elementenergy

Scotland and the Central North Sea

CCS Hub Study

Revised Final Report

for

Scottish Enterprise

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SCCS

Foreword by Scottish Enterprise

The International Energy Agency (IEA) has concluded that carbon capture and storage (CCS) is "the most important single new technology for CO_2 savings" from both power generation and industrial emitters. In order to achieve CO_2 reduction targets, IEA research shows that around 100 large-scale CCS projects would be needed by 2020, and over 3,000 globally by 2050 requiring investment totalling hundreds of billions of dollars over the next few decades.

We believe that Scotland can be at the forefront of developing CCS capabilities in Europe. We know that the offshore geography of the Central North Sea (CNS) means that CCS offers huge economic potential for Scotland in terms of storage and the potential for utilising CO_2 for Enhanced Oil Recovery (CO_2-EOR).

This report identifies that even without considering tax receipts, cautious CCS and EOR development scenarios could boost Scottish GVA by *ca*. £3.5 billion - and this figure could be doubled if early action is taken to establish the infrastructure that positions St. Fergus as one of the UK's CCS hubs.

With our world-leading oil & gas capabilities and our extensive on and offshore infrastructure, there is a real opportunity for Scotland to lead Europe in this field.

We commissioned this study to analyse the infrastructure requirements to develop the CCS sector in Scotland and create a CO_2 Storage Hub, focused on the CNS. We wanted to look at this in terms of both making best use of the available infrastructure and maximising the use of the extensive capabilities of the Scottish oil & gas supply chain.

The findings clearly demonstrate that Scotland has the potential to grow a CCS Industry organically, capitalising on the natural storage assets of the CNS and the associated infrastructure in parallel with the progression of planned CCS projects at Peterhead and Grangemouth. We believe that in combination with the substantial cost offsetting that could be achieved by utilising CO_2 for EOR, this can drive forward the industry and play a significant role in decarbonising both power generation and industrial sources in the UK and Europe.

Scotland's CCS assets

The key features of the Scottish CCS offer are:

- Multiple opportunities for CO_2 capture – Shell/SSE Peterhead-Goldeneye, Summit Power's Captain Clean Energy in the 2010s, plus other new build and retro-fit options that could be deployed in the 2020s.
- Abundant CO_2 storage capacity (tens of Gts) in the Central North Sea – the Goldeneye gas condensate field is an immediate possibility and it is likely that saline aquifers (such as the Captain sandstone saline aquifer) and many of the depleted hydrocarbon fields in the CNS can provide bankable storage capacity by the 2020s.
- Significant flexibility (or optionality) in terms of developing a CCS network rapidly, cost competitively, and with manageable investment risks. This includes opportunities for CO_2-EOR to offset CCS costs and leverage existing supply chains.
- The value of the additional oil recovered through CO_2-EOR (*ca*. 1.5 billion barrels) broadly matches the cost of implementing and maintaining a CCS network in the Central North Sea.

- At the same time Scotland would be able to meet its obligations in relation to the 2050 carbon reduction targets with an infrastructure legacy of a scale that would support UK- and European CCS.
- Existing infrastructure for CO_2 transport – Onshore pipelines connected to St. Fergus, such as Feeder 10, and well-mapped sea bed infrastructure provide an excellent starting point for full CCS deployment.
- A broad base of stakeholder support and relevant experience.

The analysis in this study identifies the key drivers of Scotland's CCS opportunities that stakeholders can influence as:

(i) Energy and climate policymaking (at the levels of individual businesses, Scotland, UK, Europe and UN), which will influence the underlying demand for CCS, technology development, and the risk profile of CCS projects and infrastructure.

(ii) The selection of Scottish CCS power projects under the current DECC CCS Commercialisation Programme and Electricity Market Reform is important for Scotland to develop a leading position in the 2010s.

- This will lead to the creation of "hubs" and "corridors" for infrastructure (onshore and offshore) that will reduce the timescales, risks, and overall system costs for CCS development.

(iii) Increasing the "capture readiness" of existing and potential new build large stationary sources of CO_2 (both power and industrial), as this will facilitate the expansion of a CCS network onshore in the 2020s.

(iv) Offshore, "storage readiness" will be driven by the creation of an attractive value proposition for storage, covering all steps from exploration, appraisal, development, operation and eventual transfer back to the State, in saline aquifers and depleted hydrocarbon fields (including for CO_2-EOR).

There is much work to be done and we welcome the recommendations for next step actions for Scotland made in this report and will take these forward along with other stakeholders and industry partners. The findings from this report will inform on-going discussion at different levels of the Scottish Government and other groups and organisations including the UK Government, European Commission and our Industry Leadership groups for both Oil and Gas and Thermal Generation and Carbon Capture and Storage.

Executive Summary

Carbon Capture and Storage (CCS) is a key technology for delivering Scotland, UK, European and global climate stabilisation objectives at least cost. In CCS, CO_2 from large power or industrial stationary sources is first captured, purified and then transported by pipeline and/or ship to deep underground rocks for permanent storage. As a variation, CO_2 injection into partially depleted oil reservoirs can also boost oil recovery and extend the life of these fields. CO_2-Enhanced Oil Recovery (CO_2-EOR) therefore provides a potentially valuable revenue stream for CCS projects as well as facilitating access to the existing supply chain.

There are many diverse challenges to developing CCS and CO_2-EOR. Recognising that infrastructure is a critical enabler for maximising the opportunities implied by the geological assets of the central North Sea (CNS). In early 2013 Scottish Enterprise issued an Invitation To Tender to carry out an impartial analysis of the infrastructure required to maximise the value of CCS and CO_2-EOR for Scotland. The project was awarded to a team led by Element Energy Ltd. and comprising Scottish Carbon Capture and Storage (SCCS), AMEC, and Dundas Consultants. This report and accompanying technical appendix represent the final deliverables from that study.

Scotland can kick-start and support large scale CCS in the UK and Europe.

The report finds that Scotland can deliver two large scale CCS projects within the 2010s, and has the potential to expand capture capacity rapidly in the 2020s. The CNS provides enough theoretical storage capacity to meet the aggressive UK and European scale CCS decarbonisation requirements for the foreseeable future (e.g. up to 2050). Some of the CO_2 transport, storage and enhanced oil recovery infrastructure required to kick start a CCS industry in Scotland is already in place. Scenarios for infrastructure that maximise the long-term opportunity for Scotland are proposed - these are well within the capabilities of existing supply chains, providing that suitable business and regulatory models can be developed quickly. The opportunities are summarised in the following table:

Table 1: Priorities for Scotland in the 2010s and 2020s

Infrastructure	Priorities in the 2010s	Priorities in the 2020s
CO_2 generation and CO_2 capture	Peterhead gas power retrofit New proposed "Captain" coal power station in Grangemouth Design studies and permits for other sites in Scotland	Operation of Peterhead and Captain Clean Energy Project New or rebuilt coal, gas or biomass power stations with CCS (or initially capture readiness), e.g. Hunterston, Longannet, Cockenzie or new/existing industrial sources retrofitted with CCS
CO_2 transport	Pipelines to service Peterhead and Captain Clean Energy projects. Future-proof St. Fergus gas terminal, Feeder10, Atlantic, Goldeneye, and Miller existing pipelines Detailed design and consenting for new infrastructure	New CO_2 pipelines and adapted existing natural gas pipelines CO_2 ship transport + port (e.g. Peterhead or near Forth)
CO_2 storage	Shell's Goldeneye gas condensate field Atlantic field/Captain sandstone aquifer area Saline aquifer appraisal Future-proofing of hydrocarbon fields	Appraisal and development of saline aquifers and hydrocarbon fields in Scottish CNS and beyond
CO_2-EOR	Selected EOR fields (data commercially confidential)	Development of anchor (and satellite) oilfields in the CNS

This summary and the main report are structured as follows: The study begins with a critical review of the opportunities for CO_2 capture at new and existing industrial CO_2 sites in Scotland. Building on this and current project plans, it identifies potential scenarios for CO_2 capture deployment in the UK and around the North Sea towards 2050. Next the study reviews storage capacity and the potential for CO_2-EOR in the Central North Sea, and identifies scenarios and opportunities for exploiting these storage and CO_2-EOR resources. Having identified source and storage configurations, the study identifies potential designs for the onshore and offshore infrastructure needed to collect CO_2 from sources and transport to stores, including the role of onshore and offshore clusters, existing infrastructure and hubs. Potential stakeholder interventions to overcome barriers to delivering the infrastructure that maximises the opportunities for Scotland are reviewed. Finally the report makes several recommendations for both Scottish Enterprise and other stakeholders to facilitate opportunities for CCS and CO_2-EOR.

Scotland has multiple opportunities for capture in the 2010s and 2020s

Scotland has at least two compelling opportunities for CO_2 capture that could be operational by the late 2010s, as well as more opportunities in the 2020s.

The two most promising opportunities for CO_2 capture in Scotland in the 2010s are the Shell/SSE Peterhead-Goldeneye CCS proposal (currently undergoing FEED study with DECC funding as part of its CCS Commercialisation Programme) and Summit Power's Captain Clean Energy Project (currently a reserve candidate in the same programme), assuming a new build power station at Grangemouth.

Figure 1: Locations and assets for Scotland's leading CCS project candidates

A technical review, based on publicly available data, has demonstrated that both the Shell/SSE Peterhead-Goldeneye and Summit Power's Captain Clean Energy projects are feasible. These projects involve experienced teams, the most mature technologies available, and locations that minimise risks and costs. They are therefore likely to provide good value for money either as part of the UK Government's CCS commercialisation programme, or through a contract agreed under Electricity Market Reform. Importantly, both these projects are ready for investment and pave the way for large scale / low cost roll-out of CCS in the UK. Both projects are robust to technical, consenting, regulatory or other evolving priorities. The rate limiting steps for both projects are securing finance and agreeing satisfactory contractual terms (risk sharing) between the project developers and the UK Government.

Looking ahead to the 2020s, other new build and retrofit capture opportunities are possible at the cluster of existing industrial or power sites in Scotland close to the Forth estuary. These capture projects are largely conceptual at present, but a high level analysis indicates technical feasibility. Making them real would require stakeholder engagement, followed by feasibility and cost studies. If implemented, capture levels in Scotland could grow from 2-4 $MtCO_2$/yr in 2020 to more than 8 Mt/yr in the late 2020s. This represents 16% of Scotland's

CO_2e emissions in 2011[1]. Early consideration of the requirements for capture should be taken to maximise feasibility and minimise future costs of installation at these sites. For site refurbishments, the site of the Longannet coal power station has already been confirmed as viable for both CO_2 capture and transport.

New build or retrofit of CO_2 sources at alternative locations in Scotland (greenfield or outside the Forth, e.g. Hunterston) are also feasible in the 2020s and beyond. These will likely require much greater stakeholder management at the outset to minimise consenting risks and secure a "social license to operate". New power generation is required in the UK to replace the ageing generation fleet. New fossil generators could locate in Scotland for ease of CO_2 transport and storage, and supply electricity to the rest of the UK. Any new large CO_2 point sources in Scotland should at least be built to a meaningful standard of capture readiness, and located close to the Forth estuary or St. Fergus corridors for ease of inclusion within potential future CO_2 transport networks.

There is abundant and "Ready" Storage capacity in the CNS

Offshore, Scotland has an abundance of geological storage under the Central North Sea (CNS), including numerous depleted hydrocarbon fields, large saline aquifers and numerous hydrocarbon fields reaching end of life which offer opportunities for CO_2 storage or storage combined with CO2 EOR. Onshore, Scotland has numerous capture opportunities onshore from new or existing power and industrial sources. There are multiple opportunities to link these sources with storage and CO_2-EOR through pipelines (existing or new, onshore and offshore) and/or shipping. There is already strong stakeholder support and experience for CCS, as well as supply chain capabilities across CCS and CO_2-EOR. Taken together, Scotland and the Central North Sea provide a compelling base for investment in CCS. This has been recognised by industry, as the majority of UK CCS projects proposed in the last decade take advantage of the diverse storage assets of the Central North Sea.

Several UK CCS deployment pathways consistent with the transition to a low carbon economy envisage a cumulative CO_2 storage capacity required in the low billions of tonnes (Gt) by 2050[2].

The theoretical storage capacity of CNS was estimated by SCCS in 2009 at 4.6 - 46 Gt, the range reflecting geological uncertainties that can be narrowed through future work. Subsequent, more detailed work by ETI arrived at a similar answer, with 40Gt calculated by building up individual reservoirs. That gives confidence in the fundamental accuracy of the original assessment. The ETI database, which is partly based on the earlier SCCS work, is now available at www.CO2Stored. This has been used throughout the present study, because of its greater detail and wider availability.

Based on the above, there should be sufficient capacity to meet the UK's needs up to 2050 using CNS stores. This would still leave capacity to satisfy a storage demand from neighbouring North Sea basin countries. However there is significant uncertainty on the performance of individual stores. Experience from the mining and the oil and gas industries suggests that not every theoretical opportunity can be converted to a safe and commercially viable store. Filtering the good stores from the bad requires detailed data and can be

[1] Based on emissions of 51.3 Mt/yr
http://www.scotland.gov.uk/News/Releases/2013/06/greenhousegasemissions07062013
[2] See for example:
http://eti.co.uk/downloads/related_documents/A_Picture_of_Carbon_Dioxide_Storage_in_the_UK(UPDATED).pdf

resource intensive and time consuming. Therefore site qualification through exploration, and appraisal activity will need to proceed in advance of demand. Lead times for storage development can span several years. The best understood site in the UK Continental Shelf (UKCS) for CO_2 storage is the Goldeneye gas condensate field in the Outer Moray Firth, for which detailed modelling by Shell has confirmed viability.

The CNS offers great geological diversity and a range of size opportunities for different types of operator giving impressive geological and business model resilience, with many types of storage available. This resilience can benefit the UK and European energy/carbon system as a whole, not just individual projects.

Given the greater distance from onshore sources (compared to the CNS), there is unlikely to be significant demand for Northern North Sea storage until the late 2020s at the earliest. However, additional storage and CO_2-EOR capacity in the Northern North Sea provides further backup and opportunity, and could also support scenarios where there is a combination of high CCS uptake and a high oil price with low availability of storage elsewhere (in the Southern or central North Sea, and onshore in Europe).

Measures to improve confidence in individual stores would be beneficial

For storage to pass Final Investment Decision, high confidence in the capacity of individual stores is required. The data gaps that must be filled to improve confidence will be site specific. They could include improved reservoir models, supported by acquisition of existing or new seismic and well log data, and for depleted hydrocarbon fields, production histories for each well. Information is dispersed, and access to good data may limit the quality and speed of decision making.

A “gold standard” would be to test local injectivity and subsurface flow, potentially using CO_2 itself, providing this could be sourced offshore at reasonable costs. The advantage of the organic development plans explored is that, theoretically at least, CO_2 test injections could be carried out as incremental modifications from initial projects. This would lower costs and challenges relative to standalone projects.

Incremental growth models are feasible for storage.

Different philosophies could guide the expansion of a CCS network. At one extreme, infrastructure could evolve incrementally or “organically”, where storage capacity grows from existing anchor stores as demand increases. At the other extreme, infrastructure could be master-planned at basin level with high integration in mind to maximise EOR potential or least system cost. The project has reviewed different development pathways, including linear “corridors” using St. Fergus gas terminal as a shoreline hub.

Because of the close proximity of storage sites to each other in the CNS, organic expansion in the 2020s is feasible for exploiting CNS storage capacity through use of stacked reservoirs or step-outs of less than 15 km. This conclusion is largely independent of initial project choice of store in the 2010s. To maximise opportunities, initial projects should include provision for additional infrastructure to test nearby stores (e.g. wells and seismic), and T-junctions to permit pipeline access.

As an example, if starting at Goldeneye (capacity > 20 Mt), expansion to the Captain sandstone saline aquifer (capacity *ca*. 150 Mt) and other saline aquifers, depleted hydrocarbon fields or EOR stores (such as Buzzard), stacked or within tens of kilometres, could deliver at least 1 Gt storage capacity (in aquifers and depleted fields). The CNS offers the opportunity for economies of scale, by using a limited number of pipelines, surface facilities and wells to access multiple reservoirs.

Given this flexibility, the choices for initial storage sites in the CNS for kick-starting a CCS industry can be left to the market. The high flexibility suggests little risk of industry choosing stores that "lock-in" a trajectory for limited CNS storage or EOR opportunities. . However, once an anchoring storage hub has been chosen, incremental growth of storage at least cost would need the appraisal, development and use of stores close to the initial store. Simultaneous use of CNS stores far apart from each other would, in general, raise system costs relative to a configurations where projects can share infrastructure.

To minimise long-term costs for the 2030s, developers should select large stores and maximise the use of these (as opposed to developing multiple small stores). CNS subsurface spatial master planning would be expected to become most valuable from the 2030s and beyond, with CCS deployment rates corresponding to many 10s of $MtCO_2$/yr. Forward planning is also essential for maximising the opportunity from CO_2-EOR

CO_2 EOR could create additional value for project developers, the UK Government and the Scottish economy

Analysis in this project reinforces previous conclusions[3] that with the early development of a UK CO_2-EOR cluster more than one billion barrels of incremental oil could be co-produced with the storage of at least 0.5 $GtCO_2$. The associated potential real pre-tax Net Present Value (NPV) from a UK CO_2-EOR cluster would be £4 bn @ $90/bbl (3.5% discount rate). If this is extended North Sea-wide the incremental production could approach three billion barrels, leading to pre-tax NPVs more than ten billion pounds. For many CNS oilfields, CO_2-EOR projects can be NPV positive under a wide range of plausible conditions. For example if there are suitable incentives for CO_2 capture and transport to allow CO_2 to be supplied for free at the platform, real oil prices are sustained above $90/bbl and the marginal tax rate is reduced for CO_2-EOR projects.

However, CO_2-EOR projects are complex, akin to new field developments. The development of an optimal integrated EOR cluster then becomes akin to managing the optimal development of a basin. The combination of CCS with CO_2-EOR creates novel project-on-project risks that need to be managed.

Industry investment in CO_2-EOR is likely to be most forthcoming if the goal of maximising the CO_2-EOR opportunity is articulated as a clear objective of the UK and other North Sea Governments. Attention can then be paid to locations, capacity planning, project sequencing, technical specification, taxation and ownership models. In the absence of this, and with some lingering scepticism over the value of CO_2-EOR by some stakeholders, the industry may delay meaningful investments until reliable CO_2 supply and regulatory environments are in place, If the capacity of CO_2-EOR only begins to ramp up in the mid-2020s, the risk then is that there is a limited window of opportunity to develop fields at low cost before they are expected to cease production by the 2030s.

[3] Element Energy *et al* for Scottish Enterprise (2012) The economic impacts of CO_2-EOR for Scotland.

Scotland offers multiple opportunities for CO_2 transport infrastructure

CO_2 transport system design is a driver of up-front and lifetime transport costs, flexibility, and a significant enabler for adoption of capture plant and storage sites. Scotland's options are new pipelines, re-used pipelines, CO_2 ship-based transport and combinations of these.

Given the long distances between sources and sinks, integrated (i.e. shared) pipeline networks, evolving as multiple sources or sinks are added over time, will be essential to maximise Scotland's opportunities beyond the initial Peterhead-Goldeneye or Captain Clean Energy projects. Topologically pipelines can be expanded through "tree and branch", "hub-and-spoke", "ring main" or hybrid structures. For these to be achieved at least overall system cost, opportunities for network expansion should be anticipated and incorporated in the design from the beginning, rather than as an afterthought. Public subsidies should explicitly include support for the incremental requirements of future proofing (e.g. "over-sizing" or T-junctions) as well as knowledge sharing on the operating conditions and performance of transport and storage infrastructure.

Shared integrated infrastructure creates a physical opportunity for one or more "hubs", i.e. nodes with multiple input or output CO_2 streams. Investment in hubs reduces costs, improves operational flexibility, and can reduce stranded asset risks.

Reusing existing pipeline infrastructure, originally developed for natural gas but that can be adapted for CO_2 transport, considerably reduces the up-front costs and simplifies the challenge of CO_2 transport from sources to sinks.

St. Fergus is a natural shoreline hub for CO_2 transport infrastructure

The geographic proximity of St. Fergus gas terminal, close to storage potential, existing pipeline infrastructure connecting St. Fergus with Peterhead and potential capture sites in the Forth, compression infrastructure and relevant skills base, makes this a natural shoreline hub for CO_2 pipeline infrastructure in Scotland.

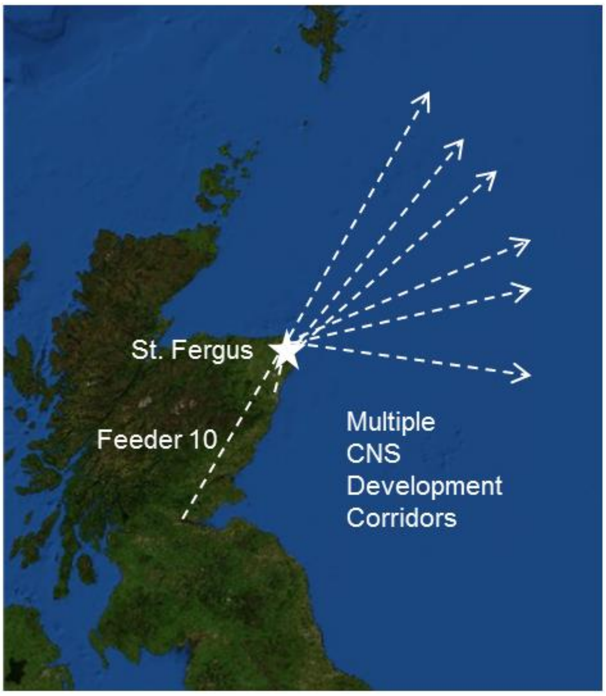

Figure 2: St. Fergus gas terminal provides access to multiple development pathways, using existing or new pipeline or shipping infrastructure via Peterhead, that can be linked to potential CO_2 storage or CO_2-EOR locations in the CNS and NNS.

The existing Feeder 10 pipeline can connect CO_2 sources in the Forth estuary with St. Fergus gas terminal

The National Transmission System Feeder 10 pipeline is a valuable asset for Scotland, and needs to be maintained so as to be readily available for CCS in the 2010s or 2020s. Feeder 10 has been fully validated through extensive FEED study, for capacity up to 2.5 Mt/yr transport of CO_2 from Avonbridge to St. Fergus, with a predicted capital cost of £77m to make the pipeline fit for transporting gas phase CO_2. The existing pipeline should be capable of supporting throughput up to 7 $MtCO_2$/yr with modest intermediate boosting, and up to 10 $MtCO_2$/yr if significant boosting capacity is added.

Existing offshore pipelines should be assessed, and if necessary maintained, for CO_2 performance.

There are dozens of existing high pressure gas pipelines in the CNS, and many ought to be available for re-use for CO_2 transport. The operating conditions for re-use (in particular the pressure) may be constrained relative to new pipelines. The St. Fergus-Goldeneye and St. Fergus-Miller natural gas pipelines have both previously been considered for CO_2 transport in detail, and should be available for re-use *providing they are maintained appropriately*. However, there are currently no financial incentives or other mechanisms to ensure that these assets are maintained in a manner that permits future use with CO_2.

CO_2 shipping adds flexibility

CO_2 shipping capacity adds value by substantially improving the flexibility of CCS development in the UK, Norway or elsewhere in the EU. Co-ordination of stakeholder activity would be required in the 2010s to build a market for CO_2 shipping capacity in Scotland in the 2020s.

A CO_2 import/export shipping hub in Scotland, for example at Peterhead Port or Hound Point (Forth), is technically feasible. Direct investments in Peterhead Port to support CO_2 ship transport would cost *ca*. £3m. In addition CO_2 pipelines (ca. £2-5m) and temporary CO_2 storage infrastructure would be required. Further work is required to understand the needs for and best ways to develop temporary storage (onshore, port-based or near shore), and the appropriate sequencing of investments for growing capacity over time.

If CO_2 shipping involves direct offshore injection, then compatible designs with new or existing platforms, subsea or floating facilities are required.

CCS network development

The literature and this study identify that a large number of plausible offshore infrastructure development scenarios for CO_2 transport, storage and EOR in the central North Sea can be developed to meet different levels of CCS and CO_2-EOR deployment.

Uncertainties on the locations, capacities and timing of capture and storage, and the need to manage specification (CO_2 composition, pressure and flow rate) place significant constraints on the transport network's design. The study does identify plausible phased pathways for offshore infrastructure that deliver capacity across a wide range of CCS and CO_2-EOR deployment at manageable costs.

A CCS development profile consistent with the UK meetings its 80% climate target at least cost through maximising the role of CO_2-EOR is shown below. Given the long distance of the largest oilfields from potential CO_2 sources, the topology, locations, capacity and phasing of a CO_2-EOR network would need to be planned to minimise costs.

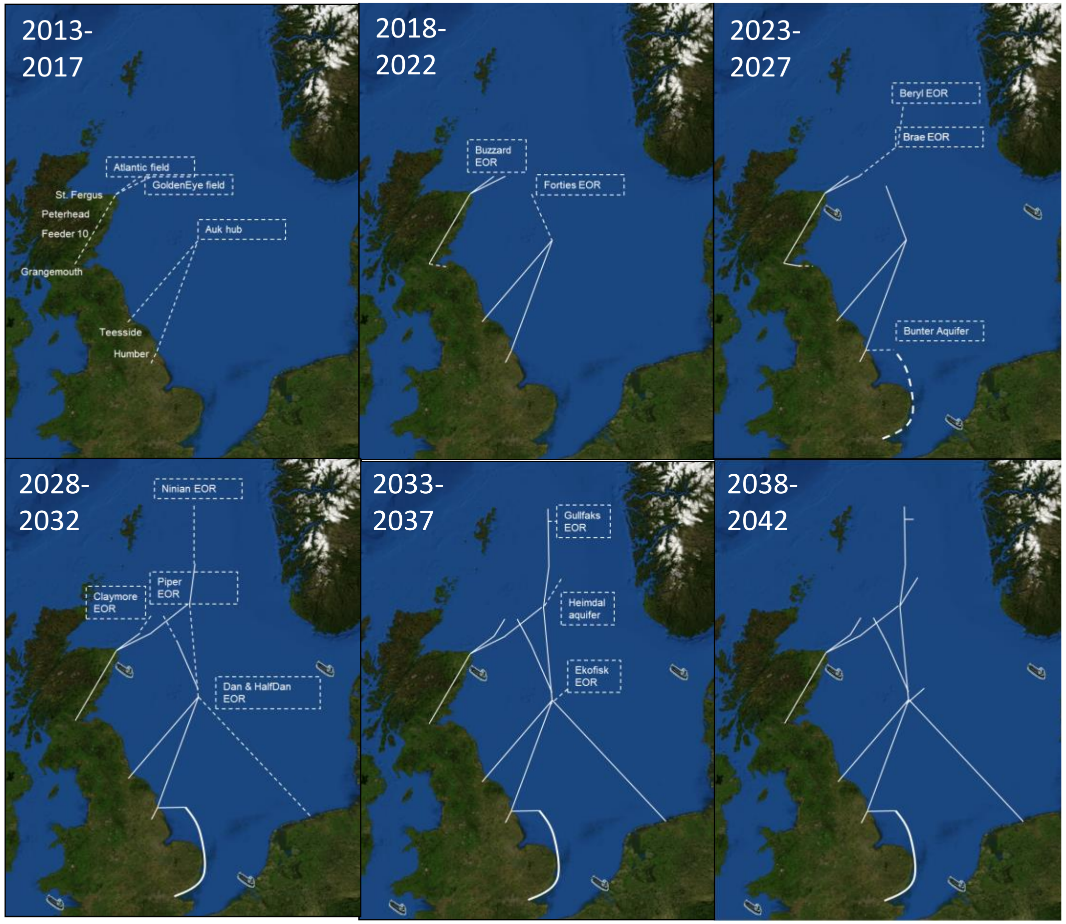

Figure 3: Phased infrastructure growth for the Aggressive Scenario indicating investment needs in six 5-year phases from 2013-2042.

It is possible to meet UK and European demand for CO_2 storage capacity in the period to 2050 with transport networks that are predominantly focussed on the CNS. Capture projects established in Yorkshire, Teesside or European hubs can make use of the CO_2 storage opportunities in the central North Sea through one or more new trunk pipeline connections – for which costs are likely to approach £0.5 bn, depending on exact length and diameter. On the basis of public data, the Forties oilfield provides the largest single CO_2-EOR opportunity and is close to other EOR candidates, making this part of the North Sea a logical offshore hub if the objective is to develop a CO_2-EOR cluster.

In the absence of CO_2-EOR, several locations within the CNS provide opportunities to anchor network development through the use of storage clusters, which can develop organically. As an example, expansion of storage from the Goldeneye gas condensate field and the Captain sandstone (a saline aquifer that has been well studied) provides access to many Gt of theoretical storage capacity in both hydrocarbon fields and saline aquifers that are in close proximity.

By helping to meet CO_2 targets, any future-proofed CO_2 pipeline network would be of national and European significance, and policy and financing mechanisms should evolve to reflect this. Importantly some of the benefits of capacity in CO_2 transport and storage infrastructure are market externalities, i.e. accrue to multiple current and future users and reducing overall energy system costs and risks –but not translating to sufficient revenues in early years to justify private investment.

Economic benefits for Scotland

Investment in CCS in the period to 2050 will result in direct, indirect and induced economic value to the Scottish economy. A high level analysis suggests the investment in CO_2 compression, pipelines, storage and EOR infrastructure corresponding to an aggressive scenario would lead to a direct GVA boost to Scotland of *ca*. £7 billion, excluding revenues (or taxes) from CO_2-EOR. The associated number of direct, indirect and induced jobs in Scotland associated with infrastructure would rise to a peak of 2000 in the 2040s, with a cumulative 44,000 person years of employment. This excludes jobs created or preserved associated with CO_2 generation or capture, or otherwise preserved in the oil industry through extended life of North Sea oil and gas industry.

If the level of CCS uptake is more limited (e.g. the “cautious” scenario described in this report), comparable boosts to Scotland’s GVA and jobs could be achieved if a pipeline hub for UK CCS infrastructure is established at St. Fergus to connect sources with storage or EOR in the CNS.

Discounted GVA for Scotland (£m, 2013-2047)	Aggressive CCS with CO_2-EOR	Cautious CCS, Limited EOR	Cautious CCS with St. Fergus Hub
Direct	£7 bn	£3.5 bn	£7 bn
Indirect	£5 bn	£2.5 bn	£5 bn
Induced	£4 bn	£2 bn	£4 bn
Cumulative person years (direct + indirect + induced 2013-2047)	44,000	22,000	45,000

Alternative business and regulatory models could drive more efficient CNS investment

Experience from the oil and gas industry suggests careful attention must be given to managing the risks related to volatile revenues and subsurface performance, carbon price and the design and stability of regulatory landscape.

A robust strategy would include funnelling a portfolio of stores through stage gates, as recommended by DNV. Few developers are maturing CO_2 stores, and individual companies are understandably keen to keep site details commercially confidential.

The current UK Government and EU's preferences for project-by-project competitive approaches, provide insufficient price signals and substantial risks for commercial developers of storage. Consequently there is a shortage of commercial storage development activity. This approach is not well suited to efficiently (i) developing backup capacity to minimise risks, (ii) developing CO_2 storage in stacked clusters, (iii) exploiting saline aquifer formations with very large areas, where pressure footprints and CO_2 migration may need to be managed, or (iv) progressing the development of a CO_2-EOR cluster.

Based on analogies with other industries and from stakeholder interviews over the course of this project, to deliver the most ambitious CO_2 transport and storage infrastructure growth rates at least cost would require a significant additional number of strong long-term price signals for CCS, alternative risk-sharing models, and/or the use of more interventionist approaches to decision making and investment. One example is the creation of a CNS regulated monopoly for transport and storage, funded partly by industry and, at least, initially the public sector, which could facilitate investment across multiple electoral and economic cycles.

As any CO_2 network topology becomes more complex, there would be additional value in supporting a forward market for trading capacity over short and long timescales. This "virtual hub" function may emerge organically in the 2020s, and is unlikely to warrant SE intervention in the 2010s.

Recommendations for Scotland

The study has illustrated that all the components are either in place, or can be readily developed, for Scotland to become a major CCS hub, supporting UK and European CCS deployment.

The CNS has by far the UK's largest variety of stakeholder interests, legacy facilities (pipelines, platforms and wells), potential physical and commercial/regulatory configurations for CCS development. This leads to a wealth of opportunity for established North Sea operators as well as new entrants. That demands leadership and flexibility, which Scotland is ready and willing to deliver.

If Scotland wishes to be a European leader in CCS, then efforts to champion CCS projects, and develop infrastructure for EOR, power and industry in the UK and Europe should be stepped up immediately and continue during the 2010s as follows:

Support for early CCS demonstration in Scotland

1. As CCS demonstration is critical, Scotland should continue to support early CCS demonstration, particularly development for the Shell/SSE Peterhead-Goldeneye and Captain Clean Energy projects which are well designed projects, ready for further investment. The Thermal Generation and CCS Industry Leadership Group can help create a common message together with hydrocarbon operators in support of these projects.

Maximising the UK and European market for CCS in the 2010s and 2020s

2. As the total opportunity for Scotland depends on the total market, Scotland should support and encourage UK and European funding for multiple CCS demonstration projects in the 2010s and early 2020s with designs that facilitate rapid capacity expansion, and a supportive legal and regulatory framework.

Supporting infrastructure that targets the CNS

3. Linkages should be facilitated between existing or planned CCS and CO_2-EOR projects around the North Sea, increasing the opportunities of appraisal and pipeline infrastructure targeting the CNS. SE can promote the proposition through its European networks and existing CCS stakeholder fora.
    - This could include working with stakeholders in Europe to identify and develop a market for CO_2 shipping, in advance of physical investments in a CO_2 import/export terminal.

Improving CCS readiness and optimising infrastructure

4. Continued awareness raising and improved understanding, including providing support measures, to fully inform stakeholders, such as planning authorities and regulators, in respect of the CCS infrastructure opportunities in Scotland, is key to successful early deployment.
    - Support for further characterisation and simulation of the diverse storage and EOR storage sites is essential to ensure the best stores are developed and to provide investors with confidence that storage performance can be managed.
    - National planning frameworks could be used to establish preferred zones or corridors for CCS infrastructure, particularly around the Forth, Feeder 10 pipeline route and St. Fergus Gas Terminal.
    - Existing large stationary sources should be encouraged to examine the feasibility of CO_2 capture and transport at their sites and to take steps that improve their CCS readiness where appropriate.
    - The close proximity of stores in the CNS provides opportunities for rapid expansion of capacity at reduced risk (due to high redundancy) and lower cost (due to high potential for infrastructure sharing) once an initial anchor project is chosen. Industry and SE should evaluate and publish detailed analysis of the infrastructure, economics, leasing/licensing structure and risk profile for the appraisal, development and operation of a CNS storage cluster, where stores are in close proximity/overlapping.
    - Marketing materials should support greater interaction between CCS project developers in the UK and Europe with oil and gas companies and their supply chains based in Scotland, as these could provide CO_2 storage or EOR services.

5. Industry in partnership with SE and key stakeholders should support detailed studies of the engineering, regulatory and commercial requirements for the future-proofing and re-use of onshore and offshore pipelines, wells, platforms and sub-sea facilities to speed up the development of and reduce the costs of CO_2 transport, storage and EOR in the CNS. This could include:
    - Experimental trials of individual assets (e.g. pipelines and wells)
    - Management of performance and liabilities of assets in the period between use for hydrocarbon production and transport and CCS.
    - Decommissioning and abandonment specification for hydrocarbon fields, which has the potential to impact future costs of CCS or EOR.
    - More detailed engineering studies (at Pre-FEED and FEED level) for CCS shoreline hub infrastructure at Peterhead, St. Fergus, or in the Forth (e.g. Hound Point and/or Grangemouth).
6. SE should continue to facilitate dialogue between North Sea oil and gas companies and their supply chains, CO_2 storage or EOR service providers, capture project developers and other CCS stakeholders.

Improving the commercial attractiveness of CO_2 transport, storage and EOR

7. Currently there are significant hurdles for commercial investment in transport, storage or EOR infrastructure, implying real risks that without further intervention, infrastructure investments made in the 2010s and 2020s will be inefficient. Scottish Enterprise should therefore continue collaborate with stakeholders such as DECC, The Crown Estate, The North Sea Basin Task Force, ZEP and European Commission to strengthen the markets for CO_2 transport, CO_2 storage and CO_2-EOR.
    - The solutions needed to maximise the CNS opportunity will likely involve a mix of stronger price signals, innovative business and regulatory models such as joint ventures and regulated monopolies, fiscal incentives, and leasing and licensing regulations that encourage first movers, promote long-term efficient use of resources available.
    - This should include analysis of models in other industries, notably the designs and licensing/financing/tax models for a regulated monopoly, public-private joint venture for infrastructure, which could accelerate CCS and CO_2-EOR deployment in the CNS.
8. When ready, the results emerging from the CO_2-EOR Joint Industry Project, notably the recommendation for the introduction of a structured field allowance and a waiver of PRT for the first CCS with CO_2-EOR projects, should be reviewed with the UK Government, North Sea Basin Task Force and the PILOT taskforce and considered along with recommendations from the Wood interim report.

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1 Introduction

Large scale deployment of Carbon Capture and Storage (CCS) is expected to reduce the cost of decarbonising the UK[4] and global[5] economy by at least 50%, and provide significant flexibility in meeting challenging climate targets. In CCS, CO_2 is captured from power stations and industrial sources, transported for injection through wells for permanent storage deep underground.

The UK Government has recently responded positively[6] to conclusions from the CCS Cost Reduction Task Force[7] that a combination of early CCS demonstration, appropriate design of CCS infrastructure, and a supportive policy and regulatory environment would significantly reduce the costs of CCS. CCS is currently in its infancy, but the cumulative global market size for CCS in the period to 2050 has been estimated in the trillions of pounds.

Scotland is well positioned to support efficient CCS demonstration and deployment[8]:

- (i) Several large scale and full chain CCS projects in Scotland have already been proposed by industry.
- (ii) There is an abundance of CO_2 storage and CO_2-Enhanced Oil Recovery (CO_2-EOR) potential in the Central North Sea.
- (iii) Existing pipeline infrastructure onshore and offshore could be re-used for CO_2 transport.
- (iv) Existing and proposed large CO_2 sources derived from coal, gas or biomass power, and industrial processes, which could provide cost-effective opportunities for CO_2 capture.
- (v) Political and industry support, organisation and experienced supply chains to facilitate implementation of CCS and CO_2-EOR projects.

Importantly, the engineering designs, cost, performance, HSE, and risk profile of several CO_2 generation, capture, transport, storage and EOR assets in Scotland and the central North Sea are well understood – and some assets are available for use now - which significantly reduces risks for public and private investors.

Scottish Enterprise has been working to support the development of CCS in Scotland since 2005. Recognising that choices on the design, capacity and location of CCS projects and infrastructure for near-term demonstration projects could significantly impact the costs, speed and ease of CCS and CO_2-EOR medium-term and longer-term deployment in Scotland, the UK and in Europe, Scottish Enterprise issued an ITT in January 2013 for an

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[4] ETI (2012) Energy System Modelling, see for example http://www.ukccsrc.ac.uk/system/files/uploads/Gammer%20Deployment%20of%20Coal.pdf or http://eti.co.uk/downloads/related_documents/2012_12_10_GD_Modelling_the_UK_energy_system_FINAL.pdf
[5] IEA (2013) Updated CCS Roadmap, available at http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapCarbonCaptureandStorage.pdf
[6] https://www.gov.uk/government/publications/ccs-in-the-uk-government-response-to-the-ccs-cost-reduction-task-force--3
[7] Cost Reduction Task Force (2013) Final Report https://www.gov.uk/government/publications/ccs-cost-reduction-task-force-final-report
[8] NSBTF (2010) One North Sea, available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2010/08/OneNorthSea.pdf; SCCS (2008) Opportunities for CO2 storage around Scotland, available at http://www.scotland.gov.uk/Resource/Doc/270737/0080597.pdf; SCCS (2011) Progressing Scotland's opportunities, available at http://carbcap.geos.ed.ac.uk/website/publications/progressingscotlandco2/ProgressingScotlandCO2Opps.pdf; Scottish Enterprise (2012) Economic Impacts of CO_2-Enhanced Oil Recovery for Scotland available at http://www.scottish-enterprise.com/~/media/SE/Resources/Documents/DEF/Economic%20Potential%20of%20CO2%20EOR%20in%20Scotland.pdf

independent assessment of the potential for CCS infrastructure in and around Scotland. In March a team led by Element Energy and comprising Scottish Carbon Capture and Storage, AMEC and Dundas Consultants were awarded the contract, based on a proposal to review:

- The potential for CO_2 capture in Scotland
- CO_2 storage capacity in the Moray Firth, central North Sea (CNS), including storage combined with CO_2-enhanced oil recovery.
- CO_2 pipeline infrastructure - onshore Scotland and offshore in the central North Sea
- The potential for a hub, for example the use of Peterhead Port for CO_2 shipping and/or St. Fergus gas terminal for CO_2 pipelines.
- The economics, and business and regulatory models for CCS infrastructure

This final report represents the final deliverable from the study, and is based on a combination of literature review, technical analysis, and stakeholder interviews.

The report is structured as follows:

Section 2 presents a review of drivers for CCS in Scotland and the Central North Sea.

Section 3 identifies the opportunities for CO_2 capture in Scotland

Section 4 examines the CO_2 storage options available in the Central North Sea region

Section 5 considers opportunities and challenges for CO_2 transport onshore in Scotland

Section 6 reviews lessons from the North Sea oil and gas industry to identify CO_2 transport, storage and EOR infrastructure needs.

Section 7 describes in detail attractive scenarios for the development of CCS infrastructure in Scotland, highlighting in particular the unique attractions of the central North Sea

Section 8 provides a perspective on the economics and risk profile of CCS projects and infrastructure in Scotland.

Section 9 provides examples of potential business and regulatory models to facilitate development of CCS infrastructure in the central North Sea.

Section 10 presents the conclusions from this study, including recommendations for Scotland.

Accompanying this draft report is an extensive Technical Appendix that provides further description of the analysis and assumptions described in this report.

2 Drivers for CCS in Scotland and the central North Sea

Multiple factors will influence the uptake, configuration and economics of CCS in Scotland and the wider North Sea region. These are summarised in Figure 4, which attempts to structure these in terms of timescale and the degree to which they can be influenced by Scotland.

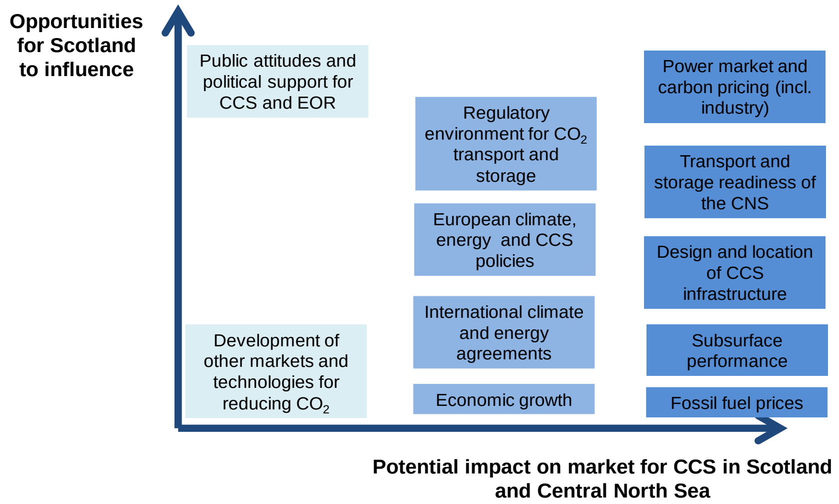


Figure 4: Stakeholders in Scotland can have some influence over several of the diverse factors that could control CCS and EOR adoption in Scotland and the CNS.

This chapter elaborates the main drivers, beginning with near-term drivers (up to 2020) and concluding with drivers that play out to 2050.

2.1 Near-term drivers (Up to 2020)

2.1.1 UK CCS commercialisation programme

The most important driver for CCS in Scotland in the short term is DECC's CCS Commercialisation Programme. The UK CCS Commercialisation Competition was developed partly to ensure that CCS is available to support the UK's legally binding target of reducing CO_2 emissions by 80% by 2050[9]. The Treasury is making available £1 billion capital funding, together with additional revenue support through the Contract-For-Difference Feed-in Tariff (a cornerstone of UK Electricity Market Reform), to support the practical experience in the design, construction and operation of commercial-scale CCS[10]. This will support multiple objectives:

- generate learning that will help to drive down the costs of CCS
- test and build familiarity with the CCS specific regulatory framework
- encourage industry to develop suitable CCS business models
- contribute to the development of early infrastructure for carbon dioxide transport and storage

[9] See http://www.legislation.gov.uk/ukpga/2008/27/contents
[10] https://www.gov.uk/uk-carbon-capture-and-storage-government-funding-and-support#ccs-commercialisation-competition

- demonstrate to a global audience the contribution that CCS could play in addressing climate change

DECC announced its two preferred projects in spring 2013 as:

- The proposal by Shell and SSE for retrofit CO_2 capture at the existing Peterhead gas power station with storage. This will likely use Shell's Cansolv post-combustion technology with pipeline transport of ca. 1 Mt/yr CO_2 for permanent storage in the well characterised Goldeneye gas condensate field.
- The "White Rose" project, comprising the Capture Power JV (Drax, Alstom, Linde and National Grid Carbon), for oxyfuel capture at a new coal power station at the Drax site in Selby, with pipeline transport of *ca*. 2 Mt/yr CO_2 to an aquifer in the Southern North Sea that is currently being appraised.

DECC has announced contracts for Front-End Engineering Design (FEED) studies for the Capture Power White Rose and Shell/SSE Peterhead-Goldeneye projects. It is unclear if the £1bn capital subsidy would be enough to support two full scale CCS projects - any requirement to provide contingency funds would make this very challenging indeed. However if both projects were sanctioned in 2015, then, allowing time for FEED, consenting, procurement, stakeholder consultations, contract negotiation, detailed design, construction, the earliest commissioning dates for each project would be 2018. Start dates closer to 2020 may be more likely given the novelty of the process.[11]

In addition, two "reserve" projects have been announced by DECC, in case the preferred projects are unable to move positively with FEED:

- The Captain Clean Energy Project, a proposal by US-based Summit Power to build a new IGCC coal power station in Grangemouth with CO_2 transport, via the existing Feeder10 pipeline, to the Aspen hub in the Captain sandstone saline aquifer, potentially followed at a later date by CO_2-EOR.
- Progressive Energy's proposal to build a new IGCC coal power station in Teesside with CO_2 transport via a new pipeline to the central North Sea initially for CO_2 storage in an aquifer, followed later by CO_2-EOR.

Additionally, the Don Valley Power Project, developed by 2CoEnergy[12], is well advanced, having already carried out the bulk of FEED analysis. This would involve construction of a large (900 MW) IGCC coal power station with transport of 5 $MtCO_2$/yr to the CNS for CO_2-enhanced oil recovery.

Whilst significant efforts went into developing Captain Clean Energy, Teesside Low Carbon and Don Valley Power projects, they are effectively now stalled and awaiting a stable positive environment created under Electricity Market Reform. It is not clear how "patient" the backers of these projects will be. It is likely that if they are developed, the technical and commercial configurations of these projects may change over time, in line with UK, European and industry funding and regulatory priorities[13].

[11] White Rose is the only CCS project nominated for Phase II of the EU NER300 CCS competition; if successful this would likely provide revenue support to that project on a "Euro per t CO_2 stored" basis.
[12] In co-operation with National Grid, Siemens, Linde BOC, Samsung C&T, Foster Wheeler, TPG, and Talisman Energy.
[13] £12m direct funding has recently been awarded through the "Tees Valley City Deal" part of which is to complete feasibility works and identify the best option to take forward an industrial CCS network. https://bdaily.co.uk/industrials/13-12-2013/tees-valley-city-deal-to-secure-12-million-investment-and-deliver-3500-jobs/

The CCS commercialisation programme involves a novel and competitive framework. Judging from the number and quality of applications, it appears that the capture-technology and fuel-neutral approach employed is an improvement over the technology-specific UK and European competitions held previously. Multi-stage competitive procurement approaches suffer from a paucity of sellers in the final phases to drive down costs and may unwittingly lock-in project designs early, reducing the opportunities for either CCS buyers or sellers to innovate in a very dynamic and evolving market. However, to date, no clear mechanism for a more co-operative approach for selecting and designing CCS projects has been established.

2.1.2 Political support

With lead times of potentially a decade between project conception and operation, for many energy/climate investments, Scotland has long appreciated the challenge in building and maintaining political support at all levels for investments in new low carbon energy industries.

At the micro level, this includes ensuring the needs of local populations that have real or perceived impacts from projects are identified and respected – for example by making careful choices on the locations and design of projects from an early stage. At a macro level, there is an on-going need for a stable, supportive economic and regulatory framework, with a strong UK supply chain, to underpin a long-term business plan for the CCS industry as a key pillar of the decarbonisation strategy for Scotland, the UK and globally.

The developers of the original BP/SSE Peterhead DF1 gas CCS proposal, the Longannet coal CCS proposal, and stakeholders in Teesside, the Humber and Rotterdam, have emphasised the immediate and longer-term local economic, environmental, and employment benefits from their CCS initiatives. In contrast, the experiences of Barendrecht (the Netherlands), Hunterston (Scotland), Kingsnorth (England), and Janschwalde (Germany) offer cautionary tales of where lack of local and/or environmental NGO support contributed to CCS projects being abandoned. Not all environmental NGOs support CCS, but several that do are likely to prefer CCS retrofit projects over new build fossil plants, and storage only projects over EOR projects. Local groups will prefer developments that resemble “business as usual”, or combine positives such as local job creation with limited negative local impacts.

2.1.3 CCS Project Requirements

Despite many tens of CCS project proposals worldwide in 2010, barely a handful of new large-scale integrated CCS projects will enter into operation before 2020. Many proposed CCS projects have been delayed, for diverse reasons. Deliverability is an important driver, beyond simple public subsidy. Expectations and lessons of technology innovation and project delivery in other sectors are relevant and have been well documented, so only CCS-specific issues are described here. To pass final investment decision, and to ensure timetables are met, the first CCS projects will require:

- A reliable source of CO_2 generation, based on either an existing source with high load factor or new build generation based on established design (including a strike price that allows for a competitive position within the merit order of GB electricity generators).

  - Some of the older CO_2 emitters may have limited visibility on the extent to which they will continue to operate, with or without CCS.
- Investable capture technology, e.g. where processes and process integration have been demonstrated in a similar operating environment and/or at a scale close to the intended plant output before final investment decision (FID) needs to be made.
- CO_2 transport route where all relevant consents are in place or can be delivered.
- CO_2 storage in sites that are sufficiently well understood and considered to provide safe, "permanent" storage, resilient to evolving regulatory environment.
- A project team with proven ability to deliver complex multi-stakeholder multi-billion pound construction projects on time, on budget, and to desired specifications.
- Sustained political support at all levels to overcome project barriers.
- A compelling value proposition (business model), with a credible source of finance, where investor returns are robust across changes in the project and environment, and where risks are allocated to those best able to manage them.
- Successful organisation, culture, and communication across multiple disciplines.

Evidence from other novel industries, and anecdotally from CCS projects suggests that insufficient consideration of these issues up-front leads to sub-optimal design, weak momentum and fragile support for projects.

Though still challenging, a number of factors make project sanction and sign off more likely under the DECC CCS commercialisation programme than previously. Arguably most important, among NGOs, the energy industry, and across the UK and Scottish Governments, and in Europe, there is a much better appreciation of the needs for CCS project and infrastructure development. The shortlisted projects have been put forward by Shell/SSE and Summit Power, who have experience in CCS project development. The broader regulatory and market frameworks for power, carbon emissions, and CO_2 storage are now more conducive to CCS investments. Developers can now draw on much more independent research into capture, transport and storage, and evidence from other projects worldwide. Uniquely, Scotland also has assets in the form of existing pipelines, platforms, wells and a reservoir, which have been validated as "CCS ready", reducing both the up-front cost and risks for investment.

2.2 Medium-term drivers (2020-2030)

The recent joint Government/industry Cost Reduction Task Force report echoes previous findings that the main drivers of CCS cost reduction in the UK in the 2020s will be:

- Economies of scale in CO_2 generation and capture
- Economies of scale in use of shared transport and storage infrastructure
- Reducing the cost of capital, through reducing technology, site and value chain risks
- Process optimisation and the use of next generation capture technologies, as these may reduce energy penalties
- Learning by doing, as developers, regulators, investors, the supply chain, and wider stakeholders will be able to optimise responses based on actual experience.

Looking to the period 2020 to 2030, the main drivers for Scotland will be based around public policy, infrastructure, stakeholders' willingness to demonstrate and deploy CO_2-EOR (which will be linked to oil prices, taxation levels and competing oil investor options) and the stakeholders' perceptions around CCS.

2.2.1 Policy Drivers

Whilst currently many of the policy levers for CCS development (including the carbon price floor, electricity market framework, CO_2 storage policy) are controlled at UK level, and some investments will also be directed at EU level, there are opportunities for stakeholders in Scotland to influence the details of:

- Further reforms to Scottish, UK, European and global energy and climate legislation, including carbon pricing (CPF, the EU ETS), targets (e.g. carbon budgets), emissions performance standards.
- CCS-specific regulation and legislation, for example
  - Evolving UK regulatory environment for capture, transport and storage
  - the CCS Directive (which sets out conditions for storage, third party access rules for infrastructure, mandates CCS Readiness examinations for new build power stations above 300 MW, and allows full chain projects to be considered single installations within the ETS).
  - Other market interventions, such as public private joint ventures or regulated monopolies for transport and/or storage.
- Broader economic policies which underpin growth in energy demand and the environment for new or re-investments in fossil power stations and carbon intensive industry the UK (including in complementary technologies such as renewables and nuclear).
- Oil economics and infrastructure, (including tax levels for CO_2-EOR, and the overall UKCS operating environment as discussed in the Wood interim report[14])
- Success with the first CCS commercialisation candidates
- Market interventions, such as the creation of new institutions or organisations to deliver CCS.

2.2.2 Stakeholder co-operation support

By analogy with other energy technologies (nuclear, wind farms, bioenergy, fracking etc.), the "perceived" success/failure of CCS in the UK or elsewhere could have potentially disproportionate knock-on impacts on the pace and strength of the above policy drivers and stakeholders' willingness to propose or work with (or against) CCS projects in Scotland. Stakeholders in CCS projects in Scotland may benefit from co-ordinated and pro-active messaging to win political and public support for projects and infrastructure.

CCS investments will compete in a crowded market alongside other energy infrastructure. Configurations for CCS including depleted hydrocarbon fields for storage or CO_2-EOR face additional challenges. The willingness of oil companies to share data or invest resources in making plans for storage or CO_2-EOR cannot be taken for granted. CO_2-EOR projects will compete for investment and support with perceived cost-benefit profiles for "storage only" projects, other tertiary recovery technologies in the North Sea, and other opportunities for oil investors.

[14] https://www.gov.uk/government/news/uk-offshore-oil-and-gas-sir-ian-woods-interim-report-published

2.2.3 Infrastructure

The drivers for the growth of a CCS network will contrast with those of oil and gas. In oil and gas, the sequence is generally a “giant” discovery which needs to be developed quickly – the associated transport infrastructure then anchors a network. Since projects are generally only developed if they are economic even at low oil and gas prices, many upstream projects generally allow for sizeable value capture (i.e. profits) along the chain, even without complete optimisation and even with high marginal taxation rates.

In contrast, the UK’s CCS industry may ramp up gradually, beginning with small (1-2 $MtCO_2$/yr) projects, eventually ramping up over decades to capacities which could be in the region of 100+Mt/yr. Projects will be (at least initially) subsidised (as opposed to being heavily taxed). However there are no guarantees on the level or timing of utilisation. The potential for lack of CO_2 supply or CO_2 storage underperformance create significant revenue risk and therefore stranded asset risk for new infrastructure. The costs and risks of (re)developing existing or new CO_2 transport and storage infrastructure, and leasing/licensing frameworks, are likely to drive any system evolution.

To achieve DECC’s aims of ensuring CCS technology is available as a cost competitive option by the 2020s, the choice and designs of the early CCS projects should support medium-term development of CCS technology and infrastructure in the UK.

Other medium-term drivers for CCS include the availability of well characterised storage site(s), existing infrastructure available for re-use, leasing/licensing and regulatory arrangements, and pilot studies at specific sites for capture and storage. With close ties to companies in the oil and gas service industries in the North Sea, Scotland can influence the availability of assets for re-use with CCS.

2.2.4 CO_2-EOR economics

The period 2020-2030 is critical for the development of CO_2-Enhanced Oil Recovery in the UKCS. The combination of high oil price (sustained above $90/bbl) and a favourable tax regime could see a significant role for CO_2-EOR if there is a reliable supply of CO_2 and appropriate transport infrastructure. The opportunities for CO_2-EOR have been comprehensively reviewed recently3 and are described further in subsequent chapters.

2.3 Long-term drivers (2030-2050)

Looking beyond 2030, the principal drivers for CCS in Scotland will be the relative costs of CCS, carbon prices, and the overall volume of CO_2 abatement required through CCS, and any remaining CO_2-EOR potential. Based on its energy system model “ESME”, the Energy Technologies Institute expects that large scale (>60 $MtCO_2$/yr) deployment of CCS in the UK from the 2030s would halve the costs of decarbonising the UK economy, whilst maintaining considerable flexibility in fuel source and end use applications. The figure for the reduction in decarbonisation costs is consistent with the International Energy Agency’s calculations for the costs of decarbonising globally.

2.4 Options for CCS in Scotland

Table 2: Most relevant options for CCS in Scotland and central North Sea

Infrastructure	Near Term Options (up to 2020)	Medium Term Options (2020-2030)
CO_2 generation	Near term - Existing Peterhead gas power station New Summit coal IGCC 570 MW power station in Grangemouth Potential for new build power stations in Yorkshire or Teesside	Other new coal, gas or biomass power stations with CCS Existing Scottish power stations that are refurbished or industrial sources retrofitted with CCS
CO_2 capture	300-400 MW post-combustion retrofit at Peterhead, possibly using Shell's CanSolv technology Pre-combustion at new IGCC plant in Grangemouth, using Siemens gasification, Linde's Air Separation and Rectisol with Siemens H-Class turbine + Small scale capture projects	Multiple post-combustion, oxyfuel, pre-combustion capture technologies Potential for next generation capture technologies (e.g. chilled ammonia, advanced amines, solid looping)
CO_2 transport	Dedicated new CO_2 pipelines and/or adapted existing Feeder10, Atlantic, Goldeneye or Miller gas pipelines – these all make use of St. Fergus gas terminal. CO_2 ship-based transport, and accompanying port facilities are technically feasible, but we are not aware of any plans	Combination of dedicated new CO_2 pipelines and adapted existing natural gas pipelines CO_2 ship transport + port Potential for transport from sources in England or Europe
CO_2 storage	Shell's Goldeneye gas condensate field Atlantic/Aspen hub in the Outer Moray Firth Storage exploration and appraisal activity	Large range of aquifers, hydrocarbon fields, CO_2-EOR candidates in Scottish CNS and beyond
CO_2-EOR	Expect at least three partially appraised projects linked to the Miller DF1, Don Valley, and Teesside Low Carbon Projects.	Choice of at least a dozen oilfields in Scottish CNS and a similar number of oilfields in NNS and Norwegian/Danish sectors also available

3 Multiple options for CO_2 capture in Scotland

Traditionally the removal of acid gases such as CO_2, has been achieved by amine scrubbing or membrane separation. The choice of capture technology has a number of knock-on project impacts, and is based on a number of factors that drive feasibility and cost (inclusive of the energy penalty costs).

These drivers include technology performance, efficiency of capture, energy penalty, capex, opex, technology maturity, emissions, space availability, CO_2 partial pressure and temperature, availability of steam/heat, cooling water, operational flexibility, site footprint, scale, commercial value of by-products, control, and safety.

Importantly, having held advanced discussions on these issues in relation to the DF1, Longannet and Hunterston CCS project proposals, stakeholders in Scotland are among the best experienced with the challenges and trade-offs worldwide.

This chapter examines the CO_2 capture potential around Scotland looking at the large power plants and industrial sites including Peterhead, Grangemouth, Longannet, Cockenzie, Dunbar and St Fergus.

3.1 CO_2 emitters in Scotland

Figure 5 below shows the key emitters in Scotland, including Peterhead Power Plant and Captain Clean Energy project, which are two of the four candidates of the CCS commercialisation programme. The majority of the large CO_2 emitters in Scotland are located close to the Forth Estuary.

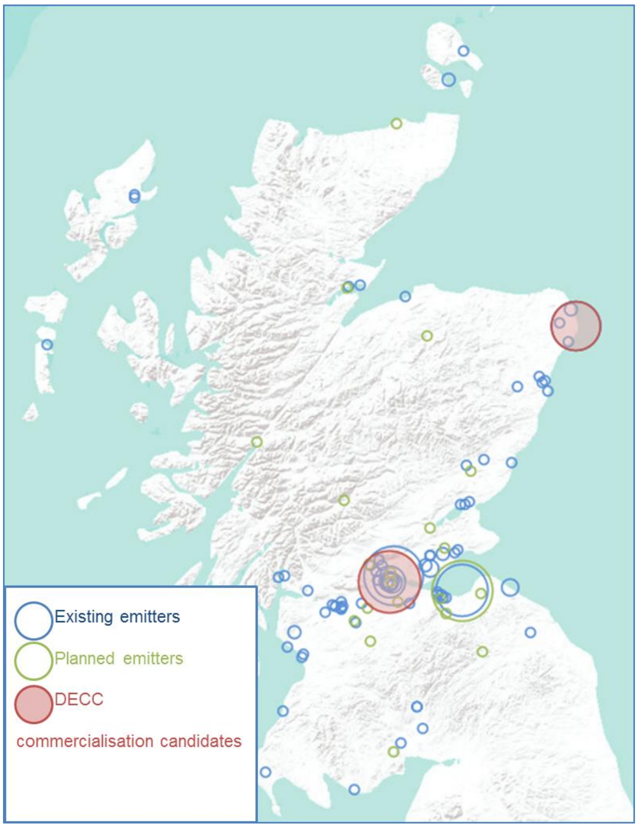


Figure 5: Scottish Emitters Current and Future (see Appendix for full list)

3.1.1 CO_2 capture at Peterhead Power Station

In March 2013, Shell/SSE's proposal for Peterhead-Goldeneye was announced by the UK government as one of the two preferred bidders in the UK's £1bn CCS Competition. This would involve retrofitting post combustion CO_2 capture to 385MW power plant resulting in the capture of 1Mt/yr for approximately ten years. Assuming the FEED study begins in 2014, consenting and FID in 2015, approximately three years for detailed design, procurement, and construction, the earliest plausible commissioning date for this project is 2018.

3.1.2 The Captain Clean Energy Project (CCEP)

The Captain Clean Energy Project was submitted in 2012 for consideration under the DECC Commercialisation Programme, and is currently a reserve candidate. The onshore element of CCEP comprises the construction of a new Integrated Gasification Combined Cycle (IGCC) coal power station with pre-combustion CO_2 capture at Grangemouth on the Forth Estuary.

The publicly announced commercial partners in the CCEP are:

- US-based Summit Power, an experienced power project developer. Summit is the developer of the Texas Clean Energy Project (TCEP), an IGCC projects linked to a CO_2-EOR worldwide that has recently reached the stage of Final Investment Decision (FID).
- Linde, a world-leading provider of gasification, air separation, and CO_2 separation (rectisol) technologies and services.
- Siemens, a world-leading provider of gas turbines

IGCC technology has already been deployed at the scale of hundreds of MW, and is a commercial alternative to supercritical pulverised coal combustion power plant. IGCC is also employed worldwide to provide alternative feed stocks for chemical processes in so-called “poly-gen” units where syngas is used to produce a variety of chemicals.

3.1.3 Comparison of Peterhead and Captain Clean Energy Projects

The capital costs for a new coal power station with capture (*ca.* £2.2 bn) are inevitably higher than a gas retrofit capture project (ca. £450m). However, it is important to understand that the more useful metric is the levelised cost of electricity, i.e. the net present cost of electricity divided by the net present MWh generated. Based on this metric, levelised costs for both projects are considered similar (range is £100-150/MWh, depending on assumptions). The large range reflects wide ranges for plausible values for the potential capital cost, discount rate, fuel prices, efficiency, and load factor. These figures exclude transport and storage. Including these could drive costs up by £50/MWh for first-of-a-kind projects which cannot take advantage of economies of scale.

3.1.4 Other power stations close to the Forth Estuary

Longannet Power Station

The existing Longannet coal power station was the host for the original DECC 300 MW post-combustion coal competition finalist. The project was developed by a consortium including Scottish Power, Aker Clean Carbon, National Grid, Shell, and CO_2Deepstore.

The project carried out FEED-level analysis, and the publication of this provides the most detailed insight into the requirements of a real CCS project available in the public domain anywhere in the world.

The FEED study revealed that the retrofit of post-combustion amine-based CO_2 capture on this *ca*. 40 year old coal power station is technically feasible and access exists or can be created for supporting infrastructure such as a CO_2 pipeline. However the costs of the proposed configuration were high, and for a number of reasons that continue to be debated, the project partners and the UK Government decided to terminate negotiations. A contributing factor is likely to be the reality that public support for CCS could and should not extend to support the operation of an otherwise uncompetitive power plant.

Following the decision not to proceed with CCS, Scottish Power (now part of the Iberdrola group) announced the planned closure of Longannet. However as the site itself has now been qualified for use for a potential CCS project, it forms an ideal location for a new power station with CCS, should others ever wish to develop at this site.

Figure 6: Longannet power station – host for Scottish Power's 300 MWe scale CCS Project proposal

Cockenzie Power Station

The coal power station at Cockenzie has been closed and is being replaced by a gas power station. In keeping with the CCS Directive, the new power station will need to meet a minimal legislative requirement for "capture readiness". However meaningful capture readiness[15], which could reduce costs and speed up CCS implementation in the future, would involve significant up-front preparation and on-going monitoring. This may be difficult for investors to justify given current policy uncertainty. The requirements for meaningful capture readiness are described in the Appendix.

3.1.5 Feasibility and costs for capture projects

Individual sites were reviewed using a standard process to provide a high level estimate of capture feasibility, preferred technology, capital and operating costs, assuming that new and existing power stations are built with the highest feasible levels of CO_2 capture. The results of this are provided in detail in the Appendix.

[15] Element Energy et al. (2012) The practical potential for CCS readiness in the gas power sector in Europe. Study for the European Climate Foundation. Available at www.ccsassociation.org/index.php/download_file/view/394/98

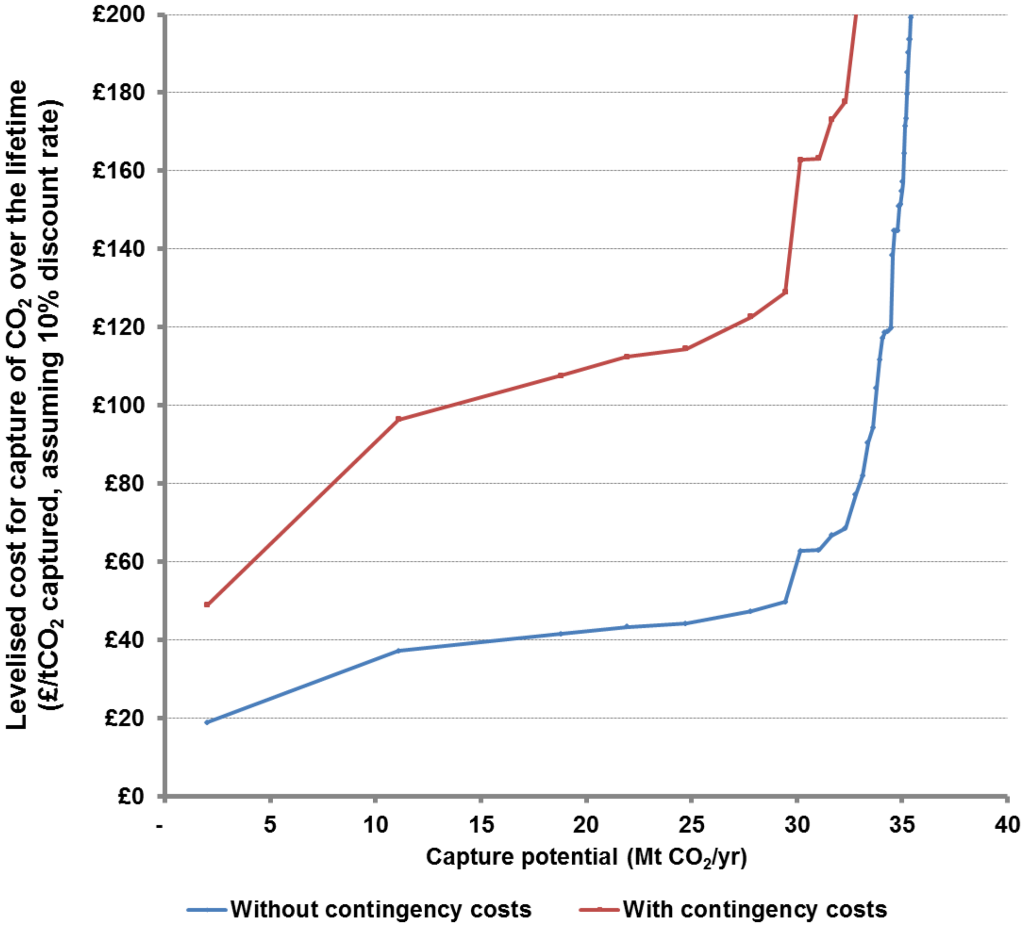


Figure 7: Marginal cost of capture curve (excludes compression, transport or storage) for new and existing power and industrial sites in Scotland.

3.2 CO_2 supply from England and Europe

3.2.1 CO_2 supply from England to the central North Sea

The two carbon intensive regions with the most active CCS programmes in England are Yorkshire and the Tees Valley. In both these regions, as in Scotland, stakeholders have spent several years developing CCS projects and transport infrastructure plans. However, following the abolition of the One North East and Yorkshire Forward Regional Development Agencies in England, efforts at co-ordinating stakeholders in Yorkshire and Teesside are at risk of stalling[16].

With the support of European funding associated with the Don Valley Power Project, National Grid Carbon has progressed the plans for an integrated onshore CO_2 pipeline network originally conceived by Yorkshire Forward with AMEC. The proposed route and design of the pipeline network allows CO_2 to be gathered from multiple power and industrial sources. The White Rose oxyfuel CCS project would initially be expected to supply 2-3

[16] The recent announcement of a City Deal for the Tees Valley is likely to add a fresh dose of momentum to industrial CCS development. https://bdaily.co.uk/industrials/13-12-2013/tees-valley-city-deal-to-secure-12-million-investment-and-deliver-3500-jobs/

$MtCO_2$/yr from a new coal power station. However, conceivably many tens of $MtCO_2$/yr could be captured if multiple sources join the network.

National Grid is currently appraising a storage site in the Bunter sandstone under the Southern North Sea. Offshore routing of a pipeline from Yorkshire to the central North Sea was previously considered by 2CoEnergy for the Don Valley Power Project. In principle it is possible for stakeholders in Scotland to influence the chosen pipeline configuration.

Progressive Energy's Teesside Low Carbon project intends to transport CO_2 from a new IGCC at Eston Grange by pipeline for storage in the central North Sea in aquifers and for EOR. If developed, additional supply could come from a number of industrial emitters in Teesside, which could connect over time. The least cost source would likely be 0.2-0.4 Mt/yr of "clean" CO_2 produced as a by-product of ammonia production by GrowHow. The scale of this suggests the principal value of this resource is as a low cost source of significant volumes of CO_2 for testing technical and commercial aspects of CO_2 transport and storage.

Interestingly, gas storage and CO_2 shipping facilities in Teesside are already well established, suggesting that this could be a convenient hub supporting a central North Sea CO_2 shipping network. This could be used for storage directly, or potentially for aquifer appraisal.

3.2.2 CO_2 supply from Europe to the central North Sea

Europe's efforts to support large scale integrated CCS projects have yet to bear fruit. None of the CCS projects supported under the EERP (European Economic Recovery Programme) are close to Final Investment Decision, and most have been postponed indefinitely. The first round of NER300 competition failed to award funding to any CCS project, due to a number of different specific reasons, including failure to co-ordinate funding with Member States. A second round of NER300 is underway, with the White Rose CCS project being the only CCS candidate proposed. Although new initiatives are under discussion, momentum has been lost and there is a need for vision and consensus as to what the nature of further EU-level intervention should be. As well as specific challenges related to CCS, the wider economic challenges in Europe have diverted policymakers' attention away from CCS.

Following the cancellation of Norway's Mongstad CCS demonstration project[17], the CCS project in continental Europe with the highest chance of implementation before 2020 is now the ROAD project involving the proposed Maasvlakte power station in the Netherlands[18]. This could result in a CO_2 transport volume of the order of 1.1 Mt/yr by 2020 by pipeline or ship transport to a nearby domestic offshore depleted gasfield (chosen for reasons of strategy, ease and cost). This project would be unlikely to use storage in the Scottish territorial waters of the central North Sea unless the base case plans fell through and a convincing business case could be made for incurring the higher transport costs for the extra distances involved.

Looking beyond 2018 however, new projects could be developed that supply CO_2 by ship or new or existing pipelines to the central North Sea. Scenarios published by the European Commission, Primes group, European Climate Foundation, CO_2Europipe, SCCS/Arup, the North Sea Basin Task Force, and academics, with the highest levels of CCS in Europe anticipate the capture of hundreds of millions of tonnes of CO_2 each year from the 2030s

[17] For details, see http://www.zeroco2.no/projects/mongstad
[18] For details, see http://road2020.nl/en/

rising through to the 2050s. Clearly lower and intermediate levels are also possible as a function of policy and technology/market development. Whilst some of the storage need would realistically be met with a combination of onshore storage and storage in other sectors of the North Sea, there would be an opportunity for Scotland to service this need, although this would require corresponding transport infrastructure.

Whilst the potential for CO_2-EOR is likely to shape the sink choices, routing, topology, capacity, specification and financing of any pipeline network, no plausible scenarios yet examined envisage a need for CO_2-EOR driving the overall levels or nature of capture in England or Europe.

3.3 Scenarios for CO_2 supply

Scenarios are representations of the way the world might develop that provide insight to policymakers. All readily available public academic, industry and Government reports were identified and reviewed describing CCS uptake scenarios relevant for Scotland and the central North Sea between 2010 and 2050.

The diversity of these published CCS development scenarios indicates the difficulties in forecasting the amount (uncertainty spans two orders of magnitude), location (even uptake at country level is uncertain, the uncertainty increasing as you move towards individual sites), costs (factor 2 uncertainty overall, rising to factor 5 uncertainty for elements of projects), and timing (even to within decade resolution) of CO_2 supply from CCS projects.

With such large uncertainties there is limited value in developing very detailed models of where, when, and how much CCS infrastructure investment is appropriate. Instead the purpose of modelling is to help with screening and identifying key themes.

Existing “bottom-up models” of decision making are unable to account adequately for the complex dynamics, uncertainties and interdependencies of policy, markets and infrastructure evolution across CO_2 generation, capture, transport, storage and EOR.

Existing “top down” models tend only to identify UK and European levels of CCS in the region of several hundreds of millions of tonnes per year by the 2030s that would be required for “least cost” solutions to the climate and energy challenge; however there is no evidence that stakeholders will follow these “least cost” pathways and there is a substantial disconnect between what is required, where the industry is today, the growth rates of analogous industries, and the mechanisms available to support rapid growth. Further there is a high dependence of the medium term (2030) system on the decisions of a few early projects.

In the absence of reliable forecasts from “top-down” or “bottom-up” analysis, hypothetical hybrid scenarios have been developed to allow stakeholders to gain insights as to the costs, benefits and risks of potential strategies, and to anchor sensitivity analysis for specific investments.

Following a deep review of previous work on scenarios, updating these to reflect recent developments in the UK and Europe, and consultation with key stakeholders, the level, timing and locations of CO_2 supply were identified as key issues that Scottish Enterprise and its stakeholders needed further insight into. Therefore two phased deployment profiles for CCS in Scotland and the central North Sea were identified. These scenarios are labelled “Aggressive” and “Cautious”.

3.4 An “Aggressive” deployment scenario for CCS

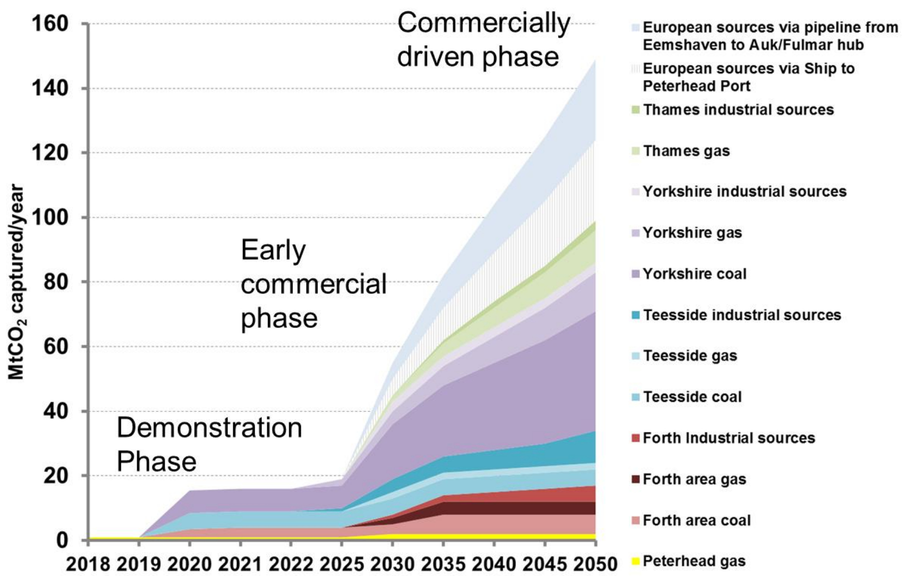


Figure 8: Assumed roll-out in an “Aggressive” CCS development scenario

In the Aggressive CCS scenario, CCS stakeholders co-operate to deliver high CCS uptake, primarily by advancing multiple projects and commercial incentives for CCS in industry and power. This represents a step change in policy relative to current ambitions but is more consistent with the ETI’s ESME analysis of the least cost pathway to decarbonising the UK economy by 80% by 2050, and the “Very High” scenario envisaged in the North Sea Basin Task Force’s One North Sea report. Strong and sustained political pressure to prioritise tackling climate change, and to choose CCS to achieve deep CO_2 cuts, would require a step change in support within the UK and internationally.

The five well developed UK CCS proposals, for capture at Peterhead, Grangemouth IGCC, Teesside Low Carbon IGCC, Capture Power (Drax) and the Don Valley Power Project, are all assumed to pass FID by the end of 2015. The projects are assumed to all reach the stage of commissioning by 2020 (potentially earlier for Peterhead). Based on initial success, a second wave of investment is assumed to occur in the 2020s, benefitting from some of the learning from these initial projects. The UK CCS installed capacity approaches 55 Mt/yr by 2030, of which 8 Mt/yr is from four sources in Scotland. By 2050 UK supply is 100 Mt/yr, with a potential additional demand on CNS storage of 50 Mt/yr from European sources.

3.5 A “Cautious” scenario for CCS development

A “Cautious” scenario assumes slower and more limited near-term intervention, and consequently CCS uptake. It assumes that intervention is limited to UK support for both shortlisted CCS projects by 2015. Investors refine proposals for other projects and slowly take advantage of the Electricity Market Reform.

Only the two shortlisted CCS commercialisation candidates are deployed. The scenario assumes that CCS is demonstrated to be successful and that there is widespread agreement to increase the pace of decarbonisation in the 2020s with carbon prices and electricity markets supportive of CCS power and industrial projects by the 2030s, including deployment of those projects currently listed as “reserve”. The level of UK capture in the Cautious scenario is *ca*. 25 $MtCO_2$/yr in 2030, of which 5.5 Mt/yr is from three Scottish sources.

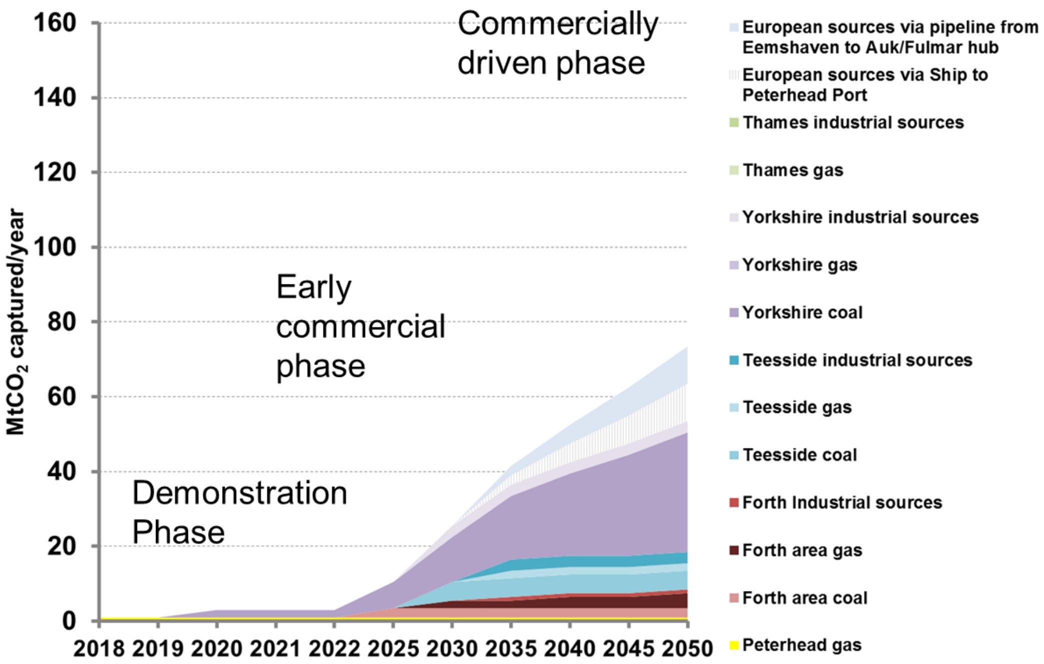


Figure 9: Assumed roll out in a “Cautious” CCS development scenario

Low levels of CCS, or indeed an absence of CCS, for diverse technical, commercial, regulatory and socio-political reasons are plausible CCS scenarios. However, as these scenarios do not align with Scottish Enterprise’s objectives for this study, and as they are unlikely to require any actions by Scottish CCS stakeholders beyond business as usual they are not discussed further in this report.

3.6 SWOT analysis of CO_2 capture in Scotland

<u>Strengths</u> • Peterhead shortlisted for DECC CCS Commercialisation Programme • Captain Clean Energy project (Grangemouth IGCC) is a reserve candidate • Site of old Longannet coal station validated as "capture ready" • High probability that new builds (e.g. Cockenzie) will be capture ready • Technical potential for CO_2 capture identified at multiple existing industrial sites, most close to the Forth estuary	<u>Weaknesses</u> • Weak demand for new large base load fossil/biomass power generation in Scotland • Absence of commercial drivers for capture readiness and implementation at existing industrial sites • Limited long-term visibility for existing industrial sites
<u>Opportunities</u> • Expand capture	<u>Threats</u> • Insufficient funding available for CCS in the levy framework • Some capture projects in Teesside and Yorkshire are further advanced than projects in Scotland • Projects vulnerable to local or environmental opposition (e.g. Hunterston)

4 Scotland's CO_2 storage resource

Subsurface geological stores into which CO_2 is injected for its long-term sequestration are a key component of the Carbon Capture Transport and Storage (CCS) chain. While there is scope for project design flexibility, unlike the other parts of the CCS chain, their location and suitability (in terms of their physical parameters) are 'non-negotiable'. The central North Sea off the eastern coast of Scotland encompasses a wealth of potential sites for the storage and utilisation of CO_2. Depleted oil and gas fields and brine-saturated sandstone suitable for the storage of CO_2 (Scottish Centre Carbon Storage, 2009) and candidate oil fields for enhanced recovery by CO_2 (Element Energy, 2012) have been identified offshore Scotland. Engineering techniques, many already well proven from the oil industry, coupled with innovative planning, may enhance the viability of these stores.

Table 3 summarises the key strengths, opportunities, weaknesses and threats for the development of the central North Sea as a Storage Hub. This chapter assesses the possibilities and quantifies the benefits for development options for the potential storage resource offshore Scotland, which is very large and laterally extensive providing flexibility when building possible CCS scenarios.

Table 3: High Level SWOT analysis of a CO_2 storage hub for the central North Sea.

Strengths	Weaknesses
• Large theoretical storage capacity, with potential for storage back-up • Many stores well understood and abundant data available • Existing supply chain and expertise • Political support • Stakeholder organisation • Many choices for location for hub, at shoreline or at several offshore locations, i.e. do not expect high dependence on specific assets. • High proximity of stores (e.g. overlapping or "stacked" areas) allows for incremental expansion at low cost, and cost sharing across multiple stores.	• Pipeline infrastructure is highly specific - need to have confidence in capacity, location and timing of capture and storage or else high risk of stranded assets. • Some of the largest stores have very large areas, are stacked, or require new (or commercially sensitive) data for development, making these challenging to license/lease and appraise efficiently, even though large areas and stacking may reduce costs in the long run • UK and European energy, climate and CCS policies are limited, so that the amount, location and timing of demand for storage is highly uncertain,and there is little financial incentive for anticipatory investment that may reduce long term costs. • Diverse storage classes may imply limited cost reduction, as little learning by doing. • Many CNS stores (including majority of EOR candidates) are several hundreds of kilometres from sources • Lack of interest from oil and gas industry
Opportunities	**Threats**
• Multiple CCS demonstration projects are based in Scotland and/or involve the central North Sea • CO_2-Enhanced Oil Recovery can provide a positive revenue stream. • Pipeline re-use potential • Well/platform re-use potential • Storage clusters can allow for cost and risk sharing • CO_2 shipping may expand access to other regions • Multiple business and regulatory models available	• Current project-based licensing and leasing and funding approach is unlikely to deliver maximum or least cost capacity in the central North Sea. • Other stakeholders (e.g. environmental NGOs, users of the seabed or sub-surface), may resist CO_2 storage projects. • Other regions may be faster or more competitive. • The business and regulatory models that maximise the opportunities for Scotland may not align with current stakeholder priorities.

4.1 Evaluation of storage opportunities in the central North Sea

4.1.1 Diversity of storage opportunities in the CNS

A high-level study (Scottish Centre for Carbon Storage, 2009) investigated a number of aspects of CO_2 storage around Scotland. In this first study of its kind in Scotland, the CO_2 storage potential, all offshore, within the Scottish Renewable Energy Zone[19] was estimated and assessed as of European significance.

The study categorised stores within brine-saturated sandstones (saline aquifers) and hydrocarbon fields identifying some of the latter as having potential for Enhanced Oil Recovery (EOR) using CO_2. All or part of each of ten saline aquifers shortlisted, out of more than 80, lie within the central North Sea; between them they could have a storage capacity in the range 4,600 to 46,000 million tonnes. Twenty of the 29 hydrocarbon fields identified, out of more than 200, also had potential for CO_2 storage.

[19] The area is formally known as the "Scottish Renewable Energy Zone (Designation of Area) (Scottish Ministers) Order 2009".

These results have since been substantiated and qualified by the ETI's £4m UK Storage Appraisal Project, although the results have not yet been made fully public. The theoretical potential CO_2 storage capacity within the central North Sea (central estimate *ca*. 40 Gt) is the largest within the UK Continental Shelf (UKCS). The **prospective** capacity will be less, as will be the case in all parts of the UK offshore (Figure 10). The storage capacity of a potential CO_2 store undergoes revision (generally decreasing) as information and understanding of the reservoir increases. A basic estimation may be made knowing only the volume of rock and percentage of space available between rock grains. However, these spaces are filled with either saline water or hydrocarbons. So when CO_2 is injected (as a dense gas) it displaces or reacts with the fluids present causing pressure increases, which can restrict the amount of CO_2 stored.

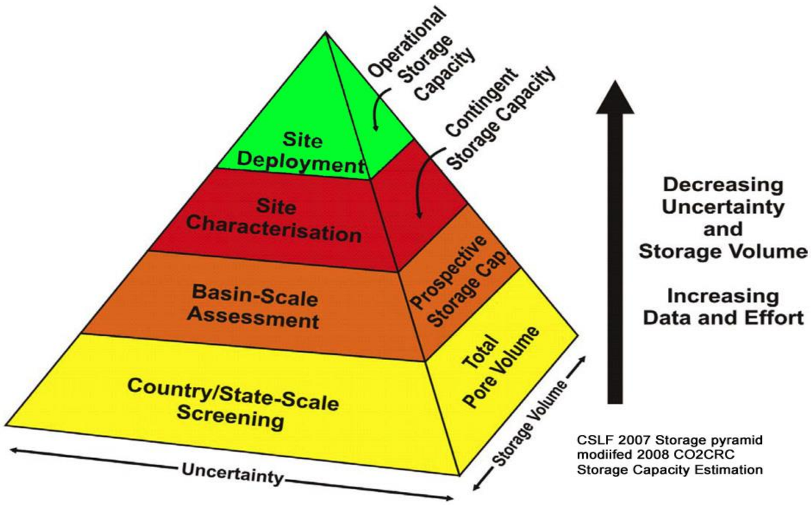


Figure 10: Resource pyramid illustrating developing assessment of geological CO_2 storage capacity

The injected CO_2 may partially dissolve in the saline water or oil, the latter being part of the CO_2-EOR process. Properties of the rocks, such as mineralogy and permeability, and fluid properties, e.g. salinity of the water and composition of the oil, will all affect the ultimate CO_2 storage capacity of the reservoir. These, and other factors, such as injection strategy, faults and fault sealing leading to compartmentalisation of the reservoir that also affect the storage capacity of a reservoir may be simulated by dynamic modelling of the reservoir (see Figure 11). Dynamic modelling, where CO_2 injection is simulated in a 3D model, populated with physical data, of the aquifer or hydrocarbon field give a more accurate storage capacity value by site-specific evaluation (e.g. Captain sandstone saline aquifer, Goldeneye Gas Condensate Field) and again the geology will be simplified in the model compared to reality. Hydrocarbon fields, with more and better data and a history of production, should generate more accurate models with better estimations of storage capacity.

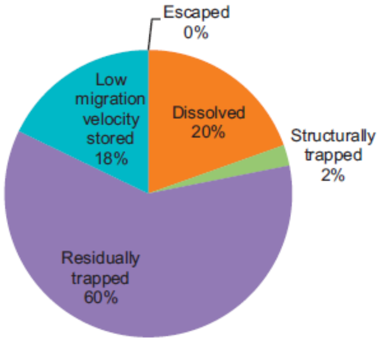


Figure 11: A mixture of trapping mechanisms can operate - the figure shows the predicted role of different mechanisms in a typical large dipping aquifer such as the Forties aquifer in the CNS 1,000 years following CO_2 injection. (Goater et al. 2013)

The CNS (including the Moray Firth) has diverse geology that increases the likelihood of there being strata suitable for storage. The CNS geology is well known from hydrocarbon exploration and production increasing the likelihood of identifying strata with characteristics suitable for storage. The differing storage characteristics permit selection of stores with small or large capacities, vertical and horizontal permeabilities, porosities, tilt angles, containment features, and depths, in a range of locations to accommodate differing injection and storage requirements.

The scenarios for storage in the central North Sea assessed in this study include a range of options and store types. The storage options include within depleted oil fields, depleted gas fields, as a component of CO_2-EOR schemes and within saline aquifer sandstones. The latter span the preserved geological sequence so that sandstones suitable for storage may be ‘stacked’ within any one area. There is a balance between younger strata that have higher porosity and permeability but may be too shallow for storage. Whereas, deeper strata may be less porous and permeable and compartmentalised by faulting, although they may be more robust due to resilience of the confining cap rocks at greater depth.

Three structural/stratigraphic configurations provide complementary risk profiles for storage containment. “Pressure cells” offer good containment and site spatial control as CO_2 is injected into a well-defined small volume. These may be the easiest to regulate and monitor, although pressure relief wells may be needed for significant capacity expansion. Four-way dip closures (domes) or fault-bounded closures, offer containment of CO_2 in a well-defined 2D area, but with more flexibility in the amount of CO_2 that can be stored as the pressure increase can be dispersed over a much larger volume. Finally tilted “open” aquifers can facilitate pressure equilibriation with the seabed and their large extent accommodates CO_2 migration away from the well. These may be more challenging to appraise, regulate or lease in the short term, but offer the prospect of the largest storage volumes.

In the central North Sea the large majority of this theoretical capacity is within saline aquifer sandstones rather than depleted hydrocarbon fields. Significant additional capacity is also located within chalk rocks, although this may be more complex to utilise. The Storage for demonstrator projects is likely to be within hydrocarbon fields, as these are better understood. Most of the hydrocarbon fields in the central North Sea contain oil and have been assessed at high level for enhanced recovery using CO_2. In some cases more detailed analysis has been carried out by commercial operators. The “high level” analysis typically involves generic assumptions based on analogy with EOR projects in the Permian basin, where well infrastructure requirements are likely to be very different. However the results of detailed analysis are commercially sensitive and have not been published.

Given the uncertainties around storage, a key feature is that the central North Sea provides a diverse portfolio of options. If the performance of these options is independent, then having a large diverse portfolio in close proximity should result in lower risk for CCS infrastructure.[20] It is currently difficult to price this additional flexibility, but the injectivity and capacity challenges experienced by the Snøhvit project might suggest that having sites with contrasting geology in close proximity is inherently valuable.

For this study, storage capacities were taken from the CO2Stored database generated from a 3 year study of the UK offshore storage resource (UKSAP). These capacities were calculated using a refined static model of the potential stores (Green *et al*., 2012). The saline aquifer strata assessed here are sandstones, although carbonate strata may form additional storage sites.

The available data allows screening level analysis, though any investors would require additional information on individual sites. Emerging from UKSAP was a “supply curve” showing tens of Gt of capacity in the CNS in the range £5-30/tCO_2, competitive with other regions of the UKCS.

4.1.2 Flexibility in the development of the storage resource

To understand how sensitive the availability of CO_2 storage capacity is to the initial development pathway, a wide range of hypothetical CCS storage development pathways were explored, focussing on sites within the Scottish Energy zone.

In each case it is straightforward to conceive how capacity can be expanded from an initial site through the use of “step-outs” or direct access using existing pipelines. Taken together results from assessment of different storage development pathways show that the initial choice of storage site does not overly restrict future access to CO_2 storage capacity.

[20] By contrast, the SNS does not have a similar suite of geological variability. It could be challenging for multiple individual operators to choose sites, because many of the large structures are pressure interconnected. Despite the initial drilling and short-term testing of 42/25 by National Grid in the Southern North Sea, further work may be required to for proof of performance viability.

Table 4: Evaluation of different storage deployment pathways

Initial field	Key issues
Goldeneye	Goldeneye and store are well characterised. Existing SAGE pipeline expected to be suitable, allowing easy access to Buzzard for EOR, or to Mey, Captain, Burns, Auk or Buchan sandstones (capacity 17 Gt). No conflicts with wind farms or marine protected areas expected Need to manage conflicts with producing hydrocarbon fields.
Atlantic	Atlantic field likely to be viable as geology is analogous with Goldeneye, but limited information in the public domain. Existing Atlantic pipeline could be used Route opens access to Mey, Captain and Burns saline aquifers (cumulative 5 Gt capacity). Limited conflict with Marine Protected Area Need to manage conflicts with producing hydrocarbon fields. Potential for expansion using Frigg-St. Fergus line to access Mey, Ekofisk, Scapa, Burns, Firth Coal, Buchan, Strathrory and Orcadia aquifers. This expansion would face little conflicts with marine protected areas, but potentially substantial conflicts with operating hydrocarbon fields.
Forties	Need to build a dedicated pipeline or ship transport. Numerous aquifers in close proximity with a combined storage capacity of 18 Gt No conflicts with wind farms Need to manage potential conflicts with marine protected areas Significant potential conflicts with oil and gas industry.
Miller	Potential re-use of the existing Miller gas pipeline (currently mothballed) Access to 8Gt capacity in hydrocarbon fields (Rob Roy, Telford, Brae, Scott, Miller and Kingfisher), including EOR, and aquifers. However this could have significant conflicts with existing hydrocarbon production. Limited conflicts expected with marine protected areas. No conflicts expected with wind farms.
Fulmar	Fulmar could be accessed via a new pipeline from Scotland, re-using the existing pipeline from Teesside to Fulmar, or by ship transport. Possible to expand with short step-outs to hydrocarbon fields Janice and Clyde with secure containment and/or EOR potential.

Taken together, results from the assessment of eight storage scenarios show that the initial choices of storage site does not overly restrict future access to CO_2 storage capacity.

4.1.3 The subsurface complexity of the central North Sea

Viewed as a 2D projection, the Captain sandstone saline aquifer (depth to storage 1,190m, area 2,900km^2) overlaps several other saline aquifers (Findhorn, Strathrory, Burns, Lossiehead, Coracle and Orcadia). The saline aquifer also hosts several hydrocarbon fields, including the Cromarty, Atlantic and Goldeneye gas condensate fields as well as the Blake and Captain oilfields (although the Captain oilfield itself may be too shallow for CO_2 storage).

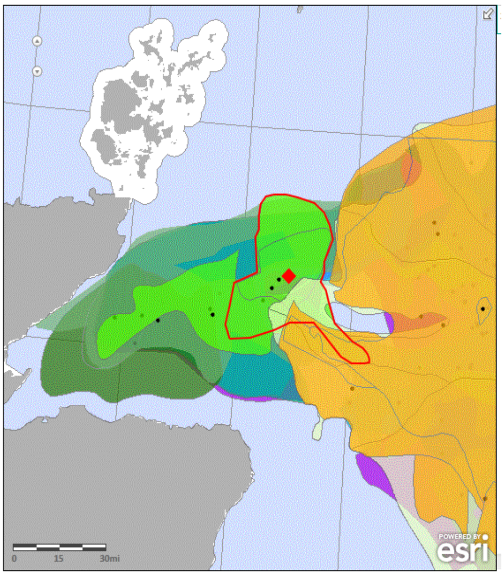


Figure 12: Captain sandstone saline aquifer has a large area, irregular shape, overlaps other stores. Colours show other storage sites in the different stratigraphic layers, red dot shows the centroid of the polygon).

The 2D maps of the saline aquifers that have an overlap with Captain sandstone saline aquifer identify that these have a variety of shapes and sizes (see Appendix).

Detailed simulations will be needed to assess usable capacity in any given part. Importantly, although the Captain sandstone saline aquifer has a theoretical storage capacity of 156 Mt (from CO2Stored), the combined capacity of the proportions of the overlying/underlying saline aquifers in the region of Captain sandstone saline aquifer may approach **eight** times this figure (*ca*. 1.2 Gt), and the overall combined theoretical capacity from all the units exceeds 5 Gt. It is not expected that all of this capacity would be exploited – the large excess of capacity relative to demand indicates the potential redundancy and scalability of the region around the Goldeneye field and Captain sandstone saline aquifer.

Innovative and flexible approaches will be required to manage storage users in close proximity, particularly for scenarios involving several stratigraphic layers in the same 2D area, or multiple users of an aquifer with very large areal extent, and regions where pressure build up or CO_2 migration over time are likely to be important. The Scottish Government, The Crown Estate, Scottish Enterprise and Shell are currently sponsoring the CO2Multistore project, a study by SCCS to resolve this challenge. The project is in progress and results are confidential and not yet available for this project.

A recent GCCSI-IEA GHG-BGS-sponsored event (July 2013) identified different approaches to subsurface mineral and pore space rights and responsibilities in Norwegian, Dutch, UK, US, and Australian jurisdictions. There appears to be no simple model that minimises conflicts and/or promotes maximum sub-surface resource development.

In all jurisdictions, there would be technical, regulatory and legal challenges for the management of the stacked stores and with large scale deployment of CCS involving multiple site operators. There are real risks that the delays are incurred and resources will be sterilised due to hypersensitivity around associated liabilities, above and beyond the already challenging storage liability conditions for an individual store.

This problem might be reduced substantially if a single storage operator is responsible for a large area or volume, i.e. regional monopolies. These organisations would have a good overview of all the assets in a given area or volume and their development needs. This could maximise the opportunity for optimal development of the pore space.[21] However the trade off would be fewer storage operators. In other industries, reduced competition is associated with lower efforts to reduce costs or innovate service offerings.

4.1.4 Conflicts of interest with other users of the central North Sea

Seabed

Geographic Information System (GIS)-based analysis has been used to examine potential conflicts of interest of storage operations with marine protected areas, wind farms and hydrocarbon production. These conflicts, whether they are benefits or threats, could occur if the reservoir is within the same stratigraphic layer (Figure 12) or through a proximity measure where fields may be in a different stratigraphic layer (for example at an up-dip location, see Appendix for details).

Spatial constraints are likely to evolve over decadal timescales. Conflicts of use with hydrocarbon production in the central North Sea are likely to become less severe by the 2030s as some cease production, whereas wind farms and supporting electricity transmission infrastructure are expected to expand over time. Ideally developers would seek to avoid running new CO_2 pipelines through an established windfarm; conversely CCS infrastructure could limit the freedom in windfarm infrastructure. Currently, the majority of CO_2 storage opportunities lie more than 100 km from the shoreline, whereas wind farms are much closer to shore. There also are limited potential conflicts identified with marine protected areas. It should therefore be possible to avoid these conflicts without significant reductions to storage capacity if developments are planned.

Taken together this suggests that the priority for spatial planning of co-location of offshore renewable and CCS infrastructure would be nearshore, e.g. ensuring appropriate siting of beach crossings.

Hydrocarbon production

In preparing the regulatory environment for CO_2 storage, DECC has confirmed that the default position will be to prioritise hydrocarbon production over storage development. Although the presence of subsurface CO_2 could provide benefits (improving recovery through pressure or mobilising otherwise stranded hydrocarbon), the complex physico-

[21] Of course this shifts the problem to the creation, selection and management of such *de facto* monopolies, and avoiding the disadvantages relating to lack of competitive pressures to reduce costs or innovate. One opportunity could be the granting, through an option mechanism linked to performance, rights over the subsurface beyond an initial leased/licensed area.

chemical properties of CO_2, including the ability of carbonic acid to corrode steel, could be of concern to operators of hydrocarbon fields.

Theoretically CO_2 contamination of a producing or newly discovered hydrocarbon field could create a risk of uneconomic development, implying a multi-billion pound threat to valuation. Thus the license holders for these fields may, in some circumstances, choose to adopt a restrictive or not-under-my-backyard (NUMBY) approach to storage development that poses a threat to their assets. These conflicts could occur if the reservoir is within the same stratigraphic layer, above or below, or simply in proximity.

4.1.5 Data availability

The central North Sea subsurface has been regionally and locally intensively mapped, and abundant seismic and well log data, reservoir models, field production and pressure histories are often available, reducing the timescales and risks of storage pre-development and development, particularly for depleted fields.

However, information useful for storage developers is fragmented. The most insightful UKCS data are commercially sensitive and held by different companies within the oil and gas industry. Even in favourable cases it can take months for CCS developers or their stakeholders to negotiate access to individual items of data. This potentially leads to missed opportunities or decisions based on an incomplete understanding of subsurface risks and performance. In contrast a scenario that favours collection and dissemination of data, and its on-going curation, are likely to lead to storage solutions with lower costs and risk profile.

Storage developers and the oil and gas industry are naturally likely to resist interventions that oblige sharing of detailed reservoir models, as these constitute valuable intellectual property, often acquired at considerable expense and effort. Potentially publication of such data would risk undermining any proactive commercial appraisal activity. However, in contrast to commercial oil and gas exploration, the levels of pro-active commercial storage exploration and appraisal are much lower than needed for the aggressive scenario. It is however difficult to see how aggressive exploitation of the storage resource would align with limited or opportunistic access to subsurface data.

4.2 Hydrocarbon fields in the central North Sea for storage

Unless storage projects are combined with enhanced hydrocarbon recovery, these will need to start storage operation following cessation of production (CoP). CoP typically occurs when the running costs exceed the revenues from field production. Hydrocarbon companies and DECC typically work together to plan for decommissioning up to 5 years ahead of the CoP date, as decommissioning projects are themselves major investments (£billions for the largest fields). However, at longer timescales it is difficult to specify when fields become available – as movement in energy prices, discoveries, changes in ownership or technology can extend field lives by more than a decade.

Figure 13 identifies the growth in cumulative storage capacity in the central North Sea from storage only projects as hydrocarbon fields are decommissioned. There are considerable uncertainties in storage capacity (which will need reservoir modelling to firm up) and the timing (an error bar of +/-5 years is shown relative to DECC's 2012 estimates of CoP dates).[22]

Despite the uncertainties, it is clear that hydrocarbon fields the central North Sea should offer considerable flexibility for infrastructure re-use, as platforms, wells, distribution pipelines, and other supporting infrastructure are likely to become available gradually over the course of development of any CO_2 storage industry. This raises the possibility of opportunistic cost reductions through infrastructure re-use. Given the age and very different design requirements between existing and future oil and gas infrastructure, the actual cost savings may be modest, and in some cases it may cost less to install new injection facilities than adapt existing platforms.

A pro-active approach would be for DECC to place the onus on asset owners to report on why re-use of infrastructure for CO_2 storage was not possible, prior to approval for decommissioning being granted. However this is unlikely to win the support of the oil and gas industry.

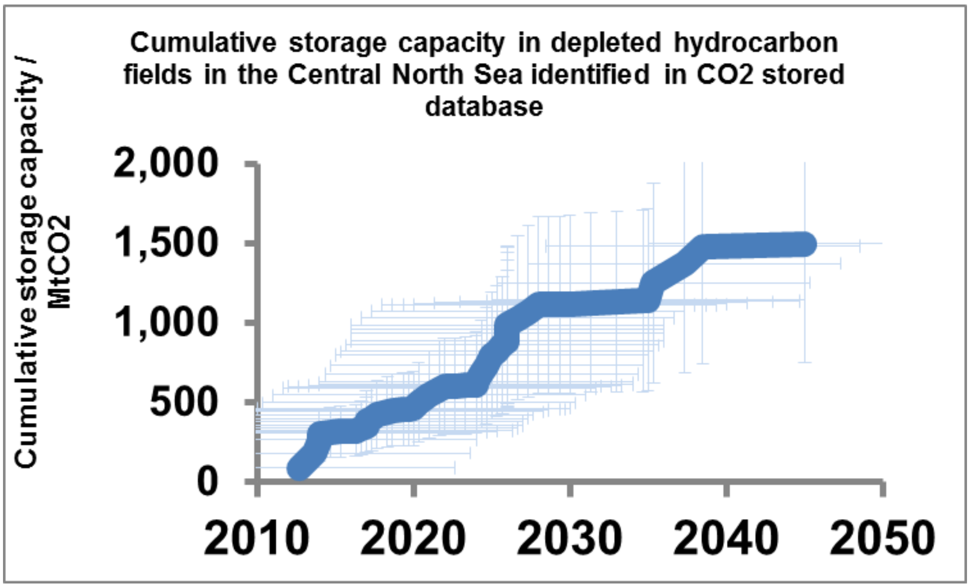


Figure 13: Cumulative capacity in depleted hydrocarbon fields in the central North Sea over time, assuming all fields become available on cessation of production.

4.2.1 The Goldeneye field

The Goldeneye gas condensate field was discovered in October 1996 (discovery well 14/29a- 3) and subsequent appraisal wells delineated the extent of the accumulation. The Goldeneye platform was installed in 2003 and is classified as a Normally Unmanned Installation (NUI) containing minimal processing facilities. The platform facilities are considered to be suitable for the purposes of CO_2 injection without major modifications. The five Goldeneye production wells are currently shut-in (2011).

[22] Estimates for CoP were kindly provided by DECC under restriction that only aggregate data could be presented. CoP data are based on DECC 2011 data. Storage capacities taken from CO2Stored database.

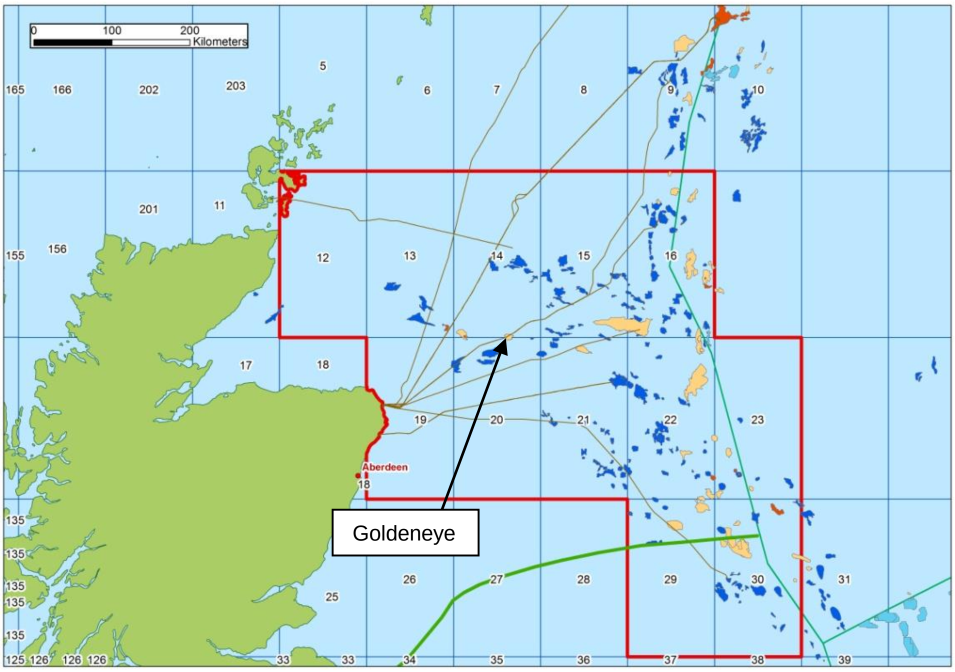


Figure 14: Location of Goldeneye Field (Hydrocarbon field and infrastructure data provided under license from UK DEAL)

In 2011, the Shell Goldeneye Asset Team published the detailed Front End Engineering study for the use of the Goldeneye gas condensate field as a CO_2 store, as an output of the first DECC CCS competition involving Scottish Power's Longannet coal power station[23]. The project was not selected, but the storage site remains, although if not used for CO_2 storage, eventually the supporting platform infrastructure will need to be removed and wells plugged. The Shell Asset Team built three models – field, aquifer (regional) and overburden utilised in simulating the effects of CO_2 injection, and populated these with data from seismic mapping, petrophysical modelling studies and Special Core Analysis. A summary of geological information that illustrates the potential of the Goldeneye reservoir as a CO_2 store is provided in the Appendix.

Consistent with the CO_2Stored database estimate of 36 Mt, the more detailed FEED study confirmed that a CO_2 storage capacity of at least 20 Mt following ten years injection from the Longannet power station. CO_2 can be injected via existing wells into the Captain 'D' sandstone interval. Hydrocarbon production from the Captain reservoir has been excellent and this suggests that CO_2 injection performance should be equally as good.

4.3 The potential to combine CO_2 storage with enhanced oil recovery

Although so-called "secondary" sea water injection for water flooding or pressure maintenance -based recovery is widely practiced in the North Sea, this still leaves close to half the original oil in place in most oilfields. A range of "tertiary" recovery techniques

[23] Scottish Power Longannet CCS FEED study (available as CD-ROM from DECC)

including thermal, chemical, microbial, acoustic, electromagnetic and gas injection techniques can be used to improve recovery.

Gas injection, using natural gas, CO_2, nitrogen or flue gases, is used worldwide and has been shown to be effective in the North Sea oilfields, for example natural gas injection in the Magnus field. CO_2-enhanced oil recovery has been practiced since the late 1970s, and globally around 170 projects are currently in operation, the majority in Texas. More recently CO_2-EOR is a component of North American and Middle East CCS projects in planning or under development.

Various generic and field studies have been carried out for more than a decade to investigate the likely incremental oil to be expected from notional UKCS CO_2-EOR schemes. There have been preliminary, and largely confidential, simulation studies in support of the DF1 (Miller), Don Valley, Teesside Low Carbon and other projects elsewhere in the UKCS, Norwegian and Dutch sectors of the central North Sea. The opportunities and challenges are increasingly well understood by most stakeholders in the UK, following the 2012 Scottish Enterprise study on the economic impacts of CO_2-EOR for Scotland.

Despite some interest from CCS project developers and continued support from the Scottish Government, a wait-and-see environment for CCS with CO_2-EOR prevails within the North Sea oil industry and UK Government. The attitude of the oil industry is likely to change significantly if a reliable supply of CO_2 is available at low or zero cost, if the perceived regulatory burdens for CO_2 storage is low, and if taxes are reduced to a level that allows returns competitive with other opportunities.

Rapid ramp up in CO_2-EOR investment in the late 2020s could take place if a first North Sea CO_2-EOR project is demonstrated to be profitable in the early 2020s. As different teams within the UK Government take responsibility for electricity markets, CCS, oil production, and taxation, going forward there will have to be a co-ordinated approach to CO_2-EOR deployment between these teams. However both industry and Government will need to show leadership and strategic risk-taking if the opportunity for CO_2-EOR is maximised within a limited time window of opportunity before fields are decommissioned[24].

Some environmental NGOs are sceptical of the combination of CCS with CO_2-EOR, which is seen by them as a way to preserve vested interests in the fossil fuel industry. The question of carbon balance for CCS projects with CO_2-EOR is complicated by uncertainty around what the appropriate counterfactual emissions would be and where/when carbon accounting boundaries should be drawn.

The PILOT Task Force, representing the UK Government and the North Sea oil and gas industry, has estimated that CO_2-enhanced oil recovery is likely to provide the largest incremental recovery of all tertiary recovery techniques (see Appendix). However the suitability and method of application of CO_2-EOR processes to North Sea oil fields will need to be determined on a field-by-field basis – there is unlikely to be a 'one size fits all' solution.

4.3.1 Indirect support

Some hydrocarbon fields in the proximity to any CO_2 transport corridors may benefit from CO_2 injection, without CO_2 actually entering the hydrocarbon-bearing pore volume itself. This is described further in the Appendix.

[24] The potential for revisiting previously abandoned hydrocarbon fields for CO_2-EOR has not yet been examined.

4.4 Storage deployment scenarios

Illustrative storage scenarios have been modelled for UK CO_2 using UK sinks including CO_2-EOR. The Aggressive scenario corresponds to the Aggressive capture scenario. The Cautious and St. Fergus hub scenarios both correspond to the Cautious level of CCS uptake, with the St. Fergus hub scenario envisaging a higher role for CO_2-EOR.

Sink choices have been made on the basis of least cost and maximal storage capacity

The difference between CO_2 supplied and stored in the scenarios represents non-UK storage, primarily assumed to be Norwegian EOR and Danish EOR projects.

4.4.1 Aggressive scenario

The mix of storage in the Aggressive scenario is illustrated below.

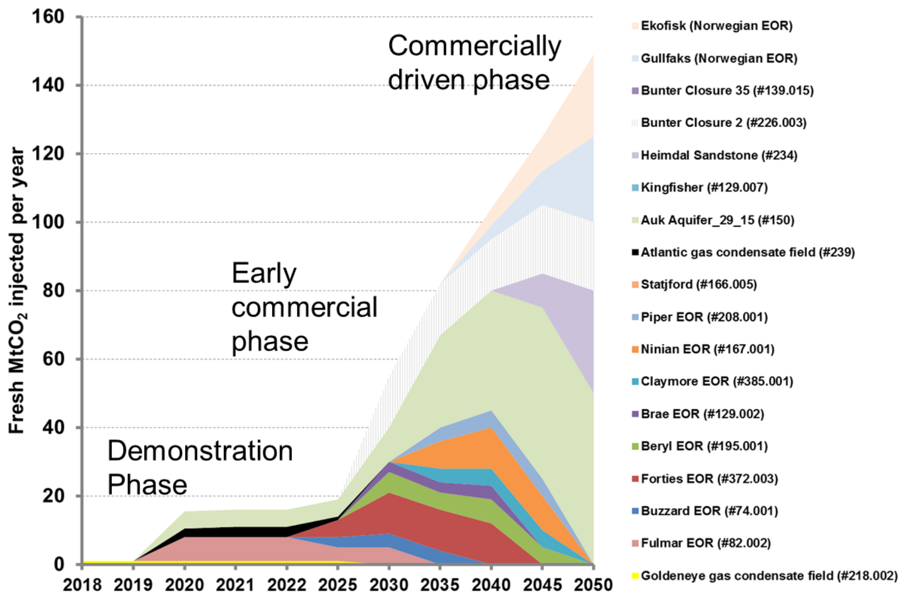


Figure 15: CO_2 Storage assumptions for the Aggressive CCS with CO_2-EOR scenarios

The Aggressive scenario assumes that the Goldeneye field is operational by 2018 for storage, followed by the nearby Atlantic gas field, both supplied from a hub at the St. Fergus gas terminal.

The Aggressive scenario assumes the presence of a “masterplan” for CCS, including agreement by oil companies, Government, and other stakeholders to maximise the role of CO_2-EOR. Initially CO_2-EOR takes place in the Auk/Fulmar cluster of oilfields, which then serves as an offshore CNS hub for aquifer and storage development. Thereafter the CO_2-EOR network expands northwards, with backup storage capacity also developed in the SNS (Bunter sandstone aquifer) and in the CNS (Captain sandstone saline aquifer). A priority is to trial CO_2-EOR in the giant Forties oilfield in the early 2020s, so that if successful this can be expanded. Buzzard is close to St. Fergus and can be accessed easily. Optimum selection of the exact choice and sequence of other fields is more sensitive to assumptions on performance, re-use assumptions, and CoP date, for which the accuracy of public data is insufficient to derive robust conclusions. The Aggressive scenario assumes CO_2-EOR extends further north in the 2030s, i.e. to the Northern North Sea (NNS, both UK and Norwegian sectors), although east to the Danish sector is also feasible.

4.4.2 Cautious Scenario

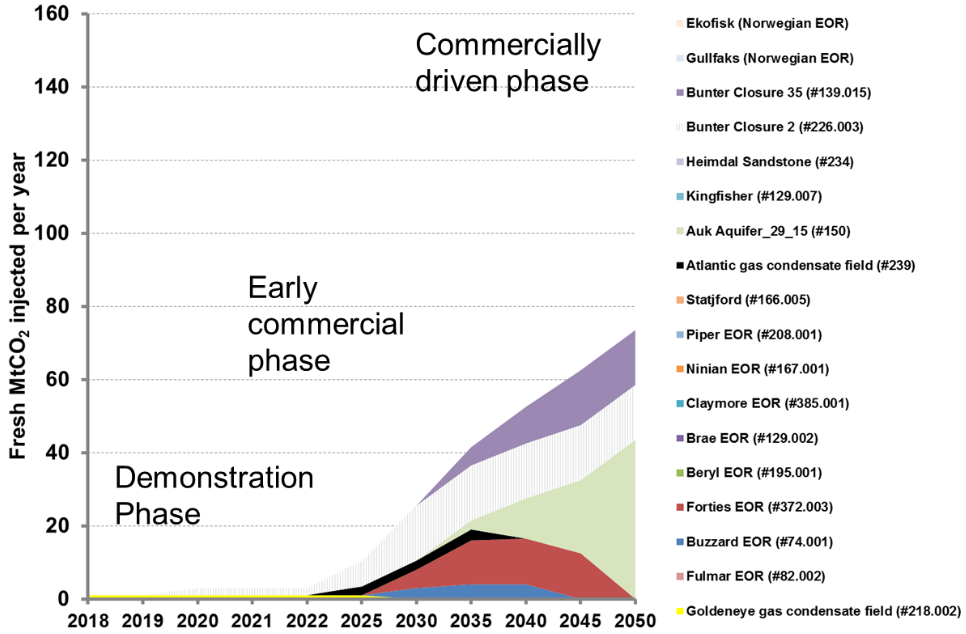


Figure 16: Storage deployment in the Cautious CCS and EOR scenario

The cautious scenario assumes slower uptake and storage-led choices in the 2010s and early 2020s. Goldeneye is deployed first, followed by the Atlantic gas condensate fields (also in the CNS), and the Bunter sandstone aquifer in the SNS. EOR projects begin only in the late 2020s (after CCS is "proven"). Assuming they are started in the 2020s, Buzzard and Forties would appear the most attractive CO_2-EOR projects to grow in the 2030s. These could continue to reinject produced and recycled CO_2 in the 2040s and beyond, but the majority of fresh CO_2 would then be directed to a limited number of very large stores. The assumption here is that other oilfields will have ceased production and no longer be available for CO_2-EOR.

4.4.3 St. Fergus Hub scenario

The St. Fergus hub scenario assumes essentially the same CO_2 supply as the Cautious scenario. However, here it is assumed that Scotland successfully positions St. Fergus as the infrastructure hub for all CCS projects in the UK, and gains the support from the oil industry for rapid CO_2-EOR trialling and maximum deployment.

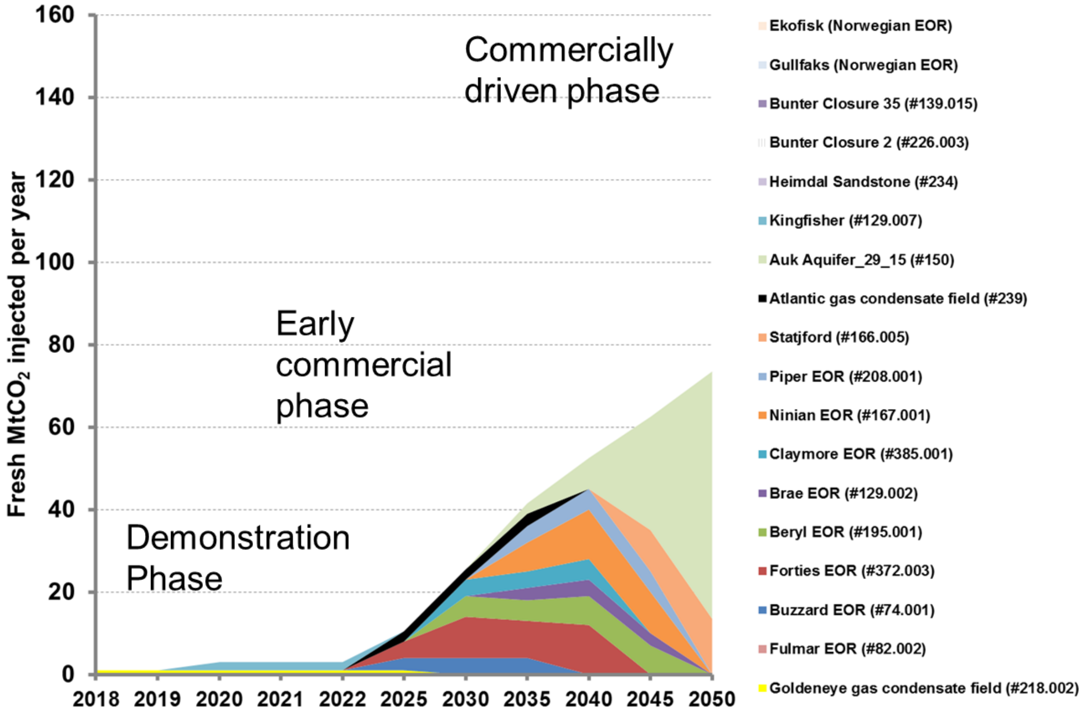


Figure 17: Storage deployment in the Cautious with St. Fergus Hub scenario

An early start of CO_2-EOR in the 2020s from a St. Fergus hub would imply a slightly different choice of oilfields (with each field having a different fresh CO_2 profile) than in the Aggressive scenario. The sequence has been designed to maximise the EOR potential, choosing fields that are in close proximity, and therefore for which incremental expansion appears feasible. The total oil production from the St. Fergus hub scenario is therefore comparable to that in the Aggressive scenario.

A flexibility of the St. Fergus hub scenario is the ability to switch from an EOR-led scenario to the use of storage-only solutions developed around the corridors or storage hubs described earlier in this chapter (for example in and around the Captain sandstone saline aquifer).

Graphs of assumed oil production for the three scenarios are provided in the Appendix.

5 Onshore CO_2 transport infrastructure in Scotland

Pipeline infrastructure is highly specific, and the location of potential storage sites and emitters dictates the practical shape of pipeline systems. CO_2 sources on the east coast of Scotland can access storage in the North Sea, whereas sources on the west coast could additionally access storage in the East Irish Sea.

Several studies have examined at high level the opportunities and constraints for onshore CO_2 pipeline infrastructure in Scotland[25]. These studies have identified key opportunities as:

- A new pipeline connecting Peterhead Power Station to St. Fergus gas terminal
- Re-use of the existing National Transmission System Feeder 10 natural gas pipeline to connect sources in the Forth estuary with St. Fergus, (e.g. as proposed for the Scottish Power Longannet-Goldeneye project and the Captain Clean Energy Project).
    - An upcoming SCCS study confirms that more than 80% of Scotland's existing large stationary sources are within 10 miles of Feeder 10.
- A new integrated CO_2 pipeline gathering network to gather captured CO_2 from coal, gas and industrial sources in proximity to the Forth Estuary.

The factors driving investment in CO_2 onshore pipeline infrastructure in general have been well described[26], and understood to be:

- Expectations for (and degree of confidence in) the future locations and capacities of sources and sinks
- Phasing of infrastructure and expected utilisation over time
- Pipeline sizing
- Flexibility, e.g. need to manage variable flow, third party access
- Consenting risk (social acceptance issues)
- Need to manage pressure and temperature of flow
- Safety management
- Business and regulatory model (e.g. ownership)

[25] Scottish Enterprise (2010) Opportunities for CO2 transport around Scotland, available at http://www.scottish-enterprise.com/~/media/SE/Resources/Documents/ABC/CO2-Transport-Options-for-Scotland.ashx

[26] Element Energy *et al*., for the IEA Greenhouse Gas R&D Programme (2009) CO_2 pipeline infrastructure: Opportunities global opportunities and challenges, available at http://www.ccsassociation.org.uk/docs/2010/IEA%20Pipeline%20final%20report%20270410.pdf

- Terrain challenges (preference to avoid hills, crossings, urban areas, areas of outstanding natural beauty or scientific interest)

This chapter will review Scotland's onshore infrastructure opportunities.

5.1 Onshore pipeline infrastructure from Peterhead to St. Fergus

If a capture project is developed at Peterhead Power Station, CO_2 could be transported directly via pipeline or ship to a storage site from Peterhead/Cruden Bay, or indirectly via St. Fergus gas terminal.

The Peterhead study by Petrofac has established that in principle three existing gas pipelines (diameters 18", 26", and 36") could theoretically be made available for gas phase CO_2 transport from Peterhead Power Station to St. Fergus. The up-front cost for re-using the 30 year-old Shell existing 18" pipeline (maximum allowable operating pressure 42 bar, total length 18 km) was estimated by Petrofac in the region £5m.

A new pipeline could also be considered, potentially making use of existing pipeline rights of way onshore, through a novel offshore route, or, as the land between Peterhead and St. Fergus is sparsely populated a new dedicated CO_2 pipeline could also take an alternate route, potentially a "branch" from Peterhead joining to a trunk pipeline from elsewhere in Scotland. Given the short distances involved, the ultimate decision around a pipeline route is likely to be strategic as the cost of a new onshore 20km pipeline is likely to be dwarfed by capture and offshore costs.

The 36" pipeline is relatively unlikely to be useful for CO_2 transport as it is presently used to supply natural gas to Peterhead Power Station.

5.2 Feeder 10 – a unique asset

Changes in the supply of natural gas have reduced the capacity requirements in some parts of the national transmission system. In 2010 National Grid announced that, following consultation, one NTS pipeline Feeder 10 was to be considered for disinvestment and reused as a Carbon Dioxide pipeline as part of the proposed CCS project at Longannet Power Station. The pipeline transits Scotland from St Fergus to the North East of England via several booster compressor stations and travelling west of Edinburgh, near Longannet and Grangemouth

The pipeline is a 36" diameter steel pipeline, approximately 280 km long with a maximum operating pressure of approximately 80 bar. It can be considered as three stages Bathgate to Kirriemuir, Kirriemuir to Aberdeen, Aberdeen to St. Fergus.

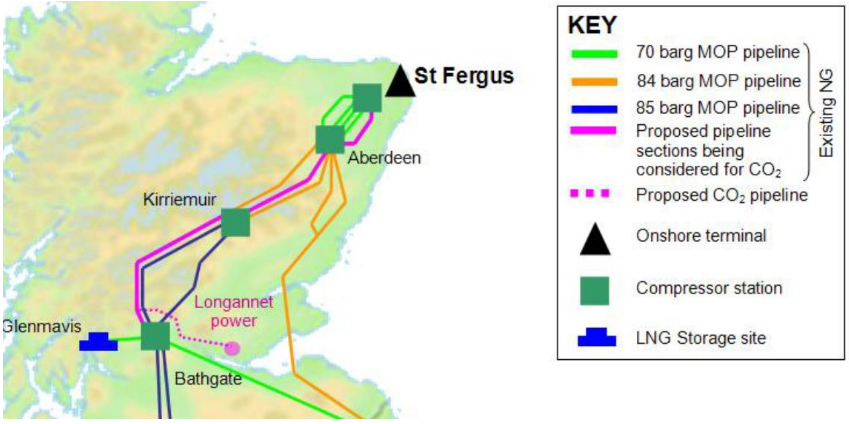
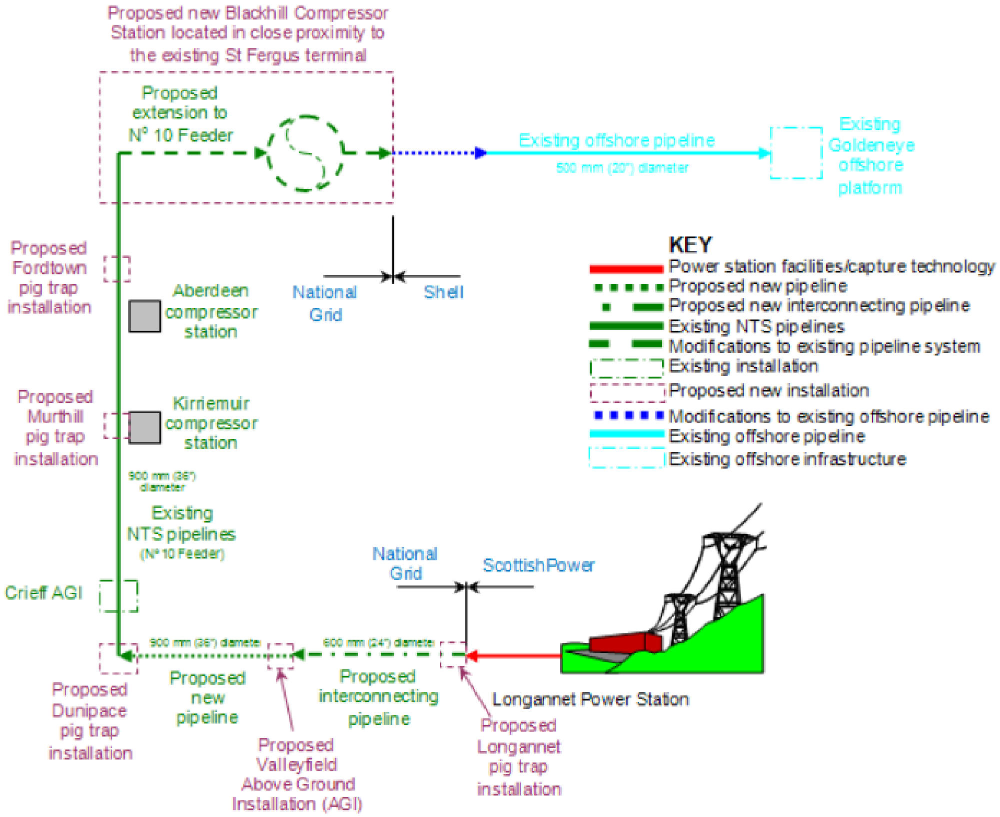


Figure 18: The sections of the Feeder 10 pipeline that were examined by National Grid for re-use with CO_2 (in pink) (Image copyright National Grid, reproduced from DECC Longannet-Goldeneye CCS FEED study).

The overall potential capacity of the pipeline is determined by its physical condition and its design limits. Natural gas in the UK is normally transmitted between 60-85 bar in the high pressure system. Carbon dioxide can be transported in a number of physical phases, typically as a gas or in a "dense phase". The phase behaviour of carbon dioxide is such that operating at ambient temperatures in a pipeline risks the presence of gas and liquid in a pipeline at the same time, this is not normally a desired condition. Operational experience in the US suggests that the optimal transport condition in new pipelines is in the dense phase or supercritical phase (typically above 80 bar), here the fluid has properties of both gas (low viscosity) and liquid (high density). This combination is generally the most cost efficient.

In the case of re-used gas pipelines the design pressure 60-85 bar is not sufficient for a pipeline to operate in the dense phase. Hence it is limited to gas transmission. To avoid two phase flow which would be difficult to manage, the transmission of gas is limited by ambient temperature conditions affecting the pipeline, typically at 3-10°C, this limits the pipeline to approximately 34bar. The original study considered gas phase transport of 2.5 $MtCO_2$/yr, comfortably within the pipelines capacity.

In addition to this design pressure condition the physical condition of the pipeline is critical. The decompression properties of carbon dioxide require specific mechanical design criteria to be met. The existing pipeline must be to the necessary design standards and consideration given to existing corrosion or damage which could negate the use of the pipeline. Internal conditions can be examined through in line inspection with pipeline inspection gauges, "pigging". National Grid has already identified potential "pig traps" for Feeder 10, as shown below in Figure 19:



Source: National Grid

Figure 19: Locations for proposed pig traps identified for the Feeder 10 pipeline. (Image copyright National Grid, reproduced from DECC Longannet-Goldeneye CCS FEED study)

The capacity of a pipeline is driven by a number of factors, flow rate, size, length, route topography and pressure drop. The pressure drop of the pipeline is critical as it is the limiting factor. It can however be overcome by adding intermediate compression. The optimal capacity of the pipeline is therefore a balance between allowable pressure drop and the cost of additional compression at the desired flow.

Current infrastructure is significantly constrained by the 34 bar pressure limit and as such the pipeline can potentially facilitate 3.5 million tonnes without requirement for substantial boosting. Between 3.5 Mt and 7 Mt/yr intermediate boosting stations will be required. Between 7 and 10 Mt/yr the costs and challenges of boosting become substantial. At these capacities a new dedicated high pressure pipeline, or potentially use of any additional natural gas feeder pipelines would likely be more cost competitive than increasing the pressure in Feeder 10. Transport of volumes above 10 $MtCO_2$/yr in the gas phase in Feeder 10 is not considered feasible, owing to the large number of booster stations that would be required.

The pipeline costs (excluding compression) expected for conversion of the Feeder 10 pipeline for use with CO_2 is estimated at £48m without land charges rising to £55m at PRE-FEED analysis, rising to £79m post-FEED. The Feeder 10 annual operating cost is estimated at £1.1m/yr.

The pipeline may require a new major accident prevention document (MAPD) to comply with pipeline safety regulations.

5.3 Extent of potential common pipeline infrastructure

New pipeline costs are determined primarily by the pipeline distance covered and capacity, and are higher for more complex terrains such as hilly or urban areas. There is a tension between optimising pipeline designs for a project and for maximising the longer term opportunity to integrate multiple CO_2 streams into a common infrastructure.

Some of the emitters in Scotland are small and widely dispersed (e.g. south, east, Fort William, Inverness/Nigg and Wick/Thurso). The drive to access storage in the central North Sea will drive infrastructure towards shore landing points on the eastern edge of Scotland, including, St Fergus, Cruden Bay and at Nigg which already have pipeline landings. Connecting these isolated small sources to a shared network would be prohibitively expensive (>£100/tCO_2 for onshore transport alone). Although one of the key issues with infrastructure is the design to enable future deployment scenarios, building a comprehensive CO_2 transport network that accesses all existing and potential future large CO_2 emitters in Scotland is not realistic.

Provisional capital costs for a hypothetical "comprehensive" pipeline network connecting 28 emitters instantly with a combined capacity in the region 28 MtCO_2/yr are estimated at £870m; running costs in the region £17m/yr. One of many challenges for such a network would be pressure management. The compression required for this network would cost £1.6 bn, with fixed operating costs of £81m/yr.

Figure 20: Hypothetical "all Scotland" onshore pipeline network connecting 28 planned or existing CO_2 point source emitters in Scotland.

In reality, any pipeline network will evolve organically, albeit in very "lumpy" and highly specific investments. With limited visibility on future CCS uptake, initial pipeline investments will be designed primarily to meet the needs of anchor projects and the follow-on projects with a realistic chance of joining a network with substantial additional capacity within the first 5-10 years of commissioning.

The more compelling opportunities are for a “cluster” of emissions in the Forth estuary/Fife area can be identified. Emitters within city boundaries should be excluded as access and safety management will be challenging.

Given these constraints, the most attractive corridor of capture potential can be identified by combining potential capture sites in the Forth estuary with emitters at Peterhead and/or hub at St. Fergus, providing access to the storage potential in the central North Sea.

Figure 21: Preferred onshore corridors for CCS development.

The costs of a Forth-based pipeline network gathering seven sources, are estimated at £150m (capex) and £3m/yr (annual opex), for a system with a capacity of 6 Mt/yr. The full pipeline network rises to £470m (capex) and £9m/yr (annual opex) if a new pipeline is constructed to transport CO_2 from the Forth cluster to St. Fergus (final system peak capacity 8 Mt/yr, following inclusion of three additional sources including capture at Peterhead power station). If CO_2 shipping became a significant industry, inclusion of additional pipeline capacity between Peterhead Port and St. Fergus gas terminal could add £6m to the overall capex (for a capacity of 10 Mt/yr).

5.4 Onshore pipelines connecting Scotland with potential CCS clusters in the Tees and Humber valleys

In addition to natural gas pipelines, other existing non-water pipelines do exist in Scotland, Figure 22. Local crude oil and multi-product fuel pipelines are operated by Ineos as well as an ethylene system with Sabic and Essar supplying ethylene to Teesside and Merseyside. Government pipelines operate locally between Leuchars/Linkswood and Inverness/Lossiemouth.

The suitability and availability of these pipelines for potential CO_2 service is challenging to assess at high level. Some would not be geographically or physically suitable; the majority of pipelines are small 200mm – 500mm and thus capacity limited. The pressure rating of each pipeline would also have to be considered as typically like natural gas infrastructure they are rated under 100bar.

Figure 22: Scottish existing non-water transmission pipelines

Even if these pipelines cannot directly be re-used, they could be investigated further to see if the rights of way for these could be an enabler for a new CO_2 pipeline.

5.5 Terrain challenges

The selection of a suitable landing point is complex and subject to access needs, manning requirements and the provision of fuel and utilities, and finally a decision based on a full cost analysis. Supplementary compression for gas systems will require significant cooling water and power for example, as shown by National Grid Carbon at the proposed Blackhills facility, part of the Longannet CCS project.

Terrain challenges near the east coast of Scotland include geological structures that can be difficult to lay pipes in, and it is common practice to avoid, where possible, population centres and protected areas (of scientific importance or outstanding natural beauty). Figure 23 illustrates terrain challenges in Scotland including Sites of Special Scientific Interest (SSSI), Special Protection Area (SPA), Special Area of Conservation (SAC), RAMSAR marine protection site (UN Protocol), Geological Conservation Review (GCR), National Nature Reserve (Scotland NNR), and Marine Conservation Area (MCA).

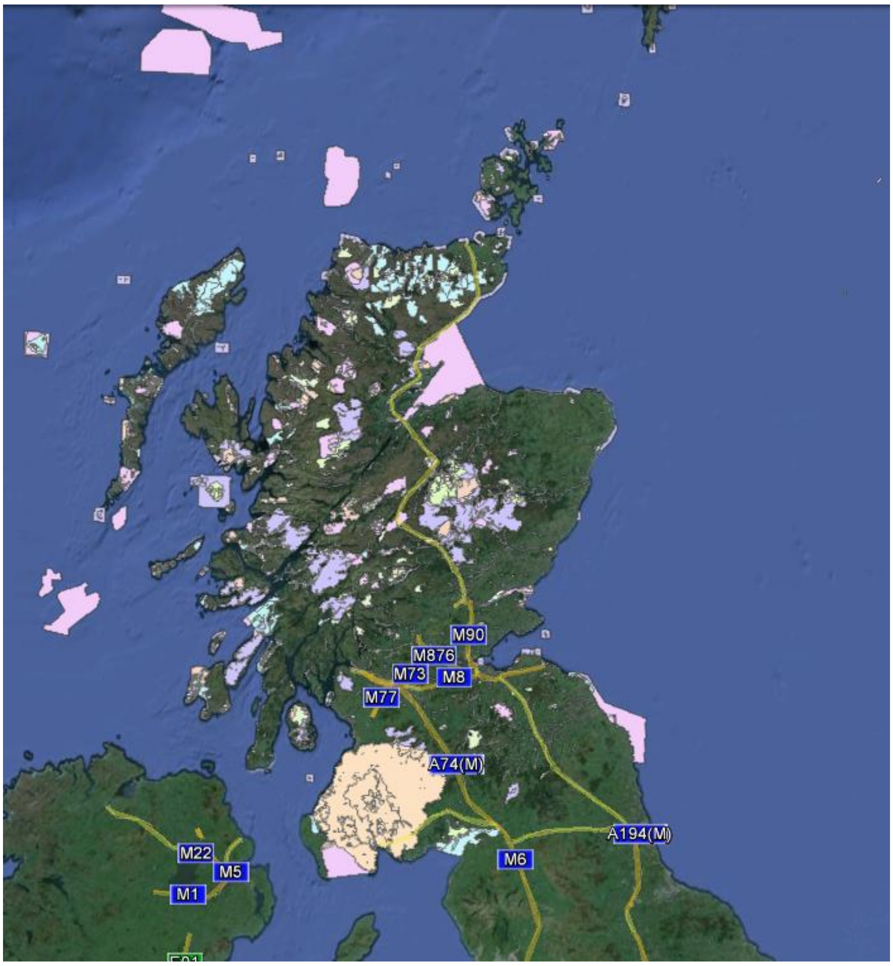


Figure 23: Scottish Environmental Constraints

The main access points for any Scottish hub depend therefore on where the bulk of emissions are captured. The most attractive pipeline options identified for new onshore pipeline infrastructure are:

(1) run up the east coast from the Forth northwards to an intermediate point, such as Cruden bay; or direct to the established pipeline landing areas at St Fergus.

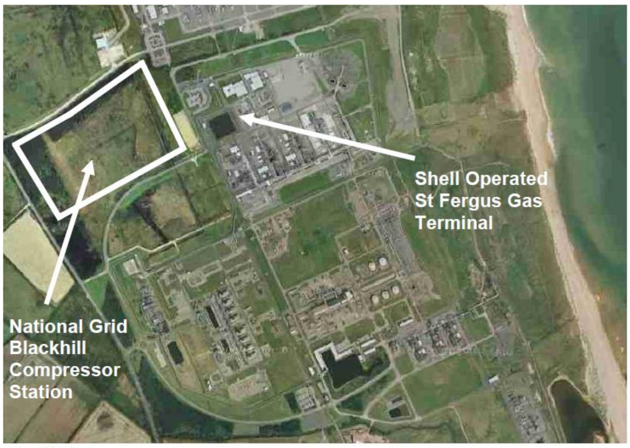
(2) Shore landings at either Cruden bay or St Fergus would be attractive for sharing CCS infrastructure with Peterhead Power Station.

(3) to conduct a shore landing on the northern coast of Fife (Figure 24); however the north shore of Fife is not necessarily conducive to a pipelay, as a sloping beach is usually preferred.

Figure 24: Northern Fife Constraints

Once the emitters are defined and the shore landing selected the route can be examined. The area of interest is effectively a narrow, populated band between the east coast and the highlands. Whilst crossing hills or mountains is possible, it is not necessarily desirable or easy.

During the Longannet-Goldeneye FEED study, National Grid identified a potential site for a new CO_2 compressor at St. Fergus as the Blackhill site at St. Fergus (see below).



Source: National Grid

Figure 25: Blackhill site at St Fergus

Previous work by National Grid on the requirements at St. Fergus has considered a number of detailed issues: Flows coming into and exiting Blackhill can be readily metered. The removal of particulates, impurities and the temperature of the CO_2 following compression can all be managed at Blackhill with conventional technologies. The site will need a revision of the existing COMAH documents and various other approvals, however the risk profile of the site is likely to be the best understood of any UK site.

5.6 Conclusions on onshore transport infrastructure:

Scotland offers a number of opportunities for onshore transport infrastructure. There is no single “optimal” solution however, as stakeholders have diverse priorities and investors will need to manage real uncertainties around the timing, location and capacities of sources and sinks, and also factor in public opinion.

Some of these uncertainties could be contained, but not eliminated, with pro-active efforts to designate corridors where CO_2 pipeline infrastructure is favoured. Based on current proposals, useful pipeline corridors would be between Peterhead and St. Fergus, around the industrial emitters near the Forth estuary, and between the Forth Estuary and St.Fergus. Connection of the small, isolated CO_2 emitters in the south or west of Scotland, or on Scottish islands, by dedicated new pipelines to an integrated network based around the Forth or the Forth-St.Fergus is expected to be prohibitively expensive, unless these sites can be anchored to a new large power CCS project.

Although there is no “optimum” solution, this does not warrant inaction. It is important to organise stakeholders to allow competing interests to be balanced and synergies to be identified[27]. Issues on which different stakeholders will have to make judgements include:

- Location/routing of pipeline
- Entry and exit specifications
- Capacity (i.e. diameters)
- Consenting/Purchasing of rights of way
- Costs
- Sequencing (i.e. network growth over time)

Inaction may lead to no CCS infrastructure, whereas even CO_2 infrastructure that is sub-optimally sized or located (from the perspective of Scotland overall) is still valuable.

The construction and operation of a new CO_2 pipeline between Peterhead Power Station and St. Fergus gas terminal is feasible.

Feeder 10 is an important asset for Scotland, and it would be valuable to qualify further and preserve this asset to ensure availability for early CCS projects. However the benefits of re-using this pipeline are primarily as an enabler in the near term; if CCS uptake is high in the long term other pipeline investments will become increasingly attractive. The existing NTS Feeder 10 pipeline provides ready access for transport of gaseous CO_2 between the Forth and St. Fergus, with a predicted capacity of up to 3.5 $MtCO_2$/yr with miminal intermediate boosting, other than at the start and end of the network. Between capacities of 3.5 Mt/yr and 7 Mt/yr one or two supplementary boosting stations would be required. If it is known in advance that capacity will exceed 7 Mt/yr, the most economic and flexible solution would be to increase capacity through additional pipelines, rather than add compressors. This could be through other NTS pipelines that become available, or new dedicated CO_2 pipelines. These solutions are likely to be more economic, flexible and practical than installing frequent booster stations on Feeder 10. Existing pipelines are already many decades old – the number of years that they can be re-used for transporting CO_2 will need to be explored on a case-by-case basis. Experimental testing of viability and on-going engagement with local residents may minimise opposition to the conversion of this pipeline for use with CO_2.

[27] Public facilitation is normal practice, for example, in creating district heat networks.

The capital cost of converting the pipeline was originally estimated at £55m, excluding compression. Following FEED study, this figure was revised upwards to £79m.

The most attractive beach crossings for a pipeline are a shore landing on the northern coast of Fife, an intermediate point on the east coast, such as Cruden Bay, or the established pipeline landing area at St. Fergus. As well as space and pipeline access (obviously), shoreline terminals would require power for compression and pumping, heat management facility (e.g. cooling water), and need to comply with stringent safety regulations related to deliberate or accidental CO_2 release. A shoreline terminal that functions as a hub would additionally require temporary CO_2 buffering facilities. The existing terminal at St. Fergus is constrained and direct replacement - rather than growth - at this site may be the most likely opportunity.

6 Offshore CCS infrastructure

This chapter reviews lessons from North Sea oil and gas infrastructure development, the key differences that need to be considered for CO_2. Previous suggestions for North Sea transport, storage and EOR infrastructure are briefly reviewed. The study then identifies four illustrative potential offshore network development scenarios, consistent with the CO_2 supply scenarios developed earlier, that allow stakeholders to profit from Scotland's onshore and central North Sea assets.

6.1 Lessons from the development of the North Sea hydrocarbon basin

Development of the North Sea as a hydrocarbon basin has progressed in a number of discrete stages. Initial exploration in the SNS yielded a number of significant gas discoveries, subsequent exploration of the CNS/NNS (central and northern North Sea) led to the discovery of large oil fields, the Atlantic margin west of Shetland is the most recent focus for exploration of new acreage.

Major infrastructure was initially developed around discrete large discoveries. These fields were large enough to justify dedicated offshore platforms, export pipeline and onshore terminal facilities.

Oil and gas extraction recovery factors have been improved with technological advances including water injection, artificial lift, extended reach and horizontal drilling and seismic imaging. Further technology development is expected.

The size of individual discoveries has tended to decrease. Development of smaller fields is facilitated by utilising existing infrastructure; either platforms/installations for fluid processing or pipelines for product export to shore.

The exploration and exploitation of large hydrocarbon fields requires very large capital investment and is subject to considerable risk and uncertainty. Even after field discovery significant investment and time is still required to estimate the quantities of oil and gas that may be recovered. Large developments are frequently undertaken by joint venture partnerships. Such an arrangement allows for the major costs associated with development to be shared between a number of different companies and reduces an individual company's exposure to the risk/uncertainty of the field size and performance.

As the basin has matured commercial transactions have changed some of the ownership patterns. For mature assets where there is a long history of production the uncertainty in field performance is greatly reduced. Some operators prefer to have a higher working interest in such assets to have greater autonomy on their future development.

Production licences have been awarded based on arbitrary 'block' boundaries. Oil and gas fields frequently straddle licence block boundaries. Where there are different participants or differing ownership splits in neighbouring licence blocks significant time and effort has been expended in field (re)-determination and unitisation to obtain commercial agreement. Such activity does nothing to improve the performance of the asset; from the perspective of reserves maximisation these activities have been a distraction. As some CO_2 stores may be much larger than hydrocarbon fields, this could eventually become a significant issue. This issue should be avoided for CO_2 storage where possible, through attention to the nature and size of areas/volumes assigned for leases and licenses.

Access to infrastructure is recognised as a critical issue to maximising recovery from the North Sea basin. Operators of existing infrastructure frequently have different priorities to the operators of new fields wishing to utilise that infrastructure. Key components of a CCS network will likely remain in service, for other users, beyond the life of the initial development project. This will not necessarily alter the technical design of such a system but should be recognised within the commercial/regulatory framework.

Many of the technologies developed for oil and gas extraction will be directly applicable in an offshore CCS industry. Subsurface storage site monitoring and management will draw on the practices of seismic imaging and reservoir simulation. Drilling technologies will be transferable to CCS storage site development. Inspection, repair and maintenance activities for wells, subsea architecture and platforms will also be comparable.

6.2 Existing data, infrastructure, supply chains in the central North Sea

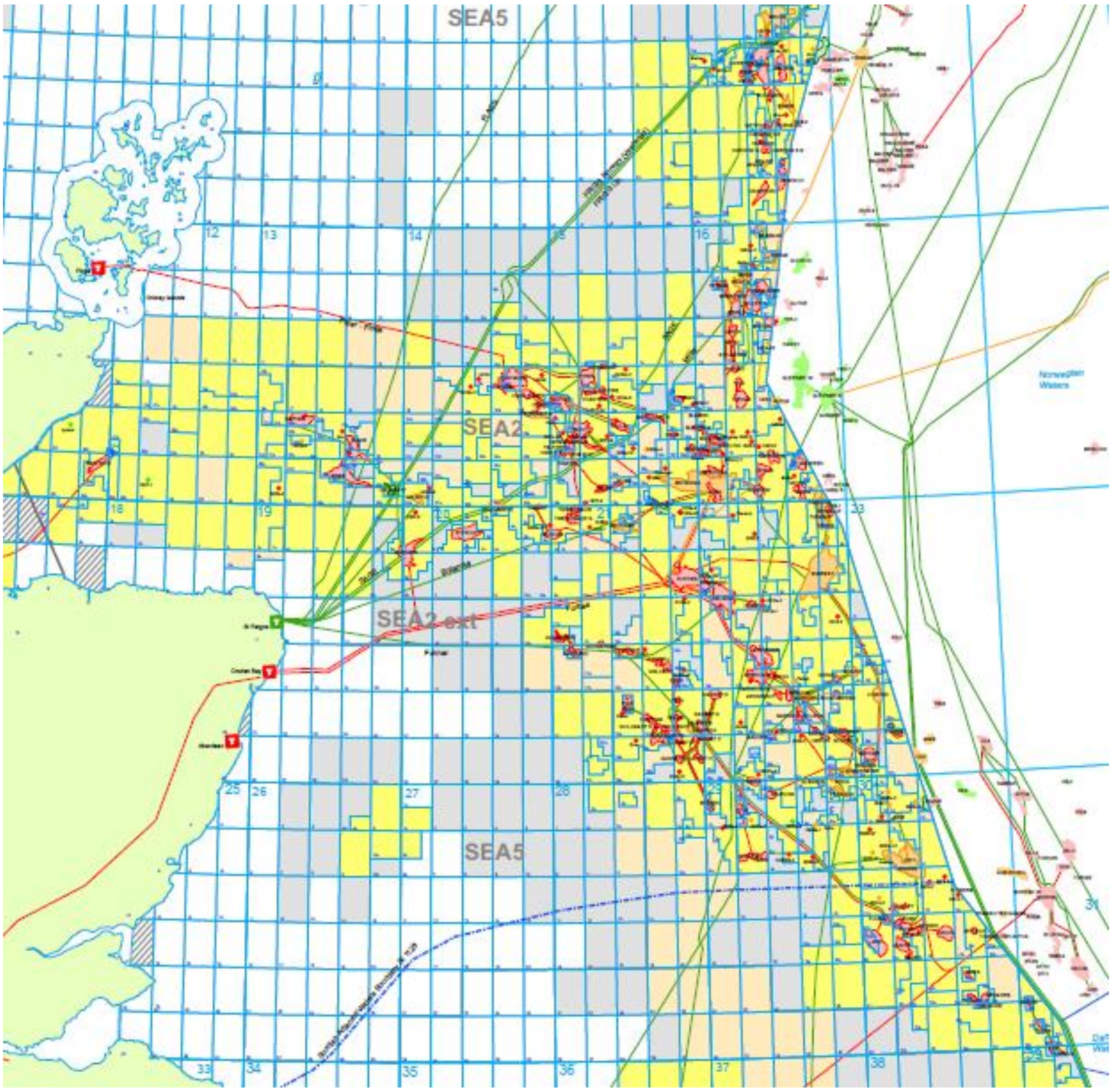


Figure 26: Illustration of existing pipeline infrastructure in the Scottish territorial waters of the central North Sea. Green lines = gas pipelines; Red lines = oil pipelines. Yellow squares – licensed oil and gas blocks.

The following information, collected from oil & gas extraction activities, will be valuable in the development of a CCS network.

- Seismic imaging (raw data and interpretations)
- Reservoir simulation models
- Field production, injection and pressure history
- Well logs and cores
- Well test data
- Formation mineralogy and brine composition

This information will be of greatest relevance to those depleted hydrocarbon fields which may be used for CO_2 storage. The same quantity and quality of information will not be available for the large aquifer sinks.

As oil and gas flows to shore decrease there is the opportunity to re-use trunk pipelines to transport CO_2 to offshore storage sites. A few lines at St. Fergus are not currently in hydrocarbon service and could be available for CO_2 transportation (Miller, Atlantic/Cromarty and Goldeneye). There is also a large distribution network in the Central North Sea, including high pressure oil and gas pipelines, some of which have already had contact with CO_2 during service. The availability of other lines is dependent on when the feeder fields cease to be economic. Forecasts of timing of pipeline availability may be made, any CCS development that relied on these may be subject to delay associated with any additional production volumes that may be discovered/exploited.

As a key component to the value of offshore production, the integrity condition of offshore trunk pipelines is carefully managed. It is likely that the end of the service life of these lines will be determined by the quantity of oil/gas available to flow through them rather than by their integrity condition. It must be recognised that these lines will have been in service for several decades by the time they become available for re-use as part of a CO_2 transportation network. As such, re-use of existing lines may be suitable only for a few years (rather than several decades for new pipelines).

There may be limited interest (and money available) for preserving pipelines for several years between hydrocarbon use and CO_2 transport. During this intervening period, there will be on-going liabilities which will need to be allocated appropriately to the original hydrocarbon industry owners, the nascent CCS industry, public bodies, or third parties. In all cases the owners will require sufficient funding to maintain the high standard of future operational capacity.

When existing pipelines are being considered for re-use, it is crucial that suitable specifications are determined and enforced for the composition of the CO_2 to be transported. Control of the moisture of the transported fluid will be essential to ensuring the integrity of existing carbon steel lines to minimise corrosion and hydrate formation, which could damage the pipeline.

As well as trunk pipelines, there may be the opportunity to re-use other offshore infrastructure. The high cost of new platforms and wells makes re-use of these attractive. Retention of floating facilities and minor intra-field flowlines will be of marginal benefit and therefore unlikely, except opportunistically. Re-use of existing infrastructure will be complicated by the decommissioning obligations of current operators. The successful transfer of stewardship/responsibility from oil and gas operator to CCS operator will be critical.

6.2.1 Supply chain

The Exploration & Production industry is serviced by a very well developed supply chain. In principle there is nothing unique about offshore CCS operations, in comparison to oil and gas production activities. The following services are applicable to an offshore CCS industry:

- Seismic
- Reservoir modelling
- Drilling & well services
- Fabricators

- Pipeline & equipment services (design/construction/installation)
- Facilities services (operation/inspection/repair/maintenance)
- Logistics
- Dive services

There will be competition for resources to secure these services with CCS industry competing against oil and gas activities (on-going production and decommissioning).

Whilst at a global level there is unlikely to be a significant supply chain constraint for CCS development, since the oil, gas, and CCS industries are difficult to predict, it could be difficult to manage supply chain capacity in a way that maximises Scotland's contribution to projects. In periods where oil prices or subsidies for offshore renewables are high, the offshore supply chain will be in high demand, increasing prices or delaying timescales for CCS. Conversely, if oil prices fall, or there is a collapse in demand for offshore renewables, then the experienced but highly mobile offshore teams may be quickly redeployed to alternative locations, again reducing CCS flexibility.

6.3 Technologies for offshore CO_2 transport and storage

Transportation of CO_2 by pipeline or tanker are the options available for connecting to offshore storage sites

6.3.1 Pipeline Transportation

The fluid physical properties dictate the minimum operating pressure, to ensure single phase flow within the line. For CO_2 transportation the pipeline pressure must maintain a suitable factor of safety above the cricondenbar[28].

As discussed onshore, the capacity of trunk pipelines for fluid transportation is limited by consideration of pressure drop and fluid flow regime. The effective pipeline capacity may be increased with intermediate pressure boosting stations, located along the length of the route. Such booster stations would include large rotating equipment, power supply (electricity or suitable fuel) and access for inspection, repair and maintenance. This is a much greater challenge offshore than onshore.

The re-use of existing and under-utilised oil/gas trunk pipelines is an opportunity that could reduce the cost of CO_2 transportation as part of a CCS network. The trunk pipelines that could be considered for use within a CCS development have already been in service for several decades. The condition of these lines needs to be critically assessed in terms of the remaining service life available, but the immediate integrity condition is not necessarily in question, if it is merely decline in production that has made the line available for re-use. Pressure operating regimes would likely be restricted to 90-150 bar. The costs of installing booster stations offshore would likely outweigh the benefits from re-using an existing pipeline.

There is no flexibility to select the capacity, or routing of existing pipelines.

There will be costs associated with the re-use of existing pipelines which will be determined by the timing of the transfer of service from hydrocarbon to CO_2 transportation. It is essential that a suitable preservation regime is developed and implemented immediately following the

[28] The minimum pressure required to prevent liquid formation

end of hydrocarbon service. Additional consideration will be required for plant/piping modification that will be required at the onshore and offshore ends of any existing pipeline.

6.3.2 Surface Facilities for CO_2 Storage

Surface facilities required for the earliest storage only projects are minimal and will include:

- Injection well flow control and isolation valves
- Pipeline isolation valves
- Instrumentation and data collection (flow, temperature, pressure)

It is expected that storage sites may be developed without the need for offshore pressure boosting, eliminating the need for major rotating equipment (pumps/compressors/turbines) offshore. However the need to intervene to service CO_2 injection wells or to manage pressure build-up in reservoirs is difficult to predict, and over time requirements may increase.

Surface facilities for offshore storage hubs should be designed to operate with minimal manning levels.

There are a number of options for surface facilities

- All equipment/wellheads on seabed
- All equipment/wellheads on raised platform (steel jacket)
- Wellheads on seabed and other equipment on floating facility (Semi-submersible, ship-shaped etc)

These are all well-established technologies with many years of use within the upstream oil and gas industry.

The selection of offshore facility type is strongly influenced by the following

- Opportunities to re-use existing infrastructure (within a limited time window)
- Extent of offshore processing required
- Number of injection wells
- Expected frequency of well intervention

A subsea solution would be suitable for an offshore storage hub that does not require offshore pressure boosting, has a small number of wells and low frequency of well intervention. Such a development will have low on-going running costs (lower manning and maintenance costs). A storage hub with subsea facilities will require a mobile drilling unit to drill the injection wells and specialist vessels (including divers and/or remote operated vehicles) to carry out inspection, maintenance and intervention activities.

Where a greater number of injection wells is required or where frequent well intervention is required a platform at the storage site may become more economical. The upfront costs of such a development scenario may be higher (to include the platform structure and drilling unit), however the unit cost of drilling and subsequent inspection, maintenance and intervention activities will be significantly cheaper. A platform at an offshore storage site need not be continuously manned. Activities can be planned for execution in campaigns at a suitable frequency (e.g. maintenance during summer months, although there will be a need to co-ordinate maintenance across the CCS chain).

It is unlikely that a (new) concrete structure would be an appropriate solution for CO_2 storage facilities with few wells or short operating lifetime. Floating facilities are cost effective for oil and gas developments where there are insufficient reserves to justify installation of fixed installations (and pipelines). Such developments include wellheads located on the seabed tied back through flowlines and risers to processing, transportation and perhaps storage facilities located on the floating installation. The key advantage of such a solution in upstream development is that a single floating installation may be re-deployed for multiple field developments at different locations. A disadvantage is a substantially higher operating cost than for fixed installations of equivalent capacity.

Although no project developers to date have proposed deploying a floating facility as part of a CO_2 storage project, stakeholders should adopt a “watching” brief to see whether the flexibility of floating systems provides benefits for CCS network expansion in the future.

6.3.3 Storage Facilities for CO_2-EOR

The surface facilities required for CO_2-EOR are significantly more complex than required for CO_2 storage only. The EOR site will require equipment for CO_2 reception and injection and hydrocarbon production, processing and export. A greater number of injection wells (compared to storage only) may be required to suitably manage the flow of CO_2 through the reservoir.

As the CO_2-EOR programme matures the concentration of CO_2 in the produced fluids is likely to increase. As the CO_2 concentration increases the produced gas may no longer be suitable for export or for use as fuel gas. With increasing concentration of CO_2 in the wellstream fluids the flow of gas (relative to oil) will also rise. Additional equipment (or plant modification) will be required to strip, compress and re-inject this gas.

The combined effect of CO_2-EOR on the composition of the wellstream is to increase the site power demand (extra power for re-injection) and to reduce the availability of gas for fuel (with increasing/varying CO_2 content the produced gas will be unsuitable for power generation).

Deployment of CO_2-EOR may require a significant change to the metallurgy of existing facilities, which, with few exceptions, are likely to be designed with no or low levels of CO_2. Elevated levels of CO_2 will make the production fluids more corrosive. To ensure safe operation it may be necessary to replace well tubulars, piping, valves and vessels with materials resistant to higher levels of CO_2.

Deployment of CO_2-EOR will involve a large number of wells and significant fluids processing and a high power demand. The combination of re-use of an existing platform, potentially with a bridge-linked platform to support the CO_2 infrastructure, is considered the most likely option for deployment of CO_2-EOR. The costs and designs for infrastructure for CO_2-EOR in fields that have already been abandoned have not yet been investigated.

6.3.4 Storage Site Development

Identification of potential offshore storage sites is largely derived from information collected as part of activities related to oil and gas exploration and extraction. Seismic imaging of the subsurface is a key tool for the discovery and investigation of potential CO_2 storage sites.

Information from drilling activities is also relevant but likely to be less accessible. The seismic and drilling information allow for estimates of potential storage capacity, some form of appraisal may be required to allow estimates of 'bookable' storage capacity. Such appraisal will likely require actual injection of CO2 over a suitable time period and range of rates.

Long term monitoring of CO_2 storage sites will be required to determine variation in injection performance, update forecasts of remaining capacity and to ensure long term integrity of CO_2 storage. The monitoring techniques deployed will be influenced by the geology of each site. The pressure within the storage site could be readily measured with downhole gauges. This can be checked using a reservoir model against the expected pressure rise from the material balance associated with the quantity of CO_2 injected.

Additionally time-lapsed seismic may be used to track the subsurface dispersion of CO_2 within the storage site

Thousands of exploration, appraisal, production and water injection wells have been drilled in the central North Sea. If depleted hydrocarbon reservoirs are to be used as CO_2 storage sites, consideration must be given to the presence of these legacy wells. If these wells have not been suitably abandoned then they could offer a leak pathway through which CO_2 (or remaining hydrocarbons) may migrate from the store as the pressure rises or if the hydrocarbon is made more mobile. Such losses pose an environmental risk, would degrade the effectiveness of the storage development and would not be acceptable to regulators and other stakeholders.

For any potential storage site it will be essential to demonstrate that existing wells do not pose a threat to the long-term integrity of the storage site. If there is insufficient evidence to demonstrate this it may be necessary to include well re-abandonment (and associated costs) as part of the storage site development project. However, it is not expected that all existing wells would need to be re-abandoned before any CO_2 was injected, as CO_2 migration is likely to be limited. However the feasibility and economics for treating legacy wells in the central North Sea require more detailed examination.

CO_2 injection wells will have a relatively simple design, comparable to water injection wells in fields that have a waterflood. Downhole equipment will be limited to pressure and temperature gauges only. The precise targeting of the location of these injection wells is less critical than can be the case for oil/gas production wells as the flow of fluids through the subsurface structure does not need to be managed in the same way.

The properties of the storage site (horizontal and vertical permeability, faulting etc) will dictate the number and design of injection wells, and the length of perforations required.

The re-use of existing wells may help to reduce the cost of a CO_2 storage site development and will defer when the ultimate cost for abandonment will be incurred. In this case at the end of hydrocarbon production activities the well would be suspended in a state that leaves it safe for an extended period of time and ready for future re-use.

The number of injection wells required will be determined by the storage site rock properties (how easily can the CO_2 be injected) and the injection rate required. Additional injection wells beyond this minimum number will be required to provide redundancy. It is expected that a very high uptime will be required from a CO_2 transportation and storage system.

6.3.5 CCS Network Development

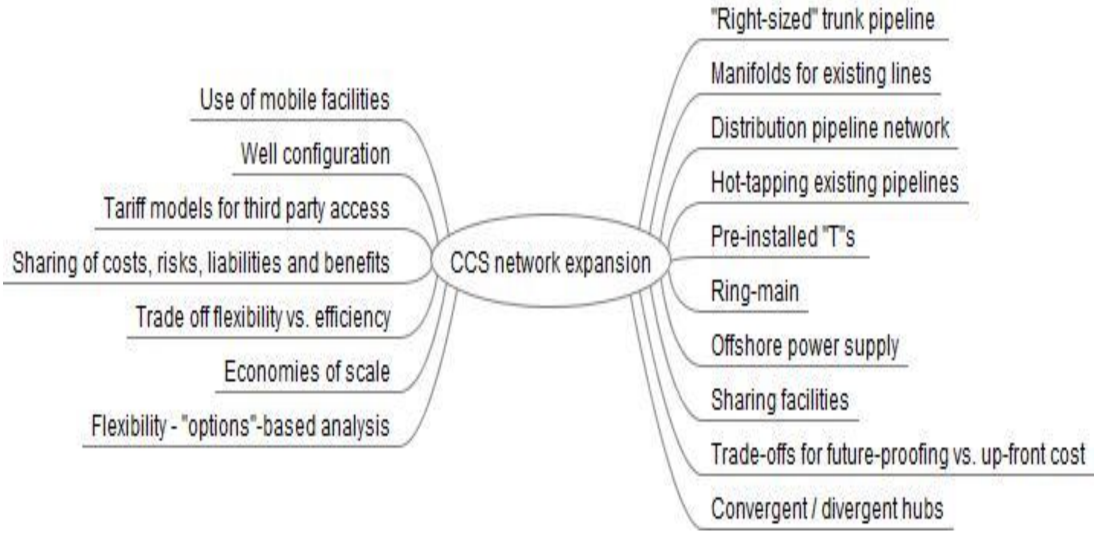


Figure 27: Mechanisms and drivers for CCS network expansion

The existing network of offshore oil and gas trunk pipelines has evolved in keeping with the size and quantity of discoveries. Early trunk lines and onshore terminals were justified by the discovery of a small number of very large fields. Through this development the choice of location for onshore terminal was influenced by the proximity to the offshore field and access for onwards transportation to market.

To prevent unnecessary proliferation of pipelines and to enable economic development of smaller discoveries the offshore pipeline network has continued to expand to provide an export route for more fields.

Frequently such trunk lines have been intentionally over-sized based on initial requirements to provide capacity for future users.

This is a credible template for the development of an offshore CO_2 pipeline trunk and distribution network, with the case study on the Forties Pipeline reported previously [Scottish Enterprise (2012)]. An initial CCS project/hub will provide the necessary demand for a major trunk line. This line can be readily designed with a number of means of providing access to future CCS developments. The extent of 'future-proofing' will be a trade-off between additional up-front costs, the expected future take-up and acceptable tariff and financing costs.

Pre-investment in the pipeline design for future users must consider both capacity and access. For additional capacity the pipeline diameter and perhaps pressure rating will need to be increased. As such changes are applicable across the entire pipeline length, such changes will have a significant impact on the pipeline cost.

For new long distance trunk lines consideration should be given for the pre-installation of Tee points. This will facilitate future tie-ins allowing a supply to be taken to additional CO_2 storage sites.

Where pre-installed Tees are not available (e.g. on existing trunk lines that are being re-used) it is still possible to make new connections. Hot tapping of pipelines is a proven specialist technique that enables tie-in to an existing pipeline without interruption to service, although this has not been demonstrated for CO_2 pipelines.

As the CCS industry matures incorporating CO_2 sources across the country diverse topologies for networks are possible – including tree and branch and ring main networks. Although not essential such an arrangement may offer additional flexibility in the matching of CO_2 supply to storage site (perhaps even on a day-to day basis). An analogy may be drawn with the distribution through the onshore gas grid where several routes may connect locations and the direction of flow may change. Isolation of a single line section for inspection, repair and maintenance will affect the flows elsewhere in the system.

As discussed, offshore pressure boosting for storage projects should be avoided, for as long as possible as the life-cycle cost of compression/pumping offshore is significantly greater than the equivalent activity onshore. For the initial storage sites it will be possible to deliver CO_2 at the offshore location with sufficient pressure for injection into the storage site.

Offshore pressure boosting may eventually become relevant as CCS expands to incorporate more distant storage site locations or support reservoirs at higher pressures. Compression facilities will be needed at EOR sites – here fuel gas availability may become limiting. It may be preferable to install an offshore pressure boosting facility to allow transportation to a storage site further away if this prevents the requirement to install an additional trunk line in parallel with existing CO_2 lines.

If offshore pressure boosting is to become part of the CO_2 distribution network, then so too must power/fuel distribution. An offshore pressure boosting station will require energy to drive the rotating equipment. Long distance transmission of electricity offshore is not novel; key cost components will include the cable and step up/down transformers. Power generation offshore could also be included as part of a CCS network development. Consideration should be given to availability of suitable fuel and compatibility with the environmental objectives of the CCS development.

Taken together this suggests a well planned offshore system will involve the creation of a very limited number of offshore hubs where CO_2 boosting can occur. If CO_2-EOR develops, the boosting should be co-located with an offshore CO_2-EOR compression and recycling facility.

6.4 Scenarios for offshore transport and storage infrastructure development

As a step towards illustrating how these factors may play out, this project has identified several potential offshore transport infrastructure growth scenarios for CCS with CO_2-EOR in Scotland and the central North Sea. These scenarios build and combine issues identified in earlier work and identified in this study. The capacities are consistent with the Cautious and Aggressive CCS and EOR deployment scenarios. The scenarios themselves are described as “Aggressive”, “Cautious” and “St.Fergus hub” scenarios.

Storage and EOR sites were chosen manually through an iterative process to try to maximise “optionality”, i.e. choosing stores that had very high levels of redundancy (based on stores with an excess theoretical capacity compared to initial needs or an area where multiple stores are in close proximity, or locations that allow switching between EOR storage or storage-only strategies depending on market conditions). Insights from the qualitative risk data in CO2Stored were also considered.

6.4.1 Offshore network for the Aggressive CCS scenario, including CO_2-EOR push

An illustrative evolution of the offshore networks from 2018-2047 in six five year phases for the aggressive CCS scenario with CO_2-EOR push is summarised as:

2013-2017

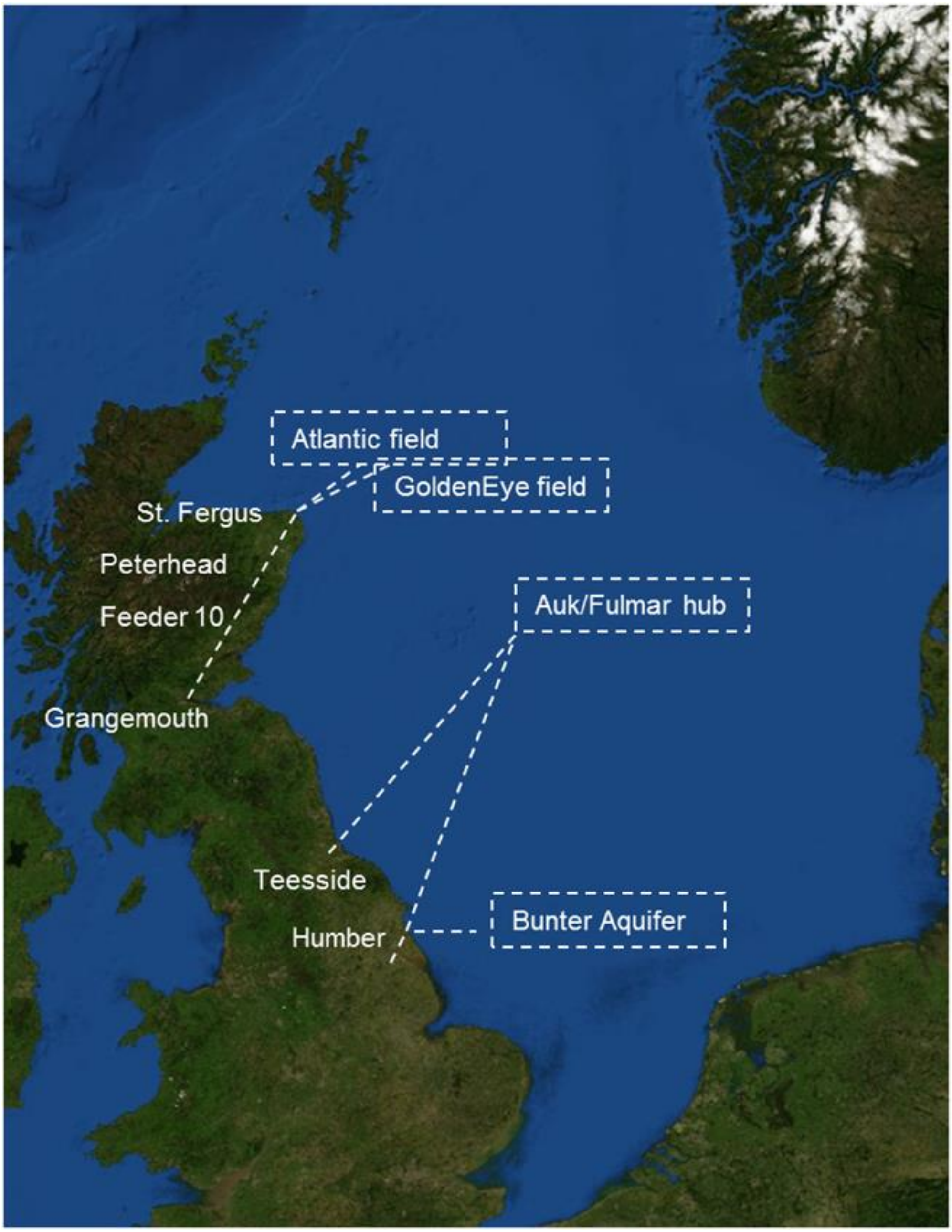


Figure 28: Infrastructure in 2013-2017. Dashed lines indicate under infrastructure under development.

Highlights are:

- Complete FEED and FID, and secure all permits for the Peterhead, Captain Clean Energy, Teesside Low Carbon, Don Valley and Capture Power projects in 2015.
- Refurbish and test where appropriate existing pipelines
- Refurbish existing platforms and construct new power capture, transport storage and EOR infrastructure as required.
- Undiscounted capex shoreline terminals £0.07bn, new/refurbished pipelines £1.5bn, storage £0.6 bn, EOR £0.8 bn.
- Capture, Transport and Storage planning, pre-development and future-proofing for a second wave of projects..

2018-2022

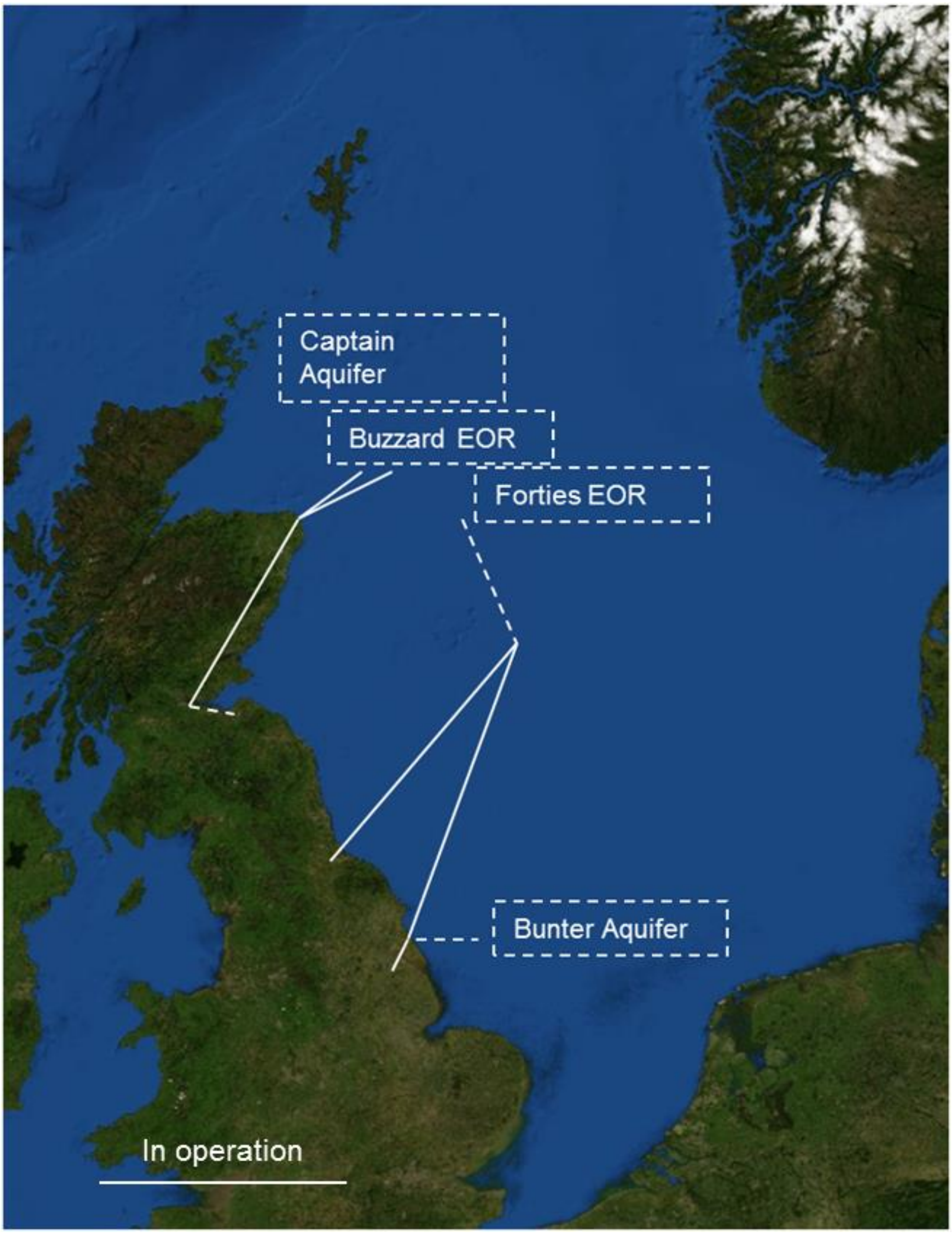


Figure 29: Infrastructure in 2018-2022. Dashed lines indicate under development. Bold lines indicate operational.

Highlights are:

- Five operational projects, two in Scotland, three in England.
- Existing pipelines speed up roll out in Scotland and CNS
- Mix of depleted field, aquifer and EOR storage as offshore hubs are created. “Hub” philosophy de-risks utilisation for storage developers.
- Streams of CO_2 (up to 1 Mt/yr) from operational storage projects are used to appraise nearby aquifers with wells, paid for at marginal cost.
- Develop new CO_2-EOR stores Buzzard (capex £0.9 bn) and Forties oilfield (pilot capex £1 bn)

- Shoreline boosting (£0.06 bn), storage backup in the Captain, Auk and Bunter saline aquifers to reduce system risk (£0.3 bn) and up to £0.8 bn in additional transport infrastructure.

2023-2027

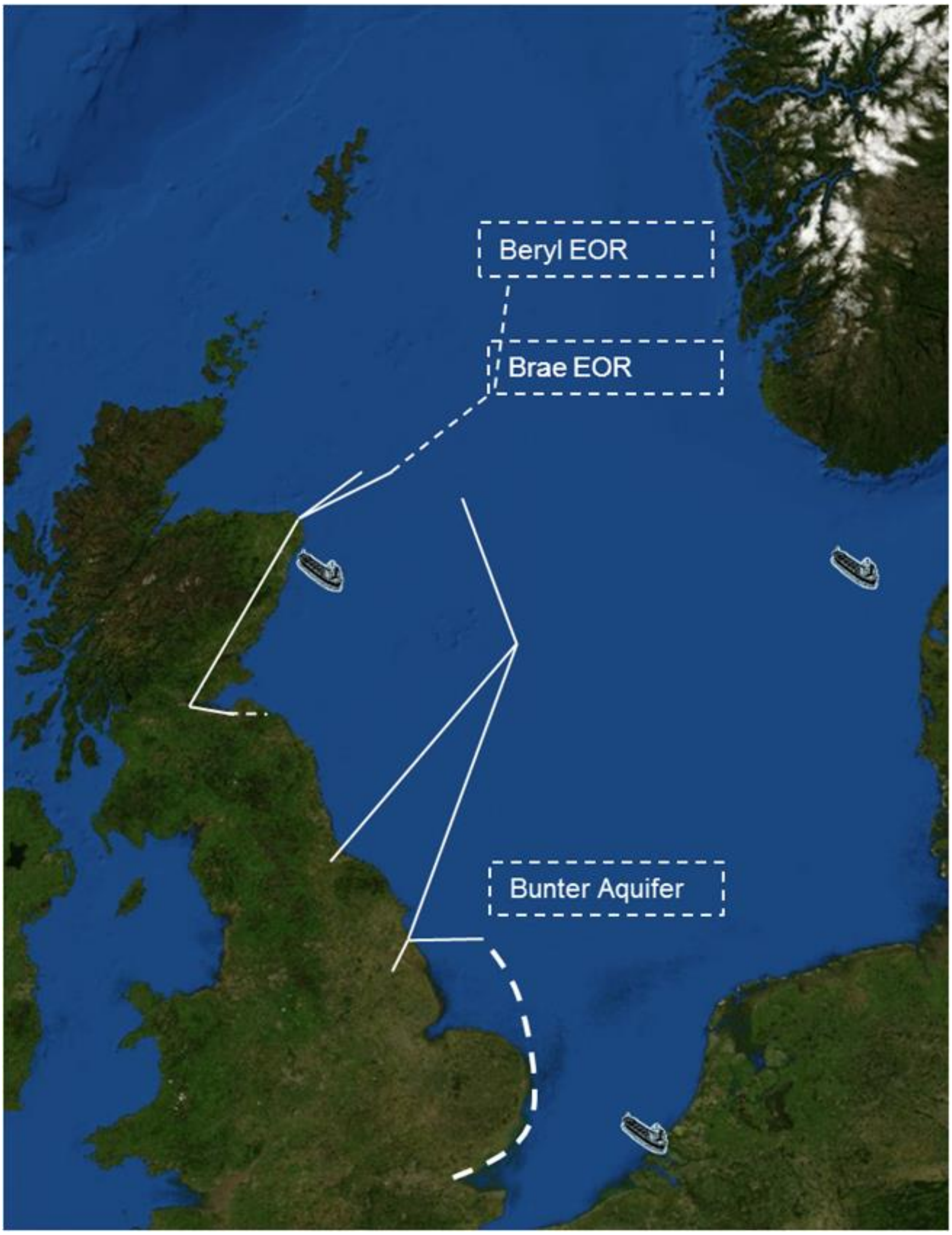


Figure 30: Infrastructure in 2023-2027. Dashed lines indicate under development. Bold lines indicate operational.

Highlights are:

- CO_2-EOR network expanded to include Forties and Buzzard oilfields
- Construction of additional CNS and SNS storage infrastructure (£4bn) and Beryl and Brae CNS EOR infrastructure £2bn
- Construction of additional capture in power and industry in Scotland and England.
- Emergence of CO_2 shipping and port infrastructure at Peterhead supplied from Europe.

2028-2032

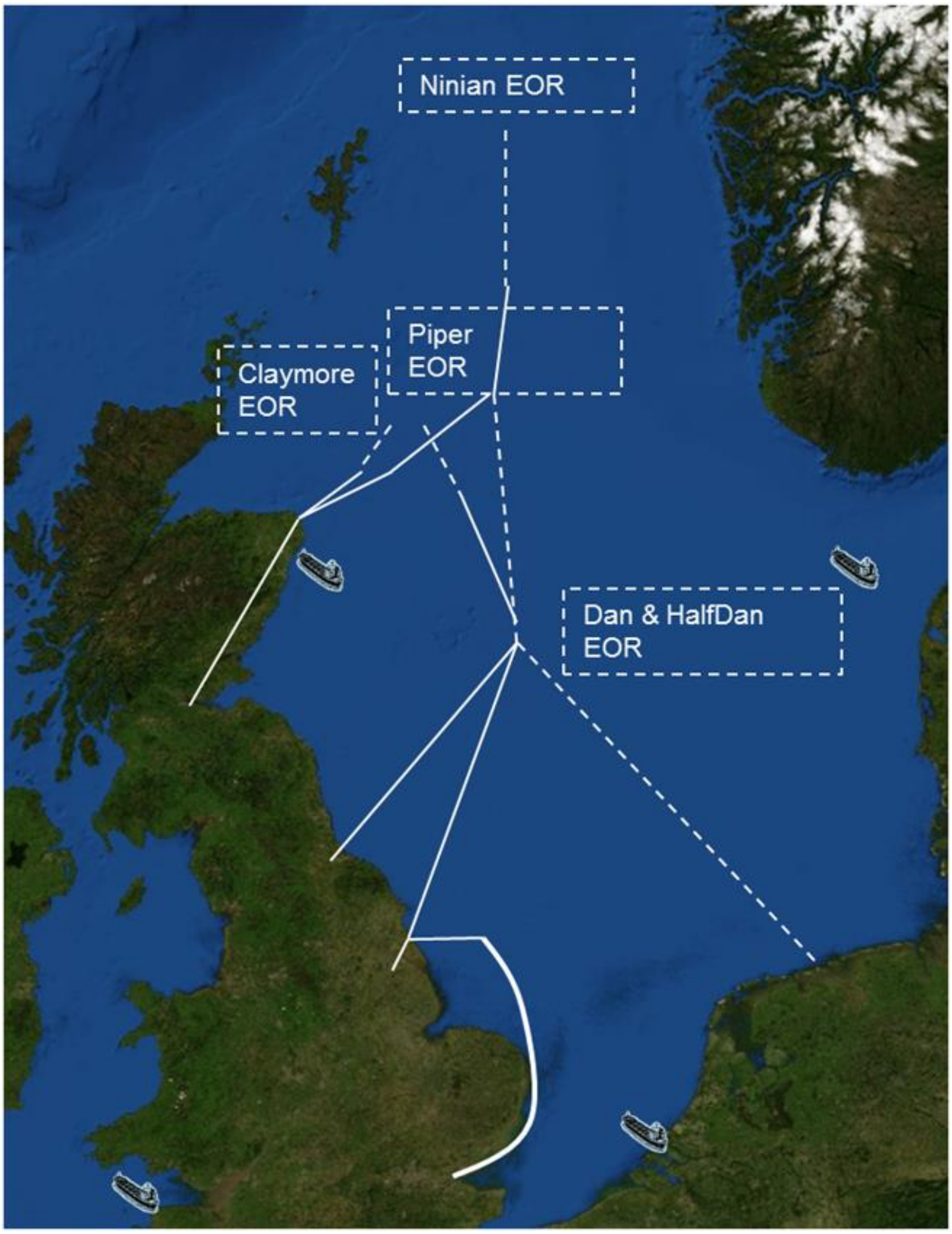


Figure 31: Infrastructure in 2028-2032. Dashed lines indicate under development. Bold lines indicate operational.

Highlights are:

- Continuation of EOR in the CNS
- Development of Claymore and Piper EOR fields in the CNS.
- Construction of pipelines and Northern North Sea EOR facilities for fields such as Ninian.
- Construction of new pipeline for transport of CO_2 from continental Europe to CNS hub.
- Expansion of storage subject to demand to include other European sinks such as Danish CO_2-EOR fields.
- Ramp up of North Sea CO_2 shipping network capacity

2033-2037

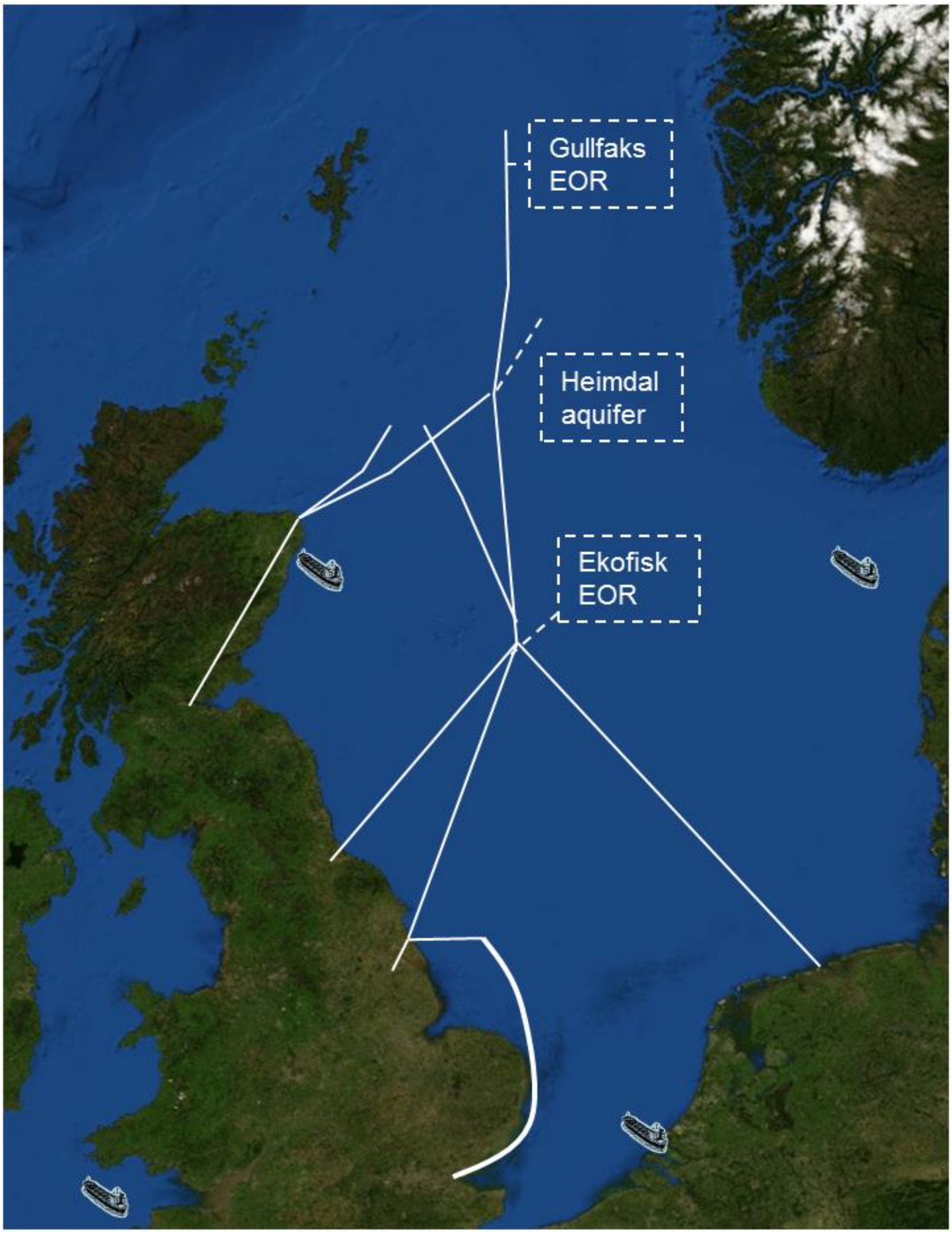


Figure 32: Infrastructure in 2033-2037. Dashed lines indicate under development. Bold lines indicate operational.

Highlights are:

- Integration of North Sea pipeline infrastructure with European CCS projects to complete backbone architecture.
- Expansion of storage subject to demand to include Norwegian sinks, such as EOR fields at Gullfaks and Ekofisk.
- Continued storage appraisal and development
- Continued use of shipping for short term or small scale projects

2037-2042

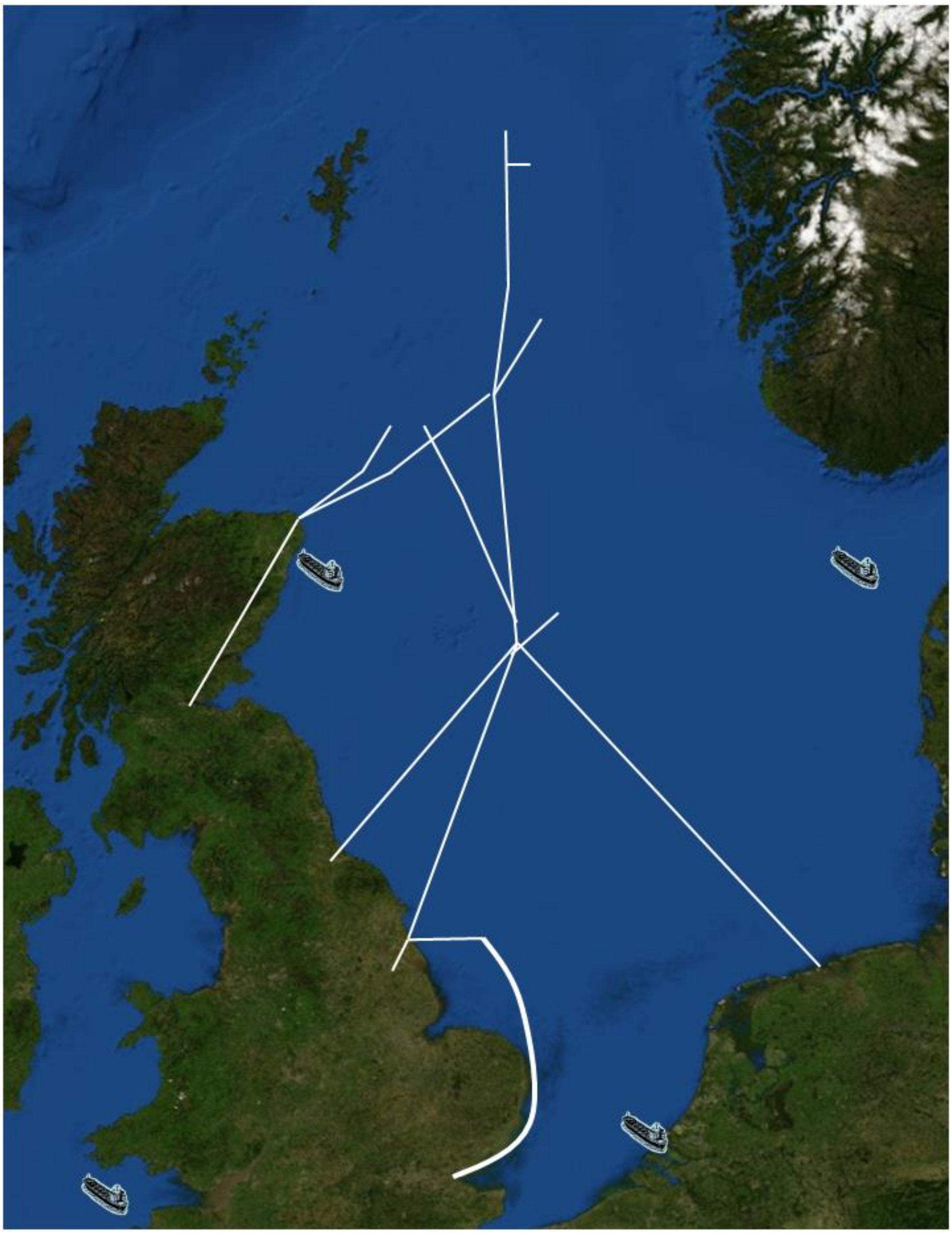


Figure 33: Figure 28 Infrastructure in 2038-2042. Bold lines indicate operational networks.

Highlights are:

- The aggressive CCS deployment scenario leads to an integrated North Sea CO_2 transport and storage infrastructure providing access to excess storage capacity that can continue to service UK and European CCS demand for many decades.
- Gradual reduction in CO_2 supply for UKCS CNS EOR projects which are now using mostly recycled CO_2 investments in anchor fields, although there is an upside potential for CO_2-EOR in satellite fields that are still operational or can be redeveloped.
- Capacity includes northern North Sea (NNS) and Norwegian storage.

Pipeline infrastructure requirements

The aggressive CCS with EOR scenario requires nearly 5,000 km of CO_2 pipeline infrastructure laid over the period to 2045. This is unlikely to pose a supply chain challenge, as there is already more than 10,000 km of pipelines for oil and gas in the UKCS developed over nearly 50 years.

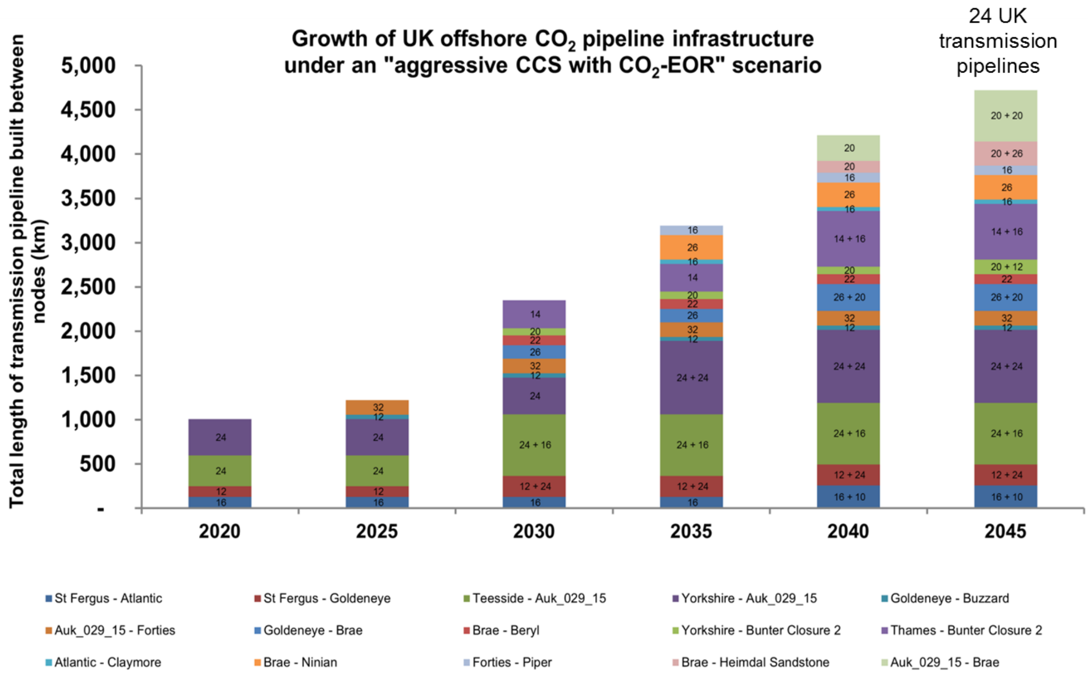


Figure 34: Growth in CO_2 pipeline infrastructure for the Aggressive CCS with CO_2-EOR scenario. Each colour reflects different network nodes. Figures inside the bars reflect the diameter of pipelines (in inches).

Well infrastructure requirements

As shown in Figure 35, the requirement for new well infrastructure poses no significant offshore industry supply chain constraint for the UKCS. By 2050, a few hundred wells are required in total under base case assumptions. Under this By way of comparison 173 wells were drilled in 2012 alone for oil and gas exploration, aappraisal and development[29].

[29] Oil and Gas UK 2013 Market Report.

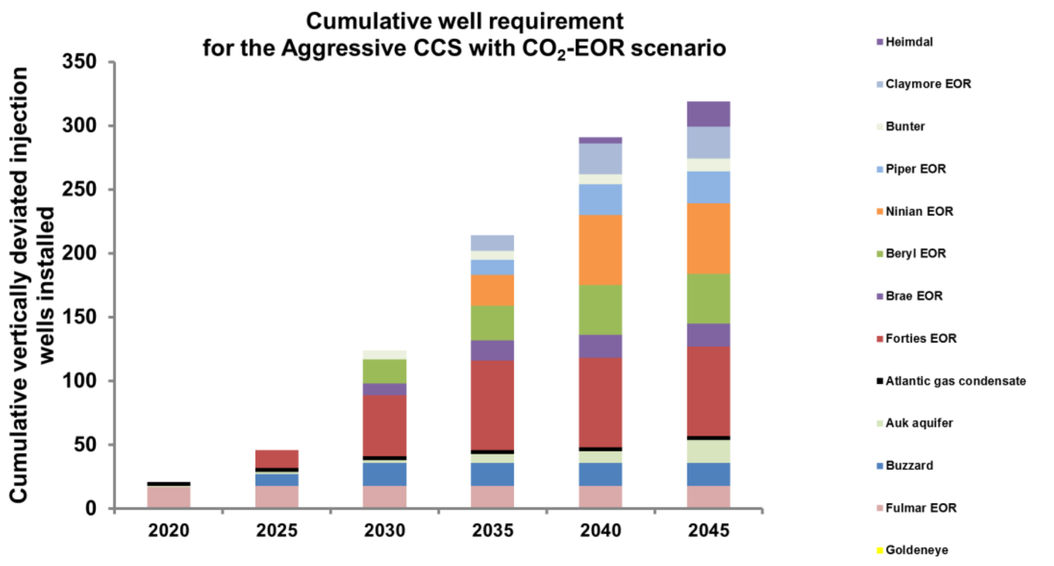


Figure 35: Cumulative well requirement for the Aggressive CCS with CO_2-EOR scenario.

CO_2 supply from Europe (e.g. Netherlands or Germany) for Scotland's CNS sinks emerges by the end of the 2020s. Although the first projects are likely to be fairly expensive, pipelines or ships could transport European CO_2 supply directly to the sink or this could be via ship or pipeline transport to St. Fergus. Some UK or European CO_2 could be stored in Norwegian or Danish sectors of the North Sea, for example for CO_2-EOR.

6.4.2 Cautious CCS scenario

A second infrastructure scenario is postulated where stakeholders go more slowly with CCS as described in Section 3.5. In this case sources in Scotland make use of the CNS in the 2020s. Sources in England make use of the southern North Sea (SNS) until the late 2020s. CO_2-EOR is limited to a couple of large oilfields, and the majority of storage is in depleted fields and aquifers in close proximity to these. Figure 36 depicts a plausible least cost growth of transport and storage infrastructure in five year phases for the cautious scenario. As previously, the topology and locations of network hubs has been based around minimising risks associated with individual stores and maintaining a high degree of "optionality".

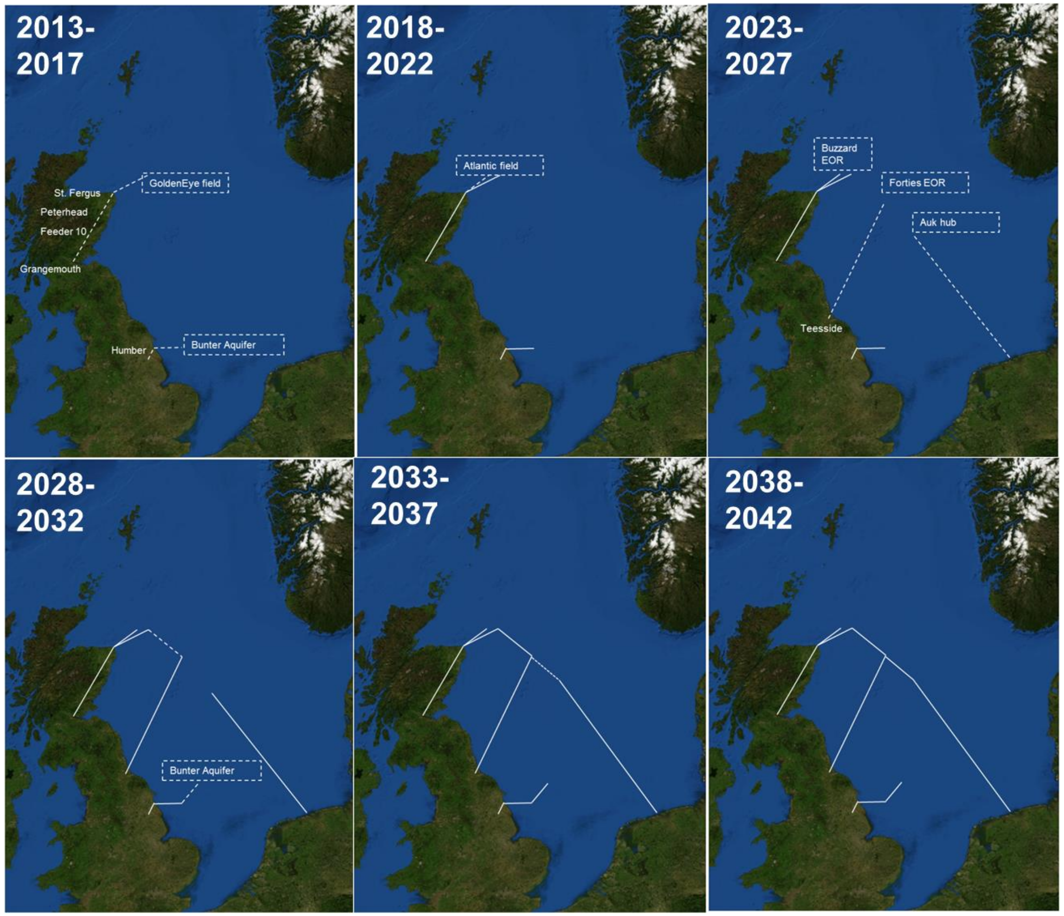


Figure 36: Cautious CCS with EOR network development. Dashed lines indicate construction/development, bold lines indicate operational pipeline infrastructure.

Details of the infrastructure and economics of the Cautious CCS scenario are provided in the Appendix.

6.4.3 Cautious CCS with St. Fergus hub scenario

A third scenario based on the cautious CCS uptake is identified where stakeholders in Scotland make a significant intervention in the design of CCS infrastructure to maximise the role of Scotland and CO_2-EOR[30]. The intervention is modelled as using CO_2 offshore pipelines via St. Fergus (for boosting) and/or ship-based transport via Peterhead Port. The outcome of this intervention is the direction of CO_2 flows from capture hubs in England and Scotland via St. Fergus to CNS stores including several CO_2-EOR candidate fields. The benefit of this approach for Scotland is maximising of the CNS resource and particularly the CO_2-EOR opportunity within a highly constrained CO_2 supply. As with the other two scenarios, hubs were selected on the basis of high optionality, i.e. each node in the network diagram provides for multiple and scalable future storage development pathways.

Details of the infrastructure and economics of the Cautious CCS scenario with St. Fergus hub are provided in the Appendix. .

[30] A St. Fergus-led strategy provides flexibility in the hypothetical event that the stores under the Southern North Sea cannot be deployed by the 2020s for any reason.

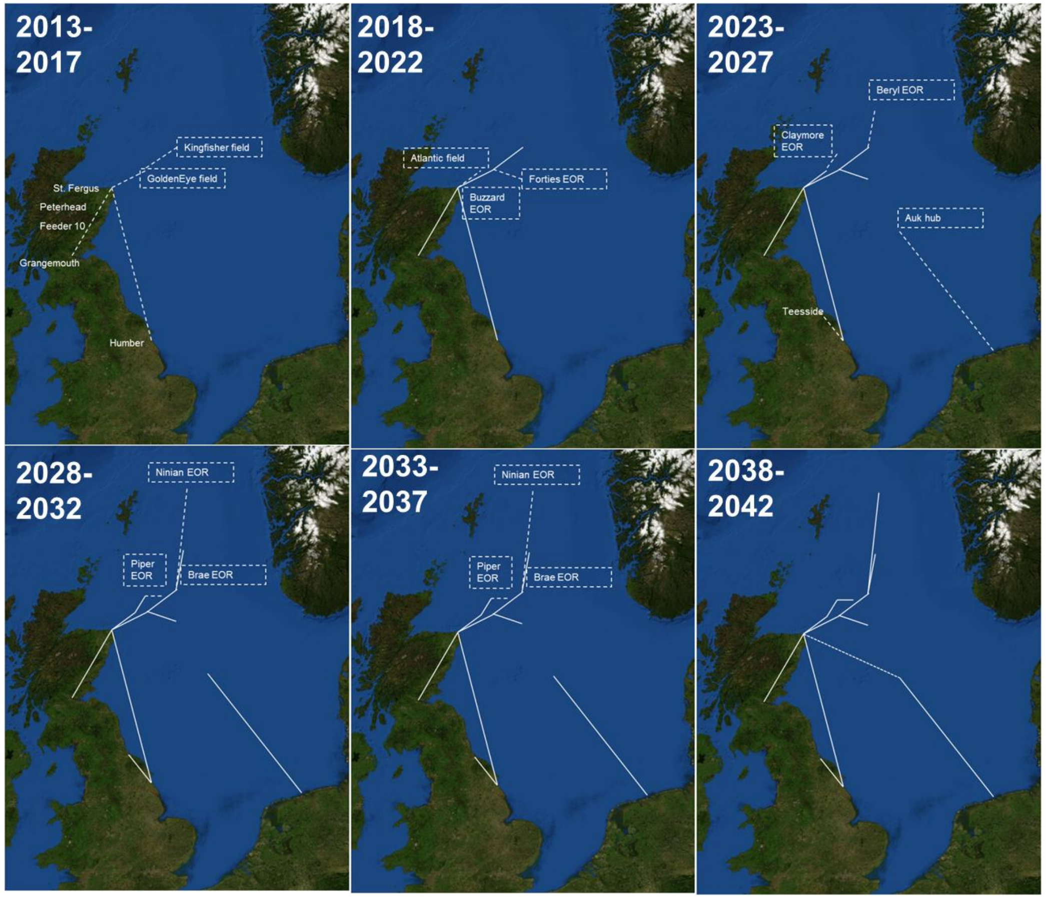


Figure 37: Cautious CCS scenario with St. Fergus hub

7 Opportunities for CO_2 shipping

7.1 Roles for CO_2 shipping

In the upstream E&P industry, sea going tankers are used to transport hundreds of millions of tonnes of oil, liquefied natural gas, liquefied petroleum gas and other chemicals. Transportation by sea going tanker is a flexible option if the product volume and/or distance to be transported are such that a pipeline cannot be justified. Yara is currently operating liquid CO_2 transport by ship between countries in the North Sea region, with capacity of 1000-1500m^3.

In the context of CCS, CO_2 shipping provides much higher flexibility around the exact locations, amounts of CO_2, and project duration than pipelines. CO_2 shipping is competitive with pipeline transport for projects where offshore distances are large, with multiple small sources or sinks, short project durations, and where pipeline consenting risks are significant. Thus CO_2 shipping could be a valuable enabler for small industrial capture projects or use of small stores (including small oilfields for CO_2-EOR), CO_2 appraisal, or supporting CO_2 transport from European sources to Scotland.

CO_2 shipping can support future pipeline development and given the wide range of configurations, it should not be viewed as a direct alternative to pipelines.

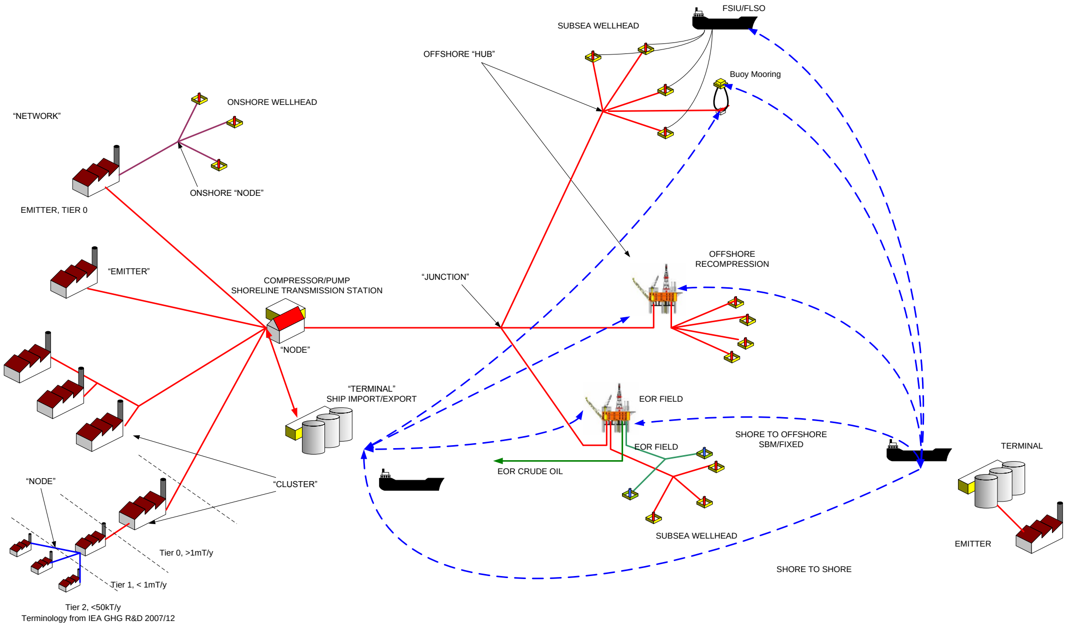


Figure 38: Diversity of potential CCS network configurations involving CO_2 shipping

Installation of a pipeline to an offshore CO_2 storage hub represents a major capital investment and would be a significant component of the overall cost. The use of sea going tankers to transport CO_2 could be deployed to reduce the initial cost associated with appraising potential storage sites (although operating costs for CO_2 ship-based solutions can be significant). In such a scenario the response of the storage site to CO_2 injection can be assessed in advance of committing to the full investment of the storage site development. This 'appraisal' information may reduce uncertainty associated with the number of disposal wells required.

If a storage site is already well understood (depleted oil or gas field), transportation of CO_2 by sea going tanker could still be utilised as an interim measure. This would enable storage revenues to be generated whilst the pipeline was being constructed/installed. There is an analogy with the development of many NNS fields which exported crude oil initially by shuttle tanker and subsequently by pipeline.

Temperature and pressure management for CO_2 transported by ship is a significant issue at loading and unloading points. Dry CO_2 would likely be supplied to a port in gas phase or dense phase at close to ambient temperatures (depending on the source and onshore transport configuration). Ship concepts typically use liquid phase CO_2 at *ca*. -50 °C and 7 bars, so a liquefaction facility is essential.

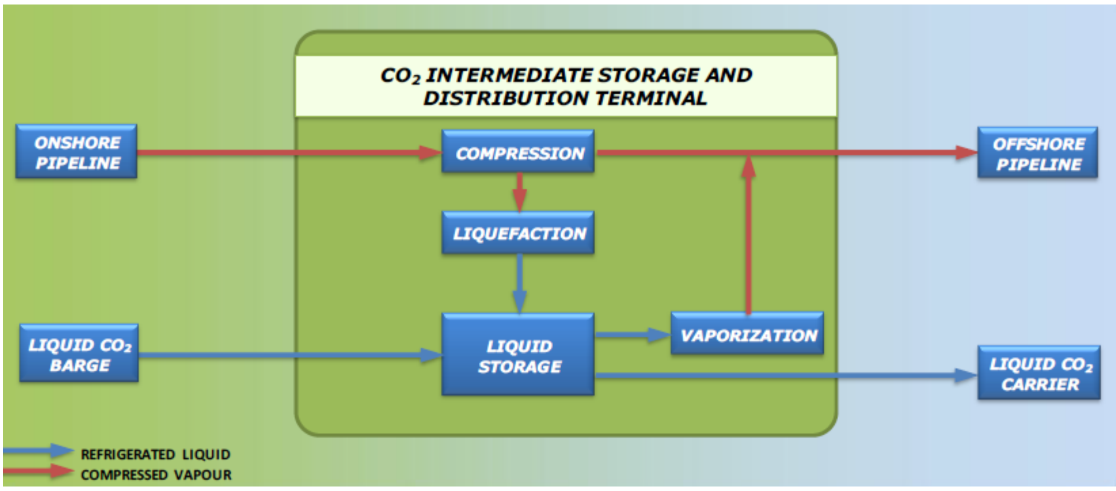


Figure 39: Port requirements identified for a liquid logistic shipping concept (Vopak, Tebodin, Anthony Veder report for the GCCSI (2013)

The ships themselves are similar to LPG ships. Liquid CO_2 can be stored in “bullets” or “spheres with a storage volume above 2000 m^3” at the terminal.

Direct unloading offshore of CO_2 would be a new challenge and represents a significant gap in knowledge. Though this is likely to be feasible, further engineering analysis is required, and an investable solution may take several years to develop. The direct delivery options involve transfer of cargo from an originating terminal to an offshore facility. To do this involves typical offshore hydrocarbon technology and processes. It is common practice for example for floating platforms to offload into ferry tankers that move between the production site and a shoreline store in relays, for CCS this route is reversed.

Production or floating storage and offloading vessels (FSOs) also possess the capability to provide temporary storage to smooth flows, i.e. decouple from the connection offshore to seek shelter in bad weather or act as a large volume ferry tanker. The critical issues are the frequency of addition to a well and the need for recompression. Depending on the process considerations it may be necessary to avoid low flow rates or lock in of a well head as a result of infrequent operations. Therefore the stop/start nature of offshore unloading operations may not be desirable. Whilst this may be an issue for some remote oil fields ship based CO_2 delivery for alternating CO_2 and water injection, perhaps with associated FSOs may prove the only option to enable EOR, or to utilise other distant storage options.

The optimum offshore injection conditions are likely to vary between reservoirs and over time as a reservoir pressure rises following CO_2 injection. Warming and pressurisation facilities will be required (which in turn imply a need for heat and power supply which may not always be available), and CO_2 injection well design may be critical to cope with transient conditions.

The other option is to establish a CO_2 terminal for import/export that is adjacent to an associated pipeline system. Here a pipeline enabled emitter or cluster with a proven access to a storage site or storage complex adds a ship unloading/loading facility at some point in the cluster. Remote dock facilities can be added by extending the onshore or offshore pipeline back to the dock. Onshore terminals associated with clusters also have a better flow profile to the store given that the emitters would already be feeding the system. The incremental difference made by ship unloading could well be absorbed into the normal flow. There are also two types of terminal, import only or dual use allowing for both the import to a pipeline based cluster or the export from a cluster to distant, non-pipeline enabled stores or users.

7.2 Port options for Scotland

Assuming a market for CO_2 transport by ship emerges, this study has identified that Scotland has several opportunities to develop a port as a shipping hub as a complement to pipeline infrastructure. However, given the attractiveness of CO_2 pipeline infrastructure relative to shipping, it is difficult to envisage scenarios where multiple port options would be required within Scotland in the 2010s or 2020s.

With a long coastline, several port options can be considered for Scotland. In all cases there would be a need to route and size any pipeline capacity connected to any shipping hub, as well as identify the infrastructure (and its areal footprint) required for temporary CO_2 storage.

On the west coast one could additionally consider a port adjacent to the proposed Ayrshire Power Plant at Hunterston or at Finnart, where there is an existing coal and oil terminal and an oil terminal. Either could service either Scottish emitters or others close to the Irish Sea. These options are described further in the Appendix.

This section focusses on Hound Point and Peterhead Ports, as these appear to have the highest relevance for CCS opportunities involving the Central North Sea.

7.2.1 Hound Point

For a shipping hub in the Forth, a facility at Hound Point or nearby (e.g. close to Cockenzie, Longannet, or Grangemouth) would allow tankers to offload into a pipeline system or export. The waters at Hound Point are sheltered and the ships less likely to be subject to adverse weather conditions. Hound Point and the associated Dalmeny facility area an oil terminal situated in the mouth of the Firth of Forth. The berth is a marine berth with no jetty facility capable of 350,000DWT vessels for the transport of crude oil. The facility is loading only, receiving crude oil from the Forties pipeline system, storage at Dalmeny and then onwards loading for export.

Figure 40: Hound Point and Dalmeny Storage Facility

Associated with any port it is essential to have temporary CO_2 storage facilities – as CO_2 supply from power stations and industrial sources is unlikely to match ship loading patterns. Transportation of CO_2 by tanker is a batch operation, compared to the continuous nature of a pipeline. This has implications on the sizing of equipment and potentially the number of wells; the required instantaneous flow rate will likely be significantly higher to achieve a desired annual average rate. Additionally consideration will be necessary for the inclusion of intermediate port storage facilities; with such facilities the number of trips a single tanker can make will be much increased.

In Scotland, both Peterhead and Hound Point have experience in the storage of petrochemicals. However the size of storage facilities for CO_2 is not well understood and could be considerable. Simple approximations for a 10 million tonne/year import/export facility with a 300km delivery radius would require approximately 4 ships and 50,000 tonnes of static storage, typically at ship operating conditions. This in itself brings significant costs even before considering the loading structures, either jetty based or single buoy mooring types. The facility at Hound Point could be added to in terms of berth and storage. The connection distance to any network is not far and connection would occur at Grangemouth.

7.2.2 Peterhead Port

Petrofac considered the following shipping system at Peterhead:

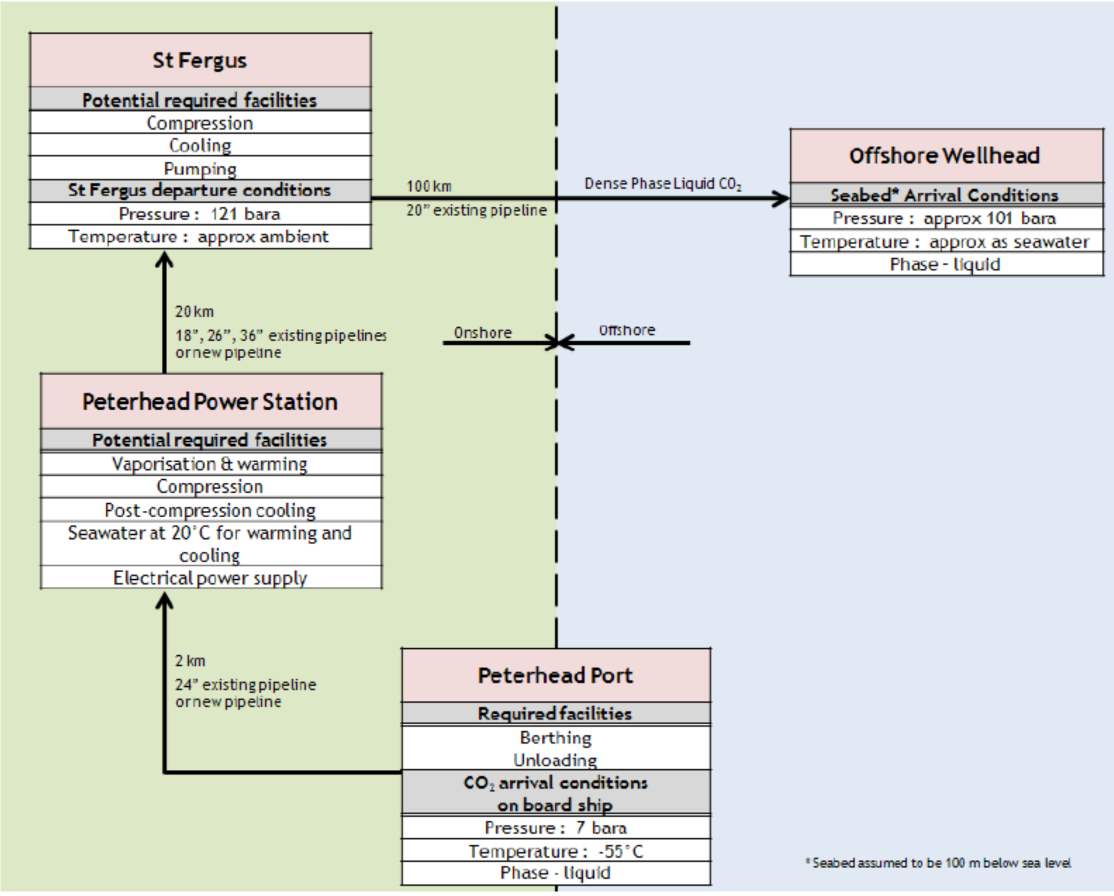


Figure 41: Schematic of CO_2 transport at Peterhead Port considered by Petrofac

The Petrofac study considered 21 development scenarios. The scenarios include:

- Maximisation of existing assets
  - Re-use of an existing 18” onshore pipeline with gas phase CO_2 (up to 4,500t/day or 1.5 Mt/yr) between Peterhead and St. Fergus.
  - Compression and temperature management at both Peterhead and St. Fergus (ca. 10 MW at each site).
  - Capex of £100m and opex of £20m/yr.
  - The offloading would take about 7 days for 30ktCO_2.
  - Significant operational constraints if existing infrastructure are re-used

- Liquid phase CO_2 transfer from Peterhead to St. Fergus
  - New 20” low temperature pipeline from Peterhead to St. Fergus (onshore or offshore)
  - Capex of £80m for capacity of 6 Mt/yr

- Direct CO_2 shipping to offshore storage
  - New shallow water mooring system for CO_2 cargo ship
  - New low temp offshore pipeline (export riser)
  - CO_2 pumping and warming needed on the ship
  - Offloading rate 15kt/day (5 Mt/yr)

The feasibility of using CO_2 shipping at Peterhead Port has been confirmed by Petrofac, although further technical analysis is required on issues such as the requirement to dredge the port and the safe management of CO_2. Any development would be classed as a Major Development under the Town and Country Planning Regulations and would require an Environmental Impact Assessment.

Peterhead Port's location near Peterhead Power Station and St Fergus is ideal in terms of loading into a pipeline infrastructure or receiving from onshore emitters, assuming successful operation of the Shell/SSE CCS project. The port historically has an oil terminal facility that may be adapted. If not then there is sufficient space to the south west of the port to host a terminal.

Figure 42: Peterhead Port

Safety Issues that warrant further consideration in the design of infrastructure at Peterhead include:

- Propagating fractures are a potential issue with CO_2 pipelines, especially when reuse of existing pipelines is being considered.
- Pressure surge in pipelines.
- Metallurgy – corrosion, erosion, brittle fracture, propagating fracture.
- Adverse weather conditions offshore, especially during offshore offloading
- Existing pipeline routing needs to be reconsidered in the light of the different fluid and conditions.
- Dispersion of releases especially those releases containing solid CO_2.
- Cold CO_2 impingement onto critical structural equipment could result in significant loss of containment
- Topography of ports may not be conducive to dispersion of CO_2
- Major Accident Hazard (MAH) potential related to the store or ship

Where a CO_2 reception port is being developed it will likely be cost effective to include such processing facilities as part of the terminal services. Pressurising the liquefied CO2 for injection will have a significant power demand; this may not be available at remote appraisal sites. Tankers used for early appraisal of storage sites should be equipped with facilities to process CO2 from cargo to injection conditions.

7.3 Business model for CO_2 port terminal

The only concept for business models involving CO_2 shipping and associated terminal in the public domain is the CINTRA Joint Venture project developed at Rotterdam. This is illustrated below.

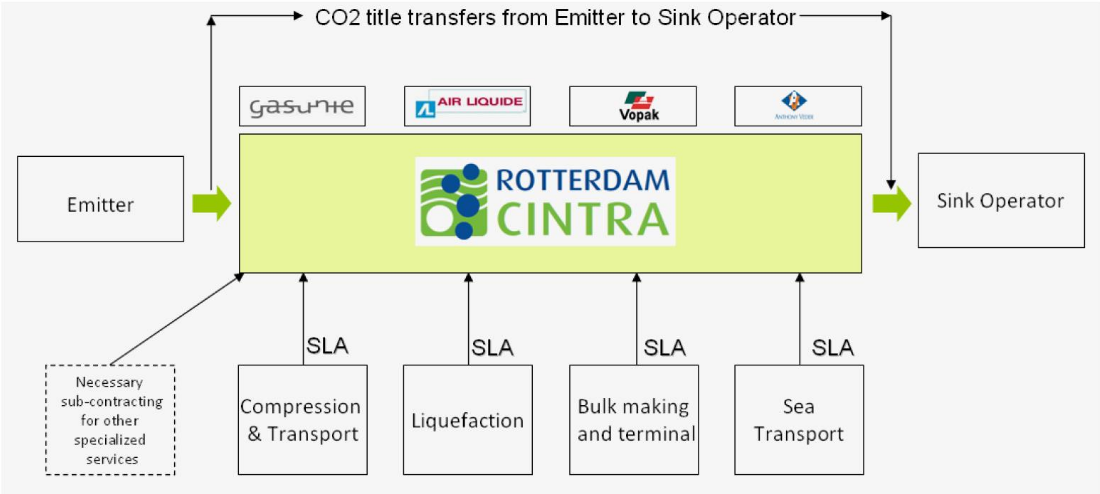


Figure 43: Service level agreements (SLA) and CO_2 title transfer for the Rotterdam CINTRA project.

Key elements of the CINTRA model are:

- Sharing of investment and risks between the national gas system operator, a commercial gas separation company, a chemical storage company, a shipping company and the port itself.
- The end customer is the emitter that derives value from avoiding CO_2 emissions to the atmosphere, although the model could be adapted to include CO_2-EOR projects.
- The CINTRA JV does not take the title for the CO_2, this is passed between emitter and sink operator.
- Take-or-pay contracts are preferred, implying revenue for the JV regardless of utilisation.
- Contracts are standardised and published to allow transparency and ease of adoption and therefore facilitate growth.

7.4 Strategic development of a CO_2 shipping terminal and Peterhead Port

Despite the benefits outlined above, none of the stakeholders interviewed during the course of this project identified any immediate proposals or need for a CO_2 shipping solution connected to any of the UK or Scotland's central North Sea CCS projects. There are no current plans to develop CO_2 handling facilities at any of Scotland's ports, or to take steps to future proof this opportunity.

In the absence of any projects around which to anchor activity, considerable intervention would be required by stakeholders wishing to develop the port's capacity for CO_2 handling. Successful development of CCS at Peterhead Power Station would be ideal and an enabler, even if that project does not intend to use Peterhead Port. However CCS at Peterhead Power Station is not absolutely essential for a CCS hub to develop at Peterhead Port.

Following the approach taken by the Port of Rotterdam, the earliest priority would be to win over and eventually organise the stakeholders that are likely to be critical to a shipping value chain, i.e. emitters, developers of capture technology, regional CCS clusters, shipping companies, providers of engineering services, temporary chemical storage facilities, offshore storage providers, DECC and The Crown Estate. Although Peterhead Port is aware of the opportunities to develop CCS, given the much smaller size of Peterhead compared to Rotterdam, the Port would need a CCS business development specialist to engage with the CCS community and build relationships and, in time, an investment case.

Once a CO_2 shipping project development appears realistic, then the site could begin enabling masterplanning and preparatory actions to reduce the risks and costs of infrastructure development. Critically this would involve co-ordinating CCS capacity and design with other ports to ensure compatibility and the correct capacity.

8 The economics of CCS infrastructure in Scotland and the central North Sea

This chapter combines the costs for different components of CCS infrastructure using a discounted cashflow model. The calculations are used to estimate the economic impacts for Scotland associated with the Aggressive, Cautious and St. Fergus hub infrastructure development scenarios. These scenarios are intended to illustrate efficient and plausible paths for CCS infrastructure, i.e. maximum benefit to Scotland for minimum investment, although alternatives may be possible. Given the underlying cost uncertainties expressed in earlier chapters, accuracy is within a factor two (i.e. +100%/-50%).

8.1 Key components of a CCS network

In general terms, the economics of CCS networks are dominated by (i) the capex, fixed and variable opex and energy costs for onshore CO_2 generation, capture, compression, transmission pipeline, hubs and boosting stations, terminals; (ii) the costs of offshore transmission pipeline (new and existing), hubs (if used), injection facilities, wells (new exploration, appraisal, injection, monitoring, or existing), power cables for electricity (e.g. for boosting), fuel, EOR platforms, injection wells, recycling equipment; (iii) Revenue, in the form of tariffs based clean electricity (or heat, hydrogen, avoided CO_2 payments, or other services), revenue models for CO_2 transport, avoided decommissioning costs, and in the case of EOR, oil revenue; (iv) Taxes (especially for EOR); and (v) the cost of financing.

8.2 The costs of CO_2 generation and capture

The levelised costs of CO_2 generation and capture (excluding transport and storage) have been covered elsewhere – levelised costs[31] for power + capture are estimated in the region £100-£150/MWh for early projects, dropping depending on configuration and assumptions. A developer would seek to negotiate a contract-for-difference feed-in tariff at the upper end, of this range, and for as many years as possible, as developers would wish to at least break even across a wide range of scenarios. The counterparty (e.g. the State) would seek to negotiate at the lower end of price range, short duration to minimise costs to consumers. If capital subsidy is requested, there will be a need to link this to specific capital project risks or knowledge sharing objectives and with provision for clawbacks if projects fail to meet agreed milestones. The space in between the upper and lower bounds provides a large opportunity for commercial negotiation, around issues such as risk allocation (e.g. strike price may be index-linked to inflation or energy price) and degree of knowledge sharing. The higher the strike price the more likely the plant will run continuously i.e. at base load, rather than intermittently.

The levelised cost for new or retrofit power stations with capture is predicted to drop below £100/MWh after a first wave of CCS projects have been demonstrated successfully, as technology develops, and as larger projects are developed.[32] For industry CO_2 capture, projects span the range £15-£100/tCO_2 captured, depending on scale, purity, timing, technical solution and complexity. The cheapest capture projects correspond to streams with high CO_2 concentration and/or from large sources, where there are synergies from infrastructure sharing (e.g. recovery of waste heat could be used to drive capture). The most expensive sources involve small or dilute CO_2 streams, with significant impurities and difficulties in integrating capture plant. Significant process and project contingencies are expected for capture, particularly in the 2010s.

Financial support will need to cover transport and storage of CO_2 as well as capture. We turn to this next.

8.3 Methodology for estimating the costs of CO_2 transport, storage and enhanced oil recovery

The remainder of this chapter concentrates on the economics of transport, storage and EOR infrastructure for the UK components of projects.

For this study, three existing models, developed and refined by the project team over successive projects, were combined to examine the overall infrastructure economics:

- AMEC's onshore CO_2 compression and pipeline model[33]
- CO_2NomicA V3, Element Energy's CO_2 transport and storage network model developed in partnership with ETI.
- CO_2EOR KickStart, Element Energy's model for the project design, revenue and taxation of individual and clustered CO_2-EOR projects.

[31] Levelised costs = cumulative net present cost/cumulative net present energy
[32] Cost Reduction Task Force (2013) Final Report https://www.gov.uk/government/publications/ccs-cost-reduction-task-force-final-report
[33] This was supplemented with the results of the Longannet FEED and Petrofac Peterhead studies, which provide estimates for the costs of re-using the Feeder 10 and Peterhead to St. Fergus pipelines.

The (arbitrary) division of infrastructure analysis into onshore, offshore transport and storage, and CO_2-EOR is illustrated in Figure 44 and described in more detail in the Appendix.

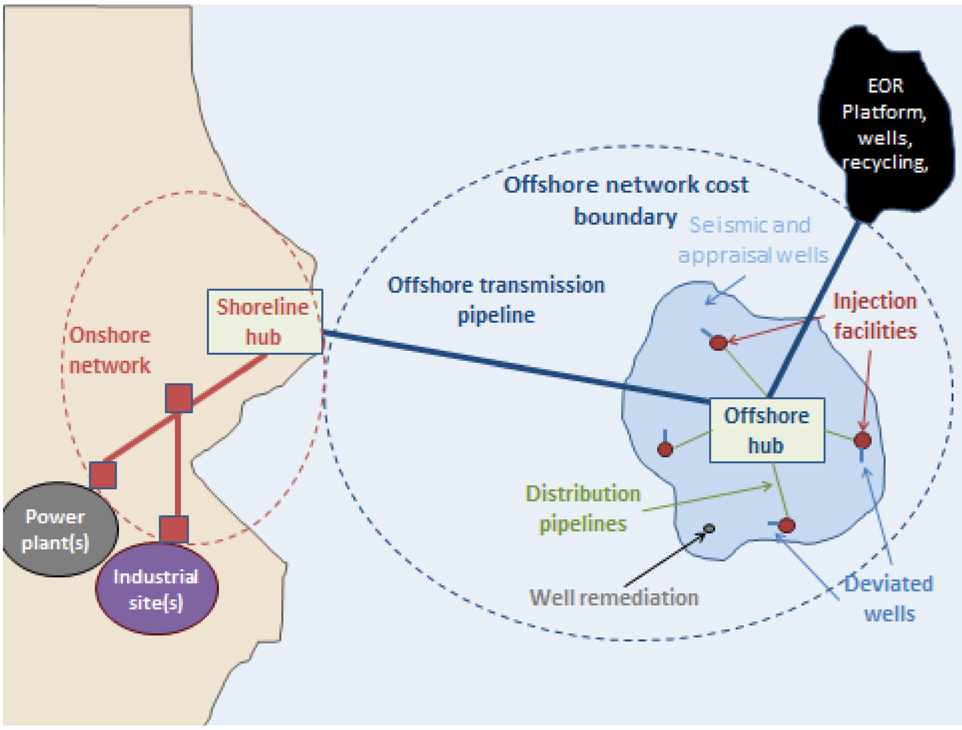


Figure 44: Scope of contributing models for infrastructure cost analysis used in this study.

The 2012 Scottish Enterprise study on the Economic Impacts of CO_2-EOR for Scotland described the breakdown of costs for CO_2-EOR infrastructure in detail recently, and therefore the breakdown of CO_2-EOR costs is not repeated in this study.

8.4 Economics of the scenarios

The Aggressive CCS scenario identified here is consistent with ETI's ESME modelling which shows that a ramp up of CCS capacities to at least 60 $MtCO_2$/yr from the 2030s is essential to meet the UK's climate target at least cost. This would save £30bn/yr (nearly 1% of GDP) compared to decarbonisation scenarios where no CCS is employed. The scenario is consistent with a mix of coal, gas and biomass power generation with CCS and industrial CO_2 capture concentrated in a handful of regional clusters in the UK.

Annual undiscounted real costs for CCS and EOR infrastructure are likely to be fairly lumpy as a function of individual projects, but in peak years with substantial EOR investments could be *ca.* £1-3bn/yr. This is modest by comparison with typical offshore UKCS investments, which was close to £12 billion last year in the oil and gas industry. CCS will share the supply chain with the oil and gas industry and vulnerable to the associated market. If future costs are discounted at an annual rate of 10%, then the cumulative real cost of infrastructure (excluding capture) is *ca*. £11 bn up to the late 2040s. Note this corresponds to *ca*. £56 bn undiscounted real investment.

However if pre-tax revenues from CO_2-EOR are considered, cumulative impact would be to balance out the capital investment in infrastructure, whilst providing multi-Gt scale storage, and wider economic benefits.

Figure 45: Discounted real offshore costs and revenues for the Aggressive CCS with CO_2-EOR scenario (assumes DECC central oil price).

Although the net system economics when including CO_2-EOR are more favourable, it is essential that distinct commercial actors within an integrated network are still able to meet their investment criteria. Post-tax profits must outweigh their costs of capital and risk profiles must align with wider strategy. In practice this means that at DECC's central oil prices, the owners of the transport and storage-only elements of the network infrastructure (including storage backup), would need to receive real effective average tariffs corresponding to £5-£32/tCO_2 for the aggressive scenario This cost would need to be passed on to capture and host CO_2 generation facilities [34].

[34]Most common range from Element Energy analysis of a large number (at least 50) sensitivities covering a range of infrastructure growth and reservoir performance scenarios, with common assumptions of (i) DECC central oil price, (ii) 10% real discount rate, (iii) oil companies are not paid for CO_2-EOR-storage services but do not pay for CO_2, and (iv) assuming oil companies benefit from a field allowance and PRT waiver, whereas transport and storage providers pay 20% corporation tax.

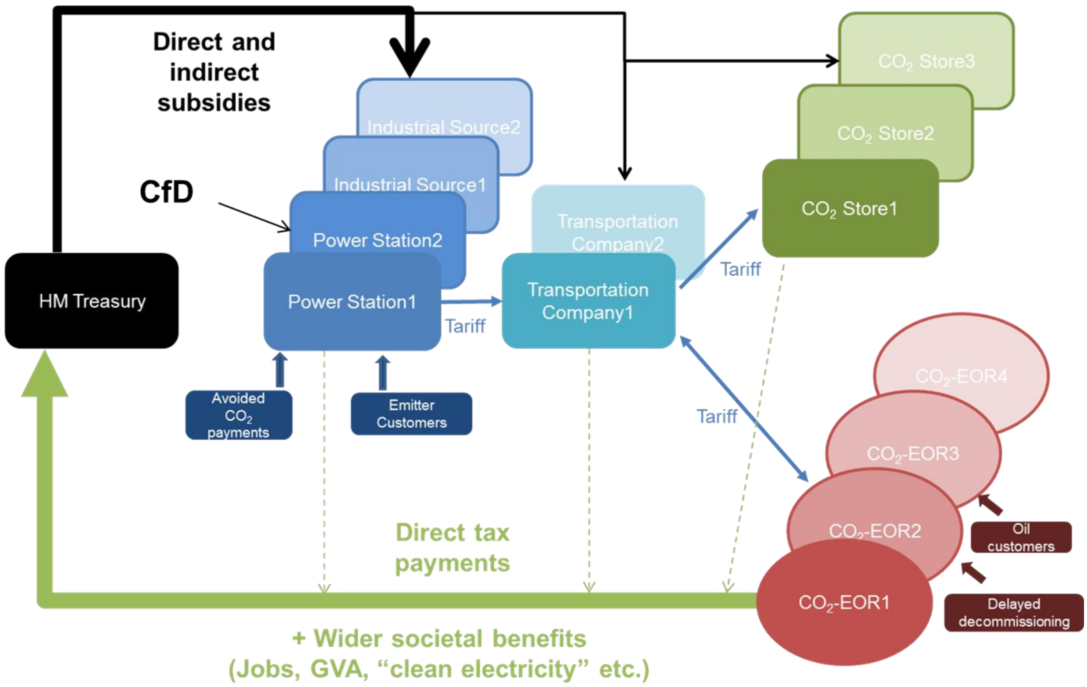


Figure 46: Cash flows for an integrated CCS network comprising CO_2-EOR.

The overall CO_2-EOR network economics compares favourably with the average effective tariffs of £10-£40/tCO_2 for UKCS transport and storage-only networks of comparable capacity that exclude CO_2-EOR[35]. The £10-40/t includes transport and storage networks that are principally southern North Sea (SNS)-based, principally CNS-based, employ a mix of storage locations, integrated and point-to-point.

This range reflects the impact of pessimistic and optimistic assumptions around network optimisation and reservoir requirements (e.g. well requirements), and variability in offshore costs which can be linked to energy prices and supply chain bottlenecks. The lower average cost networks include those with a concentration of investments in a few large scale integrated assets; the higher average £/t cost networks involve less integration and are more consistent with the current project-by-project based decision making environment.

Extra precision is not justified for analysis based on public or CO2Stored data. Better (e.g. FEED quality) engineering analysis, including reservoir performance and top-side process simulation, could narrow cost ranges substantially (although energy price and currency volatility will remain). There will still be significant variability and contingency requirement. There will always be a need to fund up-front pre-development activity (£10s of millions, very sensitive to the level of seismic acquisition and number of appraisal wells required) for storage and for EOR at risk and several years ahead of deployment. Following investment, some sites are likely fail to pass through all milestones for various reasons, and some will need to be advanced but never used, just to provide backup. There is no evidence that commercial organisations will direct the level of resources consistent with delivery the

[35] Element Energy modelling of a range of a large number (at least 100) of plausible large scale UKCS CO_2 transport and storage only networks (i.e. excluding EOR) identifies total offshore discounted real costs of *ca*. £4-10 billion for the period to 2050, depending on configuration.

Aggressive scenario under current market arrangements, which anticipate a trickle down from those power CCS projects that successfully navigate financing.

Any effective tariff will also be sensitive to contractual and financing structures, including allocation of CO_2 liabilities.

8.4.1 Discount rates

Decision making and the choice of investment hurdle rate will depend on probability-weighted analyses of potential returns. However, with few direct historical precedents, it is difficult to advise on the appropriate benchmark for CCS infrastructure. The probabilities of policy/regulatory changes or rare events (e.g. storage failure) are difficult to estimate, even to within an order of magnitude. Therefore it is challenging to make use of the simple decision trees or real options-based economic tools for assessing phased investments, that are otherwise the standard workhorses in the energy sector.

The risks of low utilisation of transport and storage infrastructure are significant, given that capture incurs substantial capital and operating costs. Ultimately the major demand for CCS for CO_2 abatement links to the level of global ambition to tackle climate change. The levels and timing of future global support for CO_2 abatement are unclear, and companies and countries that take unilateral actions are exposed to significant first mover disadvantages.

Standard capital allocation models suggest businesses targets for “worst case” NPV close to zero (i.e. break-even) at an agreed discount rate, and central case NPV sufficient to deliver returns as for alternative investment opportunities. The choice of discount rate is a key issue. The avoided emissions benefits of CCS are inter-generational in nature and Stern has argued that discount rates of close to zero may be appropriate in some cases[36]. The public sector typically uses a real discount rate of 3.5% for project evaluation. Industry tends to adopt a weighted average cost of capital may be at least 5-10% for low risk projects, but where resources are scarce, projects may only be funded if delivering considerably higher returns.

The appropriate risk premium required for CO_2 transport and storage depends on conditions and requires further analysis. An additional risk premium of at least 5-10% above the rate for low risk projects is not unreasonable. This suggests an overall commercial discount rate in the range 10-20% for evaluating CCS investments. For consistency with other reports, discounted costs quoted in this study assume a 10% real discount rate (or WACC).

Based on a real discount rate of 10%, average tariffs between £5-32/tCO_2 ought to provide sufficient comfort for infrastructure developers for the aggressive scenario described in this report. The exact figure will vary between elements of the network and over time (higher at the start). There is no need for a postage stamp or one-size-fits-all tariff for CCS infrastructure – indeed this would dilute investment signals precisely when capacity constraints need to be understood. High discount rates would demand higher transport and storage tariffs that would appear uncompetitive with other options.

[36] Sir Nicholas Stern (2008) for HM Treasury, The Stern Report on the economics of climate change.

Returns will need to be higher if it is expected that companies should cover the working capital needed to support infrastructure growth from a single company without recourse to capital markets or selling off assets.

8.4.2 Capacity vs. throughput based reward

The structure of payment for CO_2 transport and storage services influences the allocation of risks and rewards along the chain from source to sink. The details may not be revealed to third parties, either to preserve the confidentiality of commercial contracts, or because of vertical integration. This may complicate negotiation of third party access terms.

There are lessons from other infrastructure markets that can be applied to maximise the efficiency of investment. From a mid-stream CO_2 transport and storage developer's perspective the reward mechanism should be dominated by the provision of capacity (i.e. $MtCO_2$/yr) rather than utilisation ($MtCO_2$), reflecting the high fixed costs and low variable costs of pipelines and storage infrastructure. An exception would be for ship-based CO_2 transport, where variable costs (leasing) may dominate fixed costs. The tariff may need to cover a risk premium for non-supply (to EOR facilities) and/or non-acceptance (for capture).

8.4.3 Incentivising CO_2-EOR[37]

The North Sea is a high and complex tax environment compared to general corporate taxation in the UK. Therefore the principal beneficiary of EOR would be the Governments of the North Sea region. A CO_2-EOR network in the US was kick-started in the late 1970s and remains sustained through a mix of fiscal incentives at State and Federal level. Recent economic modelling by Prof. Alex Kemp at Aberdeen University suggested that fiscal incentives could also drive CO_2-EOR investments in the UKCS[38]. Under favourable scenarios, the Governments of the UK, Norway and Denmark, together could receive up to £22 billion of additional tax receipts if a substantial cluster of CO_2-EOR projects develops in the North Sea.

Under a wide range of conditions, several EOR projects would be economic (i.e. pre-tax NPV positive). However the CO_2-EOR projects would be unlikely to meet commercial post-tax investment criteria, particularly in the early years until CCS is proven, as there will be a need to cover under-performance or non-supply scenarios. The typical central case NPV shortfall for the majority of fields is of the order of hundreds of millions of pounds. There is also a requirement to manage downside risk exposures. Lack of commercial investment in CO_2-EOR leading to decommissioning would result in the UK Government would miss out on potentially billions of pounds of tax receipts (depending on the number of fields and oil price).

Previously, the UK has encouraged further development of technically or commercially challenging oil fields through amendments to the offshore fiscal regime (see Appendix). 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 and technology development benefits compared to other oil production technologies.

[37] Adapted with permission from Element Energy et al (2013) CO_2-EOR in the UK – Analysis of fiscal incentives for the CO_2-EOR Joint Industry Project.
[38] Kemp, A.G. and Kasim, S., 2012, The Economics of CO_2-EOR Cluster Developments in the UK Central North Sea/Outer Moray Firth

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”. Reducing the headline tax rate leads to high deadweight losses, which is why the UK Government has instead introduced new field allowances, which can be carefully structured.

Field allowance is a type of tax allowance, which reduces the amount of adjusted ring fence profits for the eligible company on which the company’s Supplementary Charge tax is charged. 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, shallow water gas fields and West of Shetland.

The graph below shows the discounted profitability index (NPV/discounted CAPEX) of different oil fields under four illustrative scenarios and for this analysis we assume that all oil fields have to meet the same discounted profitability index threshold, which is a widely used oil industry KPI.

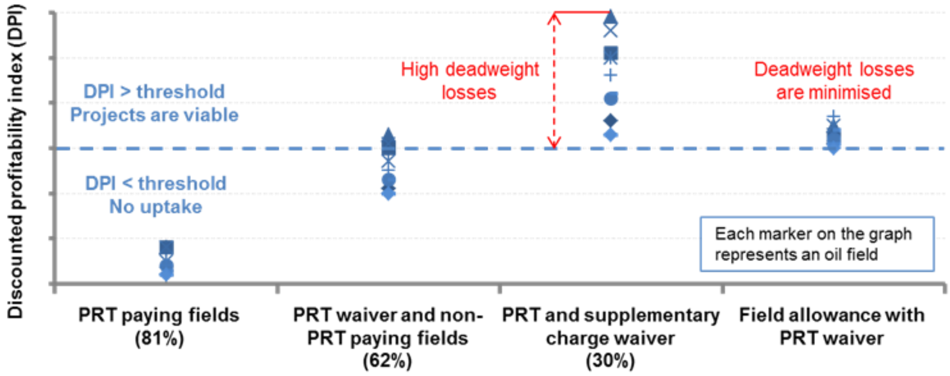


Figure 47: Comparison of changing headline tax rate and field allowances.

The first offshore CO_2-EOR project in the North Sea would incur substantial CO_2 supply and diverse regulatory and socio-political risks. Thereafter, assuming large scale CCS deployment, fiscal incentives could be tapered over time to match investor risk perceptions and thereby minimise deadweight losses.

Among the field allowances that are modelled, a field allowance based on unit development cost with PRT removal for the first projects appears the most efficient structure in terms of minimising deadweight losses. Although having a tax incentive based on a private sector KPI and estimation of unit costs face 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.

The magnitude and the structure of the field allowance may create some implementation challenges. The scale of allowance would need to be more than three times the existing brown field allowance to maximise the CO_2-EOR uptake in the UKCS (~£170/tonne oil). The reason is that unlike most oil field development projects, CO_2-EOR is not only CAPEX intensive but also OPEX and fuel intensive, with revenues uncertain and emerging over very long lifetimes (i.e. heavily discounted). Although the required amounts of field allowances are high, CO_2-EOR projects are able to bring billions of pounds of additional tax revenues for the Government.

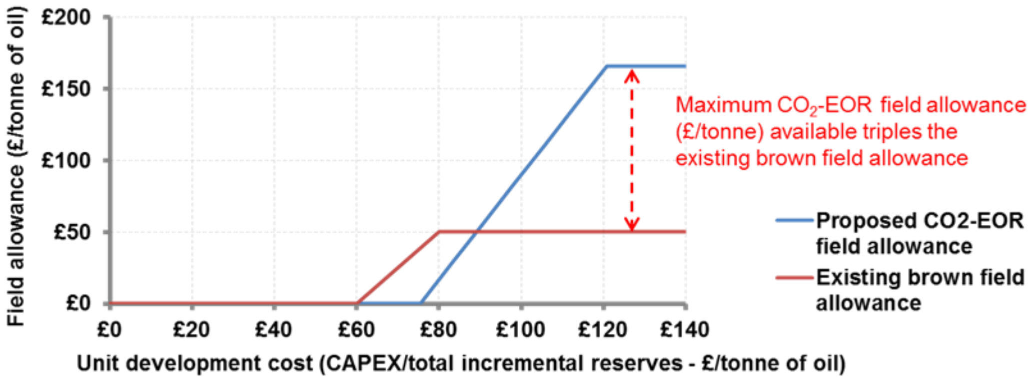


Figure 48: Comparison of a proposed CO_2-EOR field allowance with the existing brownfield allowance (£/tonne oil)

"Mid-size" and "super-major" multinational oil companies are the most likely investors in CO_2-EOR in the North Sea if there is a reduction in the headline tax rate. Super-majors have the necessary internal financial and technical resources to deliver the required investment, and a few are strategically interested in developing CCS technology. However super-major oil companies are largely exiting the North Sea. Small oil companies are unlikely to have the capital available to fund CO_2-EOR projects, except in joint ventures or for satellite projects. New entrants are disadvantaged, as incumbent UKCS oil and gas companies can offset the costs of CO_2-EOR investment against other UKCS activity, an option not available for new entrants. An additional theoretical potential investor is a national CO_2 storage company as a co-investor in EOR projects, which can make decisions on a pre-tax basis and operate with a public sector borrowing rate.

Considering the market failures around CO_2 storage, a pro-active role by Government is not without merit. Several Governments deploy national oil companies, albeit with mixed success, to maximise oil revenues and correct market failures such as information asymmetries. This is not current practice in the UKCS but Government is already heavily investing offshore in decommissioning through the tax system. Due to the 100% first-year allowances available to oil companies, 62% of the CO_2-EOR capital expenditure can be offset immediately against other ring-fence profits of the oil companies. In other words, Government already pays 62% of the investment through receiving less tax. A hypothetical national "CO_2 storage company", which could co-invest (or own existing platforms and wells in exchange for full decommissioning liability), could potentially be established in order to maximise public benefit beyond the "CO_2-EOR Push" scenario.

The NPV of CO_2-EOR projects, and hence the fiscal incentives needed, depend also on the "CO_2 transfer price". Under the current policy plans supporting CCS (e.g. Electricity Market Reform[39]), capture plants will be likely to pay a fee for CO_2 storage. On the other hand, oil companies pay a commodity price for CO_2 in the US. For the aggressive CCS with CO_2-EOR scenario described in this study, we have assumed that CO_2 is supplied to the platforms at zero cost and a field allowance is available. If there is no field allowance, then on average oil fields would need to be paid around £10/t as a CO_2 storage fee. Environmental and other NGOs may resist direct payments from the electricity market to oil companies however.

[39] https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform

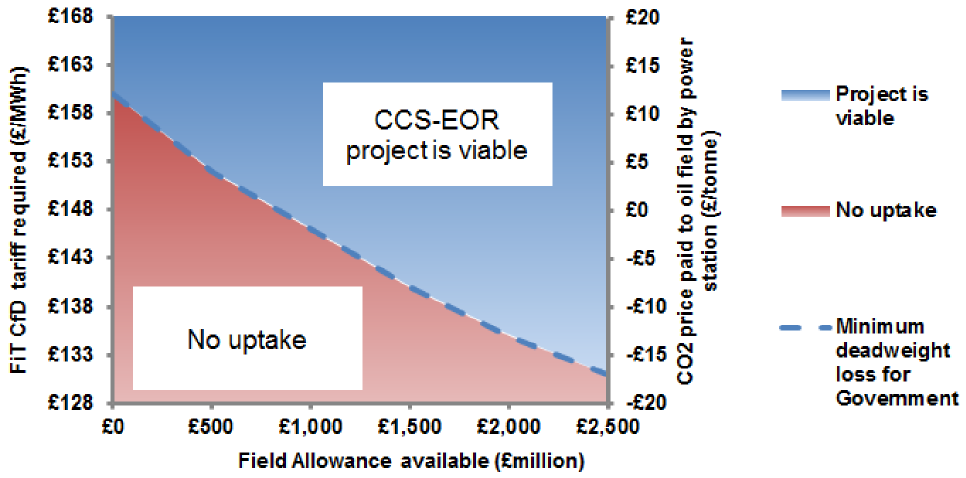


Figure 49: Illustrative interplay of onshore and offshore incentives for a network comprising an IGCC capture project with a CO_2-EOR project

Since both capture and CO_2-EOR need financial incentives relative to the status quo, it will be imperative that the levels of feed-in tariff and any fiscal incentive for EOR are aligned, and reviewed periodically, to minimise market distortions. It will also be necessary to monitor potential interactions between different offshore incentives.

Recent analysis by the LSE's Grantham Institute has highlighted the long-term challenges of unburnable hydrocarbon reserves, given a global budget for CO_2 emissions[40]. This is not explored in this study but development of CO_2-EOR infrastructure would clearly assume that there would be a demand for the produced oil at the given oil price.

[40] http://www.lse.ac.uk/GranthamInstitute/publications/Policy/docs/PB-unburnable-carbon-2013-wasted-capital-stranded-assets.pdf

8.5 Economic benefits of clustered stores

The offshore storage sites in CNS, in particular the aquifers, span over large areas and have great degree of overlap as they lie in different geological formations that are stacked on top of each other in the same 2D area on the sea bed. Though potentially more challenging from a licensing/leasing perspective, this presents an opportunity of developing multiple storage sites in parallel to access the cumulative storage but save on many of the administrative, appraisal, infrastructure and monitoring costs. This section looks at an illustrative example of Captain sandstone saline aquifer to assess the cost savings from an integrated infrastructure development of stacked saline aquifers around Captain to a segmented approach of developing the aquifers individually.

The infrastructure and economics for storage clusters have not been well examined in the literature, but logically should offer opportunities for developers:

- **Reduced costs**, particularly
  - Seismic, for appraisal and monitoring
  - Offshore hub can service multiple pipelines and reservoirs
  - Injection facilities and distribution pipeline networks to connect these
  - Potential for less restrictive pressure and temperature management if multiple sites available, although reservoirs at different depths may need different injection conditions
  - Sharing costs for well abandonment or re-abandonment
  - Substantially reduced costs if a single borehole allows simultaneous access to multiple reservoirs at different depths (this is not assumed in the baseline).
  - In the long term, reduced decommissioning costs of stores

- **Increased capacity and reduced capacity risk**
  - Backup stores available in case primary store does not work
  - increased ability to test and expand capacity, flexibly

To our knowledge no techno-economic model has been published for the analysis the costs of CO_2 storage in stacked reservoirs. This represents a gap in knowledge that needs to be corrected for fair comparison of the CNS with the SNS. For the purpose of this study therefore only a high level examination of impacts was carried out. This showed four reservoirs close to the Captain sandstone saline aquifer could be exploited cost-effectively identified savings in the levelised cost of transport and storage in the region 30-50% (*ca*. £2-4bn, real £(2012)) for an integrated approach relative to treating these stores in isolation.

With conservative assumptions, such as the requirement for up-front well re-abandonment, widely spaced subsea network supported by offshore platform hubs to manage pressure and flows, and separate boreholes for each reservoir, and backup capacity in place, the storage costs for a stacked CNS cluster with capacity building up to 100 Mt/yr are estimated *ca.* £18/tCO_2 stored, excluding eventual decommissioning and long-term monitoring. This figure could be halved with a combination of more optimistic assumptions, e.g. the use of a single CO_2 injection well to access multiple stacked reservoirs, no need for expensive offshore flow management, and limited well spacing.

Further cost savings emerge from shared CO_2 transport infrastructure, although these are highly sensitive to the location of capture, transport configuration and cost of finance.

The sequencing of the stores in a stacked cluster is not well understood, but it may be important for optimisation. For example if the intention is to exploit maximum storage, it may be cheaper and less risky to fill deeper reservoirs before shallower reservoirs, despite the higher up-front costs.

8.6 Economic impacts for Scotland

8.6.1 Methodology

CCS infrastructure investments involve material costs (e.g. steel for onshore and offshore pipelines, fuel/electricity for powering compressors etc) as well as labour in the design, installation and operation of the network. Compression, pipelines, platforms, wells are stapes of the oil and gas industry. A significant proportion of the network investment can be performed utilising existing supply chains developed for oil and gas industry, providing they are aware of opportunities, projects pass supply chain commercial criteria, and of course are competitive. Thus there is significant potential contribution to Scotland's economy and this leads to job creation.

8.6.2 Gross Value Added and job creation

The investment in the CCS network can be aggregated into four components, namely CO_2 compression, pipeline transport, storage and EOR. Each of these categories involves engineering, project management, procurement, manufacturing, construction and commissioning. Thus the total investment can be estimated for the six components of the four categories.

The share of the investment per component that is held within the Scottish economy depends upon the level of skilled labour and expertise available for that particular industry. In this way the total Gross Value Added (GVA) is calculated for each CCS scenario. However, there are some further multiplier effects of these investments further down the supply chain that results in additional indirect and induced GVA contributions. The combined effect provides the total GVA to the economy and is an indicator of the contribution towards the Gross Domestic Product (GDP). This investment is also accompanied with jobs being created. As an industry average (based on historic data for the oil and gas industry), each £1m of GVA results in 1.3 full time equivalent person years of employment. Thus the total contribution to employment opportunities, in person years, is calculated from the investment in the CCS network infrastructure.

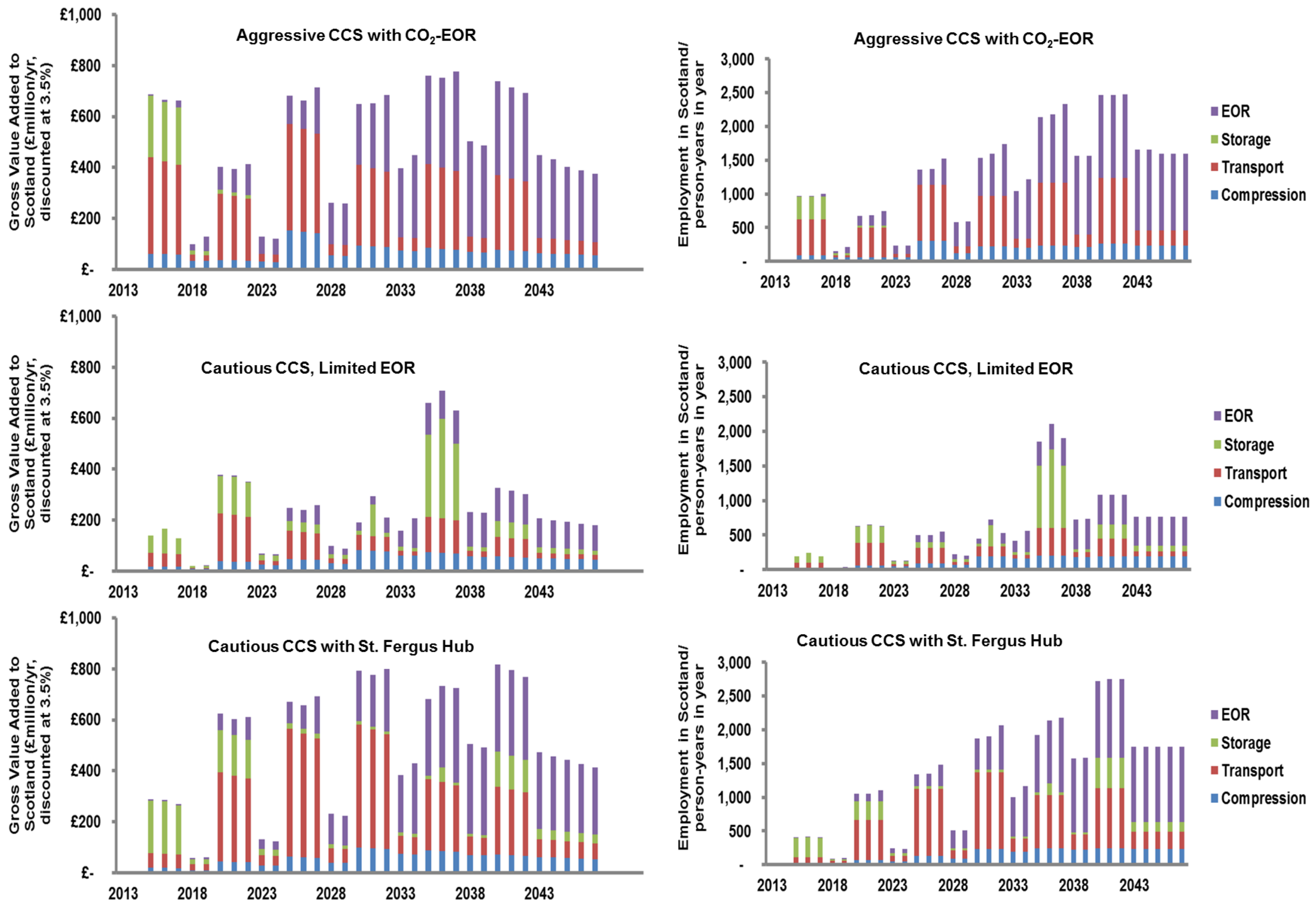


Figure 50: Total Gross Value Added (direct, indirect and induced) and Employment (person years) associated with the Aggressive, Cautious and St. Fergus Hub scenarios. Assumes economic multiplier of 2.31 and 1.3 FTE per £1m GVA.

Table 5: Breakdown of discounted GVA for Scotland for the three scenarios up to 2047.

Discounted GVA (£bn)	Aggressive CCS with CO_2-EOR	Cautious CCS, Limited EOR	Cautious CCS with St. Fergus Hub
Direct	£7 bn	£3.5 bn	£7 bn
Indirect	£5 bn	£2.5 bn	£5 bn
Induced	£4 bn	£2 bn	£4 bn
Cumulative person years[41]	44,000	22,000	45,000

[41] Identifying a single figure for the number of "jobs" is not straightforward as the contribution from different aspects of CCS and EOR will vary throughout time. The calculation that is often used is to divide the cumulative person years by 10 although there is no specific evidence or official guidance for this assumption. Scottish Enterprise Appraisal and Evaluation Team, (2013) *pers comm*.

8.7 Conclusions from economic modelling

The economic modelling carried out for this study and related projects identifies the following general principles:

- With high potential for sharing costs in storage clusters, the costs of transport and CO_2 storage-only systems from sources in Scotland to sinks in the CNS are competitive with those elsewhere in the UKCS (levelised cost £5-£30/tCO_2 stored) over a wide range of CCS deployment rates and capacities.
- There are multiple market difficulties faced by storage developers, amplified for first movers. However, current CO_2 pricing is two orders of magnitude weaker than oil price on a per tonne basis and fails to incentivise commercially risky storage exploration and appraisal, and very few commercial storage developers will invest their own funds in anticipation of distant future opportunities.
- As elsewhere in the UKCS, instead of every project having its own CO_2 pipeline, it is more cost efficient for multiple sources and sinks to share common trunk pipelines, at least up to levels of 10 Mt/yr per pipeline. Planned integrated systems should have overall lower lifetime costs than a network that evolves unplanned, although are more sensitive to external drivers such as CCS adoption, reservoir performance and interest rates.
- For relatively modest commitments on mothballing conditions, re-use of existing pipelines can reduce up-front costs by around one third, and associated challenges.
- Offshore injection facilities include, in increasing order of flexibility, subsea, fixed platforms and floating units. Requirements and costs are driven by injection well requirements, which are currently poorly understood.
- CO_2-Enhanced oil recovery at large fields can have positive pre-tax NPV at oil prices above $90/bbl and with discount rates of *ca*. 10% if the CO_2 is provided for free at the platform. However, with marginal tax rate for older fields around 81%, the post-tax returns fall well short of typical oil investor hurdle rates. Therefore a lower marginal tax rate is essential to kick start and sustain a CO_2-EOR industry. An alternative would be to create a national CO_2-EOR/storage company that could make decisions using a low discount rate and based on pre-tax income.
- With high up-front costs and expectations of a modest increase in revenues over time, transport, storage and EOR economics all benefit from low discount rates and high confidence in early utilisation. Delivering the infrastructure at least cost solution requires a regulatory and market environment that minimises the risk premium for commercial developers (or provides directly lower cost finance). This could include specifying offshore corridors and a limited number of shoreline and offshore hubs for accelerated development, to minimise stranded asset risks.
- Cable infrastructure for offshore power for pressure boosting is expensive and should be avoided for as long as possible. It would be appropriate to plan infrastructure to a limited number of shoreline and offshore CNS hubs, so that any CO_2 flow management is concentrated in as few facilities as possible. Offshore hubs should be co-located with CO_2-EOR facilities to reduce costs.
- Much of the value for the CNS resides in its high optionality, i.e. scalability, backup, geological diversity bringing resilience to individual projects and to the UK or Europe more broadly. However there is is a need for improved quantitative analysis of these benefits for policymakers.

9 Models for infrastructure development

The primary benefit from early investment in efficient CCS infrastructure (i.e. where supply and demand are well matched) would be lower future costs of meeting challenging energy and climate objectives (as well as reduced emissions to atmosphere as CCS technology is demonstrated and mobilised worldwide). This benefit is dispersed across future UK businesses, consumers and Government, and future generations worldwide, and it is not possible for any commercial businesses to monetise this. However, failure to develop suitable CO_2 transport and storage infrastructure threatens the viability of CCS as a decarbonisation option. Not only does this reduce feasibility and flexibility to decarbonise heat, power, transport and industry, the increased annual costs of decarbonisation may be close to 0.5-1% of GDP (depending on ambition and progress with other approaches). The compounding of the reduced economic growth and competitiveness from selecting more expensive decarbonisation solutions over many years could pose a serious economic challenge.

9.1 CCS market failures

A difficult market

It is very hard for countries to reach agreement on measures to restrict emissions of greenhouse gases, and how the burden should be shared (i.e. who should pay). This has an impact on the robustness of political support available for CCS, and there are cautionary tales from other sectors. However, weak or uncertain financial incentives for CO_2 capture, and continued technology/market/ project-specific risks in the 2010s and 2020s before CCS is deemed commercially proven create systematic challenges for investments in all aspects of CCS. The current market environment for investment in CCS is characterised by decision making on individual projects with an implied “trickle down” of strike price (and public subsidy for first projects) towards CO_2 transport and storage providers. However transport and storage have long critical paths and these need to be well advanced in order to be able to commit to contract. Fortunately, the Peterhead-Goldeneye and Captain Clean Energy

Project are only weakly impacted by this than other shortlisted CCS projects in the UK, as these projects take advantage of already well-examined infrastructure.

If stakeholders wish to deploy CCS aggressively, the capacity would most efficiently be developed through shared CO_2 transport and storage infrastructure. There are multiple and significant market failures and unbearable risks for commercial developers of infrastructure that could meet the capacity required in the 2030s.

Based on progress with CCS outside the UK, analogies with other UK industries, and elsewhere, a wide range of market and regulatory solutions, with varied roles for public and private sectors, are potentially feasible to resolve remaining market failures.

Given the lead times involved in developing CCS projects, one pressing challenge is to bring forward sufficient ‘bankable’ capacity, particularly in storage, available ahead of investment decisions on generation, capture and transport. This may involve screening and partially developing a portfolio of options, recognising that some may not proceed to fruition. Fortunately, with multiple existing hydrocarbon reservoirs, aquifers, existing pipelines, potential locations for capture, and flexible new pipeline and/or shipping hub transport options, Scotland and the central North Sea should afford several degrees of freedom for developers not readily available elsewhere.

Action to stimulate or improve the environment for investment in storage appraisal and development, and future-proofing the availability of the storage already well understood in hydrocarbon fields should be prioritised, to keep open a trajectory for full exploitation of the value of CCS to the UK energy system in the 2020s.

The combination of high transaction (sunk) costs, long lead times, asset specificity, a wide range of uncertainties (especially demand and storage performance) result in genuine risks that CO_2 transport and storage capacity will not available at the right time, right place or right size[42]. These uncertainties are unmanageable at either the project engineering or commercial actor levels; the private sector will not make nationally efficient but speculative anticipatory investments. Such investments are only made when potential returns are very high (e.g. oil and gas, venture capital, or pharmaceutical models) – these often provide some monopoly protection for first movers to recover costs, including the costs of unsuccessful developments. In contrast, there is an expectation that returns on CO_2 transport and storage investments will be “utility” in character, e.g. comparable to those from wastewater, waste disposal, material recycling, and in any case capped at the price of competing carbon abatement or low power generation alternatives.

To ramp up from our current base to injection rates approaching 100 Mt/yr, either a handful of “very large capacity” transport and storage networks or many “independent point-to-point” solutions would need to have navigated successfully their complex critical paths from concept to operation, a process fraught with difficulty. Either extreme involves significant challenges. Realistically attempts could fail at any stage due to technical, economic, commercial, regulatory, socio-political or other reasons, and therefore an even larger number of transport and storage concepts will need to be under evaluation even the 2010s, i.e. before CCS is deemed “proven”. Whilst infrastructure for the oil and gas industry of comparable capacity was installed in the UKCS in the 1970s, the financial drivers,

[42] The CCS Directive requires significant financial securities to cover a number of liabilities. This could include leakage of CO_2 stored when CO_2 prices are much higher than today.

technology and regulatory maturity was considerably more advanced than for CCS. The market challenges include:

- Information failure, e.g. what will be the future value of CO_2 reduction? What will be the most efficient capacity for transport and storage?
- Information asymmetry, e.g. what should be the price of CO_2 storage? What is the performance of a given reservoir?
- Property rights and concentration of market power, e.g. how should ownership be allocated efficiently given network economics and storage spatial complexity may encourage monopoly tendencies?
- Moral hazard, e.g. how to ensure the right level of risk-taking?
- Transaction costs, e.g. how can Government encourage competition?
- Positive externalities, e.g. information from CCS projects will be useful to many stakeholders, including those with no direct financial relationship to a given project
- Environmental externalities, e.g. future cumulative benefits from avoided emissions do not accrue to project developers.
- High costs of entry and exit, associated with covering storage-related liabilities for low probability events.

The importance of reservoir performance data

Storage development is data, resource, time and infrastructure intensive, but there are significant opportunities to limit time and costs by sharing data and infrastructure with the hydrocarbon production industry. However existing data that will inform estimates of reservoir cost and performance and the requirements for future proofing sites or infrastructure re-use is commercially valuable within the oil and gas industry.

With weak CO_2 price signals, there is virtually no incentive for oil and gas companies and their supply chains to share these data. The information asymmetry could restrict market entry and limits the sharing of information which arguably has public good characteristics. It also limits the likelihood that choices will be made to future-proof physical assets or take advantage of infrastructure sharing opportunities.

Further there is likely to be a wealth of storage site characterisation and operational experience that could significantly reduce the costs, risks and timescales for developers. However efforts to make “public” all data, without appropriate compensation, might stymie commercial incentives for exploration, appraisal and innovative development of storage, as developers would be unable to protect their competitive position.

9.2 International models for CCS infrastructure development

Norway

Norway has been a pioneer of CCS since the 1990s with commercial CCS investments stimulated by a high offshore CO_2 tax. Since 2008, the State-owned and funded Gassnova has been established to develop CCS. Gassnova and the Norwegian Petroleum Directorate have characterised Norway’s storage potential in detail. Upstream companies are forced to share all reservoir data with NPD, simplifying decision making. Statoil, responsible for two early projects, is partly owned by the Norwegian state. Whilst R&D continues strongly in Norway, plans for a Mongstad full scale CCS project have collapsed, partly due to spiralling costs.

The Netherlands

There has been consistent interest spanning a decade in CCS in the Netherlands from diverse stakeholders. EBN is charged with developing energy resources and oversees the exploitation of the deep sub-surface in a manner that is profitable for Dutch society, and is involved in creating a storage masterplan. Gasunie as the gas grid system operator is interested in developing CO_2 pipeline infrastructure. There is widespread expectation that the Dutch Government will take a hands-on approach to infrastructure development. Existing efforts (Rotterdam Climate Initiative, Nord Nederlands group) involve regional public sector-led coordination of industry stakeholders (e.g. in the Road project) to carry out feasibility studies, develop a vision, and factor in the regional economic impacts within the investment case.

North America

The drivers for CO_2 transport, storage and EOR infrastructure in the US and Canada include:

- Regional carbon sequestration partnership models developed to map out the useful storage in aquifers. Some of these are part-funded by the Department of Energy.
- Projects linked to well understood CO_2-EOR projects, e.g. in the Boundary Dam project in Alberta and Texas Clean Energy Project.
- Tax credits supporting CO_2-EOR.
- The desire to develop Canada's hydrocarbon reserves sustainably.

There is no obvious State or Federal co-ordination of infrastructure siting, but transport and storage solutions tap into existing EOR networks.

The Middle East

Over the past decade a handful of CCS projects have been considered in the Middle East. Beyond the operational In Saleh project in Algeria (driven partly by the need to adjust natural gas composition to meet a pipeline specification), these have limited "climate" drivers, and instead are focussed on CO_2-EOR (although some may apply for Clean Development Mechanism funding). There is a perception that some concepts were developed as "trophy" projects. The region has significant EOR potential, well understood geology, and growing demand for power and energy-intensive industries.

Three driving countries are Qatar, UAE and Saudi Arabia. In these three countries, the state is the single dominant decision maker across oil, transport, refineries, power and in financing.

9.3 UK models for infrastructure development

Since the 1980s, there has been a strong preference for major new infrastructure investment in the UK to be privately financed and to some degree led by markets. The situation is complicated at present by current tensions following the financial crisis towards capital investment vs. reducing taxes and public borrowing. Fully national provision of new infrastructure is rare in the UK; where intervention does occur, this often takes the form of public-private partnership (e.g. the Olympic Delivery Authority working with LOCOG) or regulation. Unless forced to act through granting a permit or bundle of permits, the UK Government often only reluctantly steps into discussions on nationally strategic and politically contentious infrastructure (e.g. High Speed Rail, Channel Tunnel, airport hubs);

usually decisions are reached following long review processes with outcomes that are difficult for industry to predict.

An exception is offshore oil and gas taxation, where the UK Government intervenes frequently to encourage development or minimise rent capturing by the hydrocarbon industry.

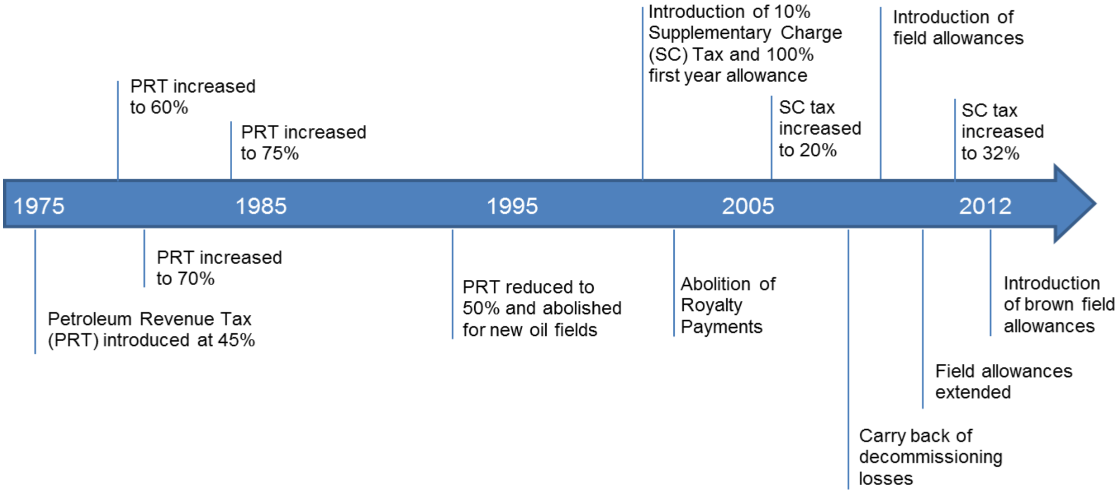


Figure 51: Frequent changes to UKCS oil and gas taxation

Where economies of scale imply monopoly service, “System Operators” are generally regulated at local, regional or national level (cf. water, wastewater, UK gas and electricity networks, trains, some ESCOs) by a designated Regulator or Authority. The system operator function clarifies incentives to run a complex network efficiently, sets specifications and provide open access for infrastructure. Even where there are regulated monopolies, competitive market pressures can be used at specific points within the value chain to encourage innovation and drive down costs. (cf. electricity generation plants and train operating compete on regulated networks).

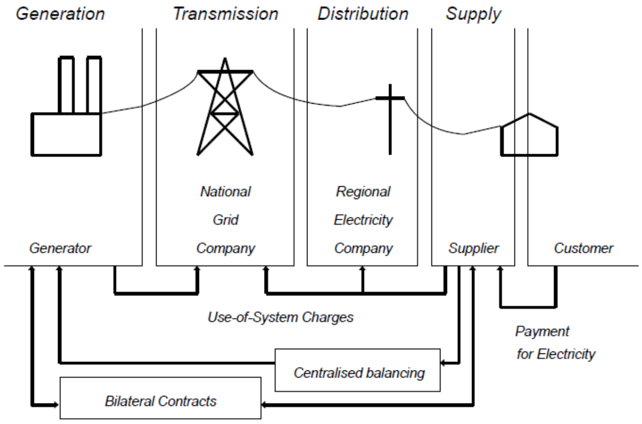


Figure 52: Existing UK electricity market includes elements of competitive and subsidised generation, national monopoly, regional monopoly, regulated supply, capacity markets, long-term power purchase agreements, reserve and response management payments.

At a more local or regional level (e.g. municipal waste management) the public sector has helped with planning locations and capacities, through mechanisms such as zoning or master planning. By way of comparison, there are clear zones and capacities for offshore wind which are released in “rounds”, and the precise sites for future nuclear plant in the UK have been earmarked. For CCS there is a need to consider the locations of generation, capture, transport, storage and EOR holistically, although to date the CCS industry has not requested a “one-stop” permitting approach.

The evolution of district heating networks illustrates the challenges of developing a functioning network. When fully established with multiple heat sources and heat sinks, these can be very energy and cost efficient. However the matching and contractual agreements with the necessary initial source and initial sink anchor projects are difficult to establish. This can sometimes be remedied (but not always) with public sector planning support, innovative energy service company models (including non-profit organisation ownership).

Whereas the most competitive markets involve multiple buyers and sellers and fungible products, the CCS industry is likely to comprise very few buyers and sellers making it difficult to price services. This creates an environment ripe for gaming or oligopoly exploitation. While there are examples where industries appear to self-regulate and co-ordinate effectively (e.g. oil pipelines, internet domains, paper recycling), there are conflicting tensions between encouraging first movers (through reducing downside risk or increasing upside reward potential) and managing eventual market power.

Models for managing risk or market power include[43]:

- Oil and gas supermajors are vertically integrated to reduce information asymmetries, transaction costs, counter-party risks, and allow any economic rents to be captured.
- Oil and gas companies frequently establish joint ventures to share exploration risk.

[43] Element Energy (2012) Business and Regulatory Models for CO_2 transport and storage, for the Energy Technologies Institute, and references therein.

- Upstream, downstream and mid-stream-led pipeline investor models exist for gas pipeline infrastructure, depending on the levels of supply and demand risks.
- Industry councils can assist with infrastructure specification and dispute resolution, with the threat of regulation or independent arbitration if no solution can be reached
- Publicly owned or regulated regional or national private monopolies could be established e.g. national oil companies or Lord Oxburgh's model of a "Carbon Storage Authority", which fully fund exploration, appraisal and development, socialising costs and risks across the economy.
- Establishing a capacity market (including options in a forward market with locational price signals), and considering the extent to which infrastructure ownership is unbundled from capacity, and facilitating the use of taps to allow third party access/by-pass.
- Establishing insurance models and a cross-industry fund to deal with payments for accidents.

Work by Element Energy for the Energy Technologies Institute considered five potential for CO_2 transport and storage infrastructure development. In order of increasing levels of public intervention, these are:

1. Government informs and enables competitive market for CO_2 transport and storage infrastructure
    - Investment models led primarily through strike price for power generators and carbon prices for industry and industry bringing forward EOR projects
    - Government provides favourable licensing (and for The Crown Estate, leasing) guidance for storage, facilitates handover from oil and gas to storage, co-operating for cross-border projects.
    - Laissez-faire approach leaves commercial investors with significant policy and regulatory risks, project-on-project technical and market risks. This implies less anticipatory investment, although it also means the risks from stranded assets are lower.
    - Most suitable when expected future capacities are low.
    - Multiple short and long-term contracts between sources, capture, sinks and transporters, which may take time to negotiate.
    - Open seasons and T-junctions encouraged to maximise efficient investment in capacity
    - Government intervenes if there is evidence of market abuse.
    - First movers have a strong influence over entry and exit specifications
    - Transport capacity is traded in spot and forward markets.

2. Industry co-ordinates and provides leadership on CO_2 transport and storage infrastructure, with Government support
    - Assumes self-regulation through a body comprising key stakeholders, with UK Government or EU enabling information sharing
    - Industry Task Force agrees sequencing and capacity of zones for offshore transport and storage infrastructure

3. Regional monopoly system operator(s) established to deliver transport and storage infrastructure in priority zones

  - A single regional provider aids co-ordination, without the excessive standardisation or bureaucracy that might be associated with a national programme.
  - Very challenging to select the preferred regional monopoly
  - Could limit innovation
  - Could disrupt demonstration projects
  - UK regional monopoly models include trains, busses, water, electricity distribution, waste, district heating
  - Economic regulation through a formula (e.g. capped returns, tariff increases linked to RPI-X%)

4. Public-private Joint Venture(s) established to deliver transport and storage infrastructure,
   - Government and industrial actors establish a JV which creates a blueprint for the location, capacity and phasing of (largely monopoly) transport and storage infrastructure, and has the responsibility for developing this.
   - Public sector involvement in the JV reduces policy and regulatory risks, whereas investment by users in infrastructure reduces stranded asset risk (supported by contractual agreements)
   - At the start need a "coalition of the willing", but over time equity shares can be changed (e.g. increased role of oil companies for EOR, selling off public sector equity, or to third party investment houses).
   - Public investment may distort energy, oil, carbon and CCS markets.
   - Ability to take small equity share limits downside risk for individual investors, and to match better the different risk-reward profiles for different industries.

5. Government design, own and operates CO_2 transport and storage infrastructure
   - Potential for efficient capacity over long-term
   - Central planning may reduce innovation and flexibility, raising costs
   - Highly disruptive intervention, contrary to current policy so challenging to obtain funding.
   - Most valuable when expected future capacities are very high.
   - UK relevant models include the Nuclear Decommissioning Authority, parts of the postal, rail, road networks, vaccination programmes in the NHS (major investment decisions are based on a UK-wide cost-benefit analysis).

Table 6: Comparison of business and regulatory models on four market challenges (red = unfavourable, green = favourable, amber = intermediate).

		Key Market Challenge			
		Inefficient T or S capacity within tight timescale (insufficient, stranded or sterilised assets)	**Unnecessary costs or risks or delays (Data & infrastructure sharing, congestion)**	**Excess transmission or storage price**	**Ease of implementation**
Regulatory Model	1. UK Government informs and enables competitive market	Risk of insufficient capacity or stranded asset risk for over-sized pipelines or market power for stacked stores	Weak mechanisms for data and infrastructure sharing and to avoid congestion	Market pressures could reduce costs, but absence of market / market power could drive up cost	Current policy
	2. Industry leadership and self-regulation (Govt. enabling)	Possible to coordinate and thereby optimise design within commercial constraints	Need to co-operate with oil/gas and other stakeholders	Industry could critique and reduce costs, but also high risk of market abuse.	Will UK CCS industry self-regulate efficiently?
	3. Regulated regional private monopolies	Likely to resolve spatial planning challenges and provide coordination, but absolute investment may still be difficult	Government could create mechanisms to force data, infrastructure sharing and spatial planning	Regulation will limit prices. Co-ordination could reduce costs	How will Government choose a T&S system operator between new entrants?
	4. Regulated regional public-private Joint Venture Monopolies	Likely to resolve spatial planning challenges and provide anticipatory investment		Regulation will limit prices. Expect anticipatory investment in national interest.	Likely to be successful but planning and up-front public funding could be difficult.
	5. Government design and build CO_2 transport and storage infrastructure	Effective if Government takes much larger control of energy and carbon reduction problem		Public infrastructure could be optimised, but it could also be inefficient.	Would require high spatial planning and up-front public investment, contrary to UK policy

Feedback from stakeholders to date indicates that options 3 and 4 are worthy of more detailed analysis. The ETI work specifically excluded consideration of CO_2-EOR from scope.

9.4 Opportunities to incentivise CO_2-EOR

Recent work by Element Energy *et al*. for the CO_2-EOR Joint Industry Project has examined a number of financial mechanisms to support CO_2-EOR specifically. These are listed below:

Intervention	Advantages	Disadvantages
Flat field allowance for CO_2-EOR	Targeted, transparent, in line with current practice for ultra-heavy oil fields.	Would be insufficient for some fields or excessive tax reduction could lead to deadweight losses.
Field allowance based on unit development cost	Targeted, transparent, in line with current practice for brownfield allowance. Minimises deadweight losses if structured efficiently.	Does not provide a strong incentive for cost reduction. Focus on CAPEX may distort investment in OPEX-heavy projects. Would require ex-ante agreement on predicted CAPEX and oil production.
Field allowance based on unit technical cost	Targeted, transparent, recognises that OPEX will have a material influence on costs.	Would require ex-ante agreement on predicted CAPEX and long-term OPEX, including CO_2 transfer prices (if included).
Field allowance based on DPI	Minimises deadweight losses if investors have the same DPI threshold.	Would require ex-ante agreement on predicted CAPEX, OPEX, reservoir performance, discount rates and revenues. Information asymmetry creates risks of "gaming" these assumptions.
Field allowance based on CO_2 stored	Likely to lead to project designs that maximise CO_2 storage Could be extended to storage-only projects. Addresses market failure for storage.	Estimating storage performance will be difficult. Does not lead to a focus on oil production, and therefore may not maximise tax revenues.
Field allowance based on incremental oil	Transparent, in line with current practice for small field allowance.	Does not promote higher oil production. Would require ex-ante agreement on predicted oil production.
Reducing headline tax rate (Supplementary charge and/or PRT)	Simple, promotes investment in a field-neutral manner	Would be insufficient for some fields without additional tax incentives; however, could also lead to high deadweight losses.
Capital grants	Simple for commercial operators, common stimulus for new technology demonstration.	Requires up-front public subsidy. Unlikely to win environmental NGO support.
Low-interest loan	Use of lower public sector discount rates makes investment more attractive.	Loans not usually appropriate for new technologies with multiple and significant risks.
Create national CO_2 storage company that could co-invest in CO_2-EOR projects	Allows a much larger number of options for CO_2-EOR. Potential for a joint company with Norway and Denmark. Revenues could support nationally strategic investments. Addresses market failure for CO_2 storage	Contrary to prevailing approach for major new UK infrastructure projects which are privately led.

An example of an efficient incentive (i.e. one that minimises deadweight losses) is provided below:

The study also identified the potential value of a "national storage/EOR company" that could take decisions on a pre-tax basis, although it is recognised that this approach is contrary to current practice in the North Sea. In the national company approach, the Government-backed organisation would agree infrastructure and liability transfer with oil companies, take the lead in data collection and analysis, site selection, pre-development and development, construction, operation, closure, although it would likely sub-contract significant elements of this to the private sector through competitive tenders or PFI-style models.

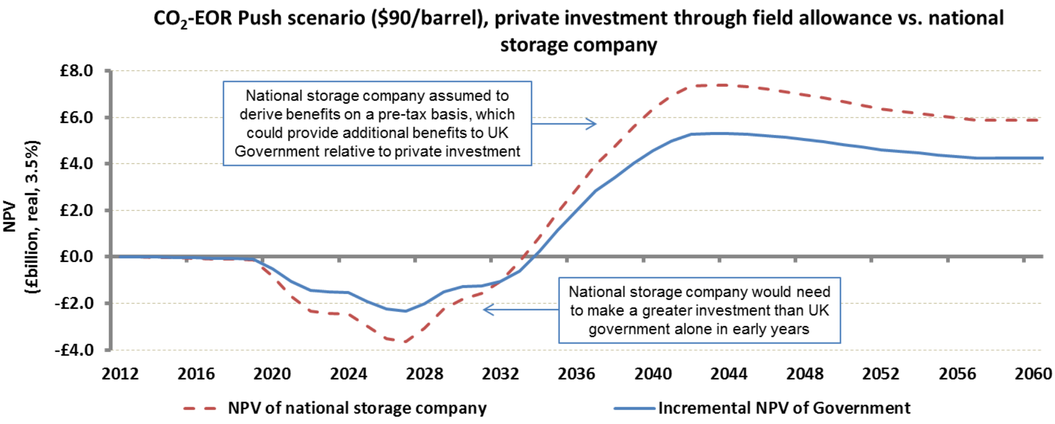


Figure 53: Illustrative benefit to Government or hypothetical national storage/EOR company (adapted from Element Energy *et al.* (2013) Fiscal incentives for CO_2-EOR).

9.5 Establishing the model

As important as the exact business model configuration is that investors experience a sense of "ownership" of the chosen model. Therefore, it would be valuable for Scottish Enterprise to facilitate both opportunistic and focussed "working group" discussions with diverse potential investors and their stakeholders interested in Scotland and the central North Sea, such as:

- Public investors, such as the UK Government's Department of Energy and Climate Change, Department of Business, Innovation and Skills, HM Treasury, HM Revenue and Customs.
- Publicly backed investors, such as Green Investment Bank, European Investment Bank, European Bank of Reconstruction and Development, Scottish Government, European Commission, and The Crown Estate.
- Pipeline companies (e.g. National Grid, Denbury, Kinder Morgan)
- Export credit agencies, e.g. from Korea or China
- Utility power companies (e.g. SSE, Iberdrola, E.On, RWE, Vattenfall)
- Independent power project developers (e.g. Summit Power, Peel/Dong, Progressive Energy, C.Gen, Drax)
- Existing industrial emitters in Scotland (e.g. Dunbar and Grangemouth)
- Gas companies (e.g. Linde-BOC, Air Products, and Air Liquide)
- Upstream energy super-majors (e.g. Shell and BP)
- Medium-size oil and gas companies (e.g. Tullow Oil, Talisman Energy, Statoil, TAQA, Maersk)
- Major engineering firms (e.g. Doosan, Samsung, AMEC, PB, MottMac, Foster Wheeler)
- Storage companies
- Dedicated CCS-EOR companies (e.g. 2CoEnergy)
- Waste management and environmental service companies (e.g. Veiola)

- Financing from the capital markets (e.g. infrastructure funds, bonds, banks and other loan providers, and providers of complex debt instruments)
- Innovative new businesses that may be publicly or privately backed or joint ventures.
- The Global CCS Institute (GCCSI)
- Europe’s ZEP Task Force
- Countries with strategic interests in CCS deployment
- Other regions – e.g. Yorkshire, Tees Valley, Rotterdam, Norway, which may wish to co-ordinate transport infrastructure provision with Scotland.

In nearly all cases, decision making in each of these organisations is fragmented, and it may be necessary to facilitate communication at technical, commercial and board levels. This could be through dedicated sessions within established events such as the traditional oil and gas conferences.

Scottish Enterprise should also continue to maintain strong relationships with environmental and consumer groups which have significant influence on UK energy policy and investments.

10 Conclusions and Recommendations

The analysis in this report details the flexibility of Scotland and the central North Sea in offering multiple opportunities for CO_2 capture, transport, storage and EOR. A wide range of infrastructure solutions can be delivered, with opportunities to kick-start infrastructure with low capital costs and risks, and expand capacity quickly as demand for CCS to meet the longer term needs of Scotland, the UK and Europe.

10.1 Storage

The storage of CO_2 is by injection into porous rocks deep (>800 m) beneath the sea bed. The injected CO_2 is stored in microscopic pores within the rock previously occupied by oil, gas or saline water. The CNS subsurface has been heavily mapped, and extensive seismic and well log data, reservoir models, field production and pressure histories, are often available, reducing the timescales and risks of storage pre-development and development, particularly for depleted fields. Considering individual fields, the capacities and costs of storage sites in the CNS span a large range but include several Gt worth of capacity in sites that are competitive with options elsewhere in the UKCS. With numerous and diverse sites in close proximity, and the largest theoretical capacity of any region of the UKCS, many “quadrant”-sized regions of the CNS offers a portfolio of stores with very likely complementary performance requirements. The portfolio collectively could reduce the risks from individual site under-performance, although infrastructure, regulatory and business model design will be critical to maximise the opportunity. Critically some stores have been examined in elaborate detail and have passed several milestones for assessment as technically suitable for storage or EOR. Of these the best advanced is the Goldeneye reservoir which can accommodate the CO_2 supply from the demonstration project at Peterhead. Goldeneye sits at the end of the Captain Sandstone saline aquifer, which has been modelled as having very attractive storage properties and a capacity 100-300 Mt. With close proximity to other stores, the capacity of a storage solution in the Captain sandstone saline aquifer can be expanded, potentially by up to 1 Gt capacity incrementally and at low cost (because of the opportunities to share costs).

In addition to the Captain Sandstone saline aquifer route, multiple other storage development pathways afford straightforward access to an initial well understood store with potential for very rapid expansion of capacity. However there is a gap in understanding the ideal mechanisms for developing large aquifers and tightly clustered/stacked stores, a particular challenge for the central North Sea which the on-going CO_2MultiStore project will address. A co-operative relationship between storage developers and with the licensees of hydrocarbon fields will need to be managed carefully in the 2020s. With the exception of the Goldeneye platform, currently there are few efforts to ensure storage readiness of decommissioned fields, high quality data for storage assessment, and reduced costs from infrastructure re-use.

10.2 CO_2-EOR

Several studies have demonstrated that CO_2-EOR ought to be technically feasible, with CO_2 storage capacities sufficient to serve multiple sources in the 2020s and 2030s, though very limited thereafter. Data asymmetries for EOR developments may reduce the rate of adoption. Combined with widespread scepticism around the viability of CO_2-EOR held by many stakeholders, there could be value in a publicly transparent assessment (at least pre-FEED quality) of the potential for an individual EOR project and EOR cluster, to inform policy development in this area.

An efficient supportive measure would be reduced taxes for CO_2-EOR projects. In the early years CO_2 supply will be limiting, but modelling suggests a combination of a PRT waiver and field allowance would be sufficient to make EOR projects commercially viable at a project screening price of $90/bbl and CO_2 supplied for free at the oilfield. Policy and infrastructure should also consider that EOR fields are close to stores, and EOR-store combinations would have more flexible economics than considering EOR alone. To date no meaningful actions are being taken to develop the UK's CO_2-EOR potential, even though the largest deployment scenarios could deliver several £billions in developer profits and tax revenues over the period to 2040.

Despite numerous desk studies, there remains an on-going need to convince a highly sceptical audience that CO_2-EOR is feasible in the UK sector of the North Sea, and that the economics could be favourable for oil companies, Government, the CCS industry, and ultimately electricity consumers and shareholders. The recent publication of FEED studies for Longannet-Goldeneye and Kingsnorth-Hewett appear to have eliminated the analogous scepticism that large scale integrated UK CCS projects are technically feasible. Publication of details of a viable North Sea CO_2-EOR project might help to move the debate forward.

Spatial analysis considering wind farms, marine protected areas, and SSSIs identified that seabed spatial conflicts for several offshore transport and storage development pathways for the CNS were unlikely to be material, although this analysis will need to be updated periodically.

10.3 Capture

Scotland offers good opportunities to implement capture with multiple fuels (coal, gas, biomass), multiple system designs (pre, post- and oxy fuel options at power and industrial sites have all been identified).

The proposed Shell/SSE Peterhead project is considered to have low development risks. As the project is a retrofit, there are no challenges in financing, permitting and construction a new power plant or with electricity transmission and fuel supply. Heat, power and cooling water are available on-site. The project intends to use Shell's CanSolv-based amine based post-combustion technology, which has passed CCS project sanction elsewhere. The Peterhead site itself has previously been assessed as viable for capture. Shell and SSE are experienced CCS project developers, and the ownership structure manages well the main project risks. Finally an existing pipeline is available to link the site from Peterhead to St. Fergus for boosting, and then on to Goldeneye. Alternatively a new pipeline could be developed with low capex.

The Captain Clean Energy Project offers opportunities to improve UK energy security and boost base load power generation capacity by several hundred MW at a time of closure of coal and nuclear sites. The proposed coal IGCC plant design borrows heavily from the Texas Clean Energy Project, which has reached Final Investment Decision. Several options are available for transport, including re-use of the National Grid NTS Feeder 10 pipeline in the gas phase, a new dense phase pipeline, or CO_2 shipping. The project team comprise experienced CCS project developers. A challenge will be to ensure momentum for this project while it is on a reserve list. The JV framework with Summit, and technology vendors Linde and Siemens should ensure that cost, supply and performance risks are well managed within the project.

For both the above projects, the global reach of the firms involved imply that any learning based in Scotland could be readily channelled to the global CCS marketplace.

This study has explored potential capture at many other sites in Scotland. Many sites are systematically screened out due to lack of space available on site for capture, difficulties in accessing the site with a new pipeline, small size, or remoteness from any plausible site of capture making transport to a hub, all of which would make CCS prohibitively expensive. However particularly attractive industrial sites include the Grangemouth refinery/CHP complex and Dunbar cement works.

10.4 Transport

The study has confirmed and elaborated the flexibility in Scotland for CO_2 transport solutions, where point-to-point solutions, based on new or existing pipelines initially, are likely to be cost effective, and only once CCS is mature in the 2020s would it be essential to provide highly future-proofed pipeline infrastructure, i.e. transport and storage infrastructure can be phased over a long timescale (which is not the case for other UK hubs). Key onshore assets are the St. Fergus gas terminal and Feeder 10 onshore pipeline which could very easily support the 2.5 Mt/yr supply from the Captain Clean Energy Project, and where capacity could be first increased by adding boosters. Later on, if capacity is expected to exceed 7 Mt/yr other Feeder pipelines might be made available or a new pipeline could be economic. Stakeholders will need to co-operate to manage any permitting challenges for pipelines to link sources to the Feeder 10 pipeline.

Several trunk pipelines in the central North Sea may become available for CO_2 transport over the likely development timescale for the CCS industry. The Goldeneye and Miller gas pipelines have already been evaluated for use in CO_2 transport and are expected to be viable, although operating pressures are likely to be lower than would be the case for new pipelines. A detailed case-by-case assessment would be valuable for the remaining pipelines. There is therefore no compelling case for any private actors to carry out case-by-case desk studies on the viability of these pipeline, or indeed experimental trials with CO_2 to confirm the viability of transport, let alone incur the costs of any measures that future-proof the availability of these pipelines for CO_2 transport. If used, however, these would likely be in operation for only a few years (because of their age), and then replaced with a new high pressure CO_2 pipeline.

Peterhead and Hound Point are two potentially attractive locations for CO_2 shipping terminals. The lack of near-term demand for CO_2 shipping at NE Scotland, and the lack of resource at Peterhead Port limit the potential to take advantage of any investment opportunities. However, Peterhead Port is physically adjacent to the Peterhead Power Station and close to St. Fergus gas terminal and could "plug into" a CO_2 transport network involving either or both of these. To develop further the technical potential of Peterhead Port, it will be important to evaluate in more detail the need to dredge the Port, examine CO_2 dispersal under a range of weather conditions, and consider the use of floating structures for temporary CO_2 buffering.

Diverse platform, subsea facilities and well designs are used in the central North Sea, and the existing supply chain would likely be able to work directly with storage developers. Short-term and long-term trade-offs are well understood in the sector.

To deploy CCS aggressively, the UK Government should fund five full chain CCS projects to be operational by around 2020. In Scotland this would include the Captain Clean Energy and Peterhead SSE-Shell projects. It would be valuable to plan for early transport infrastructure from Yorkshire and Tees Valley projects to feed directly or indirectly towards an offshore CNS storage hub, close to a large EOR play to de-risk CO_2 supply for EOR deployment. An example of least system cost infrastructure that maximises the optionality and value for Scotland is shown below:

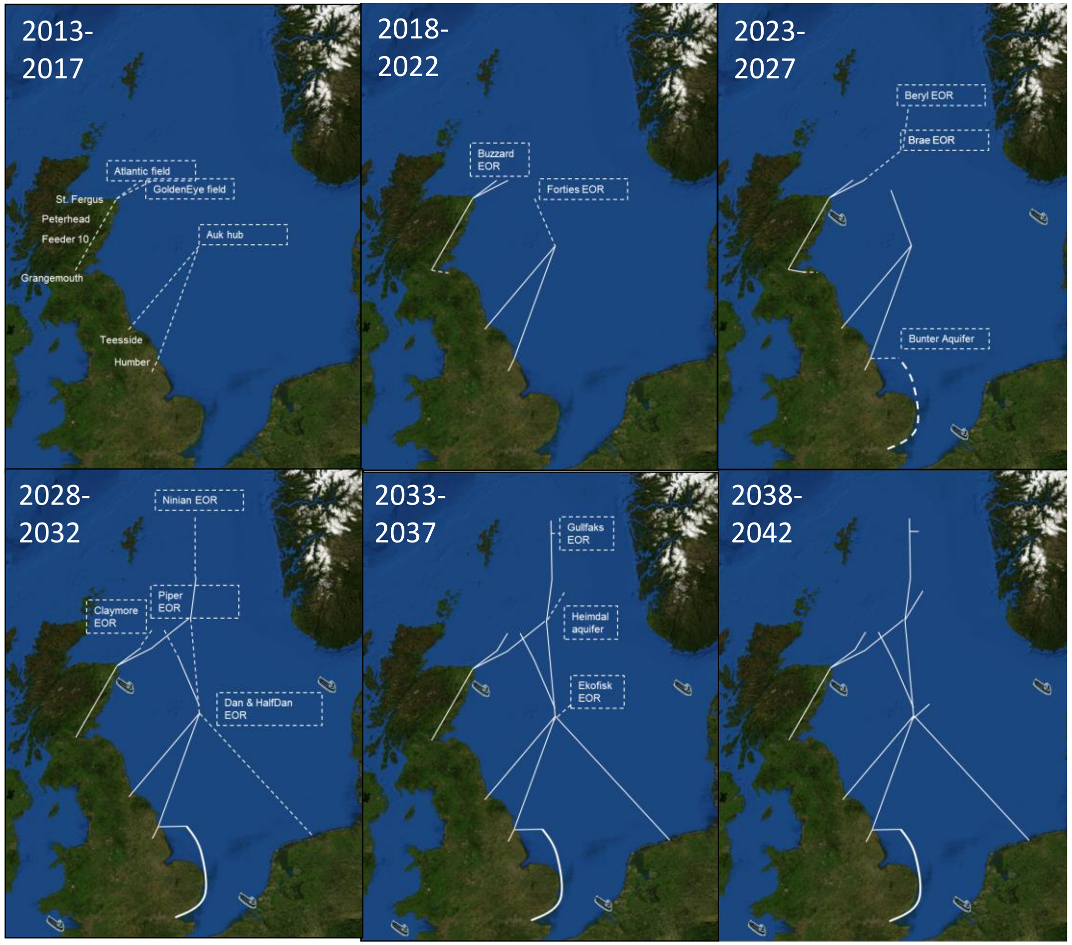


Figure 54: Planned phased infrastructure growth for the Aggressive Scenario indicating investment requirements in six 5-year phases from 2013-2042.

The aggressive approach could deliver storage of 1.7 $GtCO_2$ from UK sources and production of 1.3 billion barrels of UK oil; additional oil is available from Norwegian and Danish CO_2-EOR projects. A more cautious CCS deployment pathway would see projects implement CO_2-EOR only after CCS was demonstrated, although the narrow window of opportunity implies only a smaller amount of oil could be recovered (here modelled as 0.5 billion barrels), unless Scottish stakeholders intervene to ensure projects route CO_2 flows via St. Fergus and/or Peterhead.

Analysis confirms that the main investment risks for CCS infrastructure that project developers and public policymakers need to manage are (i) oil revenues from CO_2-EOR projects, i.e. oil price, reservoir performance, and tax; (ii) revenues of transport and storage infrastructure (i.e. tariff and utilisation, particularly in early years); (iii) capital costs (wells, platforms and pipelines) and (iv) discount rates (i.e. phased expenditure is preferred at high discount rates). To get the network started, a combination of capital subsidy, index-linked Feed-in Tariff, viable storage business model, and potentially tax incentives for EOR will be necessary, although as CCS matures support can be tapered.

While there are well developed offshore transport and storage supply chains in Scotland, the challenge for CCS projects in the 2010s and early 2020s will be the high opportunity costs from oil and gas projects.

10.5 Business and regulatory model

The report has reviewed the multiple market challenges for CCS infrastructure. The underlying challenge is that early investment maximises opportunity and reduces costs in the future, although early movers are exposed to diverse risks, including that specific assets may be “stranded”. Recent UK Government policy has significantly improved the likelihood that UK CCS projects can now be funded, which helps Peterhead-Goldeneye and Grangemouth-Atlantic projects.

However, current arrangements do not support steps by “first movers” to deliver storage readiness ahead of project sanction. The DECC commercialisation programme may provide some future-proofing of CO_2 transport and storage capacity. High capacity networks incur up-front cost, longer lead-times, higher pre-development risks, and potentially lower revenue streams if lack of capacity constraint dulls the incentive for transport and storage developers. A number of solutions have been implemented in the UK and elsewhere to resolve the challenge of investing in network capacity, including concession agreements for regional regulated monopoly system operator functions, public-private partnerships, and industry Joint Venture investments.

10.6 Recommendations for Scotland

The study has illustrated that all the components are either in place, or can be readily developed, for Scotland to become a major CCS hub, supporting UK and European CCS deployment.

The CNS has by far the UK’s largest variety of stakeholder interests, legacy facilities (pipelines, platforms and wells), and potential physical and commercial/regulatory configurations for CCS development. This leads to a wealth of opportunity for established

North Sea operators as well as new entrants. That demands leadership and flexibility, which Scotland is ready and willing to deliver.

If Scotland wishes to be a European leader in CCS, then efforts to champion CCS projects, and develop infrastructure for EOR, power and industry in the UK and Europe should be stepped up immediately and continue during the 2010s as follows:

Support for early CCS demonstration in Scotland

1. As CCS demonstration is critical, Scotland should continue to support early CCS demonstration, particularly development for the Shell/SSE Peterhead-Goldeneye and Captain Clean Energy projects which are well designed projects, ready for further investment to support Front End Engineering (FEED) studies, followed by a Final Investment Decision (FID). The Thermal Generation and CCS Industry Leadership Group can help create a common message together with hydrocarbon operators in support of these projects.

Maximising the UK and European market for CCS in the 2010s and 2020s

2. As the total opportunity for Scotland depends on the total market, Scotland should support and encourage UK and European funding for multiple CCS demonstration projects in the 2010s and early 2020s with designs that facilitate rapid capacity expansion, and a supportive legal and regulatory framework.

Supporting infrastructure that targets the CNS

3. Linkages should be facilitated between existing or planned CCS and CO_2-EOR projects around the North Sea, increasing the opportunities of appraisal and pipeline infrastructure targeting the CNS. SE can promote the proposition through its European networks and existing CCS stakeholder fora.
    - This could include working with stakeholders in Europe to identify and develop a market for CO_2 shipping, in advance of physical investments in a CO_2 import/export terminal.

Improving CCS readiness and optimising infrastructure

4. Continued awareness raising and improved understanding, including providing support measures, to fully inform stakeholders, such as planning authorities and regulators, in respect of the CCS infrastructure opportunities in Scotland, is key to successful early deployment.
    - Support for further characterisation and simulation of the diverse storage and EOR storage sites is essential to ensure the best stores are developed and to provide investors with confidence that storage performance can be managed.
    - National planning frameworks could be used to establish preferred zones or corridors for CCS infrastructure, particularly around the Forth, Feeder 10 pipeline route and St. Fergus Gas Terminal.
    - Existing large stationary sources should be encouraged to examine the feasibility of CO_2 capture and transport at their sites and to take steps that improve their CCS readiness where appropriate.
    - The close proximity of stores in the CNS provides opportunities for rapid expansion of capacity at reduced risk (due to high redundancy) and lower cost (due to high potential for infrastructure sharing) once an initial anchor project is chosen. Industry and SE should evaluate and publish detailed

analysis of the infrastructure, economics, leasing/licensing structure and risk profile for the appraisal, development and operation of a CNS storage cluster, where stores are in close proximity/overlapping.
   - Marketing materials should support greater interaction between CCS project developers in the UK and Europe with oil and gas companies and their supply chains based in Scotland, as these could provide CO_2 storage or EOR services.
5. Industry in partnership with SE and key stakeholders should support detailed studies of the engineering, regulatory and commercial requirements for the future-proofing and re-use of onshore and offshore pipelines, wells, platforms and sub-sea facilities to speed up the development of and reduce the costs of CO_2 transport, storage and EOR in the CNS. This could include:
   - Experimental trials of individual assets (e.g. pipelines and wells)
   - Management of performance and liabilities of assets in the period between use for hydrocarbon production and transport and CCS.
   - Decommissioning and abandonment specification for hydrocarbon fields, which has the potential to impact future costs of CCS or EOR.
   - More detailed engineering studies (at Pre-FEED and FEED level) for CCS shoreline hub infrastructure at Peterhead, St. Fergus, or in the Forth (e.g. Hound Point and/or Grangemouth).
6. SE should continue to facilitate dialogue between North Sea oil and gas companies and their supply chains, CO_2 storage or EOR service providers, capture project developers and other CCS stakeholders.

Improving the commercial attractiveness of CO_2 transport, storage and EOR

7. Currently there are significant hurdles for commercial investment in transport, storage or EOR infrastructure, implying real risks that without further intervention, infrastructure investments made in the 2010s and 2020s will be inefficient. Scottish Enterprise should therefore continue collaborate with stakeholders such as DECC, The Crown Estate, The North Sea Basin Task Force, ZEP and European Commission to strengthen the markets for CO_2 transport, CO_2 storage and CO_2-EOR.
   - The solutions needed to maximise the CNS opportunity will likely involve a mix of stronger price signals, innovative business and regulatory models such as joint ventures and regulated monopolies, fiscal incentives, and leasing and licensing regulations that encourage first movers, promote long-term efficient use of resources available.
   - This should include analysis of models in other industries, notably the designs and licensing/financing/tax models for a regulated monopoly, public-private joint venture for infrastructure, which could accelerate CCS and CO_2-EOR deployment in the CNS.
8. When ready, the results emerging from the CO_2-EOR Joint Industry Project, notably the recommendation for the introduction of a structured field allowance and a waiver of PRT for the first CCS with CO_2-EOR projects, should be reviewed with the UK Government, North Sea Basin Task Force and the PILOT taskforce and considered along with recommendations from the Wood interim report.

About the Authors

Element Energy Ltd is a technology consultancy providing a full suite of services in the low carbon energy sector. Element Energy's strengths include techno-economic analysis and forecasting, delivering strategic advice, engineering and the design of strategies for the coordinated deployment of low carbon infrastructure.

Scottish Carbon Capture and Storage (SCCS) is a partnership of the British Geological Survey (BGS), University of Edinburgh and Heriot—Watt University, funded by the Scottish Funding Council and Energy Technology Partnership. It is the largest CCS research group in the UK.

AMEC is a focussed supplier of consultancy, engineering and project management services to the world's oil and gas, minerals and metals, clean energy, environment and infrastructure markets.

Aberdeen-based **Dundas Consultants** provides its clients in the oil and gas industry with independent specialist services in petroleum economics, development engineering, opportunity framing, assessment and analysis and business process support.

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Caveat

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of CCS. The available data are extremely limited and analysis is therefore based around hypothetical scenarios. The information and models developed for this study have been provide a strategic understanding of opportunities, and should not be relied on for analysis at the level of individual sectors, technologies, or projects. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of Scottish Enterprise or any of the stakeholders consulted during the course of this project.