CO_2 storage and Enhanced Oil Recovery in the North Sea:

Securing a **low-carbon future** for the UK

SCCS
Scottish Carbon Capture & Storage

SCCS CO_2-EOR Joint Industry Project

This project was established to undertake a collaborative programme of work to develop an understanding of Enhanced Oil Recovery (EOR), with the aim of creating a commercial use for CO_2 captured from power plants and industry. It has focused on areas of work to address issues that are of major importance to project developers that are looking to link CO_2-EOR in the North Sea with CCS projects. The project was led by SCCS partners and funding has been provided by the Scottish Government, Scottish Enterprise, 2Co Energy Limited, Nexen Petroleum UK Ltd and Shell.

About SCCS and our partners

Scottish Carbon Capture & Storage (SCCS) is an independent research partnership of British Geological Survey (BGS), Heriot-Watt University, the University of Aberdeen, the University of Edinburgh and the University of Strathclyde. It is the largest CCS research group in the UK and provides a single point of coordination for all aspects of CCS research, from capture engineering and geoscience to public engagement, policy and economics.
www.sccs.org.uk

The views and opinions expressed by authors in this publication are those of the authors and do not necessarily reflect those of the project sponsors.

ISBN: 978-0-9927483-2-6

Contents

Key Points

The UK plans to transition into a low carbon economy by 2050 at minimum cost. That means reducing CO_2 emissions by 80% or more across the whole economy. For energy use, this means improved efficiency, combined with deployment of low-carbon and renewable electricity by 2030. Carbon capture and storage (CCS) of fossil fuels is essential to develop, because of its pervasive de-carbonisation benefits across electricity, heat, industry and transport. From 2030 CCS reduces the costs of energy transition, and makes those extra costs 2.5 x less per year by 2050.

This report shows that accelerating deployment of CCS can enable CO_2-EOR in the UKCS. Part of the CO_2 that would otherwise need to go directly to dedicated storage in CCS projects can be used to drive CO_2–EOR. That gives significant benefits to the wider UK economy - extending the producing life of the North Sea, reducing imports of oil, maintaining employment, developing new capability to drive exports, and additional direct and indirect taxation revenues. At a national level this synergy between CCS and CO_2–EOR could provide the overall most cost effective way to accelerate this energy transition between 2018 and 2030, to meet Committee on Climate Change de-carbonisation pathways. This CO_2–EOR route also achieves two desirable UK objectives. A business demand is created, which drives sequential construction of CO_2 capture, which develops learning and reduces costs of CO_2 supply, which enables cheaper low-carbon electricity. CCS by this route, with secure CO_2 storage already proven, develops more rapidly to protect the onshore UK economy and industry from increasing carbon prices.

Through this accelerated CCS deployment more CO_2 is abated, more quickly, than by any other route, and it explicitly includes emissions from the additional oil produced. Public subsidy costs of transition are very greatly reduced, and may even be profitable across the whole economy. Investment in CO_2–EOR has a national return of up to 7.2x, which is much larger than rival energy opportunities.

The North Sea, as the UK's largest sector of investment, is enabled to make a transition into a new sustainable future of multi-decade CO_2 storage. Enabling this journey requires CO_2 to be provided from sites of capture to the offshore at near zero transfer prices. International comparisons show that explicit fiscal recognition of CO_2–EOR by the UK is currently inadequate, and clear supportive legislation is lacking. New enabling fiscal regimes for CO_2–EOR projects and clusters are needed, similar in size to existing brown field or development allowances. Those new regimes must make investing in CO_2–EOR in the UK competitive with the alternative global investment opportunities open to international oil and gas companies.

Key points at a glance

- CCS is one of several routes to low-carbon intensity electricity for the grid, and directly reduces fossil fuel use emissions. In the transition to a low carbon future for the UK, fossil fuels with carbon capture will become essential in the generation and industry mix. CCS has the benefit of providing power on demand, independent of the external conditions which impact wind, tidal and solar.
- CO_2 captured in CCS projects can be publicly subsidised, and sent to permanent geological storage deep beneath the North Sea. Alternatively, additional oil production using CO_2–EOR, can provide the commercial finance, equipment infrastructure, and project management experience needed to develop lower cost CO_2 capture and secure storage, which has lasting benefit to UK low-carbon electricity.
- CO_2–EOR is a proven technology to increase oil recovery, and simultaneously stores CO_2 permanently in the subsurface. Two technically similar projects have been commercially successful in the North Sea offshore since 1998 and 2002, by injecting miscible methane gas. This gives high confidence that CO_2–EOR is achievable in North Sea oilfields. Detailed computational simulations of CO_2 injection to oil reservoirs has confirmed viability of injection and oil production. Measurements from existing CO_2–EOR operations demonstrate secure CO_2 storage into the far future.
- A carbon accounting balance of carbon produced and carbon stored, shows that CO_2–EOR continues to enable "green" low-carbon electricity produced by CCS. In addition, CO_2–EOR stores significantly more CO_2 before 2050 than the present publicly funded pathways of CCS. CO_2–EOR enables production of a limited amount of additional oil with less carbon cost than any other method.
- CO_2–EOR can be economic if the CO_2 is provided to EOR projects at a near zero transfer price, and if fiscal structures are introduced that are similar to existing brownfield and cluster allowances. This can encourage further development of existing fields, by ensuring that CO_2–EOR projects surpass international "hurdle rates" of profitability to successfully compete for funding by oil and gas companies.

Key Points

- Financial leverage into the whole-UK economy is conventionally measured as GDP or by an Economic Multiplier (EM), which measure the ratio of economic return to Government Input. Calculation of illustrative returns show, for Government input into CCS linked to CO_2–EOR, this ratio = 3.9 GDP or 7.2 EM; compared against simple CCS fitted on coal = 1.2 GDP or 2.6 EM; compared to offshore wind = 1.5 GDP or 3.3 EM. Thus a Government £1 invested in CO_2–EOR has a central case return of up to £7.2, which is 2.2 to 3.2x larger than rival clean energies. This is an exceptional return on Government investment.
- This CO_2–EOR pathway compares well to some independent propositions for future CCS pathways in the UK. The Energy Technologies Institute (ETI) envisage an optimal 60Mt CO_2/yr injection by 2030. The Committee on Climate Change "core decarbonisation scenario" of the 4th carbon budget envisages 52Mt/yr CO_2 capture by 2030 (Element Energy 2013). These can both be met by a UK CO_2–EOR market which develops annual commercial CCS projects from 2019-2030.
- CO_2–EOR strengthens the case for Government to invest in CCS, and reduces the level of investment required by providing part of the offshore transport storage capacity and storage certainty as an intrinsic part of EOR. Moving forward with CCS will reduce the cost of future implementation through learning-by-doing and accelerate the journey to a low carbon future for the UK.

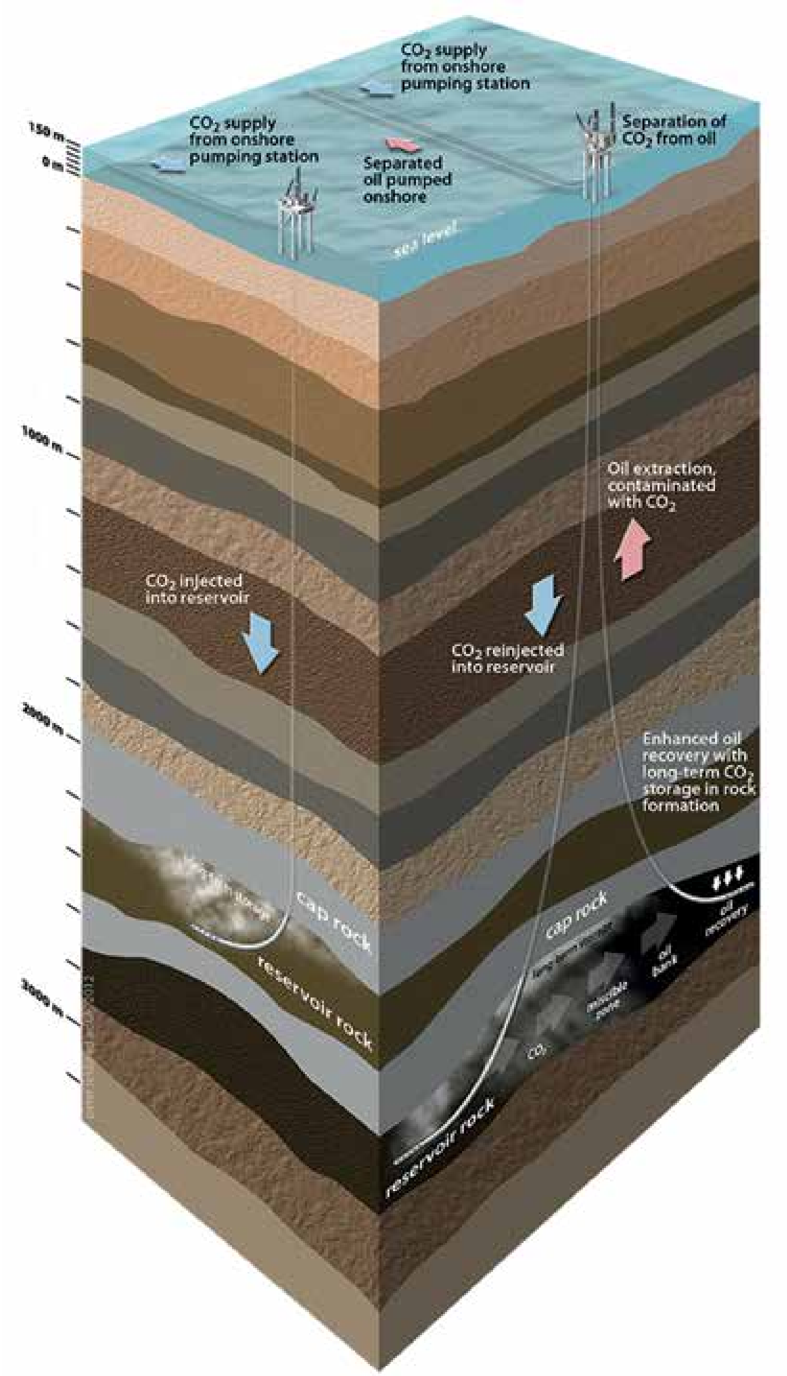

Figure 1: Cartoon of CO_2–EOR operating offshore beneath the North Sea, compared to CO_2 storage in a deep saline aquifer.. CO_2 injection is miscible with trapped oil, to make that less viscous and enhance production. The CO_2 is separated on the offshore platform, and re-injected for secure long-duration storage; the oil is pipelined to land.

Introduction

Professor Stuart Haszeldine - University of Edinburgh

Production of oil from a North Sea oilfield typically leaves 55% of the oil underground. Decreasing North Sea production, combined with consistent oil consumption in the UK, results in increasing quantities of oil being imported from elsewhere in the world. This has a high opportunity cost, due to lost employment in the UK offshore, and in the lost GDP of money paid out. Compared to North Sea oils, the imported oils have a similar carbon emission of greenhouse gas to the atmosphere when used, but can have 50% to 100% greater embedded carbon used in their extraction compared to domestic oil. It is sensible to consider the three questions of: 1) Can additional UK oil be produced profitably with enhanced oil recovery (CO_2–EOR)? 2) Can the greenhouse gas emissions of UK CO_2–EOR oil be reconciled with a transition to a low carbon economy? 3) Can a mutually beneficial link between CCS and CO_2–EOR be made? We conclude that the answer to these three questions is "yes". Development of CO_2–EOR creates an additional market pull, to use CO_2 from the CCS projects, and eliminates costs and transport and storage for CCS projects. That can rapidly enable and accelerate the utilisation of North Sea deep geology as a profitable business for CO_2 storage. That helps to rapidly reduce greenhouse gas emissions in the UK, and starts a revolution in sustainable offshore employment and offshore technology. The North Sea can become a commercially proven and guaranteed, secure site for storage of CO_2 received from across the European Union.

CO_2–EOR is the most significant method by which extra oil production can be combined with beneficial use of the CO_2 captured by CCS at power plants and industry. CO_2–EOR is a technology whereby liquid CO_2 is injected through boreholes into a deep underground oil reservoir. At subsurface conditions of high temperature and high pressure the carbon dioxide dissolves into the oil as a solvent, similar to CO_2 solvents in non-toxic dry-cleaning or in de-caffeinating coffee. The CO_2 injected is miscible, to make oil less viscous, such that additional quantities can be produced from the oilfield. The additional oil which is produced, along with some of the injected CO_2, onto the oil platform during offshore operations has its CO_2 separated under very tightly controlled processes. The additional oil is piped to shore for use, and the separated CO_2 is not released, but is returned to the deep reservoir for reuse in oil production and for permanent secure storage deep below ground into the far future. By designing maximum CO_2 injection and storage with this method additional oil is produced with a favourable carbon balance. This report produces new information on accounting of the carbon stock balance of CO_2 through that entire CO_2–EOR cycle, and produces new information on the financial benefit to the UK. This broader approach explicitly links financial and carbon calculations between the carbon production sector and the greenhouse gas CO_2 storage sector.

The development of carbon capture and storage, as a method of reducing greenhouse gas emissions from fossil fuel use, has been much slower than anticipated both in the UK and internationally. Critical factors slowing this development have been the large financial cost of investment, requiring subsidy for capital costs and price support for operational costs by national governments (as for any other low carbon or renewable electricity generation); and the lack of inherent business profitability without a high carbon price to drive investment away from extraction towards injection.

The development of CO_2 injection, in offshore oilfield settings, has also been much slower than anticipated. CO_2–EOR onshore is a well-recognised method of obtaining 5 to 20% additional production of the original hydrocarbon-in-place from existing fields. CO_2–EOR has been evaluated for many years by multiple

Table 1: Additional oil potentially recoverable from the UK North Sea, using different alternative CO_2–EOR methods (McCormack PILOT 2014). A similar volume exists beneath the Norwegian North Sea. These volumes (barrels of oil) are "unrisked", so that ultimate recovery may be less for a combination of technical and commercial reasons.

EOR Process	Estimated EOR Potential (mmstb)
Miscible Hydrocarbon flood	5400
Miscible CO_2 Injection	5700
Surfactant/Polymer (Chemical EOR)	4800
Polymer (on its own)	2100
Low Salinity Waterflood	2000

teams both in the Norwegian and UK sectors of the North Sea (Holt et al 2004, Goodfield and Woods 2002). The most recent evaluations were by Element Energy (2012), who identified 2,500 M bbl of additional oil potential from 19 fields in the UK sector. The industry-led group of PILOT (McCormack 2014), identified that CO_2–EOR has the greatest potential for improving North Sea production. The prize of additional oil is similar, between 3,000 million and 6,000 million barrels across UK and Norway. That is equivalent to 2 or three super giant oilfields. Attractions of CO_2–EOR are the benefits of abundant geological knowledge locally, a secure political climate, and a very low exploration risk. Barriers to commercial CO_2–EOR are the lack of a reliable large tonnage CO_2 supply feeding a 10 to 15 year project at 2-5Mt CO_2 /yr, and the initial cost of converting offshore facilities to inject and recycle CO_2 .There are inevitably perceived first of a kind risks for the developer, and this requires explicit government support through enabling fiscal regimes and specific regulation on changes of licensing, ownership and liability.

The purpose of this report is to join together these two dilemmas of CO_2–EOR and CCS. Is it possible that these two problems are, by analogy, two sides of the same coin? Can the dilemma be overcome and counteracted by connecting the benefits and needs of one side, to the products and needs of the other? This report says "yes", that remedy seems to be true.

The story told in this report

This report finds that CO_2–EOR is a technology which is well established onshore since 1972 (NETL 2006, 2010). For onshore development settings the boreholes to inject CO_2 are closely spaced, at tens to hundreds of metres, and the drilling costs of boreholes are small. Some of the onshore fields undergoing CO_2–EOR are similar in size and geological complexity to those beneath the North Sea. Pilot CO_2 injections have been technically successful worldwide in shallow water. But in spite of this CO_2–EOR has never been applied offshore in deeper water. In the North Sea CO_2 has been processed and injected at 1 Mt/yr from offshore platforms at Sleipner, Snøhvit and Brae. North Sea enhanced oil recovery has been trialled in 19 projects (Awan et al 2008). These include full-field gas injection operations, such as Oseberg. Importantly, two injections of miscible methane gas have been successful at full commercial scale in large UK deepwater oilfields at Ula and Magnus (Brodie et al 2012). This provides an important demonstration that miscible gas injection making oil more mobile, can be controlled and engineered between boreholes spaced widely at 1 to 2 km intervals in the UK offshore.

Multiple additional styles of EOR are available (Muggeridge et al 2014). These can all find applications in particular subsurface oil fields, or in particular business settings. However, for the UK sector of the North Sea CO_2–EOR is the process with the greatest potential. In a UK setting, engineering design can maximise CO_2 injection, rather than minimise CO_2 purchase as with onshore USA examples. This report also shows that a CO_2–EOR reservoir provides much more secure storage than a deep saline aquifer. In addition CO_2–EOR is the only EOR process which directly emplaces CO_2 underground. CO_2–EOR is the only EOR process which can contribute to building a CCS industry by reducing the amount and therefore the cost of pure storage capacity that would otherwise need to be created through subsidy for CCS only developments.

Obtaining reliable and commercially viable supplies of CO_2, which can guarantee 10 to 15 years of EOR operation and injection, has been the perennial and terminal problem for CO_2–EOR in the North Sea. However this is changing. It can be foreseen that CO_2 will become available at the scale of multiple millions of tonnes per year in the commercially useful future.

About 1.5 million tonnes per year of CO_2 is already available from UK industrial sources. A further 4.2 million tonnes per year of pure CO_2 is currently available from industrial sources in north-west Europe (SCCS 2013). Linking UK CO_2 sources to an offshore project of CO_2–EOR can use pipelines, or can utilise shipping as a chilled and compressed fluid in tankers similar to liquefied petroleum gas. CO_2 delivery to deepwater port facilities in north-east Scotland, can be connected into a distribution network which re-uses specific offshore pipelines and reaches into the heartland region of the most commercially promising CO_2–EOR fields.

A shipping facility can be constructed at acceptable cost (Element Energy 2014), to enable flexible delivery of CO2, for distribution offshore through the pipe network. That also enables access to Norwegian CO2–EOR projects. To provide an idea of scale, commencing with just these eight geographically clustered fields could produce more than 1,000 Million bbl additional oil (Element Energy 2012), whilst simultaneously storing many hundreds Million tonnes CO2 to to partially offset the extra carbon produced.

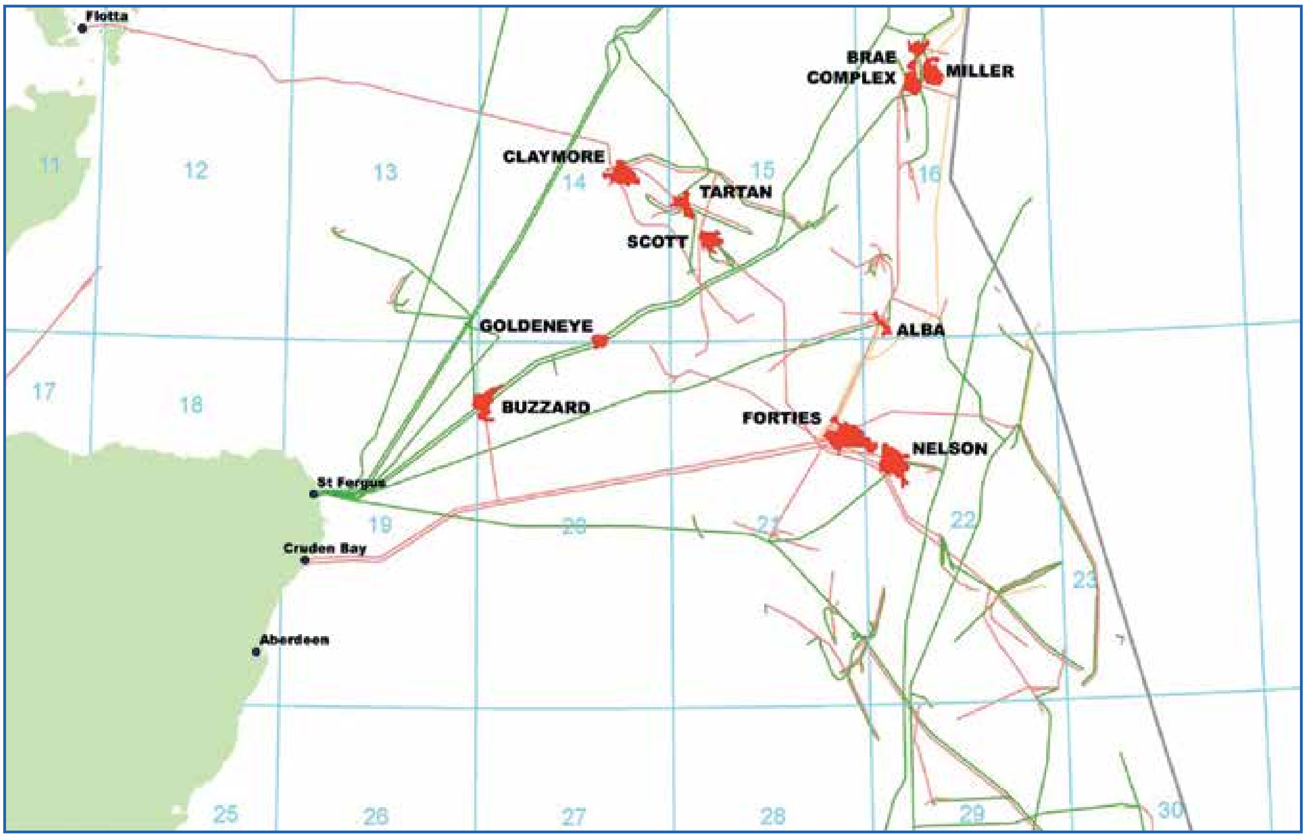

Figure 2: Map showing offshore oilfields in the Central North Sea (red), which are assessed by Element Energy (2014) and PILOT (McCormack et al 2014), to be particularly suitable technically and economically for CO_2–EOR. This is the heartland of CO_2–EOR potential in the UK offshore, and can be accessed by re-purposing existing offshore pipelines (green lines) and infrastructure at St Fergus.

Undertaking an offshore CO_2–EOR project is a very large engineering and funding exercise. This report has undertaken economic-technical modelling using two different methods. One is deterministic with scenarios exploring sensitivities to costs. The second is statistical, which stochastically explores the entire range of uncertainty using dual Monte Carlo simulations of input parameters ranging from the additional oil to be recovered, the price of engineering, and the global oil price. This produces a range of outputs to explore how to plan options for a portfolio analysis to safeguard against future events. Both methods reach similar overall conclusions, as do existing published analyses of the UK North Sea EOR portfolio (Element Energy 2014), and selected specific EOR fields (Kemp and Stephen 2014, Kemp and Kasim 2014).

Making CO_2–EOR into a commercial business requires government to create tax structures that make it worthwhile to invest; to convert the offshore oilfield for EOR; and to connect that to the source of CO_2. There are many financial variables, three of which are critical and specific to CO_2–EOR. These are the interaction between oil price – which can not be controlled, CO_2 price- which can be set from individual UK sources, or determined by supply and demand in a UK or international market, and project Profitability Index (the ratio of Net Present Value to investment) – which is impacted by UK government financial instruments. Oil companies routinely develop billion pound projects internationally, coordinating multiple equipment manufacturers and installation contractors. To enable billion pound CO_2–EOR projects to be constructed with minimum government intervention, requires that the Profitability Index exceeds the internal hurdle rate of the company to compete for investment amongst global opportunities. Reducing the cost to a company of the initial expenditure for a project is critical in raising that NPV above hurdle rate.

This is most simply achieved by the UK creating a fiscal Investment Allowance, and a Cluster Allowance for groups of EOR fields, on a project by project basis, so that a company can invest hundreds of millions of pounds without paying tax on the money used for that investment. The Government can tailor its support and avoid over-payment. This is similar in scope, and in financial amount, to the principles previously used in creating brownfield allowances – currently used in the UK. CO_2–EOR may also need to adjust the scope of what lies within that tax allowance. This creates a win-win in which projects go forward and the Government is able to benefit from additional tax revenue which it would otherwise not have realized.

CO_2 EOR depends on CO_2 being made available at a near zero transfer price. This requires public investment in CCS as part of the low carbon agenda. How can the UK assess the best candidate investments in the range of low carbon alternatives, from where it may gain maximum benefit? This report makes estimated calculations for low carbon electricity of the value and leverage of return. One method is to measure the impacts of Government investment on industrial output GDP. This report innovates the use of Economic Multipliers (EM), which are an established

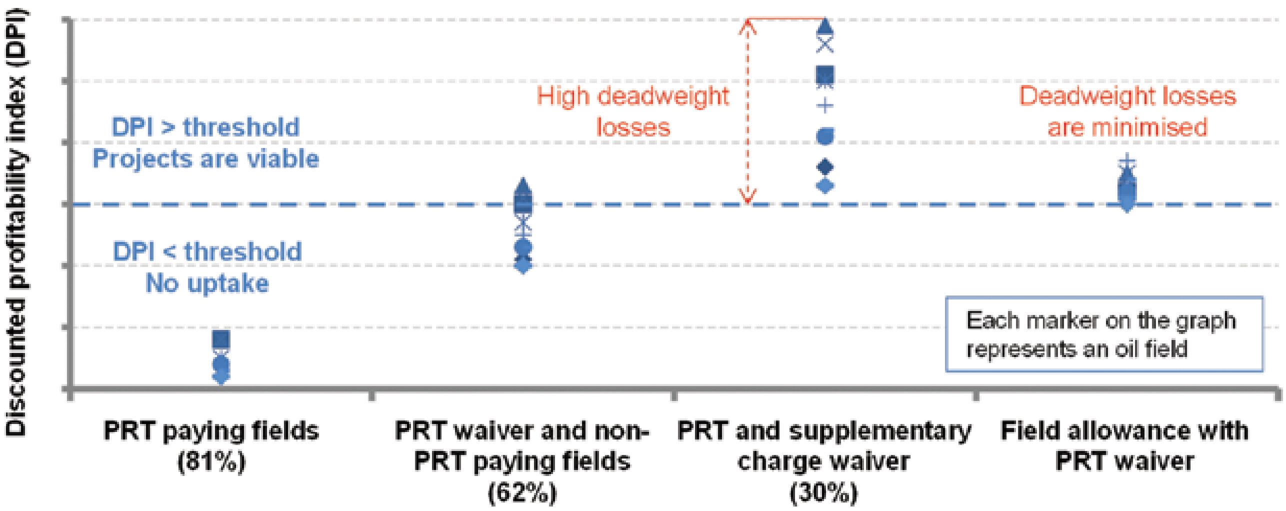

Figure 3: Experimental economic calculations of the impact to Treasury and impact to project of placing tax relief at different places in the offshore tax system. This is displayed as Profitability Index vertically, which is NPV/CAPEX discounted (Element Energy 2014, and this study). This plots projects which are differentiated "economic" (NPV positive before tax) from "commercial" (NPV high enough, and with a DPI rate of return greater than internal "hurdle rate". A general tax exemption can be insufficient, or can be good enough for some fields but an excess benefit for others (deadweight). The principle of an Investment Allowance (formerly a Field Allowance) is clearly beneficial. This targets the amount of allowance from Petroleum Revenue Tax, to vary field-by-field, so that a specific tax allowance is made to ensure the project functions, but does not make windfall profits at the expense of the Treasury. Calculations for CO_2–EOR suggest that the Investment Allowance will need to be in the region of £170/ ton oil, ie £24 /bbl.

method used to calculate the benefits of investment into regional economies within the UK. These two methods measure the leveraging of Government input into a wider effect of indirect and induced consequences in industrial activity and wealth growth triggered by increased supply chain requirements and re-spending wage income increases inside the same economy. Calculation of illustrative returns show that for CO_2–EOR this ratio = 3.9 GDP with 7.2 output EM. This can be compared against simple CCS fitted on coal = 1.2 GDP with 2.6 output EM, or offshore wind = 1.5 GDP with 3.3 output EM. Thus a Government £1 invested in CO_2–EOR has a central case return of £4 as GDP or £7.2 in terms of stimulating industrial output as a whole. These are exceptionally high returns on Government investment, being about 2.2x to 3.2x larger financial outputs for CO_2–EOR than rival clean energy investments. Across the whole economy, there is a clear financial case for Government to incentivise a linkage between CCS and CO_2–EOR. In terms of value for money, CO_2–EOR linked to CCS wins by a long way.

This report has given close attention to calculation of the carbon budget of CO_2–EOR at both the project level in offshore facilities, and at the higher national level. Both of these are analysed to compare against normal business of simple CO_2 injection offshore without CO_2–EOR recovery; and compared against CO_2 stored without the acceleration in development time provided by CO_2–EOR.

At the project level, it is necessary to avoid double counting of benefits and of carbon. The CO_2 provided to a CO_2–EOR project has resulted from combustion of coal or gas. Injection and storage of the CO_2 cannot be counted twice against both the combustion of the initial coal or gas, and the future emissions of the extra oil produced. The crucial question can be stated as "If CO_2 derived from CCS on a power plant, is reinjected offshore for the purpose of EOR, how much additional carbon emission is incurred?" The alternative to UK produced oil from CO_2 EOR is imported oil from overseas, which has its own associated emissions. The methodology for calculating the change in carbon emissions is summarised in Figure 4. For an example project it is concluded that, compared to importing equivalent oil, additional emissions add just 0.003 tCO_2 /bbl. These can be offset using the CO_2 market for \$0.3 /bbl oil, demonstrating that electricity with CO_2–EOR can maintain its low-emission green status.

At the national level in an EOR push scenario of 11 CCS annual increments of 5 Mt/yr CO_2 each, can be considered by 2030, to achieve the CO_2 injection target set by the ETI and the Committee on Climate Change (2013). That is 10 - 20GW power generation and 52 Mt/yr CO_2 (ETI 2015), similar to the scenario modelled in this report. Carbon accounting from bottom-up components, shows that CO_2–EOR, stores only marginally less tonnage than the CO_2 injected by conventional CCS, net of emissions incurred during its injection to 2030. Crucially, these 11 annual increments of pure CCS are much greater than the result of the 3 GW CCS "low" electricity scenario in 2030 from the UK Government Roadmap plan for CCS (DECC 2012).

Using price support for CCS, project by project, from national funds results in only a few million tonnes per year of CO_2 storage – a higher ambition is needed. Using CO_2–EOR stores more CO_2, stores CO_2 faster, develops more CO_2 capture plants with potential for cost reduction,

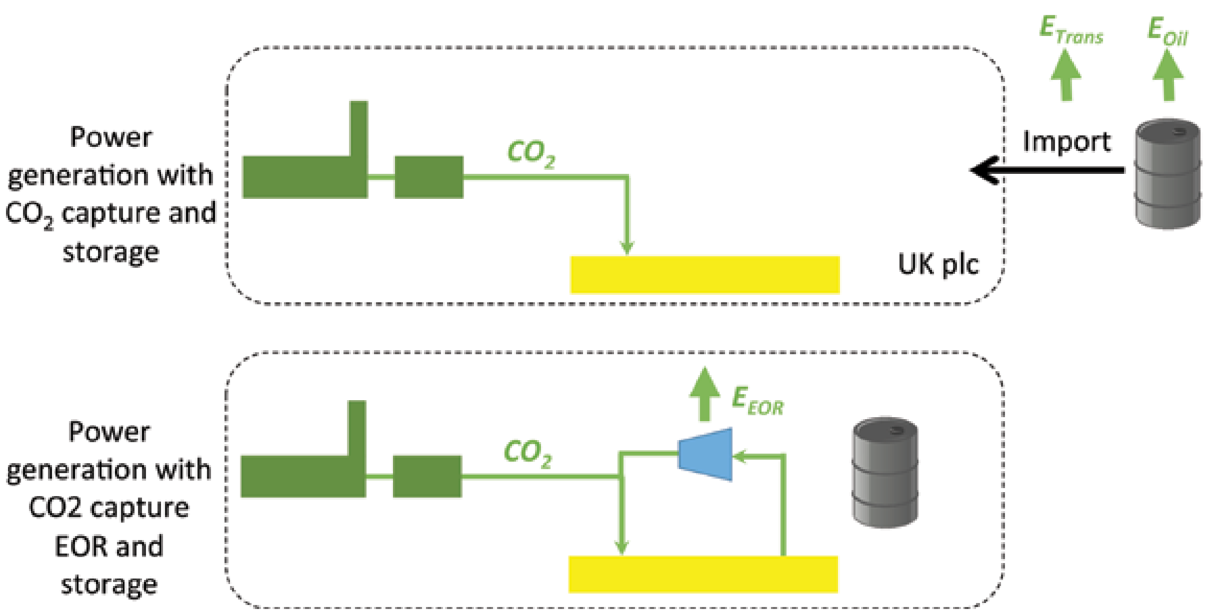

Figure 4: Framework for analysis of incremental CO_2 emissions during CO_2–EOR operations offshore compared to CCS alone. The additional offshore operations produce emissions (EEOR), but emissions from producing (EOil) and transporting (ETrans) the oil that would otherwise be imported to the UK from overseas need to be offset against EEOR.

builds CO_2 pipe networks offshore, and demonstrates CO_2 storage securely in multiple reservoirs.

Whilst testing the acceptability of a CO_2–EOR proposition among stakeholders during this report, an understandable spectrum of views was discovered. CO_2–EOR clearly differs from CCS, and is immediately perceived to be different. CO_2–EOR lies at the difficult intersection of two views of the world: is this a plan to extend fossil fuel extraction which causes climate change, or is this a plan which can develop CCS faster in order to reduce emissions? Groups tested for this report, ranged from resident publics, through offshore professionals, to environmental organisations. There is a clear skepticism that CO_2–EOR has a permissible role where it simply maximises economic oil recovery. By contrast, there is a widespread recognition that CO_2–EOR could potentially play an important role as part of a long-term managed transition into a future vision, for the North Sea offshore industries moving away from hydrocarbon production. However, questions were raised whether the regulatory and fiscal framework could be established.

Similar conclusions were reached by an European Union Joint Research Centre study (Tzimas 2005) who stated "CO_2–EOR could help Europe simultaneously reduce the emissions of CO_2, improve the security of energy supply by enhancing the recovery of European oil resources, and encourage the development, demonstration and deployment of advanced cleaner and more efficient fossil fuel energy conversion technologies by making available proven CO_2 storage sites."

In summary, the challenge is clear. North Sea oil production can continually drift downwards, or can become extended and more efficient. New industries can be created and regulated, or established positions can be maintained as they decline. It is clear that CO_2–EOR can offer a way to journey forward towards a low carbon future. And that the Government needs to travel this journey together with offshore hydrocarbon operators, energy intensive power generators and industry, and the public. If successfully navigated, then CO_2–EOR can accelerate the emergence of a new long duration industry of CO_2 storage beneath the North Sea (Figure 5).

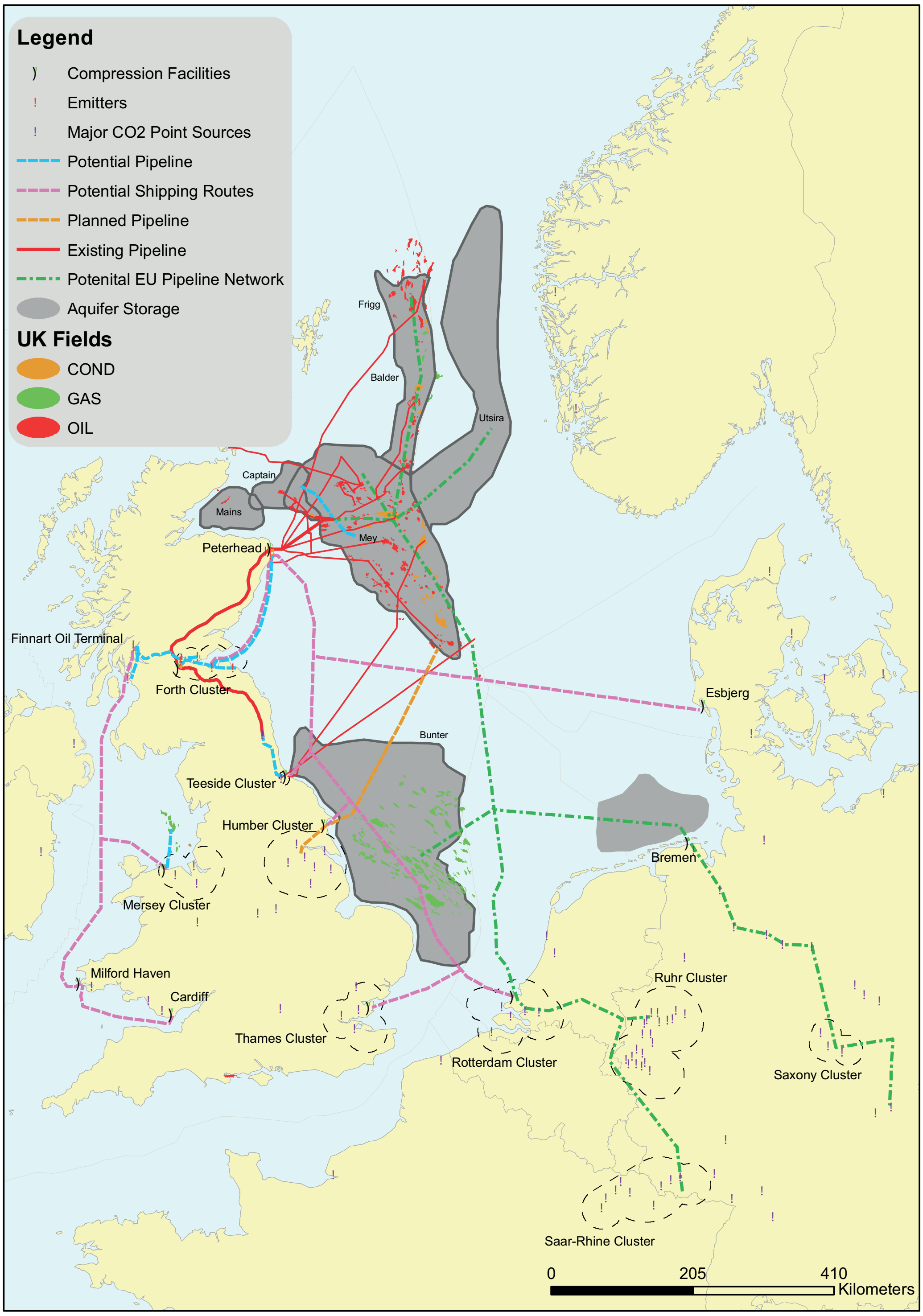

Figure 5: Conceptual vision of CO_2 storage beneath the North Sea, which is linked to emissions capture in multiple European Member States.

References

Awan A.R. et al 2008. Survey of North Sea Enhanced-Oil-Recovery Projects Initiated During the Years 1975 to 2005. SPE-99546

Brodie J. et al 2012 Review of Gas Injection Projects in BP. SPE 154008 doi.org/10.2118/154008-MS

DECC 2012 CCS Roadmap. Supporting deployment of Carbon Capture and Storage in the UK. URN 12D/016

Element Energy, Pershad 2012 Economic impacts of CO_2-enhanced oil recovery for Scotland Scottish Enterprise. www.scottish-enterprise.com

Element Energy 2013 Infrastructure in a low-carbon energy system to 2030: Carbon capture and storage. Report for Committee on Climate Change.

Element Energy, Pershad 2014 Scotland and the Central North Sea CCS Hub Study, Revised Final Report Scottish Enterprise. www.scottish-enterprise.com

Energy Technologies Institute, Day 2015, Building the UK carbon capture and storage sector by 2030 – Scenarios and actions www.eti.co.uk

Goodfield M. and Woods C. 2002 Potential UKCS CO_2 retention capacity from IOR projects Goodfield Woods DTI Improved Oil Recovery Research Dissemination Seminar, 25 June 2002. www.ecltechnology.com

Holt, T., Lindeberg, E., Vassenden, F., & Wessel-Berg, D. 2004. A large-scale infrastructure model for CO_2 disposal and EOR-economic and capacity potential in the North Sea. In: International Conference on Greenhouse Gas Technology (GHGT-7), Vancouver, Canada, pp. 391-399.

Kemp A. and Kasim S. 2014 Tax Incentives for CO_2–EOR in the UK Continental Shelf. OP131 Aberdeen Centre for Research in Energy Economics and Finance.

Kemp A. and Stephen L. 2014 The Economics of Enhanced Oil Recovery (EOR) in the UKCS and the Tax Review. OP129 Aberdeen Centre for Research in Energy Economics and Finance.

McCormack M.P., Thomas J.M., K. Mackie K. (2014) Maximising Enhanced Oil Recovery Opportunities in UKCS Through Collaboration SPE 172017 doi.org/10.2118/172017

Muggeridge A et al Recovery rates, enhanced oil recovery and technological limits. Phil. Trans. R. Soc. A 372: 20120320. http://dx.doi.org/10.1098/rsta.2012.0320

NETL 2006 CO_2 EOR Technology US Dept of Energy http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/CO2Brochure_Mar2006.pdf

NETL 2010 CO_2–EOR primer www.netl.doe.gov/research/oil-and-gas/publications/publications-archive

SCCS 2013 CCS for Industrial Sources of CO_2 in Europe WP SCCS 2013-05 www.sccs.org.uk

Tzimas E et al 2005 Enhanced Oil Recovery using Carbon Dioxide in the European Energy System JRC Institute for Energy, Petten Report EUR 21895 EN

Technical section

This section of the report consists of summaries for all the work undertaken as part of the CO_2–EOR project. Full versions of the reports – except those protected by intellectual property for which non-technical versions have been uploaded – can be found on the SCCS website: www.sccs.org.uk/expertise/reports/sccs-CO2–EOR-joint-industry-project

Overall, 17 independent pieces of work were commissioned through the Joint Industry Project (JIP). They fall into 6 categories and are presented as such in the remainder of the report.

These categories are:

- **Economics**
- **Stakeholder perceptions**
- **EOR performance**
- **CO_2 management and environmental impacts**
- **Legal**
- **CO_2 Supply**

Each of these sections has between one and four summaries, corresponding to individual reports from the JIP research.

A summary of each section is as follows:

Economics (pages 21-35)

CO_2–EOR in the UK: analysis of fiscal incentives: This work is intended to quantify the potential impacts of fiscal incentives for CO_2–EOR in the UK Continental Shelf (UKCS) in detail, recognising the additional costs, complexities, uncertainties and longer-term liabilities faced by CCS projects involving CO_2–EOR. Only a non-technical version of this report is available to download.

Techno-economic evaluation of CO_2–EOR in the North Sea: Following on from the fiscal incentives work, this project used techno-economic modelling to provide further insights into the effect of different tax incentives on the profitability of a CO_2–EOR project and UK Treasury income, for different CO_2 acquisition costs and oil prices.

Developing economic multipliers for CO_2–EOR activity: This work takes a first look at developing a multiplier which is representative of the additional economic benefits CO_2–EOR brings to an investment in low carbon electricity using CCS.

Stakeholder Perceptions
(pages 36-41)

Public and stakeholder perceptions: This work looked at understanding stakeholder perceptions of CO_2–EOR in relation to CCS and climate change mitigation. It initially used engagement with NGOs, and was subsequently expanded to include other stakeholders (North Sea industries, members of the public, finance organisations and academics).

EOR performance (pages 42-45)

Techno-economic reservoir modelling: This work modelled CO_2 injection strategies using a reservoir simulation model of enhanced oil recovery by CO_2 injection in a North Sea oil field with the aim of maximising oil production using CO_2–EOR The output of this report is proprietary and only a non-technical report is available for download.

CO_2 management and environmental impacts
(pages 46-65)

Carbon accounting for North Sea CO_2–EOR: By developing a model of a theoretical North Sea development this study conducted a high-level "life cycle analysis" of CO_2–EOR operations to assess how volumes of CO_2 stored compare to emissions from operations unique to CO_2–EOR.

A review of flaring and venting at UK offshore oil fields - an analogue for offshore CO_2–EOR projects?: Analysing operational data from offshore UK oil fields to aid EOR modelling, this work provided detailed information on flaring and venting values. This allowed assessment of the potential control that flaring/venting of reproduced gases may have on a CO_2–EOR project's lifecycle greenhouse gas emissions.

Carbon accounting: Does CO_2–EOR de-green CCS This analysis examines the whole life cycle emissions of CCS, not just at the powerplant. Two conclusions are. i) CO_2–EOR marginally increases embedded emissions in UK electricity delivery, and ii) CO_2–EOR greatly accelerates CO_2 storage from UK fossil fuel power by 2030.

CO_2–EOR: Security of storage: This study set out to quantify how much solubility trapping takes place within both aqueous and hydrocarbon phases in CO_2–EOR settings to assess the security of CO_2 storage compared to saline aquifer storage.

Measurement, monitoring and verification – enhanced oil recovery and carbon dioxide storage: This study looked to assess the differences between monitoring technology requirements for CO_2 storage in a saline or depleted hydrocarbon reservoir and in a CO_2–EOR setting.

Environmental impacts of CO_2–EOR – The offshore UK context: This study looked at the potential environmental implications of a CO_2–EOR project above and beyond those from normal oil and gas operations.

Legal (pages 66-73)

Legal aspects of CO_2-enhanced oil recovery: A clear legal and regulatory framework will be a key element in providing confidence for future CO_2–EOR operations considering the depressed emissions trading market. By examining the relevant international, European Union and national laws that would apply in the United Kingdom, important areas in the current legislation that need to be addressed have been identified.

The use of CO_2 for enhanced oil recovery on the UKCS – Selected legal and regulatory issues with a specific focus on property: The economic use of CO_2–EOR technology will depend upon a number of technical and practical challenges being overcome. This work looks at underlying legal issues which, if not properly addressed, could delay implementation or return to cause problems for interested parties at a later date.

Transboundary chains for EU CO_2–EOR: This work considered the potential legal issues arising from the movement of CO_2, and looked at both surface (pipeline or ship) CO_2 transport and subsurface migration of CO_2 across international boundaries.

CO_2 supply (pages 74-84)

Ship transport of CO_2 for enhanced oil recovery – literature survey: Considering the potential importance of CO_2 shipping for CO_2–EOR, this work was carried out to determine the extent and scope of publications on transport of CO_2 by ship, to review a selection of available literature and to extract the key findings of interest for CO_2–EOR.

Offshore offloading of CO_2 – Review of single point mooring types and suitability: This study looked at the types of single point mooring (SPM) and loading systems that can most likely to be able to be adapted to transfer CO_2 from transport ships to injection wells for EOR or geological storage. It also considered the suitability of potential mooring systems coupled to generic process route options for a CO_2 ship transport chain.

Worldwide comparison of CO_2–EOR conditions: This study compared the incentive conditions for CO_2–EOR in seven major oil-producing regions (Canada, China, Malaysia, Norway, UK, USA Onshore and USA Gulf of Mexico) with suggestions of how the UK is placed for future CO_2–EOR investment.

Economics

CO_2–EOR in the UK: Analysis of fiscal incentives

Element Energy with Dundas Consultancy and Professor Alex Kemp - University of Aberdeen

Fiscal incentives for EOR were introduced in the 1980s at federal level in the USA, and have since been playing an important role in stimulating a CO_2–EOR market that is currently worth billions of dollars per year, and establishing the existing CO_2 pipeline network, which transports more than 60 million tonnes of CO_2 per year (NEORI, 2012 and US DoE, 2010). Several states in the USA still have tax incentives for CO_2–EOR oil production.

Recent techno-economic evaluations carried out by Element Energy et al (2012), and Kemp et al.[4] demonstrated that CO_2–EOR could provide permanent CO_2 storage capacity for several oilfields in the UK sector of the North Sea, and yield positive (i.e. favourable) net present value (NPV) from oil revenues under a wide range of plausible conditions[1]. However, the CO_2–EOR projects would be unlikely to meet commercial investment criteria, particularly in the early years until CCS is proven.

The window of opportunity for CO_2–EOR in the UK continental shelf (UKCS) is limited by diminishing access to existing infrastructure. Current proposals for the UK's CCS commercialisation competition imply that the earliest plausible start date for a CO_2–EOR project would be close to 2020 (DECC, 2012). The rate of growth of any CO_2–EOR industry in the North Sea would be heavily dependent on policies adopted by North Sea governments, and the CCS and oil industries, the predicted properties of the reservoirs themselves, the economics of alternatives and, more importantly, oil prices, which have dropped from around $110 a barrel in mid-2014 to less than $50 a barrel in early 2015.

The combination of CCS with offshore CO_2–EOR is extremely challenging, as projects involve coordination of stakeholders in multiple industries, high up-front and operating costs, narrow windows of opportunity, and the need to manage multiple risks before final investment decision, during construction, operation and post-closure.

Previously, the UK has encouraged further development of technically or commercially challenging oil fields, including late stage investments or brown field development (www - HMT), through amendments to the offshore fiscal regime.

CO_2–EOR could also be supported through fiscal incentives as it contributes to storage of CO_2 that would otherwise be emitted to the atmosphere and provides environmental benefits compared to other oil production technologies. Wider benefits of increased oil production include contributions to improved security of supply, economic growth, improved balance of payments, job creation and efficient utilisation of resources.

This work aimed to quantify the potential impacts of fiscal incentives for CO_2–EOR in the UKCS in detail, recognising the additional costs, complexities, uncertainties and longer-term liabilities faced by CCS projects involving CO_2–EOR. The analysis was carried out using financial modelling of investor behaviour in response to a wide range of drivers, scenarios, sensitivities. The approach drew on published data as well as the team's own data and models for oil and gas taxation, and understanding of CCS and CO_2–EOR. No confidential oil industry data were used, and all results are therefore illustrative, based on generic assumptions.

Fiscal incentives for CO_2–EOR

A variety of fiscal incentives could be introduced to support CO_2–EOR investment, including changing the headline tax rate for CO_2–EOR fields or introducing "field allowances". A field allowance is a type of tax allowance which reduces the amount of adjusted ring-fenced profit on which a company's supplementary charge tax is based. Several types of field allowances have been introduced in recent years, including ultra-heavy oil field, ultra-high pressure/high temperature field, small oil or gas field, deep water gas field, brown field, etc.

As each oil field has unique reservoir characteristics, different oil fields need different levels of incentives. Unlike field allowances, changing the tax rate does not have the flexibility to differentiate the levels of incentives available to different oil fields. If structured efficiently, field allowances encourage new investments and maximise tax receipts without incurring substantial deadweight (incentive given – incentive required) losses.

In addition to the field allowance, there might be other types of tax incentive (e.g. paying no tax until a certain return); however, this study focuses on allowances as these would be in principle an extension to the existing tax regime, particularly in the case of the brown field allowance. Various types of field allowances are examined in this study, including field allowances based on unit development cost, unit technical cost, discounted profitability index, CO_2 storage and incremental oil produced.

Among the field allowances that were modelled, a field allowance based on unit development cost with petroleum revenue tax (PRT) removal for the first projects appears the most efficient structure in terms of minimising deadweight losses (Figure 3). Additional incentives are needed for the first offshore CO_2–EOR projects in the North Sea, potentially in the early 2020s, as they would incur substantial CO_2 supply and diverse socio-political risks. Although having a tax incentive based on a private sector key performance indicators (KPI) and estimation of unit costs faces challenges, it seems to offer a reasonable balance between incentives, efficiency and ease of application as it is very similar in structure to the existing brown field allowance.

In order to maximise CO_2–EOR uptake, the scale of allowance would need to be more than three times the existing brown field allowance (figure 6) to maximise the CO_2–EOR uptake in the UKCS (~£170/ tonne oil). The reason for this is that, unlike most oil field development projects, CO_2–EOR is not only capital expenditure (CAPEX) intensive but also operational expenditure (OPEX) and fuel intensive, with revenues emerging over very long lifetimes (i.e. heavily discounted). Although the required levels of field allowances are high, CO_2–EOR projects are able to bring billions of pounds of additional tax revenues for the government.

Scenarios for CO_2–EOR development in the UKCS

For the purpose of this study, we based our analysis on three potential deployment

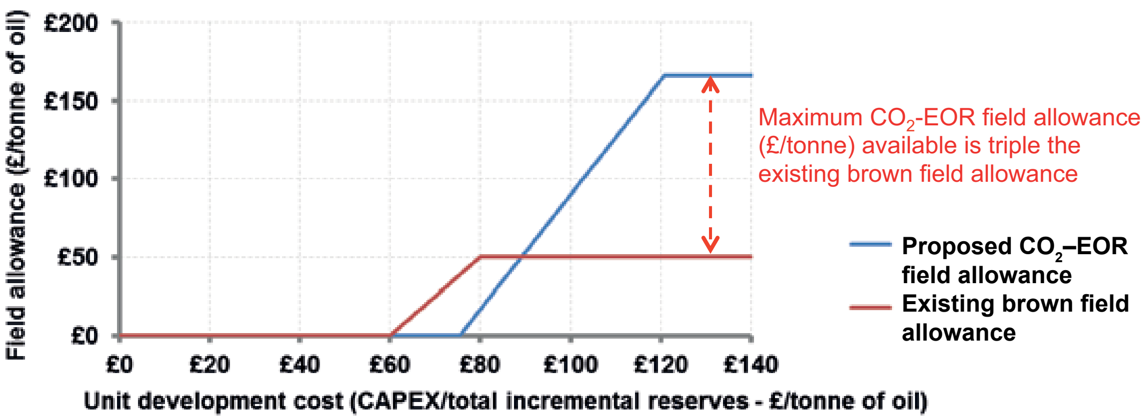

Figure 6: Comparison of the proposed CO_2–EOR field allowance with the existing brown field allowance (£/tonne oil)

pathways for CO_2–EOR in the UKCS, namely, "Go-Slow", "Pragmatic" and "Push". These scenarios differ in the volumes of onshore CO_2 capture and the level of specific policy activity to support CO_2–EOR. Figure 7 shows the UK incremental oil production profiles for the three scenarios.

Under our assumptions, CO_2–EOR offers the opportunity to store up to 550Mt of CO_2 in the "Push" scenario, while incremental UK oil production could be as high as 1 billion barrels. Additional UK tax revenues could be up to £4.3bn at $90 a barrel (£13.3bn at DECC Central (DECC 2012-2)).
However, the analysis demonstrates that, even with appropriate fiscal incentives in place, revenues for both commercial oil developers and the UK Government have a very high sensitivity to a range of factors. Most of these factors lie outside the control of either party, and include oil price, offshore capital and operating costs, and reservoir performance. It should be noted that the price of oil, which is highly uncertain, has the biggest impact on project NPV.

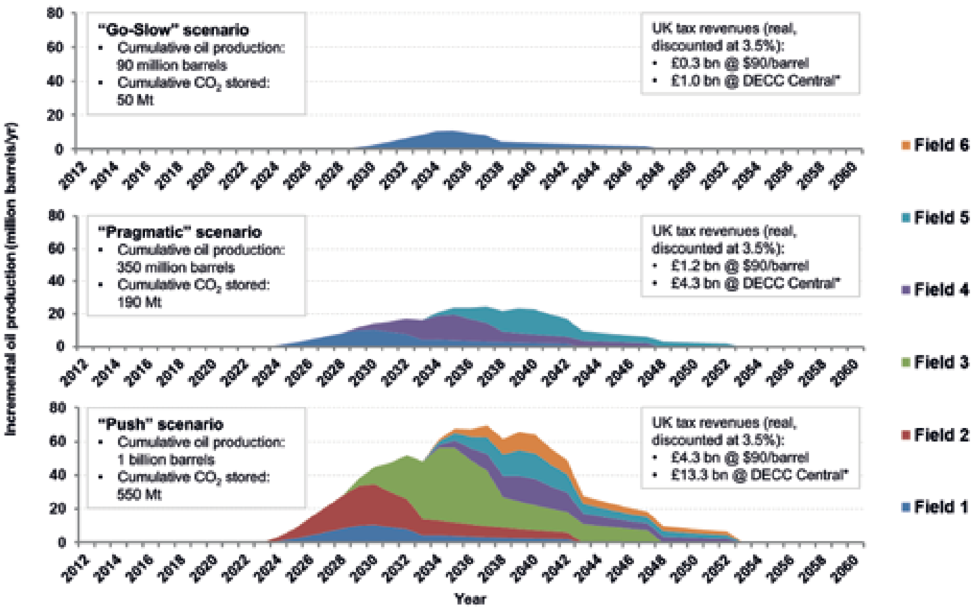

Figure 7: Predicted UKCS CO_2–EOR oil production, CO_2 storage and tax revenues

References

DECC,2012, http://tools.decc.gov.uk/en/content/cms/news/pn12_136/pn12_136.aspx

DECC, 2012-2, Central refers to DECC Central oil price scenario

Element Energy et al., 2012, Economic impacts of CO_2–EOR for Scotland, report for Scottish Enterprise.

www – HMT http://www.hm-treasury.gov.uk/press_78_12.htm.

Kemp, A.G. and Kasim, S., 2012, The Economics of CO_2–EOR Cluster Developments in the UK Central North Sea/Outer Moray Firth

NEORI, 2012, CO_2–EOR: a critical domestic energy, economic and environmental opportunity.

US Department of Energy, 2010, CO_2-driven Enhanced Oil Recovery as a Stepping Stone to What?

Conclusions and recommendations

The modelling suggests Government tax revenues would be maximised with the introduction of an efficient CO_2–EOR field allowance, and with a specific additional incentive comparable to a PRT waiver for the first demonstration CO_2–EOR project. With only a limited number of CO_2–EOR projects realistically likely to be implemented before the oil fields are decommissioned, it may be possible for these incentives to be negotiated reactively on a project-by-project basis, as appears to have been the case for other oil and gas field development projects.

However, there currently appears little appetite among oil investors to develop CO_2–EOR projects, partly as a result of multiple failed attempts to develop CCS and CO_2–EOR projects in the North Sea. Given the long lead times and the need to engage with providers of CO_2 generation, capture and transport infrastructure, an early and proactive announcement of a specific fiscal incentive for CO_2–EOR by the UK Government would send a positive signal to both the oil industry and the CCS industry. Any incentive would, however, need to be reviewed regularly as a function of market (i.e. oil prices) and regulatory conditions.

A logical pathway for public and private stakeholders wishing to develop fiscal incentives for CO_2–EOR specifically could involve the following sequence of actions:

1. As there are a number of potential routes to incentivise CO_2–EOR, each with different impacts, CCS projects and oil companies interested in CO_2–EOR should proactively initiate discussions with DECC and HMT/HMRC on preferred fiscal incentives for CO_2–EOR and supporting infrastructure.
2. CO_2–EOR project developers, Scottish Enterprise, and the Scottish Government should encourage OGA, DECC, The Crown Estate, Marine Maritime Organisation, National Grid Carbon, successors to the CCS Cost Reduction Task Force, and other interested stakeholders to include CO_2–EOR within the planning of transport and storage infrastructure.
3. CO_2–EOR project developers, Scottish Enterprise, and Scottish Government should work with other interested parties (UK Government, CCSA, The Crown Estate etc.) to quantify transport infrastructure requirements, and assess business and regulatory models for CCS with EOR.
4. If an incentive for CO_2–EOR is introduced, potential competition impacts in power, carbon, oil and CO_2 storage markets from fiscal incentives for CO_2–EOR should be understood and periodically reviewed by academics, regulators and/or the government.

Techno-economic evaluation of CO_2–EOR in the North Sea

Dr Kris Welkenhuysen, Bruno Meyvis & Dr Kris Piessens - Royal Belgian Institute of Natural Sciences

CO_2–EOR is a possible means to produce incremental oil from active oil fields. In the ongoing climate change debate, it is also welcomed as a business case for geological storage of CO_2 (CO_2 Capture and Storage, CCS). The possibility for applying this technology in the North Sea has been under discussion for several years, but the high cost and financial risk have hampered its deployment until today.

Using the techno-economic simulator PSS IV, potential CO_2–EOR projects can be evaluated in a realistic way, considering technological, policy-related, economic and geological uncertainties using Monte-Carlo calculations. For the current study, around 450 to 750 MC runs were performed (lower for the Cluster, and depending on the field and scenario), which is considered to produce results in sufficient detail for the current set-up. This number is mainly limited by computing performance. PSS IV includes a unique feature, in that it makes project evaluations considering incomplete information about the future. Next to its standard Monte-Carlo methodology, where stochastic parameter values are changed slightly every calculation, a second level of Monte-Carlo calculations and stochastic parameters are used for creating an outlook towards the future.

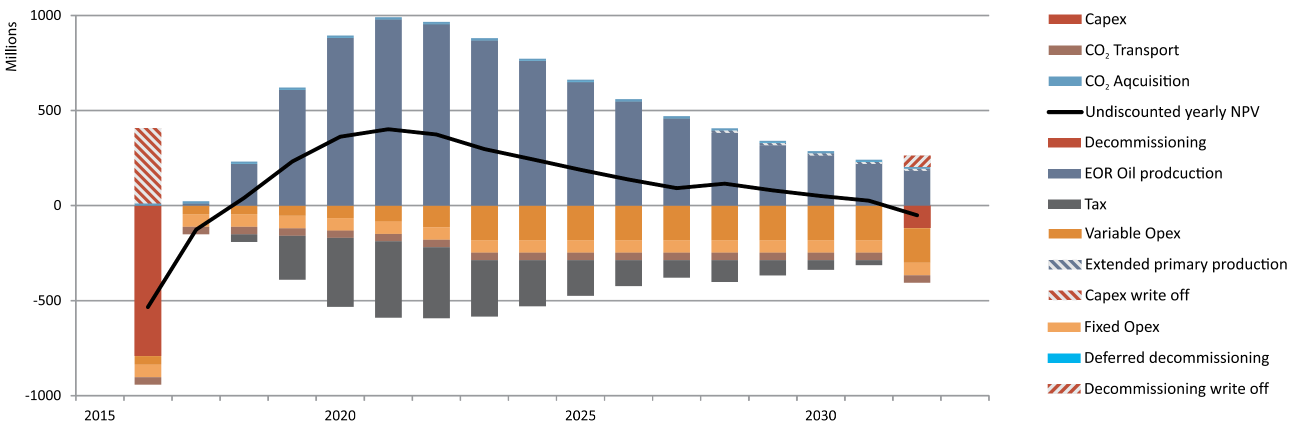

Figure 8: Typical cash flow in a CO_2–EOR project, as simulated by PSS IV, for the Claymore field in the Reference scenario. Total discounted NPV is £507m

This methodology is called "limited foresight", which produces near-optimal investment decisions. This is considered more realistic compared to an optimisation model, where actions are taken based on a perfect forecast of the future. This methodology is combined with Real Options analysis, to include the value of having future project flexibility. (Figure 8) shows the cash flow in a typical project, as simulated by PSS IV.

For the current study, the Claymore, Scott and Buzzard fields were considered as potential CO_2–EOR candidates. In an experimental set-up, an optimized cluster of the Claymore and Scott fields together was evaluated as well. Different scenarios were considered, to investigate possible impact of possible government incentives to maximise the use of natural resources and start the application of CO_2–EOR in the British offshore area of the North Sea.

In the "Reference" scenario, the 100% First Year Allowance and a 50% marginal tax rate on profit were applied. Other scenarios are deduced from this Reference scenario. In a second "Loan" scenario, a commercial loan was allowed for all investment costs. This scenario is less favourable for the total discounted NPV (Figure 9). A lowering of the tax rate to 40% in the "LowTax" however proves to be a good incentive for a higher project value. In the "LowCO_2" scenario, a government incentive related to a lowering of the CO_2 acquisition cost shows no significant effect. For Treasury income through tax, these scenarios have the opposite effect. A sensitivity analysis proves that CO_2 transfer prices to EOR in the range -10 to 10 €/t (in line with the -10 to 10 £/t used in the 2012 Element Energy report), have only a minor effect on the project's discounted value (Figure 10). The oil market price however is a major driver, with a potential high NPV for oil prices over 60 GBP/bbl.

The geological circumstances also have a significant effect on the project value. High recovery rates are predictably favourable, but also the response and timing of oil production by CO_2–EOR is important. A fast recovery of oil in EOR activities has a clear positive effect on the NPV of EOR projects, opposed to a slower, but longer recovery of the same amount of oil. Based on the geological parameters used to approximate the behaviour of three different oil fields, the added value of EOR for the Claymore field is highest, and that of Scott lowest. Regarding the additional oil produced by EOR, all scenarios except the Loan scenario allowed for the technically maximum oil recovery.

The positive effect of deferred decommissioning is relatively small in the overall cost-benefit picture of an EOR project, but may nevertheless be important in evaluating individual projects. Only for the Buzzard field, which is the most recent, the effect of deferred decommissioning is zero.

PSS IV is capable of producing more advanced results than currently presented. At this early stage, the simulated investment decision criteria were chosen on the optimistic side. PSS IV at this moment does not use a hurdle rate; at this moment it will activate a project when it is expected to generate a

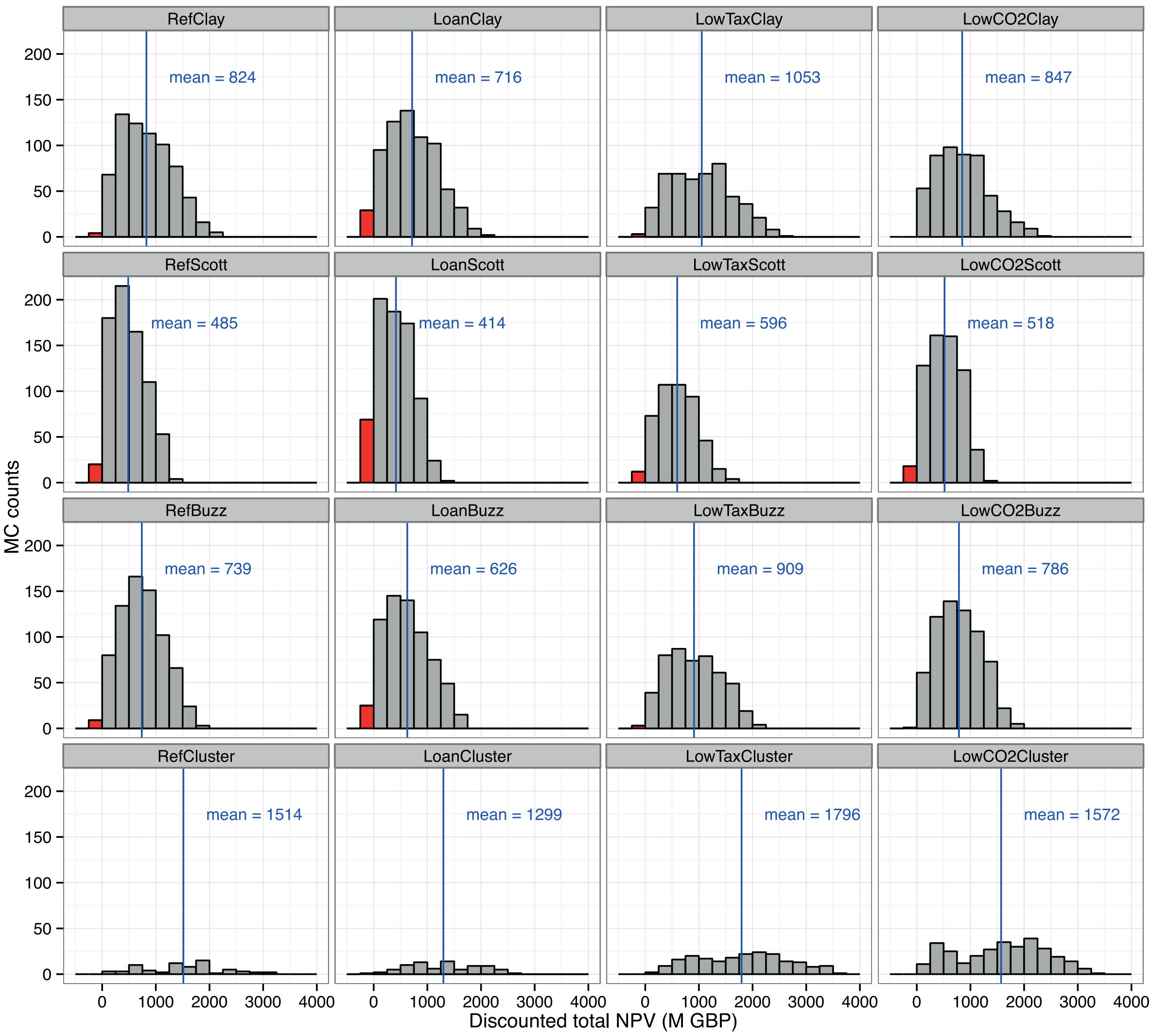

Figure 9: Histogram of the total discounted NPV for projects that were evaluated positively by PSS IV for activation, as Monte-Carlo counts. The mean value is indicated by the blue line, and projects with negative NPV are indicated in red.

positive total discounted NPV. The results in this study can therefore not be used to draw conclusions on economic cut off boundaries. For a series of additional, potentially important cost and benefit parameters, such as transport costs, reruns of PSS IV are needed. More in depth analysis of the produced results is also useful. Not included in the present study is for example an estimation of the internal rate of return.

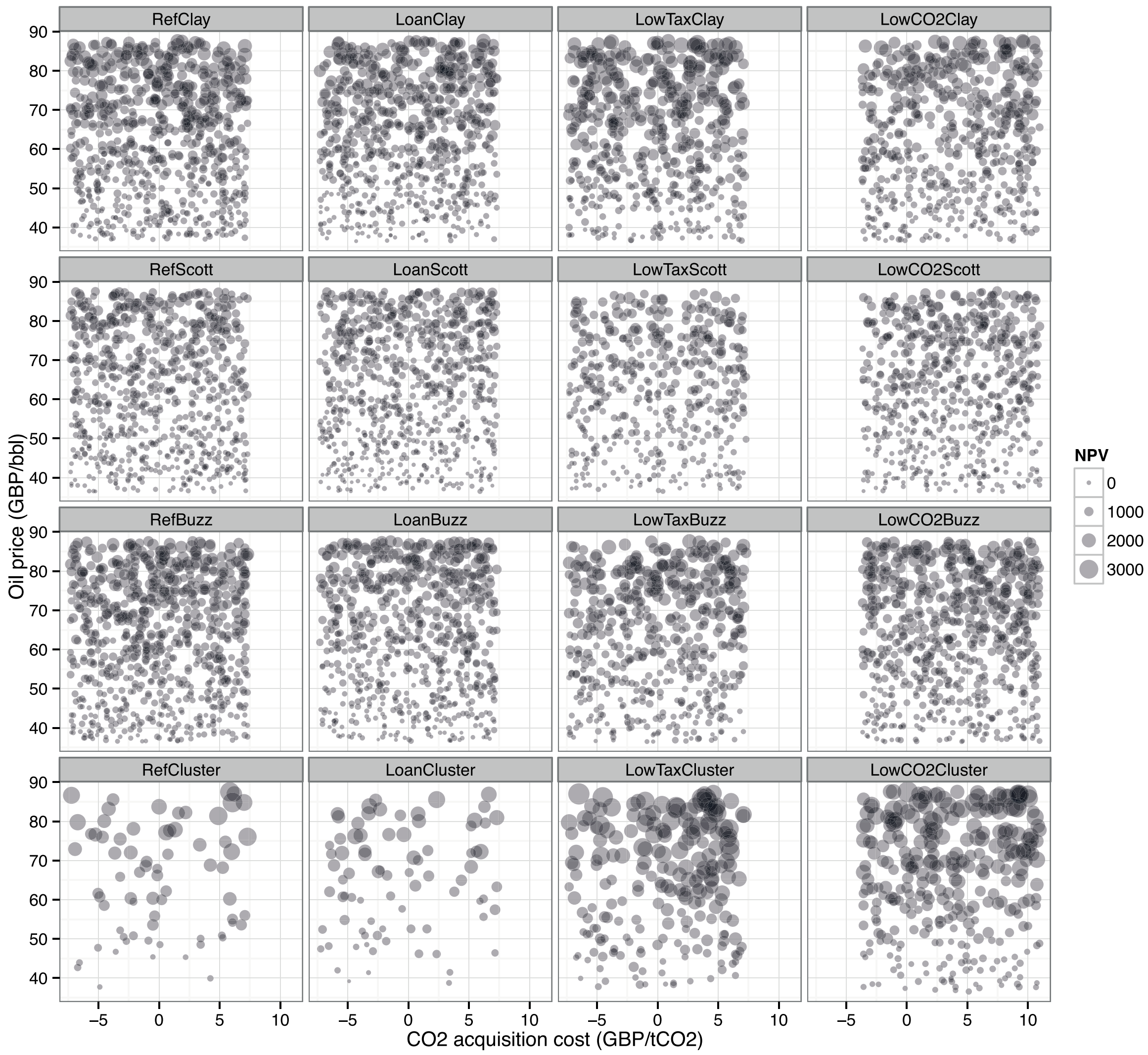

Figure 10: Cross-plot of the oil price and CO_2 price for activated projects, with indication of the total discounted NPV.

Developing economic multipliers for CO_2–EOR activity

Professor Karen Turner – University of Strathclyde

The aim of this study was to provide a preliminary assessment of how the economy-wide impacts of the introduction of enhanced oil recovery using CO_2 injection (CO_2–EOR) and upstream carbon capture and storage (CCS) activities may be considered using "multiplier" analyses. Multi-sector multiplier analysis, the simplest form of which is based on the use of input–output models, is commonly conducted particularly at the regional level within the UK to assess potential economy-wide impacts of economic disturbances, industry developments and public spending decisions.

We considered how/if input–output multipliers for the UK can/may be identified and used to compare economy-wide impacts, here focusing primarily on output and gross value added (GVA), or GDP impacts of three possible options, but with extension to other impacts, such as employment, being straightforward:

1. Offshore wind supported by CfDs (Contract for Difference)
2. CCS with pure storage supported by CfDs in the coal-powered electricity generation sector
3. CO_2–EOR drawing on the carbon capture element of the CCS in (2) and partly replacing pure storage supported by CfDs.

Multiplier methods

The full report of the study explains the derivation of a range of useful multipliers from input–output accounts that are reported for a given accounting year. The central multiplier is the output multiplier for any given industry, which tells us the amount of output (generally reported in £million) that is generated throughout the economy (across all industries) per £1 million of final consumption demand for the first industry's output. The Type I variant of this multiplier captures the direct effect of the £1 million of final demand plus indirect effects in the industry's upstream supply chain.

The Type II variant also incorporates the additional, induced, impacts of household consumption financed through income from employment in industrial production. Figure 11 illustrates how multiplier analysis allows us to consider the total benefits through economy-wide impacts of CO_2–EOR activity.

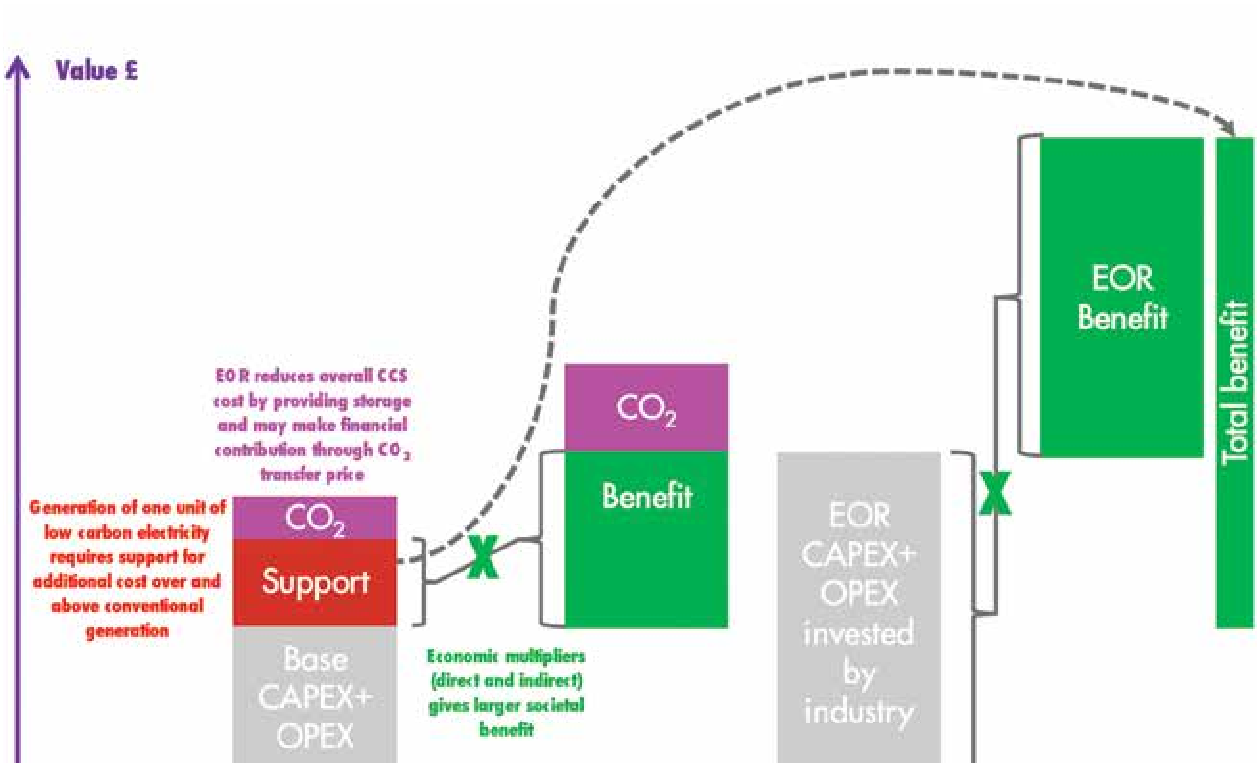

Figure 11: Capturing the impact of CO_2–EOR activity using multipliers

The key thing to understand in applying multipliers in scenario analysis is that any multiplier is basically a ratio: how much economy-wide return do we get per unit of direct demand/input requirement? Thus, in order to focus on the impact of government support through the CfD mechanism, we articulate a multiplier relationship that is the ratio of the full Type II economy-wide output or GDP impact (calculated using the relevant industry multiplier) per £1 of support from Government. In Scenarios 1 and 2, where we focus on Government support as the only direct change in demand, this equates to the industry multiplier. However, in Scenario 3, where we have an additional (private sector) demand – scaled as what is required to cover the average cost of oil produced by CO_2–EOR methods – the impact of this demand is also included in the ratio of return to government spending. Here the government spending requirement is also reduced by (a) the reduced need for storage in CCS where EOR provides demand for captured CO_2, and (b) any related transfer made from the oil and gas industry.

Data issues

Three central data issues were considered in the study:

(i) Are the relevant activities captured in available input–output data (published as part of regional/national statistics)?

(ii) If not (i.e. if the activity in question is not yet carried out in a UK or Scottish context, or was not present in the latest input–output accounting year), can a proxy industry be identified to provide "best guess" estimates of multiplier relationships?

(iii) If so, is the industrial breakdown in the UK and/or Scottish input–output accounts sufficiently detailed to permit consideration of specific multiplier effects for the activity in question?

In the case of CO_2–EOR under Scenario 3 the answer to (i) is “no” so a proxy industry multiplier must be identified. Here we focused on the example of the existing oil and gas industry. In the case of CCS under Scenarios 2 and 3 the answer to (i) is also clearly ‘no’. The proxy selected here is the existing coal-powered or gas-powered electricity generation sectors. Thus, the CCS analyses in Scenarios 2 and 3 rely on data for existing electricity generation activity. However, the answer to (iii) in these cases is “no” in the context of official input–output data published by ONS and the Scottish Government respectively. While offshore (and onshore) wind and coal-powered generation activity is present in both the UK and Scotland, along with a range of other renewable and non-renewable technologies, the published input–output tables for both the UK and Scotland report only a single vertically (and horizontally) integrated electricity sector, incorporating generation, transmission and distribution. However, we are able to draw on experimental UK input–output data for 2004 that identifies nine generation sectors in the UK case – including offshore wind and coal-powered generation – that sell all of their output to a single electricity supply sector.

Scenario results

Note that, given problems of imperfect data in particular (but also various modelling issues discussed in the full report), the numerical results (summarised in Table 2) of this study should be regarded as provisional and illustrative rather than as predictive results. Moreover, it is difficult to comment on what may constitute significant differences in multiplier values given the single year of data used, and the uncertainty about whether capital expenditures at construction stages are present and have an impact on the industry multiplier value for that year.

For Scenario 1, with offshore wind supported by CfDs, we find an economy-wide impact of £3.30 in additional output and £1.52 in additional GDP (spread across/generated in multiple industries) for every £1 of government support. Under CCS with pure storage with CfDs (with the coal-powered electricity generation sector as a proxy), the net economy-wide impacts in terms of both output and GDP remain positive but are smaller (£2.57 and £1.16 per £1 support respectively). However, the results of Scenario 3 suggest that if we consider the "bigger picture" of the potential impacts delivered by CO_2–EOR through its implied demand for captured CO_2 a significantly greater economy-wide return is realised. Not only is the unit and overall cost of government intervention decreased (while still delivering the same return per £1 support of CCS activity). The new CO_2–EOR activity delivers an additional stimulus that ripples throughout the UK economy so that the output and GDP per £1 of government support of CCS activity rise to £7.15 and £3.94 respectively.

In an appendix to the full report we report the results of sensitivity analyses for these results given different assumptions about key variables underpinning the scale of the EOR project and resulting impacts on CCS. We find that overall multiplier effects in Scenario 3 are most sensitive to assumptions about (a) the level of EOR demand for CO_2 (metric tonnes per annum); and (b) the time period (years) over which this demand occurs. Output and GDP multiplier results range from 4.33 and 2.22 respectively (where (a) is at its lowest value) to 9.32 and 5.25 (where (b) is at its highest value).

Note that the analyses here do not take account of any further impacts of additional tax revenues that would be generated as a result of expansion in the oil and gas and other industries that are positively affected. Nor do we consider any further investment in any of the technologies that may be stimulated by the impacts of government support, or consequent expansionary effects and/or changing returns to capital or labour resulting from such investment activity. Moreover, we qualify our results given the limiting demand-driven nature of the input–output model. Our conclusions recommend development of a more sophisticated modelling framework to consider such issues, and highlight a range of issues to be considered in improving the quality of data used to inform future multiplier analyses of the type carried out in this preliminary study.

Table 2: Summary of scenario results

Scenario	**Implied government intervention number** **Output**	 **GDP**
1. Offshore wind	3.30	1.52
2. Coal CCS	2.57	1.16
3. Coal CCS with CO_2–EOR	7.15	3.94

Stakeholder Perceptions

Public and stakeholder perceptions

Dr Leslie Mabon – Robert Gordon University
Chris Littlecott – SCCS

The CCS story in the UK to date has been centred on its ability to reduce CO_2 emissions. Where projects have been perceived to deliver on this outcome they have secured support from environmental groups, whereas those viewed as having negative risks for the climate have been opposed. But the potential inclusion of CO_2–EOR operations within UK CCS efforts complicates the picture.

CO_2–EOR finds itself at the meeting point of two competing energy paradigms. Is it a means of continuing and extending fossil fuel extraction, which is believed to be the cause of climate change? Or is it a means of accelerating the deployment of CCS as a response to the climate challenge? Is it possible that CO_2–EOR can be both things at once? What other benefits and risks might CO_2–EOR be perceived as providing? How might it best be managed?

We have sought to understand how these different elements are perceived by different stakeholders, and to consider the implications for policy makers. During 2012–13 we started by investigating the public positions and private concerns of Scottish environmental NGOs in respect of the potential inclusion of CO_2–EOR within UK and/or Scottish CCS policy. During 2014 we then undertook focus group research with a broad spectrum of stakeholder and public constituencies to test initial findings and investigate different perceptions across multiple locations.

Research carried out elsewhere in the world has suggested that some stakeholders may see CO_2–EOR as a means of making CCS more appealing, and that members of the public located close to potential projects may be positive about prolonging the life of existing oil fields that return economic and employment benefits. Our research sought to test these findings in the context of Scotland and the UK – where there are indeed publics and stakeholders familiar with oil and gas infrastructure, but also many others with concerns over the need for climate change mitigation. Scenarios were developed to provide a means of testing views on the relationship between CO_2–EOR as a means of maximising oil recovery and as a component of a climate change mitigation strategy.

Method

Six discussion groups were convened during summer 2014: two in Aberdeen (May 2014), two in Edinburgh (June 2014) and two in London (July 2014). Sampling was designed to include the following groups:

- Members of the public in an area with close proximity to oil production and a potential near-term CCS project (Aberdeen);
- Members of the public in an area more distant from oil production but close to past and future proposals for CCS projects (Edinburgh);
- Stakeholders with an interest in the marine environment (Aberdeen);
- Academics and other professionals with an interest in environment and energy issues, but not working on CCS directly (Edinburgh);
- Representatives of the financial – and particularly the "energy investment" – sector (London);
- Environmental NGOs (London).

Subsequently, a further discussion session was held in November 2014 with early career oil and gas professionals studying at Robert Gordon University in Aberdeen. These participants had particular experience of the development of new oil fields overseas.

Key findings

Many stakeholders and publics involved in the research agreed that CO_2–EOR needs to be considered within a broader context of energy and climate change, with objectives for its deployment articulated with respect to its coherence with climate change policy objectives. For those stakeholders with a predominant climate change motivation, it was deemed important for CO_2–EOR to deliver clear climate change benefits, the absence of which could become a trigger point for criticism and challenge – with likely negative implications for CCS as a whole. However this concern for clarity on the intended outcomes for CO_2–EOR was widespread: even those stakeholders who were most receptive to the concept of CO_2–EOR saw an essential role for policy to drive long-term investment and secure social and environmental benefits beyond those accruing to individual project operators.

There is a large gap between stakeholder views on what would be desirable outcomes and what they expect to be delivered in practice. As Figure 12 illustrates, there was a strong desire for CO_2–EOR to be situated as part of a climate change framework, with differing views on whether this could or should incorporate the aim of increasing oil production from the North Sea at the same time. This provides an opportunity for policy makers to set out a longer-term vision for how CO_2–EOR could form part of a broader transition strategy as a means of managing a shift to a low-carbon economy. But across all stakeholder groups there was scepticism as to whether policy makers would be able to deliver on either objective.

Stakeholders closest to the practical delivery of CO_2–EOR investments were the most sceptical about the ability of policy makers to deliver on any kind of outcome beyond a decline in North Sea production. This challenges policy makers to identify robust policy interventions that can provide a credible "private interest" business case to drive investment while also providing a coherent "public interest"' framework for why CO_2–EOR is necessary and appropriate.

Policy options and political framings will need to address broader concerns about why CO_2–EOR ought to be undertaken and to whose benefit. A narrow focus that positions CO_2–EOR solely as part of an effort to maximise the economic recovery of North Sea oil is unlikely to attract stakeholder support beyond those who stand to gain through employment or direct financial benefit, and may even stimulate opposition more widely if this is perceived to be in conflict with climate change objectives. For example, Scottish environmental NGOs highlighted the perception that CO_2–EOR could be "a bad price to pay for a good thing", preferring alternative means of delivering CO_2 storage.

There was nonetheless recognition across stakeholder constituencies that CO_2–EOR could potentially form part of a long-term managed transition, both for the North Sea in particular and for a longer-term shift away from fossil-fuel production more generally. This stemmed from a recognition of the embeddedness of fossil fuels in society at present, and of the possibility that CO_2–EOR might allow oil to be extracted from existing fields in a less damaging way than potential alternatives.

Policy implications

The analysis undertaken identified that policy makers will need to consider a broad canvas of policy options and public interest framings.

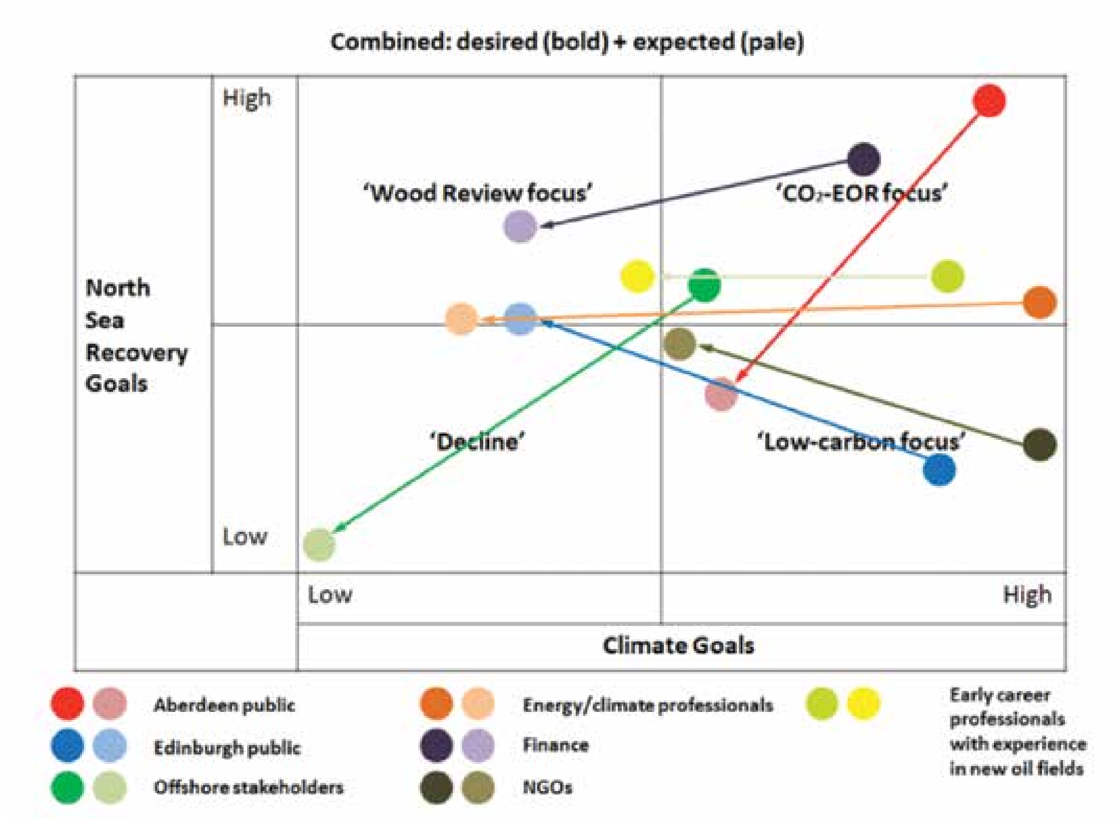

Figure 12: focus groups' desired CO_2–EOR scenarios versus expected scenarios

There was a noticeably limited positive response to the option of a narrow Wood Review focus on using CO_2–EOR solely as a means of maximising economic recovery of North Sea oil and gas. Instead, broader narratives of transition and future visions for the North Sea had greater appeal and were seen to provide a context within which public investment in a CO_2 transport infrastructure for CCS that can also enable CO_2–EOR could be justifiable.

However, the scepticism across stakeholder groups as to the deliverability of desired outcomes underlines the need for policy solutions to be technically robust as well as attractive to a range of stakeholders.

EOR Performance

Techno-economic reservoir modelling

Dr Peter Olden, Professor Eric MacKay and Dr Gillian Pickup – Heriot-Watt University

The work involved the development of a reservoir simulation model of enhanced oil recovery by CO_2 injection in a North Sea oil field. The injection of CO_2 was modelled using a full field model, following primary/secondary production of the field by water-flooding. The model was derived from a real reservoir model donated by an oil & gas operator for this study – the work commenced with the conversion of the original black oil simulation to a compositional simulation. The aim of the work was then to develop a CO_2 injection strategy to optimise hydrocarbon recovery. Features investigated in the modelling included injection type (comparing injecting seawater only, CO_2 only, or mixtures in various proportions – either water alternating gas (WAG), simultaneous water and gas (SWAG) or simultaneously but kept apart in separate wells), EOR timing in field life, choice of wells and injection rates.

There were several challenges in converting the black oil reservoir simulation of a water-flood to a compositional simulation for CO_2 injection. Conversion of a water-flood model to a CO_2–EOR model of a field is non-trivial, requiring additional experimental data, modification to parts of the input data deck that are directly related to CO_2 properties (e.g. PVT properties) and possibly other parts of the data deck also, running of simple supporting models (e.g. slimtube and box models) and potentially much longer run times for the full field model. The complexity of the model meant that both debugging the model and running the simulations took longer.

Examples illustrating the differences in simulation output for the model are shown in Figure 13 where oil saturation for the extended water-flood is compared to continuous gas injection. These variations in oil saturation distribution and concomitant variations in CO_2 distribution will lead to differences in both oil recovery and potential storage of CO_2.

The modelling program was progressed through a series of different scenarios commencing with continuous gas injection and then WAG scenarios. It became apparent that maintaining reservoir pressure is important in increasing the oil recovery from the field. Supercritical CO_2 is considerably more compressible

References

[2]Voidage replacement is where the volume of fluids produced from a reservoir is balanced by those injected – those volumes measured at reservoir conditions.

[3]Incremental oil is defined as oil produced in excess of existing or conventional operations – in this case, extended water-flooding.

[4]LOF – Life of field (since production started).

than water and, hence, like-for- like voidage replacement[2] (when compared to an extended water-flood) results in a decrease in reservoir pressure.

The incremental oil[3] recovery factors for the CO_2 injection scenarios considered for this field vary in the range ~1% to ~10% depending on the type of injection programme (continuous gas (CO_2) injection (CGI), CO_2 WAG, CO_2 SWAG, etc.). Generally WAG incremental recovery is greater than CGI, without much variance seen for different WAG ratios. The greatest increase in recovery is observed when the CO_2 injection rate was significantly increased. The range of incremental oil recovery and net CO_2 stored predicted by the modelling is shown in Figure 14.

Regardless of the type of injection programme chosen, maintaining the reservoir pressure high enough to ensure CO_2 miscibility is key to achieving higher recovery factors. Due to the higher

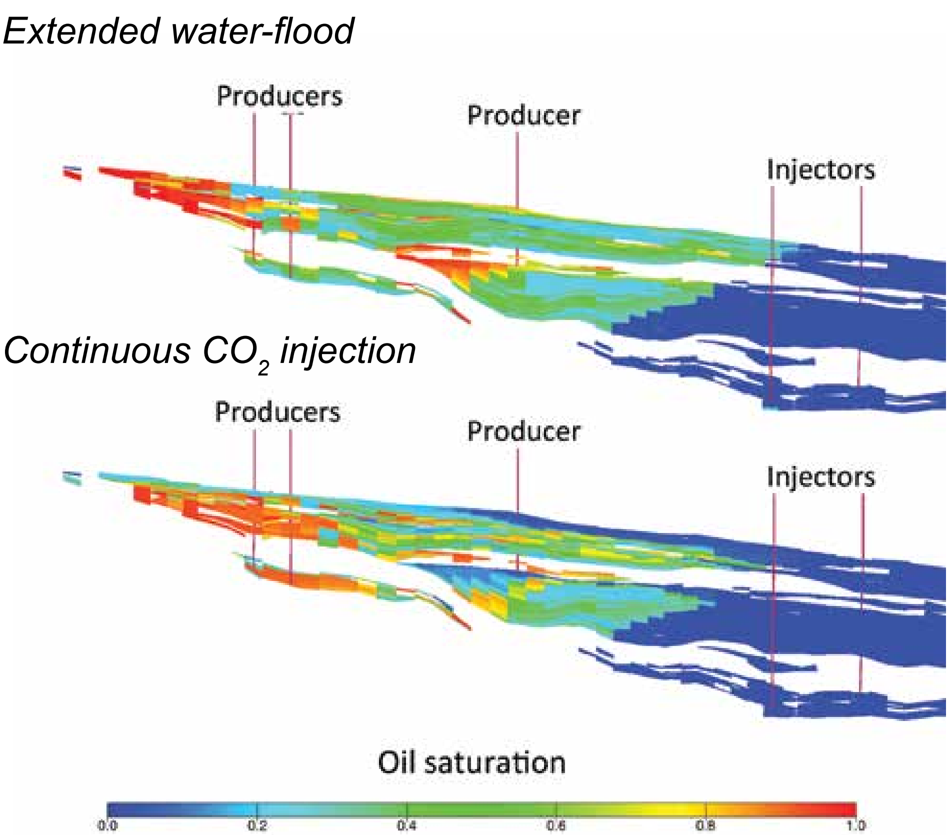

Figure 13: Examples of output showing a comparison of oil saturation distribution at a cross-section through the model at the same timestep in the simulations

compressibility of CO_2 than water, and due to the impact of CO_2 dissolution, this pressure maintenance may involve injection at higher bottom-hole rates than would be required for the equivalent water-flood.

Despite the fact that injected CO_2 will be produced and will therefore need to be re-injected, in general higher CO_2 injection rates and earlier commencement of CO_2 injection result in higher recovery factors and a greater quantity of CO_2 remaining in the reservoir at the end of the field life.

Maximising the recovery factor is generally consistent with maximising CO_2 storage – the greater the pore volume occupied by CO_2, the greater the displacement of oil from that pore volume – provided there is the facility to re-inject the potentially large volume of produced CO_2. The increasing rate of CO_2 production over time results in a reduced import requirement.

To replace water injection with CO_2 injection at the same downhole rate across the entire field would require supply of over 8 Mt/yr, although to achieve the optimal recovery factors up to twice this rate would be required. Injection of 1Mt/yr, and using seawater injection to provide the remainder of the voidage replacement, would lead to an increased recovery factor of 1–1.5% after 15 years.

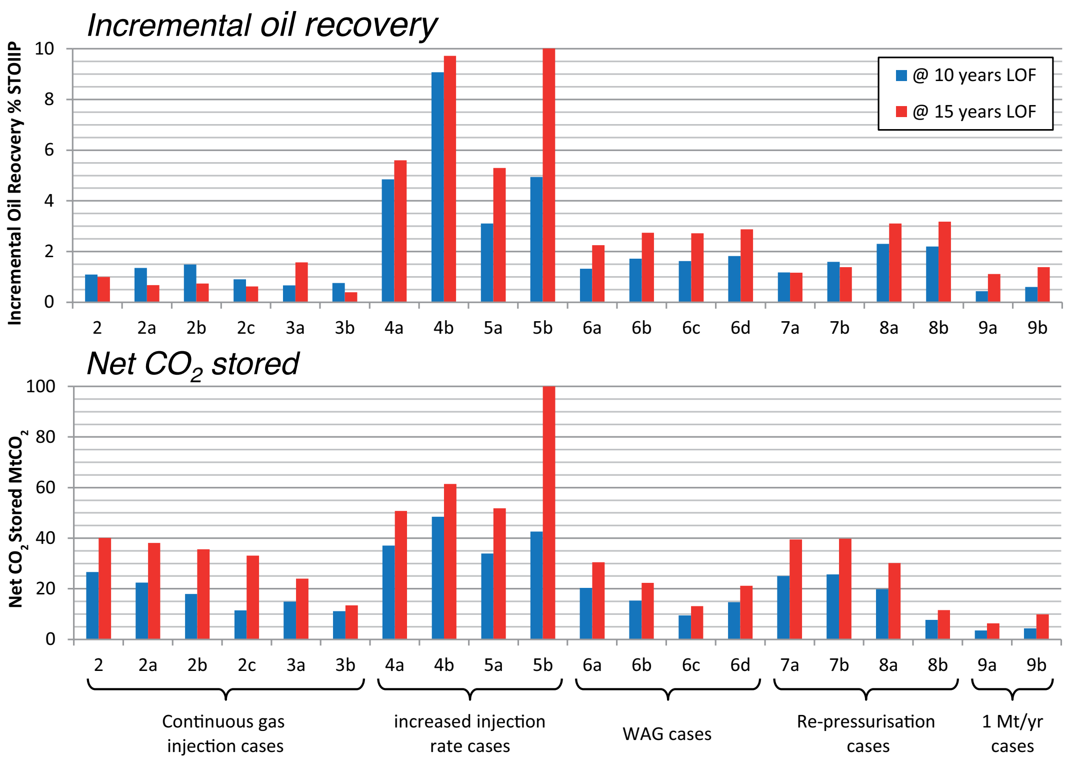

Figure 14: Summary of results for incremental oil recovery and net CO_2 stored for the simulated cases at 10 and 15 years LOF[4]

CO_2 Management & Environmental Impacts

Carbon accounting for North Sea CO_2–EOR

Jamie Stewart and Professor Stuart Haszeldine – University of Edinburgh

CO_2–EOR is regarded as an option for storing large volumes of CO_2 captured at industrial point sources with the additional potential to improve the recovery rate at depleted oil fields. It is, however, known from currently operating CO_2–EOR projects onshore in the USA that the operations and processes involved in CO_2–EOR can be energy intensive.

By developing a model of a theoretical North Sea development this study conducted a high-level "lifecycle analysis" of CO_2–EOR operations to assess how volumes of CO_2 stored compare to emissions. The accounting of CO_2 stored in a CO_2–EOR development, and utilisation of that CO_2 to estimate a net carbon balance does however rely on a number of assumptions. The key assumption is that CO_2 used in the EOR operation is CO_2 that would otherwise have entered the atmosphere if the CCS project did not have an EOR element. This does not represent the current model for early deployment of CO_2–EOR in the North Sea, where CO_2 supply will be premised on the generation of low carbon electricity from CCS projects which themselves require the credit for the CO_2 not emitted to the atmosphere. As a number of previous studies have already focused on the emissions associated with electricity generation (with CCS), and the emissions associated with the transport and refining of crude oil, this study focused on the offshore production operations that are unique to CO_2–EOR (Figure 15).

The emissions associated with transporting, refining and combusting produced crude oil are, however, incorporated in some scenarios. Emissions associated with the CO_2 capture process are not incorporated in this study.

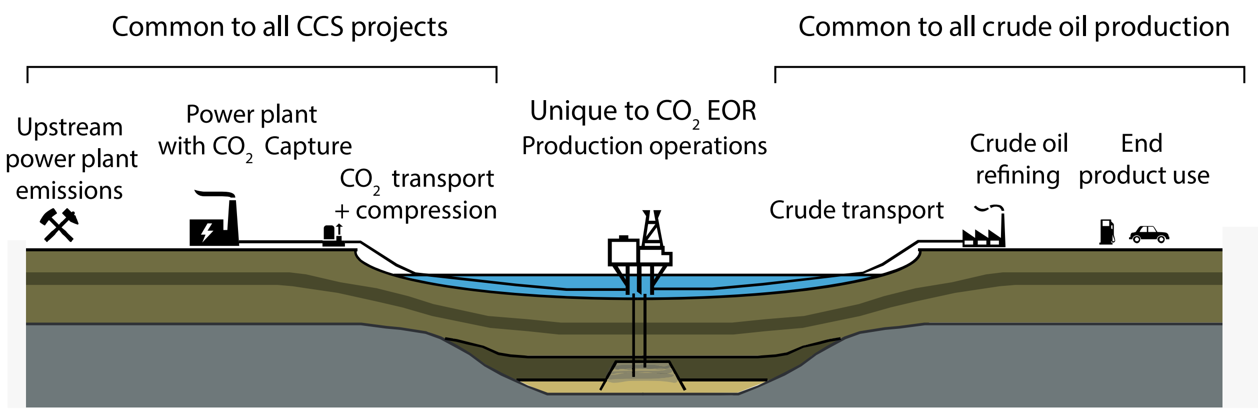

Figure 15: Overview of the CCS – CO_2–EOR chain

Two scenarios were developed that represent CO_2–EOR operations with varying goals. EOR Case 1 represents a scenario where the CO_2 supply (5Mt/yr) is diverted to another field after 10 years and recycle of existing CO_2 continues. For economic reasons, this may be the most likely scenario for an operator focused on maximising oil production, as continuation of CO_2 import for a further period is here not modelled to increase the oil production profile, which is already at its maximum (100MMbbl in both cases). EOR Case 2 represents a scenario where CO_2 is continuously supplied to the field for 20 years and injected alongside recycled CO_2. This scenario likely represents an injection strategy optimised for EOR and subsequent storage.

CO_2–EOR emission sources

The study found that emission sources related solely to CO_2–EOR operations are from gas compression in the recycle process, additional compression, fugitive emissions and emissions from the flaring and venting of reproduced gases.
It was found that emissions from flaring and venting, based on current UK flaring practice, have a dominant control on total emissions and must be reduced towards zero in future developments.
By analysing a number of US CO_2–EOR projects this is something we believe is likely to be achievable.

CO_2 storage in offshore CO_2–EOR

EOR Cases 1 and 2 store 443kgCO_2/bbl and 938kgCO_2/bbl respectively. Because oil production does not increase linearly with the volume of CO_2 injected, it can be seen that injecting CO_2 over longer periods can more than double the mass of CO_2 stored per barrel of incremental oil produced. This study highlights that in the North Sea where CO_2 may be continuously imported and injected, projects may store significantly more CO_2 per barrel of oil produced than in historical onshore projects. This requires designing and operating a project to continue injecting CO_2, even if additional oil production is not increased.

Net carbon balance

For the studied system boundary (which excludes refining, transport and combustion of produced crude) both EOR cases store more CO_2 than was emitted through operations. Emissions from each are 12.9 and 13.5MtCO_2e for EOR Case 1 and 2 respectively with 44.2 and 93.7Mt of CO_2 being stored (for 100MMbbl incremental oil production in each case) (Figure 16).

Operational emissions for each injection case do not vary greatly even when volumes of CO_2 stored over the 20-year period more than double. It is therefore strongly favourable to continue CO_2

injection into a field even if oil production will not increase at the same rate. Extending CO_2 injection beyond the 20-year period, when all EOR operations (recycling) has ceased, would improve the carbon balance even further.

The carbon intensity of CO_2–EOR oil

The carbon intensity of oil produced from North Sea CO_2–EOR can be just 54–60 $kgCO_2e/bbl$ if flaring/venting is reduced (production emissions only – excludes crude transport, refining and combustion). This compares against conventional Saudi oil 40$kgCO_2e/bbl$, or mined shale oil at >300$kgCO_2e/bbl$. These carbon intensity figures do not incorporate stored CO_2. Under certain assumptions, if CO_2 stored is incorporated into these figures, CO_2–EOR could produce oil with a negative carbon intensity.

Drawing the right "system boundary"

Selecting a system boundary has a large control on the carbon balance of CO_2–EOR projects. If emissions from the combustion of crude oil are not included, then CO_2–EOR is likely to always store more carbon than the process emits. When the theory of "additionality" is followed, and emissions from the transport, refining and combustion of produced crude oil are included within the system boundary, CO_2–EOR projects in the UKCS may have a positive carbon balance. This study concludes that a period of CO_2 injection beyond the period required to maximise oil production would be needed to produce a negative carbon balance for the extended system boundary.

Double accounting of captured and stored CO_2

Using the assumption that CO_2 stored in the EOR project is CO_2 that would otherwise have entered the atmosphere, this study finds that CO_2 stored can overcome the emissions from operations and end-product use and therefore has the potential to be a carbon negative process. If a different stance was taken assuming a CO_2 aquifer storage counterfactual, it may be the case that no CO_2–EOR operation could be carbon negative.

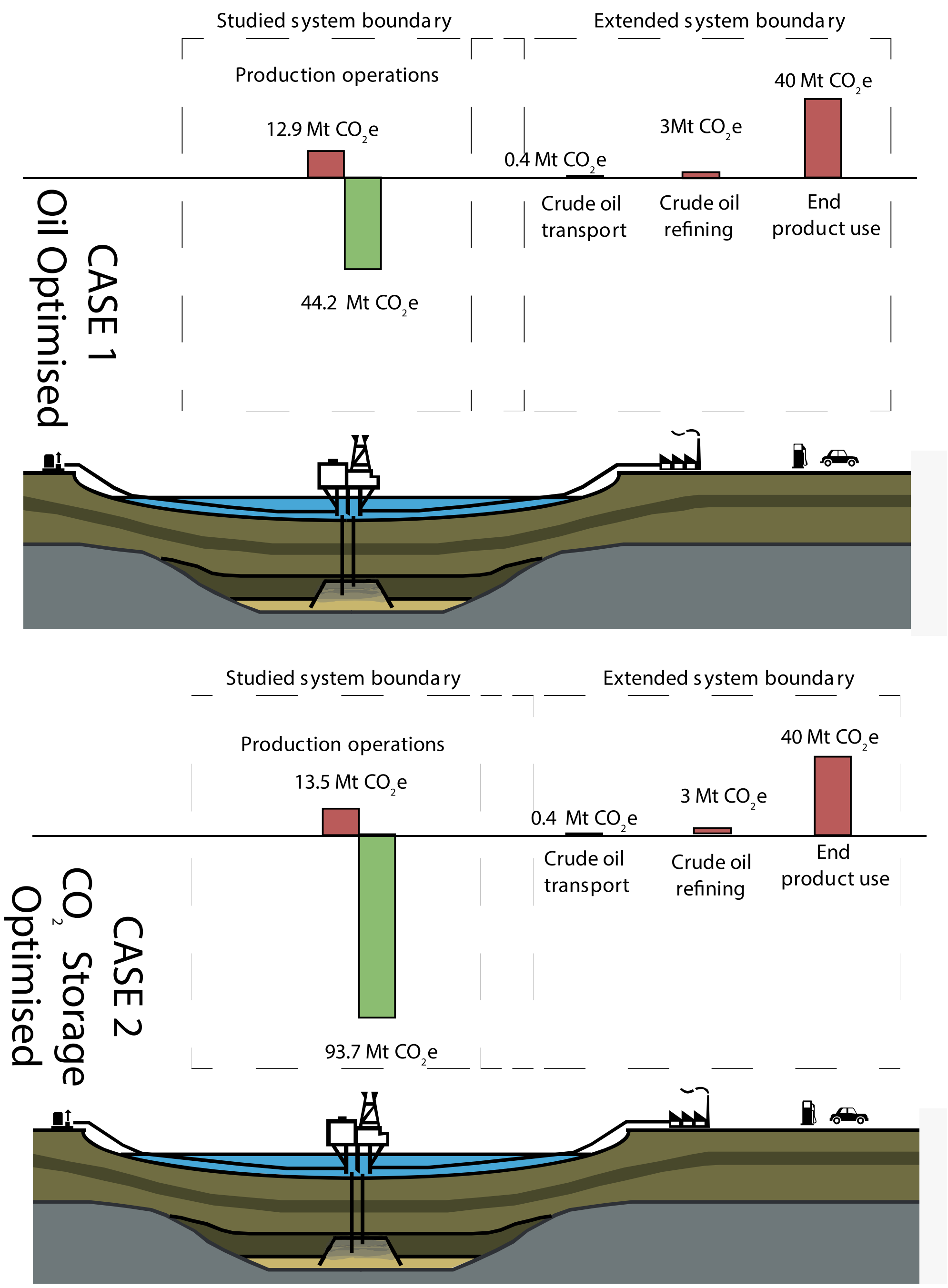

Figure 16: Overview of the 2 modelled EOR scenarios over the 20 year period. 100MMbbl of incremental oil production in each case. Cumulative emissions in red and CO_2 stored in green.

A review of flaring and venting at UK offshore oil fields: An analogue for offshore CO_2–EOR projects?

Jamie Stewart – University of Edinburgh

The previous report Carbon accounting for North Sea CO_2–EOR (pages 47-50) highlighted the significant impact that flaring/venting of reproduced gases may have on a CO_2–EOR projects lifecycle greenhouse gas emissions. As no CO_2–EOR developments currently operate in the UKCS the rate at which produced gases will be flared or vented remains unclear. This study analysed operational data from offshore UK oil fields, where it is thought that flaring/venting rates may be analogous to flaring/venting rates at proposed offshore CO_2–EOR developments. An even better analogue may exist in the form of non-CO_2 offshore EOR projects of which there a number operating in the UKCS (Awan et al. 2008). Given that some of these EOR projects utilise gas injection, much like proposed CO_2–EOR projects, flaring/venting rates at these fields in particular were analysed.

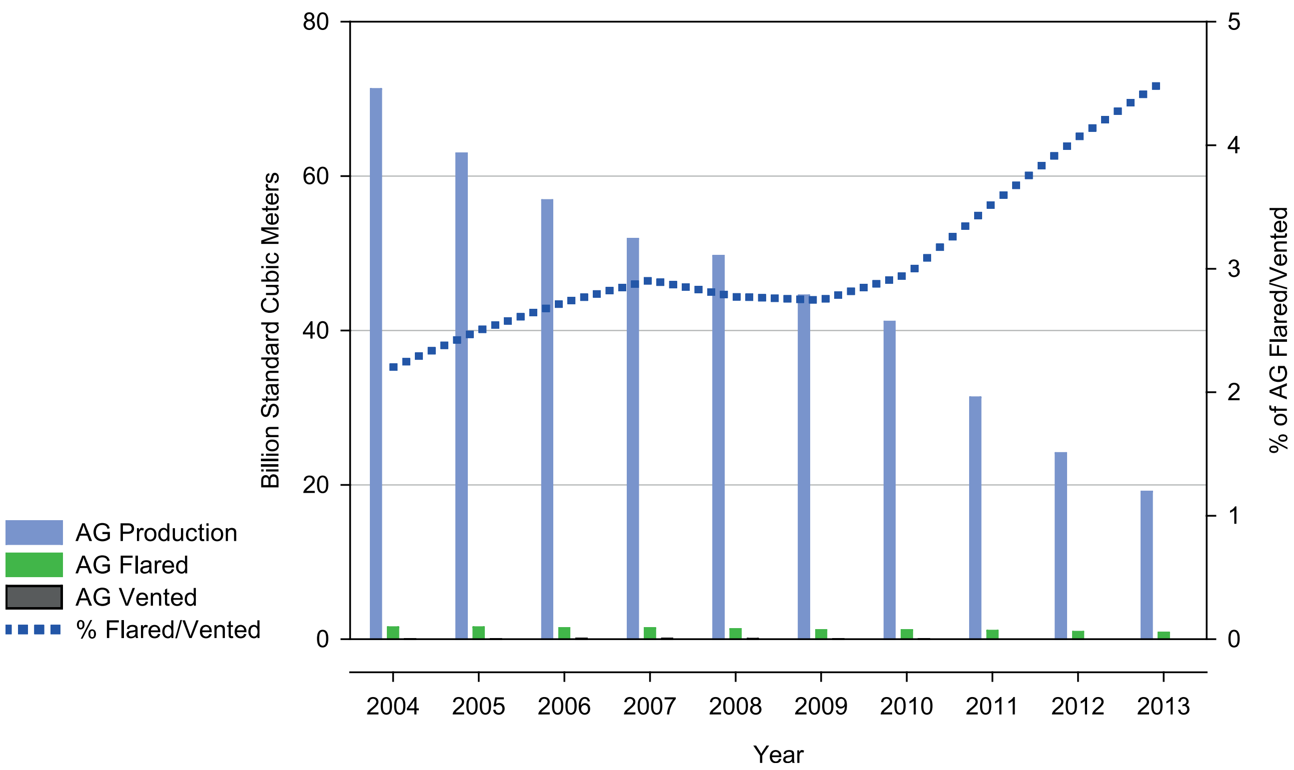

Figure 17: UKCS associated gas production, flaring and venting at all offshore oil fields

Analysis of UK-associated gas flaring and venting between 2004 and 2013

For all 212 offshore oil fields the total volume of associated gas (AG) produced between January 2004 and October 2013 was 452,925,820Ksm^3 (thousand standard metres cubed), with 12,595,106Ksm3 of gas being flared and 379,350Ksm3 vented. This equates to 3% of all AG produced at UK oil fields being flared or vented over that nine-year period. When fields developed prior to the implementation of the Petroleum Act 1998 – which required the conservation of gas by reducing any gas wastage – are removed, the percentage drops to 2%.

Year by year variability of flaring and venting rates

Figure 17 shows the annual volumes of produced AG, vented AG and flared AG for all UKCS offshore oil fields. Plotted alongside these volumes is the percentage of total produced AG that is flared or vented on an annual basis. The flaring/venting rate was lowest in 2004 when 2.2% of all of the AG produced at offshore oil fields was flared or vented. The rate was highest in 2013 with 4.5% of AG being flared or vented. This interestingly shows that, although drastic reductions in flaring rates were seen from 1980 (63% flared) to 1995 (5% flared) (World Bank, 2006), flaring/venting rates at UK offshore oil fields in the last decade have not reduced, with the highest flaring/venting rates of the period seen in 2010–2013.

Field by field variability of flaring and venting

Although the means of total AG flared or vented at UKCS offshore oil fields are relatively low compared to flaring volumes in other countries (World Bank, 2004), inspection of individual fields found a large range of 0–90% flared/vented associated gas for individual sites. Analysis of mean flaring/venting rates at individual fields developed from 1998 onwards between 2004 and 2013 found that 55 of the 99 fields sampled (56%) flared/vented between 0% and 10% of AG produced with 17 of that 55 (31%) flaring less than 1%. This highlights that it is technically possible to flare/vent low volumes (less than 1%) of produced AG.

The study found that development date, field reserve size and geographic location appear to have little control on flaring rates. Further data, that was not found to be publicly available for the majority of fields developed after 1998, would be required to explore the control of parameters such as gas-oil ratio (GOR), oil gravity and depth on the rate of flaring/venting.

Flaring and venting at fields with gas injection

Of all 212 UK offshore oil fields, 42 fields were found to have injected (methane) gas for some period between January 2004 and October 2013. The mean of total AG flared/vented at oil fields with injection capabilities between 2004 and 2013 is 3%. Interestingly, this shows that flaring/venting rates at fields with AG injection capabilities are not always reduced in relation to fields with no AG injection. This may occur due to AG injection being utilised where there is a lack of gas export facilities.

Learnings

This study has shown that greatly different apparent average flaring rates exist depending on whether the total volumes of gas are analysed at a large number of fields or mean flaring rates at individual fields are analysed. Caution must therefore be taken when selecting a representative rate of flaring/venting when modelling a proposed CO_2–EOR development. Levels of flaring and venting from existing UKCS operations are higher than experience in CO_2–EOR projects in the US, and show the importance of implementing careful control in the design and implementation of future projects.

References

Awan, A.R., Teigland, R., Kleppe, J., 2008, A Survey of North Sea Enhanced-Oil-Recovery Projects Initiated During the Years 1975 to 2005. Society of Petroleum Engineers Reservoir Evaluation and Engineering.

World Bank, 2004, Global Gas Flaring Reduction – Regulation of Associated Gas Flaring and Venting. World Bank Group. Report Number 3: http://www.wds.worldbank.org/external/default/WDSContentServer/WDSP/IB/2004/07/16/000012009_20040716133951/Rendered/PDF/295540Regulati1aring0no10301public1.pdf (accessed May 2014).

World Bank, 2006, UK Flaring Policy: http://siteresources.worldbank.org/EXTGGFR/Resources/5780681258067586081/UK_Flaring_Policy.pdf (accessed May 2014).

Carbon accounting: Does CO_2–EOR de-green CCS electricity?

Jeremy Turk and Professor Stuart Haszeldine - University of Edinburgh

This analyses the emissions difference between CCS, and CO_2–EOR. The crucial question can be stated as "If CO_2 derived from CCS on a power plant, is reinjected offshore for the purpose of EOR, how much additional carbon emission is incurred?" It is concluded that, compared to importing equivalent oil, additional emissions add just 0.003 tCO_2/bbl. These can be offset using the CO_2 market for $0.3 /bbl oil. Electricity with CO_2–EOR maintains its low-emission green status. Comparing rollout of CO_2 storage using "push" EOR, compared to a slower public funding path, an additional 1.5x to 12.7 x CO_2 (500-1290 Mt) is stored by 2050.

Aims of emissions comparison, and definition of terms

This question ignores upstream emissions. Thus no differentiation is made between CO_2 sourced from coal, or CO_2 sourced from methane natural gas. Neither is any calculation made of the CO_2 emitted from the additional oil produced. What is included, is the difference in North Sea oil production offset against the import of equivalent oil from a typical global source. Effectively, this question asks – if CCS can de-carbonise electricity production from fossil fuel, then the CO_2 captured as part of that process has to be captured, compressed, transported and injected into the deep geological underground, for the purpose of long timespan CO_2 storage. The summation of all those actions has a CO_2 budget in terms of energy used to achieve the operations. Those operations are considered to be an inevitable and inherent part of CCS, and are included in the Life Cycle carbon budgets of emissions incurred during full-chain CCS. As an alternative, that same CO_2 may be instead used as a working fluid, which is injected and recycled to produce additional oil from offshore locations. That offshore injection and recycling incurs additional CO_2 emissions. It could be argued that those additional emissions are reducing the benefits of CCS because EOR operations send less CO_2 to geological storage. If those additional emissions are allocated back to the power plant supplying the CO_2, does that significantly affect the embedded carbon in the delivered electricity from the power plant?

Method to calculate additional emissions and subtract imported oil emissions

To avoid re-calculating any emissions or activities which are essential to CCS, the problem is simplified to a calculation of the difference between transport and injection for CCS, compared to offshore CO_2 re-injection for the purpose of CO_2–EOR. Additional emissions are incurred offshore during operations for CO_2–EOR. For an individual project, these comprise: operation of EOR equipment offshore (308 MWhr/yr), venting or flaring fugitive gases (< 1% / yr imported gases). Emissions factors for these, and embedded emissions information for production and import of Saudi oil, have been compiled from published sources unconnected with CCS or CO_2–EOR. These component factors enable an assessment of the additional emissions predicted for CO_2–EOR operations offshore. The embedded carbon cost of this additional North Sea oil production is 4.25 Mt CO_2 over the project life to produce 100 Mbbl extra North Sea oil. That is compared to the 3.96 Mt CO_2 embedded carbon cost of importing 100 Mbbl Saudi Arabian oil. That is subtracted from the North Sea EOR value, to result in an additional CO_2 emission for North Sea EOR processes of 0.29 Mt CO_2. Those emissions are not directly mitigated by the CO_2 injected (which has already been produced from a fossil fuel source), so for

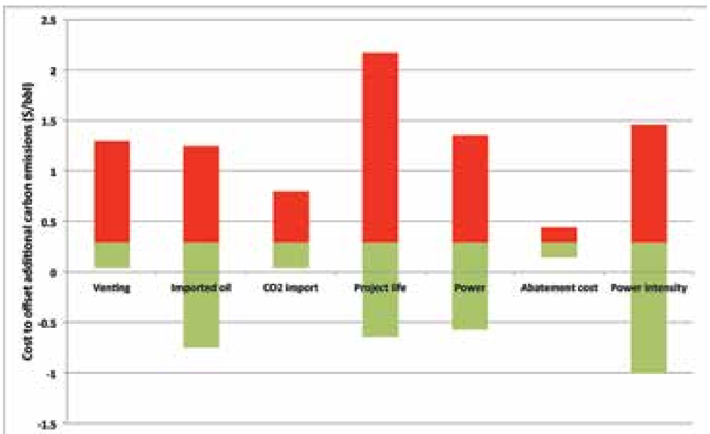

Figure 18: Illustrative calculation of the cost to purchase additional emissions resulting from offshore processes specific to CO_2–EOR operations. Calculations including sensitivity analyses, show red is high estimate, green is low, boundary is most probable. These produce a total 4.25 Mt CO_2 for 50 Mt CO_2 injected, producing 100Mbbl additional oil over a 20 year time period. That emission is offset against the emissions embedded in imported Saudi Arabian oil for production plus transport to the UK. In the graphs above, those extra emissions are purchased at a price of \$100 / t CO_2, which is illustrative of a very high estimate of the true environmental cost of CO_2 emissions. That equates to 0.003 tCO_2 / bbl additional oil.

illustration these additional emissions are "purchased" by buying emissions credits at a putative true cost of \$100/tonne, which greatly exceeds the 2015 EU market price, CO_2–EOR adds an additional cost of 0.3 \$ / bbl additional oil.

Impact of accelerated delivery of CO_2–EOR on UK CO_2 emissions to 2050

At present, in 2015, there is no CCS operational in the UK, and no CO_2 is stored. One benefit of CO_2–EOR can be conceptualised as creating a demand for CO_2, which removes costs of disposal for power operators, and consequently accelerates the development of CCS. If EOR can accelerate CCS and CO_2 storage, is that timing important? Here we analyse the UK fossil power sector CO_2 storage to 2050, comparing a Government DECC scenario of slow CCS development against accelerated development "push" CO_2–EOR.

The "slow" and "high" baselines are from DECC Roadmap for CCS (2012). Starting in 2020, a low case of 3 GW CCS in 2030 is proposed, and this analysis assumes new operating CCS capacity rising linearly to 2050. A total of 122 Mt CO_2 is stored 2020-2050. We assume a "push" of 3x 2 GW gas plant/yr, 5.5Mt CO_2/yr, producing 2.42 TWh(e) / yr of grid electricity.

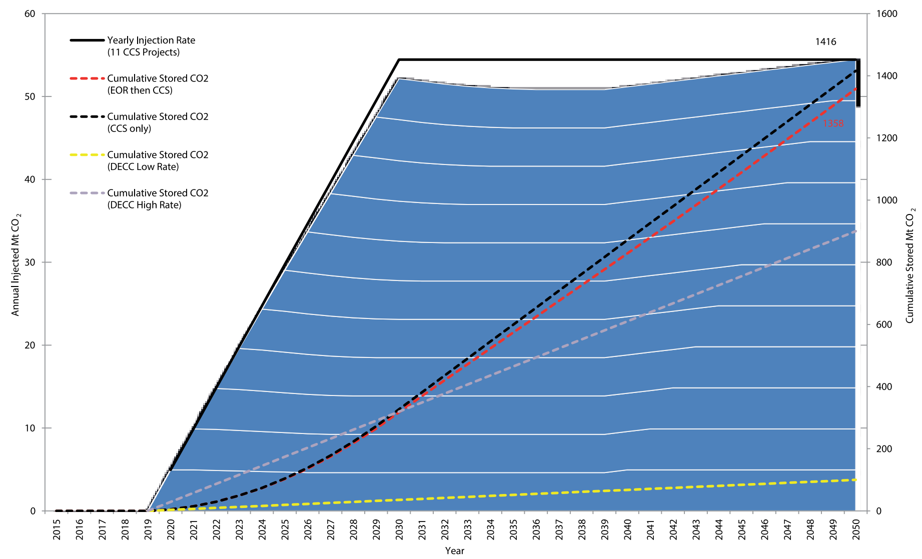

Figure 19: CO_2 storage profile for 11 identical EOR-to-CCS increments starting in 2020, adding at one per year, 1,416 Mt CO_2 could be stored by 2030 (black lines). Using an EOR-to-CCS scheme this total storage is only reduced by 58 Mt CO_2 to 1358 Mt CO_2 between 2020 and 2049, while producing 1,100 MM bbl of EOR-oil. Compare to DECC 2012 roadmap "slow rate" (yellow) and "fast rate" (purple) of CCS.

A suite of CO_2–EOR, converted to CCS increments can commercialise a "UK pathway" for CCS described by ETI (Day 2015), this requires 50 Mt/yr CO_2 stored by 2030 to decarbonise electricity. Each increment produces 5.5 Mt CO_2/yr, the first increment commences in 2020 and ten more start at one per year to meet this goal. If CCS alone is deployed to meet this goal, 54.5 Mt CO_2 / yr is injected by year 11 (2030), storing a total of 1,416 Mt CO_2 by 2050. To use the commercial advantage of CO_2–EOR, then eleven EOR increments would produce 1,100 MM bbls of EOR-oil, which reduces Saudi oil imports by 100 Mbbl/yr, from 2020 to 2049. After each EOR project ceases, mandatory CCS continues and Saudi oil imports re-commence. This suite of projects stores 1,358 Mt CO_2. The public funding route, extrapolated linearly beyond 2030, is substantially more expensive, and stores much less CO_2. By year 30 of CO_2 storage using "push" EOR, compared to the slower public funding pathways, an additional 1.5x to 12.7x CO_2 (500-1290 Mt) is stored by 2050.

CO_2–EOR: security of storage

Dr Gareth Johnson and Jamie Stewart – University of Edinburgh
Dr Peter Olden and Dr Gillian Pickup – Heriot-Watt University

Preliminary studies from CO_2–EOR in Canada have suggested that, in CO_2–EOR settings, solubility trapping takes place within both aqueous and hydrocarbon phases. This study's principal objective was to quantify how much solubility trapping takes place within both aqueous and hydrocarbon phases in CO_2–EOR settings.

The Pembina Cardium CO_2 Monitoring Pilot Project was used as a test site to determine the relative roles of solubility trapping. Firstly, two geochemical approaches using empirical data from the site (gas geochemistry, production volumes and water isotope geochemistry) were used to determine the phase distribution of CO_2 (dissolved or free-phase) at a number of production wells that were sampled monthly during a two-year CO_2 injection pilot. Secondly, a simplified reservoir simulation was performed to investigate various CO_2 injection scenarios using a model with some of the salient features of the pilot project. In particular this model was used to test the observations of the role of solubility trapping versus free-phase CO_2 trapping (Figure 20).

The two geochemical methods show that the distribution of CO_2 in the reservoir, and hence the relative role of the trapping mechanisms, is closely matched where conditions permit both methods to work.

The initial reservoir model simulation also closely matches the average CO_2 distribution and relative trapping contributions derived from the geochemical approaches, giving extra confidence in both the methods using the empirical data and the reservoir model itself. After just two years of injection it is shown that up to 26–32% of the injected CO_2 is solubility trapped.

Subsequently the reservoir model was used to model a number of alternative scenarios including: continuous CO_2 injection, WAG, injection into a depleted oil field and a saline aquifer. Results show that additional CO_2 storage by solubility trapping is achieved when an oil phase is present (25–50% solubility trapping after 5 years of injection and 45 years of equilibration) relative to a saline aquifer (<25% solubility trapping after 5 years of injection and 45 years of equilibration), hence increasing CO_2 security by reducing the proportion of injected CO_2 that remains as a buoyant free phase.

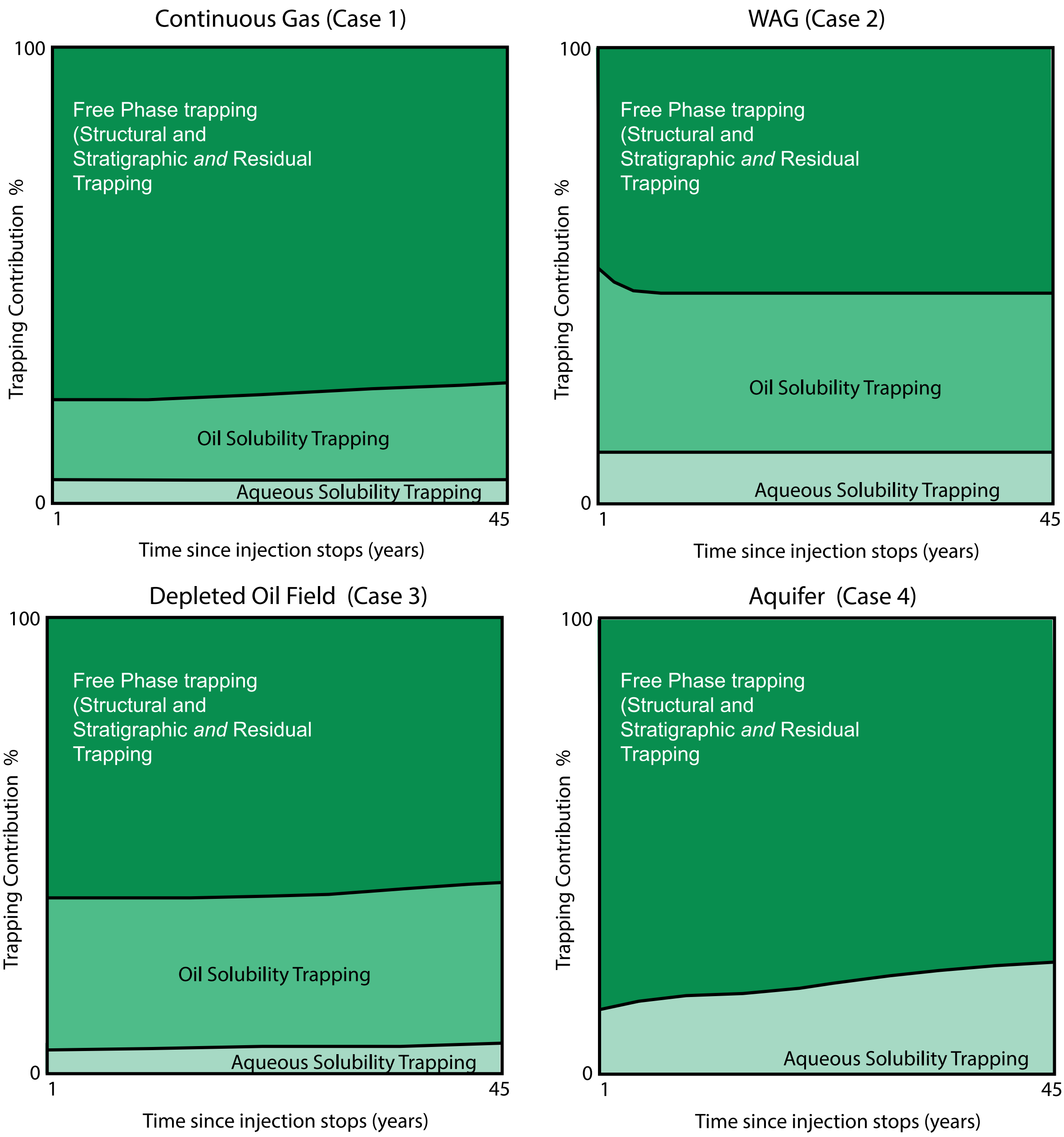

Figure 20: Relative contribution of trapping mechanisms for each modelled scenario over the first 45 years after CO_2 injection

Measurement, monitoring and verification: Enhanced oil recovery and carbon dioxide storage

Dr Gareth Johnson – University of Edinburgh

This desk based study assessed the differences between monitoring technology requirements for CO_2 storage in a saline or depleted hydrocarbon reservoir and in a hydrocarbon reservoir, when CO_2 injection is used for enhanced oil recovery (EOR) and it is assumed monitoring is required to verify stored CO_2.

First order factors dictating technology choice including geological and geographic parameters were assessed before addressing differences introduced by the choice of process (EOR or storage). A brief review found the most common monitoring technologies suitable for use in either CO_2 storage operations or in CO_2–EOR projects to not vary significantly, although the measurements and analysis do. It is found that the largest differences in monitoring technology usage are not process-related; rather they are controlled by site-specific geology and geography. However specific differences do exist due to process choice from which the following generalisations can be drawn:

Baseline measurements

Baseline measurements are typically less complex for saline reservoirs due to the unaltered state of the reservoir at the onset of a storage project. Virtually all technologies require a thorough baseline assessment. As such, operations in depleted oil and gas reservoirs and EOR projects will typically require greater assessment of baseline conditions due to their altered state which may not have reached equilibrium by the time of the project start.

Characterisation

Depleted oil and gas reservoirs and CO_2–EOR projects will invariably be better characterised before injection begins than a saline reservoir. This increased characterisation, in conjunction with the knowledge that these reservoirs have retained fluids on geological time scales, reduces the risk of unplanned CO_2 migration. This in turn could lead to less monitoring being required over aerially extensive areas than would likely be required in an uncharacterised saline reservoir.

Thorough characterisation of a saline reservoir, though costly, would also reduce the risk of unplanned CO_2 migration and hence reduce monitoring requirements.

Number of wells

Depleted oil and gas reservoirs and CO_2–EOR projects will have more wells penetrating the reservoir than a saline reservoir. On the positive side, this opens up more possibilities to deploy direct (well-based) monitoring technologies. A potential negative consequence is that more potential CO_2 migration routes are introduced. However, these routes are easily identifiable and monitoring campaigns can be devised to manage this risk.

Pressure

CO_2–EOR projects will effectively manage pressure by fluid production, reducing the risk of exceeding caprock integrities, re-activating faults and inducing seismic events. This reduced risk will impact and likely reduce the intensity of monitoring required to assure CO_2 storage integrity. Depleted oil and gas reservoir storage may in some cases (where either water-flooding or natural water recharge has not reinstated virgin pressure) have a reduced pressure at the beginning of injection. Hence, it may also have a lower risk of the pressure-induced effects outlined above and may thus benefit from a less intensive monitoring campaign. Saline aquifers, conversely, may have to actively manage pressures to reduce this risk or otherwise have more monitoring in place to detect any such effects.

No specific different technologies or monitoring strategies are recommended for EOR over CO_2 storage in either saline or depleted oil and gas reservoirs. Rather, it is recommended that the local site-specific conditions of any CO_2 injection project including the geology, geography and the level of knowledge and understanding of the reservoir are assessed in order to build a risk-based approach to selecting the appropriate monitoring technologies and deployment strategies (e.g., in Figure 21).

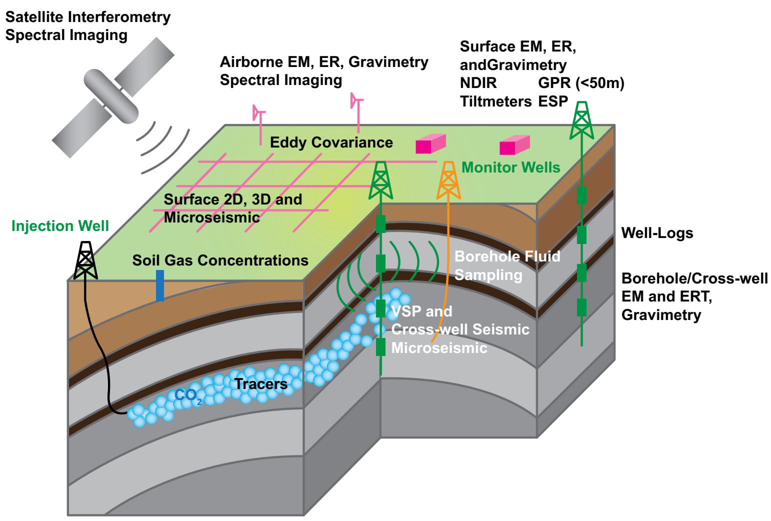

Figure 21: Possible monitoring technologies for a CO_2–EOR project

Environmental impacts of CO_2–EOR: the offshore UK context

Kit Carruthers – University of Edinburgh

The aim of this work was to determine the possible incremental environmental impacts of future CO_2–EOR projects in the UK North Sea, over and above those of the existing oil and gas (O&G) industry. Offshore hydrocarbon extraction already has some environmental impact; however, the work did not aim to quantify this. Instead, current offshore O&G equipment and activities were determined and used to identify what would be unique, or specific potential problems for CO_2–EOR. These were determined to be: CO_2 leakage; CO_2 stream impurities; enhanced trace element concentrations from geological storage; enhanced radioactive scale.

Current regulatory environment

Environmental regulations for UK North Sea oil and gas operators are set out at international (EU), national (UK) and local (e.g. Scotland) levels for the offshore environment. Oil-in-water (OIW) discharges to the North Sea are strictly limited to 30 milligrams per litre of produced reservoir fluids ("produced water"), as per the 1992 Oslo–Paris (OSPAR) Convention (as amended).

Any wastes generated offshore (solids or liquids) must also comply with the Radioactive Substances Act 1993 on radioactivity, with activity levels set for various naturally occurring radioactive materials (NORM), and technologically enhanced NORM, which may occur in waste materials.

No legally binding limits are set, however, for concentrations of potentially environmentally damaging trace elements such as mercury and lead in produced waters. OSPAR recommendations are that operators adopt a risk-based approach to their emissions, requiring that offshore producers compare modelled concentrations in produced fluids with predicted no-effect concentrations (PNEC) as set by OSPAR.

CO_2 leakage to the marine environment

The use of CO_2 is the main differentiator between CO_2–EOR and traditional offshore O&G activities. CO_2 may leak from transport pipelines, return up wells during injection, or escape geological storage. When CO_2 dissolves in water, the partial pressure of CO_2 increases, and the pH is lowered.

Both can lead to stress in marine organisms, including lowered body and skeleton calcification, and hypercapnia (increased CO_2 in body tissue and fluids). The effect of these can be to reduce nutrient uptake, reproduction success, metabolism and growth, and increase mortality and deformities. The extent of these effects depends on exposure magnitude and duration, and species type, trophic level and maturity.

Modelling of CO_2 leakage scenarios, e.g. pipeline leak versus geological storage leak, appears to indicate that the volumes of CO_2 which interact with seawater volumes are comparatively small so that dilution and mixing quickly occur. pH is therefore affected only to very minor degree (less than 1pH unit change) and/or is short lived before tidal and current mixing dilute any changes. Therefore, if CO_2 leakage were to reach the marine environment, organisms may be subjected only to short duration and/or highly localised events, and so effects would likely be minimal.

Impurities in the captured CO_2 stream may include strong acids, and capture and dehydration chemicals. They are likely to be either chemicals routinely used offshore, or to be in extremely low concentrations to meet pipeline specifications, and the likely additional environmental impact is, therefore, considered to be negligible compared with current offshore activities.

Trace elements in produced water

Deep geological sandstone formations targeted for CO_2–EOR are saturated with saline water, as well as oil. Since CO_2 dissolves in water to lower the pH, this may promote the mobilisation of rock-forming elements into solution. The Department of Energy and Climate Change (DECC) has identified a number of elements as priorities for monitoring in offshore discharges. These are: arsenic, cadmium, chromium, copper, lead, mercury, nickel and zinc. While some of these elements (e.g. copper and zinc) are essential nutrients, in large enough concentrations they all exhibit toxicity to marine life in similar fashion to CO_2 hypercapnia. Unlike CO_2, however, these elements accumulate in organisms and are magnified in concentration up the food chain.

The O&G industry already produces discharges containing these elements, and there would only be a problem if the concentrations resulting from CO_2–EOR projects are elevated above current O&G industry levels. This was estimated using laboratory batch experiments, where sandstone samples from a North Sea oil field were reacted with CO_2 and saline water, to determine whether CO_2 significantly mobilises these elements into solution.

Concentrations of the DECC elements of interest are, on the whole, not significantly increased with CO_2. Furthermore, experimental concentrations fall within the range of values for existing O&G operations. It is not expected, therefore, that CO_2–EOR activities will produce trace element concentrations which are significantly different to current offshore activities.

Scale and radioactive scale

In the offshore context, scale is the formation of sulphate and carbonate minerals within O&G reservoirs, wells and production equipment in response to changes in fluid chemistry. These scales can incorporate radioactive elements, such as uranium and radium, which are dissolved from minerals in the reservoir.

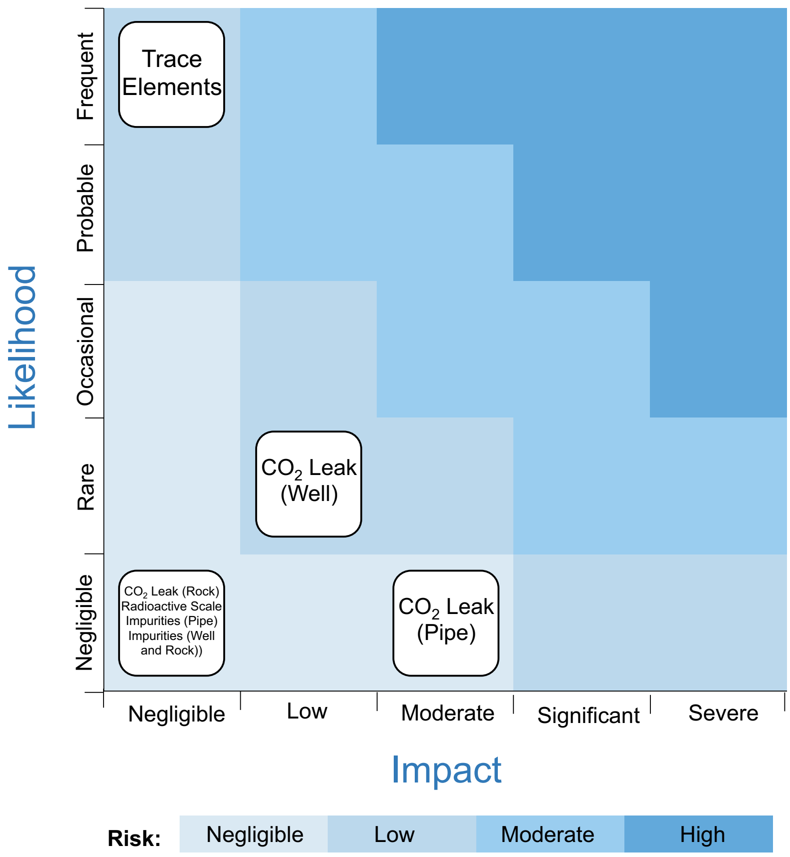

Figure 22: UKCS CO_2–EOR Anchor Project Risk

CO_2–EOR may enhance scale formation due to mobilisation of scale-forming elements. However, the routine use of scale inhibitors in the O&G industry would likely carry over to CO_2–EOR with little change in operations anticipated, and therefore little additional environmental impact.

The conceptual risk model

The results of the analysis of the potential risks associated with CO_2 leaks, CO_2 impurities, trace element mobilisation, and radioactive scaling were assessed using a conceptual risk model. The potential environmental impact of each issue was plotted against the likelihood of that impact occurring. This gives us the potential risk of each case in a CO_2–EOR anchor project in the UK North Sea (see Figure 22).

From Figure 21, we can see that CO_2 leaks from a well or trace element release from produced waters are the most "risky", but both still represent low environmental risks.

Various mitigation options could be deployed to further reduce risk, if required, such as contingencies for stopping CO_2 leaks, or the treatment of produced waters to reduce trace element concentrations. Overall, however, CO_2–EOR appears not to pose significantly more environmental risk than current O&G activities.

Legal

Legal aspects of CO_2-enhanced oil recovery

Professor Richard Macrory - University College, London

Given the current depressed emissions trading market, projects that combine enhanced oil recovery with long-term storage of carbon dioxide (CCS) for greenhouse gas abatement purposes may prove vital in securing greater commercial investment for CCS. A clear legal and regulatory framework will be a key element in providing confidence for the future. In considering the relevant international, EU and national law that would apply in the UK, we have identified some important problem areas and ambiguities in the current legislation that should be addressed.

From a legal perspective, it is important to distinguish generally between (i) pure EOR operations where CO_2 is injected primarily as a means of extracting oil or gas (although recycled as much as possible during operations, some CO_2 is inevitably left underground), and (ii) EOR operations where CO_2 is injected for storage purposes, generally following cessation of oil recovery itself. In contrast to what is happening in jurisdictions such as the USA, EOR operations in the UK in the foreseeable future are likely to be offshore and will use CO_2 acquired from power stations. The policy goals under the two regimes are different, and it is unsurprising that the regulatory requirements will be distinct. CO_2 storage operations are designed to ensure the long-term disposal of CO_2, and far greater emphasis is placed on ensuring site integrity as well as on provisions concerning the eventual transfer of site responsibility to the State.

International conventions

The main international marine conventions of relevance are the 1996 London Protocol and the OSPAR Convention. The London Protocol does not expressly mention EOR, but is unlikely to apply to any injection of CO_2 during EOR operations because of the Protocol's definition of "dumping" which does not apply to the disposal of wastes directly arising from the exploitation of seabed resources. But any storage taking place following completion of EOR operations will need to comply with the Protocol's provisions on CCS storage. Similarly, the 1992 OSPAR Convention contains a definition of "dumping" which means it is unlikely to apply to any injection of CO_2 carried out in connection with EOR operations.

EU Directive

The Preamble to the 2009 EU CCS Directive states that enhanced hydrocarbon recovery (EHR) is not in itself included in the scope of this Directive, but that the provisions of the Directive will apply where EHR is combined with geological storage of CO_2. Under general principles of EU law, a Preamble by itself cannot create an exemption, but acts as an aid to interpretation of its substantive provisions – it does not help clarity that there is no explicit exemption in the body of the Directive itself. As a result it is possible to argue that the Directive will apply to any injected CO_2 during EOR operations that is not recycled but left underground. But it is more convincing to interpret the Directive as applying only to the storage of CO_2 following the cessation of EOR operations.

The EU Directive contains important provisions concerning the acceptance quality of CO_2 injected into storage sites. Essentially, these require that streams consist "overwhelmingly" of CO_2, and are not contaminated by other substances which might affect the integrity of the site or pose environmental problems. There are significant problems concerning the application of the Directive's requirements on acceptance criteria for CO_2 streams where EOR operations combined with long-term storage are involved. CO_2 that is injected underground for EOR purposes inevitably becomes mingled with other substances under the seabed including gas and brine, and a strict interpretation of the Directive's provisions might suggest that such CO_2 could not meet the acceptance criteria, and this could severely inhibit EOR operations combined with CCS storage. The drafting is probably due to a failure at the time the legislation was developed to fully appreciate what was involved in an EOR combined operation. Current guidelines issued by the European Commission on acceptance criteria do not address this issue, and the Commission should be encouraged to develop guidance on the subject.

Under the CCS Directive, CO_2 injected into a CCS site for long-term storage is excluded from EU waste legislation. For a combined operation, any injected CO_2 should fall within the waste exclusion since in such an operation one of the purposes of capture and transporting will be that of long-term storage, even though it is used for EOR operations in the intermediate period. Nevertheless, there is potential ambiguity here, and it would be preferable to secure a more clearly worded exclusion from waste legislation to encompass CO_2 captured and transported for a combined operation.

CO_2 used in pure EOR operations cannot fall within the exemption. Although CO_2 emanating from a plant is therefore potentially waste in law, it seems likely that if it is transformed into a form suitable for EOR operations it will have fulfilled the criteria for ceasing to be waste in law as long as it is being used during EOR operations. "End of waste" criteria for particular types of waste can be developed at EU level but none have been developed for yet for CO_2 used for EOR operations. Until that happens, Member States are permitted to make their own decisions applying the basic principles of EU waste law, and it would be helpful if guidance on this issue could be developed by the relevant UK authorities.

National regulations

The CCS Directive requirements have been transposed into UK law by the Energy Act 2008 and regulations made under it. These regulations apply to CO_2 storage "with a view to its permanent disposal" and as such do not apply to CO_2 injected during EOR operations. However, the Energy Act anticipated the issue of combined EOR and storage operations by providing that the Secretary of State can make an Order applying the CCS requirements to EOR operations in any particular site. No such Order has yet been made but it is clearly a useful mechanism to ensure clarity of controls.

In the absence of any such Order, pure EOR operations fall under the Petroleum Act 1998 and are regulated under Seaward Production Licences issued by the Secretary of State. In practice, where EOR operations are followed by CO_2 disposal, sequential licences are likely to be issued, starting with a Seaward Production Licence and later converting into a Disposal Licence under the Energy Act. It is therefore important to ensure that the regimes are harmonised as far as possible, and it appears at present that there are no major inconsistencies. Integration is helped by the fact that at present both licensing regimes are administered within a single organisational unit within the Department of Energy and Climate Change.

Other jurisdictions

By way of comparison we considered the current legal controls for EOR operations and CO_2 disposal in a number of other jurisdictions including the Netherlands, France, Norway, Australia the USA and Canada. As in the UK, pure EOR operations are generally licensed under different legal regimes from those applicable to the long-term storage of CO_2, but with a recognition that the dividing line between the two operations is clearly not always easy to determine. Of all the jurisdictions, the US Environmental Protection Agency currently appears to have the most developed policy and guidelines to determine whether and at what point an EOR operation has become one for CO_2 storage, requiring distinct regulatory requirements.

The use of CO_2 for enhanced oil recovery on the UKCS: Selected legal and regulatory issues with a specific focus on property

Professor Roderick Paisley and Professor John Paterson – University of Aberdeen

There is growing interest in the use of CO_2 for enhanced oil recovery (EOR), not least on the UKCS. The economic use of this technology depends, however, upon a number of practical challenges being overcome. Can the appropriate infrastructure be established to ensure that sufficient quantities of CO_2 are reliably available for all of the fields wishing to make use of it? Is there sufficient demand to justify the necessary investment? Are sufficient onshore sources available? Can the required transport network be readily established via the reuse of existing infrastructure, or will new pipelines need to be constructed? These technical challenges can sometimes mask underlying legal issues which, if not properly addressed, could delay implementation or return to cause problems for interested parties at a later date.

There are a variety of reasons that explain why these legal issues are so problematic. In relation to activities beyond the territorial sea, for example, the difficulties arise as a result of the relative uncertainty that attends the rights that exist on the continental shelf. This uncertainty is further compounded by a general willingness on the part of the state and commercial actors during five decades of oil and gas operations to turn a blind eye to such issues. Difficulties also arise beyond the territorial sea as a result of the efforts of government over the past decade to put a framework in place for the development of offshore renewable energy projects and of carbon capture and storage. The fact that this framework differs from that which underpins oil and gas projects causes confusion. It is also the case, however, that this very confusion points out the direction in which a solution may lie – specifically, the achievement of some ultimate clarity as to the nature of the Crown's property rights beyond the territorial sea.

Onshore, on the other hand, the difficulties arise as a result of the fact that the impact of property rights is not always fully appreciated. For example, whilst a servitude may exist to allow the transport of hydrocarbons in one direction through a pipeline that crosses property belonging to another, it may not be sufficiently broadly drafted to allow the transport of CO_2 in the other direction. Where a pipeline involves dozens if not hundreds of individual servitudes, this can create a significant and potentially costly problem.

This report examines a range of issues such as these with a view to highlighting where there are problems and obstacles facing the implementation of an extensive pipeline network for the use of CO_2 for EOR as well as uncertainties relating to liabilities. It begins by establishing some fundamental propositions about the nature of CO_2 from a legal perspective, including the extent to which it may be subject to property rights and the consequences that follow. It then goes on to consider the position of the state in various zones and notes both where there is certainty as to its rights and responsibilities in relation to the CO_2 for EOR and where there is uncertainty. In the latter case, the report considers the consequences of a range of different scenarios. The penultimate section considers some specific issues associated with transportation to the seabed before conclusions are presented in the final section.

The legal – and specifically property law – issues discussed in the report are of fundamental importance to the operability of CO_2–EOR technology. A key conclusion is that, where uncertainties exist, clarification is required in order to enable better drafting for matters as diverse as funding, insurance, indemnities, liabilities, and new regulation. If this is not achieved, then unexpected and potentially expensive problems may arise, both for contractors and the Crown. The position is all the more confused because of the apparent disjunction between the approach adopted when CO_2 is transported and injected into the subsurface offshore for purposes of sequestration and the approach adopted when the same basic processes are conducted for the purposes of EOR. There appears to be no reason for the differential approach from the perspective of property law and, indeed, every reason to conclude that what currently exists is incoherent and the result of ad hoc interventions as different issues have emerged beyond the territorial sea.

Transboundary chains for EU CO_2–EOR

Rudra Kapila and Professor Stuart Haszeldine – University of Edinburgh

CO_2 storage is regulated by EU states within their exclusive economic zone (EEZ), of up to 200 nautical miles. Transboundary issues are twofold: firstly, CO_2 may originate in one member state, to be injected beneath waters of a different state; secondly, fluid movement after injection may physically relocate CO_2 into pore space beneath the waters of an adjacent member state. The issue of transboundary pressure interference is not considered. Evidence was gained from reviewed publications, and "grey" reports, as well as interviews with experts from seven stakeholder groups.

The two most relevant treaties are (i) OSPAR, a modification to which was ratified in 2007 "formally enabling" cross-border transport for the purposes of CO_2 storage, including CO_2–EOR; (ii) the London Protocol which has enabled CO_2 storage since 2007. However, transboundary movement of CO_2 under Article 6 has still to be ratified and requires the agreement of two-thirds (i.e. 27 of 40) of the signatories to the Protocol. CO_2 used for EOR will, though, be exempt, as it is related to the exploitation of seabed mineral resources, including hydrocarbons. A second method to enable transboundary CO_2 movement is that two states can bilaterally agree the export of CO_2 for storage.

Small quantities of CO_2 for food and drink are already moved as commodities by ship between North Sea states, and this provides a precedent, although scaling this up 1,000 times may require diplomatic support. It is unclear within the CCS Directive if transport of CO_2 by ship removes liability to purchase EU- Emissions trading scheme (EU-ETS) certificates, even if CO_2 is later securely disposed of by EOR, because ships are outwith the EU-ETS. A solution is for the state receiving CO_2, to designate those ships as EU-ETS facilities. The International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) for larger CO_2 ships need to be adapted, but multiple small vessels can already work. The design concepts for larger vessels are completed. From a legal standpoint, shipping is seen as simpler – with fewer and smaller liability and legacy problems – than modifying or constructing pipelines.

For transboundary chains of CO_2 pipeline transport, and storage sites which straddle licence or international boundaries, the existing legal approach to hydrocarbon unitisation and cost sharing is likely to be adaptable. To enable conversion of oil fields to EOR, suitable fiscal incentives are needed. For these EOR purposes, CO_2 should be legally defined as a commodity, not a waste. However if an EOR project transitions into being pure CO_2 storage, then the definition of CO_2 as a waste triggers greater difficulties in transport, monitoring, and certification of storage – including the difficulty of export from one state to another under the London Protocol.

Liability concerns can be at state level, usually undertaken by negotiation, and at civil level EU liability law is not harmonious between states. Diligence during normal project evaluation by legal firms can make multilateral private contract consortium agreements. Bilateral state agreements may be useful to define the physical location of shipping under the CCS Directive, or to allocate regulatory responsibility and leakage liability for cross-border pipelines or storage sites. Private commercial contracts, adapted from those for hydrocarbons, will need to consider liability more closely than the existing "loss of income" approaches currently taken.

In summary, CO_2–EOR project chains face no special legal challenges around the North Sea, provided that CO_2 is defined as a commodity not a waste. When considering legal implications, CO_2 shipping implies less cost and liability, but may lose EU-ETS exemption if bilateral agreements are not made. The EU Commission needs to provide Directive guidance to include CO_2 shipping within EU-ETS. Pipeline transport of CO_2 for EOR has no legal impediment. Successful EOR projects could provide exemplars to establish pragmatic ratification of London Protocol Article 6, which currently prohibits transboundary CO_2 transfer. Fiscal incentives are needed to stimulate CO_2–EOR investment, rather than decommissioning. Liability frameworks already exist in private contract law, but need adaptation from hydrocarbons to specific CO_2–EOR risks.

CO_2 Supply

Ship transport of CO_2 for enhanced oil recovery – literature survey

Dr Peter Brownsort – SCCS

Transport of carbon dioxide (CO_2) by ship may fulfil a key role in the development of CO_2-enhanced oil recovery (EOR) in the North Sea where a flexible transport system would be advantageous. This survey aimed to determine the extent and scope of publications on transport of CO_2 by ship, to review a selection of available literature and to extract the key findings of interest for CO_2–EOR.

The full report gives an overview of available literature and brief reviews of the more important reports and papers (Box 1), mostly from Japan, Korea and mainland Europe. The literature establishes that CO_2 can be transported by ship using known technologies, related to those developed for liquefied petroleum gas (LPG). Indeed, a small fleet of liquid CO_2 carriers already operates in European waters serving the industrial gas and food and drink industry markets. Most publications on CO_2 shipping, however, are focused on carbon capture and storage (CCS) and few consider the special requirements of CO_2–EOR. In particular, the interface between shipping and well injection is not widely covered for CO_2–EOR.

Box 1

Mitsubishi Heavy Industries, 2004, *Ship transport of CO_2, IEAGHG Report No. PH4/30.*

Svensson et al., 2004, *Transportation systems for CO_2 – application to carbon capture and storage.*

Hegerland, Jørgensen and Pande, 2004, *Liquefaction and handling of large amounts of CO_2 for EOR.*

Doctor et al., 2005, *IPCC special report on carbon dioxide capture and storage: Chapter 4 – Transport of CO_2.*

Aspelund, Mølnvik and de Koeijer, 2006, *Ship transport of CO_2: technical solutions and analysis of costs, energy utilization, exergy efficiency and CO_2 emissions.*

Aspelund, 2010, *'Gas purification, compression and liquefaction processes and technology for CO_2 transport' in Developments and innovation in CCS technology.*

Omata, 2011, *Preliminary feasibility study on CO_2 carrier for ship-based CCS.*

Vermeulen, 2011, *CO_2 Liquid Logistics Shipping Concept (LLSC) – overall supply chain optimization.*

ZEP, 2011, *The costs of CO_2 transport.*

Roussanaly, Bureau-Cauchois and Husebye, 2013, *Costs benchmark of CO_2 transport technologies for a group of various size industries.*

Yoo et al., 2013, *Development of CO_2 terminal and CO_2 carrier for future commercialized CCS market.*

Technology for CO_2 shipping

Shipping of CO_2 is most effective as a liquid at temperature and pressure conditions close to the triple point; typically 6.5 bara at -52°C is recommended. The main process stages are shown in Figure 23. The technology required is based on that for other cryogenic liquids such as LPG and liquefied natural gas. Liquefaction equipment and its energy requirement account for a large proportion of the cost of CO_2 shipping systems. Ship proposals are generally based on well-established LPG carrier designs; capacities of up to 100,000m^3 have been proposed.
Ship loading and onshore offloading employ conventional techniques for cryogenic liquids; however, offshore offloading at a storage/EOR site requires novel techniques and is a main area of technological uncertainty in the transport system.

Several alternative single point mooring and transfer technologies are available. These may need adapting for CO_2 handling and the optimum system is likely to be location-specific. Liquid CO_2 must be warmed and pumped to a temperature and pressure suitable for injection; this will be specific to the well and reservoir and will change with maturity of the site. The expertise exists to determine the project-specific conditions and equipment required. Injection rates achievable will also be specific to the individual site. Optimising CO_2 flow across both transport and injection may have cost implications that have yet to be properly considered.

Intermediate storage of liquid CO_2 is necessary between liquefaction and ship loading. Storage may also be needed offshore for CO_2–EOR as continuous injection or specific injection profiles may be needed. This potential requirement for offshore storage has barely been mentioned in the literature and evaluation of its consequences for cost is another significant gap in knowledge.

Figure 23: CO_2 Ship transport chain – main process stages

Regulation and health, safety and environmental aspects

There are several areas of liquid CO_2 transport by ship and associated processes where hazards exist. However, all publications reviewed imply or conclude that risks can be controlled to an acceptable level by application of existing engineering practices and procedures under an appropriate regulatory framework. Liquid CO_2 shipping design and operation must comply with the International Gas Carrier Codes that also govern liquid petroleum gas (LPG) and liquid natural gas (LNG) shipping; these activities have a very good safety record over an extensive period.

Asset flexibility, costs and financial risk

The potential role for shipping in the development of CO_2–EOR and CCS, first proposed in the early 2000s, is generally supported by the body of literature. Shipping of liquid CO_2 at large scale is feasible with known technologies and can provide a transport system that is flexible in terms of space and time. Shipping allows collection of CO_2 from different source locations or transport hubs and delivery to different storage or EOR sites. It allows for sequential addition of capacity as CCS or EOR is deployed initially and during growth. When storage/EOR projects reach completion, shipping capacity can supply new sites being developed. If CO_2 ships are no longer required, they can be converted for use as LPG carriers and maintain their value.

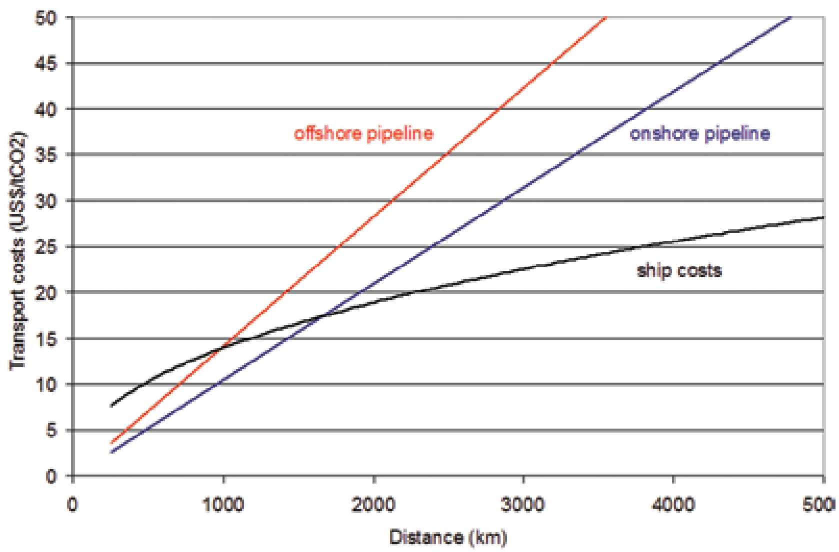

Figure 24: Shipping costs

Cost estimates for CO_2 shipping systems vary between studies, depending on assumptions made for the main parameters: scale, transport distance, ship size, utilities costs, financial variables and project lifetime. Estimated costs for distances relevant to the North Sea range between 10–30 €/t-CO_2. The greatest costs are associated with liquefaction and the shipping operation. However, compared to pipeline costs, CAPEX is lower for shipping systems while OPEX is higher. To generalise, total specific costs of CO_2 shipping are higher than pipelines over short distances but lower over longer distances (see Figure 24). The "break even distance" varies between150–1,500km depending on the specific assumptions of the case studied.

The capital investment required for a liquid CO_2 shipping system is low compared to the alternative of an offshore pipeline. Together with the flexibility described, this means shipping is seen as having relatively low financial risk, which may benefit early CCS or CO_2–EOR projects. Methodologies for estimating ship-based transport system costs are available but costs cannot easily be generalised, as they are case specific. Overall, the costs of shipping CO_2 can be competitive with pipelines in the right circumstances, generally where volumes are lower and transport distances higher. Several studies have found shipping to be competitive at distance/volume combinations relevant to EOR in the North Sea.

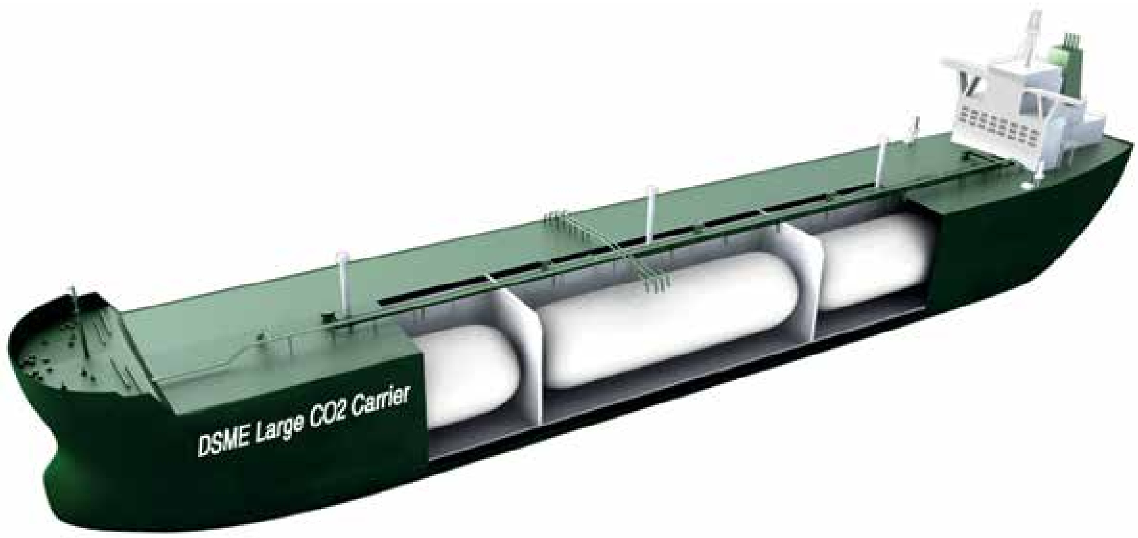

Figure 25: Conceptual drawing of very large CO_2 carrier, source Yoo et al, 2013

Worldwide comparison of CO_2–EOR conditions

Dr Peter Brownsort – SCCS

Comparison of fiscal and industry conditions in seven global regions where CO_2–EOR is active or under consideration

Regions compared:

Canada, Norway, USA Onshore, UK, China, Malaysia, USA Gulf of Mexico

The conditions for carbon dioxide enhanced oil recovery (CO_2–EOR) in seven major oil-producing regions have been compared in terms of tax regime and incentives, general regional availability of CO_2, existing or potential infrastructure to supply CO_2 and the degree of maturity of CO_2–EOR and carbon capture and storage (CCS) in the region. The study suggests that the UK would need to take major steps, such as introducing significant financial incentives and state-supported provision of infrastructure, to be seen as a leading contender for investment in CO_2–EOR by multinationals, compared to other regions where conditions are more favourable.

Taxes and incentives

Broadly speaking, oil taxes can be divided into two groups based on either production volume/value or net income. The regions examined apply different combinations and balances between these. Corporate income taxes in European jurisdictions are much higher than in North America and Asia, although production volume/value based taxes and royalties in the latter regions make up for this to some degree. Details of taxes, including royalties and other charges, and tax structures for each region are given in Table 3. Specific incentives for CO_2–EOR, also summarised in Table 2, are offered in certain circumstances against taxes and/or royalties in the USA, Canada and Malaysia. Tax credits for capture of anthropogenic CO_2 are offered to source companies in the USA to increase CO_2 supply availability, as a preferred alternative to incentivising EOR directly.

Differences in tax allowances, ring-fencing rules and incentives mean a straightforward comparison between regions is difficult. A crude ranking of tax burden (lowest to highest) for CO_2–EOR operations would suggest an order of North America, Asia, Europe, but this

Table 3: Comparison of oil taxes and incentives for EOR

Region	Taxes applied to production value	Taxes applied to net income	Incentives
USA Onshore	**Summary: 12–38% of production value.** Royalty – 12–30%, paid to rights owner; rate negotiated or result of bidding. Severance Tax – rates and tax base detail vary with state, generally based on gross production value at wellhead (example rates; Texas 4.6%, Alabama 8%; Alaska is different, 25% based on net value at pipeline end.	**Summary: 35% net income.** Combined federal and state rate against net cash income; state rate 0–12%, essentially deductible from federal rate. Not ring-fenced; can offset losses/deductions across whole company and value chain.	**USA federal regime:** 15% of costs of EOR deductible when oil price low and 100% of costs of tertiary injection deductible – both subject to repeal proposals. Tax credits $10/t-CO_2$ for CO_2–EOR and $20/t-CO_2$ for CCS, available to companies capturing anthropogenic CO_2; total limited to 75Mt-CO_2. **USA individual states:** Reductions or allowances against Severance Tax in Mississippi, North Dakota, Oklahoma, and pending in Florida.
USA Gulf of Mexico	**Summary: 18.75-26.75% of production value.** Royalty – 18.75% since March 2008. Previously 16.7% or, earlier, 12.5%. Severance Tax – only applies in state waters; rates and bases vary as for onshore.	**Summary: 35% net income.** Combined federal and state rate against net cash income; state rate 0–12%, essentially deductible from federal rate. Not ring-fenced; can offset losses/deductions across whole company and value chain.	As above.
Canada	**Summary: 10-45% of production value.** Royalty – Crown Land royalties vary 10–45%; freehold royalties vary also, no detail found.	**Summary: 25-31% net income.** Federal rate (2013) 15%, state rate varies 10–16%. Charged on net income at corporate level; no ring-fencing.	Saskatchewan: Crown Royalty reduced to 1% of gross EOR revenue initially, increasing to 20%; freehold production tax reduced to 0% initially, increasing to 8%. Alberta: Royalties capped at 5% where eligible.
Malaysia	**Summary: 10% of production value.** Developers require Production Sharing Contract (PSC) with PETRONAS, who take first 10% of volume as royalty, plus share of "profit oil" negotiated under contract. Also "signature bonus" paid to PETRONAS for contract. PSC not required in Malaysia–Thailand Joint Development Area (JDA).	**Summary: 38% net income.** Petroleum Revenue Tax (PRT) charged at 38% on net income from production and transport operations within Malaysia. Other operations subject to Income Tax of 25%. Lower PRT rates and progressive with time in JDA; arrangements in place with Thailand to avoid double taxation in JDA.	Annual investment allowances against PRT increased to 60–100%
China	**Summary: 6-21.5% of production value, or more.** PSC required, "signature bonus" payable to state. Royalty – up to 12.5% for PSC prior to Nov 2011. Resource Tax – 5% of sales revenue offset by VAT and various exemptions, since Nov 2011. Mineral resources compensation fee – 1% of sales revenue. Special Oil Gain Levy – 20–40% of value above $55/bbl, i.e. progressive from 0% at $55/bbl to 15.5% at $100/bbl, and more for higher barrel values.	**Summary: 25% net income.** Many expenses including other taxes and levy deductible before income tax.	
Norway	**Summary: 0% of production value.** No royalty	**Summary: 78% net income.** Corporate Income Tax (CIT) 27%, on net operating profits. Resource Rent Tax 51%, on net operating profits of offshore extractive and transportation activities, including onshore supporting activities. Charged at corporate level; not ring-fenced, but limits to transfers of deductions between on- and offshore activities.	
UK	**Summary: 0% of production value.** No royalty.	**Summary: 50–75% net income.** Corporation Tax (CT) 30%, on profits from oil and gas exploration and production, ring-fenced, cannot offset losses in other parts of company/value chain. Supplementary Charge (SC) 20%, similar basis to CT, additive to CT (reduced from 32% in 2015 Budget). Petroleum Revenue Tax 50% (35% from 01/01/2016), charged for fields receiving development consent before March 1993, on profits calculated by statutory method on field basis; deductible from income before CT and SC.	

should be treated with caution and will depend on the specifics of project and company involved.

Availability of CO_2, infrastructure and experience

The availability of supply of CO_2 to potential EOR operations in the regions compared was considered in terms of absolute scale of CO_2 sources in the region, the location of sources, the existing, planned or potential CO_2 transport infrastructure available, together with the degree of maturity of EOR and/or CCS operations. Generally, these factors are most advantageous for USA Onshore, with Canada close behind, and least favourable in Malaysia, with Norway and the UK slightly more favoured. China is intermediate as a whole, but with more variation between factors. USA Gulf of Mexico should share most of the advantages of the neighbouring onshore region; however, the existing demand onshore, together with the increased complexity of offshore operation, reduces the favourability in terms of these factors.

The only region where infrastructure and a market supplying CO_2 for EOR are already established is USA Onshore (see Figure 26), with developments in Canada following somewhat behind.

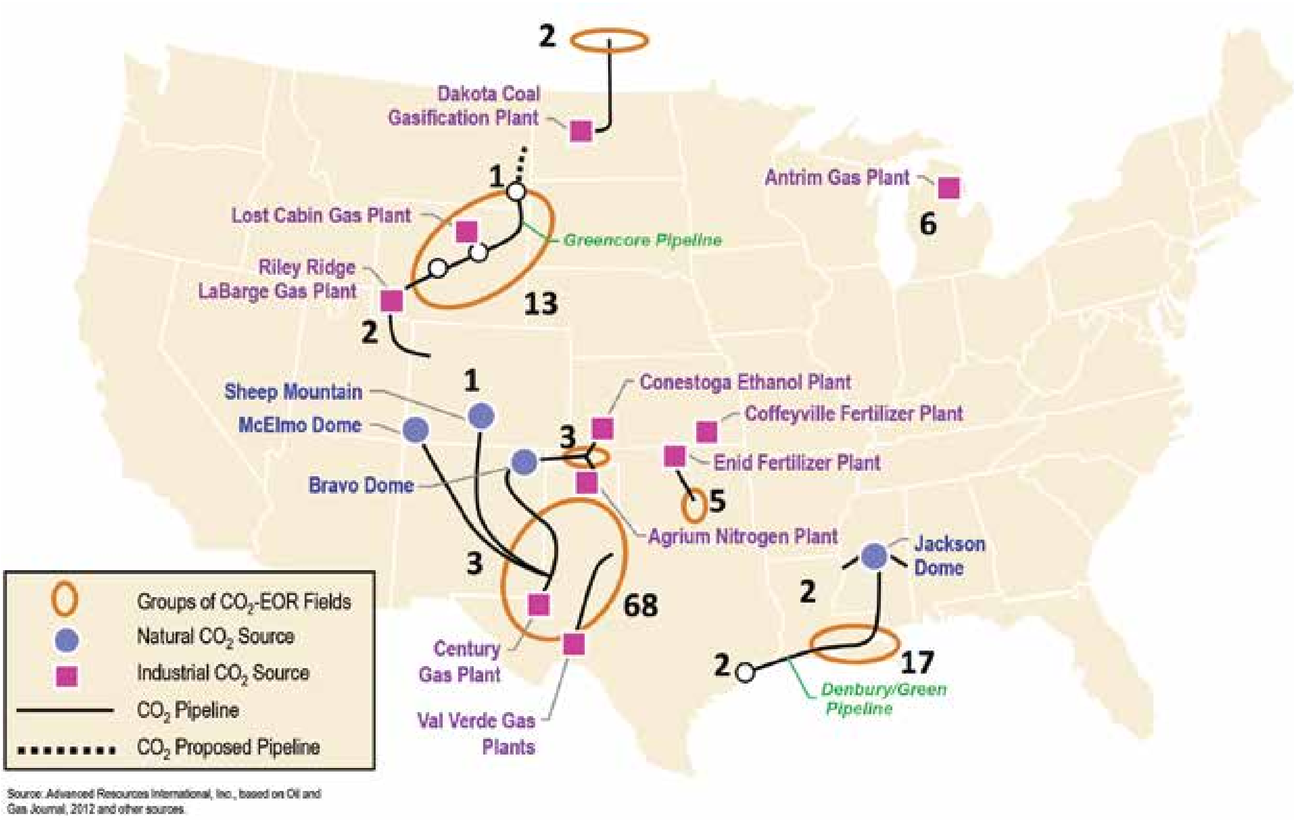

Figure 26: North American CO_2–EOR operations and CO_2 sources

Offshore offloading of CO_2 - Review of single point mooring

Dr Peter Brownsort – SCCS

There are many types of single point mooring (SPM) and loading systems that have been developed for the transfer of hydrocarbon and other fluids from production wells, platforms or floating storages to tankers. Several of them can probably be adapted for transfer, in the opposite direction, of carbon dioxide (CO_2) from transport ships to injection wells for enhanced oil recovery (EOR) or geological storage.

This desk-based study looked at the types of SPM available, their key characteristics and potential suitability for CO_2 offloading. The study developed a flow-chart based selection guide for a CO_2 offloading mooring, taking account of some constraints of location, material and equipment characteristics and operations. It also considered the fit of potential mooring systems to some generic process route options for a CO_2 ship transport chain.

Single point mooring types

Over 35 named offshore mooring/loading systems are in use globally. These can be grouped into eight categories, seven of which are SPMs:

- Conventional (spread) moorings, not SPM, sheltered waters only
- Articulated (e.g. single anchor leg, articulated column)
- Buoy (e.g. catenary anchor leg, vertical anchor leg)
- Fixed tower/jacket SPM
- Floating tower/spar SPM
- Submerged flexible riser (e.g. single anchor loading, submerged loading system)
- Submerged buoy (e.g. several tightly tethered submerged buoy systems, hybrid riser systems)
- Turret (swivelling manifold integrated into vessel, internal or external, fixed or disconnectable).

Selection of offloading system

The selection of a single point system for offloading depends on a number of factors including location of offloading point, CO_2 condition at transfer, availability of suitable flexible hoses and ship design. Most of these factors are dependent on the individual case involved and it is, therefore, not possible to give a general recommendation of offloading system. However, using available information a tentative logic flow-chart has been proposed to narrow down options for single point offloading systems (Figure 27).

Four key questions relate to (i) the need for buffer storage at the offloading point; (ii) process equipment available on the ship; (iii) acceptability of permanently submerged flexible hoses for supercritical CO_2 transfer; and (iv) dynamic positioning capability of the ship. An assumption was made that flexible hoses suitable for cryogenic liquid CO_2 transfer in, or under, seawater are not available.

Using the flow-chart, four generic route options were tested to give an initial screening of potential CO_2 offloading systems (offshore offloading or near-shore offloading to a pipeline terminal, each with and without buffer storage at offloading point). For each route a number of possible systems were identified. However, the routes involving liquid CO_2 offload to buffer storage have more limited options.

Recommendations

- Detailed knowledge of the downstream process design (CO_2 injection profile and rate, injection temperature and pressure, reservoir properties, platform capabilities) is needed before selecting a suitable offloading system.
- Specialist advice on mooring and offloading design is needed to define a suitable system.
- Improved understanding of the suitability of flexible hoses for CO_2 transfer would be beneficial, particularly for permanently submerged situations and for cryogenic liquid transfer.
- The need for buffer storage after offloading is a key question that depends on design of the injection operation; projects should assess this factor critically before progressing with transport chain design.

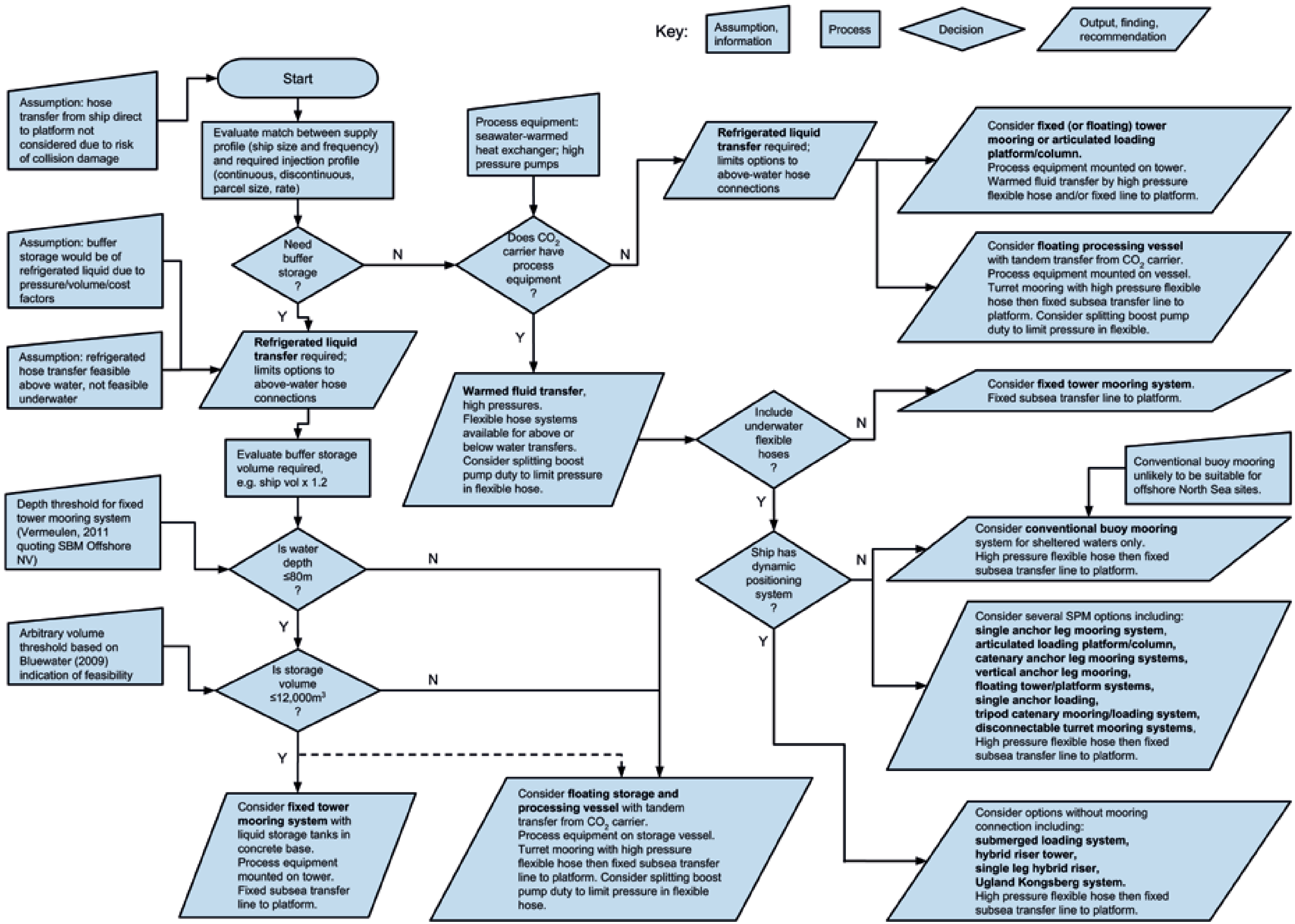

Figure 27: CO_2 offshore offloading system selection guide

Full or non-technical reports of the research summarised in this report can be found on the SCCS website at: www.sccs.org.uk/expertise/reports/sccs-co2-eor-joint-industry-project

SCCS would like to thank the following organisations for providing funding support to the SCCS CO_2-EOR Joint industry project:

Scottish Government; Scottish Enterprise; 2CoEnergy; Nexen; Shell

Contributors to this report:

Dr Peter Brownsort
Kit Carruthers
Dundas Consulting
Element Energy
Professor Stuart Haszeldine
Dr Gareth Johnson
Rudra Kapila
Professor Alex Kemp
Chris Littlecott
Dr Leslie Mabon
Professor Eric MacKay
Professor Richard Macrory
Bruno Meyvis
Dr Peter Olden
Professor Roderick Paisley
Professor John Paterson
Dr Gillian Pickup
Dr Kris Piessens
Jamie Stewart
Jeremy Turk
Professor Karen Turner
Dr Kris Welkenhuysen

Editors: Dr Matthew Ball (SCCS)
Indira Mann (SCCS)
Gordon Sim (SCCS)
Design: Gillian Kidd
(University of Edinburgh)
Nicola McDonald
(bagelfishdesign.co.uk)
Proof-reader: Alison Platts

Image Credits:

Front/rear cover © Dabarti CGI/Shutterstock
Page 24: Graphic © iDesign/Shutterstock and Image © Denphumi/Shutterstock
Page 39: Graphic © iluistrator/Shutterstock and Image © Will Robb Photography
Page 45: Graphic © IhorZigor/Shutterstock and Image © curraheeshutter/Shutterstock
Page 49: Graphic © iDesign/Shutterstock and Image © ssuaphotos/Shutterstock
Page 69: Graphic © Rashad Ashurov/Shutterstock and Image © Paolo Bona/Shutterstock
Page 76: Graphic © WladD/ShutterstockImage and Image © Visionsi/Shutterstock

SCCS is a research partnership of British Geological Survey, Heriot-Watt University, the University of Aberdeen, the University of Strathclyde and the University of Edinburgh. Our researchers are engaged in high-level CCS research as well as joint projects with industry, with the aim of supporting the development and commercialisation of CCS in the UK and abroad. **www.sccs.org.uk**

SCCS

Scottish Carbon
Capture & Storage