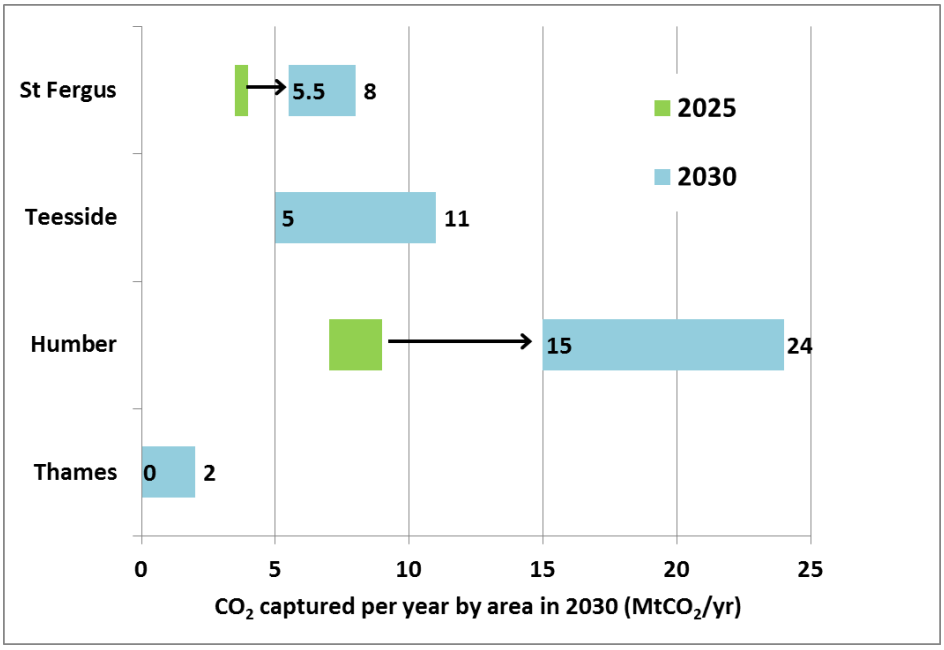

Figure 6 Range of possible CO_2 supply by key locations in 2025 and 2030. Comparison of Cautious and Aggressive Scenarios developed by Element Energy[30]. Both UK Commercialisation Competition plants start operation in 2020.

3.4 Availability of Storage CO_2 only and CO_2-EOR.

Screening of the North Sea using known geology and likely costs identified 12.6 Gt[31] storage capacity (Figure 7), out of a maximium un-risked potential of 78 $GtCO_2$. The NNS and CNS have substantial aquifer potential, but they too poorly understood to be considered (Figure 5). Depleted oil fields are better characterised than aquifers, so could offer lower cost and risk.

Giga tonnes	Depleted Oil and Gas Reservoirs	Saline Aquifer	CO_2-EOR
NNS	1.3		tba
CNS	0.6	2.1	0.8
SNS	3.2	5.4	0.3
TOTAL	**5.1**	**7.5**	**1.1**

Figure 7 Storage capacity from stores selected from UKSAP data that were assessed to have 'reasonable' costs and security prospects. Source ETI 2014

The best CO_2-EOR fields could add 800 $MtCO_2$ in the Central North Sea[32]. Once a CO_2-EOR field ceases oil production it may be available for storage depending on the characteristics of each field.

3.5 Leading fields for CO_2-EOR

High-level screening of the fields in the UKCS suggests 500-700 million barrels could be recovered, mostly in the Central North Sea, storing 350 $MtCO_2$[33], based on reservoir characteristics, remaining oil and distance to a likely CO_2 supply hub, but not their economic viability. Less suitable fields could raise this to 1,500 million barrels, storing 800 $MtCO_2$.

[30] Element Energy 2014b
[31] ETI 2014 UK Storage Appraisal Project (UKSAP)
[32] SCCS, Senergy, Kemp
[33] Senergy 2013

Only three of the leading fields are considered to have 'CO_2 compliant' metallurgy, which would reduce capital cost of a CO_2-EOR development, although one has already ceased oil production and another is expected to COP before 2025.

Figure 8 shows a range of estimates for leading candidate fields. Detailed modelling is needed to reduce the uncertainty for the amount of incremental oil and CO_2 stored, which could be as high as +/- 50%[34]. For example, the presence of gas caps or strong aquifer support are not included.

Field Name	Location	CO_2 Storage capacity $MtCO_2$	Projected incremental oil (million barrels)	Close of Production Date	Potential for EOR	Initial injection volume ($MtCO_2$/yr)
CNS						
Scott	CNS	31 (45)	95 (105-224)	2015	Good	~5
Forties	CNS	80-138 (77)	420 (177-295)	2025	OK	~12
Nelson	CNS	25	52-94			~3.5
Alba	CNS	18	36-67			~2
Tartan	CNS	21	48-80			~2
Claymore (Main, Central, Northern)	CNS	47 (28)	142 (64-107)	2030	Good / OK	~3
Piper	CNS	20-46	140	2030	OK	~6
Buzzard	CNS	36 (39)	108 (80-145)	2040	OK	~5
NNS (South)						
Miller	NNS (S)	17 (21)	52 (48-80)	Closed	OK	~3
Brae	NNS (S)	34 (14)	104 (30-54)	2025	Pilot	~5
NNS						
Murchison (UK)	NNS	26	79	Closed	OK	
Brent	NNS	165	501	2015	Good	
Dunlin	NNS	27	83	2015	Good	
Thistle	NNS	27	82	2015	Good	
Cormorant	NNS	52	157	2020	Good	
Statfjord (UK)	NNS	209 (UK+Norway)	635 (UK+Norway)	2020	Good	
Beryl A	NNS	77	232	2020	Good	
Ninian	NNS	96	292	2030	Good	

Figure 8 Overview of potential fields suitable for CO_2-EOR. Figures are estimates of potential[35].

Injection volumes

For CO_2-EOR to proceed, the supply of CO_2 needs to meet the initial injection volume. In Figure 8 this ranges between 2 and 6$MtCO_2$/yr, with Forties requiring about 12$MtCO_2$/yr. Data is not provided for the NNS as these are expected to have ceased production before CO_2 is available.

[34] Element Energy 2012 CO_2-EOR report, page 8.
[35] Sources SCCS 2009, Senergy 2013, Kemp 2013

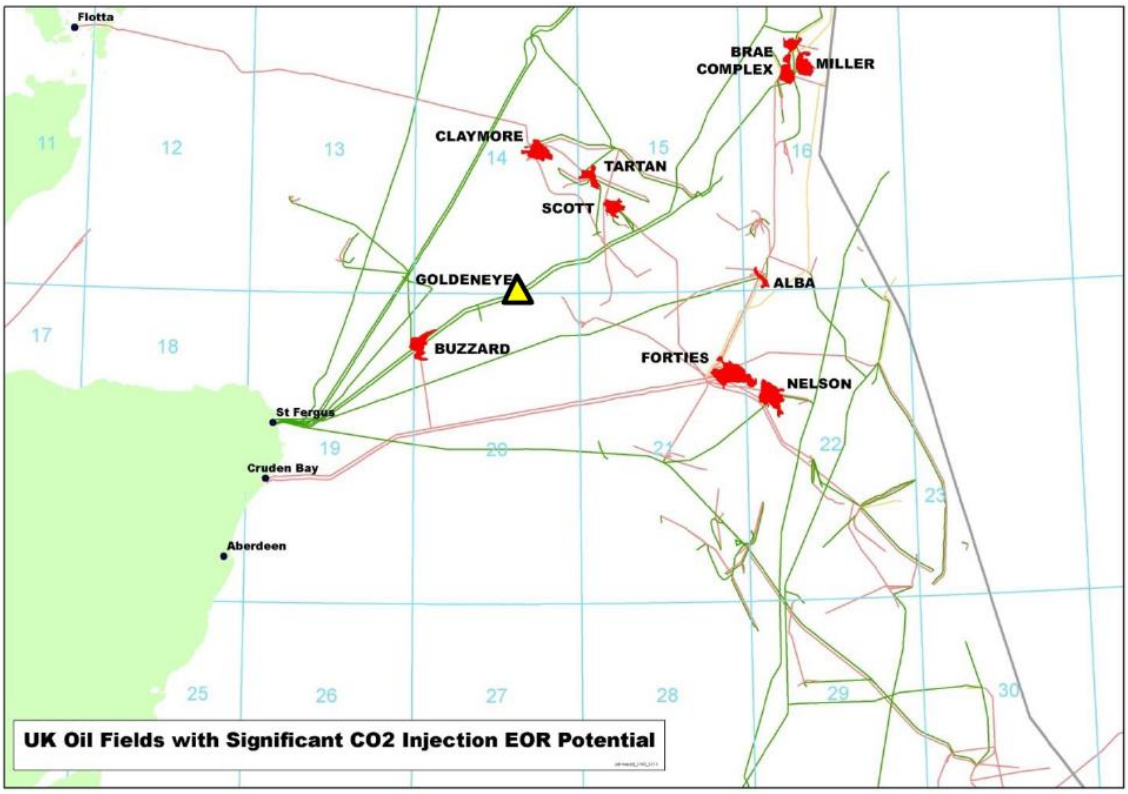

Figure 9 Map of Central North Sea with oil fields with significant potential for CO2-EOR shown in red. Existing gas pipelines are shown in green and oil pipelines in mauve. Source [Thomas 2015]

Field closure dates

One critical factor affecting the overall potential from CO_2-EOR is the expected field closure date. By the late-2020's currently planned closure of the leading fields (Figure 10) could halve the potential additional oil. Only Buzzard is likely to remain beyond 2030 and by the early 2040's all the leading fields could be closed. A continued low oil price could bring the closure dates forward for more mature fields.

Redeveloping fields is likely to be more expensive than fitting out an existing field, particularly if valuable infrastructure has been removed. If a field has the potential to be redeveloped decommissioning should consider if any infrastructure could be reused.

3.6 Window of opportunity

With sufficient CO_2 for a first project not expected in the CNS until mid-2020s there is a limited window of opportunity for realising CO_2-EOR in the UK (Figure 10). In order to keep all the remaining fields open in 2025 a supply of 17MtCO_2/yr would be needed, of which 12MtCO_2/yr would be for Forties. In 2030 three fields are expected to remain available, requiring 9MtCO_2/yr to keep them open. The red line indicates the supply of CO_2 that might be available drawing CO_2 from Scotland, via St Fergus, and Teesside. Higher volumes may become available depending on the scale of capture deployment, but St. Fergus alone is unlikely to deliver the CO_2 required to keep all the fields open.

The demand curve in Figure 10 represents the maximum required. Early supplies of CO_2 in 2025 of about 5MtCO_2/yr could be used for smaller fields. If all the proposed capture plants in Scotland are built then 8MtCO_2/yr may be available by 2030, enabling additional CO_2-EOR fields. The demand

curve does not take into account recycling of CO_2, which would reduce demand for imported CO_2 over time. The impact is hard to estimate as it is dependent on the field, but it could make CO_2 available for other projects. Detailed modelling of supply and demand would be beneficial to understand how the supply and demand may be optimised.

While the current low oil price could bring closure dates forward, a strong drive to deliver CO_2 could mean some fields may consider postponing closure in order to utilise the CO_2 for EOR.

The fields in the NNS, (pale colours), are not included in the CO_2 demand profile as the distance to the fields and their closure dates mean that CO_2 is unlikely to be available in time. If CO_2 did become available it may be possible to redevelop these fields, the cost of which is largely unknown.

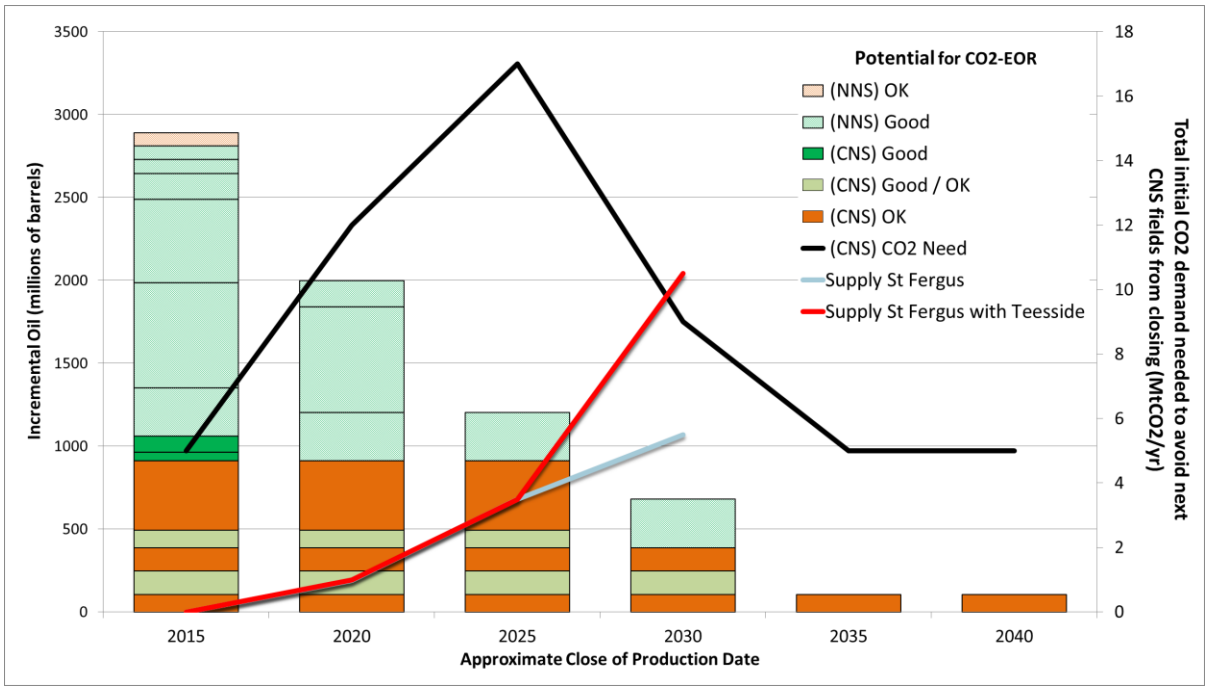

Figure 10 Potential oil recovery from leading candidate fields based on date of closure. Two-thirds of the potential oil is in fields that could close by late 2020's. Split by field, location and suitability for CO_2-EOR. Black line indicates initial CO_2 supply required to keep open CNS fields due to close that year. Red and pale blue lines show CO_2 supply from Teesside

4 Economics and commercial arrangements

CO_2-EOR has higher risks than conventional oil extraction and high upfront costs compared to conventional extraction. The economics are strongly determined by the oil price and the cost of the supplied CO_2, as well as the recovery performance. CO_2-EOR provides direct benefits to CCS by providing low cost storage, which could amount to over 200 $MtCO_2$ by the mid-2030s, and would reduce the cost of CfDs, thereby reducing the cost of generation for the emitter.

The broader benefits that CO_2-EOR could bring to the energy system, along with the additional oil revenue are expected to provide a return on the government investment required to enable the early development of CO_2-EOR. Policies that improve the economics and reduce the commercial risks, such as modifications to the tax regime for the specific fields would encourage the necessary private investment, assuming a viable oil price and sufficient CO_2.

4.1 CO_2EOR project economics

Income to fund capture, transport and storage for CCS on power stations comes through the EMR CfDs and avoided EUETS emissions. Industrial CCS is currently only funded by avoided EU ETS.

Studies suggest that CO_2-EOR projects can be economic but not commercial, as they would not meet the investment criteria of the oil companies even at an oil price of $90/barrel [36]. CO_2-EOR projects require significant CAPEX and, unlike a new oil or gas field, do not benefit from an early flush of oil.

The biggest economic risks (Figure 11) are from the oil price and cost of CO_2 supply, with oil recovery performance also having a big impact, based on an oil price of $100/barrel. CO_2 price risks can be mitigated against through commercial arrangements, but oil price and reservoir performance risks are harder to mitigate. Tax incentives and stability would help mitigate these large risks.

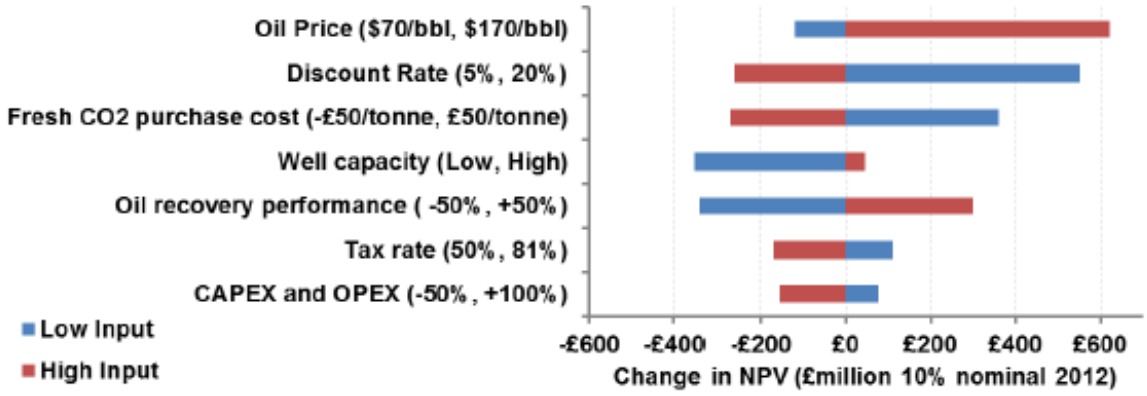

Figure 11 Illustrative example of sensitivities of NPV to various variables[37].

4.2 Cost reductions

The initial CCS projects will have to cover the cost of developing the transport network and infrastructure. Spare capacity means Phase 2 projects should bring transport and storage costs below £10/MWh. Teesside's first project will be higher to cover the pipeline to the CNS or SNS[38].

[36] Element Energy 2014, SCCS, 2Co
[37] Element Energy 2012 *Economic impacts of CO_2EOR recovery for Scotland*

Reusing exiting gas pipelines will reduce costs, such as the Peterhead CCS project, which plans to reuse the gas pipeline to the Goldeneye platform. Two other offshore pipelines, Goldeneye–Miller and St Fergus–Forties, could be reused to supply other CO_2-EOR fields[39]. However, no incentives are in place to maintain these pipelines, which may risk their future use[40]. Onshore the Feeder10 gas pipeline could capture projects connecting to St Fergus, although it is limited to 6.1Mt/yr[41].

Operational and commercial learning will de-risk future projects, with cost reductions from increased scale. Evidence from Boundary Dam in Canada, the first full chain CCS project, suggests that learning rates on future development of both CO_2-EOR and CCS technologies – could be as high as 30% between successive projects[42]. However, the benefits for early Phase 2 CCS projects may be reduced as they may develop in parallel to the Commercialisation projects.

By 2025 these savings could mean the strike price for power station CfD's could fall below £100/MWh. A scenario that prioritises the development of CO_2-EOR projects, to reduce the cost of storage, delivers the lowest overall investment cost in CfD payments by 2030, compared to a CCS only scenario and a mixed scenario, but with low CO_2-EOR deployment[43].

4.3 Incentives

A field allowance could be offered to CO_2-EOR projects to reduce their tax burden. As Figure 12 indicates the scale of the incentive would need to be proportionate to the price of CO_2. However, identifying a 'fair' solution will not be easy, when there are multiple actors involved[44].

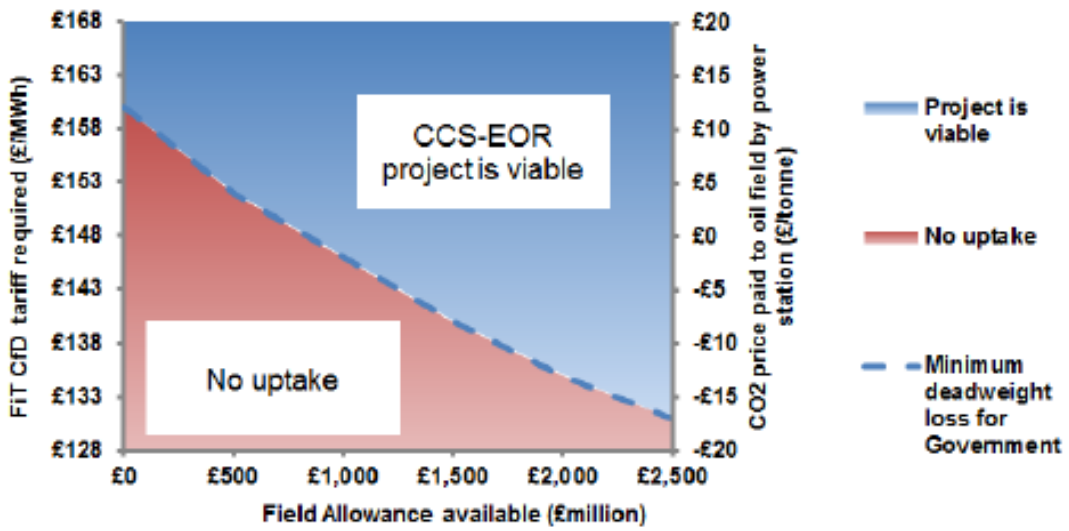

Figure 12 Illustrative interplay between power sector and CO2-EOR for a network comprising of an IGCC capture project. Source SCCS[45]

[38] Element Energy, Poyry 2015
[39] Kemp 2012
[40] Element Energy 2014
[41] Element Energy 2014 (see also EE2014 Appendix).
[42] Verbal evidence from Sask Power presentation.
[43] ibid
[44] SCCS
[45] SCCS 2014a *CO_2-EOR in the UK: Analysis of fiscal incentives*

5 Matching CO_2 sources and sinks/uses

CCS and CO_2-EOR are closely interrelated, which will create commercial risks during development and their operation. Commercial models will be important to mitigate risks for the sectors involved. Developing a CO_2 transport network will mitigate those risks, helping to accelerate their development.

The shape of the CO_2 transport network in the North Sea will be influenced by the ambitions for CO_2-EOR, as it is likely to determine where CO_2 from Teesside is taken for storage[46]. Decisions about building a pipeline from Teesside will influence where new storage site appraisal needs to develop.

5.1 Mitigating risks

The various parties involved face different risks which will need to be mitigated through commercial models and policy in order to progress CO_2-EOR. Linkages and dependencies will establish between the oil sector and the power sector, where they have not existed previously. New entities will be needed to deliver the transportation and storage aspects.

Counter-party risks and costs to any party through loss of service from other parties in the supply chain raise a substantial barrier to investment. For the oil company a loss or delay in supply would reduce revenue from oil recovered. For the emitter, the inability to off-load CO_2 will lead to penalties from purchasing EU ETS credits and loss of CfD revenue. For a storage company, which will provide back-up stores to help balance the CO_2 flow, diversion of CO_2 to EOR will affect its revenue stream.

Aggregation of sources, to deliver the reliable supply of CO_2 needed for EOR, will reduce variations in flow, but will make the commercial interactions complicated. An EOR project may have to pay a capacity payment to the store operator to compensate for lost revenue, but this might weaken the economics of the CO_2-EOR project. Furthermore, calculating the CfD for a CCS project where CO_2 might go to EOR will need to account for any cost reduction this offers, to ensure that it is not regarded as the power sector subsidising the oil industry: including any CfD payment made to the store even if it is not receiving the CO_2.

A more complex calculation for CfDs will be required on a network which might have different emitters, including power and industry, and a variety of CfD values, as it will be unclear where the CO_2 originated.

5.2 Business models for delivering CCS and CO_2-EOR

Establishing a CO_2 transport company would transfer the management of CO_2 flows and liabilities to the operator, who could charge a fixed transport and storage cost. Various models have been proposed for progressing the transport and storage infrastructure. ETI proposed five options that could be considered with increasing levels of public intervention:

1. Government informs and enables competitive market for CO_2 transport and storage infrastructure.
2. Industry co-ordinates and provides leadership on CO_2 transport and storage infrastructure, with Government support.

[46] ETI, Element Energy

3. Regional monopoly system operator(s) are established to deliver transport and storage infrastructure in priority zones.
4. Public-private Joint Venture(s) are established to deliver transport and storage infrastructure.
5. Government design, own and operates CO_2 transport and storage infrastructure.

Capacity would most efficiently be developed through shared CO_2 transport and storage infrastructure[47]. This could be through a 'Market Maker'[48] where a publicly supported transport company would negotiate a price for taking CO_2 from the capture projects and delivering it to the store and CO_2-EOR operators.

5.3 Liabilities and ownership

In a networked system, ownership and liabilities for the CO_2 will have to be transferred so any losses will be classified as an emission, for which the current 'owner' is responsible, and therefore pays any associated fees. CfD payments means that transfer of ownership of the CO_2 does not imply that the credit for the emissions is transferred, even if the CO_2 is purchased as a commodity. Credit will need to remain with the initial emitting source with any leaks or emissions associated with the subsequent handling of the CO_2 accounted for by the individual companies.

[47] ZEP 2014, Element Energy 2014
[48] ZEP 2014

6 Policy implications

The success of CO_2-EOR is dependent on the early development of CCS to ensure a supply of CO_2 is available ahead of the oil fields closing. This will require several capture plants to be sanctioned by 2020 in order to deliver CO_2 by 2025. Decisions will also be needed to ensure the source of CO_2 for subsequent EOR projects, including supporting the additional cost of diverting a Teesside pipeline from the SNS to the CNS.

Figure 13 outlines the key milestones for securing early CO_2-EOR projects. The red arrows highlight a critical pathway, but uncertainty about the number and timing of capture plants in Scotland, means a CO_2 pipeline from the south to the CNS would be needed, most likely from Teesside.

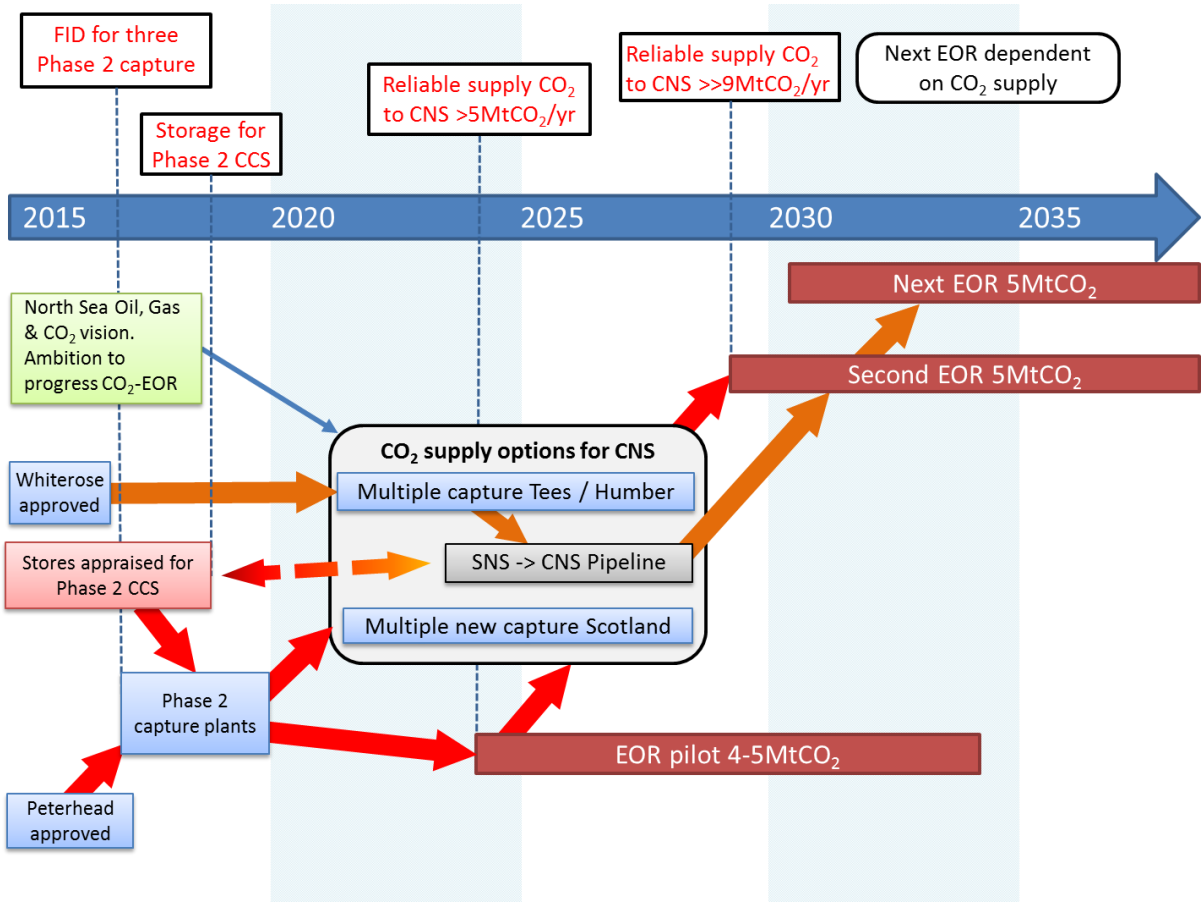

Figure 13 Critical stages and timeline for the delivery of early EOR projects, showing dependencies. Red lines show critical path, but uncertainties around delivering a reliable supply for second EOR project by late 2020s means orange path should also be considered. Note a decision on pipeline development has a significant bearing on the location of new store appraisals.

Modifications will be needed to the EMR to ensure the benefits of developing capture clusters and shared infrastructure are adequately captured. Current criteria do not make allowance for cost benefits from clustering capture projects around key coastal hubs. Similarly, co-locating power stations near industrial sites will provide the transportation infrastructure to allow industrial CCS at a cost that will not be prohibitive or detrimental to their competitiveness.

6.1 Return on investment from wider economic benefits

Public investment to subsidise the development of a CO_2 network would ensure its efficient development[49]. This investment would help de-risk capture projects and accelerate the development of CCS and CO_2-EOR, enabling direct returns from potential oil revenues and wider benefits to the energy system and the economy (Figure 14). Economic analysis suggests that economic multipliers for CO_2-EOR mean these wider benefits could be more than double that for offshore wind[50].

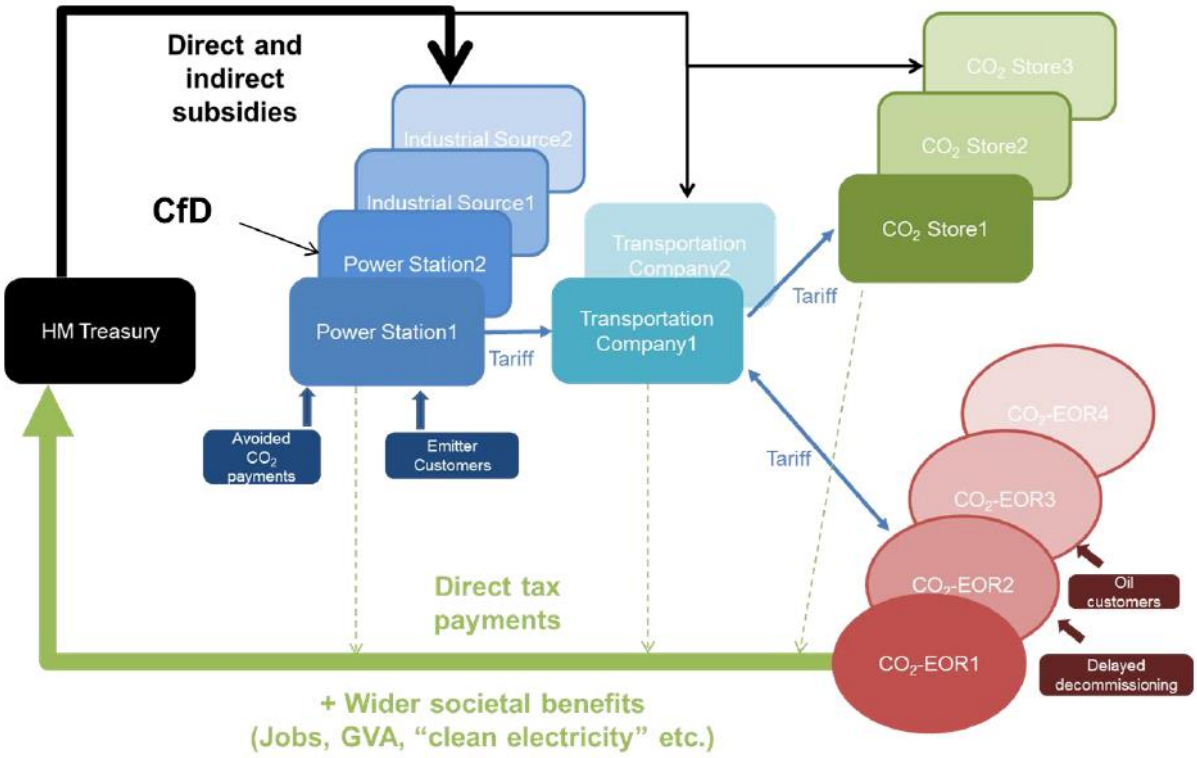

Figure 14 Cash flow for an integrated CCS network comprising CO_2-EOR[51].

Multiple and significant market failures and unbearable risks mean that current incentives are likely to be insufficient for commercial developers to develop this through the market alone. Figure 15 compares the incremental NPV on investment by government for developing CO_2-EOR through interventions to support private investment on a field-by-field basis, to that of investment in a national CO_2 storage company. Although the storage company would require higher investment in the earlier years the returns are much higher than investment through field allowance.

6.2 Storage

The current preference by the UK government and the EU for a project-by-project competition provides insufficient price signals and substantial risks for commercial developers of storage. Consequently there is a shortage of commercial storage development activity. This approach is not well suited to efficiently progressing the development of CO_2-EOR.

[49] Element Energy 2014, ZEP 2014
[50] SCCS 2015
[51] Element Energy 2014 *Scottish Enterprise CCS Hub Study*

If an oil field is to accept CO_2 it will also need to prove that the CO_2 will remain in place, including post-closure monitoring. In some fields it may be possible to inject additional CO_2 for storage beyond what is needed for EOR. Clarity is needed as to the requirements for a licence under the EU CCS Directive for EOR projects to be able to take CO_2. CO_2-EOR projects are currently not included in the EU CCS Directive and do not need a storage licence to take CO_2, but would need to qualify for one if it is to offer emission reduction credits allowing the capture plant to avoid paying the EU ETS and to claim a CfD on power generation, in the same way as a pure store.

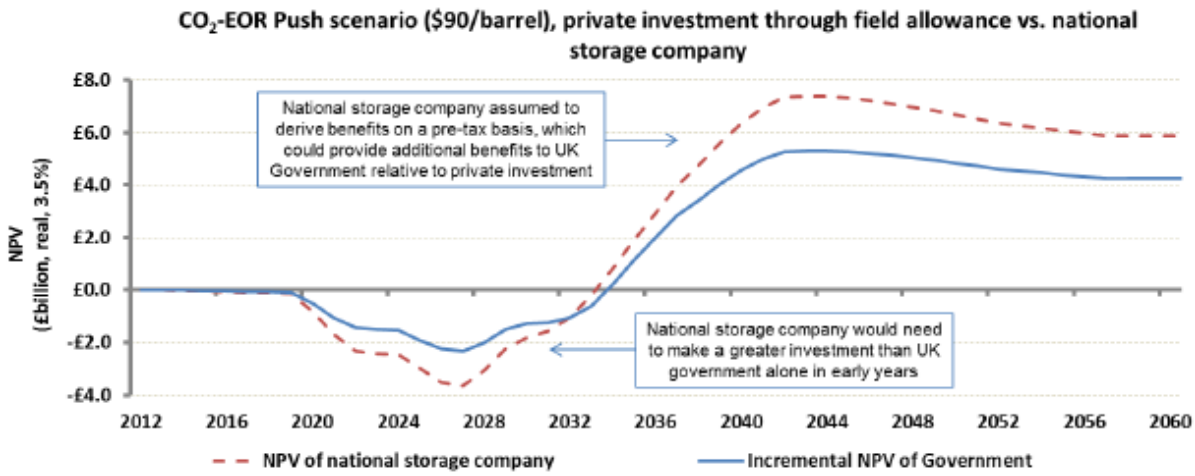

Figure 15 Government NPV in a CO_2-EOR Push Scenario with NPV for a hypothetical national storage company[52]

6.3 Decommissioning costs

Decommissioning tax arrangements need to be resolved, especially for PRT fields, where a change in definition of the fields operation might affect the scale of the tax breaks offered. i.e. closing an oil field comes with certain arrangements to cover the costs, whereas if the field was defined as a CO_2 store, having been used for EOR, abandonment may move it into a different decommissioning category, which would change the tax breaks available, particularly for PRT fields.

[52] SCCS 2014a

7 References

CRTF 2013 *The Potential for Reducing the Costs of CCS in The UK: Final report*, published by the UK Carbon Capture and Storage Cost Reduction Task Force - May 2013.

DECC 2011 Guidance Notes – *Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998* DECC March 2011

DECC 2013 *CCS EOR Workshop*, Aberdeen 1st October 2013: Summary Paper issued by DECC and PILOT

DECC 2015 *UKCS Oil and Gas Production Projections*

EC JRC Dec 2005 EOR using CO_2 in the European Energy System [REF to: A.-C. Aycaguer, M. Lev-On, and A. M. Winer. Reducing Carbon Dioxide Emissions with enhanced Oil Recovery Projects: A Life Cycle Assessment Approach. Energy & Fuels 15:303-308, 2001

ETI *A Picture of CO_2 Storage in the UK: Learnings from the ETI's UKSAP and derived projects*

ETI 2015 *CCS: Building the UK carbon capture and storage sector by 2030 – Scenarios and actions.* ETI, Element Energy & Poyry

ETI 2014 *A Picture of CO_2 Storage in the UK: Learnings from the ETI's UKSAP and derived projects* Energy Technology Institute

Element Energy, Poyry 2015 *CCS Sector Development Scenarios in the UK* For ETI, April 2015

Element Energy 2014 *Scotland and the Central North Sea, CCS Hub Study (Revised Final Report)* for Scottish Enterprise March 2014 http://www.element-energy.co.uk/wordpress/wp-content/uploads/2014/06/Element-Energy-Scottish-CCS-Hub-Study-Revised-Final-Main-Report-310314c.pdf

Element Energy 2014b *Scotland and the Central North Sea, CCS Hub Study (Revised Final Appendix)* for Scottish Enterprise March 2014

Element Energy 2013 *Infrastructure in a low carbon energy system to 2030: Carbon Capture and Storage* Report for Committee on Climate Change July 2013.

Element Energy 2012 *Economic impacts of CO_2-enhanced oil recovery for Scotland* for Scottish Enterprise July 2012

European CCS Directive http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32009L0031

Kemp AG & Kasim S 2014 *The Economics of CO_2-EOR Cluster Developments in the UK Central North Sea/Outer Moray Firth* North Sea Study Occasional Paper No. 123 University of Aberdeen

RAEng 2013 *Decommissioning in the North Sea*

SCCS 2009 *Opportunities for CO_2 Storage around Scotland – and integrated strategic research study* Scottish Centre for Carbon Storage and Scottish Government 2009 http://www.gov.scot/Publications/2009/04/28114540/0

SCCS 2014a *CO_2-EOR for in the UK: Analysis of Fiscal Incentives. Final non-technical report*, 20th January 2014 (Emrah Durusut and Harsh Pershad, Element Energy Ltd). Support by Alan Crerar, Dundas Consultants and Professor Alex Kemp, University of Aberdeen. For Scottish Carbon Capture and Storage (SCCS)

SCCS 2014b *Carbon Accounting for Carbon Dioxide Enhanced Oil Recovery* Jamie Stewart and Stuart Haszeldine for SCCS November 2014

Senergy 2013 *Review of UKCS Miscible Flooding and Appraisal Potential* Senergy for DECC by David Hughes Sept 2013

TSDG 2014 *Delivering CO_2 storage at the lowest cost in time to support the UK decarbonisation goals* UK Transport and Storage Development Group workshop held in May 2014. Crown Estate.

ZEP 2014 *Business models for commercial CO_2 transport and storage: Delivering large-scale CCS in Europe by 2030* European Technology Platform for Zero Emission Fossil Fuel Power Plants June 2014

7.1 Overview of recent activity - tbc

- Element Energy
- SCCS – JIP
- ETI – CCS
- CCSA
- DECC CCS strategy
- OGA – Wood Review
- UKCCSRC

7.2 Units and Glossary

The energy sector and oil industry use different notation for the units.

All tonnes refer to metric tonnes.

1 tonne of oil = 7.33 barrels.

Oil industry refer to 1,000 tonnes as Mt and a million as MMt. A billion is MMMt or 1,000MMt.

Energy industry uses kt, kilo tonnes, as 1,000 tonnes; Mt, mega tonnes, as 1,000,000 tonnes and Gt, Giga tonnes, as billion tonnes.

All millions and billions are short. This is important particularly for understanding quantities of CO_2.

Million = 1,000,000

Billion = 1,000,000,000 (thousand million)