

CO₂ for Enhanced Oil Recovery Needs Enhanced Incentives

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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], Gulf of Mexico and Persian Gulf offers adjacent countries a unique opportunity to extend the use of oil and gas infrastructures. It also provides an opportunity to develop sustainable solutions in response to the challenges 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 [3,4]. Existing barriers to implementation are difficult to overcome without strong economic drivers. At this time there is only a fledgling market in CO₂ credits and there is a lack of definition regarding measuring and monitoring rules and regulations for Carbon Capture and Storage (CCS). Furthermore, the recognition of CCS in either Joint Implementation (JI) or Clean Development Mechanism (CDM) projects under the Kyoto Protocol is still being formulated. The purpose of this paper is to examine some of the benefits of creating additional economic incentives so that industry may lead in the development of the CO₂ value chain through the economic potential of CO₂ for EOR in these oil regions while the other market and regulatory issues are worked out.

Identifying the CO₂ Value Chain

The concept of a CO₂ “value chain” with large-scale commercial use of CO₂ is well established in the US oil industry 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 through our work on the CO₂ for EOR in the North Sea (CENS) Project how international commitments to reduce GHG emissions have extended the potential scope of the value chain to also encompass;

- Pure sources of CO₂ (e.g. refineries, hydro-crackers, 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.

The CO₂ value chain is important because it shifts the focus of GHG emissions away from being a regulatory problem to creating a commercial resource. Wherever a value chain exists, a market will evolve, and with stable policies and a ‘defined playing field’ the most efficient pricing mechanisms will be established and foster further CO₂ reductions. In the next decade this chain could be a mechanism for wealth creation and provide viable policy alternatives for governments to develop new industrial activities, ensure energy security and help combat climate change.

Markets will evolve and projects will develop along the CO₂ value chain, but the use of additional incentives right now to kick start this market may have the biggest impact in the long run on both the volume of CO₂ sequestered and the amount of oil produced.

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, while 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 all 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 2004 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*).

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 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 were 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.

With respect to this last point, the US DOE Fossil Energy, Office of Oil and Natural Gas has published six regional reports highlighting the potential to produce 43 billion barrels of oil using CO₂ for EOR. Recent activity by the EOR Coalition has sponsored changes to the tax code to increase the investment tax credit for EOR from 15% to 25% and to raise the top threshold on the price of oil under which the tax credit is applicable. The incremental oil produced under this proposal will provide new tax revenues making this proposed incentive cash positive to the US Treasury. In a market where security of oil supply has the greater focus, incremental tax revenues and incentives to sequester large quantities of CO₂ through EOR will be realized from this proposal and on average produce 3.2 barrels of oil for every tonne of CO₂ sequestered.

CO₂ EOR for Europe and the North Sea Continental Shelf (NSCS)

Although not identical, we argue that much of the past experience from the United States 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 NSCS and future costly decommissioning.
- Increasing dependence upon energy imports.
- Growing commitment to reduce CO₂-emissions on account of climate-change.

With NSCS production peaking, most operators are making strategic decisions regarding decommissioning versus economic life-extension. Annual platform operating costs often exceed \$50 million, while decommissioning costs can vary from \$150 to \$450 million depending upon the size of operations. There exists a limited window of opportunity for deciding whether to implement a CO₂-flood that is governed by the declining production profiles of each reservoir and availability of CO₂. Decisions for securing supply and using CO₂ will need to be taken within the next 4–6 years [9]. Unfortunately decommissioning a field's platform before tertiary recovery takes place will most likely preclude reopening a field for that next 6-15% of original oil in place and the oil and its associated tax revenues will be lost as a benefit to the government and country.

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 2030. A major conclusion was that Europe can become almost 70% dependent upon imported energy. The possibility of providing “clean” coal, extended oil production, and “greener” natural gas—through decarbonisation, EOR and CO₂ sequestration—is therefore of considerable relevance.

Future GHG emissions are being constrained in line with international commitments through National Allocation Plans. Emission trading is perceived as a key enabling mechanism that will facilitate real reductions of GHG emissions. The EU ETS began operation in 2005 and already recognizes CO₂ CCS as a remediation methodology subject to agreement of the necessary measuring and monitoring protocols. However, even though CO₂ credits have traded near €18 per tonne of CO₂, the unknowns regarding future National Allocation Plans for CO₂ emissions and the uncertainty of the system after 2012 mean it will take years before the system provides secure financial incentives in which to base large infrastructure investments.

CO2-EOR in the UK and Norwegian Sectors

Although sequestering large volumes of CO₂ from mainland Europe will be important for the EU, it would initially appear to be the governments of the United Kingdom [11] and Norway [12] that share the most immediate vested interests to create a demand for CO₂ in the North Sea.

For the UK exchequer this could provide substantial benefits from taxation on incremental oil, delays in platform decommissioning costs, additional jobs, and improved balance of payments due to reduced energy imports. Estimates within the DTI Sharp programme put CO₂ EOR incremental production between 0.9 and 2.3 billion barrels. The UK Chancellor Gordon Brown in his Budget Speech of 16th March 2005 stated that the government would examine “how it might support the development of CCS in the Climate Change Programme Review, including the potential for new economic incentives. In a region where pre-1993 oil field operations are taxed at an effective rate of 70% and post-1993 oil field operations are taxed at an effective rate of 40%, there is significant benefit potential to both oil field operators and the Treasury to encourage the use of CO₂ for EOR to produce oil that otherwise would stay in the ground.

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 (NPD)* conservatively estimates that a potential of 1.5 - 2.0 billion barrels CO₂-incremental oil exists on the NCS with a value of \$45 - 55 billion. However, on 26th April, the Ministry of Petroleum and Energy announced that a completed NPD study [13] concluded that “CO₂ injection does not appear to be a commercial alternative for improved oil recovery for the licensees on the Norwegian shelf.” The study stated that the break even price on oil produced by CO₂ was between \$26 and \$33 per barrel and therefore too expensive to risk in the volatile oil market at this time.

There have also been numerous screening studies undertaken to assess the scope to use CO₂ as a miscible gas for EOR on the NSCS—however few of these are available in the public domain. These studies have provided some useful insights regarding barriers to implementation, as is described below from the perspective of the operator:

- (i) Oil price assumptions: Studies previously assumed an oil price in the range from \$14 - \$17.50 /bbl and have recently considered prices in the range of \$20 - \$25 /bbl. Governments are not at risk of committing large capital sums for EOR projects and can afford a different view on oil price. With the 10-year forward price curve on Brent crude in excess of \$37 /bbl, Governments can be assured that the right fiscal incentives can be funded from incremental taxation from incremental EOR produced oil.
- (ii) Alternative options: While many mature field operators have chosen to extend water flooding, blow down the field or use hydrocarbon gas for miscible injection; if the right incentive mechanisms were implemented, it is not too late to reconsider CO₂ for EOR.
- (iii) Project cash flow: A major objection to CO₂-floods by operators in the US and Canada has been the relatively high initial investment and CO₂ costs coupled with a possible long response time of 1–2 years before noticeable incremental oil production. For smaller independent operators moving into the North Sea, such considerations can be just as important as maximising total recovered reserves.
- (iv) Security of CO₂ delivery: While working on the CENS Project, we have established the interest in CO₂ sources to provide in excess of 25 million tpy of CO₂ and the interest in parties to build the CO₂ infrastructure under the right contractual structures. The delivered price for CO₂ should range between €20-35 per tonne of CO₂ without consideration of CO₂ credits. CO₂ emission credits will further reduce the delivered cost but unfortunately are not bankable at this time and require further clarification beyond 2012. An incentive programme for sources of CO₂ that helped further reduce the delivered cost of CO₂ will encourage an even wider uptake for CCS as each reduction of €6 /tCO₂ is nearly equivalent to €2/bbl of oil. An incentive programme that encourages EOR will realize for the respective Government 40%, 70% or 78% of any further delivered cost reductions through oilfield taxation.

- (v) Project risk management: Operators know that CO₂ will enable them to recover significant quantities of incremental oil and the technology exists to do it. However, North Sea operators are not provided with an incentive to encourage them to make the significant investments required in a CO₂ for EOR project. They do not receive sufficient reward to compete for internal capital against a new field development in another oil region with lower production costs. Governments are in competition for investment capital in their oil regions and more costly tertiary recovery will not take place without incentives that address this fact.

Incentive Mechanisms

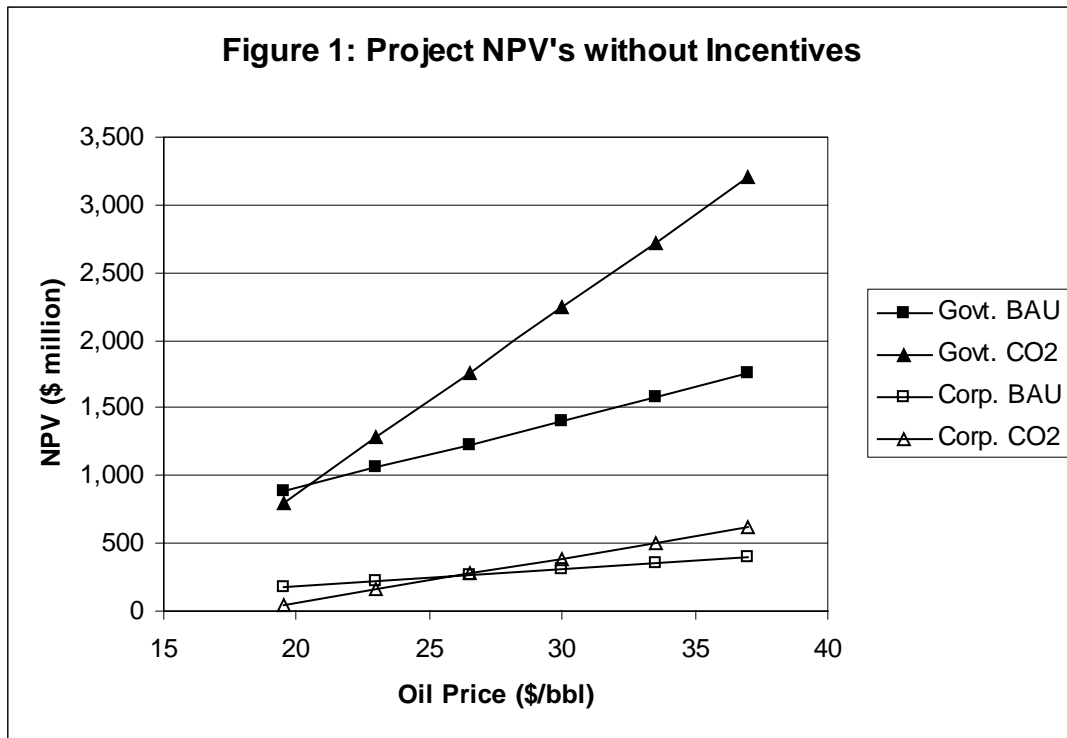
Incentive mechanisms to encourage CO₂ for EOR could take many forms. The US experience indicates that Investment Tax Credits of 15-25% help reduce the pain for the large investments and purchased CO₂ required before incremental oil production is realized. In countries with high effective tax rates or countries where Production Sharing Agreements (PSA's) or other contractual structures and not taxation define what an oil producer realizes, a different production related incentive may be necessary to cover the greater investments and operating costs experienced during tertiary recovery of oil. Future recognition of CO₂ credits through trading systems or CDM and JI mechanisms may also provide incentives to the CO₂ for EOR operator but in high tax or PSA regions, these benefits may be mostly realized by the host country.

One scheme that does appear to handle several of the aforementioned issues was suggested by the *Norwegian Confederation of Oil Industry (OLF)* and described as a 'Volume Allowance' on incremental oil. The allowance was a non-cash deduction from revenues for tax purposes equivalent to \$2.15 /bbl. However, because there were substantial investment allowances already available for proposed projects, the impact of this additional allowance would not be realized for some years into production. Therefore, we proposed and have evaluated the use of an after tax Volume Credit provided for all incremental oil production. The absolute value may be similar to that proposed by the OLF but this needs further discussion between the operators and respective governments.

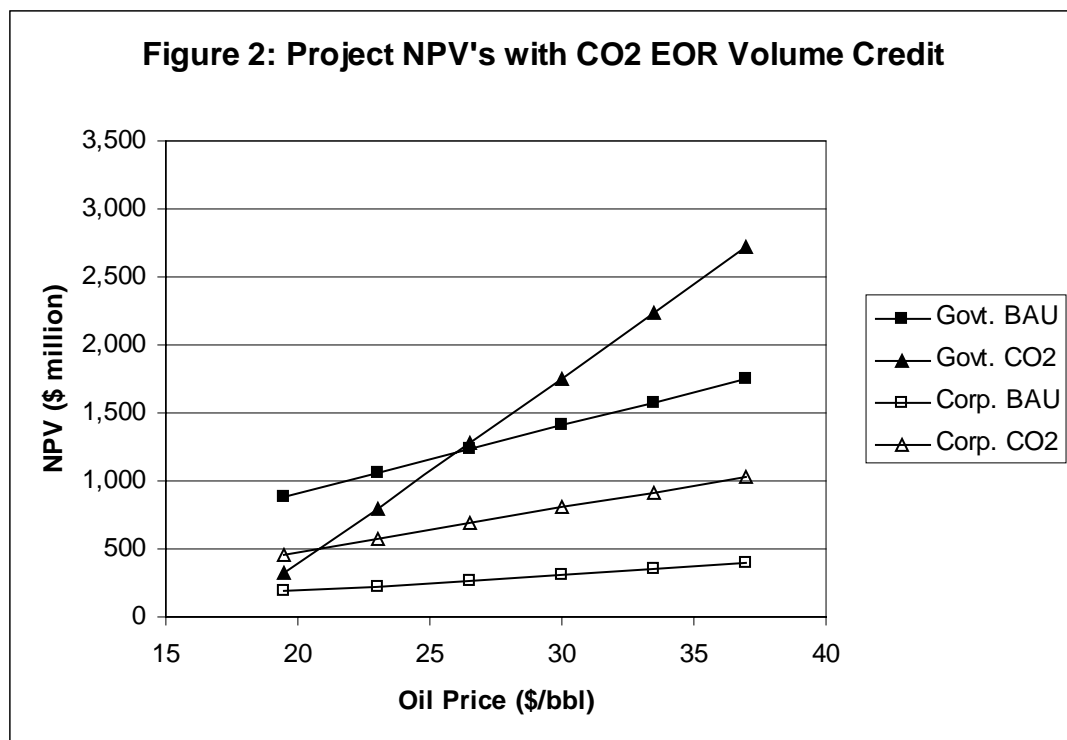
A 'Volume Credit' as we prefer to call it provides investment incentive by providing a known minimum after tax profit margin to an operator independent of oil price and encourages the maximum extraction of EOR oil. The incremental oil production will be that production over an agreed decline curve. While these curves have been difficult to establish for new oil fields, they are readily understood and already provided to the governments on existing oil fields. The use of a minimum margin in this way helps offset the significant increase in operating costs that an operator has with tertiary production in comparison to their alternative investments when evaluated at moderately low oil prices. Again in the UK and Norwegian sectors, profits above this minimum level will be taxed at 40%, 70% or 78% depending on the prevailing rate.

To illustrate the impact of the Volume Credit, we used the proprietary CENS economic model to evaluate a North Sea operating field subject to a high tax rate that had two alternative projects; (i) further intensive water flooding as the business as usual case (BAU) and (ii) the addition of CO₂ for EOR to the same water flood as the CO₂ case. The incremental prizes were respectively 80 and 220 million barrels of oil and over 50 million tonnes of CO₂ would be sequestered in just one field in the CO₂ case. Substantial investments were made for the total CO₂ project while 25% of the amount was needed for the BAU case. It was assumed that CO₂ would be delivered to the platform at a cost of \$48 per tonne, substantially above all costs proposed by the CENS project but conservatively offered here.

The chart in Figure 1 below demonstrates the Net Present Value (NPV) realized by the operating field and the government's treasury for the BAU and CO₂ cases. Because of the high tax environment, it is seen that the government realizes substantially more of the value from either project. The cross over point in which the CO₂ case is better than the BAU case is above \$26 per barrel for the operator and approximately \$20 per barrel for the government. However, the economic return provided the operator was insufficient to win an allocation against other investment prospects that are currently required to be economic in the \$22 per barrel range.



The chart in Figure 2 represents the impact on those same two cases if a Volume Credit of \$4.30 per barrel was instituted. Now the CO2 case has a substantial jump in NPV such that the crossover point is below \$13 for the operator but has moved upward to \$26 for the government. However, the government maintains through the tax regime, significant upside value from the CO2 case if further technical and market developments decrease the cost of delivered CO2 or increase the value of the produced oil. CO2 for EOR may be an expensive way to produce oil but there can be clear financial benefits to all players along the CO2 value chain, but in many areas there is a limited window of opportunity to implement CO2 for EOR projects.



Summary and Way Forward

Key issues for the oilfield operators are (i) perception of market oil price, (ii) incentives to investment, (iii) cost of delivered CO₂ and (iv) security of CO₂ supply. For the CO₂-supplier it is, (i) cost for capturing and gathering the CO₂, (ii) future regulations constraining CO₂-emissions, (iii) cost of alternative options for CO₂-avoidance and (iv) secure contracting strategies for CO₂ supplied and transported. To address these issues there needs to be dialogue across several industrial sectors (e.g. oil & gas, power, process, chemical and refining) as well as with three government bodies (Finance, Energy and Environment). The key facilitating parameters are market oil price, CO₂ delivered price and government incentives. It is the type and magnitude of the incentives that will draw the parties together to realize much of the potential incremental oil prize.

Furthermore, no other commercial solution has the potential to reduce CO₂ emissions as much as CO₂ for EOR. Capture costs will come down through experience and CO₂ credit-trading systems will mature in due time. Governments in all major oil regions therefore have an excellent opportunity to accelerate implementation of large-scale CO₂ sequestration through Enhanced Oil Recovery by focusing on economic incentives to promote CO₂ for EOR. Thus attaining meaningful reductions in CO₂ emissions and ensuring security of energy supply.

(See www.co2-global.com for additional analysis.)

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