Large-Scale CO2 Sequestration on the Norwegian Continental Shelf: A Technical, Economic, Legal and Institutional Assessment

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SCOPE OF DOCUMENT

This CO2-Infrastructure Study Report describes an interdisciplinary assessment of the benefits and how one might initiate large-scale gathering, transportation and storage of carbon dioxide (CO2) on the Norwegian Continental Shelf (NCS). The proposed pipeline transportation infrastructure could eventually gather CO2 from throughout large areas of industrial northern Europe. It could also represent a technological advancement that would become the mainstay for permitting substantial reduction in European emissions of CO2 whilst also ensuring extended activity in the maturing oil reservoirs throughout the North Sea.

This report, together with referenced documentation, considers aspects of such a concept covering CO2-capture, transportation and permanent storage. And also related legal issues, climate policy, and business strategy including roles for the private and public sectors.

The document is therefore a multidisciplinary compilation based on contributions from the five project partners that have participated with the Study during the period from June 2002 though until March 2004.

The original project proposal was presented by Hustad *et al.* (2000). A revised scope of work by Lindeberg (2002a) dated 13 Feb 2002 was subsequently accepted for funding by the ***Research Council of Norway (RCN)*** and integrated with a complimentary study being conducted by the ***Norwegian Petroleum Directorate (NPD)*** regarding CO2-EOR potential on the NCS (Mathiassen, 2003).

The partners have contributed individually within their specific field of expertise and have also met on a regular basis to exchange knowledge and discuss issues within a broader setting. We believe that this aspect of the work has permitted an improved understanding and dissemination of the issues.

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This document refers to itself as the Study Report.

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STORSKALA CO2 DEPONERING PÅ NORSK SOKKEL: EN TEKNISK, ØKONOMISK OG JURIDISK VURDERING

RESULTATSAMMENDRAG PÅ NORSK

Prosjektet har framskaffet en flerfaglig vurdering omkring utfordringer og muligheter for storskala lagring av karbon dioksid (CO2) i geologiske formasjoner på norsk sokkel. Som et eventuelt klimatiltak vil dette også påvirke mulighetene til praktisk reduksjon av betydelig mengder CO2 i forbindelse med kraft- og industriutslipp i Nord-Europa fra Kyotoperioden (2008 – 12) og fram til 2050.

Det har blitt utviklet en teknisk og økonomisk modell for CO2-injeksjon i norske oljereservoar og akviferer. Modellen brukes til å definere spesifikke deponerings-scenarier, og beregner nøkkeltall som meroljeproduksjon, mengde CO2 som lagres i oljereservoarene og i akviferer, samt investering- og driftskostnader forbundet med et deponeringsprosjekt. Inkludert i dette er kostnader for rørtransport av CO2 fra eksportterminaler i Emden og Kårstø. Modellen beregner også en mulig salgsverdi av CO2 levert fra eksportterminalene. Bruk av modellen er demonstrert ved et scenario der 67 millioner tonn CO2 deponeres over en 40 års periode.

Muligheten for å få godkjent deponering av CO2 innenfor Kyotoavtalens rammer er diskutert, og konklusjonen er at dette fremdeles er uklart og at spørsmålet må avklares før mulige aktører vil være villige til å investere i et system for geologisk lagring av CO2. Kostnadene for slik lagring må også vurderes i forhold til eventuelle politiske rammebetingelser og framtidige CO2 kvotepriser, som er også estimert.

En vurdering av juridiske aspekter i forhold til geologisk lagring av CO2 viser at det er en rekke spørsmål som må avklares i forbindelse med nasjonal og internasjonal lovgivning.

Utfordringer forbundet med å utvikle en infrastruktur for CO2-lagring i samarbeid med myndigheter og private deltagere er også behandlet. Det er klart at et økonomisk regime med incentiver for kommersiell deltagelse i nødvendige investeringer ikke er til stede per i dag. For å realisere et slikt system for storskala geologisk lagring av CO2 vil det være nødvendig med en form for deltagelse fra myndighetene, som også vil få nytte av infrastrukturen både som et tiltak mot utslipp av klimagasser og gjennom inntekter forbundet med økt økonomisk aktivitet og meroljeutvinning (EOR).

Prosjektdeltagere fra SINTEF, CO2-Norway, BI, CICERO, Nordisk Institutt for Sjørett, Juridisk Fakultet og Oljedirektoratet, har deltatt med bidrag til denne CO2-infrastrukturstudierapporten. Prosjektet er finansiert gjennom Klimatekprogrammet hos Norsk Forskningsråd.

LARGE-SCALE CO2 SEQUESTRATION ON THE NORWEGIAN CONTINENTAL SHELF: A TECHNICAL, ECONOMIC, LEGAL AND INSTITUTIONAL ASSESSMENT

EXTENDED EXECUTIVE SUMMARY

This Study Report provides a preliminary interdisciplinary assessment of the scope, challenges, benefits, and risk associated with possible utilisation of the Norwegian Continental Shelf (NCS) for large-scale storage of carbon dioxide (CO2). It is assumed that CO2 will be sequestered as injectant gas in mature oil reservoirs or alternatively stored in saline aquifers.

The scope for carbon storage within the Kyoto Protocol (KP) and as part of the Kyoto flexible-mechanisms, remains uncertain and needs to be clarified if commercial participants are to be active with major investments for developing capture, transportation and storage of CO2. Furthermore the competitiveness in terms of cost per ton of carbon avoided compared to other methods for carbon avoidance is still dependent upon the extent of economic incentives and political constraints that national governments will impose in order to achieve their climate mitigation objectives.

There are still a number of challenges to consider before one can take advantage of geological carbon storage within an efficient climate policy regime. These can be grouped as political and institutional on the one hand, and technical and economic on the other hand.

Within political and institutional terms an important challenge remains the uncertain status of storage as a policy measure under a Kyoto (or Kyoto-like) regime—other issues are the ability to monitor and verify leakage, and deciding how this option should be linked to the Kyoto flexible mechanisms. Geological carbon "storage" quotas could be included within emissions trading. Alternatively carbon capture and storage projects could be defined as joint implementation (JI). However the fact that the KP has not yet entered into force increases uncertainty. Furthermore accounting, verification and responsibility rules are being discussed, but have not yet been well developed for geological carbon storage (IPCC, 2002).

In technical and economic terms one issue is the risk of leakage from storage sites; this has institutional implications in terms of the handling of responsibility for such leakage—if the amount stored is large, even a small leakage may be significant. The government may be willing to accept a risk of leakage provided that a CO2-storage project satisfies certain criteria. This alternative could be combined with the government taking the responsibility, but introducing a fee per ton of geological carbon storage to be paid by the companies as a risk premium to cover potential future expenses. An alternative is to require that the responsible companies finance an insurance fund that could cover future expenses.

An important economic challenge is the large investments in infrastructure that will be required, and the inherent benefits with economies of scale. Invariably CO2 capture, transportation and storage projects are more attractive if developed in a co-ordinated manner on a large scale—which in many cases would also mean involving two or more nations. In terms of competitiveness with other CO2 abatement measures, geological carbon storage is today only of interest under particular circumstances—primarily where CO2 injection can be used for EOR. However, in the near future (one decade) it might become a competitive mitigation option on a larger scale if CO2 prices increase and technical improvements lower the cost of geological storage. But this depends crucially on the assumption that a future climate regime will have binding quantitative emission-reduction targets, so that there is a market for CO2-emission reductions or removal. And also that marginal abatement cost—and thus the permit price—is significantly higher than what is expected during the Kyoto period from 2008 through to 2012.

In the initial phase of development of a CO2-infrastructure it is important to identify how this may evolve in collaboration between the public and private interests—given that the economic regime and incentives for commercial investment is not yet available. Examples regarding such evolution can be observed from changes that have occurred around the world whenever the economic fundamentals for finding, producing and marketing hydrocarbons has changed (i.e. deteriorated). Countries such as Indonesia, Malaysia, United States, and even the United Kingdom—as well as Norway itself—have invariably modified their fiscal regimes in order to ensure continued investment in development of the national assets that would otherwise be left behind with no value.

It is probable that there are still many smaller fields remaining in the North Sea that have yet to be discovered and / or exploited. Also, there will continue to be many profitable water-flood projects that constitute an alternative to CO2 for EOR. However, if the additional recovery of nearly 3 billion potential barrels of incremental oil (based on tertiary methods) is to occur then fiscal modifications are necessary to stimulate and create a “CO2 category” of production in the North Sea that would also ensure significant regional reduction in emissions of CO2.

We indicate in this report that there is a mutual inter-dependence between participants. The fact that large, irreversible investments must be undertaken up-front also implies that a rational organisation of the project may be critical for it to be commercially interesting.

Furthermore, we show that 'options' and 'flexibility' has value, and that the 'option' values may influence investment decisions (e.g. whether to initiate full-scale implementation immediately or start on a smaller scale).

We observe in the context of international and national law, that specific judicial issues need clarification regarding the legal status of carbon storage in oil reservoirs and saline aquifers on the NCS. At present, it appears that international dumping rules limit the possibilities of such storage. Irrespective of these, CO2 storage is covered by the general rules in international law on prevention of marine pollution. However some activities covering use of CO2 for EOR fall within the accepted practices governed by the Petroleum Act, while other future activities with respect to carbon storage in aquifers remain unclear.

Although the injection and storage of CO2 in petroleum reservoirs and aquifers is generally covered by the Pollution Control Act, the Act should be clarified to avoid any uncertainties in this respect.

The overall scope for storage within oil and gas reservoirs on the NCS is estimated to be about 16 GtCO2 (giga tonnes of carbon dioxide), while the saline aquifer storage capacity could represent an additional 800 Gt—equivalent to around 70 years of European CO2 emissions.

We estimate emissions from industrial and power generation sources around the North Sea rim—that could reasonably be envisaged to feed into a North Sea CO2-infrastructure—is between 360 to 490 mtCO2/yr. With a stricter emission regime within the EU these sources may stabilise at around ~450 mtCO2/yr through to 2020.

The techno-economic analysis uses a "Base Case" CO2-storage scenario over a 40 year project lifetime which assumes gathering 67 mtCO2/yr—this is around 15% of the total potential volume.

The Base Case scenario requires a capital investment of $13.4 billion with an averaged annual operating cost of $253 million. The project, using a combination of EOR and aquifer storage, would sequester approximately 2.7 GtCO2 and produce an estimated $50.6 billion in revenue from the incremental oil produced—not including incremental gas and gas liquids, which would also be substantial. The project would on average represent 3,200 man-years and result in a reduction in the CO2-sequestration cost in the order of $8 to $12 per tonne of CO2.

The total incremental oil production is estimated to be 335 million Sm^3 (2.1 billion bbl). This comes in addition to the oil that would have been recovered if the fields had continued to be produced as a water-flood only. With a 17.6 year averaged project lifetime per oilfield, this corresponds to an average oil production of 328,000 bbl/day for 17.6 years!

The table below shows that the average oil recovery factor from the reservoirs is calculated to be 53.7% of the original oil in place (OOIP), whilst the incremental oil recovery is on average 7.9% of OOIP.

Total Oil Produced	2,270	million Sm^3
Oil Recovery Factor	53.7%	% HCPV
EOR oil	335	million Sm^3
EOR oil as % of OOIP	7.9%	% HCPV
Stored CO2 in oil reservoirs	1,153	mtCO2
Total CAPEX	10.40	$billion
Annual OPEX	490.0	$million /year
Project NPV	~0	$million

Summary of Key Parameters for the "Base Case" Storage Project Scenario.

The immediate challenge regarding how to develop a CO2 infrastructure has also been studied under the scope of the present study. It is clear that the economic regime and incentives for commercial stakeholders to co-ordinate participation regarding such investments is not yet available. However, if government was to be part of the commercial analysis through initial participation as an investor—and one also included the long-term valuation on avoided CO2-emissions—then the project represents a plausible policy option in conjunction with a future strategy for climate-change mitigation.

If the countries around the North Sea share a commitment to reduce GHG emissions, then all involved parties can work together to find solutions that function on the macro-level rather than only in the self interest of each party (which would entail an additional social price greater than an optimal solution). This is why CO2 for EOR is a realistic first option that is constrained only by the limit on volume of carbon that can be stored in a finite number of accessible mature fields. The advantages associated with this option appears to be considerable:

- The CO2 that is captured, transported and injected into oil and gas fields becomes a product generating wealth and capital that offsets the cost associated with building and operating the transportation infrastructure. Jobs, capital investment, tax revenue, emissions reduction, and technology development, are all consequences that will allow parties to work together to solve a major common challenge regarding GHG emissions.
- Developing a commercial market for CO2 in conjunction with EOR will help stimulate technology promoting improved capture of CO2 from fossil

power plants while also reducing emissions of sulphur (SOx) and nitrogen oxides (NOx).

- Coal and NG can become “green” fuels ensuring substantial energy security for the EU and possibly providing an alternative to nuclear power.
- Gasification coupled with CO2 capture may revitalise the power generation industry in a clean and cost-effective manner, thereby ensuring an efficient commercial transition through to a sustainable energy regime in the future. It is also feasible to assume that the technology will be adopted in other industrial sectors such as the cement and steel industries—which are also major industrial emitters of CO2.
- Laws and regulation can rapidly evolve recognising the extent and way that CO2 will be allowed to be sequestered, with safeguards that are reasonable for the sinks employed for this purpose. Contracts for sale and purchase of CO2 will also evolve to protect all parties within a commercial setting.
- Market mechanisms will emerge that allow for the levelling of investment versus revenue from what will by definition be a very front-end loaded endeavour.

The purpose of this Study has not been to present specific conclusions, but rather instead identify a broad spectre of inter-related issues that will need to be addressed in a coherent manner if one wishes to pursue a viable path towards carbon storage.

Furthermore we observe that a long-term perspective needs to be identified in order to ensure success. To proceed on an *ad hoc* basis—project by project with limited perception regarding the overall effect on all segments of industry—can quickly lead to a wasted and misguided investment effort. Integration of a CO2-infrastructure into a national energy and environmental policy must therefore be a pre-requisite. Invariably it is the role of society—being the largest benefactor of such a project—which needs to be evaluated in more detail.

Kongsberg, 15th August 2004.

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1. LONG-TERM CONSIDERATIONS FOR CO2

The future impact of carbon dioxide (CO2) on our society is uncertain, but of such a nature as to be a cause for concern. Although CO2 is a global issue, individual nations will have different options regarding a credible response. For each country and region there will be geographical, political, economic and societal constraints that determine what may be the most expedient measures for minimising emissions: clearly the economic situation for countries like India and China is substantially different from that of the OECD and western Europe; some may argue that the socio-political differences between Europe and the United States also needs to be considered when addressing their respective greenhouse gas (GHG) emissions. Thus we already observe that solutions regarding future energy—and wealth of nations—is far more complicated then just the issue of regulation and technology.

Within this context the Norwegian situation is possibly unique, and can be considered as an opportunity for business development creating new industry, and ensuring sustainable use of natural resources.

Since the beginning of the 20th century Norway has prospered with an abundance of hydroelectric power. Subsequently, following the discovery of oil on the Norwegian Continental Shelf (NCS) in the late 1960’s it has grown to be the worlds fourth largest oil exporting nation. And is now becoming a major provider of natural gas (NG) for the growing European Union (EU) member states. But Europe is also acquiring gas from North Africa and the Former Soviet Union (FSU)—and increasingly so, as these countries (presumably) become politically more stable in the next two or three decades.

However, Norway also possesses substantial capacity for storing CO2 if it could be gathered and transported from the European mainland back onto the NCS. The use of CO2 for tertiary enhanced oil recovery (EOR) would increase overall oil recovery, ensure a prolongation of the offshore industry (employment), and secure considerable additional revenue through taxes.

As explained in this Study Report, if CO2 can be provided to the oilfield operators at a cost and within a time-window compatible with tertiary phase of production on the NCS, then there could be substantial societal benefits and an opportunity for continued development of the CO2 transportation infrastructure after the oil era. This would also ensure a long-term perspective for large-scale CO2 sequestration as is described more fully in this document.

Furthermore, although beyond the scope of this Study Report, decarbonisation of natural gas, carbon sequestration, and development of commercial technology for clean (“zero-emission”) fossil fuels, are all pre-requisites for a commercial path through into the future use of hydrogen and electricity (termed “hydricity”) as main energy carriers. Also there should also be a role for Norwegian natural resources and technology development ensuring that Norway again becomes a “clean” energy supplier to North Europe.

This report is set out in seven main Chapters that present summary compilation of work conducted by each of the five project partners who have participated with the project during the period from June 2002 though until March 2004.

In Chapter 1 we provide a general introduction.

In Chapter 2 the research organisation ***CICERO*** have addressed the issues regarding climate-change, Kyoto mechanisms and GHG-emissions, as well as leakage and overall cost comparison with alternate options for CO2-avoidance.

In Chapter 3 members of staff from the ***Department of Public and International Law*** and the ***Scandinavian Institute for Maritime Law*** at the ***Faculty of Law***, Oslo University have contributed. They have addressed the status and identified potential ambiguities regarding existing legislation covering CO2 within international and national law for both aquifer storage and use in hydrocarbon reservoirs.

In Chapter 4 the ***School of Management BI*** have looked at private versus public organisation, as well as flexibility and options that may prevent certain parties to participate in such a project.

In Chapter 5 the company ***CO2-Norway*** presents an overview of potential sources and cost for capture of CO2 from power plants and other industrial complexes in North Europe and Norway.

In Chapter 6 the reservoir group within ***SINTEF Petroleum Research*** describe development of:

(i) a model to determine the transportation cost of CO2 in a large-scale pipeline infrastructure.

(ii) an EOR-module that estimates the incremental oil recovery due to injection of CO2 into water-flooded reservoirs.

(iii) a techno-economic model that calculates key technical and economic costs for CO2 storage.

We emphasise that the purpose of the work to date has not been to present specific conclusions, but rather identify a broad spectre of inter-related issues that will need to be addressed in a coherent manner if one wishes to pursue a viable path towards the next phase of developing the potential for storage of CO2 on the Norwegian Continental Shelf.

1.1 CARBON SEQUESTRATION AND ENHANCED OIL RECOVERY

To place the present Study Report in context we here include a brief review of past experience, and build upon this knowledge to describe the specific challenges of supplying CO2 to the Norwegian Continental Shelf (NCS); in particular to stimulate the use of CO2 as an injectant gas for oil reservoirs.

The use of CO2 for enhanced oil recovery (EOR) was first established in conjunction with mature reservoirs in the Permian Basin (see Fig. 1) during the early 1970's. At that time tertiary recovery projects were stimulated by special tax concessions—and price control exemptions—as an incentive during a period when US domestic oil production was beginning to decline rapidly. These "tax-floods", although being commercially successful, were not optimal with respect to their use of CO2, but did provide the operators with considerable insight regarding reservoir behaviour, CO2-handling, corrosion mitigation, and recycling following breakthrough of CO2 into the production wells.

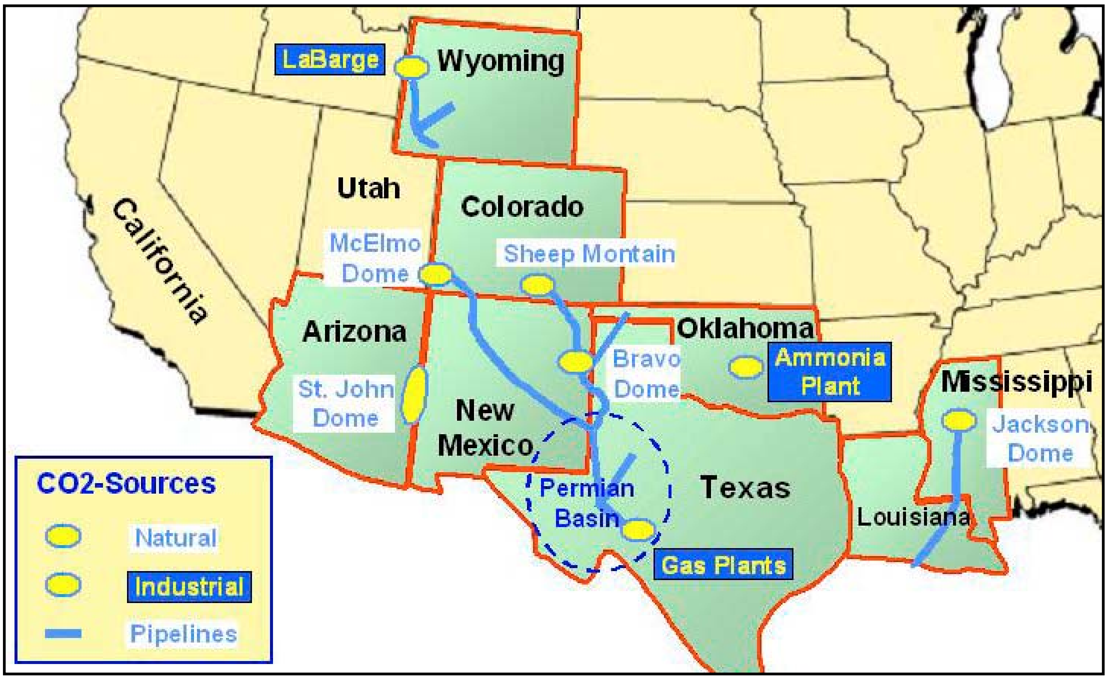

Fig. 1: Map showing CO2 sources, transportation pipelines and extent of CO2-EOR in the South and South-West United States. The Permian Basin is the worlds largest CO2-flood region. The first flood was opened in 1972, but there are now over 50 active projects producing more than 145,000 bpd. The 1,500 km pipeline infrastructure from McElmo, Sheep Mountain and Bravo Dome delivers more than 23 mtCO2/yr. In year 2000 with oil at $18 /bbl the average price of delivered CO2 was $12 /tCO2 (Source: KMCO2 and Jarrell et al., 2002).

The first floods were based upon industrial (anthropogenic) CO2. But with a growing awareness of its favourable qualities, demand rapidly increased for the use of naturally occurring CO2 which had to be transported over longer distances through extensive pipeline infrastructures as illustrated in Fig. 1.

The successful development of CO2-EOR in the United States is also shown in the Fig. 2 where the white region highlights the growth in use of CO2 from 1984 through to year 2000. By which time CO2-floods were responsible for more than 180,000 bpd (barrel per day) representing 28% of total incremental US-EOR barrels.

Interestingly the expansion starting around 1986 coincides with the introduction of the *U.S. Federal EOR Tax Incentive*. This is a 15% tax-credit which applies to all costs associated with installing the flood, CO2-purchase cost, and operating costs for CO2-injection (Jarrell *et al.*, 2002, pp.132).

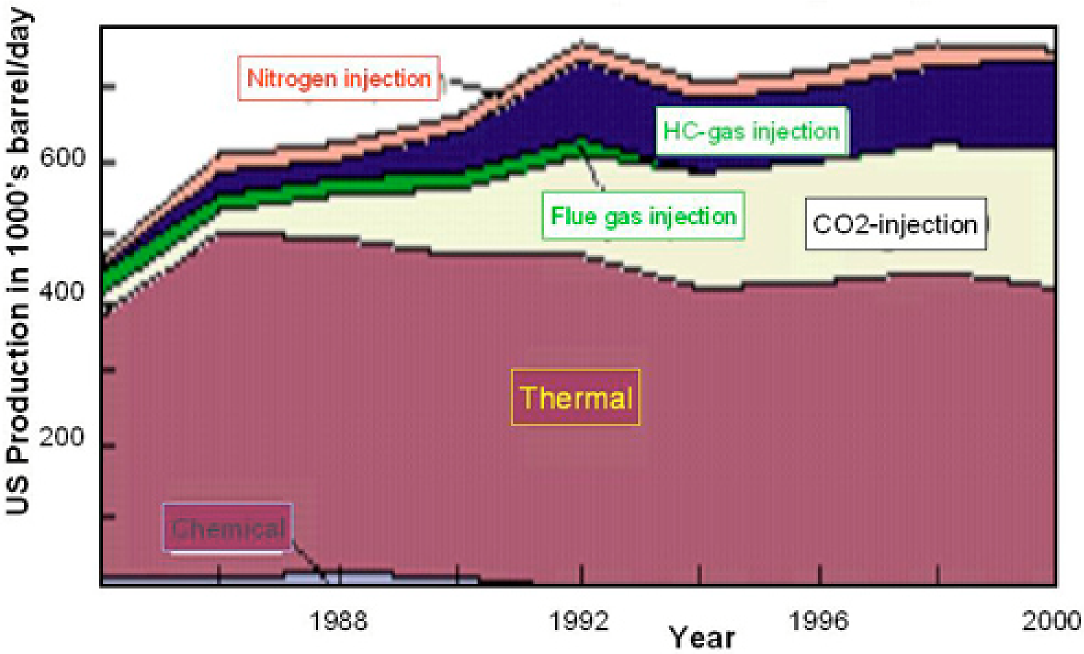

Fig. 2: Graph showing various techniques that are employed for enhanced oil recovery (EOR) in the US over period from 1984-2000. There was in 1998 a total of 92 Thermal (steam) EOR projects producing 439,000 bpd. There was 66 CO2-EOR projects producing 179,000 bpd. With 11 miscible gas injection projects producing 102,000 bpd. Finally Nitrogen injection projects producing 28,000 bpd.

There are currently eight states[1] in the United States that offer additional EOR tax incentives on incremental oil produced. While there is no EOR tax credit, *per se*, the state of Texas offers a severance tax exemption on all the oil produced from a CO2-flood reservoir. It is therefore perhaps not coincidental that the Permian Basin, West Texas is currently producing more than 80% of all CO2-EOR production in the US[2].

[1] These states are Arkansas, Colorado, Mississippi, Montana, New Mexico, North Dakota, Oklahoma and Wyoming.

[2] According to the *Oil & Gas Journal*, (15 April 2002), there were 75 active CO2-floods world-wide producing 194,000 bpd of incremental oil—equivalent to 8.4% of reported global EOR production.

1.2 THE NORTH SEA CHALLENGE

In similarity with several major US oil regions in the mid-80's, it is recognised that the North Sea Continental Shelf (NSCS) is moving from "secondary" to tertiary phase of oil production as is highlighted in Fig. 3. The secondary phase on the NSCS has predominantly featured large-scale water-flooding and—particularly on the NCS—use of alternating water and gas (WAG), where it is the miscibility of the hydrocarbon (HC) gas within the reservoir that helps to improve overall oil recovery beyond that achieved with water-flooding.

In the United States it has long been shown that CO2 has similar, and often better reservoir miscibility behaviour for tertiary EOR than HC-gas; this, together with tax incentives, originally helped promote capture from certain cheap anthropogenic sources and later the larger scale use of naturally available CO2. The abundant source of inexpensive CO2 was also able to free up more valuable HC-gas for sale.

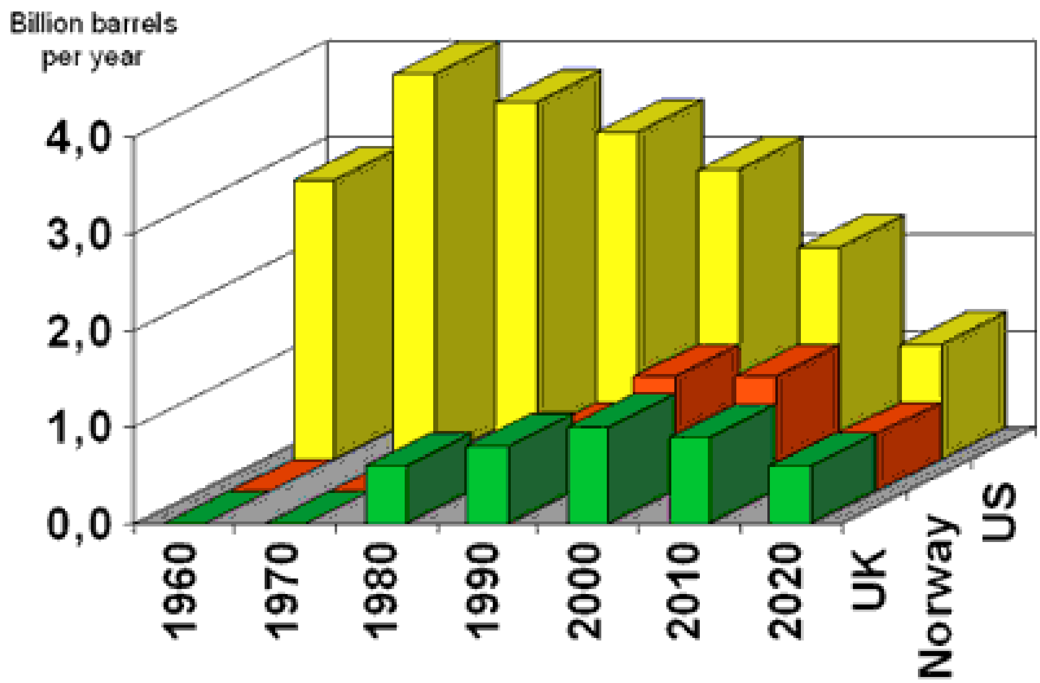

Fig. 3: Oil Production (bn bbl/yr) in United States, Norway and the United Kingdom for period 1960-2020. The North Sea is currently entering its tertiary phase, similar to that which occurred in the United States around 1980.

For such a transition to occur in the North Sea the issue remains availability of CO2 in volumes, and at a price, that would make CO2 for EOR competitive with alternative options for tertiary oil recovery.

The technologies and concepts proposed for delivery and CO2-flooding on the NCS are essentially already proven—albeit in some cases on a different scale and context compared to the offshore environment. However integration, logistics, operations and maintenance of the complete CO2-supply chain (from capture and gathering at the sources to permanent storage in the reservoir) will pose engineering challenges; but these can also be adapted for safe and efficient use in an offshore environment.

The real challenge for initiating CO2-flooding on the NCS is twofold, both of which need to be addressed before any larger volumes of CO2 will be used for EOR purposes—let alone carbon sequestration. These are:

(I). Firstly there is the 'first mover' risk that project participants will be exposing themselves to—possibly on behalf of many other project stakeholders that may stand to benefit if the project were to go ahead and succeed. Handling this risk exposure should not be underestimated, as it can be critical to the investment decision process and timing with respect to declining production as indicated in Fig. 3.

(II). Secondly there has to be an 'economic incentive' for <u>all</u> participants in the project <u>and</u> the key significant factor for any CO2-EOR is always the anticipated price per barrel of oil. If the price of oil is low, then there is currently no valuation on the CO2 that would justify the investment for CO2-gathering, transportation and storage, while providing a competitive rate of return on capital invested. If the price of oil is high, then the project may produce satisfactory return on capital invested <u>and</u> additional tax income to the host government through incremental oil that would not otherwise have been produced using more conventional technology for tertiary recovery.

With regards to 'first mover risk' it is possible for participants to actively manage project risk and potential burden sharing, but this will have a 'barrier' cost associated and there will be continuous comparison with alternative options for tertiary EOR. One may also emphasise a possibility for technology transfer and flexibility with regards to commercial agreements between project participants. However the ultimate risk is with respect to 'economic incentives' and is governed by the price of oil—the only project participant capable of absorbing this economic risk is ostensibly the host government. And it is invariably the government that will be (by far) the largest benefactor a CO2-EOR project (Austell and Hustad, 2004).

Furthermore, concern regarding climate-change and reduction in GHG-emissions have also provided additional incentives for considering use of *anthropogenic* CO2 in the maturing oil reservoirs on the NCS.

Governments also need to identify <u>all</u> their project related streams of revenue; including direct taxes, indirect taxation (due to jobs, field life-extension, deferred decommissioning etc.), and all other societal benefits together with CO2-avoidance cost that would otherwise have accrued due to forthcoming commitments to curb GHG-emissions.

There are three fundamental economic indicators that help quantify the commercial viability of the CO2-EOR project:

(i) The delivered price of CO2 at the oilfield.

(ii) The value of permanently stored CO2 as a greenhouse gas (GHG).

(iii) The price for a barrel of oil.

Given these three key indicators, then any potential participant can do a reasonably accurate economic analysis to identify whether a project can satisfy its own economic criteria.

For the time being the concept of stored CO2 (as a GHG) only has a value to the governments. This emphasises the fact that mechanisms for certification and valuation of underground sequestered CO2 are still being discussed, and may eventually only be agreed upon—by the governments! A commercial participant may therefore currently attribute no significant value to CO2 that is used for EOR—beyond the value of incremental oil. Therefore without strong involvement from government, commercial participants are reluctant to make investment decisions until the economic benefits are definitively clarified so as to reduce risk of involvement in such CO2-EOR projects. It is the way in which each host government addresses the uniqueness of tertiary hydrocarbon production that will determine the success or failure to encourage investment in this final phase of the NCS and its transition into a carbon depository while facilitating the transition to a sustainable energy infrastructure.

2. UNDERGROUND STORAGE OF CARBON AND CLIMATE POLICY

Carbon dioxide (CO2) sequestration (alternatively termed carbon storage) has become one of the major policy options to mitigate man-made ("anthropogenic") emissions of greenhouse gases (GHG) that cause climate-change. The three major storage options are biological sinks (forests and soils), geological sinks, and sequestration in the deep ocean. In this Study Report we focus on storage in geological formations, and assess its potential as a major and substantive climate policy measure.

There are also reasons to expect that governments might see a strategic interest in developing geological carbon storage technologies, and therefore make investments or create economic incentives that lower the cost of this option. One reason they would be interested in exploring the potential of geological storage is the fact that the major global fossil fuel reserve is coal. In addition, major coal reserves are found in the United States and in key developing countries like China and India. These developing countries are likely to achieve prolonged economic growth and related growth in energy use based on coal, since it is not probable that they will face (stringent) carbon emission caps during the next decades. The cost of coal can be competitive with oil and gas, given that most of the associated air pollution that leads to health problems, increased corrosion of materials, and crop damages can be removed through inexpensive measures. These countries may also be willing to subsidise coal extraction and permit its use to such a degree as to save spending on imports of oil and gas, and shield local communities dependent on coal mining.

Geological carbon storage can be defined as the systematic storage of carbon dioxide, captured from fuel combustion or processing, in stable geological formations such as hydrocarbon fields and aquifers, thus preventing its release to the atmosphere.

The most interesting geological formations are hydrocarbon fields (oil and natural gas), sub-sea aquifers, coal seams, and salt caverns. In this study we focus on offshore hydrocarbon fields (oil and gas reservoirs) and 'salt-water' aquifers, but not on onshore aquifers.

Biological carbon sequestration has been included in the Kyoto Protocol framework, and extensive work has been invested in analysing the scientific underpinnings of this mitigation option, and in negotiating rules for definitions, methodologies and verification. Much less efforts have been put into developing geological carbon sequestration as a policy option under the Kyoto Protocol.

In spite of the high investments in innovation to develop CO2-storage as a mitigation technology, there has been relatively little focus on the key political aspects. We discuss here two essential dimensions of geological carbon storage. The first relates to institutional and political aspects, such as the status as a policy measure in international climate policy agreements (foremost the Climate Convention and the Kyoto Protocol), relevant reporting and verification procedures, and linking to the flexible mechanisms under the Kyoto Protocol. In a broader context we explore if the institutional underpinnings of geological carbon storage are sufficient to give companies and governments strong enough incentives to venture into initiating such projects.

The second dimension relates to technical and economic aspects, such as storage capacities, danger of future leakage from storage sites, economics of scale, characteristics of geological carbon storage, and the competitiveness of geological carbon storage in terms of costs per ton of CO2 compared to estimated permit prices under the Kyoto Protocol, and beyond.

2.1 GEOLOGICAL CARBON STORAGE IN CLIMATE AGREEMENTS

One key question is whether a Party to the Kyoto Protocol can attain emission reduction credits for geological carbon storage under the first and subsequent commitment periods.

The references to carbon storage in the climate agreements are of a general nature and thus in terms of sinks and reservoirs of GHG's. Neither CO2 nor geological carbon storage is specifically mentioned. The only exception to this is the Marrakech accord, where fossil fuels technologies storing GHG's are mentioned, but in the context of potential adverse effects on developing countries from mitigation measures. It appears that formal recognition of geological carbon storage is lacking in the climate agreements, which is in line with the view of IEA (2001), page 26. Thus the incentives for countries and companies to engage in geological carbon storage are to a large extent so far missing in the climate policy context.

2.1.1 Analogies with Rules for Biological Carbon Storage?

Under the Kyoto Protocol, carbon storage can be accounted for under the categories LULUCF (Land Use, Land Use Change and Forestry), waste and to some extent industrial processes. However, storage is not accounted for consistently within these categories. As described in more detail below, in the LULUCF sector there have been long political discussions that were concluded in the Marrakech accord[3]. A substantial amount of work has been spent on the scientific underpinnings and on negotiating operational rules for this mitigation option.

Many technical difficulties and delimitation challenges have created a rather complicated set of rules. In addition political considerations (*e.g.* the need to strike a

[3] UNFCCC document FCCC/CP/2001/13/, Add.1, Add.2, and Add.3.

compromise between countries with different interests) have contributed another layer of complexity. This is the background for a number of constraints on the use of biological carbon storage under the Kyoto Protocol commitment period 2008 until 2012.

There are some important similarities between biological and geological carbon storage, but one significant difference is that the former is dependent on biological processes that take time, whereas the latter is more of a physical process where injection is much less time-consuming. Another difference is that biologically stored carbon will eventually "leak" to the atmosphere unless the biological stock (*e.g.* forest biomass) is maintained forever. By contrast carbon stored in stable underground geological structures could in principle stay there for thousands of years and longer without any specific human actions as long as the rate of leakage is zero (or very close to zero).

There may however, be some of the same critical arguments in the case of geological carbon storage. First, both types of carbon storage can lead to other environmental consequences. Second, there are uncertainties about the permanence of the storage and concern about the accuracy of which the removals can be monitored and verified.

Due to technical complexities and the possibility of similar political considerations as in the case of biological carbon storage, constraints on the use of geological carbon storage may become embodied in operational rules for this mitigation option, provided that more specific rules are to be negotiated. A possible outcome is that only storage in some types of geological formations are eligible, that there is a ceiling on the volume stored for each country, that there is a constraint on the share of such projects under the joint implementation mechanism, and, finally, that there is a limit to banking of such credits.

2.1.2 National Emissions Reporting and the Flexible Kyoto Mechanisms

The Kyoto Protocol encourages use of (biological) carbon sequestration technologies in general terms, but with no specific reference to geological carbon storage. A major unresolved issue if such projects should be undertaken relates to accounting for geological carbon storage, namely the allocation of credits when sequestration of CO2 takes place in a country other than where they were generated.

The huge storage capacity offshore in Norway implies that it might also be feasible to sequester CO2 from power plants and industrial complexes located in other countries than Norway. Consequently, a clarification is needed whether the exporting or receiving country will get the credits. There are three possibilities:

1) Handled through the flexibility mechanisms of the Kyoto Protocol, for example as joint implementation (JI) projects.

2) Seen as an end of pipe technology for each emission sources. In the case where the CO_2 is transported over borders, the credits are given to the country whose emissions were avoided.

3) Reported as a separate sink category. In the case where the CO_2 is transported over borders, credits are given to the receiving country.

In the case of transfer between countries given possibility 2) or 3), geological carbon storage need not be based on the Kyoto mechanisms. In the case of possibility 1), one country could export CO_2 to a neighbour country for storage in its geological formations. In such a case the CO_2 volume could be framed as a transfer of quotas under emissions trading, or transfer of credits under joint implementation or CDM. Thus a country could sell "storage" quotas or credits at the international market. The purpose of the flexibility mechanisms is to enhance international cost effectiveness.

As an example geological carbon storage in an oil reservoir can be defined as a JI project. This mechanism implies that two industrialised countries can co-operate to carry out a project that lowers emissions of GHG's in one of the countries. Given possibility 2), Norway does not have any direct incentives to handle emissions from other countries. Therefore an economic compensation must be given to Norway to cover transportation and storage costs. In the case of possibility 3), the country where emissions are avoided does not have any direct incentive to capture CO_2 as another country receives the credits. Since carbon storage contributes to meeting the CO_2 receiving country's commitments under the Kyoto Protocol, it should be willing to pay the country where emissions originate from in order to at least cover its capture and transportation costs.

2.1.3 Reporting, Verification and Review of Carbon Storage

Reporting and review of GHG emissions and removal is an important part of the implementation of the Kyoto Protocol. The reason is that most emissions and capture cannot be directly monitored in a practical manner. To a large extent the emission data that form the basis for assessing compliance with the commitment has to rely on estimates. The emphasis of reporting and review in the Kyoto Protocol is to assure that the emissions and emission-reductions that the Parties report are real, as far as can be judged. All Parties to the *United Nation Framework Convention on Climate Change (UNFCC)* have to report emission data. The Parties of Annex I (i.e. industrialised countries) of this convention have to report detailed, annual data in a common format.

Parties also have to implement and demonstrate appropriate quality assurance and quality control (QA/QC) procedures of the estimates. When practically feasible a Party should use independent verification methods to increase the credibility of the inventory. An important part of the reporting is a documentation explaining in detail how all the estimates of emissions and removals have been obtained (National Inventory Report). The submitted inventory will according to the Kyoto Protocol be reviewed by an expert review team. In order to get credits for carbon sequestration in geological reservoirs, the reporting obviously has to satisfy the general reporting requirements as described above.

The removals have to be accounted for in an appropriate source (sink) category. Because the CO2 can be transported over borders both capture from each source-category, transport and injection have to be reported in a transparent manner independently on how credits are given. This will ensure that the amount captured and stored can be cross-checked.

Irrespective of what method of crediting that is decided, the only practical option is that the receiving country (for example Norway) would have to take the responsibility to monitor, verify and report possible emissions from leakage in their national emission inventory. Thus if emissions from another country are sequestered within Norwegian territory, it would therefore be a Norwegian responsibility to verify and report leakage. This applies even if the reservoir has been abandoned. These future monitoring costs have to be reflected in the total costs of a project. But this might be difficult due to the very long expected retention time (thousands of years).

2.2 CAPACITY FOR CO2 STORAGE ON THE NORWEGIAN CONTINENTAL SHELF

Statoil has since October 1996 injected about one million tonne CO2 per year (mtCO2/yr) from the Sleipner field into the Utsira aquifer formation in order to avoid carbon tax on the CO2 emissions (Kaarstad, 2002). Mathiassen (2003) using the Norwegian Petroleum Directorate (NPD) data base, recently screened 128 candidate fields on the NCS and conservatively concluded that the potential incremental oil from CO2-EOR projects could be in the range 1.5-2.0 bn bbl, thereby inferring a “proven” requirement for between 500-650 mtCO2 in the Norwegian sector through until 2025. However the ultimate storage capacity for CO2 on the NCS is much larger, and sufficient to store a sizeable share of European emissions for decades. Holt *et al.* (2000) estimate a total storage capacity of 33 GtCO2 in oil and gas reservoirs of which about half is within the NCS, thus inferring a potential for storing over 16,500 mtCO2 in oil and gas reservoirs alone[4]. The potential for aquifer storage within Western Europe (that is the EU and Norway combined) is again according to Holt *et al.* (2002) around 800 GtCO2 in aquifers throughout Western Europe.

[4] This number is optimised with respect to maximum storage while the NPD Report focuses on optimal CO2 incremental oil recovery.

The total Norwegian capacity can be compared to emissions from the European Union (EU) in 1990 of about 3 $GtCO_2$/yr, and the 2001 emissions in Norway of 42 $mtCO_2$/yr. Thus the theoretical capacity for oil and gas reservoirs in Norway is in the region of one-half of the total EU emissions for 11 years. Furthermore if half of the aquifer capacity is used and assuming that half again of this is situated within the NCS, then the storage capacity becomes 200 $GtCO_2$, which would be enough to store all EU emissions for 67 years (assuming emissions at 1990-level).

2.3 THE RISK OF LEAKAGE FROM STORAGE SITES

The issue regarding permanency of geological carbon storage could be an obstacle for political acceptance. Studies show that some leakage is likely, either because the geological formations are not completely sealed, or could be disturbed (e.g. earthquakes), or because the injection points could become unstable over time. For oil and gas reservoirs the current leakage rate of CO_2 to the atmosphere is likely to be relatively small due to the fact that these geological structures have contained the hydrocarbon gases for a very long period of time. However, there is limited experience with the injection of CO_2 under such sub-sea conditions.

Hawkins (2002) suggests that one cannot be confident that current systems have leakage rates of less than 0.1%/yr. Dooley and Wise (2002) assume a leakage rate of 1.0%/yr, but this is an average over different types of geological reservoirs. Leakage rates may differ between saline aquifers and oil and gas reservoirs; and these latter have proven to be able to store gases for long periods of time. Lindeberg (2002b) has employed models to estimate emissions over the reservoir life-time. His results suggests very low leakage rates for current years, and that annual leakage rates are not constant, but have a peak in emission rate after about 2,000 years, and a subsequent decrease in emission rate after that.

Even if a considerable share of the CO_2 should leak from a reservoir to the atmosphere over time, temporary storage has a value because climate-change is delayed. But future leakage can cause problems if a threshold of atmospheric greenhouse gas concentrations is exceeded some time in the future, leading to a steep increase in marginal damages from climate-change, and if there are insufficient inexpensive backstop technologies available to reduce emissions of greenhouse gases to keep concentrations below the threshold. Dooley and Wise (2002), Hawkins (2002), and Hepple and Benson (2002) all find that the annual leakage rate must be lower than 0.1% if geological storage should be an attractive mitigation option[5]. If the leakage rate is higher, targets for atmospheric greenhouse gas stabilisation in the range of 450 to 550 ppmv could become unattainable. Herzog *et al.* (2003) employ

[5] In the best cases the seepage rate must be lower than 1.0% while in the worst cases the rate must be lower than 0.01%.

an economic modelling framework where all carbon mitigation options are seen as more or less temporary, and asks what the value of temporary storage is: they find that (temporary) carbon storage is attractive if carbon prices remain (nearly) constant or if there is a backstop technology that caps the costs in the not too distant future.

Due to the long time horizon relevant for geological carbon storage it is problematic to leave the full responsibility for potential future leakage with the companies investing in this option. This emphasises the government's responsibility both for the emissions and for reporting. Furthermore, there is uncertainty with regard to monitoring since the exact amount of carbon stored cannot be determined. In addition there is uncertainty with regard to future leakage of CO2 from geological storage sites: a cost-effective standard for monitoring leakage rates is needed. The costs of monitoring and verification for a long period have to be taken into account when assessing the costs of sequestration.

One practical way of handling the risk for leakage is for the government to establish minimum requirements to be fulfilled by carbon storage projects, see Lindeberg (2002b). A second option is to transfer the responsibility for the permanence of the carbon storage to the government after a fixed time period, e.g. after 20 years. A third option is to credit the company for instance 80% of carbon sequestered, and leaving all future responsibility for leakage with the government. Obviously such responsibility could induce extra future costs on the government; in particular if future leakage rates are significantly higher than anticipated. Either the government could be willing to accept this risk, or it would require, as a fourth option, that relevant companies finance an insurance fund that could cover future expenses, or the government puts a fee per ton of geological carbon storage as a risk premium to cover potential future expenses for the state.

2.4 THE COST OF CARBON CAPTURE AND STORAGE

Geological carbon storage can involve significant capital investment (CAPEX) costs due to the requirements for large investment in infrastructure such as pipelines, compressors, pumps and other facilities, in particular if it is developed on a large scale involving multiple sites and a sizeable infrastructure. In this context geological carbon capture and storage exhibits economies of scale properties. This may imply that there are gains to be attained through close collaboration between neighbouring countries.

With large CAPEX the capture and storage cost per ton of CO2 can become relatively high compared to alternative mitigation options. Given that the Kyoto Protocol enters into force, the interesting question is if geological carbon storage can have a competitive price per ton of CO2 compared to the quota and credit prices at the international market? Inter-linked with this is the fact that Russian "hot air", non-participation of the United States, and inexpensive forest credits from developing countries, all contribute to lowering the quota and credit prices.

However, the main commercial motivation for oil and technology companies to take an interest in research and development into CO2 capture and technologies for geological carbon storage, is their interest for enhanced oil recovery (EOR) and injecting CO2 during the final tertiary phase of an oil reservoirs production history. Thus geological carbon storage in oil reservoirs could have an interesting combined potential both in terms of GHG mitigation and EOR.

The question we explore here is, whether, and under what circumstances this option is viable for mitigating human-induced ('anthropogenic') climate-change. We examine cost estimates for geologic carbon storage technologies and assessments of future carbon markets from previous studies. EOR is of particular interest in the case of oil reservoirs since this can lower the climate policy-related cost threshold for geological carbon storage significantly. We will combine this information to give an overall assessment of the economic viability of geologic carbon storage as a climate mitigation option—today, and in the near future (through until 2020).

The information available about geological carbon storage technologies is sufficient for making rough cost estimates, such as ours, but do not permit a more comprehensive cost analysis—such as constructing marginal abatement cost curves for carbon storage. We will however estimate a total cost per ton of CO2 captured. The study adds to the literature on geological carbon storage by linking costs per ton of CO2 to estimated prices per ton of CO2 equivalent in the Kyoto emissions trading markets. These estimates are seen also in the light of sets of circumstances that reflect uncertainties regarding the development and cost of geological carbon storage technologies, and future permit prices at the international markets under the Kyoto Protocol. Beyond 2012 these uncertainties are even larger.

Source	Current Cost ($/tCO2)	Near-Term Cost ($/tCO2)
Anderson and Newell (2003)		
- coal/gas power plant	45-58	34-42
- integrated gasification combined-cycle	28	17
- hydrogen production from natural gas	10	
Hustad and Austell (2004)		
- coal power plant	25	
- gas power plant	33-35	
- ammonia from natural gas	38-42	
- integrated gasification combined-cycle		15-20
Johnson and Keith (2004)		
- coal power plant		20
- gas power plant		48
Hendriks *et al.* (2000)		
- Natural gas combined cycle	41-66	
- Furnace/combined heat and power	6-45	

Table 1: Cost estimate for capture of CO2 from various industrial processes.

The process of geological carbon storage can be broken down into three main cost components: CO2-capture, compression and transport, and storage. Cost estimates will vary significantly between different fuels and types of processes (e.g. between coal-fired power production to ammonia production from natural gas). Capture costs will evidently vary between coal and natural gas-fired power plants—the concentration of CO2 is much higher in the flue gases following coal combustion than from natural gas combustion.

Transport costs vary between modes of infrastructure (e.g. ship or pipeline), and the storage costs between types of reservoirs (i.e. oil and gas reservoirs versus aquifers).

Source	Transport ($/tCO2)	Storage ($/tCO2)	Total ($/tCO2)
Anderson and Newell (2003)	5.60-10.80*	1.40-8.20	7-19
Hustad and Austell(2004)	10-13		
Johnson and Keith (2004)			8.20
Hendriks *et al.* (2000)	12-28*	1-16	13-44
* Cost is given per 100 km pipeline. We assume an average transport of 400 km—equivalent to locations in Denmark or Northern UK out to oil reservoirs within the NCS.			

Table 2: Cost estimate for transportation and storage of CO2 within an infrastructure scenario as envisaged in this document. Quoted in US$ per tonne CO2.

In this paper we are concerned exclusively with carbon capture from fossil fuel combustion processes and geological storage; Table 1 and Table 2 summarise capture costs together with transportation and storage costs estimated in some recent studies.

2.4.1 The Role of Enhanced Oil Recovery (EOR)

Carbon storage has the potential of generating substantial income streams from enhanced oil recovery (EOR) which involves injecting CO2 to pressurise oil reservoirs in order to facilitate extraction of additional oil. EOR can potentially recover an additional 6-15% of the original oil in place (OOIP), and thereby increase total recovered production from an oil reservoir by 10-30% (Hustad and Austell, 2004). This implies that the oil or gas extraction period for a reservoir is prolonged.

Similarly, carbon storage can also be used for enhanced gas recovery (EGR), and enhanced coal-bed methane (ECBM) production. Anderson and Newell (2003) claim that opportunities for enhanced recovery would be insufficient for larger amounts of CO2 storage. The value of EOR depends on the amount of additional oil recovered per ton of CO2 injected and the oil price. Typically the EOR response is around 0.6; that is, for every ton of CO2 injected, 0.6 tons of additional oil is recovered. With oil prices that range from around $15-25 /bbl, then we could expect an EOR valuation of $9-15 /tCO2.

The price paid by current EOR operations for CO2 lies in the range $11-18 /tCO2 (Anderson and Newell, 2003). Given an oil price of $18 /bbl, Hustad and Austell (2004) indicate that the value to the oilfield operator for delivered CO2 in the North Sea is around $12 /tCO2—given the current fiscal regime.

2.4.2 The Carbon Market and Permit Prices

With binding restrictions on emissions of GHG's, the abatement and / or removal of emissions gains an economic value. To date, the most significant agreement that restricts emissions is the Kyoto Protocol (KP).

In assessing the market for carbon storage, we will therefore consider studies encompassing both the KP and future climate agreements. However the emphasis will focus on studies dealing with the KP because the emission reductions and the market structure have already been negotiated, and there is much less room for speculation regarding likely carbon prices: the majority of Parties to the Protocol have committed themselves to specific reductions in their GHG emissions. The Protocol also establishes three so-called flexibility mechanisms that Parties to the KP may use to help them comply with their commitments: emissions trading, Joint Implementation (JI), and the Clean Development Mechanism (CDM), and we note that each mechanism has its own type of permit[6].

The supply of emission permits depends on marginal abatement cost curves in each of the participating countries, the availability of competitive biotic sink projects, and the supply of "hot air"[7]. The price, or prices, of the KP permits will determine whether or not geological carbon storage will be a competitive option. The literature on estimating permit prices is extensive[8]. Most of these studies assume that the permit market will be a relatively liquid market with an equilibrium permit price. In the studies reviewed, the price estimates, given in tons of CO2 equivalent (CO2e), range between $0-15 /tCO2e. While this is a relatively large range, most studies seem to indicate a permit price in the region $5-10 /tCO2e as the most likely outcome.

It is invariably difficult to estimate carbon prices under a future climate regime. The estimated prices will depend heavily on the policy assumptions that are made: the size of the emission reductions to be undertaken, and the availability of mitigation options. Furthermore, the longer we look into the future, the more uncertain assumptions about economic parameters and technological change will become. Nevertheless, such studies have been undertaken, and the price estimates they provide are the only ones that are available. Some recent studies give price estimates in the region $23-37 /tCO2e by 2030, depending on the emission targets (Baumert *et al.*, 2002; Johnson and Keith, 2004).

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[6] Unless further specification is required we will refer to the trading units (quotas and credits) under all the Kyoto mechanisms as 'permits'.

[7] "Hot air" is the term used to describe the excess permits allocated to Russia and certain Central and Eastern European states.

[8] We have limited our review to studies that consider international emissions trading, and where the United States is not a party to the Kyoto Protocol.

2.4.3 Comparing Carbon Storage Costs and Permit Prices

Based on the reviews of geological carbon storage options and costs, the potential for EOR, and price estimates from the carbon market under international climate policy agreements, we have created sets of circumstances to evaluate the economic viability of carbon storage as an option for climate-change mitigation. We provide low, medium and high estimates for permit price and geological carbon storage cost intervals—based on the reviewed studies. Together these estimates produce nine sets of circumstances for the economic viability of geological carbon storage. These are presented in Table 3.

		Geological carbon storage cost per tonne CO2		
		"Low"-but with EOR income ($7-21)	"Medium" ($40-50)	"High" ($75-95)
Permit price ($/tCO2e)	"Low" $0-5	-2 to -26	-35 to -50	-70 to -95
	"Medium" $10-15	-11 to +8	-25 to -40	-60 to -85
	"High" $25-35	+28 to +4	-5 to -25	-40 to -70

Table 3: Net economic benefit of geological carbon storage under various assumptions.

With respect to permit price, in the "Low" estimate we assume a competitive international permit market under the KP, where market power by Russia in particular is not fully exercised, but where all available CDM projects are carried out. For the "Medium" estimate, we still assume that the KP is implemented, but this time that market power is exercised fully, and that due to institutional barriers and high transaction costs, (no or!) only a limited number of CDM projects are carried out. For the "High" estimate we look beyond the KP, and at a possible future climate agreement with more severe emission reduction commitments.

When it comes to geological carbon storage technologies, we have again made three different sets of assumptions that give rise to three different cost estimates. For the "Low" cost-estimate, we assume a low cost geological carbon storage technology, such as the integrated gasification combined-cycle process with near-term technological improvements. We further assume that the CO2 is used for enhanced oil recovery. The "Medium" cost-estimate is based on the best existing technology for a gas- or coal-fired power plant, with medium transportation costs, and no income from EOR. For the "High" cost-estimate we make less optimistic assumptions regarding the best available geological carbon storage technology for a gas-fired power plant, and we assume high transportation costs and no EOR.

The table shows that geological carbon storage is likely to be economically viable only in the case where costs are low and permit prices are high. The combination of a low geological carbon storage cost and a medium permit price can also be viable. These conditions are marked with grey shading in the table. For all other circumstances we find a negative net economic benefit of implementing geological carbon storage. These cost estimates therefore confirm that geological carbon storage for EOR can be profitable. And as indicated in other sections of this document such activities are already occurring within some oil reservoirs where CO2 has been made available.

While the permit price and geological carbon storage cost estimates are independent of each other in other respects, there is a clear correlation over time. If we look beyond 2012 we expect carbon prices to rise, as long as more ambitious climate policy agreements are adopted, and we also expect technological advances to bring down the cost of geological carbon storage. Over time one might therefore expect to see a shift towards the lower left-hand corner of the table, where the economically favourable circumstances are found.

Even though we expect that carbon capture and geological storage will improve its cost-benefit ratio over time, we also have to bear in mind that other carbon abatement options may emerge over time. Cheaper abatement options might be developed, and could lead to a downward pressure on the carbon price. Rapid improvement in renewable energy technologies, for example, could significantly reduce carbon prices and consequently make geological carbon storage less competitive.

2.5 CONCLUSIONS

Carbon storage in geological formations has considerable potential as a GHG mitigation option. While aquifers, gas fields, coal seams and salt caverns have a potential for storing CO2, oil reservoirs have an additional benefit in terms of EOR, making these formations particularly interesting candidates. In the case of Norway there is a sizeable storage capacity within the NCS that is sufficient to store a large share of European CO2-emissions for many decades.

There are however a number of challenges to sort out in order to take advantage of geological carbon storage within an efficient climate policy. These can be grouped as political and institutional on the one hand, and technical and economic on the other hand.

In institutional and political terms important challenges are the uncertain status as a policy measure in the Kyoto Protocol (KP). Other issues are the possibility to monitor and verify leakage's, and deciding how the option should be linked to the flexible mechanisms under the KP. Geological carbon "storage" quotas could be framed under emissions trading, or carbon capture and storage projects could be framed as joint implementation. The fact that the KP has not yet entered into force adds to this uncertainty. Accounting, verification and responsibility rules have not been well developed for geological carbon storage. There would also be a need for clarification of accounting rules for Norway to be able to store CO2 on behalf of other countries.

In technical and economic terms one issue is the risk of leakage from storage sites, which has institutional implications in terms of the handling of responsibility for such leakage. If the amount stored is large, even a small leakage may be significant. The government could be willing to accept a risk of leakage provided that a carbon dioxide storage project satisfies certain criteria. This alternative could be combined with the government taking the responsibility, but introducing a fee per ton of geological carbon storage to be paid by the companies as a risk premium to cover potential future expenses. An alternative is to require that the responsible companies finance an insurance fund that could cover future expenses.

An important economic challenge is the large investments in infrastructure required, and related economies of scale properties. Therefore carbon capture, transportation and storage projects are more attractive if developed in a co-ordinated manner on a large scale—which in many cases would mean involving two or more nations. In terms of competitiveness with other CO2 abatement measures, geological carbon storage is today only of interest under particular circumstances, primarily where CO2 injection can be used for EOR. However, in the near future (one decade) it might become a competitive abatement option on a larger scale if carbon prices increase and technical improvements lower the cost of geological carbon storage. This conclusion depends crucially on the assumption that a future climate regime will have binding quantitative emission reduction targets—so that there is a market for CO2 emission reductions or removal—and also that marginal abatement cost, and thus the permit price, is significantly higher than what is expected for the Kyoto period (2008-2012).

Due to the shortcomings and uncertainties we have mentioned, companies and governments today have only weak incentives to venture into geological carbon storage. If these obstacles are sorted out through an international co-ordinated political initiative, the potential of geological carbon storage to enhance the cost-effectiveness of carbon dioxide mitigation policies could be put to a real test.

3. LEGAL CONSIDERATIONS

3.1 INTRODUCTION AND BACKGROUND

Sequestration of greenhouse gases (GHG's) and in particular carbon dioxide (CO2) by way of injection and storage into geological formation in the subsoil on the continental shelf raises several legal questions. In this chapter of the Study Report we present an overview of these questions, and what we see as the most likely legal answers.

The legal problems and solutions vary with different forms of injection; CO2 may be injected either into petroleum reservoirs or into natural aquifers in the subsoil. Injection may either be part of offshore petroleum activities, be independent of such activities, or be combined with it in different ways. Linked to petroleum activity, injection may be carried out either as a part of a production strategy to obtain enhanced oil recovery (EOR), or as a means to avoid emissions of CO2 to the atmosphere. If CO2 is taken from onshore activities, the injection itself may take place from installations that are or have been used for petroleum purposes, from installations that have been specially constructed for injection purposes, or from pipelines directly from the shore into the reservoir / aquifer.

The discussion of legal issues is based on the assumption that there is a certain risk—albeit small—for leakage of CO2 into the sea from underground CO2 deposits, and therefore a possibility of marine pollution. The effects of this on the marine environment are uncertain, but we assume that there is a risk of harm to marine life that must also be taken into consideration.

First, we discuss issues of *International Law*: The question of States' right to use the continental shelf and / or the seabed and subsoil within its territory (and extended economic zone) for such a purpose, and the international rules that govern such activities. In particular we consider international conventions for the protection of the marine environment by pollution from land-based and offshore sources, and from dumping of waste. Furthermore international rules on environmental impact assessment may also need to be taken into consideration[9].

Second, we discuss the *National Rules* that apply to CO2-injection. We focus the discussion on the application of the main acts, namely the Pollution Control Act and the Petroleum Act with regulations. We do not discuss national legislation that does

[9] How CO2-injection will be seen in relation to the general obligations and the flexible mechanisms in the Kyoto Protocol, will be discussed in other parts of this Study Report, and will not be taken up here (see also IPCC, 2002). Nor will the various questions related to relevant EU rules—which apply to Norway through the EEA agreement—be discussed. One issue here is the question of right to access

not apply to the sea area, such as the Planning and Building Act. This Act applies to installations onshore for deposit purposes, such as pipelines, in the same way as for other buildings and constructions. Neither do we discuss such special legal issues as the application of tax law on CO2-injection, nor issues of private law (contract law) and private international law which may arise between the various actors taking part in an injection scheme.

Neither international nor national law has rules that explicitly apply to CO2 injection into the subsoil. Therefore, some of the conclusions may be doubtful. If CO2-injection is seen as a possible solution to the problem of greenhouse gas emissions in the future, we recommend that some of the general rules and regulations are amended in order to clarify how they apply to CO2 injection. In this connection, one must bear in mind that amendments of international rules require participation by and agreement between states. If this is not achieved, international rules may limit the possibilities for CO2 injection even if Norway wants to undertake this option.

3.2 THE RIGHT TO USE AQUIFERS AND RESERVOIRS FOR INJECTION PURPOSES

Who—if any—has the right to use aquifers and reservoirs for injection purposes? This is a question of international law as well as national law.

In international law, the question is if the coastal state has sovereign and exclusive rights to use the underground for this purpose. In national law, the question is whether reservoirs and aquifers are subject to state ownership, or whether they may be used freely for this purpose by any legal subject.

3.2.1 International Law

This issue is regulated by the ***UN Convention of the Law of the Sea (UNCLOS)***. The Convention provides the coastal state with sovereign rights to;

> *i.a. "exploit natural resources … of the waters adjacent to the seabed and of the seabed and its subsoil, and with regard to other activities for the economic exploitation and exploration of the zone … in the extended economic zone (EEZ)".*

For Norway the EEZ extends 200 nautical miles from the coast (baseline) (art. 56). The same applies to the exploitation of "natural resources" on the continental shelf (art. 77). We find that this covers the use of aquifers and reservoirs for injection purposes, both with the purpose of enhancing oil recovery and for deposit purposes. This conclusion is obvious with regard to injection of CO2 for EOR. When it comes to injection solely for disposal purposes the interpretation of art. 77 to cover this

to the sequestration facilities for other EEA states on a non-discriminatory basis. The IPPC-directive and the general requirement of best available techniques (BAT) will be touched upon briefly.

activity is less straightforward than of art. 56, but the result is still considered to be valid. The main conclusion is that;

> *Norway has sovereign and exclusive rights to use underground aquifers and reservoirs on the continental shelf and in the EEZ for injection of CO2 for both deposit purposes and enhanced oil recovery (EOR).*

Many known oil and gas reservoirs stretch across the borders between the continental shelf of Norway and that of neighbouring countries, in particular United Kingdom. This may also be the case with some of the aquifers that are suited for injection of CO2.

> *Norway cannot unilaterally decide to use such reservoirs and aquifers for CO2-injection. An agreement between the parties is necessary.*

3.2.2 National Law

Who—if any—has the right according to *national law* to exploit underground aquifers and reservoirs for these purposes?

The right to use aquifers and reservoirs for *petroleum activities* is regulated by the Petroleum Act. According to this Act the State has the property right to underground petroleum resources on the continental shelf and the exclusive right to exploitation of these resources. As owner, the State may regulate the use of petroleum reservoirs, and of aquifers for petroleum activities, either to deposit CO2 as waste or to enhance oil recovery. It is, however, unclear whether a permit pursuant to the 1963 Continental Shelf Act may be necessary in order to use aquifers for disposal of CO2 as waste from petroleum activities.

For other resources than petroleum the 1963 Continental Shelf Act is applicable. This Act covers scientific research and exploration, and exploitation of underground natural resources[10] other than petroleum, in internal Norwegian waters, the territorial sea and on the continental shelf. According to section 2 of the Act the State has the right to such underground natural resources. It is our view that the expression "underground natural resources" should be interpreted as covering aquifers and reservoirs for use as CO2 deposit. This means that the state has the exclusive right to such use, to control such use and to issue necessary regulations.

[10] In Norwegian: "undersjøiske naturforekomster".

3.3 INTERNATIONAL RULES ON MARINE POLLUTION (IN PARTICULAR DUMPING)

3.3.1 United Nations Convention on the Law of the Sea (UNCLOS)

According to UNCLOS art. 194,

> *States shall take, individually or jointly as appropriate … necessary action to prevent, reduce and control pollution of the marine environment from any source … .*

The first question is whether CO2-injection is "pollution" in the meaning of the Convention. "Pollution" is defined by art. 1 (4) as;

> *"the introduction by man, directly or indirectly, of substances or energy into the marine environment … which results or is likely to result in such deleterious effects as harm to living resources and marine life, hazards to human health, hindrance to maritime activities ... etc."*

The question is whether the apparently small risk of leakage of CO2 from an underground deposit into the sea makes injection of CO2 "likely" to result in such effects. Since the volumes of deposited CO2 may be substantial, and the amount of emitted gas may be very significant if a leakage occurs, we find that a leakage from a deposit should be regarded as pollution in the sense of the UNCLOS. Consequently, injection of CO2 into aquifers and reservoirs is covered by the general rules on marine pollution in the convention.

However, in actual fact, the more precise rules in regional and global conventions about marine pollution from land-based sources, offshore installations, and dumping, take precedence over UNCLOS.

3.3.2 OSPAR Convention

The OSPAR Convention for the Protection of the Marine Environment in the North East Atlantic requires that the member states *"take all possible steps"* in order to prevent and remove marine pollution. In this work they shall apply the precautionary principle, the polluter pays principle and the principle of best available techniques / best environmental practice (BAT)[11]. The control regimes of the convention apply to the "maritime area", which includes the seabed and the sub-soil of the seabed (art. 1 (a)). Thus deposit of CO2 in the underground on the continental shelf is covered by the convention. However, the rules are rather complex, and some of the conclusions that follow may still be subject to further interpretation.

[11] A special appendix to the Convention (Appendix 1) lays down criteria for the definition of Best Available Techniques.

The convention distinguishes between discharge from land-based sources (art. 3 and Annex I), dumping (art. 4 and Annex II), and discharge from offshore sources (art. 5 and Annex III). All these sources are relevant for injection of CO2 into the underground.

For discharges from "land-based sources" and "offshore installations" the convention leaves it to the states to take necessary measures on the basis of the mentioned principles[12]. Discharges are strictly subject to authorisation or regulation. This governs the application of the national pollution control legislation on discharges from these sources.

The convention prohibits dumping. Dumping is defined as "any deliberate disposal of wastes and other matters from vessels, aeroplanes and offshore installations" (art. 1 f (i)). We find that CO2 as a waste product from production should be regarded as "waste or other matters", and so dumping of CO2 is covered. It follows that it is prohibited to transport CO2 from land-based sources by a vessel and inject it into the underground either from the vessel, or from an offshore installation. Most probably it is also prohibited to inject CO2 from an offshore installation if the CO2 has been transported from land to the installation through a pipeline (and it is not regarded as discharge or emission from offshore sources, see below). Offshore installations are defined as installations placed in the sea area with the purpose of "offshore activities". "Offshore activities" is defined as exploration and exploitation of petroleum resources (art. 2 j and l).

This in turn means that deposit of CO2 from other types of installations than petroleum installations is not regarded as dumping, but discharge from land-based sources, and therefore not prohibited by the convention[13]. It must however be regulated and controlled by the state according to the general rules in the convention on pollution from land-based sources. This clearly applies to the case where CO2 is brought to such an installation from land through a pipeline. If the CO2 is brought to the installation by ship, however, the injection from the installation will probably be regarded as dumping.

The dumping prohibition does not apply to "discharges and emissions from offshore sources" (Annex III, art. 3). This means, in our opinion, that injection of CO2 into reservoirs in order to enhance oil recovery, and injection of CO2 simply as a waste product from the petroleum production in order to dispose of the CO2, do not fall

[12] Protocols lay down targets for the reduction and gradual phasing out of discharges of various hazardous substances, but CO2 is not covered by any protocol.

[13] This may seem paradoxical. It follows from the Convention's definition of "dumping", "offshore installations", "offshore sources" and "offshore activities". It should be added, however, that the dumping prohibition in the global London Protocol on dumping also applies to these situations. It

under the dumping prohibition. Such discharges are allowed under the convention. The state must, however, take "all possible steps to prevent and eliminate" pollution from these types of injection, through authorisation or regulation, and on the basis of the aforementioned principles.

The question of whether the OSPAR prohibition on dumping applies to carbon injection and storage in the subsoil on the continental shelf has for some time been discussed in OSPAR's organs. A report from its Group of Jurists and Linguists was presented by the Secretariat to the Biodiversity Committee of OSPAR in February 2004 [14].

3.3.3 The London Convention on Dumping

It is not clear whether this global dumping convention applies to underground injection of CO2. It prohibits *"deliberate disposal at sea"*. The text does not cover the sub-soil. The question of underground disposal of radioactive waste has been discussed in the organs of the convention on several occasions. Apparently, opinions have differed and no clear conclusions can be drawn.

The prohibition applies to dumping of *"industrial waste"*. Most likely, CO2 from land-based industry and power plants must be regarded as industrial waste, but this has not been formally clarified.

The convention does not apply to waste from the exploitation and production of petroleum. This means that it is not prohibited to inject CO2 as a waste product from the offshore petroleum production, or for the purpose of enhancing oil recovery from the reservoirs.

> *Provided that dumping into the subsoil is covered by the convention, the injection from offshore petroleum installations of CO2, which is not produced in the offshore petroleum activity, and not used for the purpose of enhancing oil recovery, is prohibited.*

The definition of dumping also covers the disposal of waste from *"other man made structures at sea"*. It is not clear whether this covers pipelines that are connected to land-based sources and transport CO2 from land directly into reservoirs or aquifers. It is clear, however, that,

> *it is prohibited to transport CO2 from land to an offshore installation and inject it from the installation into the subsoil.*

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seems uncertain whether the expression "offshore installation" also covers the situation where an offshore installation has been converted into an installation for CO2 sequestration.

[14] *Placement of Carbon Dioxide in the Maritime Area*, BDC 04/8/1-E(L). Our views correspond largely with this report, which is however more detailed, and reflects various viewpoints within the Group of Jurists and Linguists.

3.3.4 The 1996 London Protocol on Dumping

This protocol to the London convention has somewhat stricter rules than the convention itself. The protocol is not yet in force, but it has been ratified, by among others Norway, who is therefore obliged to act in accordance with it. Furthermore, it will be wise to follow the protocol, since underground injection of CO2 is a long-term project and the protocol most likely will come into force.

The protocol explicitly applies to *"the seabed and the subsoil"*. The protocol prohibits dumping of *"wastes or other matters"*. Most likely, CO2 as a waste product from production etc. will be regarded as such, and it is not among the listed types of waste that are exempt from the prohibition.

Injection of CO2 derived from production of petroleum on the continental shelf is not covered by the convention. Therefore, it will not be prohibited to dispose of CO2 as waste from such production, nor to use CO2 to enhance oil recovery.

It is uncertain whether it is prohibited to dispose of CO2 from land-based sources directly into the underground through a pipeline from land. This depends on how the expression *"man made structures at sea"* is interpreted. Independent to what follows from OSPAR, also injection from an offshore installation that has been constructed especially for the purpose is regarded as dumping and therefore prohibited.

3.3.5 Environmental Impact Assessment (EIA)

Before a decision is made by Norwegian authorities to inject CO2 into the subsoil on the continental shelf or within the EEZ, a procedure for environmental impact assessment may have to be carried out in accordance with rules of international law. Relevant rules on EIA in a transboundary context are found in the ***Espoo Convention*** and the EC directive on EIA. At present, injection and storage of CO2 is not covered by the categories listed which require such transboundary assessment procedures, but this may of course be changed.

3.3.6 Conclusions

The international rules on dumping do not give quite clear answers to all the questions raised. However, we find that the OSPAR convention and the London Protocol together prohibit the disposal of CO2 as waste, from other sources than offshore petroleum production, into underground reservoirs and aquifers. They do not prohibit injection of CO2 as waste from offshore petroleum production, or for the purpose of EOR. It is doubtful whether injection directly through a pipeline from land is regarded as dumping and thus prohibited.

Injection that is not dumping, and thus prohibited, must nevertheless be regulated in order to prevent and control marine pollution, according to the general rules of the

OSPAR convention on pollution from land-based sources and offshore petroleum production. The regulation must be based on international principles of environmental law such as the precautionary principle, the *"polluter pays"* principle, and the principle of best available techniques (BAT).

3.4 NATIONAL RULES TO PROTECT THE ENVIRONMENT: POLLUTION CONTROL ACT

3.4.1 The Field of Application of the Pollution Control Act

The Act applies to "pollution". The first question is whether the definition of "pollution" in the Act covers injection of CO2 into the underground. Pollution is defined as the discharge of liquid or gas into the water, air or ground, which is or may be harmful to the environment. The threshold is low. The injection will probably not in itself be regarded as pollution, since it will not harm the environment. However, since there is a certain—although small—risk of leakage of significant amounts of CO2 from the underground into the sea, and this may affect marine life, the injection most likely falls under the definition of pollution, and the Pollution Control Act applies.

The area of application of the act on the continental shelf and in the EEZ has some limitations. According to § 4, the main rules of the act apply to "regular" sources of pollution from "the exploration and exploitation of subsoil natural resources on the continental shelf"[15]. We find that "subsoil natural resources" most likely covers aquifers and reservoirs on the continental shelf, and that injection is a "regular" source of pollution. As a consequence, injection into the subsoil on the continental shelf is covered by the act, whether the purpose is waste disposal or to enhance oil recovery. In addition, the act applies to pollution sources in the EEZ (including its subsoil), or pollution that threatens the EEZ, if the source is a Norwegian vessel or installation[16].

The Act does not cover injection in the EEZ outside the continental shelf from foreign vessels or installations.

To avoid uncertainties, the act should be amended to include clear rules on CO2 injection into the subsoil on the continental shelf and in the EEZ.

3.4.2 Regulation of Injection and Storage

Any activity that may create a risk of pollution is generally prohibited by the act (§ 7), unless it has been lawful through regulations or an individual pollution permit.

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[15] "...undersøkelse etter og utnytting av undersjøiske naturforekomster på kontinentalsokkelen..."

[16] So, even if the aquifers and reservoirs on the continental shelf are not defined as "subsoil natural resources", the act will nonetheless apply to all types of injection in the EEZ from Norwegian sources.

A pollution permit is required both for the company that carries out the injection, and for the activity that wants to deliver CO2 to an installation for injection. The international rules on marine pollution define the freedom of action for the Pollution Control Authorities in making their decisions, (see section 3.3 above). To the extent injection is regarded as illegal dumping according to the international rules, a pollution permit can not be granted.

However, if the injection in question is not covered by the international dumping prohibition, Norwegian Pollution Control Authorities (SFT) may accept it through a pollution permit or regulations. The permit must be based on the aforementioned principles. Injection should only be permitted if this is seen as the best solution from an environmental point of view, combined with economic considerations, and with conditions that minimise the risk of leakage. We recommend that such conditions should include maximum leakage level, regular monitoring, and—to some extent—research on possible environmental effects of CO2 leakage.

Summing up, the act gives the authorities the necessary tool to control injection in order to protect the marine environment.

3.4.3 The Present Regulation on Dumping

The 1997 Regulation on dumping in the sea and watercourses implements the rules on dumping in the OSPAR convention into Norwegian Law. The content herein corresponds to a large extent to the wording in OSPAR.

However, there is one important difference: In the regulation, dumping is defined as disposal of "waste or other matters"[17] "in the sea or watercourse"[18]. In our view, this wording can not be interpreted to cover the subsoil. Therefore the regulation does not apply to injection into the underground, and it has to be revised if it is established that OSPAR applies to CO2-injection.

Otherwise, the wording of the regulation is in accordance with the OSPAR text on dumping. The dumping prohibition does not apply to injection of CO2 from petroleum activity, whether the purpose is EOR or disposal of CO2 as waste from petroleum activity. Neither does it apply to injection from an offshore installation that has been specially constructed for other purposes than petroleum production. For these types of injection, the ordinary rules of the Pollution Control Act apply.

3.4.4 Liability and Compensation for Environmental Damage

The Pollution Control Act has special rules on liability for environmental damage, based on strict and severe liability for the operator of the installation or activity that

[17] "… avfall eller annet materiale …"

[18] "… i sjø eller vassdrag."

causes the damage. Leakage of CO_2 from underground deposits into the sea may harm the marine environment. It is however, very difficult to see how this can result in a type of damage to public or private interests that may entail a loss that can be compensated.

The Petroleum Act has special rules on compensation to Norwegian fishermen for loss caused by petroleum installations and pollution and waste from petroleum activity. These rules do not apply to loss caused by the injection of CO2, which is not related to petroleum activity. It should be considered to amend the legislation so that damage to fishermen from other types of installations and waste due to CO2-injection may be compensated accordingly.

3.5 NATIONAL RULES ON OFFSHORE PETROLEUM ACTIVITY: PETROLEUM ACT

3.5.1 Regulation Governing the use of Reservoirs for Injection

The regulatory situation for injection of CO2 is found to vary with the circumstances under which the CO2 is injected. Three main situations have been identified:

- When CO2 is injected for the purpose of EOR, it is either injected directly into a petroleum deposit, or into an aquifer[19] that is in direct contact with the petroleum deposit. In both instances, the injection of CO2 into the formation is covered by the scope of application of the Petroleum Act[20].
- When reservoir formations are used “for the sole purpose of disposal of CO2 that is not a product from petroleum activities” on the Norwegian continental shelf, then exploitation is covered by the scope of application within the Act for the Continental Shelf in lieu of the Petroleum Act.
- When reservoir formations are used “for disposal of CO2 that is the direct result of production of petroleum” on the Norwegian continental shelf, the regulatory situation seems unclear. Most likely, the exploitation of the reservoir is covered by the Petroleum Act. For the two actual storage cases which are now either in place or under development, information received from the ***Ministry of Oil and Petroleum (OED)*** indicates that the authorities have viewed the disposal

[19] An aquifer is a geological formation with a certain porosity and permeability, where the pores are filled with water. Such aquifers are sometimes also well suited to provide pressure support into an oil reservoir as the petroleum is produced.

[20] Act 29 November 1996 No.72 relating to petroleum activities.

to be a part of the petroleum activities, and thereby covered by the scope of application of the Petroleum Law [21]

There is not established any concession system with regard to the handling of potential applications for exploitation of sub-sea natural resources other than petroleum resources. There is a regulation regarding scientific research for natural resources[22], but there is no regulation regarding exploitation of such resources. Establishment of a concession system for such exploitation is considered necessary (in addition to the system of pollution permit pursuant to the Pollution Control Act).

3.5.2 Injection for Enhanced Oil Recovery (EOR)

Most of the relevant activities are covered by the Petroleum Act, which has a wide functional scope of application. When the Act was amended in June 2003, the geographical scope of application was broadened, in the sense that also land-based utilisation of produced petroleum is covered, provided that such utilisation is necessary for, or an integrated part of the production of petroleum. This implies that the Petroleum Act covers most of the main activities connected with injection of CO2 for EOR, and the different provisions providing legal basis for the authorities to govern the petroleum activities therefore also apply to the injection activities.

The different relevant provisions have been analysed, both with regard to limitations to the contents of the individual administrative decisions, and with regard to what conditions must be present to be able to make a decision. *The main conclusion is that the provisions give sufficient basis for governing the relevant activities*.

However there are special considerations regarding land-based power plants. In the preparatory comments[23] to the amendment of article 1-4 (scope of application) in the Petroleum Act, it is stated that if a land-based power plant delivers electricity or heat necessary for the production of petroleum, then the power plant is covered by the scope of application of the Petroleum Act. There may be reasons to investigate further whether land-based power plants should be covered by the Petroleum Act also under other circumstances than the one mentioned *i.a.* also when the power plant does not deliver energy for the production of petroleum. One circumstance that might constitute reasons for such a plant to be covered by the Petroleum Act is the

[21] The relevant cases are the ongoing injection of CO2 from the Sleipner field, and the planned disposal of CO2 from the LNG facility covered by the Snøhvit development.

[22] Regulations relating to scientific research for natural resources on the Norwegian continental shelf etc. Stipulated by Royal Decree of 31 January 1969 pursuant to Act of 21 June 1963 relating to scientific research and exploration for and exploitation of sub-sea natural resources other than petroleum resources section 3.

[23] Ot.prp. nr. 46 (2002-2003).

delivery of CO2 for EOR from the power plant. In this case the delivery of CO2 may be necessary for the production of petroleum.

3.5.3 Injection for Disposal: Circumstances that make the Petroleum Act relevant

There are a number of circumstances that connects the injection of CO2 for storage purposes to the sub-sea petroleum deposits in such a way that the Petroleum Act is considered to regulate the activity[24].

On this basis, the Ministry can decide upon injection of CO2 from facilities used for production of petroleum in connection with approval of a development plan, *cf.* section 4-2 of the Petroleum Act. Furthermore, in connection with installation abandonment, the Ministry can decide that facilities formerly used in the petroleum activities can be used for other purposes, *cf.* section 5-3 of the Petroleum Act. It is submitted that this also includes purposes for the disposal of CO2.

3.6 NEED FOR AMENDMENTS TO THE PRESENT LEGISLATION AND NEW REGULATIONS

3.6.1 Amendments to the Petroleum Act

The legal basis for exploitation of other reservoir formations (than petroleum reservoirs) for disposal of CO2 in connection with the petroleum activities needs to be clarified.

The scope of application of the Act should be amended to cover all power plants that deliver CO2 to petroleum installations for EOR. In other words, such power plants should be covered by the Act irrespective of whether they deliver power to the installations or not.

A separate transportation licence pursuant to section 4-3 of the Petroleum Act is required when another licence group than the one that operates the field(s) to which the pipeline is connected operates a pipeline. However, it is unclear whether section 4-3 covers licences for transportation of CO2. This calls for a clarification and most likely an amendment of article 4-3 to also cover licences for transportation of CO2.

For most of the other relevant activities, the legal basis for decisions and conditions relating to the activities is considered to be sufficiently clear.

3.6.2 Amendment to the Act for Exploitation of the Continental Shelf

To avoid uncertainties regarding the State’s rights to resource management over other reservoirs than petroleum reservoirs, there should be made an amendment to Section 1 of the Continental Shelf Act. It should also be considered whether there is a need to ascertain that all use of other reservoirs for disposal purposes should be covered by the same Act, regardless of what is the source of CO2.

[24] In addition, the injection of CO2 for disposal purposes is regulated by the Pollution Control Act.

3.6.3 Amendments to the Pollution Control Act

To avoid uncertainties as to the field of application of the Pollution Control Act, the Act should be amended as regards its general application to injection of CO2 into the subsoil of the continental shelf and the EEZ. This should extend regardless of the nationality of the company carrying out the injection, and regardless of whether the source that produces the CO2 is within or outside Norway.

If it is established that the OSPAR dumping prohibition applies to CO2-injection into the subsoil, the present regulation on dumping must be amended accordingly.

3.6.4 A Concession System for Exploitation of Reservoirs

There is a need to establish a concession system for exploitation of other geological reservoirs for disposal purposes. Such concession system should *i.a.* contain criteria for evaluating the different reservoirs, in terms of security against leakage and against unwanted migration of CO2 into other parts of the reservoir. Such other parts may be used for other purposes, such as fresh water supply for injection purposes. Furthermore, the criteria should form basis for choosing which of several applicants should be granted a licence, and for linking conditions to the licences.

As a first step, one can establish a concession system in the form of regulations pursuant to the Continental Shelf Act. The regulation of the petroleum activities serves as an example in this respect. Initially, petroleum activities were subject to regulations pursuant to the Continental Shelf Act. If large-scale projects for injection of CO2 (for depletion purposes) are developed, one can—as a second step—foresee a separate Act for such activities. Again, the regulation of petroleum activities can be an example; the Petroleum Act of 1985 replaced the former regulations (adopted pursuant to the Continental Shelf Act), when petroleum activities had developed to a large-scale industry on the NCS.

4. COMMERCIAL CONSIDERATIONS

This chapter considers how an infrastructure for using CO2 may possibly be developed in collaboration between government and private sectors. Given specifically that the economic regime and incentives for commercial participation regarding investment in such an infrastructure for gathering, transportation and storage of CO2 is not yet present.

We indicate that there is a mutual interdependence between agents, and the fact that large, irreversible investments must be undertaken up-front, implies that a rational organisation of the project may be critical for the project to be commercially interesting. Furthermore, we show that options and flexibility have value, and that the option values may influence investment decisions (e.g. whether to start full-scale implementation immediately or start on a smaller scale).

The chapter is organised in three sections covering introduction, the economic organisation of a CO2-infrastructure, and the value inherent in options and flexibility.

4.1 INTRODUCTION AND BACKGROUND

The practice of using CO2 for EOR was first exploited in the mature onshore fields of the Permian Basin, Texas in the early 1970’s (see chapter 1.1). Transferring this practice to the maturing oil reservoirs of the Norwegian Continental Shelf (NCS) offers an opportunity for the extended exploitation of existing oil and gas supplies, as well as providing a commercial pathway through to larger-scale CO2 sequestration within the whole of the North Sea.

Such use of CO2 may also be an effective method for removing existing emissions from the overall GHG-emissions inventory of the participating host nations. International commitments to reduce GHG’s may therefore make the project particularly interesting, despite the fact that the scope for carbon storage within the “flexible” Kyoto-mechanisms still remains uncertain (see chapter 2 for additional discussion).

Furthermore, if the evolving international emissions trading system (ETS) will permit that capture and storage of anthropogenic CO2 be included, then this would inevitably increase the net present value (NPV) of a proposed transportation project through the additional sale of CO2 emission reduction credits (ERC’s). However, as also discussed in this Study Report, with continued uncertainty regarding the legal status and a limited window of opportunity for investment decision to use CO2 for EOR in the North Sea, then many of the major mature fields may choose alternative strategies for tertiary production.

During the early stages of developing a CO2-transportation infrastructure it is envisaged that coal-fired power plants in North Europe, as described by Sharman *et al.* (2003), can be initial large-volume suppliers of CO2.

This is primarily determined by the fact that;

(i) there are few sources of available Norwegian CO2 in comparison with volumes that are necessary to initiate tertiary CO2-floods and justify initial investment in the infrastructure.

(ii) the Norwegian CO2 will probably be more costly—due to economies of scale—than CO2 that may be gathered from power plants and industrial complexes in North Europe (Kaarstad and Hustad, 2003).

There are, however, a number of investment decisions that have to occur before CO2 can be used for tertiary production and EOR. And an infrastructure for CO2 involves the following activities:

(i) power plant CO2-capture.

(ii) transportation

(iii) CO2-injection for EOR

(iv) CO2-stripping and recycling[25],

(v) storage capacity.

The CO2 may be transported through a pipeline or by ship (or a combination of the two). Clearly, these alternatives have very different cost structures. Transport by ship involves small fixed costs, but high variable costs. Transport through a pipeline involves large fixed costs, but only small variable costs.

Although using CO2 for EOR is not new, the process will involve a significant 'learning curve' effect when transferring the experience to offshore installation on the NCS. This being true for all the activities (i)-(v) with the exception of (ii) transportation.

4.2 ECONOMIC ORGANISATION

A system to transport CO2 from land to offshore oil-installations, where it is used for EOR, will involve a number of mutually dependent participants:

- The oil companies will have to make large investments offshore, and it will subsequently be expensive to switch back to alternative forms of tertiary oil recovery.

[25] In Chapter 6 we present a techno-economic analysis that initially assumes that reproduced CO2 is re-injected into the oilfield without removing the associated hydrocarbon gas.

- Investments in CO2 pipelines require substantial transport volumes as soon as possible in order to be profitable.
- If a power plant is to invest in a CO2-capture system, then it will need a transport system and buyers for the CO2.
- Economies of scale imply that the project may have to involve several companies on both sides of the market.

The mutual dependence between the agents, and the fact that large, irreversible investments must be undertaken up-front, implies that the rational organisation of the project may be critical in order for the project to become commercially viable. In this respect government may therefore play a role as co-ordinator if the project is commercially interesting, and / or provider of economic support if the project is socially valuable but not commercially attractive for the private sector.

4.2.1 Ownership and Contracts

Traditionally, economists have not focused much on ownership and contracts. However, this has changed over the last 20 years (see Grossman and Hart (1986) and Hart and Moore (1990) for seminal contributions; also Hart (1995) and Laffont and Martimort (2002) for an overview of the literature).

Contracts and ownership are instruments that are used to ensure efficiency in transactions. Problems may arise if complete contracts are difficult to write or enforce. A standard example is the 'hold-up' problem, modelled in (among others) Grout (1984). These arise in transactions between two agents if one or both of the agents make irreversible and relationship-specific investments before the transaction. If the investments cannot be protected by contracts, then the investing part may end up in a weak bargaining position after the investments are undertaken, and will therefore tend to under-invest. A standard example is a car manufacturer and a subcontractor. If a subcontractor invests in machinery and know-how that are specific to a particular car, the car manufacturer may receive part of the gain, and under-investment may result. The 'hold-up' problem may be solved in several ways: through contracts (if possible), through mutual ownership, or in some situations by reputation effects.

Because oil companies, power plant operators and pipeline owners will all have to undertake substantial, irreversible, and to a large extent relationship-specific investments, the hold-up problem is definitely relevant for the CO2 project. The challenge is to construct contracts that protect the investments and at the same time are sufficiently flexible to ensure efficient trade *ex post*. If this is not possible, joint ownership may be necessary.

We assume that the marginal cost of CO2-transport through the pipeline is zero. The marginal value of CO2 is assumed to approach a given threshold (which may be stochastic), and then drop rapidly. The marginal cost of CO2 includes the loss from reduced energy production, while reduced carbon taxes could be deductible. We assume that the cost is positive (although this is not essential).

If both the cost of producing the CO2 and the gain for the oil company are deterministic (and thus perfectly predictable), an optimal contract is easy to construct, as no flexibility is needed *ex post*. However, if for instance, the demand for CO2 is variable, economic efficiency requires that the marginal value of CO2 for the oil producer should be equal to the marginal production cost of the power plant. A remedy for obtaining this may be to introduce a pre-determined price for the additional purchase of CO2. It is important to avoid renegotiations of the contract later on, as this may well result in strategic positioning from the agents *ex ante* which will reduce or even eliminate the joint surplus of the project. Below we progressively go through the detail design of optimal contracts in more complex situations.

The problem of insufficient contracts and hold-ups are even more serious if several agents on both sides of the market must be included in order to utilise economies of scale. If one oil company and one power plant operator initiate the project and make irreversible investments, they may end up in a weak bargaining position when bargaining with new agents that want to join their network. Potentially the new agents will secure a substantial surplus. As a result, the initial investors may lose on their investments. Foreseeing this, the investments may not be made in the first place or may be undertaken, but on an inefficiently small scale.

Co-ordination problems may be even more severe because of learning effects. Due to lack of experience with the technology, the 'learning curve' in the CO2 project is likely to be steep. Furthermore, with worker turnover, knowledge and know-how will tend to diffuse quickly to other firms in the industry. Thus, there may be an incentive to wait and hope that other firms will invest first and go through a costly learning process, to then join the project when and if costs fall. As a result, the project will develop too slowly from a social point of view, or alternatively not develop at all (Jovanovic and Lack (1989); Caplin and Leahy (1993)).

One solution to this problem is that all the agents are initially included. However, a relatively large number of agents imply asymmetric cost structures and potentially asymmetric information regarding the profitability of the project. Reaching an agreement between all the involved parties may then prove difficult. In particular, some of the agents will always have an incentive to attempt to free ride on the rest by not paying their share of the up-front expenditure.

With many agents on each side of the market, investments in pipelines have much in common with investments in infrastructure like roads and railroads. For these kinds of investments, co-ordination problems often prove overwhelming, and a separate owner of for example the road, may lead to inefficient pricing and under utilisation of the infrastructure. In which case it may be optimal for the state to organise and to finance part of the project. However, it should also be clear that the existence of potential co-ordination problems does not by any means imply that the project should necessarily be profitable. If the profitability of the project is high, it is likely that the involved agents will also be able to find ways to deal with the problems.

On the other hand, there may be additional reasons as to why government should support a project—namely if the social value of the project exceeds the costs involved. The social value may exceed the private value for several reasons, but most importantly the following two:

1. The social value of reducing CO2-emissions is not matched by an equally large private gain.
2. The Petroleum Revenue Tax.

Ad. 1: The open issue at this point concerns the pricing of CO2. Given that the Kyoto Protocol (KP) is ratified or a Kyoto-like regime emerges, the social value of reduced CO2-emissions may be substantial. However, it is not certain that reducing CO2-emissions will translate into large private gain. This will strongly depend on the policy measures used to combat such emissions. If the government introduces taxes or tradable quotas that reflect the social cost of CO2-emissions, the private and social gains from avoiding emissions will be equal for relatively small volumes. For large emissions (i.e. large enough to influence the tax or credit price), the private value of reducing the emissions will be smaller than the social value even with these policy measures.

With other policy measures, the social and the private value of reducing CO2 emissions will typically not coincide. Often industry emissions are not taxed, or are taxed at a lower rate than CO2-emissions emanating from consumption. If credits are introduced, they are often distributed according to initial emissions or the potential for CO2 reductions, in which case the private gain from investing in CO2-reducing technology prior to the allocation of credits may be low.

If the social value of reducing emissions exceeds the private value, it follows that the social value of the project may well be larger than the private value. Furthermore, as the project potentially may be quite large, the social value of reduced CO2-emissions may well exceed the private value even if "perfect" policy measures like taxes are introduced. Finally, uncertainty about what policy measures the government is going to implement will in itself reduce the private agents' incentives to invest in the project.

It is interesting to observe that the value implicitly attached to reduced CO2-emissions in the green-certificate system in the Norwegian power market probably far exceeds any reasonable forecast on CO2-taxes or emission reduction credits (ERC's). If one takes this implicit price as the social value of reduced CO2-emissions, the difference between the social and the private value of the CO2 project will probably be very large.

Ad. 2: Much of the return on investment in the CO2 project will accrue in the form of increased offshore oil revenues. This revenue is taxed at a rate of 78%. On the other hand, a substantial fraction of the investments will be made onshore, at a tax rate that (in Norway) is much lower at 28%. This will create distortions if the fraction of investments undertaken under the "higher tax regime" is smaller than the fraction of the income from the project that is taxed at the high tax rate. The resulting distortions may be detrimental even for projects with substantial pre-tax returns.

Still, as with co-ordination problems, it should be clear that even if the social value of the project exceeds the private value, this does not imply that the social value has to be positive. If the project is far from being privately profitable, it is not likely to be socially desirable either.

4.3 FLEXIBILITY AND OPTION VALUE

Traditional methods (e.g. NPV) fail to accurately capture the potential value of investments in an environment of widespread uncertainty and rapid change. Flexibility has become a major source of value and options (real options) must be taken into consideration in modern project valuation and risk analysis.

The CO2-infrastructure transportation project includes several different aspects with regards to options. We will first discuss some of these and then provide a very simple example of how to calculate the value of one important option.

4.3.1 The CO2-Infrastructure Project and Options

Potential suppliers of CO2, such as the Danish coal-fired power plants owned by Elsam, produce primarily electricity and district heating into a liberated market that is subject to price fluctuations. At the same time they would like to ensure that their plants maintain a 'base-load' status so that they do not have to cycle overall plant output excessively and reduces operational life. However with emerging wind power—having preferential access to electricity market when available—the coal plant operator is currently having to reduce output on windy days, or alternatively sell electricity at a much reduced market price (sometimes zero!) in order to also satisfy demand from customers purchasing district heating and steam.

A far preferential scenario could be that the power plant operator maintains high availability of the 'base-load' configuration plant with CO2-capture, and converts the excess electricity to hydrogen via electrolysis when electricity prices would otherwise have been forced low. Such a project is currently being evaluated by Danish grid operators and power companies (Sharman *et al.*, 2004). The volumes of hydrogen produced in this manner are not excessive and can initially be spiked back into the NG pipeline infrastructure[26] at periods when gas prices are favourable.

Therefore, we observe, that in practice a power plant operator—in addition to CO2—may want to value a portfolio of products including electricity, steam, hot-water and possibly in the future hydrogen. Clearly the option to optimally switch between different types of production may therefore have value, depending upon relative prices; also not irrelevant in this context, is a need to have 'base-load' capacity in order to provide grid stability when wind power predominates—this too has a value to the grid operator, and 'availability' is currently also a source of income to the power plant operator.

Switching options may also be relevant for other parts of the project. For instance, if future circumstances where to change so that CO2 transportation was to become uneconomic, then the pipeline could have an alternative use by being converted to natural gas. Switching would however involve significant expenditure—and the viability of this alternative use is not clear—but the option does nonetheless alleviate some of the projects future risk exposure to unforeseen events.

The option to defer investment may also have value. By waiting, one can learn about prices, in particular the price of oil, electricity and CO2-credits. If prices develop favourably, the project will be realised—otherwise the project will be rejected.

Related to the option of deferring investment, is also the option to increase the scale of the project. Sometimes it is necessary to start on a small scale in order to be able to extract necessary information about potential revenues. If revenues prove favourable, involvement will increase.

Additional positive effects may be achieved by starting on a small scale if there are significant 'learning curve' effects, for instance in learning more about how to capture the CO2. These 'learning curve' effects may be unique to the parties directly involved in the project, or more general in nature. If learning effects are general, this may be an argument for the government to take an active part in a project start-up.

Alternatively deferred investment may be detrimental for CO2-EOR as oilfields have very critical windows of opportunity when switching from 'secondary' to 'tertiary' phase of oil production. If CO2 is not commercially available at the right time in a fields life then the operator cannot afford the option to wait, and will either have to

[26] To form *hythane*, the concentration of which will not require any modifications to existing NG customers.

plan for decommissioning or initiate alternative techniques like extensive water-flooding and / or hydrocarbon (HC) miscible gas-flooding.

4.3.2 An Example

It is impossible to exploit all the potential options to a full extent. Oil companies will not make the necessary investments unless they are confident that potential suppliers of CO2 will also make the necessary investments. Hence, co-ordination is important, and CO2-suppliers must commit to supplying CO2 even when electricity prices are high.

For simplicity we have chosen to focus on two alternatives: (i) start full-scale implementation immediately and assume delivery of 31 mtCO2/yr on a yearly basis, or (ii) start on a small scale with 2 mtCO2/yr and an option to increase to full-scale after 4 years.

We assume that investment alternative (i) has zero NPV. To determine the value of the option to increase the scale of the project under alternative (ii), we make the following assumptions:

1. The project is started as a pilot study with 2 mtCO2/yr. Because of the relatively small amount of CO2 involved we assume that the gas is transported by ship (implicitly we also assume that no significant learning about transportation through a pipeline occurs). Due to the small-scale the NPV of the pilot study will be negative.
2. After 4 years there is an option to increase to the full-scale 31 mtCO2/yr.

The valuation of the option to increase the scale of the project can be determined by using the Black and Scholes (1973) option pricing model. The input used in the model was based on the following information:

- The full-scale investment costs are $9 million (Markussen *et al.*, 2002).
- The risk-free 4-year (annual) interest rate is 4%.
- The standard deviation of the project revenues is 25% (measured on a yearly basis).
- Time to maturity is 4 years (at which time the full-scale option may be exercised).

Using the Black-Scholes model[27] we can calculate that the value of the option is $1.56 billion. Including the pilot study, the value of the project will be somewhat

[27] The model pricing formula assumes the underlying price follows a geometric Brownian motion with constant volatility. It is historically significant as the original option pricing formula published by Black and Scholes in a landmark paper from 1973. For more information use Google with "Black-Scholes option pricing".

less than $1.56 billion. It must be emphasised however, that the option value depends on the variables used in the model. For instance, a higher standard deviation will increase the value, while a lower standard deviation will decrease value.

What we learn from the above example is that flexibility has value. The NPV of the large-scale project is zero. The pilot study has a negative NPV. However, a pilot study could provide important information about revenues. If the experiences from the pilot study turns out to be positive, the large-scale project should be initiated.

However when assessing the two options one must also include the potential loss in revenue from mature fields due to deferred investment and possible premature decommissioning.

5. OVERVIEW OF NORTH EUROPEAN CO2 SOURCES

The potential for securing CO2 from different sources around the North Sea has been investigated and is presented in this chapter, together with a brief overview regarding status of some relevant technologies for CO2-capture and handling. When available we also discuss details describing costs and technology development.

The purpose of this chapter is not to provide an exhaustive overview, but rather an indication of relative magnitudes and the potential scope for near-term and future gathering of CO2 into a large-scale CO2-transportation infrastructure.

5.1 THE IEA-GHG R&D PROGRAMME WORLD DATA BASE OF CO2 SOURCES

A comprehensive overview of industrial sources of CO2 (throughout the world) was reported by Hendriks *et al.* (2002) as part of work commissioned by the *IEA-GHG R&D Programme*. This data base has been extensively used in the present study to estimate the overall potential for CO2-emissions in Northern Europe through to 2020.

The global database contains over 14,640 entries and has collated information covering reported and estimated CO2-emissions from: power plants, oil refineries, gas processing plants, major industrial sources (e.g. ammonia, hydrogen, ethylene, ethylene oxide, cement, iron & steel plants), as well as other sources. The cumulative world CO2-emission in 2000 from these sources was 13.4 GtCO2/yr when estimated using the IEA-GHG Database.

To predict the likely emissions in 2010 and 2020, emissions at the existing sites were increased based on the expected growth rate for individual sectors; the anticipated reduction of specific energy consumption for each sector was also factored in. Based on the growth projections, global CO2-emissions from all sources were estimated to grow by 36% in 2010 to 18.2 GtCO2/yr, and by 76% to 23.3 GtCO2/yr in 2020.

The database provides information on names and location of sources, as well as details on operation, production and annual emission of CO2. Furthermore, the reliability for the source of information is also assessed and categorised.

For Western Europe (that is the OECD member countries) the database has 2,069 registered sources comprising: ammonia plants (68), cement plants (349), ethylene plants (55), ethylene oxide production (15), gas processing complexes (45), hydrogen production (50), iron & steel works (217), power plants (1,171) and refineries (99).

For the present screening we have focussed on using only the data with good reliability, point source emissions above 50,000 tCO2/yr, and a location (given in longitude and latitude co-ordinates) that ensures a proximity less than 100 km from the North Sea rim.

In the present Study Report we have identified approximately 440 sources around the North Sea rim comprising: ammonia plants (13), cement plants (21), ethylene plants (23), ethylene oxide production (10), gas processing complexes (21), hydrogen production (14), iron & steel works (22), power plants (51) and refineries (18). An indication regarding the location of these sources is also provided in Fig. 4.

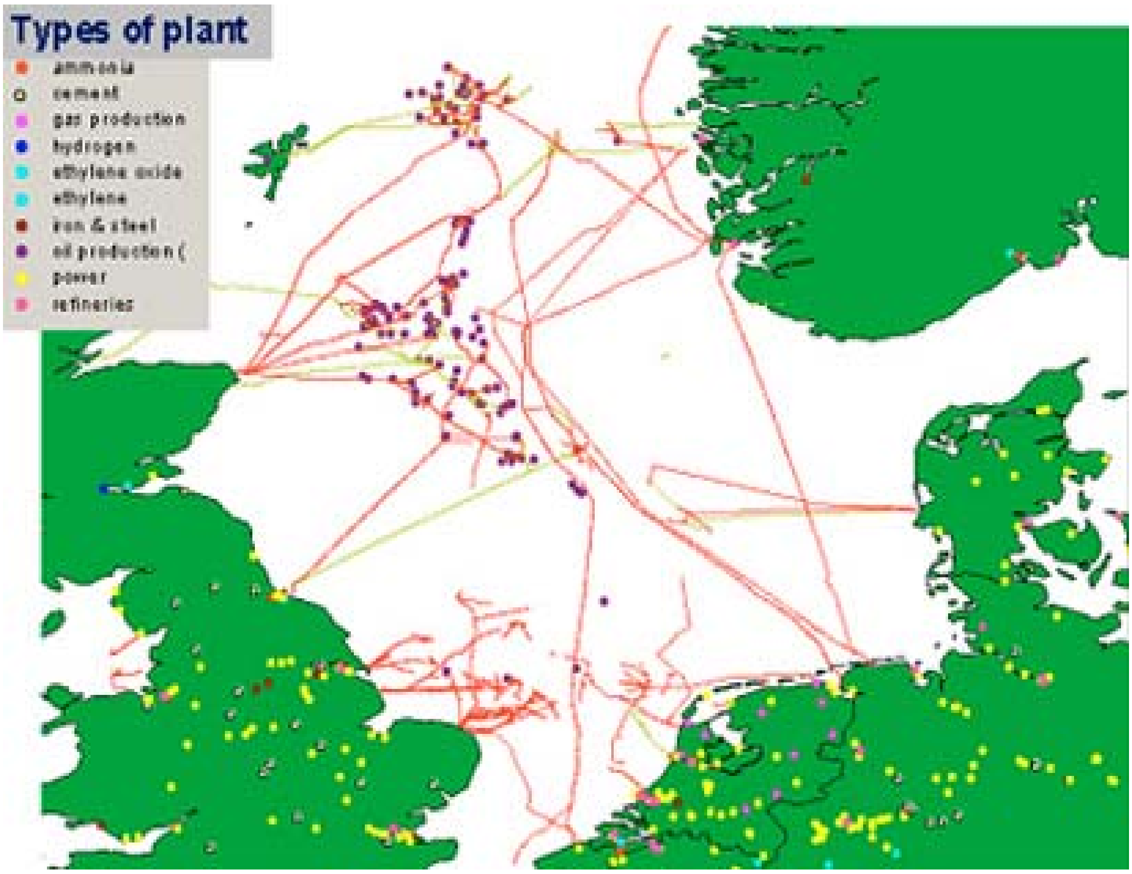

Fig. 4: Location of many larger sources of CO2-emissions around the North Sea Rim area. There are many large point sources that already have concentrated CO2 (> 98%) such as ammonia (red) and hydrogen (blue), and ethylene oxide (light blue) plants. The power plant sources (yellow) are most numerous having 12-14% CO2 concentration with coal firing and 3-4% with NG-fired combined-cycle plants. Cement plants and iron & steel works will usually have between 20-30% concentration of CO2 in their flue gas[28].

The IEA-GHG Database is not comprehensive, but it does represent the most up to date and available information that provides a reasonable indication of present and future potential for the gathering of CO2 from within Northern Europe within the region roughly indicated by Fig. 4.

[28] The concentration of CO2 in the flue gas is an important parameter for how costly it is to remove CO2 from a specific source.

A summary of the results for the North Sea rim is provided in Table 4 where we also for comparison purposes show emissions for the whole of West Europe and Global.

Region	2000 (mtCO2/yr)	2010 (mtCO2/yr)	2020 (mtCO2/yr)
North Sea Rim	360-490[29]	500	470
West Europe (OECD)	1,710	1,980	2,200
Global	13,440	18,200	23,300

Table 4: Table showing estimated emissions of CO2 (in million tonne CO2 per annum) from all industrial sources for years 2000, 2010 and 2020 within the North Sea Rim, West Europe (OECD members) and Global.

The main conclusion to draw from Table 4 is that total emission from around the North Sea rim could lie in the region of ~450 mtCO2/yr. With the emergence of a stricter emission regime within the EU it may also be credible to assume that these emissions could stabilise somewhat, as is also indicated by the prognosis for 2010 and 2020. Furthermore total emissions would appear to be compatible with the size of the proposed CO2-transportation infrastructure considered in this Study Report where we have indicated gathering around 15% of the total potential volume.

5.2 GATHERING CO2 FROM INDUSTRIAL SOURCES

5.2.1 Ammonia and Hydrogen Production

Ammonia plants have up to 98% pure CO2-streams and therefore require no additional CAPEX for CO2 capture. Ammonia production can be subdivided into two main classes[30]: (i) production from steam reforming (worldwide covering about 83% of the production), and (ii) production from partial oxidation (about 17% of the production). Over 80% of the ammonia is used in the production of fertilisers. The remaining is used for various applications like the production of caprolactam, acrylonitrile, aniline, alkanolamines, etc. (Hendriks and Papameletiou, 1997).

There are two CO2-streams that can be identified within ammonia plants: (i) the flue gas stream of the burners, with a CO2 concentration of typically around 8%, and (ii) the pure CO2-stream. Modern plants produce approximately 1.2 tCO2 per ton of ammonia if operating on natural gas or alternatively 2.0 tCO2 per ton of ammonia with heavy oil gasification.

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[29] The spread here represent difference between reported emissions (360 mtCO2/yr) based on reporting through the period 1995-2000 and estimated value based on data from other sources.

Within West Europe ammonia production emits around 14.6 mtCO2/yr, although by 2020 this is estimated to have reduced to 11.7 mtCO2/yr, thereby reflecting a general trend within the industry. In total we estimate there to be roughly 5.6 mtCO2/yr from plants located around the North Sea rim.

Wherever CO2 is not already exported then investments in liquefaction plants and harbour facilities will be required. Ammonia plants are often suppliers of CO2 to the food and drink industry. Such sales can result in a seasonal variation in availability.

Total CAPEX for a 0.5 mtCO2/yr plant handling facility prior to shipping, including production, storing and export of liquid CO2 is estimated to be around €60 million (Kaarstad and Hustad, 2003).

In North Europe there are the following main ammonia plant sites;

(i) ***Norsk Hydro, Porsgrunn, Norway***: At existing production capacity utilisation, the amount of CO2 available for EOR is limited to less than 0.1 mtCO2/yr. Almost all the pure CO2 from this plant is exported for the food and beverage industry. If the plant operates on full capacity it will produce more CO2 (amount needs to be clarified), which can be made available for EOR. More export of CO2 from this plant will probably imply need for extended export facilities and thus extra investment.

(ii) ***Norsk Hydro, Brunsbüttel, near Hamburg***: There are currently no liquefaction plant and no export facilities at the port facilities and the plant is therefore a potential full capacity source with 0.7 mtCO2/yr available. Detailed studies would need to be conducted in order to clarify potential investment costs.

(iii) ***BASF, Ludwigshafen, on the Rhine***: This plant produces approximately 0.7 mtCO2/yr from ammonia. However it is a more awkward site due to its inland location.

(iv) ***Norsk Hydro, Sluiskil, near Terneuzen***: Site is close to the Belgian border. The plant generates approximately 1.7 mtCO2/yr but internal consumption is about 1.0 mtCO2/yr.

(v) ***BASF, Antwerp***: Has nearly 1.1 mt/yr of concentrated CO2 that is based upon ammonia, hydrogen and ethylene oxide facilities, along with 1.5 mtCO2/yr that is low concentration emissions from the ethylene cracker and other sources.

[30] There is also a third class for production from water electrolyses, but this represents less than 1% of the global production.

(vi) ***Ammonia Plants, UK***: The facilities of *Terra Nitrogen*, Severnside has access for ships up to 11,000 tons and 0.34 mtCO2/yr available. Another plant on Teesside has 0.4 mtCO2/yr. The *British Oxygen Company (BOC)* has a second plant on Teeside with 0.17 mtCO2/yr available.

(vii) ***Ammonia Plants, Europe***: In total there are estimated 68 ammonia plants in western Europe of which 13 have been included in the present database.

Ammonia plants also produce hydrogen by steam reforming or partial oxidation (gasification). In these processes, hydrocarbon feed reacts with oxygen at high temperatures to produce a mixture of hydrogen, carbon monoxide, CO2 and methane.

Hydrogen plants fall into two groups depending on the type of CO2-removal system. Plants built since the late 1980's tend to use pressure swing adsorption (PSA) for purification, while older facilities use wet-scrubbing. After separation of hydrogen, the remaining (fuel) stream has typically a 50% CO2-concentration. This fuel is redirected to the reforming section, where it is combusted. The resulting CO2 in the flue gas may be 20% or higher (Fleshman, 2001).

In Europe hydrogen currently represents 6.1 mtCO2/yr and is estimated to grow to 9.3 mtCO2/yr by 2020—this probably reflects a growing need for more industrial hydrogen within the refining sector to supplement higher quality transportation fuel. Within the North Sea rim area we currently estimate hydrogen to have a potential for supplying around 1.7 mtCO2/yr.

5.2.2 Cement Production Plants

Carbon dioxide is produced during cement production by calcination of raw material and by combustion of fuel. The main source of CO2 is production of clinker, the intermediate product from which cement is made. High temperature kilns are used for the calcination reaction where limestone (calcium carbonate) breaks down into clinker (calcium oxide) and CO2. The CO2 emission from clinker amounts to about 0.5 kg of CO2 per kg of clinker.

The second source of CO2 is from fuel combustion. The amount of CO2 emitted during this process is mainly influenced by the technology applied and the type of fuel used; mostly coal and natural gas, but also fuel oil, petroleum, coke and alternative fuels. On average 55-60% of the direct CO2-emissions stems from process emissions and 40-45% from fuel combustion. The concentration of CO2 in the flue gas is relative high and generally in the range 20-30%, depending on fuel type and technology applied (IEA-GHG, 1999). European emissions of CO2 from this sector were 150 mtCO2/yr in 2000, while the global estimate was 935 mtCO2/yr (Hendricks *et al.*, 2002).

The *Norcem Plant*, near Porsgrunn emits close to 1.0 mtCO2/yr. The plant management believes that it may be possible to achieve a CO2 concentration of 25-30% before eventual capture (Haugen, 2003). This plant may be an interesting source of Norwegian CO2 and could therefore be studied in more detail.

5.2.3 Ethylene and Ethylene Oxide Production

The bulk of industrial ethylene is produced in crackers requiring high levels of energy. CO2 emission are caused by combustion of gas oil and / or naphtha resulting in a 10-15% CO2-concentration. A small fraction of these emissions is a pure stream of CO2 (>99%).

In the present Study Report we observe that within the North Sea rim there are 23 specific sources for ethylene production representing emissions of 25.2 mtCO2/yr.

Ethylene oxide is formed by reacting gaseous ethylene and oxygen over a solid catalyst. The main by-products are CO2 and water. The principle use of ethylene oxide is in the manufacture of ethylene glycol and higher alcohol's which find important applications in automotive antifreeze, explosives, cellophane, polyester resins, synthetic fibres and rubbers, and hydraulic fluids. It is also an important intermediate in the manufacture of glycol ether solvents, ethanolamines and non-ionic detergents. The CO2 is currently removed and either vented or used locally.

In the present Study Report we estimate that, within the North Sea rim area, emissions from ethylene oxide production represent a modest 1.0 mtCO2/yr.

5.2.4 Iron & Steel Works

In integrated steelworks iron ore is reduced with coke to form pig iron. This is then further reduced in blast furnaces to produce steel. CO2 emissions result from the combustion of coke and derived gases. In electric arc-furnace steel production, scrap is molten together with cold pig iron. The heat needed to melt the charge is provided by the energy liberated when the arcs are struck between the electrodes and the charge, although additional energy is provided by the combustion of fossil fuels. CO2 emissions result from the combustion of these fuels and carbon in the iron.

Available data from the industry regarding their CO2 emissions is preliminary and varies considerably from plant to plant. Within the database it has been assumed that in steel making there is an emission factor of 0.14 kg CO2 per kg steel.

Estimates of European emissions from this sector for 2000 were 142 mtCO2/yr, reducing to 110 mtCO2/yr by 2020[31]. Within the North Sea rim area we estimated that 33 mtCO2/yr could be available for gathering.

[31] Again reflecting an industry in regional decline. This incidentally makes it very difficult to source such CO2 because the plant operators will be inherently cautious about entering binding agreements to deliver!

5.3 CO2-CAPTURE FROM COAL-FIRED POWER PLANTS

As already made evident from Fig. 4, the largest potential source of CO2 around the North Sea rim is from the power generation sector, and specifically coal-fired power plants. It is estimated that the European power industry emits 1.2 GtCO2/yr from approximately 1,170 identified sources. For the North Sea rim we collated information based upon 51 sites representing 240 mtCO2/yr. A substantial proportion of this is based upon coal combustion.

Coal-fired power plants therefore represent a large and comparatively secure source for CO2 in conjunction with developing a large-scale transportation infrastructure. The reason for this are:

(i) The available volumes from large power plant complexes are compatible with typical CO2-EOR volume requirements of the major North Sea oil reservoirs that are currently in declining production[32].

(ii) Several large power plants are located near the North Sea rim and therefore have a geographical proximity that is comparatively close to the potential CO2-sinks and could readily tie in to the main pipeline infrastructure.

(iii) Emissions from coal power-generation represent about one-third of total European CO2-emissions[33], and will be subject to future GHG-emission restrictions. The industry is therefore proactively seeking alternative solutions in order to substantially reduce its emissions in a cost-effective manner.

(iv) Coal-fired power plants with CO2-capture could represent a secure long-term source of clean fossil power for the European economies.

Inevitably the challenge for the power industry is one of reducing the cost for CO2-capture whilst maintaining plant efficiency and reliability when handling the large volumes of emitted flue gas that need to be treated.

[32] In a preliminary screening performed within the CENS Project in 2001, a portfolio of 13 fields was identified in the UK, Norwegian and Danish sectors. These typically required between 2 to 8 mtCO2/yr for duration varying from 15 to 25 years. The annual CO2 potential of these fields was approximately 30 mtCO2/yr with a total volume of 680 mtCO2 over the project life of 25 years (Markussen *et al.*, 2002).

[33] Furthermore information in the IEA-GHG Database suggests that power generation represents around 70% of EU industrial CO2-emissions.

5.3.1 CO2-Capture Plant Concept & Feasibility Study

Towards the end of 2001 the Danish coal-fired power plant operator Elsam initiated a *"CO2-Capture Plant Concept & Feasibility Study"*. Costs and performance was analysed for a stand-alone post-combustion CO2-capture plant that could be retrofitted (and integrated) alongside one of Elsam's five existing coal-fired power plants.

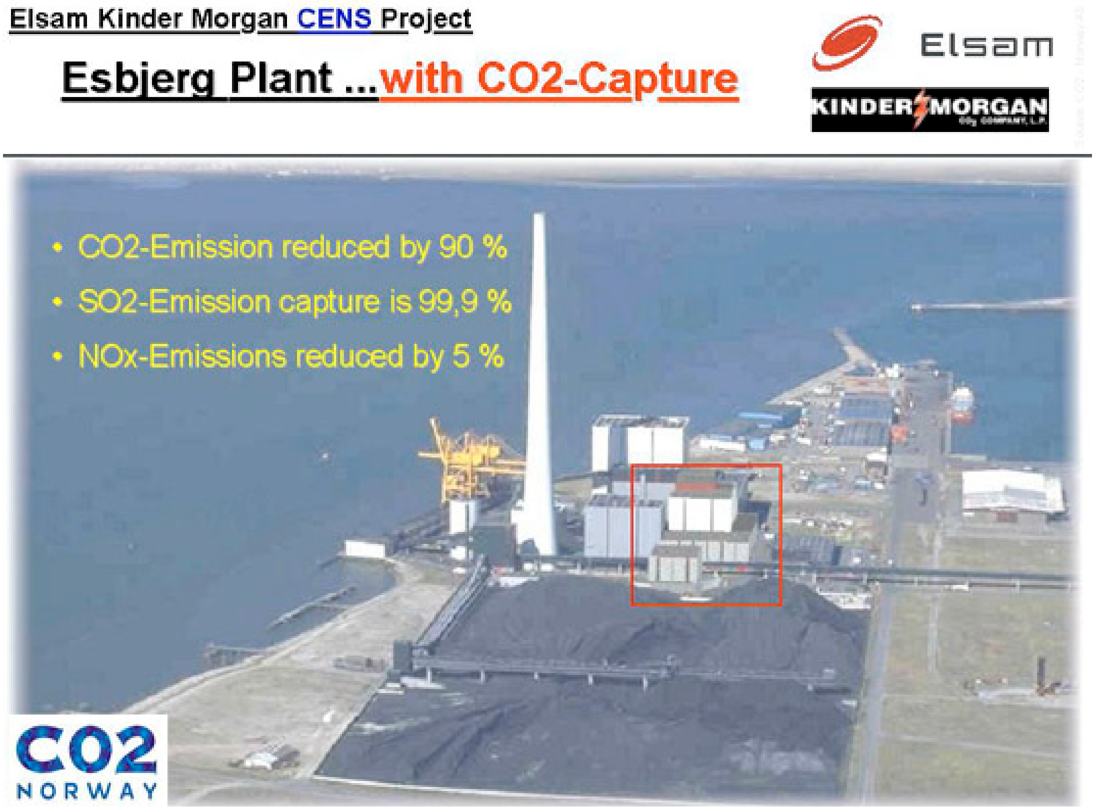


Fig. 5: Aerial view of the Elsam coal-fired power plant Esbjergværket including an artist impression of the CO2-capture plant (within the red square). The smaller building (nearest, on this side of the road) houses the CO2 compressors, while the large (mostly white) building is the amine plant. The grey building immediately adjacent to the left, is the existing plant for Flue Gas Desulphurisation (FGD).

Costs were initially established through an in-depth engineering analysis of the coal-fired combined heat and power plant (CHP) plant at Esbjerg (ESV) on the West Coast of Denmark. The main objectives of the Study were:

- Ensure commercial availability of the CO2-capture technology.
- Assess technology risk with respect to scaling and cost estimation.
- Estimate CAPEX and OPEX costs.
- Identify area requirements and plant layout.
- Integrate and optimise the performance for the Esbjerg plant.

The study confirmed that CO2 could be captured and made ready for delivery at 140 bar with a cost of about $25 /tCO2 at plant perimeter fence[34]. Although the scope, depth and detail of the study was at that time only indicative, it did provide sufficient reassurance for Elsam to continue with further development of the overall concept regarding CO2-capture from their existing coal-fired power plants.

5.3.2 CO2-Capture from Natural Gas v's Coal-Fired Power Plants

The on-going work at Elsam regarding post-combustion CO2-capture technology has also entailed identifying the economic advantages for capturing CO2 from coal-fired power plants compared to Natural Gas Combined Cycle (NGCC) power plant as proposed to be constructed for Norwegian onshore power generation. The main differences here are as follows:

- The CO2 content in the flue gas from coal-fired power plants is 3-4 times more concentrated than that from a NGCC plant. Given plants with equal power export, and assuming an efficiency of 45% for coal-fired and 55% with NGCC (together with 90% and 80% CO2-capture respectively), then it will be possible to aggregate more than twice the volume of CO2 at a coal-fired power plant compared to a NGCC plant. The investment in infrastructure will therefore be higher at a NGCC plant on a CO2-captured per unit basis.
- The higher content of O_2 in the flue gas from a NGCC plant increases the thermal energy necessary for amine regeneration and increases degradation of the solvent, causing higher operation costs per tonne of captured CO2.
- The price of captured CO2 will be the same for a coal-fired power plant and a NGCC plant with a NG to coal price ratio of 1.6. Over the medium term Elsam expects a NG to coal price ratio of 2.5. This means that the price of CO2 from a NGCC plant will inevitably be more expensive than the price of CO2 captured from a coal-fired plant.

Finally it is also worth noting that the cost of CO2-capture from the Danish coal-fired power plants is lower than other estimates for conventional coal-fired power plants. The reason for this can be summarised as follows:

- Ultra clean flue gas with FGD and SCR (for low NOx) is already installed, thereby removing this capital investment from the cost of CO2-capture economics.

[34] Cautionary Note The quoted prices in this section were all made using FY-2001 dollar and electricity rates. Subsequent fluctuations in the currency and electricity prices will inevitably influence the dialogue when negotiating a delivered CO2-price. Furthermore this price will also depend on the required supply profiles, volumes and degree of utilisation of both the CO2-capture plant and the power plant in general.

- Ultra efficient power plants provide steam at 290 bar / 580°C and therefore minimises efficiency drop (see Fig. 6) in conjunction with integration of a CO2-capture plant.
- Integration with district heating also helps reduce and optimise losses with respect to overall plant efficiency.

As shown in Fig. 6 the large energy consumption of the process causes a reduction in electrical efficiency; less electricity is generated from the power plant, however in practice it becomes difficult to define the overall plant efficiency because CO2 is now an important additional commercial by-product.

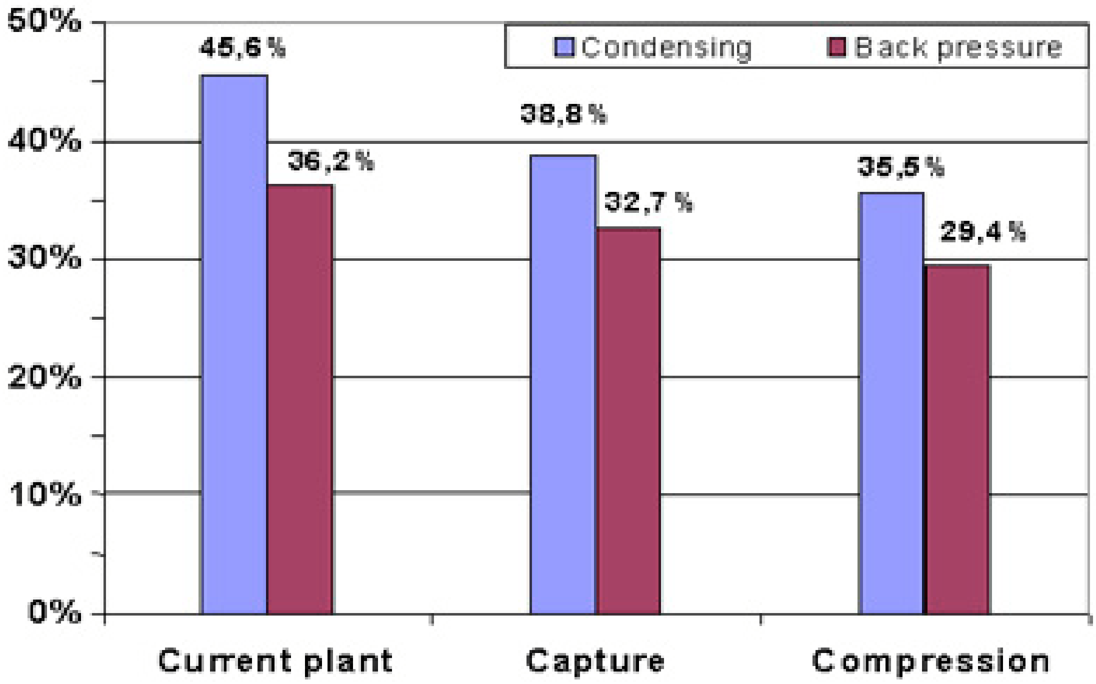


Fig. 6: The Esbjergværket is one of the most efficient power plants in the world at 45.6% electrical efficiency in the Condensing mode. With CO2-capture and compression the electrical efficiency will be reduced by 10.1%-point to 35.5%. Compression of CO2 to 140 bar requires ~27.5 MWe and is equivalent to 3.3%-point. In 'Back Pressure' mode the plant is also providing district heating and the electrical efficiency is reduced by 6.8%-point to 29.4%, but with CO2 as additional by-product.

To optimise operation of coal-fired power plants having CO2-capture, it is important to note that they will need to operate as base load with about 80-90% availability. This is in order to operate economically whilst supplying the CO2 volumes needed by its customers.

5.4 POTENTIAL CO2-SOURCES IN THE UNITED KINGDOM

The United Kingdom[35] has numerous power plants as well as a number of large industrial facilities that generate in excess of 200 mtCO2/yr. Along the North Sea coastline there are already two existing coal-fired plants (Drax and Ratcliffe) totalling over 6,000 MWe of capacity that have necessary FGD equipment installed[36] producing in excess of 20 mtCO2/yr. There are three power plants (West Burton, Cottam and Eggborough) totalling another 6,000 MWe of capacity which have FGD units under construction and are therefore also prime candidates for future CO2-capture.

There are two proposed integrated gasification combined cycle (IGCC) facilities that have received, or are currently obtaining, government permissions to build with the potential of collecting 7.0 mtCO2/yr as part of their pre-combustion processes[37]. Each of these sources have been contacted (Austell, 2003) and have expressed an interest in CO2-capture and storage (CCS).

On Teeside the *Terra Nitrogen* ammonia plant emits 0.4 mtCO2/yr and BOC hydrogen plant emits 0.17 mtCO2/yr. At Grangemouth, Scotland BP have a hydrogen plant emitting ~0.15 mtCO2/yr. In total there is dispersed throughout the UK approximately 1.5 mtCO2/yr in conjunction with ammonia and hydrogen production.

Furthermore the SAGE separation facility in St. Fergus, Scotland is currently stripping 0.7 mtCO2/yr from natural gas.

The UK government has also called for much greater reductions in CO2-emissions in accordance with their own *Royal Commission Report*[38] and the longer-term goals of the UNFCCC. The government has not presently taken any steps to create incentives for CO2-emitters to capture CO2, but they are focusing on the need to support CCS before the very large oilfields are decommissioned and the opportunity for EOR is lost. This was made evident in the recently published *Energy White Paper* (DTI, 2003) which called for an immediate six-month study of the potential for CCS and the need for economic drivers.

[35] An overview of UK activities is available at the DTI web page "Review into the feasibility of CO2 Capture and Storage in the UK" (See http://www.dti.gov.uk/energy/coal/cfft/co2capture/index.shtml).

[36] Flue gas desulphurisation (FGD) for removing SOx, and selective catalytic reduction (SCR) for removing NOx, are pre-requisites for treatment of flue gas in order to also capture CO2 using post-combustion amine scrubbing.

[37] These are being developed by *Progressive Energy Ltd* at Teeside and *Coal Power Ltd* at Hatfield.

[38] This calls for advocating 60% reductions in GHG-emissions by 2050.

5.5 GATHERING CO2 IN THE ANTWERP ROTTERDAM AREA

There are several industrial regions around the North Sea rim that have a considerable potential for gathering larger volumes of dispersed CO2 into a common export hub. An example of this is the Antwerp and Rotterdam Area (ARA) where there are at least four major potential sources of pure CO2;

- in Antwerp at the *BASF / Air Liquide* facilities.
- in Rotterdam at the *Shell Pernis* refinery and the neighbouring *Air Products* facility which both operate hydrogen plants.
- approx. 40 km west of Antwerp at the *Norsk Hydro Sluiskil* ammonia plant.

These industrial sites are within a distance of 80 km or less from each other, and have harbour facilities located at or close to the sites. Additional sites may also be incorporated within a larger gathering system, if onshore CO2 pipelines are included as sketched in Fig. 7.

Fig. 7: Preliminary sketch showing a possible onshore CO2-pipeline gathering system for the Amsterdam and Rotterdam area. The system could collect around 4 mtCO2/yr before further transportation out into the North Sea. In this southern sector of the North Sea there is also an interest for using CO2 for Enhanced Gas Recovery (EGR). (Image is provide courtesy of the CENS Project.)

5.5.1 The Shell Pernis Refinery, Rotterdam

Shell has a 90% ownership in the *Pernis* oil refinery while ***Statoil*** owns the remaining 10%. With a need for additional hydrogen in the refining process, there is a hydrogen plant at the site that produces very pure and dry CO2 which is currently vented to atmosphere. Availability of CO2 from the refinery is approximately 0.5-1.0 mtCO2/yr, however total CO2 production is possibly twice as much, but some of this is currently supplied to the beverage industry (Haugen, 2003).

Shown in the adjacent (inset) image, there is available land within the fence at the refinery to build a CO2 plant for liquefaction and storage prior to export. Port facilities for shipment of CO2 are also available nearby.

Air Products have a neighbouring plant with ~0.33 mtCO2/yr that may be used as an additional source.

Preliminary estimates suggest that total investment costs of a complete plant for production, storing and export of 1.0 mtCO2/yr of liquid CO2 at the Pernis site will cost in the order €100 million (Kaarstad and Hustad, 2003).

5.5.2 BASF Antwerp

BASF and production partners operate 54 different production units in 4 production sectors at their Antwerp facility covering agricultural chemicals, plastics and fibers, finishing products and chemicals and speciality chemicals. The site occupies 600 hectors and is 60% developed. The site has 4,550 meters of quayside and significant space located near both the quayside and the sources of CO2 for CO2-liquefaction, dehydration and storage. Major pipelines carrying natural gas, hydrogen and oxygen enter and leave the site so that there are existing rights of way for possible future CO2-pipelines.

There are three main sources of nearly pure CO2 on the BASF site. The ammonia plant produces 0.70 mtCO2/yr of 98% pure CO2. The ethylene oxide plant produces 0.15 mtCO2/yr of 90% pure CO2. Finally ***Air Liquide*** is completing a new hydrogen plant on the site that will produce 0.24 mtCO2/yr of 98% pure CO2, yielding a total from the site of 1.09 mtCO2/yr.

In addition to this, the ethylene cracker produces a stream of flue gas containing 10% CO2 totalling 1.5 mtCO2/yr that could be captured in the future using the same amine technology that Elsam is proposing in Denmark.

5.5.3 Norsk Hydro Ammonia Plant, Sluiskil

The ammonia plant in Sluiskil is approximately 40 km in a straight line from Antwerp and about 80 km in a straight line from Rotterdam near the town of Terneuzen. The site has approximately 0.7 mtCO2/yr of excess production, but the available amount, is only in the order of 50,000 tCO2/yr (*Source: Hydro Agri*). The remainder is currently sold as liquid, food-grade CO2 exported by ship from Sluiskil as shown in Fig. 8.

*Fig. 8: Three of the CO2-ships owned by **Hydro Gases and Chemical** shown in port. Each has two CO2-tanks with total capacity between 900-1200 tCO2 for each ship. Maximum speed is 12 knot.*

As CO2-liquefaction is already taking place in Sluiskil, there is probably little or no need for additional investments in production or storage capacity. Harbour facilities are expected to be good with necessary loading facilities available.

5.5.4 Additional Sources in the Antwerp and Rotterdam Area

There is also *Dow Chemical* at Terneuzen who operate a large ethylene cracker: *BASF* and *Fina* in Antwerp operates a small cracker. *Air Liquide* in addition to the new hydrogen plant at the BASF site, also operates a hydrogen infrastructure with connecting pipelines and production facilities to Terneuzen, Bergen-op-Zoom and Rozenburg all in the Netherlands, and extending as far as Dunkerque, France—all with access to coastal facilities. Also in the same vicinity is a hydrogen plant in connection with the *Total* refinery in Vlissingen. Finally the possibility for gathering the CO2 from inland riverside (Rhine) sources could also be investigated further.

5.6 NORWEGIAN INDUSTRIAL SOURCES FOR CO2

5.6.1 Kårstø Industrial Complex, Rogaland

The Kårstø complex north of Stavanger has a key role in the transport and treatment of gas and condensate (light oil) from important areas of the NCS.

Kårstø receives gas from Statoil's Åsgard development, and other fields in the Norwegian Sea, through the *Åsgard Transport Trunkline*. A new facility at the complex to process these supplies into sales gas started operation in Oct 2000. Processing facilities at the complex separate natural gas liquids from rich gas arriving by pipeline. These NGLs are then split into propane, butanes and naphtha. Propane is stored in two large rock caverns with a combined capacity of 90,000 tonnes. Total on-site[39] emissions where approximately 700 mtCO2/yr in 2001 (SFT, 2004).

In addition to the *Statpipe / Norpipe* system to Emden, lean gas from Kårstø is sent today through the *Europipe-II Trunkline* to Dornum on the German coast. (See also inset map reproduced in section 5.6.6 on page 63.)

Kårstø could be of interest as a potential CO2-hub on the West Coast of Norway for the following reasons:

- In addition to currently emitting about 1.2 mtCO2/yr from gas turbines and boilers, CO2-rich natural gas comes in through the *Åsgard Transport* from the Norwegian Sea fields of Åsgard and Kristin (starting 2005). The so-called *Craier* CO2 is extracted from the ethane distillation at Kårstø as an “azeotrope” (a mixture of liquids that boils at a constant temperature, at a given pressure, without change of composition) between CO2 and ethane. The volume of CO2 in this mixture is presently about 0.13 mtCO2/yr, but will be increasing as the Kristin field comes on stream.
- Kårstø is a possible hub for CO2-ships coming in from places like Antwerp, Rotterdam, Brunsbüttel and Melkøya with unloading into an intermediate storage and later pipeline transport to the Tampen area.

[39] This does not include CO2 transported to Kårstø from offshore activities.

5.6.2 Mongstad Refinery and Industrial Complex, nr. Bergen

The oil refinery at Mongstad near Bergen in western Norway is a modern, highly-upgraded facility with an annual capacity of 10 million tonnes of products including petrol, diesel oil, aviation fuel and other light petroleum products. The facility belongs to ***Mongstad Refining AS***, which is in turn owned 79% by Statoil and 21% by Shell. It is the largest refinery in Norway, and is medium-sized in a European context.

Fig. 9: Mongstad refinery is at present the single largest emission site for CO2 in Norway. In 2006 it will emit ~1.7 mtCO2/yr. Also, Mongstad Energiverk is proposing a 240 MWe (320 MWth) combined heat and power (CHP) plant (see insert) so that total CO2 emitted from the refinery and the CHP plant may then be 2.3 mtCO2/yr.

Export facilities at Mongstad make this Norway's largest port in tonnage terms, and the second-largest oil port in Europe after Rotterdam. It is also in close proximity to some of the mature offshore oil reservoirs in the Tampen area to the west.

5.6.3 The Energy Park, Risavika, Stavanger

The Energy Park ("Energiparken") is located on the old site for the Shell Sola refinery. The site has been completely refurbished and in Feb 2004 *Lyse Gass*, a subsidiary of ***Lyse Energi AS***, initiated first delivery of NG through a dedicated pipeline from Kårstø and running south across the Boknefjord to supply the Stavanger region.

Fig. 10: Aerial image of the Shell refinery site at Risavika taken during refurbishment of the site around 2002. The Energy Park will be located in the quadrant to lower left of the image. The NG pipeline from Kårstø is brought onshore adjacent to the small harbour on the left of the image.

Lyse have already indicated an interest to construct a new 750 MW NGCC power plant at the Energy Park and are also promoting a zero-emission demonstration power plant with CO2-capture and handling, that is part of the ZENG Program[40]. Potentially if a CO2-infrastructure is made available and commercial technology for CO2-capture evolves, then the region could supply an estimated 1-2 mtCO2/yr after 2010.

[40] The *Zero Emission Norwegian Gas (ZENG) Program* is a joint development between ***Lyse Energi AS*** and ***CO2-Norway AS***. The program is evaluating construction of a 40 MWe Pilot & Demonstration zero-emission power plant at the Energy Park, with support from the *Research Council of Norway* under their *Klimatek Program* (see www.co2.no for further details). The plant will be based on the oxygen-fuel combustion technology that has been developed and tested by *Clean Energy Systems Inc.*, Sacramento, Ca. This development work is presently also funded by the *California Energy Commission* and *U.S. Department of Energy*.

5.6.4 Tjeldbergodden, Aure Kommune

Tjeldbergodden is a major industrial complex in Aure kommune on the West Coast south of Trondheim. It is the landing point for NG through Haltenpipe from the gas fields in the southern part of the Norwegian Sea. The complex currently comprises; (i) gas receiving terminal, (ii) a major methanol plant covering ~13% of production for West Europe, (iii) air separation unit (ASU) providing oxygen, nitrogen and argon for the regional market, and (iv) an LNG plant covering regional truck distribution of natural gas.

In Feb 2004 Statoil, the main site owner, indicated an intention to invest between NOK 3.7-5 billion to expand the facilities with a new methanol production plant integrated into an 800 MWe NGCC power plant. Potentially, if realised, Tjeldberg-odden could in the future emit > 4 mtCO_2/yr and become a major source for Norwegian CO_2.

5.6.5 Snøhvit LNG Plant, Melkøya, Hammerfest

The ***Snøhvit Project*** will become Europe's first export facility for liquefied natural gas (LNG). Natural gas will be produced through sub-sea facilities at a water depth of 250-345 meters 140 kilometres out in the Barents Sea.

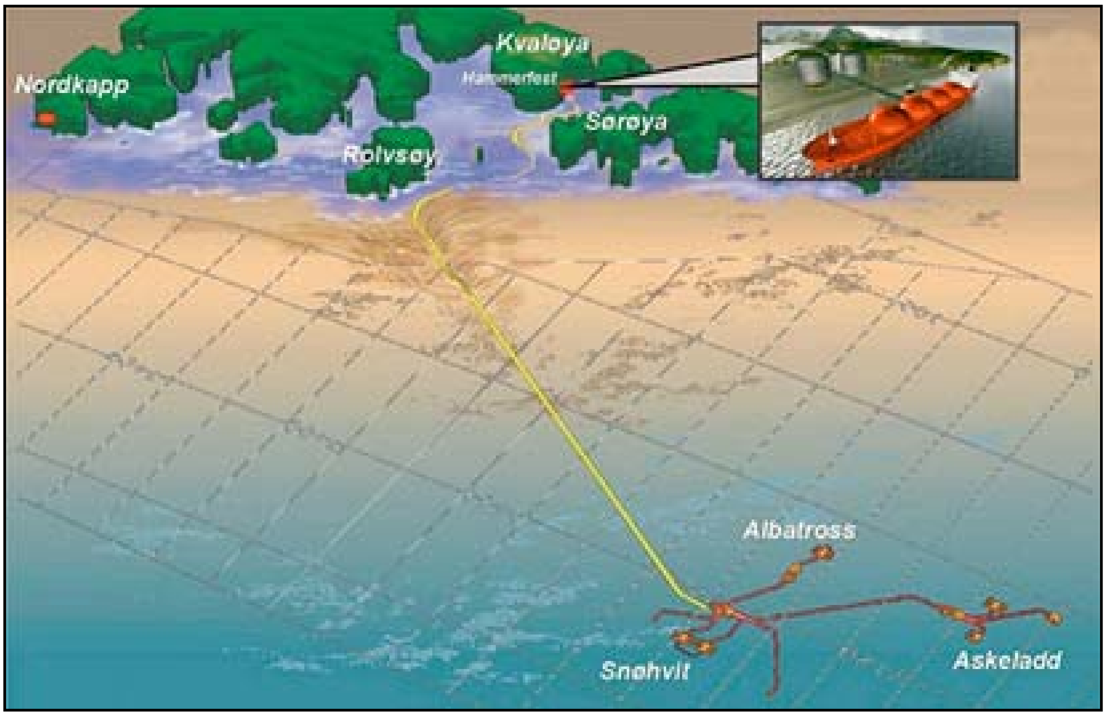


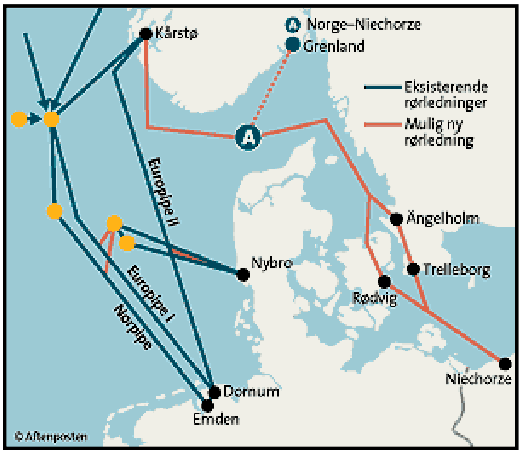
Fig. 11: Illustration showing the Snøhvit, Albatross and Askeladden sub-sea development and the multiphase pipeline to the LNG plant on Melkøya outside the town of Hammerfest. Not shown is the return pipeline for 0.7 mtCO_2/yr from the LNG plant to Snøhvit for injection in a separate well.

The recoverable reserves are 190 billion cubic metres NG, 113 million barrels of condensate (light oil) and 5 million tonnes of natural gas liquids (NGL). The produced NG will be transported in a 140 km multiphase pipeline to an LNG plant on Melkøya just outside of the town of Hammerfest. The annual export of LNG will be 5.7 billion cubic metres or 4.1 million tonnes. Construction started in 2002 with contractual gas deliveries scheduled for Oct 2005. Total investments will be NOK 45 billion plus the cost of ships to transport the LNG to customers in USA, Spain and Portugal.

The NG from the Snøhvit field contains CO2 that will be removed to a very low level at the LNG plant. It is currently envisaged that about 0.7 mtCO2/yr extracted in this way will be returned through a CO2-pipeline for injection in a dedicated well to an aquifer reservoir under the Snøhvit gas field. A further 0.9 mtCO2/yr will be emitted to atmosphere from five gas turbines for power generation and compression. Potentially these 1.6 mtCO2/yr could be transported by ship and be available for CO2-EOR delivery by 2008-10.

5.6.6 Grenland, Herøya and Porsgrunn Area, Telemark

The Grenland Area constitutes a major industrial complex on the East Coast of southern Norway with approximately 100,000 industrial jobs. Main sources for CO2 emissions are: Norcem cement works, Brevik; Norsk Hydro ammonia plant, Herøya; Noretyl ethylene plant, Rafnes where production is planned to increase by 50% from the current level of 650,000 tonne/year. Petroleum raw products are predominantly transported by ship from Kårstø.



There are extensive efforts on-going to promote investment in the *Austerled Trunkline*, which is a proposed pipeline (marked in red on adjacent map), thereby securing a NG infrastructure into the region. The pipeline would eventually transport gas from Kårstø to Niechorze, Poland. And could also be instrumental in providing additional supplies to East Denmark and South Sweden. Although this project is still subject to economic and political assessment in all countries concerned, it does represent a genuine opportunity for Sweden to switch from nuclear power to gas, and for Poland to reduce CO2-emissions and its dependence on NG from Russia when fuel-switching from coal.

However, even without *Austerled*, there remain considerable efforts in the Grenland Area to develop existing industrial complexes and gather a potential 1-2 mtCO2/yr.

5.7 OFFSHORE CO2-SOURCES

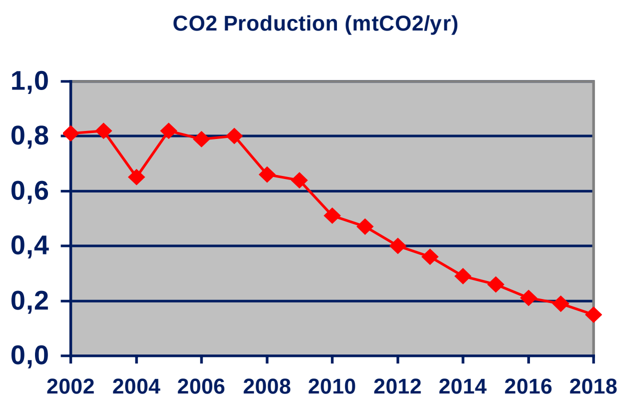
The offshore sector is responsible for a total 12.4 mtCO2/yr in 2002 and represents 30% of total Norwegian CO2-emissions in that year (SFT, 2004). Main source is single-cycle gas turbines (ranging in size from 5-40 MW power output) covering power requirements and compression on the platforms.

5.7.1 The Sleipner CO2

The Sleipner field is located midway between Stavanger and Peterhead, Scotland about 240 kilometres from shore in approximately 80-110 meters water depth. The first platform, the gravity base concrete *Sleipner-A* shown adjacent (on right of image) was installed on the field in 1993.

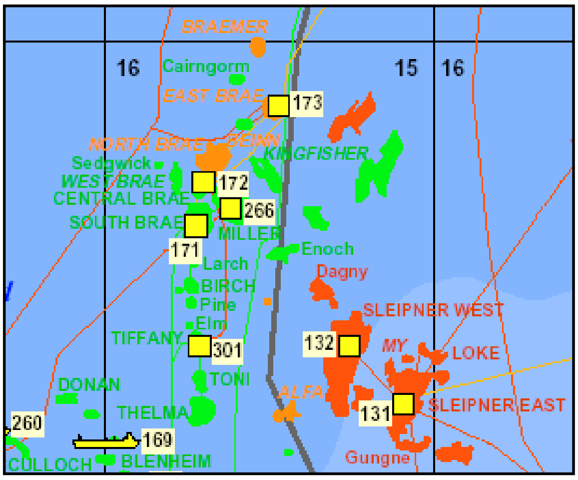
Sleipner-T (Treatment) was installed in 1996 and is a smaller steel platform containing the worlds first offshore CO2-removal plant. Here close to 1.0 mtCO2/yr is removed from the 7-9% CO2-rich natural gas from the *Sleipner West* platform located 12.5 kilometres from the other Sleipner platforms. The CO2 is being compressed (but not dried of water) to just over supercritical pressure on *Sleipner-T*, transported over the bridge to *Sleipner-A* and injected in a dedicated well to the *Utsira* saline aquifer formation 1,000 meters below the sea bed.

Sleipner has long been viewed as a potential source of already concentrated CO2 for any CO2-EOR project. As shown in the adjacent graph the CO2 production starts to decline rapidly from about 0.8 mtCO2/yr in 2007 to a level of about 0.15 mtCO2/yr by 2018. It has therefore been tentatively concluded that the Sleipner CO2 is of marginal interest as a CO2 source for EOR, however it does represent a potential 5-7 mtCO2 that could be available through until 2018+.



5.7.2 Associated Gas at Brae

Typical of some of the fields on the North Sea Continental Shelf (NSCS), there are also two potential sources of CO2 gas associated with the Brae fields operated by



Marathon. The first is the nearly 0.75 mtCO2/yr removed from Brae and Beryl gas at the *SAGE Facility* at St. Fergus, Scotland. This nearly pure CO2-stream is emitted from the amine capture system and would need to be dried and compressed. The second source of Brae CO2 is on the West Brae platform amounting to another 0.75 mtCO2/yr, however this is currently injected into the East Brae formation along with other associated gas to maintain the pressure in East Brae. This gas as well as the gas currently going to St. Fergus could be stripped of CO2 on the West Brae platform in order to make more space available in the SAGE line for gas export.

Transportation of the SAGE CO2 could be handled by future ship, a future new line from Scotland to carry CO2 from other sources as well, or possibly through the reversal of the Miller Pipe from the Miller field to Peterhead near St. Fergus. BP, who controls this line, has stated that they would prefer to see this line used as a natural gas line, but in the absence of available gas to Peterhead, they are considering the reversal of this line for CO2 transport.

As in the Sleipner case above, the CO2 available from Brae will be on a decline in the coming years, but there is sufficient CO2 available to contemplate this as a future source while other larger and more longer term sources can be brought on line.

5.7.3 Offshore Platform Power Generation

The offshore sector has been growing steadily in importance in the Norwegian greenhouse gas budget. Today about 30% of the total Norwegian CO2-emissions comes from the offshore sector.

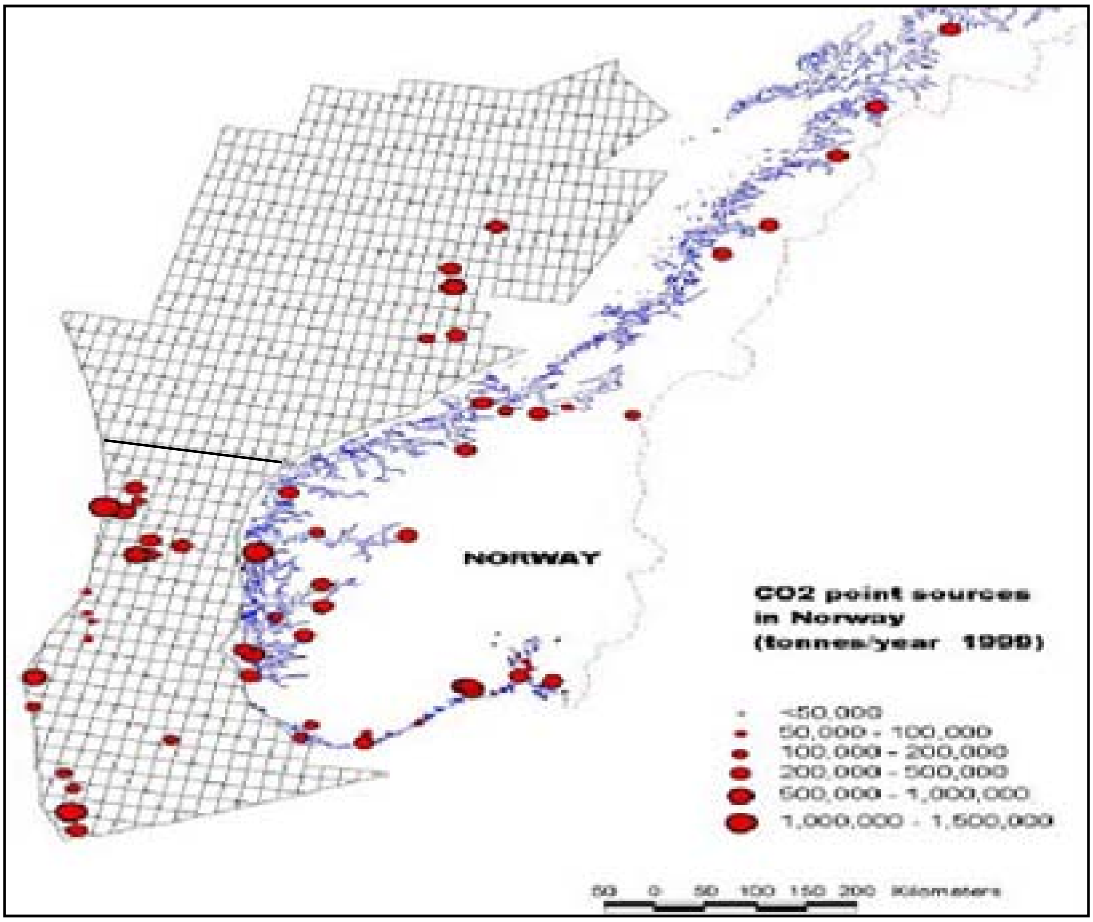


Fig. 12: Map of CO2 point sources in Norway, with the location of both onshore and offshore sources shown. Total Norwegian emissions in 2002 where 40.9 mtCO2/yr with 12.4 mtCO2/yr offshore. Of these 9.5 mtCO2/yr was from the mature regions south of the 62º latitude (solid black line drawn approximately half way between Bergen and Trondheim). The remaining 2.9 mtCO2/yr of emissions where north of the line in the newer areas of the Norwegian Sea.

A number of studies have over the years been conducted to see if CO2 could be removed from Norwegian offshore gas turbines. The main motivation for this being the existence of an offshore tax on CO2 since 1991 varying between NOK 300 and close to NOK 400 /tCO2 (equivalent to $40-53 /tCO2). The studies, which have included both post- and pre-combustion technologies, have all so far concluded that offshore CO2-removal is much more costly than can be defended by the CO2-tax.

In the future these specific costs will inevitably reduce and the potential for gathering CO2 from platforms would also be improved if a main pipeline infrastructure were to be available.

6. A TECHNO-ECONOMIC MODEL FOR CO2 STORAGE

In this Chapter we summarise work describing modelling of a large-scale storage scenario where CO2 is used both for enhanced oil recovery (EOR) in 18 reservoirs on the Norwegian Continental Shelf (NCS) and excess CO2 is deposited in an unspecified number of aquifers.

The project lifetime in the selected scenario is 40 years where 67.2 mtCO2/year is deposited. In the early phases of the scenario most of the CO2 is injected into the oil reservoirs, but throughout the period more and more CO2 is injected into aquifers in order to have a constant deposition rate throughout the project period.

A limited set of sensitivity analysis have been made for the scenario where the oil price, the cost of CO2 for EOR, investment and running costs, injection rates and total lifetime of the project have been varied. For the various cases studied in the sensitivity analysis, the potential for incremental oil production varies between 335 and 403 million Sm^3. This is equivalent to between 7.9 and 9.5% of the original hydrocarbon pore volume.

The value of the delivered CO2 is determined by the NPV of the EOR projects, which therefore, in combination with the cost for transportation, determines the initial purchase price of the CO2 from sources (e.g. the power industry and industrial complexes in northern Europe). For the cases studied the price varies between US$7.90 and US$12.90 per tonne CO2.

6.1 THE CO2 PIPELINE INFRASTRUCTURE

Fig. 13 shows a map over the North Sea with the major CO2 pipelines for a proposed scenario drawn in. The infrastructure consists of the main pipeline from Emden to the Ekofisk area and continuing further on to the Statfjord field within the Tampen area. A feed line allowing transport of smaller amounts of CO2 from Kårstø to the main pipeline between Ekofisk and Statfjord is also included. The lengths for the various parts of the pipeline infrastructure are summarised in Table 5.

Emden is here envisaged as a juncture where CO2 from various point sources in North and Central Europe can be collected in an export terminal. It is assumed that dry compressed CO2 in a dense state (minimum pressure 60 bar, maximum temperature 20°C) is delivered to Emden. A similar, but smaller, export terminal is placed at Kårstø that receives CO2 with the same specifications.

The main component in Emden and at Kårstø is compressor plants where CO_2 is compressed to the desired export pressures (200, 250 or 300 bar) and further cooled to 20°C before being transferred into the export pipelines.

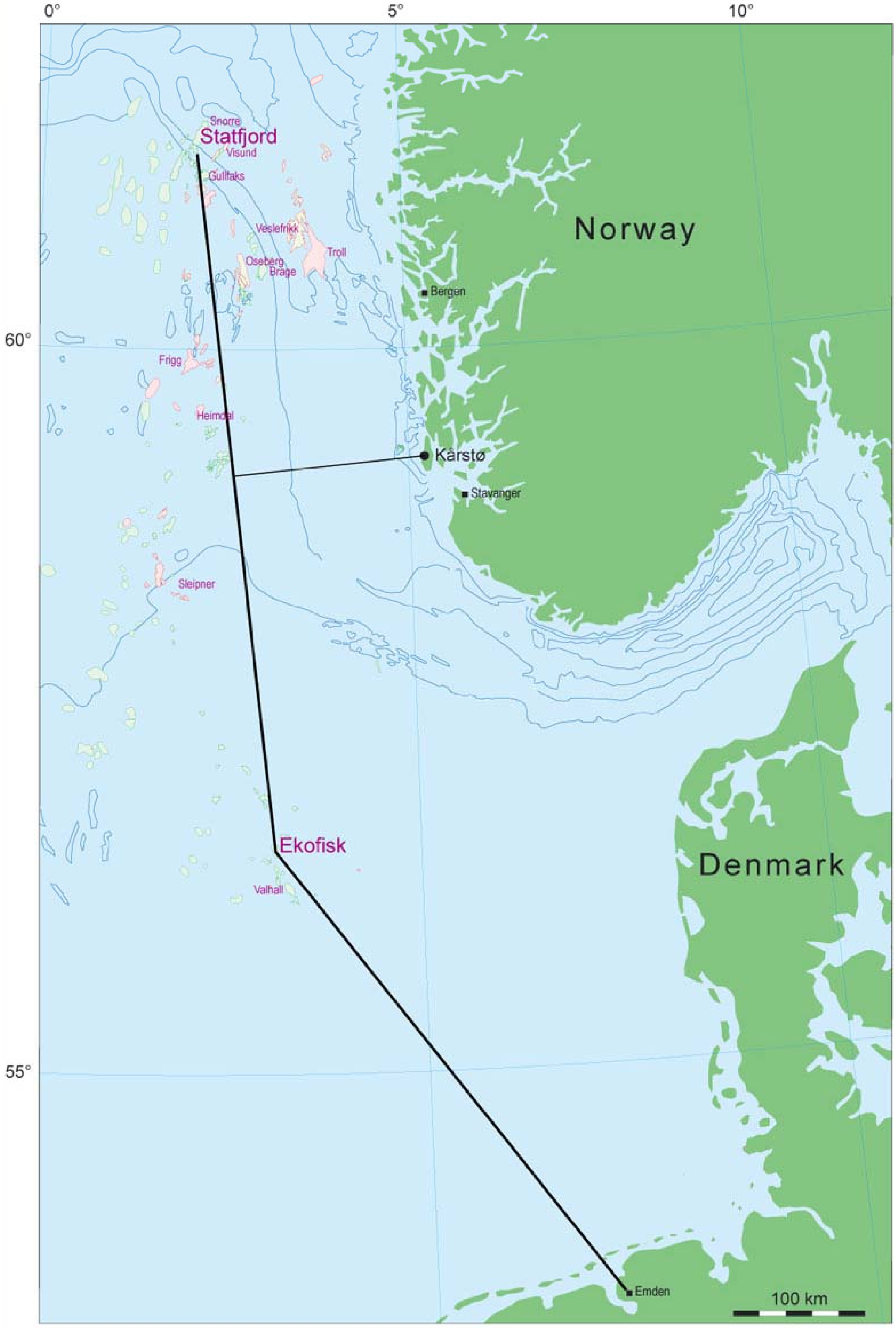


Fig. 13: Map showing main CO2-infrastructure pipeline from Emden to Tampen.

The main pipeline will be fitted with draw-off branch points along the line to allow CO2 to be delivered to the reservoirs and storage sites of interest situated to minimise the transportation distances to the various sites.

Pipeline section	Length (km)
Emden - Ekofisk	440
Ekofisk - Statfjord	550
Kårstø to main pipeline	203

Table 5: Lengths of the main pipeline sections in a proposed CO2-Infrastructure transportation system.

A module for the transportation costs of CO2 in the described infrastructure has been developed based on techno-economic data as described in detail by Holt and Olivier (2003). The maximum transport capacity of the main pipeline is 80 mtCO2/yr. The maximum draw-off in the Ekofisk area is 40 mtCO2/yr and maximum export from Kårstø is 5 mtCO2/yr. Minimum delivery pressure of CO2 in the oil provinces was set to 100 bar. Furthermore we have used the following key parameters:

- Economic lifetime for the pipeline infrastructure is 40 years.
- Interest rate for capital investments is 7%.
- Energy costs is assumed as $0.05 /kWh (approx. NOK 0.35 /kWh).
- Compressor operational costs are 5% of CAPEX per year.
- Pipeline OPEX is 1% of CAPEX per year.

Fig. 14 shows calculated transportation costs for CO2 as function of capacity and amount of CO2 draw-off at Ekofisk. When CO2 is delivered both to the Ekofisk and Statfjord areas the transportation costs are average costs. The model also calculates specific costs for CO2 delivered to the two regions. This option may be used if a CO2-storage scenario is constructed where constant amounts of CO2 are drawn off in the two regions.

For most of the calculations shown in the figure, CO2 is only delivered from Emden. If CO2 is also delivered from Kårstø the transportation costs increases somewhat. For a total capacity of 80 mtCO2/yr and delivery to Tampen only, the transportation costs increases with $0.074 /tCO2 or $5.9 million/yr if 3 million tonnes/yr is exported from Kårstø.

The costs for CO2 transport by ship has also been estimated based on CO2 from a source near Hamburg delivered to the field Oseberg Øst. The transport capacity for the ship was 20,000 m^3 (approximately 23,000 tCO2) with a transport capacity of ~1.3 mtCO2/yr.

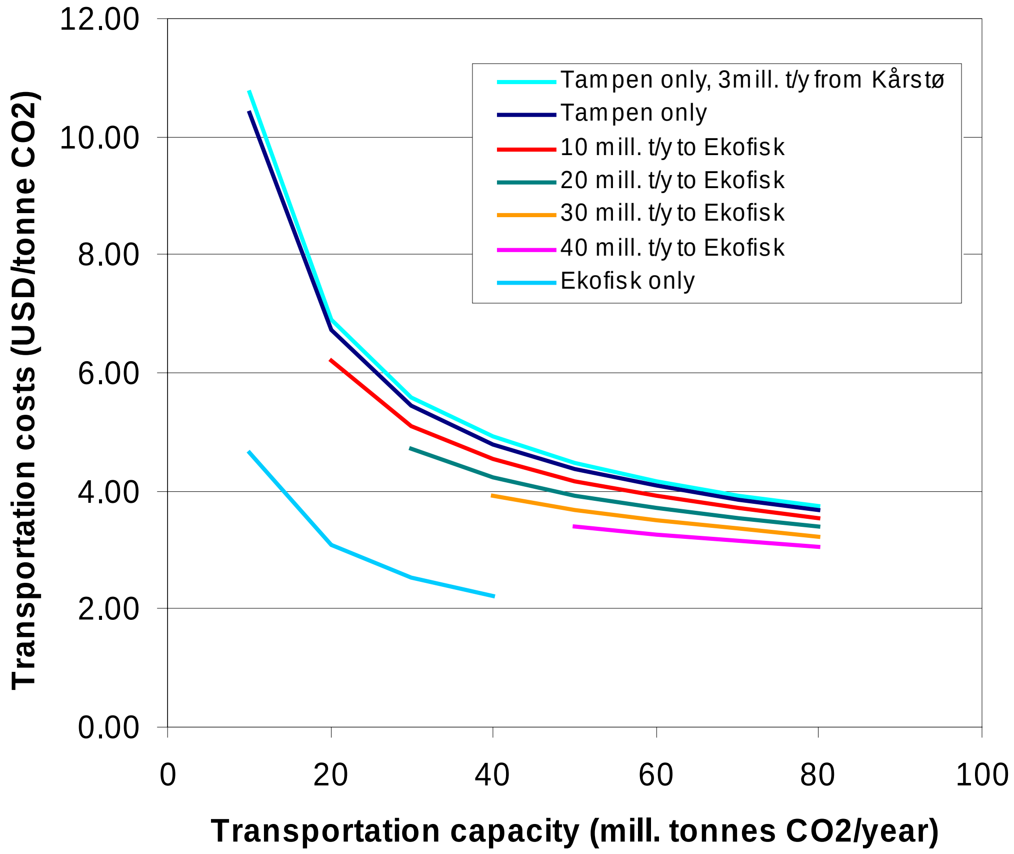


Fig. 14: Comparison of pipeline transportation costs with variation of total volume of CO2.

The transportation cost was estimated to $23.60 /tCO2 which includes costs for cooling and compression of CO2 for ship transport. The ship transportation cost alone was $13 /tCO2. The costs for ship transport may be reduced by building larger and less expensive ships, but it would seems difficult to compete with the costs of pipeline transport in large volumes of CO2 over comparatively short distances.

6.2 THE EOR-MODULE

The background for the development of the EOR-module was to make a simple model for the estimation of the additional oil recovery expected due to CO2 injection into water-flooded reservoirs, as a function of the reservoir state. This model can be used to estimate the EOR potential for all fields in the North Sea, and identify the fields that are most suited for a tertiary CO2 process.

The approach taken was to define a generic sandstone reservoir, with realistic heterogeneity, and use a reservoir simulator to predict the performance of water injection followed by miscible CO2-injection. This was done for different injection rates, length of water-flooding before gas injection, oil density, oil viscosity, vertical permeability, and rock heterogeneity. Subsequently explicit functions of the same variables were fitted to the simulation results, to calculate production profiles of oil, water, and gas, as well as the time before water and gas breakthrough.

The model can be applied in the analysis of real fields that have been water-flooded. Values for a set of dimensionless groups are calculated for the real field. In order to use the model, the values should be within the range used in the simulation study. A dimensionless average water-injection rate and realistic values for oil properties should be used. Input parameters to the model should be chosen so that the dimensionless groups in the model have the same values as in the real field. The observed water breakthrough times can be used to establish suitable effective reservoir communication parameters (vertical permeability and heterogeneity). Then the model can be used for prediction of the response of CO2-injection.

The simulation model used was based on the stochastically generated model used in the *10th SPE Comparative Study* (SPE, 2001). The original 60x220x85 cell model contained 35 layers representing a shallow marine Tarbert-like formation, and 50 layers representing a fluvial Ness-like formation. In this work, the Tarbert-like part of the reservoir model was used.

The simulations were performed with *Geoquests Eclipse 100* reservoir simulator. The 60x22x35 cell original model was coarsened, using *Pseudo* to generate up-scaled permeability and porosity values on an 8x28x9 grid. The model was given a tilt of 6° (on average) in the length direction. In addition, a random variation was added to the top of the reservoir, in order to create bumps and valleys that could focus the flow of segregated gas. The model size was enlarged a factor 2.16 in order to allow a 1000 metre well distance. The shape of the reservoir and the distribution of porosity are illustrated in Fig. 15.

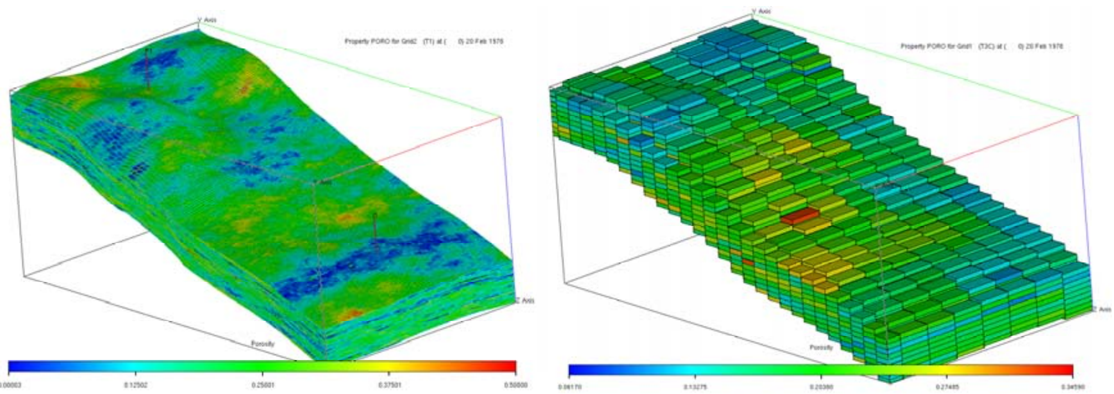


Fig. 15: Original and Coarse Tarbert-like Model.

By use of the reservoir model simulations of CO2 injection after water-flooding had been performed for variations in relevant input parameters. The parameters used in the sensitivity study are shown in Table 6.

The simulations were run for 2.5 pore volumes (PV) injected volume. This implies that the three times for the start of gas injection correspond to early start, late start, and water injection only. A total of 216 simulations were run. Vassenden and Wessel-Berg (2003) provide more details regarding development of the EOR-module together with additional results.

Prior to curve fitting, the injected volume was expressed in units of the real pore volume (PV) at reservoir conditions. The production was expressed in units of the initial hydrocarbon pore volume (HCPV) at surface conditions. Also water and gas production volumes were normalised by HCPV.

Property	**Legend Code**	**Values**		
Injection rate, PV/year	R	0.008	0.024	0.072
Time for start gas-injection, PV water injected	G	0.5	1.5	2.5
Stock tank oil density, kg/m^3	D	599	963	
Oil viscosity factor	M	1.0	0.3	
Heterogeneity exponent	H	0.66	1.0	1.5
Factor k_z	V	1.0	1000	

Table 6: Model and process parameters used in the sensitivity study. (Legend Codes are used in the figure legend.)

For each simulation, curves were fitted to each of the oil, water, and gas production profiles. The fit-functions had nine curve-shape parameters: water breakthrough time, gas breakthrough time, four parameters to describe the curve-shape during water displacement, and three for the gas displacement. The fit functions were different for the three phases. The functional dependencies are:

$$V_o = F_o^{WI}(PV_{inj}\left|\vec{P}_o^{\,w}(q_{inj},\rho_o,\mu_o,\alpha,k_z)\right.) + F_o^{GI}(PV_{inj}\left|\vec{P}_o^{\,g}(PV_s,q_{inj},\rho_o,\mu_o,\alpha,k_z)\right.)$$

$$V_w = F_w^{WI}(PV_{inj}\left|\vec{P}_w^{\,w}(q_{inj},\rho_o,\mu_o,\alpha,k_z)\right.) + F_w^{GI}(PV_{inj}\left|\vec{P}_w^{\,g}(PV_s,q_{inj},\rho_o,\mu_o,\alpha,k_z)\right.)$$

$$V_g = F_g^{WI}(PV_{inj}\left|\vec{P}_g^{\,w}(q_{inj},\rho_o,\mu_o,\alpha,k_z)\right.) + F_g^{GI}(PV_{inj}\left|\vec{P}_g^{\,g}(PV_s,q_{inj},\rho_o,\mu_o,\alpha,k_z)\right.)$$

Here, PV_{inj} is the total injected number of pore volumes, including both water and gas. The volumes are functions of one variable, PV_{inj}. The symbols after the vertical bar are curve-shape parameters. The parameters describing curve-shape are described as a vector that includes PV_{wbt} and PV_{gbt} (water and gas breakthrough times, respectively) and other parameters, including the following input variables;

- Process variables: q_{inj} is the injection rate of both phases, and PV_s is the starting time of gas injection (expressed as how many pore volumes of water were injected before CO2 was injected).
- Fluid parameters: ρ_o and μ_o are the oil density and viscosity, respectively.
- Geological parameters: The heterogeneity parameter α and the vertical permeability multiplier k_z .

The functions describing cumulative production have two terms, one describing the response to water injection (WI), and the other showing the additional response to gas injection (GI).

The sensitivity of production profiles to the different input variables listed in Table 6 is described by the functional form of the curve-shape parameters as functions of the input variables. Either, the functional dependency was a linear dependence in all variables with optional cross-terms, or it was specified as a function of other curve-shape parameters, depending on which method gave the smallest deviation with fewest parameters; 71 constants were employed to match the oil production for 216 simulations. Furthermore 50 additional constants were required to match the water production. The gas production was matched by a modification of the oil fit function, using the same parameter values as the oil fit function. The model thus involves 121 constants to describe the oil, water, and gas production as a function of time for the 216 simulations.

A first estimate of the constants in the functional relationships was obtained by fitting to the observed curve-shape parameters. Then, the constants were adjusted to minimise the total square sum of deviations between simulated and model production profiles, for all simulation runs simultaneously.

Fig. 16 presents some selected production curves. The seven curves illustrate the effect of each of the input variables. The effect of increasing rate is seen from the difference between the black and marine curves—the lowest rate has higher recovery in water-flooding due to the stronger influence of gravity. Two different start times for gas injection are illustrated in the marine and blue curves (trivial effect). The effect of oil gravity is seen when the blue and black dashed curves are compared—the curves are almost overlapping because the comparison was done at high rates where viscous forces are dominating.

The change from the dashed curve to the green shows the effect having a factor of 0.3 smaller oil viscosity—the water-flood is significantly more effective due to the improved mobility ratio, but the effect on the gas injection is small. From green to ochre, the heterogeneity increases, and this is seen to reduce the oil production both in the water-flood and in the gas-flood.

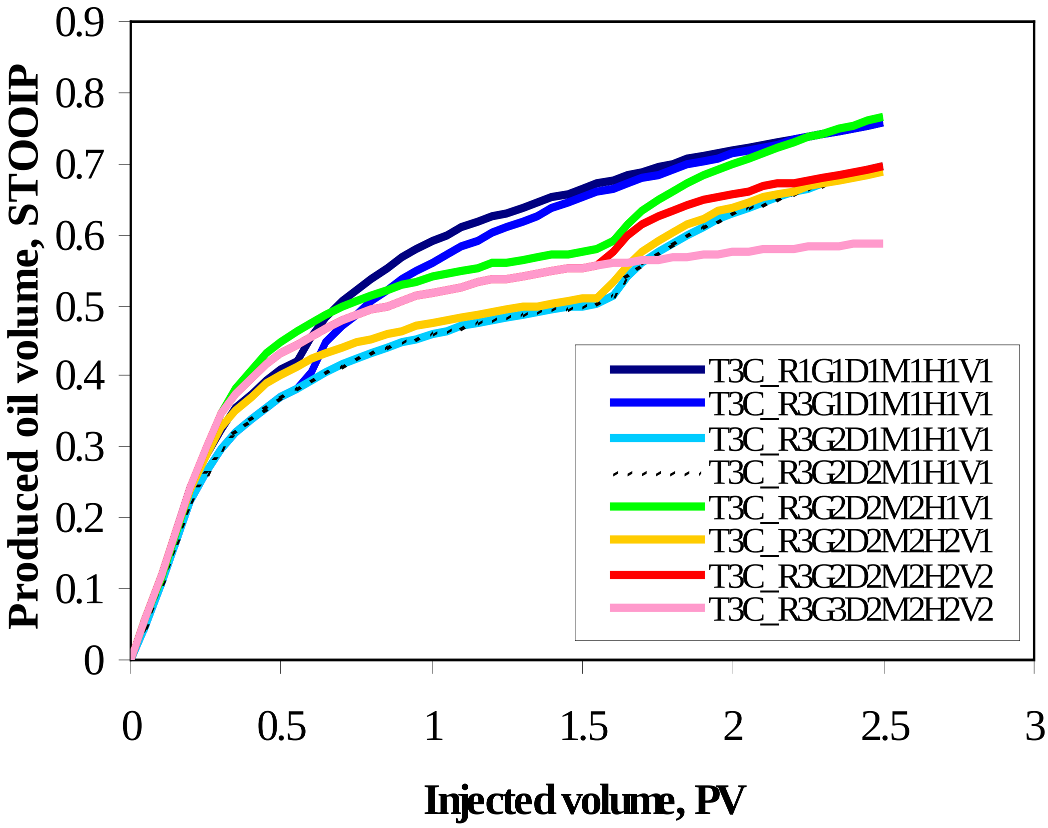


Fig. 16: Simulated production curves for selected parameter combinations. The curve legend code refers to the data entry number for each data type shown in Table 6.

From ochre to red, the vertical permeability was increased one thousand fold. This improves the water-flood, but reduces the efficiency of the gas-flood. At first sight one may think that increased vertical permeability would increase segregation to the bottom of the reservoir, and thus reduce the efficiency. However, the high-rate flood is already viscous dominated, and the segregation effect is determined by the fact that viscous cross-flow stabilises the displacement front. The water from a leading water finger in a high permeability layer will leak off to the neighbouring low permeability layers, and enhance the flooding of the low permeability layers at the cost of the high permeability layers.

From red to pink, the start of the gas injection has been delayed, and the pink curve illustrates the water-only displacement.

The features of the EOR-module are further described below using the Brage field as an example. Fig. 17 shows yearly rates of produced oil, incremental oil due to CO2-injection, water and gas and real production rates for oil (taken from the database of

Norwegian Petroleum Directorate and published in their fact pages for Norwegian oilfields that are available at www.npd.no).

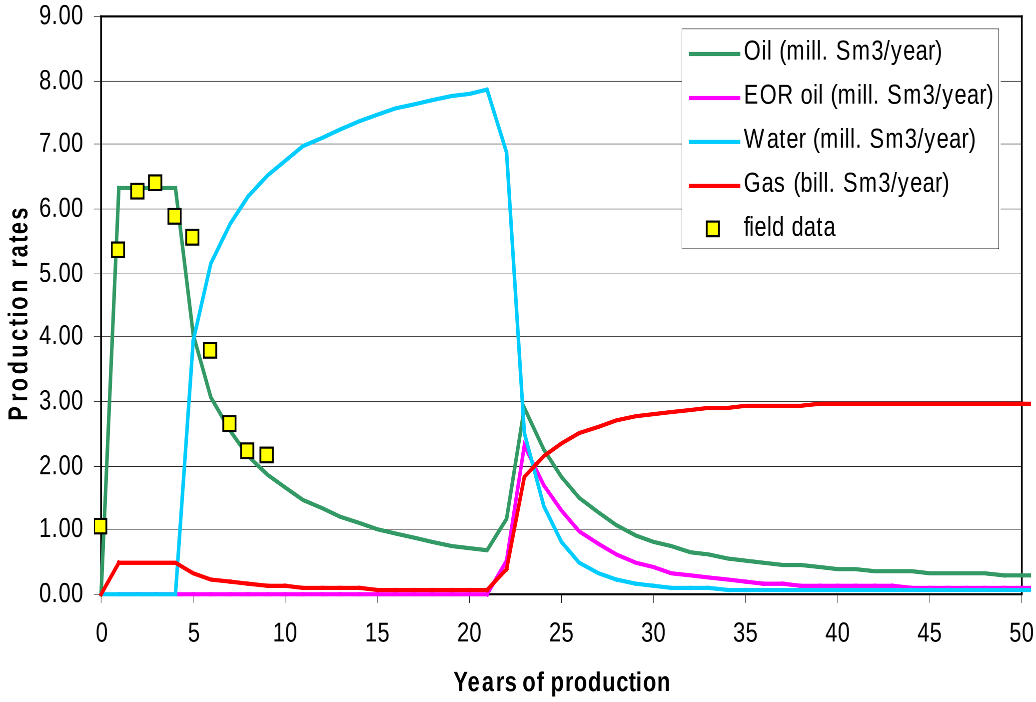


Fig. 17: Production profiles for the Brage field.

The oil production from the field started in 1989 and in this example CO2-injection commences in 2010 (that is following 21 years of water injection). The modelled production profiles have been tuned to the field data by using the k_z factor and heterogeneity factor that have been introduced for tuning. An injection rate of 4.6 mtCO2/yr is used as input to the model. This gives a plateau rate of 6.3 million Sm^3 oil/year. The EOR-module requires a constant injection rate for both fluids during field lifetime.

As seen from Fig. 17, for this example the incremental oil production and CO2 breakthrough occurs the same year as CO2-injection started. Water production also started to decrease the same year and subsequently declines rapidly; indicating that much of the water injected before CO2-injection starts actually remains in the reservoir. If CO2 had been injected as alternating with water (WAG) then water production would have continued with a higher rate. WAG-injection is often used in conjunction with CO2-injection projects both in order to improve the sweep, by reducing the CO2 mobility, and to reduce the amount of CO2 required for injection. If the objective of the CO2-injection project is both to improve the oil recovery and to store CO2 in the reservoir, continuous CO2-injection may be the preferred method. In planning a specific project both injection schemes must be considered. The present EOR-module allows only for continuous injection.

The amount of water that is produced after CO2-injection starts will depend on the relative permeability of the rock material in the reservoir; this may vary between fields but such variations cannot be studied by the present model. The water production profile as shown in Fig. 17 nevertheless illustrates an important feature of a continuous CO2-injection process as the rate declines rapidly throughout the flood. Compared to a continuous water injection, for a CO2-WAG problems with high water-cuts are reduced. This may offer significant advantages as the cost of water treatment may be reduced and the environmental load from discharges to the sea will be minimised.

6.3 THE TECHNO-ECONOMIC MODEL

This model integrates the EOR-module described in section 6.2 above with economic quantities that enables calculations of cost and incomes related to both CO2-EOR and aquifer storage projects.

The model is a spreadsheet-based tool and consists of a main field sheet where all relevant information regarding the oil reservoirs that are going to be included in a specific scenario are defined. From the information in the main field sheet, specific field sheets calculates the EOR profiles for each reservoir or field as shown by the example in Fig. 17.

Economic quantities related to each CO2-injection project to be studied in a scenario are calculated in an economy sheet. Here starting time for the water and CO2 injections are entered, while investment and running costs for each project are calculated based on the CO2-injection rates defined in the field sheet. Economic parameters for each project are transferred to each of the specific field sheets. On these sheets project economics are calculated based on incremental oil profiles, investment costs (CAPEX), running costs and costs for CO2.

In the present version of the model it is assumed that all reproduced gas is re-circulated, and the amount of imported CO2 therefore reduces over time. The cost for CO2-transportation is entered in the economy sheet based on the capacity of the main CO2-infrastructure.

The investment costs for a CO2 incremental oil project are calculated based on costing of the following elements:

- tapping point for CO2 on the main transport line.
- branch CO2 pipeline to the field.
- riser.
- modification of oil production process.
- CO2 compressors.
- injection gas drying plant.

- injection wells.

Most of the listed costs are capacity dependent, and the compressor costs are also dependent on the wellhead pressure. The running costs consist of the following:

- CO2 costs.
- running and maintenance of the process equipment.
- energy costs.

For each project the project economy expressed as yearly cash flow is calculated and the accumulated discounted net cash flow is found. The project stops the last year with positive cash flow, and main figures are transferred to the economy sheet where they are summed for the given scenario.

On a scenario sheet profiles for incremental oil production and CO2 stored in the oil reservoirs for the given scenario are calculated. This sheet also finds a profile for CO2 to be stored in aquifers since a constant delivery of CO2 is transported through the infrastructure over the lifetime of the scenario. Necessary investment costs and running costs for aquifer storage are calculated in the scenario sheet. A purchase price for CO2, which is the price the suppliers of CO2 can obtain for the CO2 fed into the pipeline infrastructure (assuming constant rate during the project lifetime), is also calculated in the scenario sheet.

More details regarding the techno-economic model is given by Holt and Lindeberg (2003).

6.4 A CO2-STORAGE SCENARIO

By use of the techno-economic model developed it is possible to construct specific scenarios for CO2-injection into the oil reservoirs and aquifer storage within the NCS. In order to determine optimal scenarios with respect to economic parameters (e.g. NPV), the fields that yield the highest recovery of incremental oil and show the best project economy should be identified. Furthermore, the start times for injection into the various fields need to be phased in a manner that allows as much as possible of the transported CO2 to be used for EOR in order to minimise the volume of CO2 that needs to be deposited in aquifers.

As most of the fields in the North Sea are in a mature state with decline in oil production (cf. Fig. 3), the time windows for start of EOR projects are likely to be narrow—this issue has not been specifically addressed in present evaluation. With this background a “Base Case” scenario is presented below where CO2-injection is started in most of the sandstone fields included in the Study Report during the period 2010-2015[41].

CO2-injection into the chalk reservoirs is somewhat delayed, however. Although the giant chalk reservoirs are among the fields with the longest production histories, the resource outtake and relative production rates of these fields (Ekofisk and Valhall) are low.

Field	Start of Production	Start CO2-injection
Snorre	1992	2012
Brage	1989	2010
Gullfaks	1986	2010
Statfjord Brent	1979	2010
Statfjord Nord	1995	2010
Statfjord Øst	1995	2010
Vigdis	1997	2015
Tordis	1995	2015
Sygna	2000	2012
Snorre B	2000	2020
Veslefrikk	1990	2012
Oseberg Sør	2000	2015
Oseberg Øst	1999	2015
Balder	1999	2015
Gyda	1990	2010
Ula	1986	2012
Ekofisk	1988	2016-2023
Valhall	1982	2017

Table 7: Start of oil production and of CO2-injection for fields included in the Study Report "Base Case" scenario.

The production histories of the chalk fields are different from most of the sandstone reservoirs as no, or only limited, volumes of water has been injected. The EOR-module assumes that water has been injected prior to CO2-injection, and this gives added uncertainty to the calculations made by the module for these fields. For some sandstone fields HC-gas has been injected in addition to water. Fields undergoing

[41] Year 2010 is here considered to be the earliest possible starting point.

massive gas injection (e.g. Oseberg, Grane, Visund, and the Statfjord reservoir on Statfjord) have not been included in the scenario, but other fields with more limited gas injection are included.

The fields included in the present scenario are summarised in Table 7 that also includes the year for start of oil production and the proposed year for start of CO2-injection.

For the Ekofisk field water injection started in 1988. Prior to this the field was produced by pressure depletion. In the modelling of these fields the start of oil production was set to 1988. In the EOR-module the original oil in place (OOIP) for these reservoirs was reduced with the amounts of oil produced up to 1988.

Reservoir pressure is important with respect to the volume of CO2 that is injected and stored, and for the displacement efficiency of injected CO2. For the EOR modelling in the present scenario, reservoir pressures published by Mathiassen (2003) have been used. Furthermore, no sensitivity analyses with respect to reservoir pressures have been made in the present work. It is assumed that all fields give oil recoveries as for miscible processes. Variations in reservoir pressure will also change the CO2 density that can influence the displacement efficiency. Many of the fields are presently below original reservoir pressure and can possibly be re-pressurised.

6.4.1 CO2-Storage Profiles for Base Case Scenario

CO2-storage profiles for the fields included in the Base Case scenario are shown in Fig. 18. The total injection rate of CO2 in the first project year (2010) is 67.2 mtCO2/yr. A CO2-transport infrastructure for this capacity is therefore used, and it can be seen from the figure that the full capacity is only utilised the first year. Since the suppliers of this amount of CO2 are dependent on a continuous delivery, this amount is assumed delivered throughout the project period (set to 40 years). Excess amounts of CO2 that is not used in oil production must therefore be injected into aquifers. The amount for aquifer injection is also shown in Fig. 18.

In the model CO2-injection for oil production will continue as long as the net cash flow for each injection project is positive. The profiles in Fig. 18 are determined for a set of economic parameters as shown in Table 8.

Costs for compressors and the gas drying plants are not entry parameters for the model, but they are implicitly included in the economic model based on injected volumes and wellhead pressures. These costs can only be changed through the offshore factor.

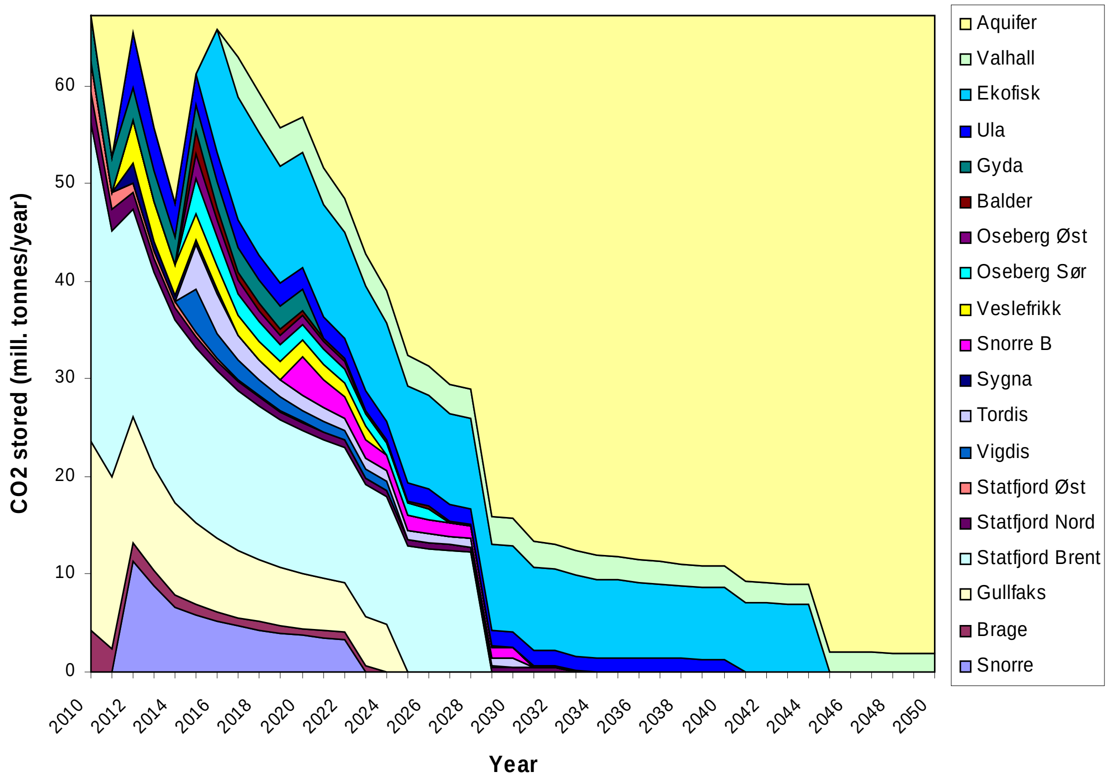


Fig. 18: CO2-storage profiles for "Base Case" scenario.

The cost for transportation of CO2 was calculated using the CO2-transportation module with a total capacity of 67.2 mtCO2/yr, where all the CO2 is exported from Emden at 200 bar export pressure. The same transportation costs for all fields have been used in these examples, for simplicity, although the off-take of CO2 varies with time between the Ekofisk region and other regions. Furthermore, specific sites for aquifer storage have not been evaluated as these are considered to be abundantly available.

On the assumption of an approximately zero NPV for the sum of all the fields included, then the CO2-transportation cost of $12.80 /tCO2 has been calculated using the present scenario. With this value for CO2, some of the projects exhibit a positive NPV while other fields experience a negative.

Fig. 18 shows incremental oil production profiles for all fields included in this scenario. Total performance of the project with respect to oil production, incremental oil production, CO2 stored in the oil reservoirs, total investment costs, total running costs (operation, maintenance and energy), and the sum of the NPV of all the fields, is summarised in Table 9.

Economic Parameters	Value	Unit
Well cost	7.5	million $/well
Modification of oil production system	400	$/ (bbl/day)
Engineering costs	25	% equipment costs
Contingency costs	25	% equipment costs
Offshore factor	2	
Running and maintenance	5	% equipment costs
Energy compressor	0.07	$/kWh
Discount rate	10	%
Oil price	24.00	$/bbl
CO2 cost	12.80	$/tCO2
CO2 transport cost, Tampen	3.90	$/tCO2
CO2 transport cost, Ekofisk	3.90	$/tCO2

Table 8: Economic parameters used and calculated in the techno-economic model.

The total incremental oil production is reproduced in Fig. 19 and is equal to 335 million Sm^3 which comes in addition to the oil that would have been recovered if the fields had continued to be produced with water injection only.

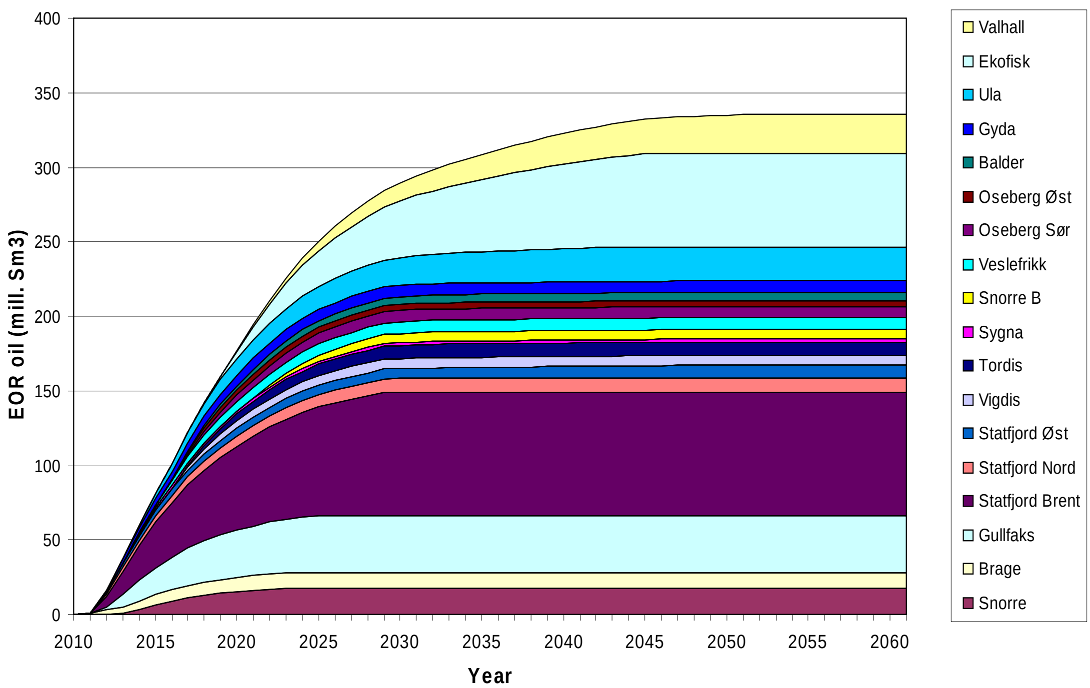


Fig. 19: Profiles for incremental oil production in the “Base Case” scenario.

With a 17.6 year average project lifetime, the total incremental oil recovered corresponds to an average oil production of 328,000 bbl/day for 17.6 years.

Total Oil Produced	2,270	million Sm^3
Oil Recovery Factor	53.7%	% HCPV
EOR oil	335	million Sm^3
EOR oil as % of OOIP	7.9%	% HCPV
Stored CO2	1,153	mtCO2
Total CAPEX	10.40	$billion
Annual OPEX	490.0	$million /year
Project NPV (~ 0)	-29.6	$million

Table 9: Summary of the "Base Case" scenario project performance.

It is observed in Table 9 that that the average oil recovery factor from the reservoirs is 53.7% of OOIP while the incremental oil recovery is on average 7.9% of OOIP.

6.4.2 Aquifer Injection of Excess CO2 and the Value of CO2

The excess CO2 shown in Fig. 18 must be disposed of by injection into aquifers. In the present work the specific sites for such injection have not been considered. However in order to find the value of CO2 at the export terminals the cost of transportation and injection of the excess CO2 has been estimated by a simplified analysis that is described below.

The excess CO2 is transported through the main pipeline infrastructure at the same cost as for the CO2 used for EOR. At the injection sites the CO2 is compressed from 60 to 100 bar and injected through wells with an assumed capacity of 5 mtCO2/yr. In the calculations it is also presumed that new injection wells and 3 MW compressor modules are installed depending on the need for capacity as defined by the aquifer injection profile (cf. Fig. 18). A one-year lead-time is assumed for all new investments. The cost of the compressor modules and wells, as well as the running (including energy) and maintenance costs are then calculated as for other process equipment.

In order to determine a value for all the CO2 that is delivered from the CO2-sources, it is assumed that an independent commercial entity purchases all the CO2 from the industrial sources delivered to the export terminals (i.e. Emden in this specific scenario). Parts of the CO2 are sold to the field operators that cover the transport costs for these amounts. For the amounts to be deposited in aquifers the unit has to cover the transportation costs, necessary investment costs for equipment, as well as running and maintenance costs.

The main economic items of the CO2 aquifer storage project are summarised in Table 10. The accumulated discounted net cash flow for the storage project is shown in Fig. 20. The purchase price of CO2 has been adjusted to give a zero net present value. The starting time is 2010. All the CO2 is injected into the oil reservoirs this year. Since the first investments in wells and compressor modules are made the same year, but the net cash flow is positive due to large incomes from sales of CO2.

Item	**Unit \ Price**	**Amount \ Duration**
Sale of CO2 to oil producers	$12.80 /tCO2	c.f. profile in Fig. 18
Purchase of CO2	$7.90 /tCO2	67.2 mtCO2/yr
CO2 transportation cost	$3.90 /tCO2	
Well cost	$7.5 mill. each	Total of 14 wells
3 MW compressor module	$35 mill. each	Total of 5 modules
OPEX	5% of CAPEX	
Energy costs	$0.05 /kWh	

Table 10: Summary of major economic factors for the Aquifer Storage Project. Duration is 40 years and discount rate is 10% with assumption of zero NPV.

The accumulated discounted net cash flow development for the aquifer storage project is very different compared to a CO2-EOR project.

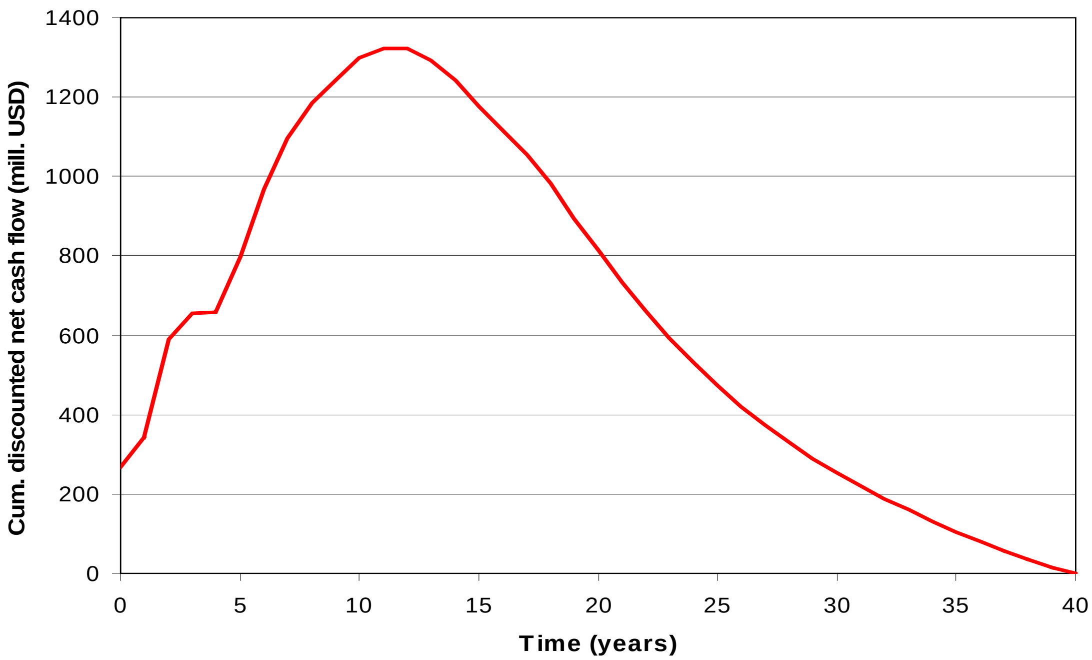


Fig. 20: Accumulated discounted cash flow for lifetime of the CO2 Aquifer Storage Project.

For aquifer storage only the net cash flow is positive the first 12 years, and for this reason it could appear optimal to end the project at this time. However, in the integrated system of CO2-sources, a CO2-transportation infrastructure, oil reservoirs and aquifers, the total project time has been set to 40 year in the present scenario.

6.4.3 Sensitivity Analysis

A limited set of sensitivities of the key figures for the total CO2 EOR / aquifer storage project has been made by varying the oil price, the cost of CO2 delivered to the oilfields, the investment costs, production rate from the chalk fields and lifetime of the project. The various cases are summarised in Table 11, and the results are presented in Table 12 through to Table 14.

Case No.	Description of Case Parameters for Sensitivity Analysis
1	"Base Case" with oil @ $24 /bbl and CO2 @ $12.80 /tCO2
2	Oil price increased to $28 /bbl but same CO2 cost
3	Oil price as in 2, but the cost for CO2 increased for zero NPV
4	Oil price and CO2 as in 2, increased injection into chalk reservoirs.
5	Oil price and rates as in 4, but with reduced CAPEX
6	Oil price @ $35 /bbl, increased CO2 cost, increased injection rates
7	Increased oil price and CO2 cost, 30 years project time and incr. rates

Table 11: Variation of parameters in the Sensitivity Analysis.

The "Base Case" scenario (Case 1) presumes an oil price of $24 /bbl and a CO2 cost for the oil producers of $12.80 /tCO2. For this case the CO2 cost was set to the value that gives approximately zero NPV of the total EOR projects. The purchase cost of CO2 was then determined to be $7.90 /tCO2.

In Case 2 the oil price was increased to $28 /bbl, but the CO2 cost remains unchanged. With higher incomes from sales of oil the CO2-EOR projects continue for a few more years (~6 years depending on the field) whilst the amount of incremental oil and stored CO2 increase. Since more CO2 is sequestered, then the costs of aquifer storage decreases and the incomes from CO2-sales increases.

These factors also resulted in the CO2 purchase price increasing from $7.90 to $8.30 /tCO2. Most of the profit for the increased oil price was received by the oil producers—as can be seen by a large positive NPV for the incremental oil recovery project.

In Case 3 the cost of CO2 for the oil producers was increased to $19.90 /tCO2. This gave a close to zero NPV for the incremental oil production project. With a higher cost for CO2 the oil recovery project terminated earlier than the Base Case in spite of an increased oil price. The amount of incremental oil decreased compared to the Base Case scenario. All the profit for the increased oil price was thus given to the suppliers of CO2, whom in this case could receive \$12.80 /tCO2.

Case No.	Total Oil (Sm^3)	Total Oil (% HCPV)	Incr. Oil (Sm^3)	Incr. Oil (% HCPV)
1	2,269	53.7	335	7.9
2	2,318	54.9	356	8.4
3	2,252	53.3	329	7.8
4	2,390	56.6	381	9.0
5	2,404	56.9	376	8.9
6	2,457	58.2	403	9.5
7	2,381	56.4	367	8.7

Table 12: Summary of the Sensitivity Analysis.

In Case 4 the injection rate of CO2 into the Ekofisk and Valhall fields increased with factors of respectively 2 and 3. Due to this, the CAPEX and OPEX increased as shown in Table 13. In order not to exceed the transport capacity of the main CO2 pipeline, the start of CO2-injection for Ekofisk was delayed to 2023.

Case No.	CAPEX (\$bill)	OPEX (\$mill/yr)	NPV (\$bill)	Spec. Inv. Cost (\$/bbl incr. oil)
1	10.40	490	~0	4.9
2	10.40	490	3.77	4.6
3	10.40	490	~0	5.0
4	11.56	543	4.25	4.8
5	7.82	418	4.72	3.3
6	11.56	543	10.76	4.6
7	11.56	543	2.79	5.0

Table 13: Summary of the Sensitivity Analysis (cont'd).

The production of incremental oil increased from the chalk fields. The oil price was \$28 /bbl and the CO2 cost for the oil producers was \$12.80 /tCO2. Again most of the profit for the increased oil price was received by the oil producers as seen by a further increase in the NPV for the incremental oil recovery projects. As more CO2 was stored in the oil reservoirs the purchase cost of CO2 increased somewhat compared to Case 2.

Case No.	Stored CO2 (mill. tonnes)*)	CO2 Utilisation (bbl CO2 /bbl oil)**)	CO2 Cost ($/tCO2)	CO2 Purchase ($/tCO2)
1	1,153	5.3	12.80	7.90
2	1,269	5.5	12.80	8.30
3	1,115	5.3	19.90	12.80
4	1,353	5.5	12.80	8.50
5	1,308	5.4	12.80	8.40
6	1,486	5.7	15.00	10.50
7	1,273	5.4	15.00	10.30

*) Stored in the oil reservoirs. **) Reservoir volume CO2 / standard volume of incremental oil.

Table 14: Summary of the Sensitivity Analysis (cont'd).

In Case 5 the offshore factor for process equipment was reduced from 2 to 1. Reduced CAPEX also resulted in reduced OPEX costs. The oil price was $24 /bbl and the CO2 cost for the oil producers was $12.80 /tCO2. The injection rates for Ekofisk and Valhall in this case (as well as in Case 6 and 7) were the same as in Case 4. More incremental oil was recovered compared to Case 1, both due to prolonged project times and reduced running costs; the EOR projects continued for several more years compared to the Base Case. The profit for the reduced CAPEX costs was received by the oil producers, but due to increased storage of CO2 in the oil reservoirs the purchase price of CO2 increased to $8.40 /tCO2 as indicated in Table 14.

In Case 6 the oil price was increased to $35 /bbl and the cost of CO2 was increased to $15 /tCO2. The investment costs were as in the Base Case. Due to the increased oil price, the oil production continued beyond the periods for Case 2 and in this case the incremental oil production reached 403 million Sm^3 as shown in Table 12. Due to the increased cost of CO2 the purchase price increased to $10.50 /tCO2, but most of the profit due to the increased oil price went to the oil producers.

In Case 7 the lifetime of the EOR and the aquifer injection projects were decreased to 30 years. As was the economic lifetime of the CO2-transportation infrastructure. This resulted in an increase in the cost of transportation from $3.90 to $4.10 /tCO2. In this case the oil price and the CO2 cost were set to $28 /bbl and $15 /tCO2, respectively. Due to a higher cost for CO_2 the amount of stored CO_2 became less than in Cases 4 and 6. Also a higher proportion of the total amount of CO_2 was stored in the oil reservoirs—however, this resulted in a CO_2 purchase price of \$10.30 /tCO_2.

6.5 DISCUSSION OF THE CO2 STORAGE SCENARIO

Only one scenario and a limited set of sensitivity analysis within this scenario have been studied in the present Study Report. Furthermore only Norwegian fields within the North Sea have been included in the scenario, and a few additional potential candidates are not included. Fields in the UK sector situated within reasonable distance from the main CO_2-pipeline are not included. The present scenario is nevertheless useful to illustrate key figures related to a possible large-scale CO_2 storage era in the North Sea, and the capabilities of the techno-economic model.

6.5.1 Estimated EOR Potential

The incremental oil recovery due to CO_2-injection varies between 329 and 403 million Sm^3 in the constructed scenario. In addition to this comes all the oil that is not defined as incremental oil, but produced during the CO_2-EOR project. It is likely that many of the fields would have been closed down without the EOR project. The real incremental resource outtake is therefore likely to be larger than the values indicated.

The EOR potentials for the Base Case scenario is about 7.9% HCPV. For the three fields Brage, Gullfaks and Ekofisk, Mathiassen (2003) has referred to studies that indicate EOR potentials of 3.7-7.7%, 3.1-5.1%, and ~5.6% respectively, which are somewhat lower than the present estimates. However without more details regarding the three field studies it is not possible to conclude that the present EOR-module overestimates the potential.

Experience from real field projects world-wide has demonstrated that CO_2 injection is a powerful method to enhance the oil production from water-flooded reservoirs. On average the CO_2-floods included in *SINTEF Petroleum Research's* database (with 115 projects) have resulted in incremental oil recoveries in excess of 12% and 17% of original oil in place (OOIP) for sandstone and carbonate reservoirs, respectively. In this context the average incremental oil production estimated in this Study Report appears to be conservative. Furthermore CO_2-floods in the Permian Basin, Texas indicates that the CO_2-EOR experience there lies in the range of 6-15% of OOIP (Coleman, 2003).

In the techno-economic model every field project runs as long as the net cash flow of the project is positive. As seen by the sensitivity analysis for the scenario the duration of each project and therefore the EOR potential is sensitive to the oil price, CAPEX, and OPEX, as well as the cost of CO_2.

The CO2 utilisation presented in Table 14 is in reservoir volumes of CO2 used per standard volume of incremental oil. With an average value of 5.4 and an average CO2 density of 644 kg/m^3 this corresponds to 3.5 $tCO2/Sm^3$ incremental oil[42]. In addition to displacing the incremental oil the injected CO2 will also displace oil not defined as incremental (approximately equal volume as the incremental) and large volumes of water.

The volume balance in the EOR-module is always positive, which means that larger volumes are injected compared to the produced volumes. This means that some of the injected volumes are lost in the formation and this also contributes to the relatively high CO2 consumption factors. If the loss of injected CO2 is reduced then costs for injected CO2 will be reduced. The CO2-injection projects will then continue for longer time and the total incremental oil production will increase somewhat.

In the EOR-modelling it was assumed that the oilfields had been water-flooded prior to CO2-injection. For a few of the fields included in the scenario some HC-gas is presently injected into reservoirs, mainly in conjunction with WAG-injection processes.

For all the fields that have been subjected to HC-WAG, the potential incremental oil production due to CO2-injection may be lower than predicted by the EOR-module. During HC-gas injection the gas will have a tendency to segregate due to low density. In a WAG process segregation of gas and water will often result in that the upper parts of the reservoir will be gas-flooded and the lower parts water-flooded. However due to the higher density of CO2 compared to gas, other regions of the reservoir may be swept and the EOR potential may still be high.

The EOR-module developed using a sandstone reservoir model has also been used to calculate the EOR potential for chalk fields (Ekofisk and Valhall). Larger uncertainties in the model predictions for these fields are anticipated.

6.5.2 The Value of CO2

As seen above, significant amounts of CO2 are also deposited in aquifers. This varies between 51-60% of the total CO2 transported through the infrastructure. If a larger proportion of the CO2 can be used for oil recovery the purchase price of CO2 will increase. This price is also dependent on the oil price and the profitability required by the oil producers. In the present scenario the purchase price of CO2 varies between $7.90 and $12.80 /tCO2.

[42] This is probably conservative and can be compared with a value of 1.8-2.2 tCO2/Sm3 oil that is based on experience from on-going CO2-floods in the Permian Basin, West Texas (Coleman, 2003).

With more fields included in the scenario and improved knowledge about the optimal starting points for CO2-injection in each specific field, a scenario with a higher utilisation of CO2 for EOR could possibly be constructed. To optimise the CO2 utilisation the injection rate into the fields could also be varied during the project life-time; in the present model constant injection rates have been applied. Because of this and the timing of the projects in the scenario, the capacity of the CO2 transportation infrastructure is possibly higher than it might need to be.

Sequestration of CO2 in geological formation may become a main option to reduce CO2 emissions in Europe. In which case one may speculate that quantities in the order of several hundred mtCO2/yr may be available for storage, and EOR can only contribute by sequestering a small fraction of the total quantities to be deposited. However, early in a *"CO2-sequestration era"* the use of CO2 for incremental oil production can contribute to reduce the total costs of storage as illustrated by the following example:

Lijima (1988) indicated that the cost of CO2 separation from power plant flue gasses and compression for pipeline transport was \$25 /tCO2. Undrum *et al*. (2000) indicate \$25 /tCO2 as a lower cost for CO2 separation and sequestration from a large (1,260 MW net output) combined-cycle power plant. A similar price has been evaluated for capture and compression of CO2 from Danish coal-fired power plants (see chapter 5.3.1).

With \$25 /tCO2 as a reference cost for compressed CO2 delivered at the perimeter of a power plant. And a cost for CO2 transportation in a land-based CO2 gathering infrastructure comparable to the transportation cost in the main offshore pipeline (that is \$4 /tCO2 including additional compression), then the total cost for aquifer storage amounts to \$34 /tCO2. We also include a \$1 /tCO2 injection cost.

If the CO2 incremental oil production / aquifer storage project can purchase the CO2 for \$8 /tCO2 the storage cost is reduced from \$34 to \$21 /tCO2, where it is assumed that the infrastructure project covers offshore transportation and injection. With a purchase price of \$12 /tCO2 the storage costs are reduced to \$17 /tCO2, which represents a price reduction of 50%.

Bolland and Undrum (2003) indicate that NGCC electricity generation (including CO2-capture and compression) has a net thermal efficiency of 49%. Assuming a heat of combustion for natural gas of 48 MJ/kg and a CO2 coefficient of 2.39 kgCO2/kg gas, then 2.69 MWh are produced per tonne of CO2. With the aquifer storage cost above, CO2 separation and storage result in an increase in the power cost of 1.3 cent/kWh. With the combined CO2 incremental oil production / aquifer storage project as sketched in the present scenario, then this cost can be reduced to 0.8 or 0.6 cent/kWh.

6.6 ECONOMY AND INCREASED ECONOMIC ACTIVITY

To illustrate the economic activity related to the CO2-storage scenario, investment costs (CAPEX) and running costs (OPEX) for the main CO2-pipeline infrastructure, the incremental oil recovery projects, and the aquifer storage project are summarised in Table 15.

The OPEX for the oil recovery projects and the aquifer storage project will vary with time as CO2 injection for specific fields come on-line and terminate. The values shown in Table 15 for the oil recovery projects is therefore the sum of the running costs for all the fields included in the scenario; these have been averaged over the total project lifetime (40 years) using an average EOR project lifetime of 17.6 years. For the aquifer storage project average running costs during the total project lifetime is used. The data in Table 15 is valid for the Base Case scenario. Energy costs and CO2 costs are not included in the OPEX shown in the table below.

Item	CAPEX ($ bn)	OPEX ($ mill/yr)
Main CO2-infrastructure	2.74	34
Oil recovery (EOR) projects	10.40	216
Aquifer Storage	0.28	3
Total	**13.42**	**253**

Table 15: Summary of investment and running costs for the CO2 storage projects.

Table 15 shows that significant economic activity will be generated by the EOR and aquifer storage projects, both in conjunction with investment phase and during the 40-year operational period. The accumulated OPEX will be $10.12 billion while the value of the incremental oil produced will be $50.6 billion. If OPEX where converted to labour using a man-year cost of $80,000 /year the projects will result in an average employment of 3,200 persons during the 40-year period.

In the economic calculations no tax related issues are presently included. Inclusion of depreciation of the investments, taxes and revenues will affect the profitability of the projects. The NPV and IRR calculated for the scenario is therefore an expression of the total profitability of the projects. The analysis can therefore be considered as a socio-economic approach. Although no taxes and revenues are included in the analysis, there will inherently be public income as a consequence of the projects through all the economic activities associated with both the investment and the operation phases of the projects. These aspects have been addressed in more detail in other parts of this Study Report and related documentation listed in Chapter 8 “Documentation prepared by the project partners”.

6.6.1 Further Work

This Chapter presents a techno-economic model that has been developed so that it could be applied within a framework of specific project definitions. Only one storage scenario has been investigated , and the sensitivity analysis for this scenario is limited. In order to make new and more accurate scenarios several activities are proposed in a possible project continuation:

Better predictions for the costs for the necessary modifications of the process equipment for CO2-injection and for the running costs should be made. The possibility to separate CO2 and hydrocarbon gas should also be considered. If CO2 separation is implemented, additional incomes from gas sales will be obtained, both gas associated with the incremental oil and gas from the oil produced after CO2 injection has started, but not defined as incremental. For the fields with a high gas to oil ratio this may become viable provided that there is available space for the large installations needed for a CO2-separation plant.

All the fields included in the model are presently considered as separate projects. However, many fields are operated from the same platforms, and a co-ordination of the CO2-floods for a group of fields may result in better utilisation of CO2, and the necessary process modifications for CO2-injection can be optimised.

As discussed in section 6.5.1, the volume balance of the EOR-module is not closed as injected volumes are larger than those produced. The reason for this phenomenon is not clear and should be studied further, and the EOR-module should eventually be corrected. The functionality of the model should be improved in order to make it a general tool that can be used by any interested party. In it present state a few operations must be done manually, and the output data should be organised better.

Field data are still missing for a few possible candidates for CO2 injection in the North Sea. For a few fields included some parameters are missing and are thus only estimated. Also fields in the Danish and UK sector can easily be included in the model.

Each field is in the model considered as only one reservoir with average properties. In a refined model separate reservoirs can be included in the model and phased into CO2-injection at more optimal timing.

In the analysed scenario CO2 is injected at present reservoir pressures. Increased pressures may be needed to ensure that miscible displacements are obtained, and the volumetric sweep may be optimised by changed CO2 densities.

With better field specific data and information about the states of the fields, the time windows for start of CO2-injection for the various fields may be better defined. This can result in scenarios with improved total utilisation of CO2. To improve the field specific parameters, close communication with the operators will be needed.

In the present model, all gas after CO2 breakthrough is re-injected. For some fields the CO2 content in the injected gas after breakthrough soon becomes high, whereas for other fields the hydrocarbon fraction in the injection gas may become so high that it affects both miscibility and sweep efficiency.

As an alternative to re-injection of produced gas, a solution where only pure CO2 is injected into the oil reservoirs, and the produced CO2 containing gas is injected into aquifers could have been constructed. However, the techno-economic performance of such a scenario would be similar to the present case that has been evaluated.

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9. LIST OF ABBREVIATIONS AND ACRONYMS

ARA	Antwerp and Rotterdam Area in the Netherlands.
ASU	Air Separation Unit used to extract oxygen and / or nitrogen from air. (Also Argon in small quantities.)
CAPEX	Capital investment cost for a project.
CENS	The CO2 for EOR in the North Sea project that is developed by Elsam, KMCO2 and IN-CO2 ApS.
CCS	Carbon Capture and Storage.
CDM	Clean Development Mechanisms originally described in the KP article 12.
CES	Clean Energy Systems Inc. based in Sacramento, California.
CHP	Combined Heat and Power plant.
CO2	Carbon dioxide (alternatively CO_2).
ECBM	Enhanced Coal Bed Methane recovery from coal seams.
EEZ	Extended Economic Zone beyond territorial waters.
EGR	Enhanced Gas Recovery.
EOR	Enhanced Oil Recovery generally associated with the third (‘tertiary’) phase of production in an oilfield production life.
EU	European Union.
ETS	Emissions Trading System for sale and purchase of CO2-credits. Originally proposed in the KP article 17.
FGD	Flue Gas Desulphurisation for reducing sulphur emissions primarily from coal-fired power plants.
FSU	Countries within the Former Soviet Union
GHG	Greenhouse gas.
GtCO2	Giga tonne of CO2 is 1,000 mtCO2.
HC	Hydrocarbon gas: often associated with use in a WAG.
HCPV	Hydrocarbon Pore Volume.
IEA-GHG	International Energy Authority – Greenhouse Gas R&D Programme.
IPCC	Intergovernmental Panel on Climate Change established in 1988 by the World Meteorological Organisation and the United Nations Environment Programme.
JI	Joint Implementation is a mechanism originally defined in the KP article 6.
KMCO2	Kinder Morgan CO2 Company based in Houston, Texas.
KP	Kyoto Protocol signed in Kyoto on 11 December 1997, but has yet to be ratified by all parties.

LNG	Liquid Natural Gas.
LULUCF	Land Use, Land Use Change and Forestry.
mtCO2	a million tonnes of CO2.
NCS	Norwegian Continental Shelf.
NG	Natural Gas usually comprising of up to 94% methane and less than 2.5% CO2 in order to satisfy sales specifications.
NGCC	NG-fired Combined Cycle power plant.
NGL	Natural Gas Liquids.
NOK	Norwegian currency. (Typically there are 7 NOK per US$).
NPV	Net Present Value of a project.
NSCS	North Sea Continental Shelf comprising the UK, Danish and Norwegian oil producing sectors within the North Sea.
OECD	Organisation for Economic Co-operation and Development.
OPEX	Annual project operational expenses and costs.
OSPAR	(Oslo – Paris) Convention for the Protection of the Marine Environment in the North East Atlantic.
OOIP	Original oil in place within a reservoir before production started.
SCR	Selective Catalytic Reduction of NOx from flue gases.
SFT	The Norwegian Pollution Control Authorities.
UNCLOS	United Nation Convention on the Law of the Seas.
UNFCCC	United Nations Framework Convention on Climate Change adopted in New York on 9 May 1992.
US$	US dollar currency (also used just $ sign).
WAG	Alternating Water And Gas injection scheme that is typical in secondary and tertiary phase of oilfield production. To date on the NCS one has used excess hydrocarbon gas.
ZENG	*Zero Emission Norwegian Gas* development program that currently proposes to construct by 2008 a 40 MWe zero emission power plant at the Energy Park, Risavika, Stavanger.