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FISCAL MECHANISMS TO PROMOTE CO2 FOR ENHANCED OIL RECOVERY IN THE NORTH SEA: UNDERSTANDING THE CO2 VALUE CHAIN

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Abstract

The use of carbon dioxide (CO2) for enhanced oil recovery (EOR) in the maturing oil reservoirs of the North Sea [1] offers adjacent countries a unique opportunity for improved use of existing oil & gas infrastructure. It also provides an opportunity to develop sustainable solutions in response to the challenge of continued use of fossil fuels, climate-change and compliance with international commitments to reduce greenhouse gas (GHG) emissions [2].

However implementation of such projects requires alignment of commercial interests along a complete CO2 value chain (from "conception to grave") and also needs to transcend international boundaries [3]. Such barriers to implementation are difficult to overcome when there is no commodity market for CO2 in the North Sea arena. The purpose of the present paper is to discuss some of the benefits of creating incentives so that industry develops the North Sea potential for EOR using CO2. This would also ensure a commercial CO2-sink for North Europe and could substantially reduce the economic cost of GHG-mitigation [4].

Identifying the CO2 Value Chain

The concept of a carbon dioxide (CO2) "value chain" with large-scale commercial use of CO2 is well established from the oil industry in the United States where naturally occurring CO2 has been cost-effectively used as miscible injection gas for increased oil production during the past 30 years. However in the past 3 - 5 years we have also seen how international commitments to reduces GHG emissions has extended the potential scope of the value chain to also encompass;

- Pure sources of CO2 (eg. refineries, hydrocrackers, ethanol production etc.).
- CO2-capture from power plants and industrial complexes.
- CO2-gathering, handling and interim storage.
- CO2-transportation (ships and / or pipelines).
- CO2-hubs, terminals and export facilities.
- CO2 for enhanced oil recovery (EOR) and large-scale sequestration.
- CO2-credit generation, certification and trading.

Furthermore, we observe that three main drivers currently govern the incentive to invest and develop projects along this value chain. These are; (i) pending constraints on carbon emissions, (ii) corporate due diligence (including exposure to future risk as well as public image etc.), and (iii) the possible use of CO2 for EOR.

To date no company may seriously attribute a value on the 'physical' CO2 that is substantially beyond $10 per ton. However the cost of moving CO2 along the complete value chain will usually be greater than $30 /tCO2. And yet potentially in the next decade this chain could be a major creator of wealth within the global economy and provide viable policy alternatives for governments to develop new industrial activity, ensure energy security, and help combat climate-change.

In such a context it is also necessary to understand; (i) why the value chain is important, (ii) who are the stakeholders, (iii) how it should best evolve, and (iv) what it may contribute to the future wealth of society and

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nations. This paper briefly discusses these issues whilst drawing on our experience from developing CO2 projects both in the United States and in the North Sea[1]. We describe some of the immediate barriers that are ostensibly holding back investment decisions—possibly delaying measures for larger-scale CO2-mitigation—at a time when such implementation could be critical for practical demonstration of a way forward.

Why is the CO2 value chain important? Because it shifts the focus of CO2 and GHG emissions away from CO2 being a regulatory problem, over to creating a commercial resource. Wherever a value chain exists, a market will evolve, and with a 'level playing field' the most efficient pricing mechanisms will be established. As governments become more serious about society embracing the true cost of CO2-emission reductions, then creating a commercial value chain will also help establish the lowest cost for CO2-avoidance.

Who are the Stakeholders? Any person, company or societal body that may have a vested interest in the value chain functioning as efficiently as possible. Furthermore, we observe that the perception of being a stakeholder may—in some cases—only become apparent once CO2 is passing along the complete chain in a commercial manner where all participants are achieving their return on investment (ROI) and pre-requisite hurdle rates.

How can the CO2 value chain best evolve? There are many ways by which it can evolve, and there are a few specific ways by which it can be impeded and evolve inefficiently. In an early phase, the role of government appears to be to ensure that the market has incentives to choose the most efficient path.

Can the CO2 value chain contribute to the wealth of society and nations? The chain can be the bridge by which we move from our current fossil infrastructure through to a sustainable 'hydricity' (ie. with hydrogen and electricity as carriers) supply of energy. Essentially the value chain can extend the permissible transition period by several decades to permit sustainable development and commercial implementation of renewable energy sources.

CO2-EOR Experience in the United States and Texas

It is the unique properties of supercritical CO2 that improves oil production in the final (tertiary) phase of reservoir life; allowing operators to recover oil that would otherwise remain in the ground after the end of conventional water-flooding [5]. This was first exploited in the mature fields of the Permian Basin, West Texas during the early 1970's. At that time associated CO2 from natural gas production was separated and vented to atmosphere—thus being readily available for tertiary oil recovery. Projects were subsequently stimulated through special tax and regulatory incentives as well as some pioneering work undertaken by *Shell Western E&P* and *Mobil Producing Company* in a period when United States domestic oil production was beginning to decline.

To defray higher costs associated with CO2 for EOR projects, the United States tax code has since 1979 (when crude oil was still under price controls) included 'tertiary incentives'. Initially under *Department of Energy* price controls, there was a volume price exception that allowed CO2-EOR crude to be sold at then free market prices. Subsequently there was an exemption from the *U.S. Windfall Profits Tax* and a credit for production fuels from non-conventional sources. Finally the *U.S. Federal EOR Tax Incentive* was codified in 1986. There are currently eight states that offer additional EOR tax-incentives on incremental oil, whilst CO2-floods recover 206,000 bopd representing 31% of total United States incremental EOR-barrels and 12% of the nations domestic oil production.

In Texas there is no EOR tax credit *per se*, but instead a severance tax exemption on <u>all</u> oil produced from a CO2-flooded reservoir. Such fiscal incentives combined with commercial drivers and natural resources has resulted in the Permian Basin becoming the worlds largest CO2-flood region with more than 59 of the worlds 75 registered CO2-EOR projects (*Source: Oil & Gas Journal – EOR Survey*, April 2004).

West Texas currently has 3,900 km of integrated CO2-pipeline infrastructure; in 2003 over 25 million tonnes (fresh) CO2 was transported to the region primarily from the natural reserves at McElmo Dome, Sheep Mountain and Bravo Dome in order to satisfy a growing demand. In May 2004 the Basin produced 190,000 CO2-incremental bopd compared with a global estimate of 225,000 bopd (*Source: Kinder Morgan CO2 Company*).

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[1] See websites at http://www.kindermorgan.com/business/co2/ and http://www.co2.no/

Holtz *et al.* [6] identified over 1,700 significant oil reservoirs in Texas having a total potential of 31 billion barrels recoverable oil. The *Texas Bureau of Economic Geology* recently completed a study [7] and assumed if 10% of this was amenable to CO2-EOR then it would result in an economic value of $226 billion (equivalent to 1.48 million jobs). This compares to the current 260,000 persons who are directly working in the oil & gas industry with a $12 billion annual payroll—but which is declining at approximately 5% per annum.

It is also poignant to note that in 2002 Texas emitted approximately 350 mtCO2/yr of which the *U.S. Environmental Protection Agency* identified 240 mtCO2/yr as coming from power generation and with a large proportion based on coal-fired lignite plants. These are predominantly located in East Texas and—together with purer sources of industrial CO2—are considered most amenable to CO2-capture using available 'near-term' technology. Furthermore this anthropogenic CO2 is geographically well located between the existing CO2-floods in the Permian Basin and potential EOR activity that will inevitably evolve offshore in the Gulf of Mexico.

There are therefore several criteria that explain growth of the CO2-EOR market in the state of Texas;

- Cheap anthropogenic CO2 sources was originally available from within the region. To sustain growth this was quickly supplemented with larger volumes of natural CO2 from neighbouring states.
- The tax regime was stimulated by the oil crisis of 1973 that coincided with the first CO2 projects in the Basin. Subsequently fiscal measures and projects evolved simultaneously to promote CO2-floods.
- With growing demand and a natural CO2 supply, the infrastructure evolved rapidly thereby reducing transportation costs by approximately 40% in the first two decades.
- With time, improved reservoir screening methods considerably reduced risk associated with implementation of CO2 floods; experience on one field was often extrapolated onto a neighbouring field. Technology and infrastructure clustering also made subsequent growth much easier.
- Improved experience of CO2-flood design ensured more optimal use of the available CO2. There also evolved a better understanding of handling corrosion in an economical manner, as well as improved technology for pumping and recycling CO2.
- There still remains an enormous market potential for incremental oil both onshore and offshore, and there are large quantities of both natural and anthropogenic CO2 sources available.

Finally, we observe that New Mexico, California, Kansas, Oklahoma, Louisiana, Wyoming, North Dakota, and Alaska, all have some unique opportunities for developing large-scale CO2 commodity markets—both in conjunction with EOR and for future GHG-mitigation. Furthermore, the state of Kansas has just recently initiated a program whereby it is planning to back a $200 million bond issue to promote growth of EOR in that state.

CO2-EOR for Europe and the North Sea

Although not identical, we argue that much of the past experience from the United States—and specifically West Texas—can be considered when evaluating the potential scope for offshore CO2-floods in the North Sea. Furthermore within the European Union there is a culmination of three issues that may help initiate the policy decisions necessary to ensure a future commercial role for CO2 [8]. These are:

- Declining oil production from the North Sea Continental Shelf (NSCS).
- Increasing dependence upon energy imports.
- Growing commitment to reduce CO2-emissions on account of climate-change.

We discuss briefly below how these three aspects inter-relate to help promote a CO2 value chain:

Declining North Sea oil production: The oil reservoirs on the NSCS move into decline in the period 2000–2005; specifically on the UK sector this has already occurred, whilst Norway should pass peak oil production in 2005. Most operators are having to make strategic decisions regarding decommissioning versus economic life-extension: annual platform operating costs often exceed $50 million, whilst decommissioning costs can vary from $150 to $450 million depending upon the size of operations. Decisions are therefore very critical for the corporate bottom line.

There exists a limited window of opportunity for deciding whether to implement CO_2-floods that is governed by the declining production profiles of each reservoir and availability of CO_2. Typically investment decisions for securing supply and using CO_2 will need to be taken within the next 4–6 years [9].

European dependence upon energy imports: In 2001 the European Commission presented a discussion paper [10] proposing revised fiscal and market incentives to tackle key issues regarding the internal energy market, energy security and challenge of climate-change through until 2030. A major conclusion was that Europe can become almost 70% dependent upon imported energy from Russia, the Middle East, and North Africa. The future role of coal, oil and natural gas in addition to nuclear power and new renewable energy will remain a critical issue; the possibility of providing "clean" coal, extended oil production, and "greener" natural gas—through decarbonisation, EOR and sequestration—is therefore of considerable relevance to Europe.

Commitment to GHG mitigation: Carbon dioxide is by far the largest contributor to European GHG-emissions, and future emissions are being constrained in line with international commitments. Although some individual countries are struggling to meet their target emissions, inclusion of 10 new member states provides considerable opportunities for more cost-effective reduction of total emissions from within the EU-25 countries.

Emission trading is perceived as a key enabling mechanism that will facilitate real reductions of GHG-mitigation in the future. There already exist trading schemes within Europe and several countries have recently published their allocation plans for sector-based CO_2-emissions that will come into force in the period 2005–2008. Europe is therefore completely committed to constraining future GHG-emissions independent of eventual ratification of the Kyoto Protocol by the original signatories.

CO_2-EOR on the UK and Norwegian Sector

Although sequestering large volumes of CO_2 from mainland Europe will be important for the EU, it would initially appear to be the governments of United Kingdom [11] and Norway [12] that share the most immediate vested interest to create a demand for CO_2 in the North Sea.

For the UK exchequer this could provide a substantial revenue stream from taxation on incremental oil, additional jobs, and improved balance of payments due to reduced energy imports. A commercial CO_2 value chain within the UK sector will also provide the coal industry with an opportunity to revive at a time when it is baring the brunt of national commitment to reduce GHG-emissions. At the same time, improving domestic access to coal and oil should maintain a diversification of major energy supplies, whilst nuclear power remains politically complicated and renewable sources are far from being commercial—nor practical for 'base load' power generation.

The Norwegian government is recognised as being well versed with managing its oil assets, and still retains a large equity ownership through its stakes in Petoro (100%), Statoil (78%) and Norsk Hydro (44%) and a 78% offshore taxation rate. The *Norwegian Petroleum Directorate* (see www.npd.no) conservatively estimates that a potential 1.5 - 2.0 billion barrels CO_2-incremental oil exists on the NCS with a value of $45 - 55 billion.

Recent work, funded by the *Research Council of Norway*, considered all aspects regarding technical, economic, legal and institutional implications of large-scale CO_2 transportation from Europe onto the NCS [13]. The study assumed gathering 68 mtCO_2/yr at Emden, Germany into a pipeline and delivering the CO_2 to a combination of 18 mature fields, as well as saline aquifers (to permit optimal injection rates for EOR). The estimated capital investment was $13.4 billion with an averaged annual operating cost of $253 million over 40 years. The project would in total sequester around 2.7 GtCO_2 and produce $50.6 billion in revenue from an estimated 2.1 billion bbl incremental oil—not including incremental gas and gas-liquids, which would also be substantial. The transportation infrastructure project represented 3,200 man-years and constituted a reduction in the CO_2-sequestration cost in the order of $8 - $12 /t$CO_2$.

There have also been numerous screening studies undertaken to assess the scope to use CO_2 as a miscible gas for EOR on the NSCS—however few of these are available in the public domain. Fields that have been studied in some detail by the owners and operators include; Brage, Brent, Draugen, Ekofisk, Forties, Grane, Gullfaks, Miller, Norne, Snorre, Statfjord, Visund, Volve and several smaller fields considered as possible pilots in the chalk formations in the south between the Norwegian and the Danish sector. These studies have also provided some useful insights regarding barriers to implementation, as is described below from the perspective of the operator:

(i) Oil price assumption: Probably all studies to date have assumed an oil price in the range from \$14 - \$17.50 /bbl. With recognised volatility of the market oil price, it is established practice for oil companies to maintain a conservative stance, and it is only recently that some of the majors have indicated that they might consider revising their estimates using an oil price of \$18 - \$20 /bbl. In general CO2-floods recover more oil than alternative tertiary options so that their relative economics would also improve.

(ii) Alternative options: With high operating and maintenance costs on offshore platforms, then extended water-flooding followed by abandonment is often perceived to be a cost competitive alternative for some of the older installations. This would appear to be the case with Forties that was studied extensively for its CO2 potential by BP before being sold to *Apache Corporation* in 2003[*]. Alternatively fields like Brent and Statfjord appear to have decided to go straight into a 'blow down' mode requiring minimal reservoir maintenance costs. A third option that is being implemented at Ekofisk—and being assessed for Gullfaks—is to have an expanded drilling program that ensures continued secondary production with implementation of an extensive water-flood (EWF)[*]. Fourth, some fields have available hydrocarbon (HC) gas that has already been used for miscible injection—at Snorre the operator determined there was reduced incremental benefit when switching to CO2, while Visund is a miscible HC-WAG that may need to import more gas in the future. However, recently the sales value of HC gas has increased considerably thereby making this option less attractive for the operator, and potentially permitting fields to reconsider CO2 as an alternative.

(iii) Project cash flow: Timing is a critical feature for investment in CO2-EOR projects. A major objection to CO2-floods by operators in the United States and Canada has been the relatively high initial investment costs coupled with a possible long response time of 1–2 years before noticeable incremental oil production. For smaller independent operators—that are currently moving into the North Sea—such considerations can be just as important as is maximising total recovered reserves and attaining an acceptable project NPV.

(iv) Security of CO2 delivery: We also note that security of CO2 supply is a critical considerations for oilfield operators; without an established infrastructure they need reassurance regarding supply from Day-1. To date the role and responsibility of an eventual supplier and aggregator of CO2 to 'off-takers' has evolved on an *ad hoc* basis. How this is handled, either by ensuring incentives for commercial companies or a commitment from governments to facilitate, is currently a key issue that needs to be addressed in the coming 12–18 months if some of the potential candidate fields are not to choose alternative tertiary options.

(v) Project risk management: Risk is the ultimate deterrent for impeding CO2-flooding on the NSCS. If project participants identify high-risk elements, then they will increase the requirement for project IRR and thus reduce the efficient pricing mechanism within the value chain. Absorbing some or much of this risk is probably the most cost-effective method for government to participate constructively within the project.

One scheme that does appear to handle several of the aforementioned issues was suggested by the *Norwegian Confederation of Oil Industry (OLF)* as a 'volume allowance' on incremental oil[2]. The allowance was a tax rebate equivalent to \$2.25 /bbl. In our economic analysis [14] such an allowance, on payable taxation, could for the operator equate to an incremental support on the CO2-purchase price equivalent to \$25.50 /tCO2. This focuses directly on a tax incentive for CO2-incremental oil rather than the CO2. It also provides a fixed production margin to offset the increased costs of tertiary production—thereby protecting the oilfield operator making the significant investments associated with EOR activities, whilst retaining for the Norwegian government (through the existing 78% tax regime) any upside if oil prices increase. We are currently investigating how this allowance also performs within tax regimes of other North Sea countries.

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[*] We note that this option does not *per se* preclude a CO2-flood being implemented at a later date when the water to oil cut becomes too large. From the reservoir perspective optimal CO2-flooding should commence as early as possible in the reservoir production life cycle. However from an economic perspective optimising the transition from secondary to tertiary CO2-WAG will also be a function of timing, operating expenses, additional capital investment, CO2 availability and price.

[2] The *OLF* proposal was originally intended for all 'tail-end' incremental production, and has recently been turned down by the Norwegian government. We are here suggesting it should apply to only CO2-EOR incremental oil.

Summary and Way Forward

Key issues for the oilfield operator ('off-taker') are (i) perception of market oil price, (ii) risk exposure, and (iii) security of CO2 supply. For the CO2-supplier, it is (iv) cost for capturing and gathering the CO2, (v) future legislation constraining CO2-emissions, and (vi) cost of alternative options for CO2-avoidance. Currently none of these issues are straightforward to anticipate. Furthermore one also needs to attain dialogue across several industrial sectors (e.g. oil & gas, power, process, chemical and refining) as well as with three government bodies (typically we have Finance, Energy and Environment departments).

The key facilitating parameter is market oil price and government behaviour. In our economic analysis we observe [15] that with oil price below $28 /bbl most CO2-EOR projects will need government support. However governments can attain a positive project present value (through taxation) provided market oil price remains above $20 /bbl. Furthermore a CO2-credit value of say $5 /tCO2 is roughly equivalent to $2 /bbl on the market price for oil. Another words if longer-term crude oil prices stabilise close to $30 /bbl, there is every reason to assume that market forces can prevail and CO2 could become a commodity product in the North Sea. But this will probably not happen without guidance and support from governments—who also appear to have the largest incentive to ensure that CO2 is used for EOR in the North Sea.

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