MECHANISMS AND INCENTIVES TO PROMOTE THE USE AND STORAGE OF CO2 IN THE NORTH SEA

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The use of carbon dioxide (CO2) for enhanced oil recovery (EOR) in the maturing oil reservoirs of the North Sea, offers the adjacent countries a unique opportunity for extended exploitation of existing oil and gas supplies while developing sustainable solutions in response to the challenge of continued use of fossil fuels, climate-change, and compliance with international commitments to reduce GHG-emission. However, it is only when government is an active participant that the concept reveals a «win-win-win» situation for all stakeholders, including the host governments.

Markussen et al. (2002) described a generic scenario where if some of the most mature candidate fields of the North Sea Continental Shelf (NSCS) were to adopt CO2 for tertiary oil recovery, then with a 25-year “economic” lifetime the project could conservatively produce 2.1 billion barrels of incremental oil while sequestering 680 mtCO2 in recognised secure depositories. Assuming price of oil at $20 /bbl then the net cost for CO2 capture and sequestration was less than $1.50 per tonne—thus representing one of the cheapest options available to the host nations for CO2-emission reductions, whilst also ensuring extended use of the already substantial investments that have been made on the NSCS.

In this paper we focus on describing near-term barriers and mechanisms that might create incentives for oil companies to use CO2 for EOR, as well as identifying some of the longer-term benefits this might entail for the host economies. We emphasise how the ultimate risk is with respect to ‘economic incentives’ that are governed by the price of oil; the only project participant capable of absorbing this economic risk is ostensibly the host government.

From the CO2 experience in the United States during the past 30 years, we observe that it has been federal government tax credits and specific State allowances that have created the prerequisite incentives to initiate tertiary oil production using CO2.

Furthermore, if CO2 for EOR on the NSCS were to depend upon the climate-change issue, then many of the major mature fields will have chosen alternative strategies for tertiary production—or decommissioned—before clarification of some remaining key issues were available. However given an initial incentive to adopt CO2 soon, then the subsequent future role of CO2-EOR for CO2-mitigation could be substantial, and provide European policy makers with practical energy options within a future carbon-constrained economy.

Governments will have several roles to play in conjunction with promoting CO2 projects on the NSCS. However, during the early stage of development, this should focus on creating a genuine demand for CO2 through modifications to the prevailing fiscal regime so that the commercial participants may rapidly initiate CO2-EOR project development.

Subsequently, governments need to ensure a longer-term value for sequestered CO2 that is compatible with the proposed Kyoto mechanisms for GHG-mitigation and evolving Emission Trading System (ETS).

1. A BRIEF HISTORICAL PERSPECTIVE ON CO2 FOR EOR

1.1 Past Experience from the United States

The use of CO2 for enhanced oil recovery (EOR) is actually well understood, and an established practice within the oil industry. The mechanisms by which miscible CO2-gas injection helps improve oil production in the final (tertiary) phase of oil reservoir life were first exploited in the mature fields in the Permian Basin, West Texas (see Fig. 1) during the early 1970s. At that time CO2, associated with natural gas production from the oilfields, was being vented to atmosphere and was therefore readily available for tertiary oil recovery. Projects were also stimulated by some pioneering work being undertaken by Shell Western E&P Co. and Mobil Producing Co.—in combination with special tax concessions, and price control exemptions—as an incentive during a period when United States domestic oil production was beginning to decline rapidly.

However, these so called “tax-floods”, although being commercially successful, were not optimal with respect to their use of CO2; but they did provide the operators with considerable insight regarding reservoir behaviour, CO2-handling, corrosion mitigation, and CO2-recycling following breakthrough of the gas into the production wells.

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2 In general miscibility between the dense “fluid like” phase of CO2 and oil is characterised by a “multiple-contact” process whereby components of the oil and the CO2 transfer back and forth until the oil-enriched CO2 is indistinguishable from the CO2-enriched oil. The resulting single phase fluid has improved density and viscosity properties that make it more amenable to oil recovery—this being particularly the case when there is an alternating water and CO2-gas (CO2-WAG) injection process.

The SACROC (Scurry Area Canyon Reef Operators Committee) Unit, near Midland, West Texas is a good example of a field that has been through all the production phases of a oil reservoir's life—and is now one of the largest CO2-floods in the world: operation covers an area of 200 km sq within the depleted Kelly Snyder oilfield in the eastern part of the Permian Basin.

Fig. 2: The SACROC Unit with approximately 2.8 billion (bn) bbl of original oil in place (OOIP) was at one time the seventh largest producer in the US with a peak of 211,000 bpd. Primary production started in 1948, while secondary oil recovery with water injection was implemented in 1954. A CO2 immiscible flood was subsequently implemented in 1972, and a tertiary CO2 miscible flood was implemented in 1995. The production curve also shows prognosis through to 2012 following a $1 billion investment by the present owner KMCO2, where they expect to get daily production above 40,000 bpd from a low of 8,000 bpd. SACROC has produced more than 1.2 bn bbl oil since its discovery in 1948, and it still has significant additional reserves that are recoverable by CO2-flooding.

Early supply of CO2 in the period from 1972 to 1975 came from natural gas processing plants about 270 km away from the oilfield; the CO2 was a by-product that otherwise would be emitted to the atmosphere. In 1996 SACROC was also connected to supplies of natural CO2 from the domes at Bravo and McElmo (see Fig. 1) through the CO2-pipeline infrastructure that was predominantly developed by the Shell CO2 Company (now part of KMCO2).

Assessing the incremental performance of CO2-floods can be subjective in that the CO2 injection rarely encompasses a whole reservoir structure. Furthermore with regards to the early CO2-floods, it was clear that many of the incentives were not so much to optimise the CO2 mechanism as opposed to optimising the tax rebate. In this sense one can conclude that virtually all the original CO2-floods were an economic success.

Indications at SACROC, based on results over a 7-year period covering an area of 11 km sq and 100 wells, suggest an incremental oil recovery of 7.5% of the OOIP. In general, one assumes that CO2-floods will recover an additional 6 - 15% of OOIP depending on the reservoir structure and degree of capital investment in the project.
In contrast, the average oil recovery from reservoirs in the United States is only 32% of OOIP—compared with the realistic target\(^4\) of above 45% for the NSCS. However, EOR is already responsible for over 12% of total US oil production. Furthermore, the successful development of CO2-EOR is shown in Fig. 3 where the white region highlights the growth in use of CO2 from 1984 through to year 2000, at which time CO2-floods were responsible for more than 180,000 bpd representing 28% of total incremental EOR barrels produced in the United States.

**Fig. 3:** Graph showing various technologies that are employed for enhanced oil recovery (EOR) in the United States over period from 1984 – 2000. There were in 1998 a total of 92 Thermal (steam) EOR projects producing 439,000 bpd. There were 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 (Jarrell et al., 2002).

The US experience from the past 30 years clearly reveals that there are several (obvious) criteria that explain the growth of CO2-EOR, and these are:

- Comparatively cheap *anthropogenic* CO2-sources (or CO2 as associated gas) were nearly always available within the region.
- The fiscal regime was either already in place or evolved alongside the project to promote incremental oil production (note: not CO2-mitigation!).
- The infrastructure evolved rapidly, thereby reducing CO2-transportation costs by approximately 40% in the past two decades.
- Improved screening methods have reduced risk considerably. Experience on one field can often be extrapolated onto a neighbouring field. Thus technology and infrastructure clustering also makes subsequent growth much easier.
- Improved CO2-flood design ensures more optimal use of CO2.
- Improved understanding with respect to handling corrosion in an economical manner. As well as improved technology for handling, pumping and recycling CO2.

\(^4\) This percentage difference obviously reflects the higher investment costs required in order to extract oil offshore on the NSCS. Once made, the incentive to maximise recovery before abandoning is also present.
• There is an enormous market potential for incremental oil.
• There are still large quantities of natural CO2-sources available.

We note that in addition to the United States, there were also according to the Oil & Gas Journal, (15 April 2002), 75 active CO2-floods registered world-wide5 producing 194,000 bpd of incremental oil—equivalent to 8.4% of reported global EOR production—however 95% of this is produced within the United States.

1.2 Tax Incentives for EOR projects using CO2 in the United States

To defray higher costs associated with implementation of CO2 for EOR projects—as well as limit oil imports and maximise crude oil production from older fields that might under other circumstances be abandoned—the United States tax code has had, in one form or another, a “tertiary incentive” since 1979 when crude oil was still under price controls.

Initially there was a volume price exception for price controlled oil, to allow crude oil so produced to be sold at then free market prices; then there was an exemption from the US Windfall Profits Tax, and also a credit for production fuels from non-conventional sources; finally, the US Federal EOR Tax Incentive was codified in 1986. Interestingly we also observe in Fig. 3 that this coincided with a growth in use of CO2.

The EOR Tax Incentive is a 15% tax-credit defined in Section 43(c) (2) (A) of the Internal Revenue Code of 1986, and applies to all costs associated with installing the CO2-flood, CO2 purchase cost, and CO2 operating costs for injection. When the credit is taken, the remaining 85% of the qualifying costs are expensed (or depreciated) normally (Jarrell et al., 2002, p.132. See footnote 3 on p. 2).

Also, there are currently eight 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 under Rule 50, a severance tax exemption on all the oil produced from a CO2-flooded 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 United States.

Permitted costs include actual costs as well as intangible drilling costs associated with the project. However costs associated with primary and secondary production are explicitly excluded from being considered, oftentimes when there is a clear connection (such as crude oil tanks). The tax credit is thus for tertiary methods of hydrocarbon recovery only, but the expenses allowed to be taken extends also to the cost of the fluid being used, as well as actual drilling, re-completion, land and other costs associated with the well or wells that are part of the EOR project.

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5 These were: United States (66), Canada (4), Trinidad (4), Hungary (3), Turkey (1), Russia (1) and recently Brazil (1). Furthermore, we note that there have been additional CO2 projects for Enhanced Gas Recovery (EGR) proposed in Canada and the Netherlands.
2. A PERSPECTIVE ON CO2 FOR THE NORTH SEA

In this section we discuss how the situation regarding a potential role for CO2 in the North Sea could be initiated on a similar basis to that which has evolved in the United States. Subsequently it could continue beyond the period for tertiary oil production to encompass extended use of decarbonised fossil-fuels in combination with an extensive capacity for underground CO2-storage. Although beyond the scope of the present paper, this would also facilitate a commercial transition to new-renewables within a hydrogen and electricity (termed ‘hydricity’) based economy. Furthermore we foresee a transition that would be compatible with the challenges posed by climate-change, whilst at the same time accepting the role our existing fossil-based infrastructure has established since the introduction of coal in the 19th century and oil in the 20th century.

Changes that envisage restructuring our existing energy—as well as transportation—infrastructure, rarely occur on the basis of single events. However within the European arena we see that there may be a unique culmination of three major political and economic issues that could help initiate the policy decisions that would ensure and benefit from the future role of CO2.

For the European countries the three key issues are:

1. Declining oil production from the North Sea Continental Shelf (NSCS).
2. Increasing dependence upon energy imports—in particular from the Former Soviet Union (FSU) and North Africa, in addition to the Middle East.
3. A growing commitment to reduce CO2-emissions on account of climate-change.

In the following subsection we discuss each of these issues in more detail.

2.1 Declining North Sea Oil Production

We invariably observe that the most important difference regarding comparison between the United States and the NSCS is that Northern Europe has very little naturally occurring CO2. In marked contrast it has had a substantial oversupply—especially in the Norwegian sector—of excess hydrocarbon (HC) gas. This has therefore historically resulted in a tradition for either water-flooding or alternating water-and-gas (WAG) injection, when performing the secondary phase of oil production, and more recently considering projects for the final tertiary phase.

The abundance of HC-gas, that was effectively ‘queued’ before gaining access to market, has recently disappeared due to the increasing demand for natural gas (NG) in the UK, and a foreseen ‘cleaner’ energy demand from within the European Union. Thus the previous attractiveness of using ‘stranded’ HC-gas for oil production has substantially decreased—but remains accepted practice in a conservative environment that emphasises ‘low-risk’ as a key criterion on any change of procedure.

Despite this, it has also been well recognised by the major North Sea operators that CO2 could have a beneficial effect in excess of current practice—if it were available in sufficient volumes and at a cost compatible with alternate technologies for EOR.

Typically we observe that Norway in 2002 exported 65 bn Sm3 Natural Gas, but probably used an additional 50 – 55 bn Sm3 of HC gas for pressure maintenance and injection gas into its oil reservoirs. Although much of this gas will be available for subsequent sale after oil production is phased-out, it is estimated by the Norwegian Petroleum Directorate (NPD) that about 20% of this gas will not be recoverable.
Forties is a good example of a very successful field that originally had 4.2 bn bbl of original oil in place (OOIP) when discovered in 1970. It was opened for production by BP in 1975 and within 3 years reached a peak production of nearly 500,000 bpd. Subsequently, a very efficient secondary sea-water injection programme ensured that 59% OOIP has to date been recovered. However with current production down to 50,000 bpd and a 9:1 ratio between water and oil, ultimate recovery using existing infrastructure is expected to be around 62% OOIP. This would still leave 1.6 bn bbl remaining in the field after planned production close.

BP was therefore one of the first to seriously assess the available options for tertiary production. Based on the prevailing reservoir conditions, it was quickly concluded that miscible gas injection was the only solution that could yield a significant contribution to additional recovered reserves. The choice for HC-gas was constrained by a requirement of having to use expensive NGL’s to ensure that minimum miscibility pressure (MMP) was achieved. Following further screening studies it was concluded that CO2 would recover an additional 4.7% (based on OOIP) given an injection rate of up to 4 mtCO2/yr over a 15-year tertiary production period.

![Comparison between US and North Sea oil production (1960 - 2020).](image)

The US has more than 20 years of experience with tertiary EOR compared with the North Sea.

Fig. 4: The similarity between present oil production profile for the North Sea and that in the United States around 1980 is shown in the above figure. The fact that both the UK and Norwegian sectors are starting to go ‘off-plateau’ is inevitable and for many of the larger fields a near-term reality; some smaller fields have already closed, and in particular we have UK oil production declining rapidly. The Norwegian sector is switching to production of natural gas (NG) for the European market and is destined to be exporting 80 - 100 bn Sm3 within the 2005 - 08 timeframe.

However BP subsequently reported that they would not pursue these plans, primarily due to the high investment costs requiring possibly two new platforms to replace the existing five platforms that would be too expensive to retrofit for handling the more corrosive combination of CO2 and water. Furthermore the company identified problems with supplying the necessary volume of CO2 at a price that was compatible with the ability of the CO2-EOR project to pay for itself. Finally, though, we acknowledge that BP was among the first to emphasise the need for a revised fiscal regime in order to make the CO2-EOR project competitive with other international investment projects that the company had within its global portfolio.
Behind these conclusions, one should also note that all the major oil companies operating on the NSCS are also large national emitters of GHG’s, and will inevitably have a political agenda attached to most of its dialogue and proposals concerning CO2. For this reason it still remains challenging to assess the relative merits of individual CO2-EOR projects, without also understanding the broader context within which the project exists.

In April 2003 BP sold Forties to the US-based Apache Corporation, thereby also confirming a growing trend for the final phase of recovery in the North Sea where the major oil companies gradually pull out and smaller independent operators move in.

**Fig. 5:** In 2002 the CENS (CO2 for EOR in the North Sea) Project being developed by the Danish coal-fired power plant operators Elsam and the US-based Kinder Morgan CO2 Company (KMCO2), proposed a CO2-pipeline infrastructure capable of delivering 30 mtCO2/yr to numerous oilfields in the North Sea using ‘anthropogenic’ (man-made) CO2 captured from coal-fired power plants located in Denmark and the UK, together with industrial sources on the West Coast of Norway.

Another field that has been extensively studied for CO2 is **Ekofisk** with an estimated 6.7 bn bbl OOIP. This was discovered in December 1969 and—operated by Phillips Petroleum—became the first field in the Norwegian sector to start production in 1971. It is genuinely classified as an ‘elephant’ field having production planned through until 2028 when the current licence expires; there are those who foresee the possibility of production beyond 2040!

Following primary depletion (with some excess gas re-injection), the operator initiated an extremely successful water-flood starting in 1987, which is scheduled to continue through to 2010 - 12.

Present estimates for recovery are 46% OOIP. This indicates that there could be as much as 3.7 bn bbl remaining to be targeted for tertiary EOR, and the current operator ConocoPhillips has therefore conducted extensive screening studies regarding different technologies for tertiary recovery. Results were published in a classic paper from 2000 covering five different
options where CO2 was estimated to be the second best alternative after ‘oxygen-enriched’ air injection, that is basically a self-sustaining combustion (thermal) process within the reservoir.

The estimated potential for a CO2-WAG was 5.6% OOIP representing 360 million bbl. This typically equates with 6 - 8 mtcO2/yr over the tertiary production lifetime, but it was at that time concluded that there was no possibility of supplying this volume of CO2 to the field.

However, ConocoPhillips emphasises that there are other outstanding issues regarding uncertainties with respect to use of CO2 in the chalk formations which predominate in the southern part of the North Sea. They also need to resolve specific details concerning formation of hydrates in the vicinity of the CO2-injectors that occurred following an early pilot test conducted back in 1996. Despite these issues ConocoPhillips are continuing to evaluate both CO2 and thermal combustion for tertiary EOR—although emphasising that Ekofisk will not be doing a transition to tertiary phase production until probably 2012 - 14 period.

In April 1998 Norsk Hydro presented what was then termed their HydroKraft Project comprising of a 1200 MW Integrated Reformer Combined Cycle (IRCC) power plant with CO2-capture. This would contribute 10 TWh of electricity to the Norwegian electricity grid while supplying 4 mtcO2/yr for injection into the Grane oilfield that was due to start production in 2003. The project proposal was subsequently shelved, primarily due to high risk regarding complexity, economic costs, and the challenge of scheduling a new power plant concept in combination with delivery of oil from a field that would have to enter production on a tight commercial schedule.

The HydroKraft Project was embroiled within an ongoing political CO2-debate in Norway that included the departure from office of the ruling coalition government in March 2000. However the project proposal did stimulate more detailed studies regarding potential for CO2-EOR within the Norwegian Continental Shelf (NCS). These studies, conducted under the auspices of the Confederation of the Oil Industry (OLF), also included detailed work on Brage and Gullfaks.

The Brage reservoir is a comparatively complicated geologic formation with 0.9 bn bbl OOIP. Production started in 1993 and peaked with 140,000 bpd in 1998. Current production is at 40,000 bpd but declining. The platform was originally due to be decommissioned in 2005 with only 280 million bbls produced representing 31% OOIP. However, (primarily) the use of new drilling technology suggests a possible life-extension beyond 2010. Furthermore, recent studies by the operator Norsk Hydro suggest that an additional 38 million bbl incremental oil might be available with CO2-EOR representing 4.2% OOIP.

The Gullfaks reservoir located in the Tampen Area was discovered in 1978 and production started in 1986. At that time there was an estimated 3.7 bn bbl OOIP, of which 2.1 bn (51%) will be recovered using secondary water-flooding. Currently nearly 90% is already produced and Gullfaks is in rapid declining production. For this reason the operator Statoil has during the past two years conducted extensive screening to evaluate the potential for CO2-EOR starting by 2008. Modelling results to date have been encouraging and indicate that of the order of 5 - 8% OOIP could be recovered given an injection rate of between 3 - 5 mtcO2/yr for a 10-year duration. Statoil is currently evaluating the overall economics and is scheduled to make a decision regarding more detailed pre-engineering and qualification studies within the first quarter of 2004.

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Mathiassen\textsuperscript{8} (2003) recently screened 128 candidate fields on the NCS and conservatively concluded that the potential incremental oil from CO2-EOR projects was in the range 1.5 - 2.0 bn bbl, thereby inferring a requirement for between 500 - 650 mtCO2 in the Norwegian sector through until 2025.

A similar detailed screening has not yet been conducted for the UK offshore oil sector, but should intuitively yield a similar magnitude regarding potential for CO2-EOR. However, a more general appraisal of CO2-capture and carbon storage\textsuperscript{9} has been made by the UK Dept. of Trade and Industry (DTI).

Finally we note that an EU funded screening study by Holloway\textsuperscript{10} (1996) concluded that the total carbon sequestration potential on the NSCS including saline aquifers was equivalent to several hundred years of emissions from European power generation and industrial sources.

To conclude we observe that the technologies and concepts proposed for delivery and CO2-flooding in the NSCS 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 it is generally felt that these can be adapted for safe and efficient use in an offshore environment.

For the offshore industry it is therefore the economic incentives that need to come into place before they can make the necessary capital investment. And as we also infer throughout this paper, there is no single commercial project participant that can on their own carry the project unless governments recognise that in the long run they will become the largest benefactor.


2.2 Security of European Energy Supplies

The European Commission Green Paper\textsuperscript{11} regarding Energy through until 2020 highlighted some of the key dilemmas confronting the EU countries who will be growing more and more dependent upon imports. By 2020 it is estimated that over 70\% of regional energy will have to come primarily from North Africa, the Middle East and Former Soviet Union (FSU). At that time, the paper also identifies a substantial phasing out of nuclear power and continued reliance on fossil fuels despite extensive policies to promote renewable energy.

The scope for European countries to control the price mechanism of its primary energy sources will be limited (to say the least), and with growing fuel-switching to less carbon-intensive fuels, its exposure to supply line disruptions regarding imported natural gas will become more apparent: it is evident that faced with some realistic scenarios, then diversity and self-sufficiency will be high on the political agenda in Brussels.

\textbf{Fig. 6:} The European energy and oil deficit is highlighted by the above graphs showing rising consumption that will inevitably need to be covered by net imports. Furthermore there is limited scope for satisfying oil and gas demand through production from the North Sea.

Evidently the move to renewable energy sources (primarily wind) is a key response. But experience from for example of West Denmark, where electrical generation from wind can represent over 20\% of the annual electricity production, has also highlighted the need for grid control, inter-connectors and a base-load power generating capacity that can continuously handle fluctuations in the availability of renewable energy. The situation in the UK is considered to be particularly exposed regarding these issues due to limited possibility to export through inter-connectors to the European mainland.

The \textit{EU Green Paper} also indicates that continued use of existing base-load alternatives, like coal and nuclear, will remain in production for longer than is possibly being acknowledged in

\textsuperscript{11} “European Union Energy Outlook to 2020” available at \url{http://europa.eu.int/comm/energy/en/etf_2_en.html}.
certain quarters at the moment. In fact, it concludes that in 2020 over 90% of primary energy will still be based on fossil fuels and nuclear power. Certainly within this context there will be a role for clean-coal and carbon sequestration that could substantially help stabilise the transition from fossil to renewable energy in the next 30 - 40 years without undermining the commitment to reduce GHG-emissions.

### 2.3 Climate-Change and GHG-Emissions

The European countries have a growing—and confirmed—commitment to reduce their GHG-emissions independent of the fate of the Kyoto Protocol. Within this context the scope for a regional carbon-constrained economy appears plausible. However, a pre-requisite to maintaining economic growth whilst remaining competitive on the global market, will be policy incentives for both industry and consumers in order for them to change established practice and consequently reduce emissions in a cost-effective manner.

**Fig. 7:** Global CO2 Emissions and Annex-I Countries. The Kyoto Annex-I countries must reduce their CO2-emissions by 13.7% to fulfil their commitments according to the Kyoto Protocol. To achieve a stabilisation of the CO2 content in the atmosphere at 550 ppmv (twice the pre-industrialisation level) the IPCC recommends a global reduction in GHG-emissions of more than 50%.

A future cost on carbon will have a major role to play within this policy portfolio. To date such a cost mechanism has been sporadic and uncertain for long-term project planners. Perhaps the most established mechanism to date has been the Norwegian CO2-tax that is applicable to offshore emissions in the Norwegian sector of the North Sea. The tax has been in existence since 1991, and during that period has varied in the range $35 - 50 /tCO2, thereby representing a persuasive incentive to constrain and remove emissions on the offshore installations.

Possibly the most decisive consequence of the Norwegian CO2-tax to date has been the decision by the operator Statoil in 1996 to start separation and injection of nearly 1 mtCO2/yr at Sleipner West into the Utsira saline aquifer in order to make the produced Natural Gas compatible with specification for sales gas to the European market.
It is interesting, though, that with the introduction of an emissions trading system (ETS) proposed for 2005, then the future role of an offshore CO2-tax is brought into question. Until there is clarification from the policy makers regarding whether offshore will be part of a trading system or not, then the risk associated with making further substantial investment in projects to reduce offshore emissions will be considerably stifled; the alternative scenario is basically that a project might be allowed to purchase CO2-credits at possible prices as low as $5 - $10 /tCO2 for the period 2005 - 12. We here emphasise that it is the uncertainty—and not the cost—that is most disconcerting for the operators.

Onshore we observe that the Danish government has imposed a CO2-tax of DKK 40 /tCO2 ($6 /tCO2) for emissions above a capped level imposed on the power generating industry. In practice this has probably not been sufficient to stimulate any substantial investment in new technology, but has instead been passed onto the consumer as an increased electricity tariff. On a purely economic basis the tax would probably need to be in the region $20 - $25 /tCO2 in order to stimulate serious investment into large-scale CO2-capture plant technology.

Inevitably the most important mechanism envisaged has been the future cost for a CO2 Emission Reduction Credit (CO2-credit). However, here too, project planners are uncertain regarding validity, certification, and a credible price mechanism on which they can base cost-estimates. Despite there being multiple emissions trading systems already in existence—UK, Denmark, Norway and the EU have their own different proposals that presumably will eventually need to merge into a single system—it is difficult to envisage how this will happen sooner rather than later in the 2005 - 08 timeframe.

The overall impression we have is that if CO2 for EOR were to depend upon the climate-change issue, then before it could sensibly happen on the NSCS most of the major mature fields will have chosen alternative strategies for tertiary production—or decommissioned. However, given an initial incentive to adopt CO2 soon, then the subsequent future role of CO2-EOR could be substantial and provide the European policy makers with some genuine options for the future in a carbon-constrained regional economy.
3. THE ROLE OF COMMERCIAL PARTICIPANTS

CO2 in the North Sea can produce a “win-win-win” situation for multiple project participants, whilst ensuring that the largest benefactor will be the host government through both fiscal revenue, restructuring of the energy infrastructure, and longer-term societal benefits. However, the initial challenge is primarily that of creating incentives and involving the commercial participants in such a way that they are willing to engage in project investment. To achieve a rapid development, the role of CO2 for EOR is paramount and coincides with the requirements of oilfield operators and governments to recover more oil from the existing reserves.

The main economic incentive for any CO2-EOR project is always the 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 ensuring a competitive rate of return on the capital invested. If the price of oil is high, then the project may produce satisfactory return on capital invested, and additional tax income to the host government through incremental oil that might not otherwise have been produced using more conventional technology for tertiary recovery.

The relationship between price of oil and value of CO2 for EOR is revealed by the three straight lines that differentiate between projects in the Norwegian sector (red), UK sector (blue), and (dashed red line) in Norway with a modified depreciation of 3 instead of 6 years. The main observation is that with oil valued below $18/bbl then the CO2-EOR project can only afford to pay $10 - $12/tCO2 (given the current economic framework). If the price for delivered CO2 is at $35/tCO2, then the EOR project requires averaged oil price in range $27.80 - $29.20/bbl to achieve 10% IRR “After-Tax” within the present taxation systems in UK/NO sectors. However this excludes an estimated $2.4 billion that would accrue to each of the respective governments as tax income generated by the project.

We also observe that there is a ‘first mover’ risk that project participants will be exposing themselves to—possibly on behalf of many other project stakeholders that may stand to

Fig. 8: The relationship\textsuperscript{12} between price of oil and value of CO2 for EOR is revealed by the three straight lines that differentiate between projects in the Norwegian sector (red), UK sector (blue), and (dashed red line) in Norway with a modified depreciation of 3 instead of 6 years. The main observation is that with oil valued below $18/bbl then the CO2-EOR project can only afford to pay $10 - $12/tCO2 (given the current economic framework). If the price for delivered CO2 is at $35/tCO2, then the EOR project requires averaged oil price in range $27.80 - $29.20/bbl to achieve 10% IRR “After-Tax” within the present taxation systems in UK/NO sectors. However this excludes an estimated $2.4 billion that would accrue to each of the respective governments as tax income generated by the project.

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\textsuperscript{12} The relationship was evaluated using the CENS Economic Model (CEM) and the portfolio of fields shown in Fig. 5 together with generic data encompassing the complete CO2-EOR value chain from capture, gathering, transportation, injection in the reservoir, and recycling. The CEM has been extensively vetted by project participants (as well as third-party oil companies) using ‘conservative’ assumption for project techno-economic assessment.
benefit if the project were to go ahead and succeed. It is possible for participants to manage project risk associated with reservoir performance, new technology and unforeseen expenses (contingency) actively, but this will have a 'barrier' cost associated and there will be continuous comparison with alternative options for tertiary EOR. Handling risk-exposure should not be underestimated, as it can be critical to the investment decision process and timing with respect to declining production.

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 value of the incremental oil (ie. volume and price).

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

For the time being the concept of stored CO2 (as a greenhouse gas) 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 will probably only be agreed upon—by the governments—after the UNFCCC – IPCC Report on Carbon Capture and Storage is completed in early to mid 2005. A commercial participant may therefore currently attribute no significant value to CO2 that is used for EOR, beyond the value of incremental oil.

A final point to note is that with delivered CO2 costing in the range $35 - $38 /tCO2 together with the oil industries practice of evaluating projects on the basis of a 'long-term' oil price at $18 /bbl, then there is no way that independent commercial participants can invest in CO2-EOR projects. It is only when one considers the interaction between the commercial participants along with the interests of governments, that it is possible to see the potential benefits that may accrue to all parties if the CO2-EOR project were to go ahead.
4. THE ROLE OF GOVERNMENT AND FISCAL MECHANISMS

For commercial participants the economic value and risk associated with initiating CO2-EOR within the current fiscal regime is not by itself sufficient to permit an investment decision to be made—without the involvement of the host government. The extent to which government may choose to be involved could vary depending upon the available opportunities (with respect to specific early projects) and other participants. However in assessing its role, government should identify all the project related streams of revenue, including direct taxes, indirect taxation (due to jobs, field life-extension, deferred decommissioning costs, etc.), and all other societal benefits together with CO2-avoidance cost that will otherwise accrue due to their forthcoming commitments to curb GHG-emissions.

An example of this is provided using the CENS Economic Model (CEM), where assuming a ‘base-case’ scenario with price of oil at $20 /bbl and delivered cost\(^{13}\) of CO2 at $35 /tCO2, in combination with the portfolio of fields shown in Fig. 5, then the UK and Norwegian governments could have a present value tax income (based on incremental oil and associated jobs) of $2.46 and $2.37 billion respectively. However, in Fig. 8 it is shown that the oilfield operators can only realistically pay $14.40 /tCO2 on the UK-sector, or $11.10 /tCO2 in the Norwegian sector under the present fiscal regime.

The incentive for governments to participate lies partly in the fact that during the proposed 25-year lifetime of the project there will be approximately 650 mtCO2 that is sequestered permanently in geologically proven secure depositories within the UK and Norwegian sectors. Government may therefore choose to facilitate the project through directly supporting the price for delivered CO2. This would represent a CO2-Support mechanism of $20.60 or $23.90 /tCO2 respectively for UK / Norway that would result in a net present value tax deficit of $0.87 and $0.47 billion in the respective countries. Taking into consideration the captured CO2, this represents a CO2-sequestration cost\(^{14}\) of $2.10 /tCO2 and thereby represents one of the cheaper options available to government for large-scale reduction of existing CO2-emissions—capable of achieving reductions greater that 20 mtCO2/yr even within the 2008 - 12 Kyoto timeframe.

We also note that in the same project scenario, but with oil price at $24 /bbl, then the required CO2-Support mechanism reduces to $10.00 and $13.40 /tCO2 respectively for UK / Norway and would result in a net present value tax income of $0.84 and $0.94 billion in the respective countries.

Using the CEM it is possible to conclude that the CO2-EOR project scenario has a “break-even” price for oil around $21.50 /bbl, at which price all commercial participants will obtain an “After-Tax” IRR of 10% while the support required from government will just equal the tax income generated by the project. Whenever oil is above this value then the project has a positive NPV.

The above examples emphasise how the economic risk can be handled despite oil price market fluctuations; but we have so far not attributed any value within the project to the

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13 The CEM indicates that $35 /tCO2 is a realistic price for CO2 that is delivered ‘end-of-pipe’ through the pipeline infrastructure capable of transporting up to 30 mtCO2/yr as shown in Fig. 5.

14 The CO2-avoidance cost will be slightly higher in order to take account of the CO2 expended by the project during its lifetime—but should not include carbon associated with incremental oil produced. Within the context of a global oil market, CO2-EOR projects should be recognised as redirecting oil company resources from developing more expensive new oil reserves in possibly environmentally sensitive areas, such as the Arctic and deep-ocean, to focussing on improved recovery from existing reserves in established regions.
possible use of a CO2-credit which may be certifiable for a large portion\(^{15}\) of the CO2 that is captured and sequestered. This is because the role of credits needs to be evaluated in dialogue with the governments. In principle if one or more governments were to contribute with a CO2-Support mechanism— as indicated in the examples above— then they might justifiably presume that whatever credit is generated, along with the ‘physical’ CO2 sequestered, should be handed over to them.

The value of a CO2-credit would appear to depend upon where it resides. In the first scenario (with oil at $20 /bbl) the required market value that the commercial participants would need to obtain for their CO2-credit would be equivalent to the stated CO2-Support mechanism price that the government is contributing through its participation in the project—in other words a currently unrealistic valuation of $20 - $24 /tCO2-credit. However, for the government, their real cost is probably the resulting CO2-avoidance cost that lies in the range $2 - $3 /tCO2-credit.

Given the fact that once the market price for oil is above $21.50 /bbl then the net cost of acquiring these credits for the government becomes zero, there would seem to be a need for some dialogue within the project regarding how the “upside” of credit valuation\(^{16}\) is handled.

Another aspect regarding the CO2-credit trading market is that even a modest market valuation for a CO2-credit would represent a substantial cash injection into the project and thereby reducing the project “break-even” oil price. We observe, using the CEM, that a valuation of $5 /tCO2-credit is equivalent to reducing the project “break-even” oil price by $2 /bbl to $19.50 /bbl, and thereby making the project even more robust to market fluctuations.

Above we have identified one mechanism whereby governments may participate in the project and support the cost of delivered CO2— while at the same time acquiring comparatively large volumes of CO2-credits, despite a low market valuation. The major drawback of this mechanism is that it requires recognition of geologically stored CO2 to be part of the accepted Kyoto mechanisms, and also necessitates bilateral dialogue between host countries regarding certification of CO2 that is physically transferred across national boundaries. Both of these issues will take time to be resolved by the governments, and will probably not happen in a timeframe that is compatible with investment decisions for declining production in some of the major and most important oilfields on the NSCS.

An alternative scheme has recently been proposed within the Norwegian sector by the Confederation of the Oil Industry (OLF) as part of KonKraft\(^{17}\) who have suggested a “volume allowance” (VA) on incremental oil representing a tax rebate of NOK 15 /bbl (equivalent to $2.15 /bbl). The mechanism is of particular interest because it focuses directly on the tax incentive for incremental oil rather than the CO2.

The authors have recently updated the CEM to include the VA, and we observe that for the fields on the Norwegian sector, assuming oil price at $20 /bbl, then an allowance of $2.10 /bbl can be directly equated with the CO2-Support mechanism of $23.90 /tCO2 that was presented previously. However the government net present value tax-deficit has now reduced from $0.47 to $0.28 billion, thereby indicating that the VA may also be a more efficient means for the government to participate within the project. If there was also a value

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\(^{15}\) We note that not all the CO2 that is captured and handled within the project need necessarily be valid for credits. New power plants, for example, and existing emissions which are subject to national restrictions, need not immediately be certified as a CO2-credit.

\(^{16}\) Optimal redistribution of CO2-credits within the CO2-EOR project is beyond the scope of the present paper.

\(^{17}\) See the following url: http://www.olf.no/konkraft/prosjekt/
of $5 /tCO2-credit on the sequestered CO2 available to the project participants, then the government would have a net tax income of $0.19 billion.

Alternatively, if we continue to presume that it is too early to attribute a value on the CO2-credit, but assume that the prevailing market oil price will be $24 /bbl, then the oilfield operator may realise a 13.3% IRR and the government a tax income of $0.73 billion.

We believe that the above discussion shows there are mechanisms that the host government should pursue in order to promote CO2-EOR projects on the NSCS.

The subsequent implications would then be that governments could ensure;

- An optimal resource utilisation on the NSCS and maximise oil and natural gas recovery throughout the lifetime of the region.
- The commercial competitiveness of industry whilst achieving regional Kyoto targets for GHG-mitigation.
- A leading role with respect to facilitating co-operation between countries having CO2-sources and those with possible CO2-EOR projects.
- Harmonisation and clarifying incentives needed to stimulate further investment in CO2-reduction and infrastructure development for CO2-sequestration.

In addition there are other positive benefits to society and to the governments. Examples of these could be;

- Establishment of a CO2-infrastructure that will promote further implementation of CO2-EOR projects.
- Recognition that CO2-EOR projects in the North Sea will have a significant global “signal value” with respect to how oil and gas production may develop in a future carbon-constrained global economy.
- CO2-EOR projects of this kind (offshore, high volume, possibly involving CO2-ships, etc.) can in the medium to longer run also be highly beneficial for regional manufacturing, engineering supply industry, ship owners and oil companies.
- CO2-EOR projects on the NSCS can ensure that CO2 becomes a valued product. This will greatly assist in making CO2 capture from power generation and industrial sources a commercial reality sooner rather than later.

The proposed “volume allowance” (VA) provides an economic incentive for the oilfield owners to secure the rate of return they need to make the capital investments necessary to extract the incremental oil. The oilfield owners can then sign long-term contracts for the supply and transportation of the CO2, thereby securing the return needed to invest in CO2-capture technology and transportation systems. Furthermore, the VA ensures an economic incentive to extract more oil, while sequestering CO2, extending field-life, maintaining quality jobs in a declining industrial sector, and providing an opportunity for significant increases in government tax revenue.
5. CONCLUSION

There is a genuine possibility for the nations around the North Sea basin to create a commercial demand for man-made ('anthropogenic') CO2. Such a demand would ensure continued use for existing industrial complexes and energy-infrastructure, whilst building further upon the extensive capital investment that has already occurred on the North Sea Continental Shelf (NSCS) during the past 35 years. The use of CO2 for enhanced oil recovery (EOR) will secure an estimated 10 - 20 year life-extension for many of the existing fields, and ensure improved recovery of oil that essentially already belongs to the host governments (and that would not otherwise have been recovered).

A demand for anthropogenic CO2—gathered in a cost-effective manner from existing fossil-based power generation and industrial complexes—would provide governments with more flexible options for ensuring a smoother transition through into a carbon-constrained future whilst promoting development of technology for CO2-capture, gathering, transportation and permanent sequestration. Furthermore, it is one of the fundamental paths through to the more rapid introduction of a hydrogen and electricity ('hydricity') energy economy; initially this would be based on decarbonised fossil fuels, but can then readily integrate new-renewable energy sources as these become commercial.

To achieve such goals, governments need to work together with commercial participants in order to structure mechanisms that create incentives for the oil industry to demand CO2 for use in EOR projects. Governments must also ensure that there will be a value on sequestered CO2: in this manner CO2-emitters can invest in technology to capture, gather and handle their emissions.

The authors have in this paper, and in earlier papers, evaluated societal benefits of CO2 for EOR; we have also presented these ideas at recent conferences. The main thrust of our work has shown:

- EOR using ‘anthropogenic’ CO2 is—and will remain—more costly than the use of naturally occurring CO2, as has evolved in the United States during the past two decades.

- Fiscal tax policies regarding oil extraction in the North Sea are currently less favourable than those found in the United States, and there are presently no specific incentives for CO2-EOR activities.

- Experience shows that the use of CO2-EOR yields an additional 6 - 15% of the original oil in place (OOIP) and therefore can produce 10 - 30% more oil from a chosen field.

- CO2-EOR will result in additional jobs being created on platforms and onshore facilities. Also, the government commitment to help with costs for platform decommissioning will be further delayed.

- Each field has a window of opportunity to implement CO2-EOR near the end of the secondary water-flood and before decommissioning. If not implemented at this time, it will be too costly in the North Sea to re-commission a field because the targeted oil will be too limited.

- Oil produced by CO2-EOR will usually not be recovered using conventional primary and secondary methods of extraction. Therefore the oil and its associated economic benefits will be lost if CO2-EOR is not implemented.
• There is sufficient revenue from the oil sales to justify the expense of CO2-EOR, but it may require an adjustment of fiscal policy with respect to oilfield taxation in order to stimulate initial investment in such projects.

• There need to be economic mechanisms to either value the CO2 sequestered in geologic structures and / or increase the value of oil produced from CO2-EOR projects.

• A value for sequestered CO2 may be realised in the implementation of proposed European Emissions Trading System (ETS), but sequestering CO2 must first be accepted as a reduction technique within the Kyoto mechanisms, and this will not happen until after the UNFCCC – IPCC Report on Carbon Capture and Storage is completed in early to mid 2005.

• The Norwegian OLF / KonKraft has proposed a number of changes to tax policy including a potential “volume allowance” mechanism for oil produced from EOR activities. The allowance contemplated is approximately $2.15 /bbl as a tax credit against the current “Special Tax” payments. This mechanism provides a fixed production margin to offset the increased costs of EOR production, protecting the oilfield operator who makes the significant investments associated with EOR activities, whilst retaining for the government the 78% tax regime to cover any upside if oil prices increase.

• Mechanisms such as the “volume allowance” can be implemented today, thus encouraging the use of CO2-EOR and realising the societal benefits of EOR as early as possible, while issues regarding CO2-credit trading are discussed.

• A “predictable” valuation on CO2-credits within an ETS can substantially reduce project risk and the overall costs of delivered CO2. This would further enhance the value of CO2-EOR projects for both the operator and governments.

Individually, the oilfield operators have limited opportunity to gather sufficient CO2 for an economic EOR project. Therefore, with government acquiescence, there should be an implementation of a major infrastructure for CO2-gathering and transportation that could provide the necessary background for a wider number of fields to participate, and thus ensure that economies of scale are realised rapidly. In this paper we have not focussed on the details regarding the CO2-infrastructure, but we believe it may most readily evolve through an integration of both pipelines and ship transportation of CO2.

Finally, we note that the proposed “volume allowance” on the Norwegian sector should be evaluated by other governments because it provides an incentive that may permit the most efficient and rapid introduction of CO2-EOR projects throughout the NSCS.