Techno-economic evaluation of CO_2-EOR in the North Sea

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Contents

1. Executive summary

CO_2-EOR is a possible means to produce incremental oil from active oil fields. In the ongoing climate change debate, it is also welcomed as a business case for geological storage of CO_2 (CO_2 Capture and Storage, CCS). The possibility for applying this technology in the North Sea has been under discussion for several years, but the high cost and financial risk have hampered its deployment until today.

Using the techno-economic simulator PSS IV, potential CO_2-EOR projects can be evaluated in a realistic way, considering technological, policy-related, economic and geological uncertainties using Monte-Carlo calculations. For the current study, around 450 to 750 MC runs were performed (lower for the Cluster, and depending on the field and scenario), which is considered to produce results in sufficient detail for the current set-up. This number is mainly limited by computing performance. PSS IV includes a unique feature, in that it makes project evaluations considering incomplete information about the future. Next to its standard Monte-Carlo methodology, where stochastic parameter values are changed slightly every calculation, a second level of Monte-Carlo calculations and stochastic parameters are used for creating an outlook towards the future. This methodology is called “limited foresight”, which produces near-optimal investment decisions. This is considered more realistic compared to an optimisation model, where actions are taken based on a perfect forecast of the future. This methodology is combined with Real Options analysis, to include the value of having future project flexibility. Figure 1.1 shows the cash flow in a typical project, as simulated by PSS IV.

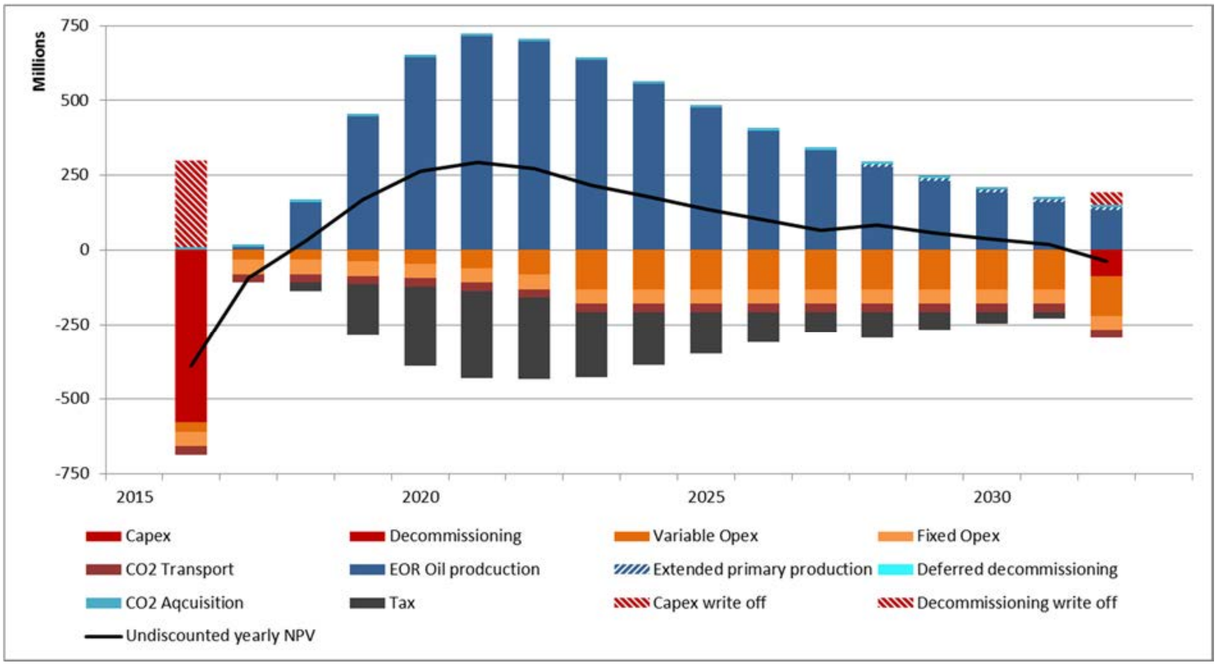

Figure 1.1. Typical cash flow in a CO_2-EOR project as simulated by PSS, for the Claymore field in the Reference scenario. Total discounted NPV is 507 M GBP.

For the current study, the Claymore, Scott and Buzzard fields were considered as potential CO_2-EOR candidates. In an experimental set-up, an optimized cluster of the Claymore and Scott field together was evaluated as well. Different scenarios are considered, to investigate possible government incentives to maximise the use of natural resources and start the application of CO_2-EOR in the British offshore area of the North Sea.

In the “Reference” scenario, the 100% First Year Allowance and a 50% marginal tax rate on profit were applied. Other scenarios are deduced from this Reference scenario. In a second

"Loan" scenario, a commercial loan was allowed for all investment costs. This scenario is less favourable for the total discounted NPV (Figure 1.2). A lowering of the tax rate to 40% in the "LowTax" however proves to be a good incentive for a higher project value. In the "LowCO_2" scenario, a government incentive related to a lowering of the CO_2 acquisition cost shows no significant effect. For Treasury income through tax, these scenarios have the opposite effect. A sensitivity analysis proves that the CO_2 price has only a minor effect on the project's discounted value (Figure 1.3). This finding is in line with the lack of effect of the lowered CO_2 acquisition cost. The range of CO2 acquisition costs is constructed from a capture cost of 22 GBP/t and a CO_2 ETS price of 15-29 GBP/t. The oil market price however is a major driver, with a potential high NPV for oil prices over 60 GBP/bbl.

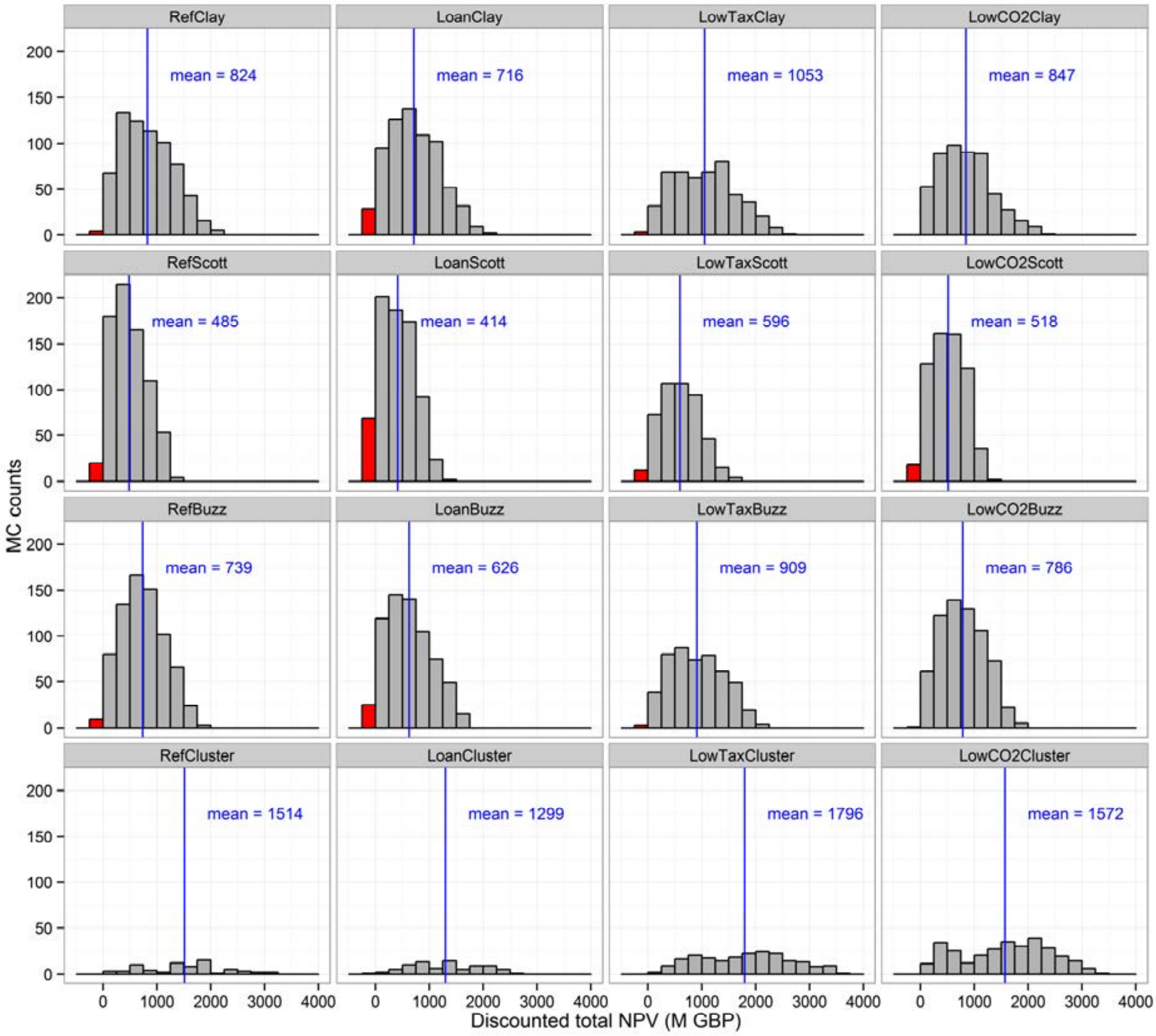

Figure 1.2. Histogram of the total discounted NPV for projects that were evaluated positively by PSS IV for activation, as Monte-Carlo counts. The mean value is indicated by the blue line, and projects with negative NPV are indicated in red.

The geological circumstances also have a significant effect on the project value. High recovery rates are predictably favourable, but also the response and timing of oil production by CO_2-EOR is important. A fast recovery of oil in EOR activities has a clear positive effect on the NPV of EOR projects, opposed to a slower, but longer recovery of the same amount of oil. Based on the geological parameters used to approximate the behaviour of three different oil fields, the added value of EOR for the Claymore field is highest, and that of Scott lowest. Regarding the additional oil produced by EOR, all scenarios except the Loan scenario allowed for the technically maximum oil recovery.

The positive effect of deferred decommissioning is relatively small in the overall cost-benefit picture of an EOR project, but may nevertheless be important in evaluating individual projects. Only for the Buzzard field, which is the most recent, the effect of deferred decommissioning is zero.

PSS IV is capable of producing more advanced results than currently presented. At this early stage, the simulated investment decision criteria were chosen on the optimistic side. PSS IV at this moment does not use a hurdle rate; at this moment it will activate a project when it is expected to generate a positive total discounted NPV. The results in this study can therefore not be used to draw conclusions on economic cut off boundaries. For a series of additional, potentially important cost and benefit parameters, such as transport costs, reruns of PSS IV are needed. More in depth analysis of the produced results is also useful. Not included in the present study is for example an estimation of the internal rate of return.

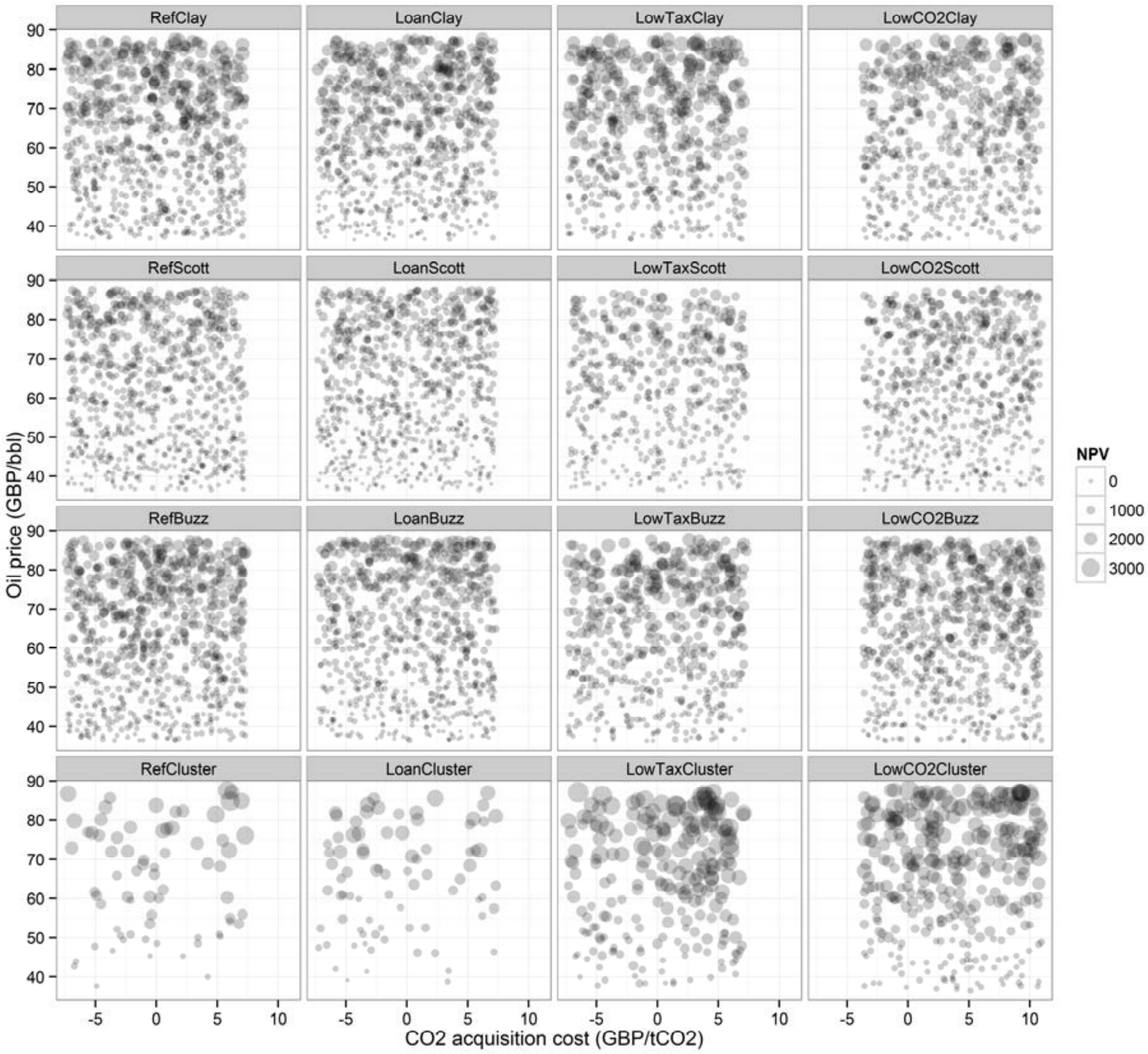

Figure 1.3. Cross-plot of the oil price and CO_2 price for activated projects, with indication of the total discounted NPV.

2. Introduction

There has been oil production from the North Sea for more than four decades. The average recovery rates are close to 50% OOIP, although variations from 10% to 70% are possible due to differences in field characteristics and production strategies (Element Energy, 2012). Attaining maximum economic recovery should be regarded as a priority in a mature petroleum province such as the North Sea. To increase the recovery rate tertiary or enhanced oil recovery (EOR) could be initiated. This study will focus on CO_2-EOR. Although CO_2-EOR is well established onshore, for example in the USA, it is much less common in offshore situations. The main reasons which inhibit offshore CO_2-EOR are the higher risk and the considerable capital expenditures for offshore installations compared to an onshore environment, as well as the current absence of affordable CO_2 sources (Kemp et al., 2014).

This study will estimate and evaluate the feasibility of CO_2-EOR projects in the North Sea area, considering different tax incentives. The impact of implementing these different tax incentives in the existing UK offshore oil & gas tax system will be evaluated as well for the oil companies as for the government. The four tax incentives which will be considered are listed here, and a detailed description can be found in section 5.4 (Tax incentives).

- **Reference: 100% first year tax relief on CAPEX**
- **Loan: Commercial loan for CAPEX (CAPEX annualisation)**
- **LowTax: Lowered tax on additional EOR oil production (lowered total profit tax)**
- **LowCO_2: Lowered variable OPEX (e.g. Treasury funds CO_2 acquisition cost)**

For this study the Policy Support System version IV (PSS IV) will be used. The PSS IV uses advanced economic principles such as Real Options Analysis and Modern Portfolio Theory. In order to make accurate predictions, it attempts to realistically simulate economy and investment decisions based on near-optimal project evaluations that take into account future uncertainties (Piessens et al. 2012). The main advantage of the PSS IV compared to other simulators is that it avoids perfect foresight, guaranteeing a more realistic approach. The future path can deviate from the set values in the Monte Carlo iteration. Hence, investment decisions are not perfect, because the outcome is not already known, which is the case for perfect foresight simulators (Rupert, 2014).

The PSS IV simulator has the following approach: a fixed set of oil (potential CO_2-EOR) fields, in this case the Claymore, Scott and Buzzard oil fields, is assessed for the best investment options on a yearly basis through a finite timeframe. Each year an analysis is made from a company's point of view, which (combination of) field(s) should continue normal operation, be turned into CO_2-EOR operation or closed down. Oil field and EOR performance is simulated as lognormal production curves. CO_2 recycling, production delays, primary production extension etc., are considered along with a multitude of other cost and performance data. Investment incentives are mainly driven by CO_2 and oil prices.

All monetary calculations were made in Euro, and converted afterwards using a 0.73 conversion rate GBP/Euro. Quantities of CO_2 are expressed in metric tonnes, volumes of oil are expressed as million barrels (MMbbl; about $159*10^6$ liters).

3. CO_2-enhanced oil recovery

This chapter provides a basic understanding of CO_2-EOR. First, the sources of CO_2 and the basic mechanisms of transport of CO_2 by pipeline are explained. Then, the dynamics of primary as well as enhanced oil recovery are addressed.

1.1 The capture and transport

The first step in CCS, and largest in terms of costs, is to capture the CO_2. This can be done by concentration, recovery or capture of a high purity CO_2 stream (IPCC, 2005). Large stationary point sources of CO_2 are favourable for CCS (IIASA, 2012). Alternatively, collecting several CO_2 sources into a single pipeline, i.e. a trunk line, is cheaper than transporting smaller amounts independently due to economies of scale (Ramirez et al., 2011), however, using high capacity trunk lines requires large initial investments (IPCC, 2005). The captured CO_2 can then be transported to the oil platform using pipelines or ship transport. Because pipeline technology is a reliable and mature technology that is useful for transporting large quantities of e.g. oil, natural gas, condensate, CO_2 and water (Guijt, 2004) and because the safety risks are known and can be minimised by risk abatement technologies and safety measures (Damen, Faaij, & Turkenburg, 2006), this study will only consider pipeline transport.

The main elements of a pipeline system are the pipeline itself, booster stations, metering stations, controls systems valves, and pipeline inspection gauges. Pure and dry CO_2 can be safely transported using carbon steel pipelines, because it causes no internal corrosion (European Commission, 2011). Impurities, however, can have a great impact on the transport requirements such as the design of the pipeline. When, for example, CO_2 has a large water content, the mixture becomes highly corrosive and weakens the pipeline integrity. Minimising contaminants and consequently the risk for pipeline or ship damage is hence very important. The composition of the CO_2 stream depends on the source type, the capture technology and the fuel use. In addition the CO_2 has to meet the minimum miscibility pressure (MMP), i.e. the CO_2 and the oil need to be miscible in order to produce the incremental oil using miscible CO_2-EOR. Therefore too stringent purity requirements will have a negative impact on the capture costs and the technology options (Ramirez et al., 2011).

This study assumes a near pure CO_2 stream (95-100% purity) that is in accordance with the MMP requirements and other issues such as corrosion and safety. In some cases, existing natural gas pipelines can be re-used for CO_2 transport. Apart from corrosion by the CO_2 stream, the outer walls of the pipelines must be coated to protect against corrosion by seawater. The coating is the primary barrier to corrosion of a pipeline (Palmer & King, 2008). Additionally, cathodic protection prevents corrosion at areas of damaged coating. In general, the higher pressure of the CO_2 compared to natural gas transport requires an increase in the wall thickness of the steel pipes. A doubling in pressure doubles the required thickness. Moreover the thickness of the steel for offshore pipelines should be at least 2.5% of the diameter. An economic trade-off is made between a higher inlet pressure, an increase in diameter and the placement of booster stations (Knoope et al., 2014). Booster stations (also referred to as pumping stations) are used to counteract pressure losses along the pipeline. However, placement of booster stations offshore is unfavourable because of the difficulties with offshore installation and maintenance and the need for an offshore platform with energy supply, which is very expensive (Knoope et al., 2014). Hence, larger diameters are applied to reduce the pressure drop along the pipeline (Huang, Rezvani, McIlveen-Wright, et al., 2008).

1.2 Oil recovery

The typical profile of oil production over time starts with little production of oil and builds up to a peak or plateau. Then, the production declines until the moment when the oil production has reached the bottom economic limit. Figure 3.1 shows a typical production profile of primary production.

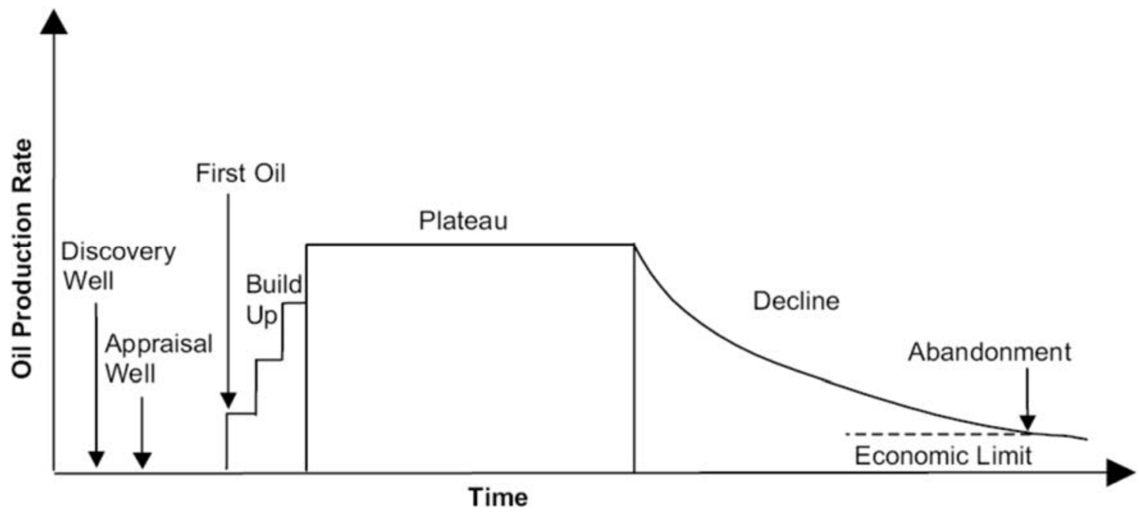

Figure 3.1: Typical production profile (Robelius, 2007)

In order to extend the lifetime of the oil field, primary production can be followed by secondary and tertiary oil production (Figure 3.2). In this study the following definitions for primary, secondary and tertiary oil production will be used: Primary oil production is when oil is produced from wells under natural pressure or by means of pumps (artificial lift). Secondary oil production is when water flooding is used to push the oil through the reservoir to the well. Injection of hydrocarbons (e.g. natural gas) to maintain pressure is also considered as secondary recovery (Alvarado & Manrique, 2010). Tertiary oil recovery, also referred to as enhanced oil recovery (EOR) is a technique to extract oil from the reservoir, when primary and secondary recovery techniques are exhausted (Element Energy, 2012; Hook, 2009). EOR techniques can be categorised into thermal, gas injection, chemical injection and other.

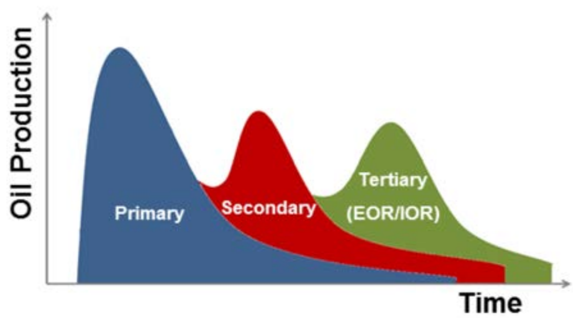

Figure 3.2: Primary, secondary and tertiary recovery over time. Adapted from Element Energy (2012)

EOR can be applied using water-alternating-gas (WAG) injection schemes, i.e. hydrocarbons, nitrogen or CO_2 is alternated with water flooding. Gas injection has been most widely used for light, condensate and volatile oil reservoirs. CO_2-EOR is a process in which high pressure CO_2 is injected into an oil-bearing stratum. This study focuses on miscible CO_2-EOR[1]. The miscibility of the CO_2 and the oil determine the oil displacement. The ratio of the mixture largely depends on reservoir temperature, pressure and oil composition (Advanced Resources International, 2010). Figure 3.3 provides a schematic overview of the CO_2-EOR process. Because of the high mobility of CO_2, which would greatly reduce the effectiveness of the injections, it is most common for the CO_2 not to be injected as a continuous fluid stream, but using WAG injection

[1] Immiscible displacement CO_2-EOR yields lower recoveries compared to miscible conditions (Heddle et al., 2003)

schemes. Water is less mobile than CO_2 and hence the sweep efficiency is improved, while also preventing early CO_2 breakthrough in producing wells (Heddle, Herzog, & Klett, 2003). The injected CO_2 mixes and dissolves into the reservoir oils, resulting in low viscosity, enhanced mobility and low interfacial tension (Lee & Kam, 2013). CO_2 acts as a propellant, and, because it reduces the viscosity of the oil, as a solvent. The oil is remobilised and is displaced to the oil production well (Advanced Resources International, 2011), accompanied by substantial amounts of CO_2. Recycling the CO_2 by separating it from the oil, drying it and re-injecting it in the reservoir will reduce the demand for fresh CO_2 considerably. For these processes, CO_2 recycling facilities are required to separate, dehydrate and recompress the CO_2 (Melzer, 2012). Figure 3.4 shows a conceptual oil production and CO_2 injection profile for a CO_2-EOR project.

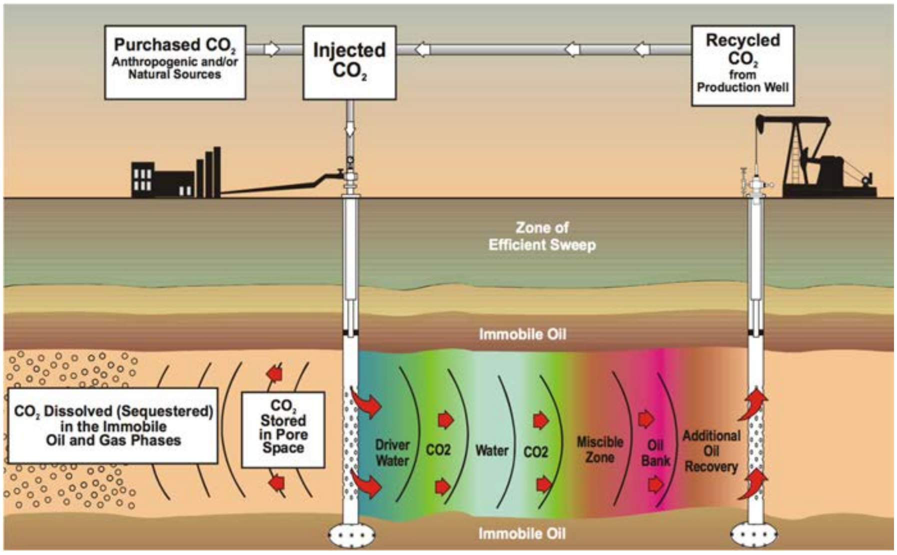

Figure 3.3: Schematic overview of CO_2-EOR (Advanced Resources International, 2010)

In the first year, all CO_2 needs to be transported to the CO_2-EOR project and injected into the oil field. The amount of injected CO_2 is increased and the oil production follows. Production of oil usually starts after 18 to 24 months of CO_2 injection (Advanced Resources International, 2011). The oil production reaches a peak and declines until the point of economical production shutdown, usually after 10-15 years. This study assumes that eventually all CO_2 is stored in the reservoir.

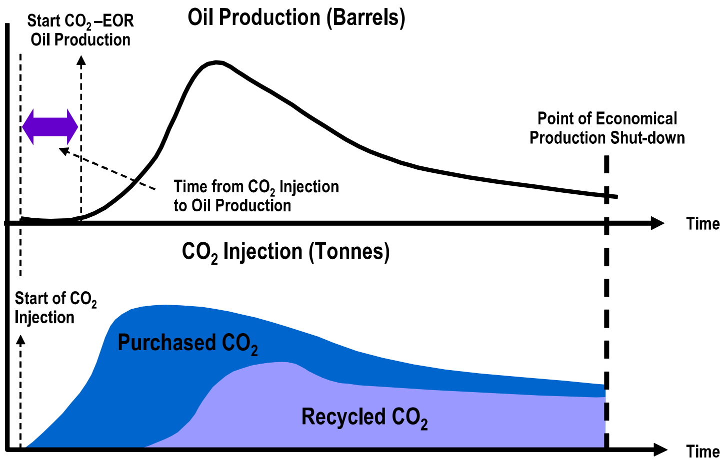

Figure 3.4: Conceptual CO_2 injection profiles and oil production, from Bellona (2005) in Advanced Resources International (2011)

4. The simulator: Policy Support System (PSS)

The methodology of the Policy Support System described in this chapter is based on the final report "policy support system for carbon capture and storage" , Piessens et al., 2012 and the MSc thesis "Impact of geological uncertainty on project valuations for offshore CO_2 enhanced oil recovery", Rupert, 2014. In support of this report the simulator has been upgraded to the latest version, PSS IV.

1.3 PSS SIMULATOR STRUCTURE

The Policy Support System version III (PSS III) is a techno-economic ad-hoc CCS simulator developed at the Royal Belgian Institute of Natural Sciences by the GeoEnergy team of the Geological Survey of Belgium. The simulator is purpose-built to address policy-related questions regarding the future of CCS. It is a true simulator since in essence it uses input data and a set of equations to calculate a probable future result. A bottom-up approach was chosen to make realistic project decisions with high detail in particular fields. This opposes to a top-down model, where the total system is analysed from the highest level down, in general without reaching the detailed bottom level which is used as input for the bottom-up method.

The PSS III Simulator was specially designed to be able to handle almost any range of uncertainty. To introduce uncertainty, the parameters are defined as stochastic parameters with an uncertainty distribution ('inner Monte-Carlo'): a normal, lognormal or uniform (block) distribution. The repetitive character of setting these values at random in a specified uncertainty distribution is called Monte Carlo analysis. True random data from atmospheric noise (160MB) is used to set values for the stochastic parameters in each Monte-Carlo iteration. Perfect foresight is avoided to guarantee a more realistic approach: the future path can deviate from the set values in the Monte-Carlo iteration. In each year the routing module calculates the cheapest route from each reservoir or border to any location. The economic module will consider all existing industrial installations for retrofitting and all possible future installations and their technology options, per sector. PSS III makes decisions based on production cost. These will be calculated using Real Options Analysis (Brekke & Schieldrop, 2000), and decisions are made with the Modern Portfolio Theory (Markowitz, 1987). It is important that the actual future costs and benefits that the projects will be confronted with in PSS III are different from the cost and benefit outlooks at the time project decisions are taken. This method comes close to real life, where decisions are based on current knowledge, but actual values of technology parameters and political/economic circumstances such as costs, performance and CO_2 price are not exactly known in advance. In short, investment decisions are not perfect because the outcome is not already known, which is the case for perfect foresight models. Each project decision is made based on its own future projections, with information available at that time. The actual future parameter may be different, but are only revealed when simulation reaches that point in time. This results in more realistic investment risk assessment.

The simulation of CO_2-EOR activities were not yet integrated in PSS III, but have been added to the latest version of the simulator, PSS IV. The main difference between CO_2-EOR and CCS is the goal: CCS is aimed at storing CO_2 while CO_2-EOR is aimed at extracting more oil from a field. Moreover, they differ in terms of the role that CO_2 plays, the factors influencing operation and the complexity. A brief overview of how CO_2-EOR activities are evaluated in PSS IV is outlined below.

PSS basically matches CO_2 sources with suitable sinks based on economic criteria and feasibility. The similarity between CO_2-EOR and standard CCS projects is the requirement to transport large quantities of CO_2. However, the economic decisions in CO_2-EOR projects are fundamentally different, because the production of incremental oil is an important economic motivation, next to the benefits of geologically storing CO_2. Somewhat simplified, most CO_2-EOR projects use CO_2 primarily to boost oil production, while CCS regards CO_2 as undesired by-product that needs to be isolated from the atmosphere. Hence, the CO_2 requirements in CO_2-EOR projects are defined by the CO_2 demand side (optimising for incremental oil recovery), while standard CCS projects focus on the CO_2 production side (storing all captured CO_2). The selection criteria for a suitable location differ, because CO_2-EOR is used in oil fields that are typically nearing depletion, while this aspect of timing is absent in many standard CCS locations (e.g. saline aquifers) where screening will first of all focus on sufficient storage capacity, etc.

The value of CO_2-EOR projects is intrinsically also more complex to assess than CO_2 storage projects, because of the relation to primary oil recovery, CO_2 production to the surface and the influence of CO_2 recycling on the external CO_2 demand. PSS IV simulates CO_2 storage in CO_2-EOR projects using an approach that is modified from Piessens et al. (2012). Multiple techno-economic parameters are added to include CO_2-EOR aspects such as EOR ratio, recycling ratio and oil price. For these parameters, the time aspect is essential.

1.4 TRANSPORT COST

In this study, the starting point for pipeline investment costs are the equations embedded in PSS (Piessens et al., 2009) and adjusted for offshore use in the North Sea (Rupert, 2014). The material costs are calculated using pipeline length, outer diameter of the pipeline, steel costs, operational pressure, allowable stress in the pipeline and factors for under-thickness tolerance and threading, mechanical strength and corrosion. Labour costs are based on empirical data from the Oil & Gas Journal (Smith, True, & Stell, 2005; True & Stell, 2004; True, 2003). Different terrain (raster) and hinder (vector) factors for cost calculations are applied, including height, landfall (beach crossing), and pipeline crossings. Figure 4.1 show the bathymetry of the North Sea region, which is used in PSS IV for pipeline calculations. Figure 4.2 shows a map of the area of the North Sea under consideration, with the existing pipeline trajectories (Harvard, 2014; Norwegian Petroleum Directorate, 2014; Petroleum Economist, 2006; Publieke Dienstverlening op de Kaart, 2014; TU Delft, 2014; Worldmap, 2014).

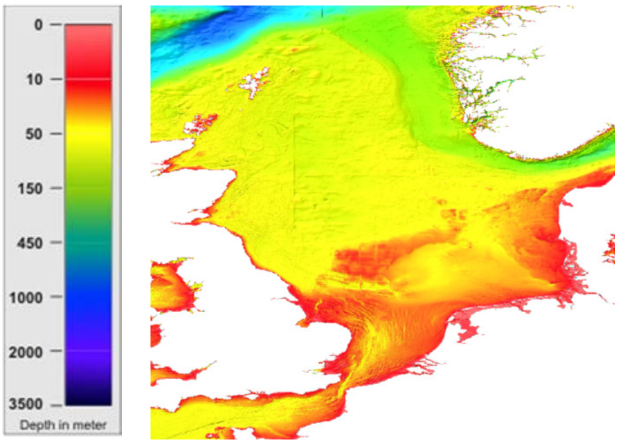

Figure 4.1: Bathymetry for North Sea region, from EMODnet (2014)

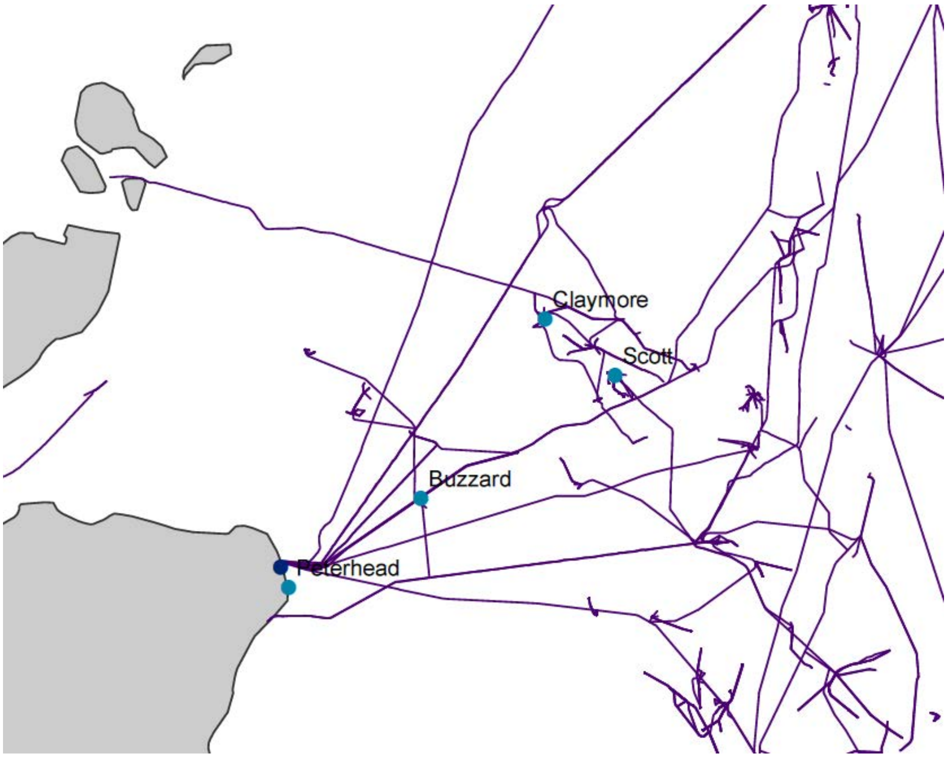

Figure 4.2: Location of the CO_2 source (Peterhead), the potential CO_2-EOR fields, and the existing pipeline infrastructure in the North Sea.

The route calculated by PSS IV is the least-cost pathway from the CO_2 source and optimised for both costs by going over the cells in the grid and crossing pipelines. Figure 4.3 shows an example of the routing optimisation in two situations. In situation b, the least-cost route is to cross the existing pipeline twice, while in situation a, it is better to avoid crossing the pipeline.

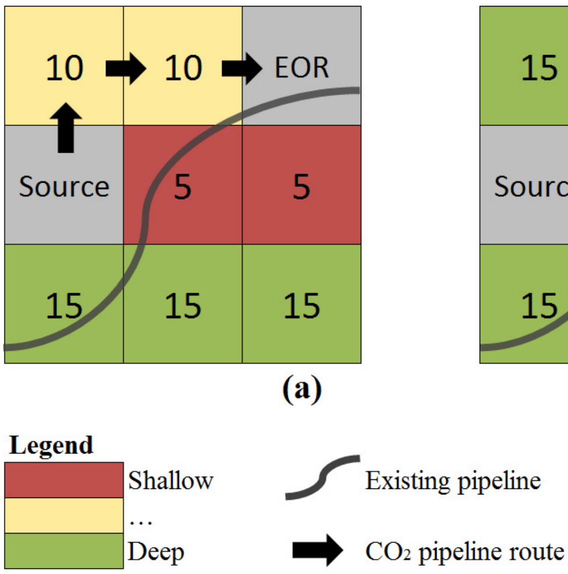

Figure 4.3: Example of a 3x3 cell grid. The numbers in the cell represent the costs for the pipeline. Two different situations are illustrated. Assume the costs for crossing an existing pipeline is 7.5. In situation a, the least-cost route is 10+10=20 (as compared to crossing the pipeline: 5+7.5+5+7.5=25). In situation b, crossing the pipeline is the least-cost route: 5+7.5+5+7.5=25 (as compared to 15+15=30). The grid, possible trajectories and calculations are strongly simplified to demonstrate the basic principle.

1.5 Economic evaluation

As explained above, the simulator consists of two nested Monte-Carlo loops. For convenience the largest one is called the outer Monte-Carlo and the smallest the inner Monte-Carlo. In a first step the stochastic parameters for the first year are randomly chosen within the defined interval within the outer Monte-Carlo loop. The stochastic parameters are now set for the whole duration of one of the outer Monte Carlo loops, in this case until 2050. This would however imply perfect foresight. In other words, the future path is known. To avoid this, a second, inner Monte-Carlo loop makes calculations with outlook parameters, of which the value is initially based on the "real" outer MC value. With time however, the parameter values can divert. This modelling approach is directly based on real life investment decision making. Information of today is available, e.g. next year's oil price can only be estimated within an interval. When looking further into the future, uncertainty grows and this interval grows as well.

The probability range is defined by a value with which the parameter can rise or fall every year. In order to clip unrealistic values, a 90% probability interval is defined that contains 90% of all possible future pathways (based on random walk). Every possible future pathway, which may hold different investment decisions such as starting an EOR project or abandoning a project, is calculated several times in this inner MC.

Project NPV results are grouped per next year's decision, and the best risk versus return option is chosen to be activated. The best decision can also be to continue primary production. The NPV is thereupon calculated using the "real" values of the outer MC. After that the inner Monte-Carlo makes the calculations to make the decision of the following year. This procedure is repeated until 2050 and represents one outer MC calculation. For each scenario, multiple outer MC calculations have been made (see Table 6.1).

5. Data

1.6 CO_2 source

The selected hub for CO_2 capture for the simulations in this study is located in Peterhead.

The CO_2 hub location is selected based on CO_2 emissions from large point sources in the North Sea area and whether construction of pipelines is possible and existing harbour infrastructure can be used. One of the major advantages of Peterhead is that (oil) pipelines to the considered oilfields already exist.

In order to reduce the time needed for the simulations, only one hub for CO_2 capture is selected. This, however, includes a strong limitation on the amount of CO_2 that can be captured. To solve this problem, the amount of CO_2 which can be captured at Peterhead is assumed to be unlimited.

The cost of capture of the CO_2 and transport to an onshore hub is assumed to be carried by the CO_2 producer (with an appropriate support mechanism for low carbon emission, e.g. ETS system and/or other). CO_2 which would otherwise be destined for pure CO_2 storage in a CCS scenario, is transferred to an EOR project at between -10 and 10 Euro/t CO_2 (-7.3 – 7.3 GBP/t), which is in line with the -10 to 10 GBP/t CO_2 used in the Element Energy (2012) study.

Fresh CO_2 injection is assumed to be constant in time throughout the whole project. After 2 years recycled CO_2 will be injected as well, increasing the total amount of CO_2 injected. The amount of recycled CO_2 will increase until reaching a fixed maximum of 75% the yearly injected fresh CO_2 5 years later and will remain constant for the duration of the project, resulting in a two-step injection graph (Figure 5.1).

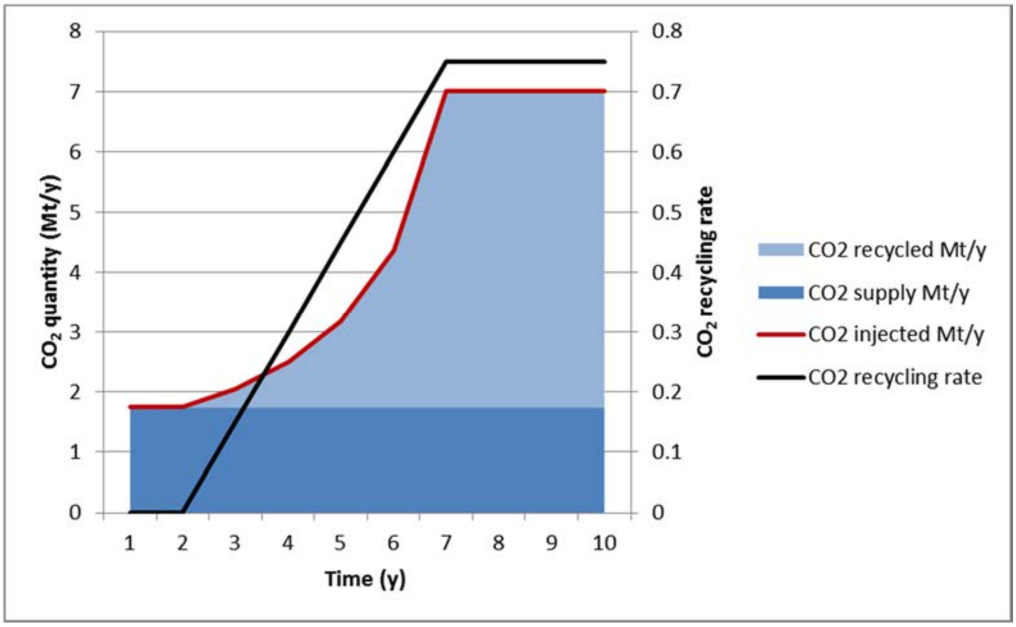

Figure 5.1: Example of the CO_2 supply, injection and recycling quantities, and the evolution of the CO_2 recycling rate, for the Claymore field. Parameter values remain constant after year seven until the end of the CO_2-EOR project.

1.7 Primary oil production and CO_2-EOR

In this study the profiles of primary and secondary production are modelled using lognormal curves. These curves are appropriate because they give a good approximation of the actual production curve (Rupert, 2014). Because the area beneath a lognormal function is by definition equal to 1, a scale factor is used to represent the total amount of oil recovered. Hence, the scale factor must be equal to OOIP (Oil Originally In Place) multiplied by the recovery factor. The assessed recovery factor for primary production of these fields are all close to 46% of OOIP, which is the value that will be used in these simulations. Creating the lognormal primary production curves is done using the real production data and for the most recent field, Buzzard, future projections are used as well. The production curves are defined with the parameter that can be found in Table 5.2.

Because the North Sea province is considered a mature oil province, the shape of the oil production curves can be approximated with high certainty. Consequently the mean of the production, defining the shape of the production curves is a fixed, non-stochastic value for each of the considered oil fields.

Similar to the primary recovery, the production curve for enhanced oil recovery is also simulated with a lognormal curve. EOR production has however a high degree of uncertainty. To account for the geological uncertainty of the reservoirs, this study uses two stochastic variables for the oil production curves. The EOR recovery rate defines the height of the curve, which corresponds to more or less oil produced per year and in total. The µ (mu) factor defines the stretch of the curve and the position of the peak, which corresponds to a fast or slow reservoir response. The recovery factor is able to vary between 8% and 12% of OOIP and the µ is able to vary between 1.9 and 2.1. With these parameters, Monte Carlo analysis will construct different production curves. Figure 5.2 shows possible variations of a synthetic production curve.

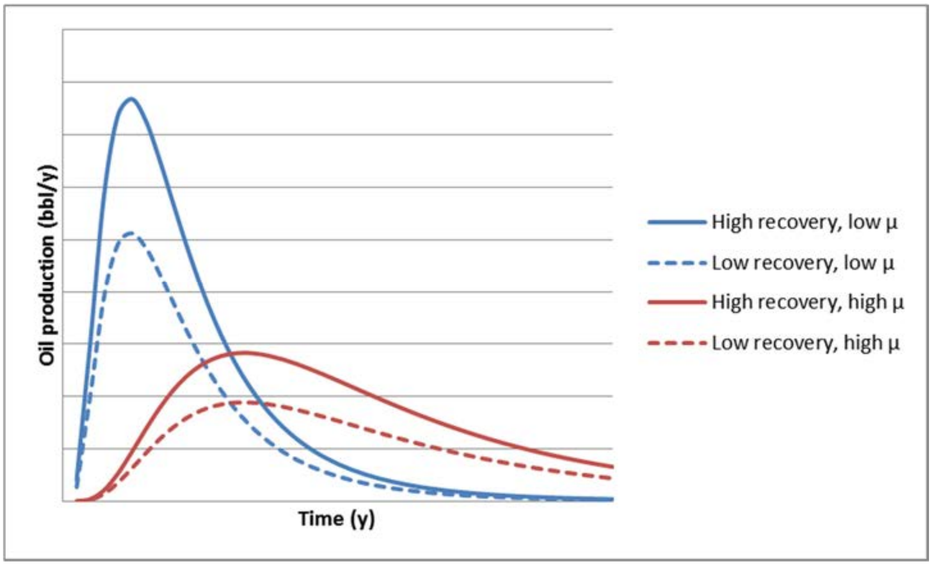

Figure 5.2: Example of the variation of production curves, when changing the parameters of the lognormal curve. The EOR recovery rate defines the height of the curve (more/less oil produced), and the µ factor defines the stretch and the position of the peak (fast/slow reservoir response) (Rupert, 2014).

The oil fields used in this study are Claymore, Scott and Buzzard, all located in the UK sector of the North Sea. The techno-economic parameters that are needed to construct the projects are for primary production (OOIP, production recovery factor etc.) and the CO_2-EOR potential (incremental barrels recovered, annual injection etc.). The OOIP of the Claymore oil field is 1455 MMbbl (European Commission, 2005), with an approximate primary recovery production of 669 MMbbl (recovery factor of 46%). For the Scott oil field, the OOIP is 946 MMbbl, with an estimated primary production of 435 MMbbl. Finally, the OOIP for the Buzzard oil field is 1200 MMbbl. Primary production is estimated to be 552 MMbbl. The input parameters for primary and EOR production are listed in Table 5.1. An overview of the values for the input parameters of all the fields is shown in Table 5.2.

Table 5.1: PSS IV reservoir input parameters

Input parameter	Unit	Remarks
PrimOOIP	MMbbl	Oil originally in place. Physical amount of oil available in the reservoir
PrimRec	Fraction	Recovery rate. Fraction of oil that is recovered during primary and secondary oil production.
PrimMean	-	Mean of lognormal curve for primary oil production. Calculated from the mode.
PrimStD	-	Standard deviation for lognormal curve of primary oil production.
OilProdMin	M GBP	Boundary condition for simulation purposes. Minimum required annual revenues from oil during primary production.
EORRec	Fraction	Recovery rate. Fraction of oil that is recovered during EOR.
EORMean	-	Mean of lognormal curve for EOR.
EORStD	-	Standard deviation for lognormal curve for EOR.
EORDelay	Years	Delay in oil production when EOR is started, i.e. time before first EOR oil is produced.
EORCO2RecycRate	Fraction	Recycling rate of CO_2, expressed as a fraction of CO_2 injected.
EORCO2RecYMax	Years	Time at which CO2RecRate reaches the maximum value, because the recycling of CO_2 builds up over time.
EORCO2RecycDelay	Years	Delay in CO_2 recycling, i.e. time before first CO_2 is produced.
EORCO2Require	Mt/y	Maximum amount of CO_2 required for injection (i.e. maximum injection rate, sum of freshly supplied and recycled CO_2).

Table 5.2: Overview of input parameters of primary and EOR production.

Parameter	Claymore	Scott	Buzzard
PrimOOIP (MMbbl)	1455	946	1200
PrimMean	2.6	1.65	1.9
PrimStD	0.98	1.2	0.65
PrimRec	0.46	0.46	0.46
OilProdMin[2] (M GBP)	120	78	99

[2] All based on Claymore. The production minimum (MMbbl oil per year) is determined by dividing this number with the oil price in the relevant year.

EORRecovery	0.08-0.12	0.08-0.12	0.08-0.12
EORMean	1.9-2.1	1.9-2.1	1.9-2.1
EORStD	0.65	0.65	0.65
EORDelay (y)	1	1	1
EORCO2RecycRate	0.75	0.75	0.75
EORCO2RecycDelay (y)	2	2	2
EORCO2RecYMax (y)	5	5	5
EORCO2Req (Mt/y)	7	4.6	5.8

Oil field data and data concerning primary and CO_2-EOR production were collected from different sources and combined to obtain a coherent set of values for all PSS IV parameters, which required some assumptions by the authors (especially for the uncertainty ranges). Primary oil production curves were fitted on production data from the UK DECC (2015). OOIP and recovery rate data were collected from the European Commission (2005), Sandrea & Sandrea (2007). Other data regarding EOR performance were combined from these previous sources, as well as data from Holt et al. (2009), Klokk et al. (2010), Element Energy (2012), and Kemp & Kasim (2012).

1.8 CAPEX and OPEX for CO_2-EOR

When primary and secondary oil recovery is decreasing and reaches non profitable conditions, an evaluation will be made if CO_2-EOR should be initiated. This will highly depend on the capital expenses (CAPEX) and the operational expenses (OPEX) of CO_2-EOR. The CAPEX are the costs involved for the retrofit of an oil platform and include reworking of existing wells, CO_2 injection wells, CO_2 recycling facilities, etc. This study only considers oil platforms that can be retrofitted for CO_2-EOR. Transport investment and operational costs are not included in this CAPEX and OPEX, but added as a separate annualised transport cost (see 4.2 Transport cost).

The operational expenses can be categorised in the fixed and variable OPEX. The fixed OPEX are independent of the amount of oil production or CO_2 injected, for example the costs for operation and inspection, maintenance, logistics and monitoring . The variable operation expenses are for example the costs for compression, injection and recycling of CO_2, oil production and transport etc. In this study they are assumed to be linear dependent on the amount of CO_2 injected. Table 5.3 shows the different costs used in this study.

Same as for the production data, the economic data was collected from different sources and combined to obtain a coherent set of values for all PSS IV parameters for the Claymore field, which required some assumptions by the authors. These values were then scaled for the Buzzard and Scott fields. The main sources for these cost data are Gozalpour et al. (2005), BERR (2007), NOGEPA (2009), Element Energy (2012) and Mendelevitch (2014).

Table 5.3: OPEX and CAPEX

Fields	Fixed OPEX (M GBP/y)	Variable OPEX (M GBP/$MtCO_2$)	CAPEX (M GBP)
Claymore	47.9	19	577

Scott	31.1	19	375
Buzzard	39.4	19	476

1.9 Tax incentives

Currently there are a number of reasons that inhibit the start of CO_2-EOR projects. The uncertainty, the high tax rates and the complexity retain the necessary investments. This study will estimate and evaluate the feasibility of CO_2-EOR projects in the North Sea area, considering different tax incentives. The impact of implementing these different tax incentives in the existing UK offshore oil & gas tax system will be evaluated for both the oil companies and the government/Treasury. In this study four scenarios will be considered.

The current tax system consists of the three following elements. Firstly the Petroleum Tax (PRT) is a special tax on oil and gas production. It is a field based tax charged on profits arising from individual oil fields and not charged on the cumulative profits from all oil fields owned by a company. PRT is exclusively charged for fields established before 16 March 1993. The PRT was set at 50%, and is now lowered to 35% for chargeable periods ending after 31 December 2015. Secondly the Ring Fence Corporation Tax (RFCT) is a standard corporation tax to all companies with the addition of a 'ring fence'. The ring fence prevents taxable profits from oil and gas, extracted in the UK or UK Continental Shelf, being reduced by losses from other activities outside the ring fence or by excessive interest payment. From 1 April 2008 the main rate of corporation tax in the ring fence has been fixed on 30%. Finally the Supplementary Charge (SC) is an additional charge of 30% on a company's ring fence profits excluding finance costs. The SC has been reduced for profits since 1 January 2015 to 20%. This results in a current tax rate of 50% on a company's ring fence profits and up to 67.5% for oil fields established before 16 March 1993. All scenarios are variations of the first "Reference" scenario, and divert only for the parameters that are indicated in the following paragraphs.

Scenario 1: Reference

The first scenario is similar to the current tax system with a 100% first year tax relief on investments (capex and decommissioning; 100% First Year Allowance). Investments are written off 100% against other profits within the ring-fence. The Petroleum Revenue Tax is abolished which results in a total tax on profit of 50%. The price of acquiring CO_2 is set between -7.3 and 7.3 GBP/tCO_2 (-10 and 10 €/t). Opposite to the convention in the Element Energy (2012) study, positive values for this parameter are regarded as gain, negative as cost. The oil market price is set between 36.5 and 87.6 GBP/bbl (50 and 120 €/bbl).

All stochastic parameter values are fixed at a single value for the whole 2015-2050 timeframe for each individual Monte-Carlo calculation (oil price, CO_2 price, EOR recovery factor and EOR production curve mean). Although possible in PSS IV, no changes over time for these parameters are allowed.

Scenario 2: Loan

In the second scenario the 100% first year tax relief is replaced by a commercial loan for investments, over the entire lifetime of the investment (capex annualisation).

Scenario 3: LowTax

The third scenario is similar to the first, with a lowered tax on additional EOR oil production. The total tax on profit is set at 40%.

Scenario 4:LowCO₂

In the fourth scenario the OPEX costs are lowered by treasury funds for CO_2 acquisition cost. The state funds 3.65 GBP (5 €) per tonne of CO_2 to the capture operator, which results in a cost reduction for the EOR operator of 3.65 GBP/tCO_2. This results in CO_2 price of -3.65 to 10.95 GBP/t (positive = gain).

Table 5.4. Main parameter values for the four scenarios. The capex is either considered to be paid at the start of the project, with 100% First Year Allowance (FYA, current policy), or annualised over the project's lifetime as a commercial loan.

Scenario	Oil price (GBP/bbl)	CO_2 price (GBP/t)	Tax on profit (%)	Capex
Reference	36.5 - 87.6	-7.3 - 7.3	50	FYA
Loan	36.5 - 87.6	-7.3 - 7.3	50	Loan
LowTax	36.5 - 87.6	-7.3 - 7.3	40	FYA
LowCO_2	36.5 - 87.6	-3.65 - 10.95	50	FYA

6. Results

1.10 Introduction

PSS IV was run for the four fields/cluster and four scenarios. The number of Monte Carlo (MC) calculations made for each field and scenario combination are listed in Table 6.1. For most field-scenario combinations, calculations range between 450 and 750. Differences in MC numbers are caused by differences in calculation speed. For the Clusters, the number of calculations is lower, due to the exponential increase in calculation time for multiple fields. The Cluster simulations are at this point still in an experimental phase, and results should be treated likewise.

Table 6.1. Number of Monte-Carlo calculations made by PSS IV for each scenario and field.

Field	Reference	Loan	LowTax	LowCO_2
Claymore	685	694	495	518
Scott	747	749	458	628
Buzzard	735	673	495	658
Cluster	78	83	210	331

When PSS IV activates a project, different costs and gains are applied over time, which produces an undiscounted yearly NPV, and a discounted total NPV. A typical investment and cash flow example is given in Figure 6.1. In PSS IV, it is assumed that the capex is spent in a single year. This example shows a CO_2-EOR project for the Claymore field under the Reference scenario, at a stochastically chosen oil price of 43.3 GBP/bbl and a CO_2 price at 4.5 GBP/t. The total discounted NPV of this project is 507 M GBP, or 12.4 GBP/bbl. In this Reference scenario, the investment costs in red are written off against other profits in the ring-fence in the same year as incurred (hatched red). Primary production for this project normally finished in 2024. From 2025 on, the primary production is regarded as a benefit to the CO_2-EOR project (hatched blue). The benefit of deferred decommissioning (light blue) is relatively small for this project, and barely visible. In the Loan scenario, both investment costs are annualised over the whole project lifetime.

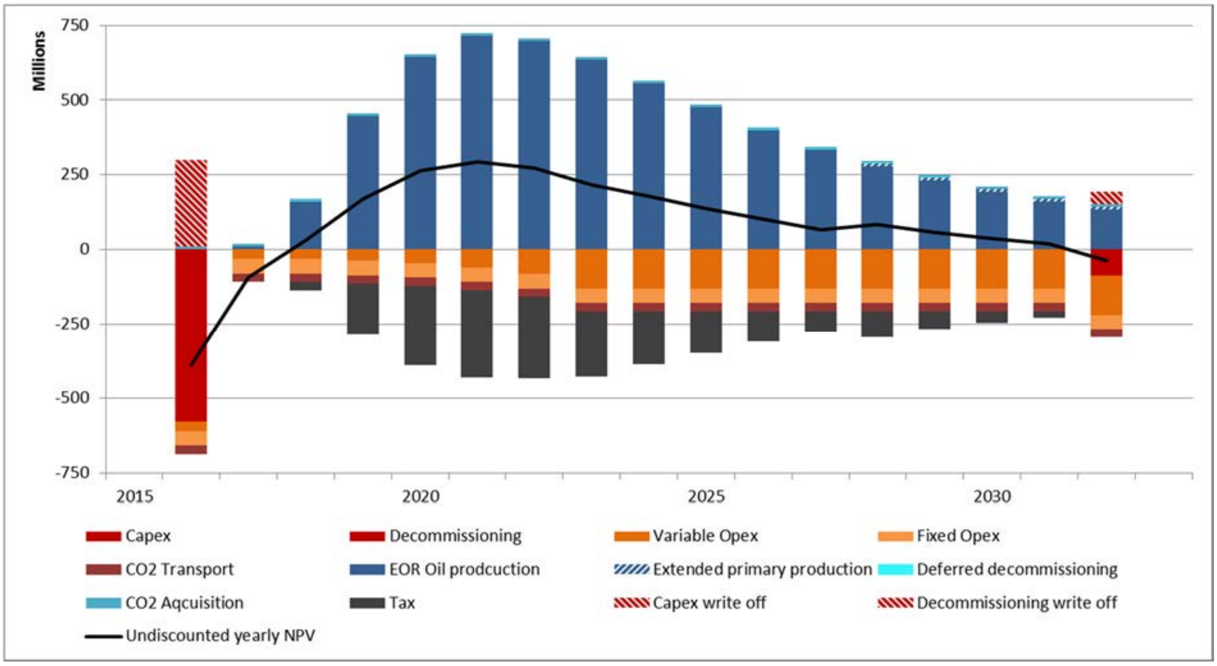

Figure 6.1. Typical cash flow in a CO_2-EOR project as simulated by PSS, for the Claymore field in the Reference scenario. Total discounted NPV is 507 M GBP.

1.11 Development probability

A first indication for the potential success of CO_2-EOR in the North Sea is the development probability of the fields. This is calculated as the number of Monte-Carlo calculations in which a CO_2-EOR project is activated, divided by the total number of calculations made. A second indicator that is used, is the number of calculations in which a project was activated, but ended up with a negative total discounted NPV.

For all field-scenario combinations, except those for the field cluster, the development rate is 100%. This is however unlikely in reality, and indicates that the threshold for activation is too low. The number of calculations with negative NPV's is quite low as well (0 to a few percent). The reason why the total discounted NPV of a project that was activated based on prior evaluation can be negative, is because the principle of limited foresight is applied. In analogy to reality, an evaluation of a project is made with an outlook towards the future, with parameter values that differ slightly from what will actually happen in the future. This provides a less-than-optimal solution, but is a better reflection of reality than optimisation methods. The development rate for the Clusters ranges around 80-95%, which better reflects the investment risk for CO_2-EOR in the North Sea.

Table 6.2. Development probabilities and chance on negative NPV, in %.

Field	Reference		Loan		LowTax		$LowCO_2$	
	Tot	*Neg*	*Tot*	*Neg*	*Tot*	*Neg*	*Tot*	*Neg*

Claymore	100	0.58	100	4.18	100	0.61	100	0
Scott	100	2.68	100	9.21	100	2.62	100	2.86
Buzzard	100	1.22	100	3.71	100	0.61	100	0.15
Cluster	84	0	94	1.20	96	0	78	0

1.12 Project value

In Figure 6.2, histograms of the total discounted NPV of projects activated by PSS IV are shown. Prior to activation, PSS IV first evaluates potential CO2-EOR projects based on an outlook of the techno-economic environment with limited foresight. Activated projects are therefore projects that would be chosen to invest into in real life as well.

Compared to the Reference scenario, the Loan scenario shows an overall lower NPV. The LowTax scenario has a possibility for higher NPV's, though low and even negative project values can still occur. The $LowCO_2$ scenario shows no significant difference to the Reference scenario, indicating that CO_2 cost has a minor influence on total project value.

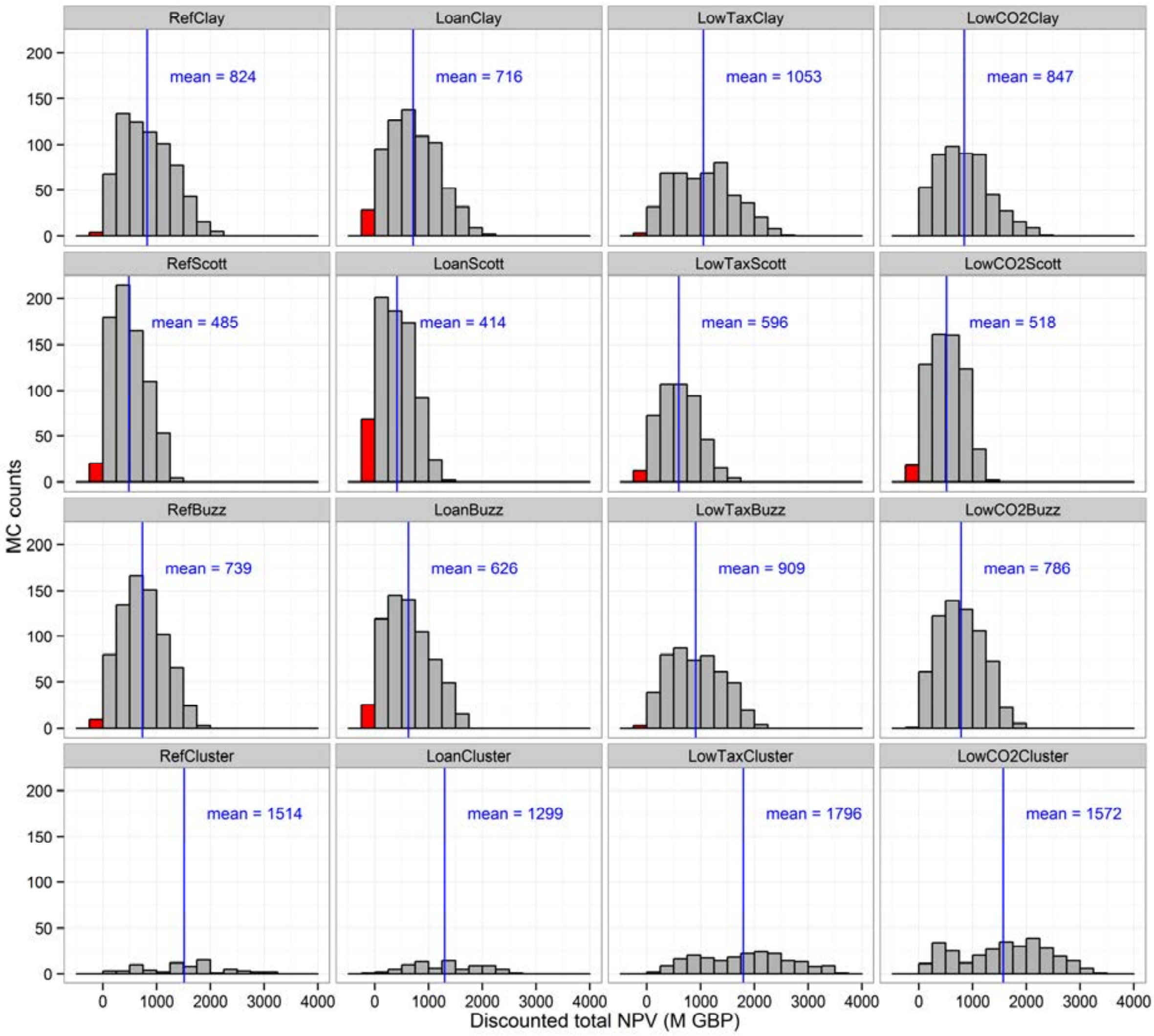

Figure 6.2. Histogram of the total discounted NPV for projects that were evaluated positively by PSS IV for activation. The mean value is indicated by the blue line, and projects with negative NPV are indicated in red.

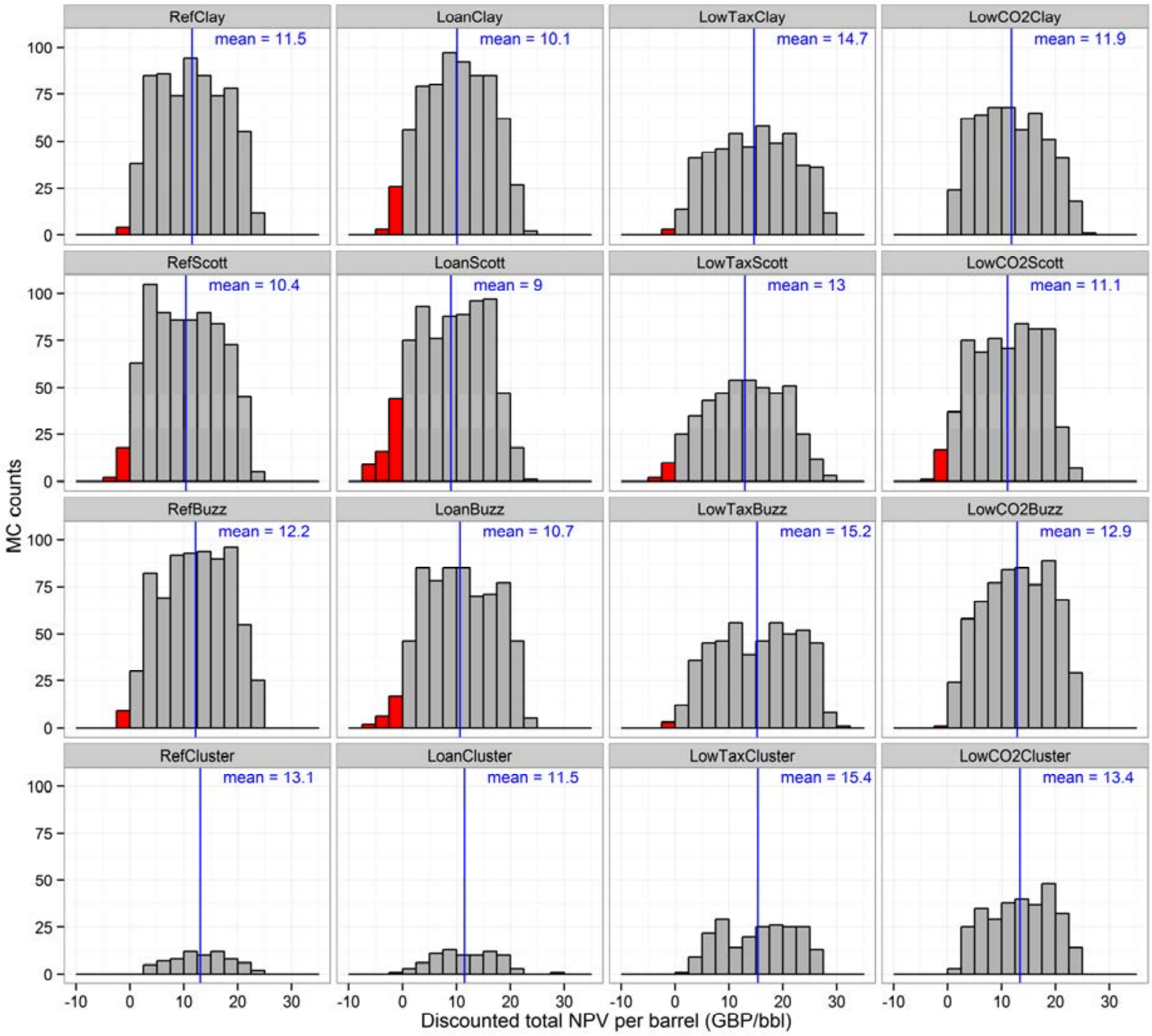

Figure 6.3. Histogram of the total discounted NPV per barrel of oil produced by EOR for projects that were evaluated positively by PSS IV for activation. The mean value is indicated by the blue line, and projects with negative NPV are indicated in red.

1.13 Tax scenario comparison

The influence of the different scenarios on the total discounted tax or Treasury income are shown in Figure 6.4. Treasury income is always positive, which means that at this moment, tax write-off or lowering the CO_2 acquisition cost in the LowCO_2 scenario are not added as treasury losses. The Reference and LowCO_2 scenario are a more advantageous. The Claymore field is able to generate the most tax income, followed by the Buzzard and the Scott fields. The Cluster fields have a larger spread compared to the other fields, because both fields can be activated together or separately.

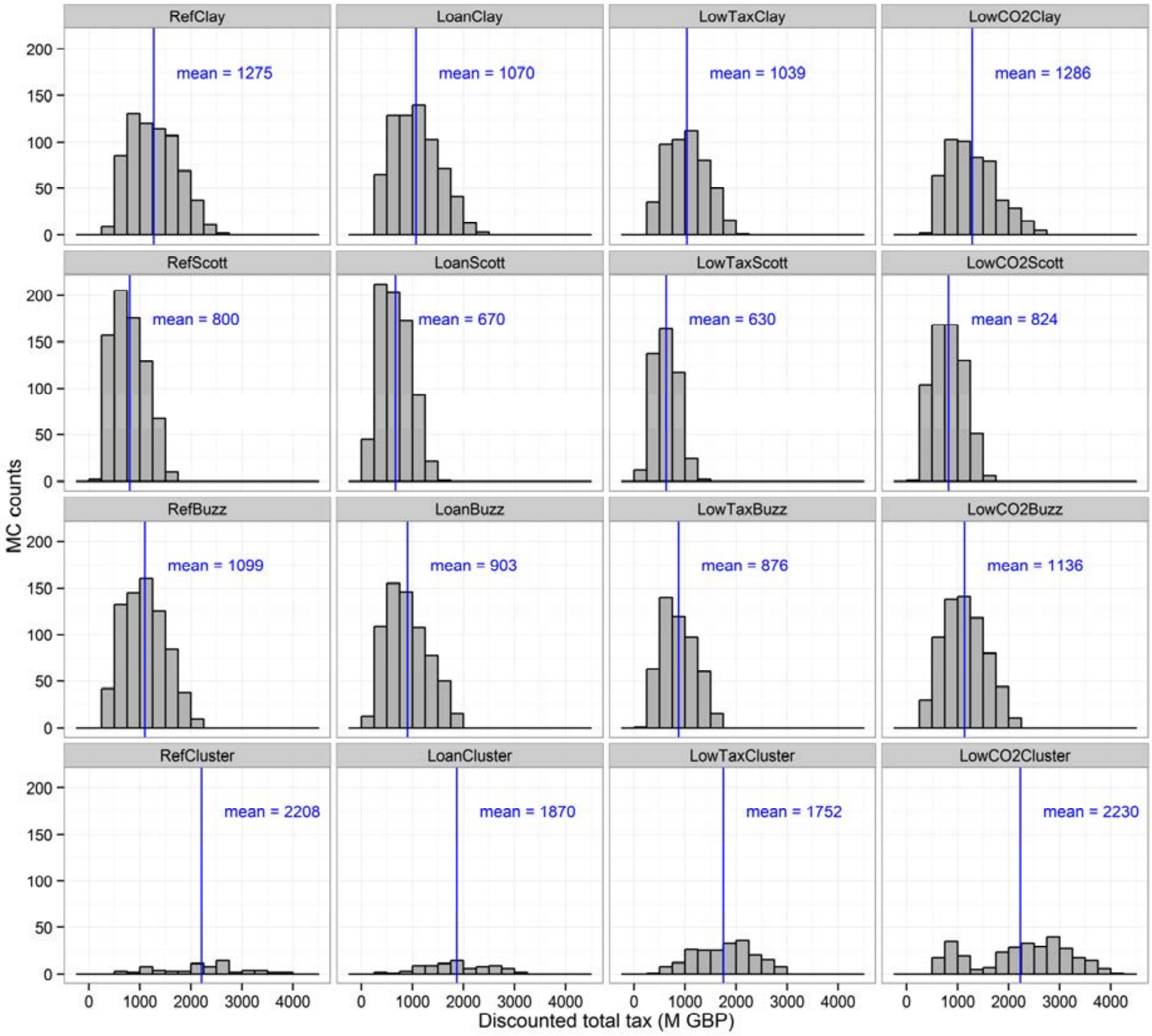

Figure 6.4. Histogram of the total discounted tax or Treasury income for projects that were evaluated positively by PSS IV for activation. The mean value is indicated by the blue line.

The total discounted NPV and tax of the different scenarios are compared for each field in Figures 6.5a-d. The correlation between NPV and tax is very linear for every scenario. Only for the Cluster, the range is somewhat larger. This is explained by the fact that two different fields are operated together.

The Reference scenario (blue) provides the highest Treasury income for a certain NPV, followed by the LowCO_2 and the Loan scenario. The LowTax (green) scenario has the highest NPV/tax ratio. In this figure, it is also clear that the Loan scenario (red) has a higher chance on negative NPV's for activated projects.

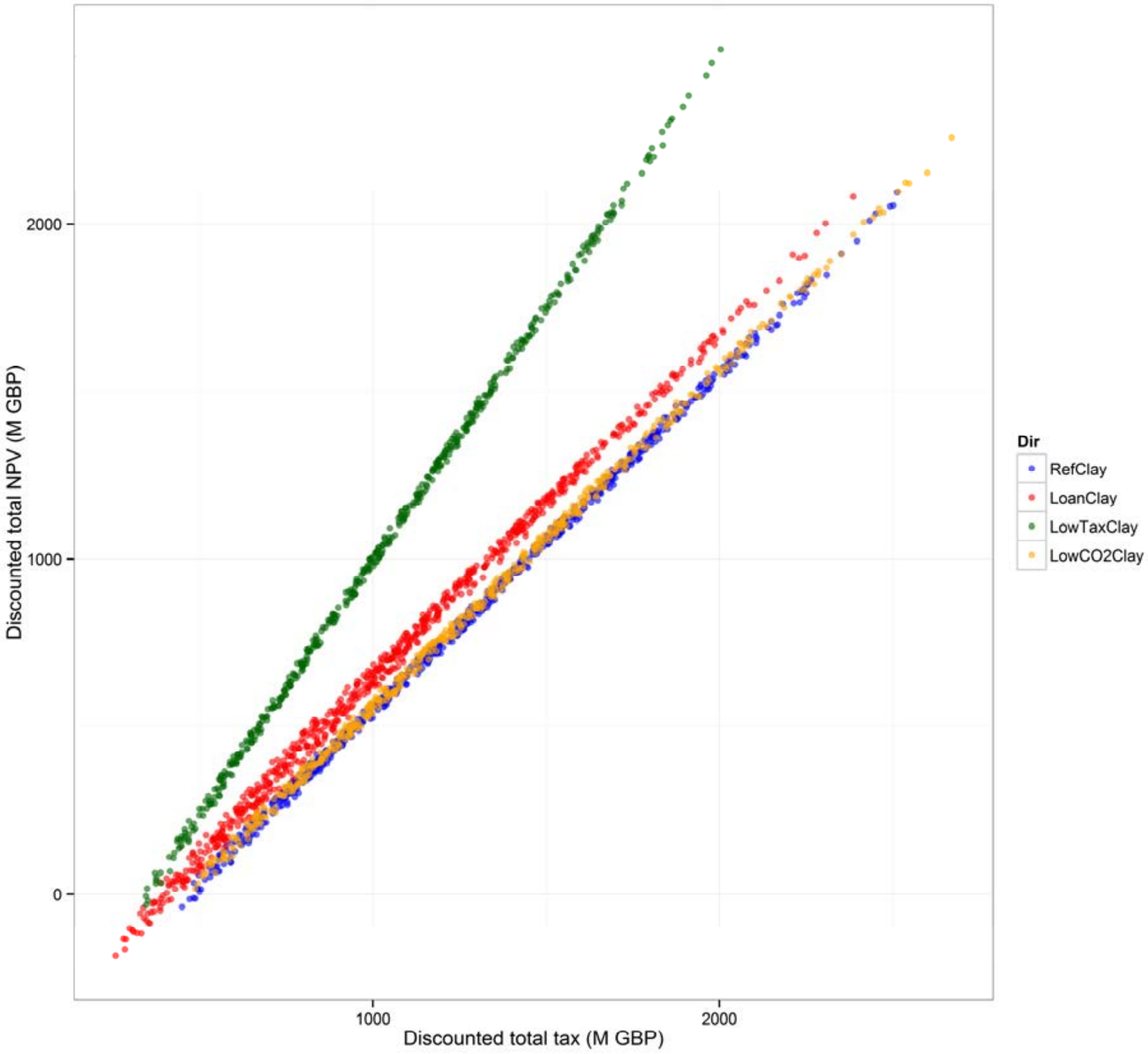

Figure 6.5a. Cross-plot of the discounted total NPV and discounted total Treasury income for the Claymore field, for each scenario.

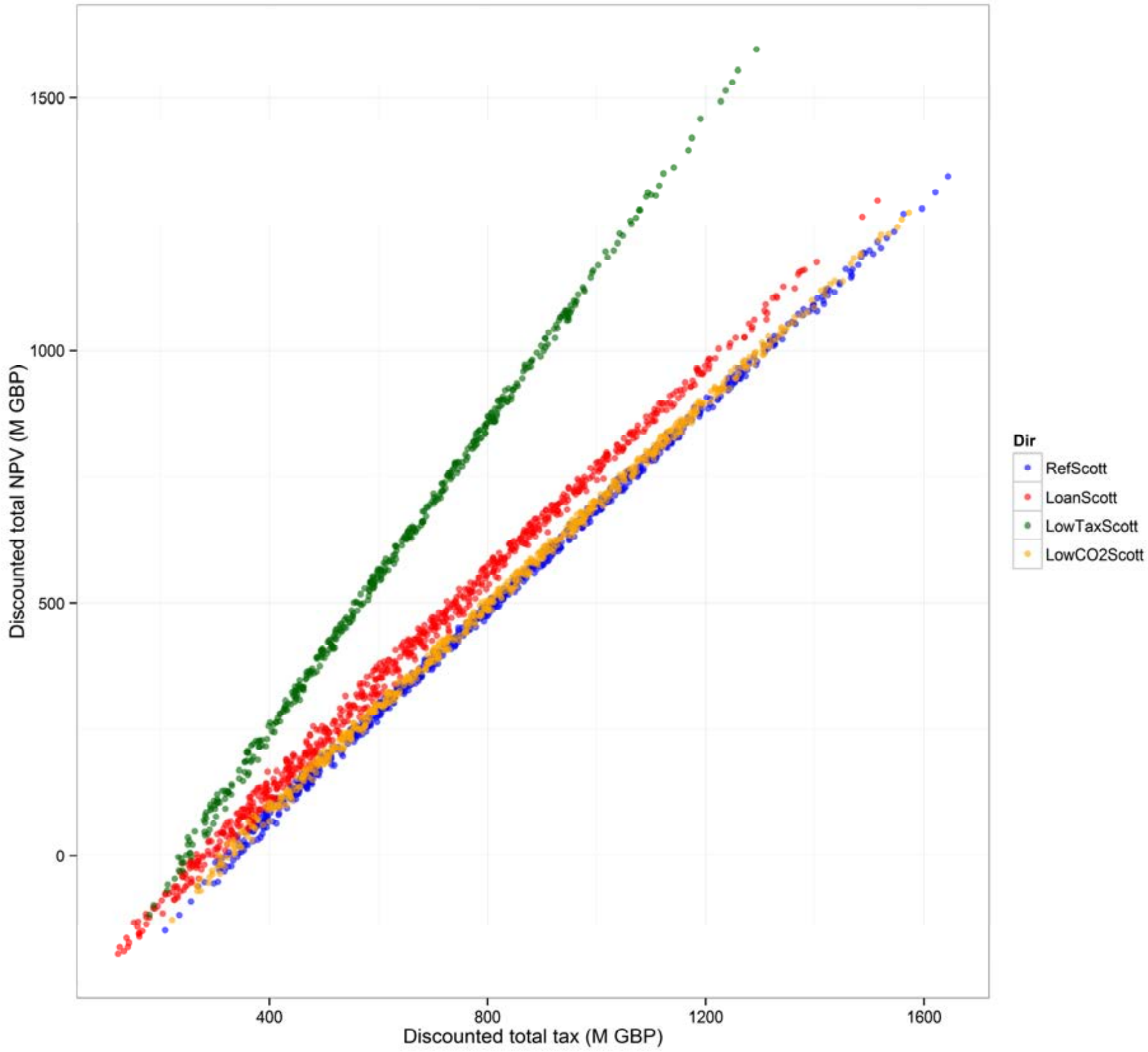

Figure 6.5b. Cross-plot of the discounted total NPV and discounted total Treasury income for the Scott field, for each scenario.

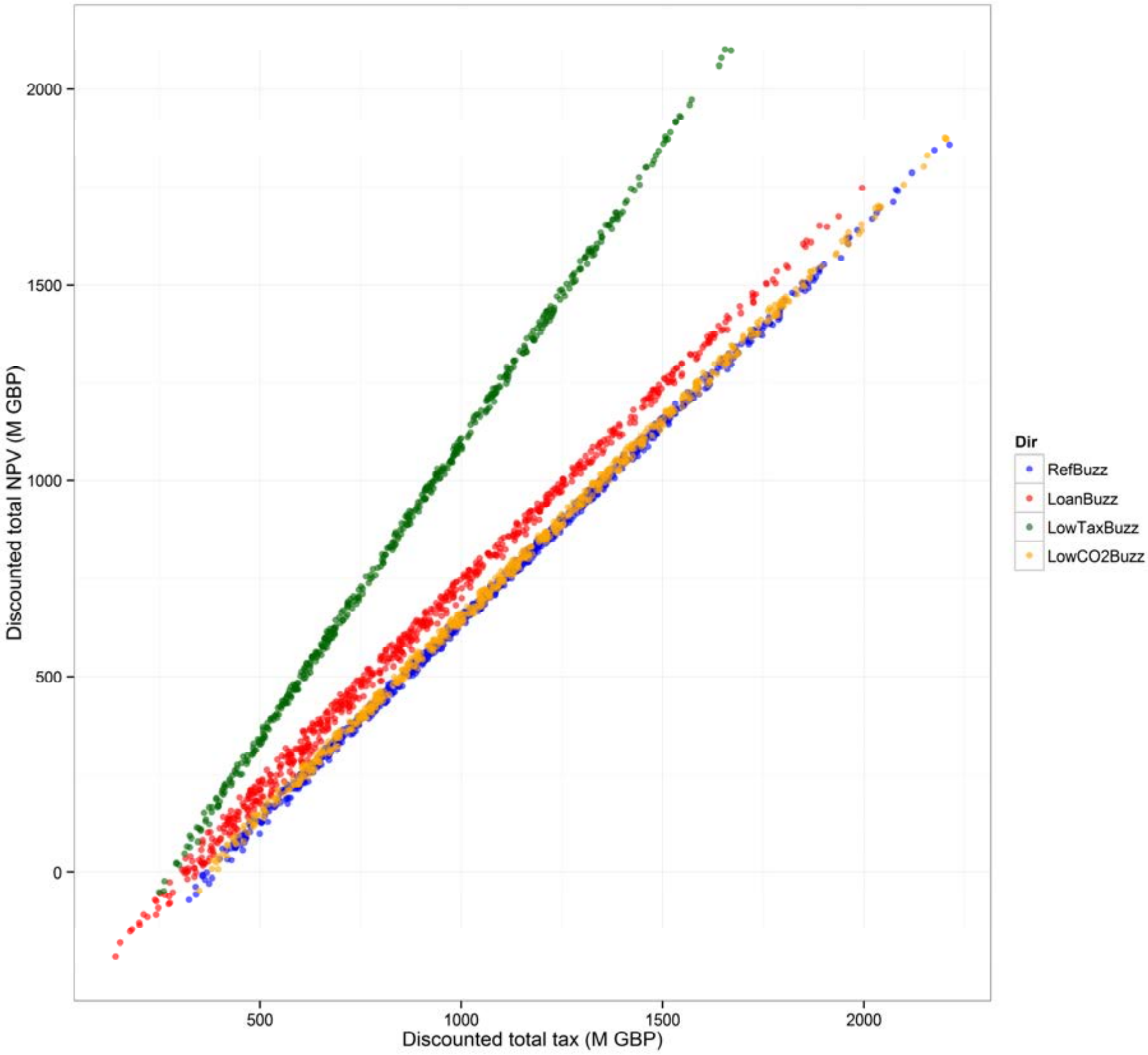

Figure 6.5c. Cross-plot of the discounted total NPV and discounted total Treasury income for the Buzzard field, for each scenario.

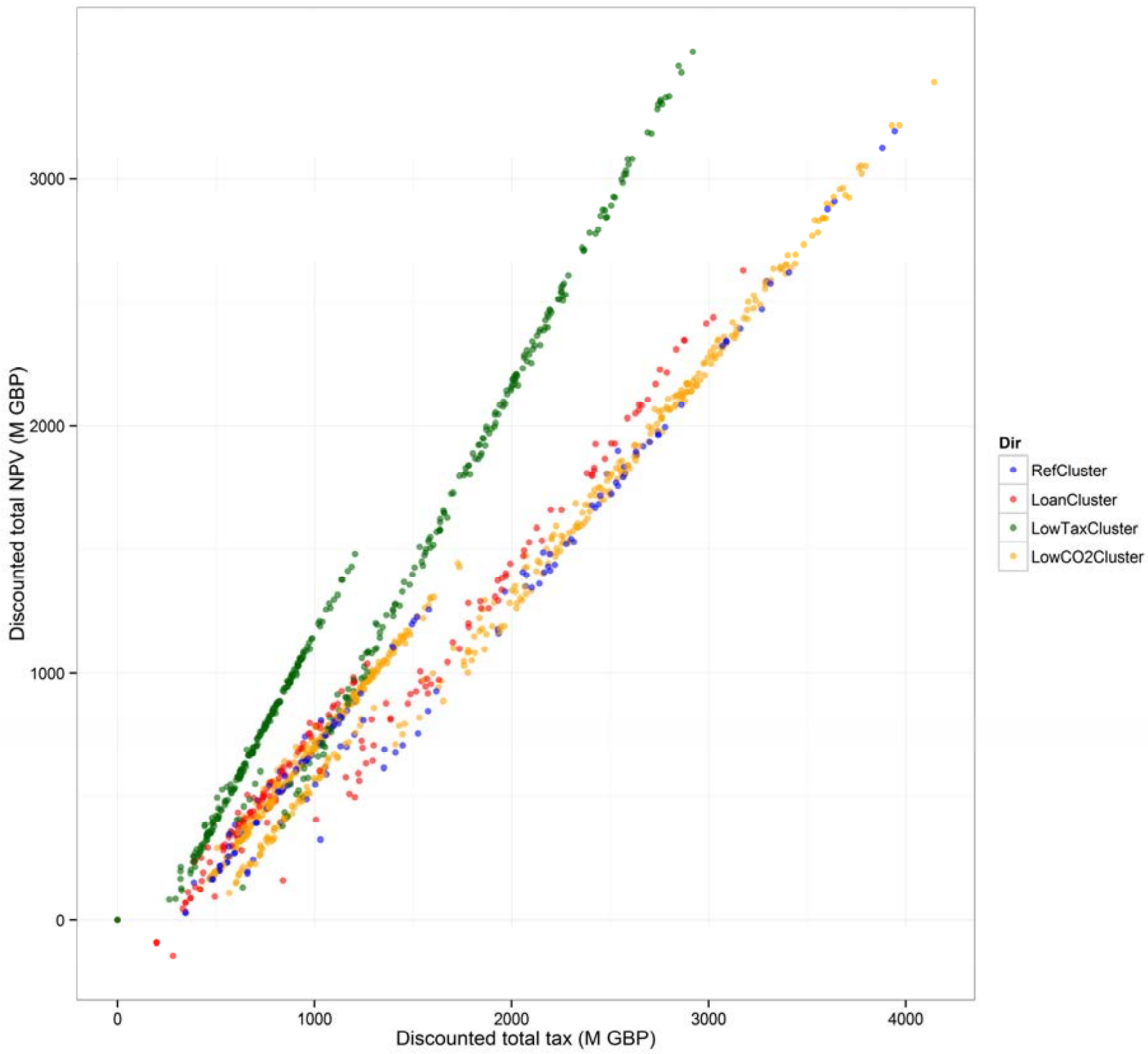

Figure 6.5d. Cross-plot of the discounted total NPV and discounted total Treasury income for the Cluster of the Claymore and Scott fields, for each scenario.

1.14 Sensitivity analysis

The oil market price and the CO_2 price are two of the four stochastic parameters in the PSS IV simulations. The aim is to identify which range of both parameters is optimal for developing a CO_2-EOR project and maximum profit, and which range is best for Treasury income. For each Monte-Carlo calculation in which an EOR project is activated, the oil price and CO_2 cost are cross-plotted per scenario and field (Figure 6.6). The size of the plotted dots represents the project total discounted NPV. In general, the highest NPV's are observed in the upper right quadrant. The major trend that can be observed here is the influence of the oil market price, with a clear positive correlation with NPV. A correlation with CO_2 price is also present, but this parameter clearly has less influence. The Loan scenario shows a reduction of NPV, while the LowTax scenario provides an increase. The LowCO_2 scenario has no significant difference compared to the Reference scenario. Results also show the differences between fields, with the Claymore field able to generate highest project value, and the Scott field lowest value. If the range of CO_2 prices was extended to include lower values, a more apparent relationship and cut-off value become visible.

As visible in Figure 6.7, the oil price is clearly the main driver for the success of a CO_2-EOR project. Overall NPV is clearly in relation with oil price for all scenarios. In a few cases, an oil price around 40 and 50 GBP/bbl causes a negative NPV. While there is still a positive correlation visible, the CO_2 price (positive = gain) has a minor influence on the NPV (Figure 6.8).

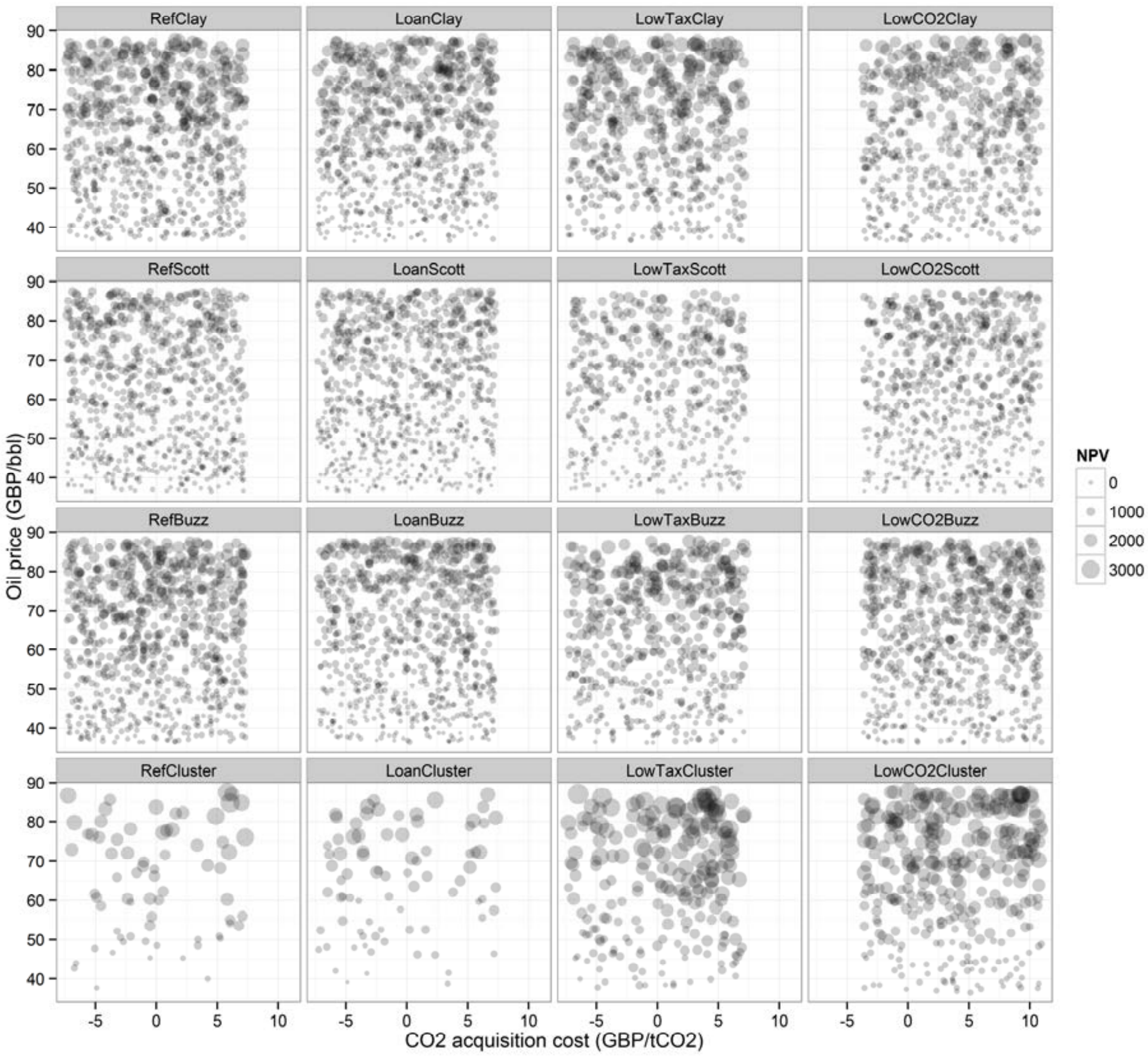

Figure 6.6. Cross-plot of the oil price and CO_2 price for activated projects, with indication of the total discounted NPV (in M GBP).

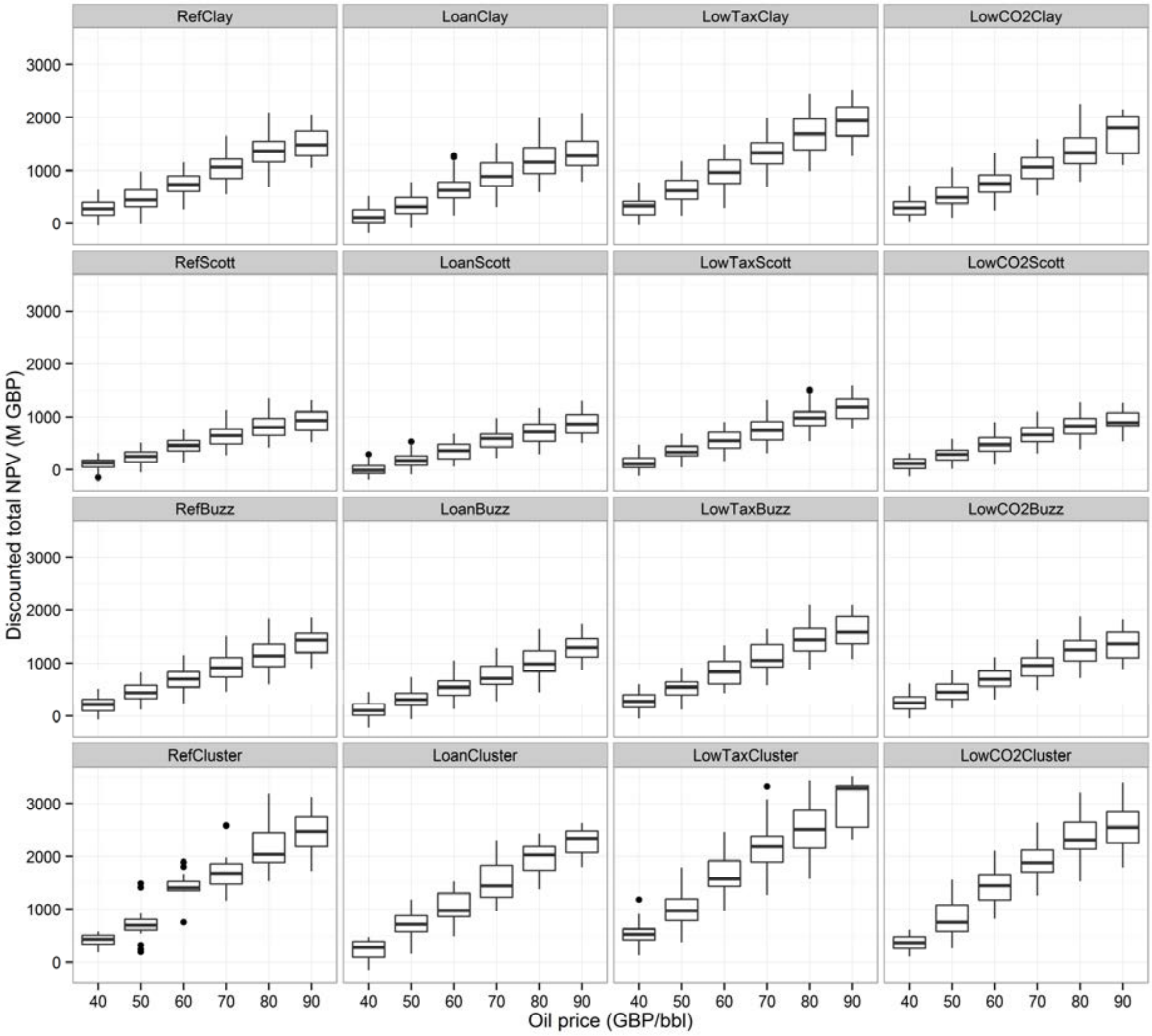

Figure 6.7. Sensitivity analysis of the oil market price on the total discounted NPV (in M GBP). A clear positive correlation between oil price and total discounted NPV is present. The box corresponds to the 25th and 75th percentile, with an indication of the average. The whiskers extend 1.5 times the range between the first and third quartiles. Other data is plotted as outliers.

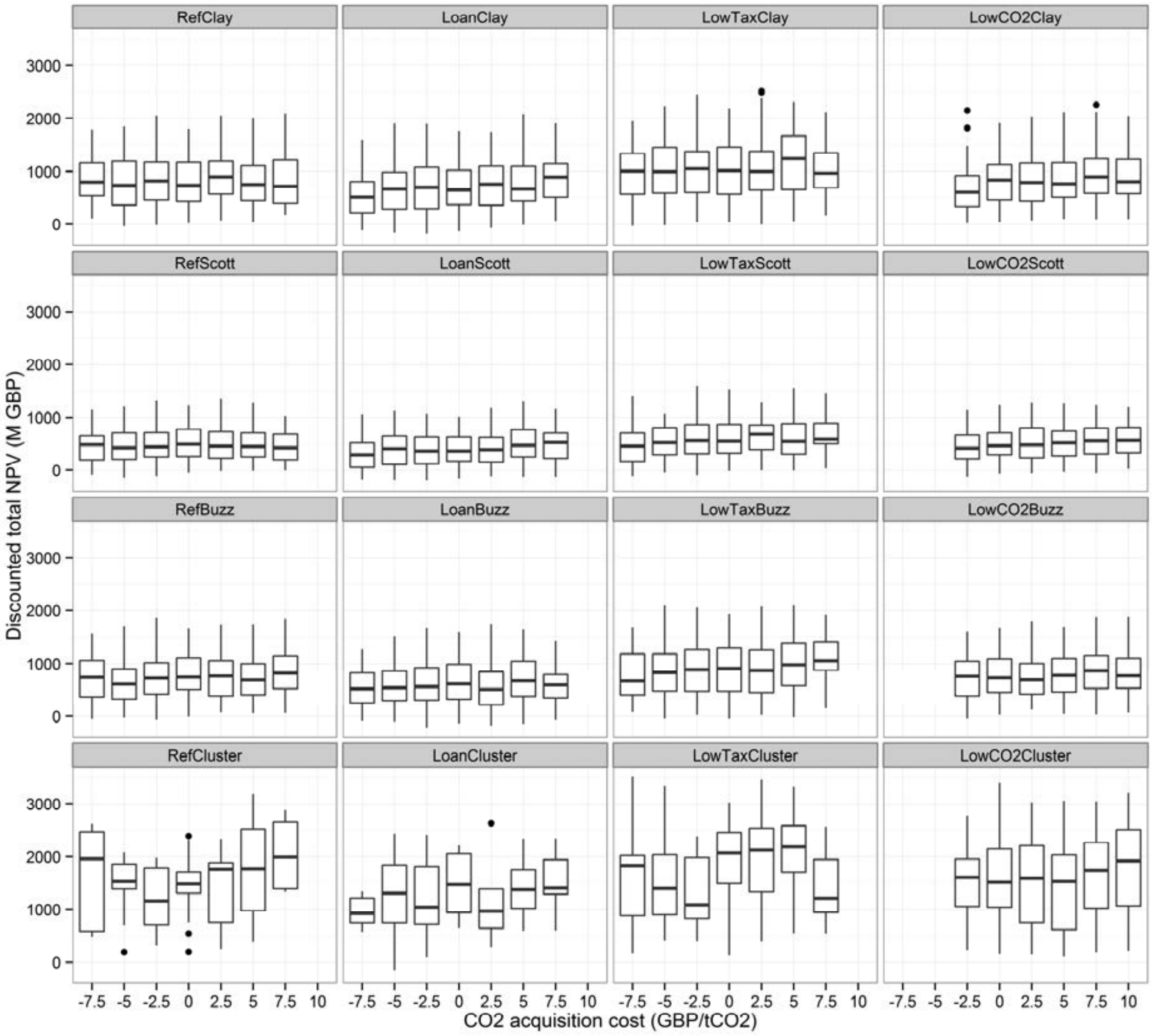

Figure 6.8. Sensitivity analysis of CO_2 price (positive = gain) on the total discounted NPV (in M GBP). The influence of CO_2 price on the total discounted NPV is minor in comparison with the oil price, but still observable. The box corresponds to the 25^{th} and 75^{th} percentile, with an indication of the average. The whiskers extend 1.5 times the range between the first and third quartiles. Other data is plotted as outliers.

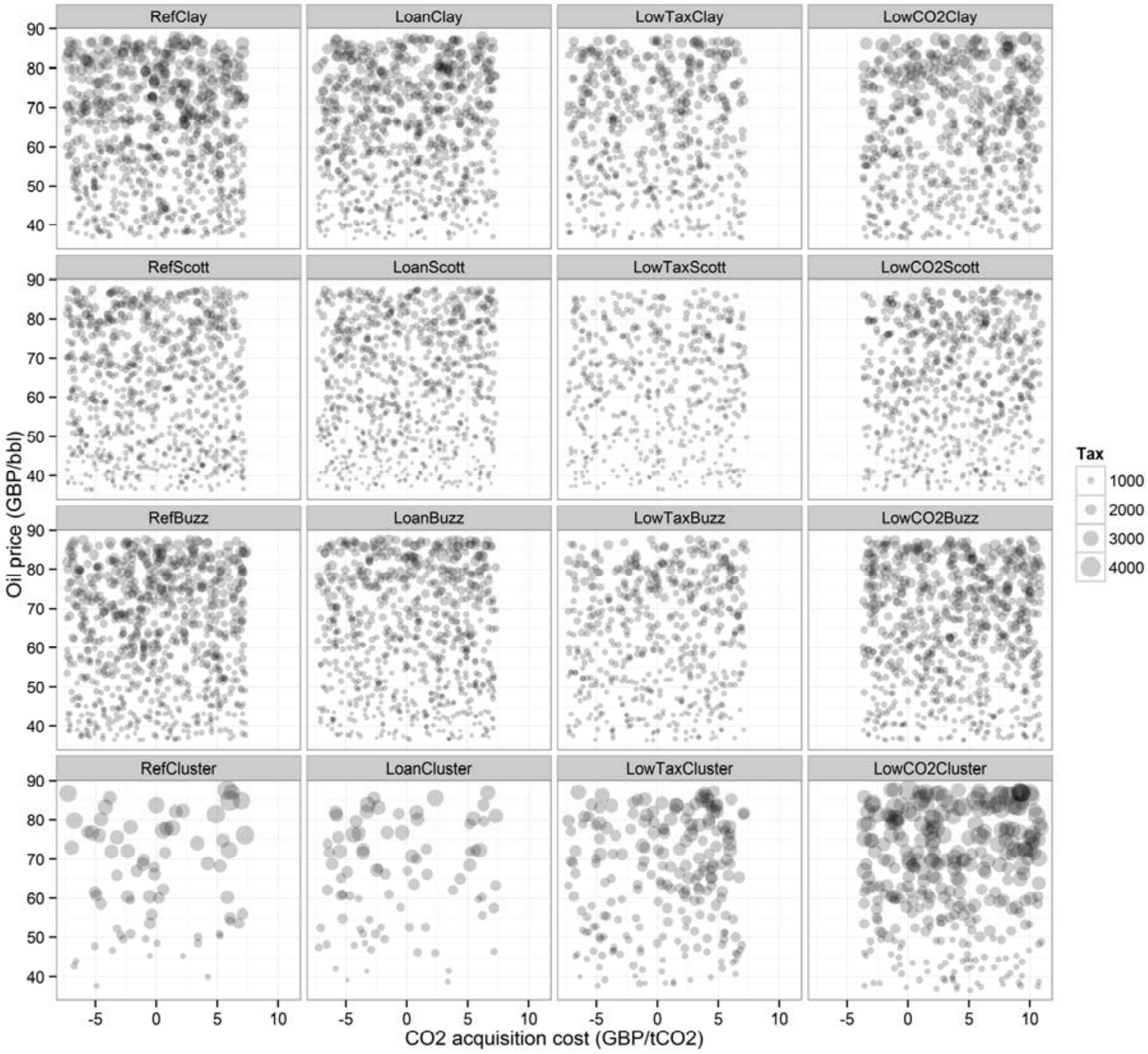

Figure 6.9. Cross-plot of the oil price and CO_2 price (positive = gain) for activated projects, with indication of the total discounted tax or Treasury income (in M GBP).

The other two stochastic parameters which were used in the PSS IV simulations are directly related to the reservoir and its performance in an CO_2-EOR project (Figure 6.10). The recovery factor dictates which portion of the OOIP can be produced, and the μ of the lognormal EOR production curve influences the shape of the curve: low values produce a high and short (in time) peak, high μ values give a low peak which is stretched in time (see Figure 5.1). The highest NPV values can be observed in the upper left quadrant. A higher recovery factor is obviously advantageous, as is a fast reservoir response which provides fast return. A low μ will cause a longer period of operational costs.

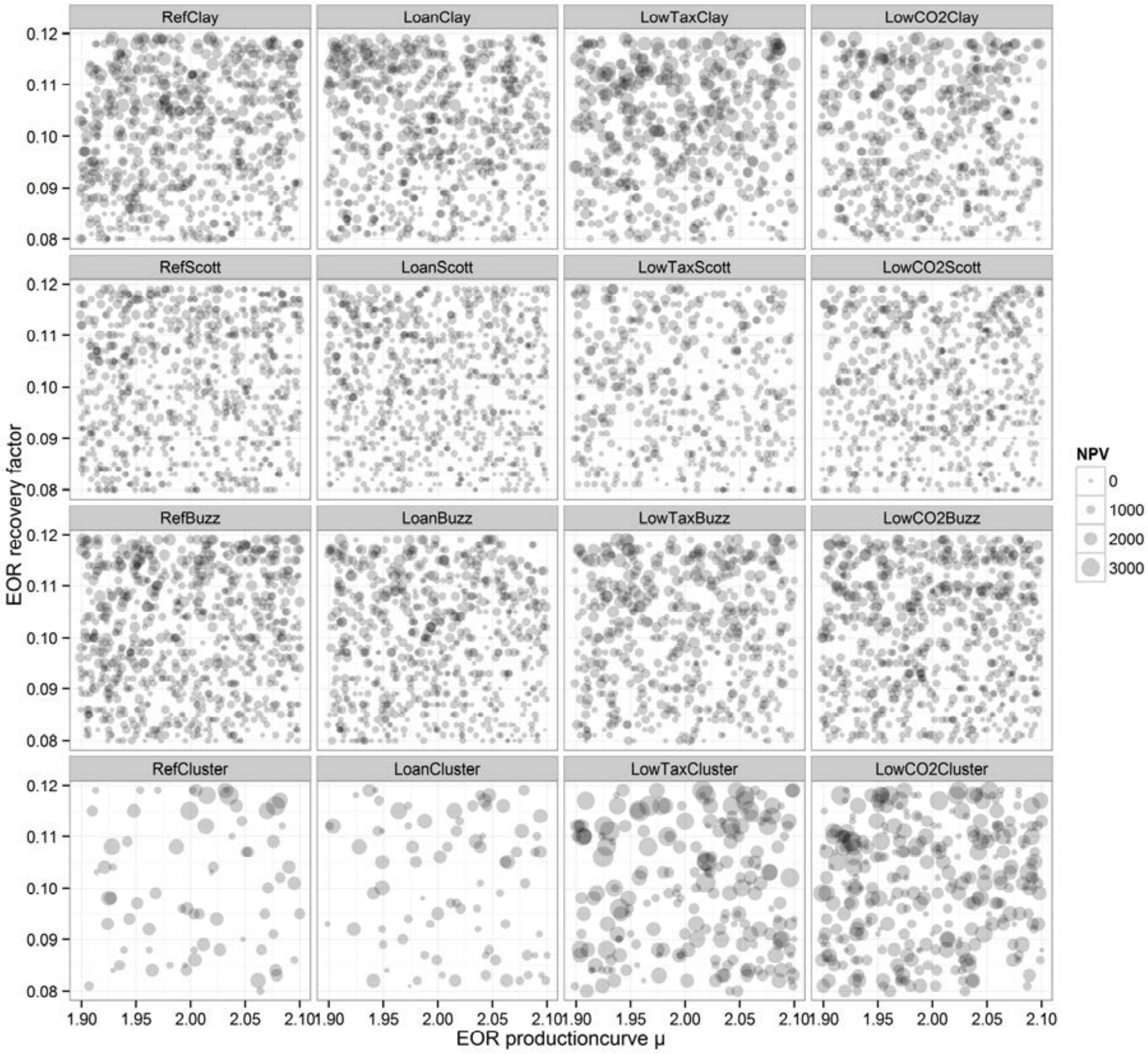

Figure 6.10. Cross plot of the two stochastic geological parameters: EOR recovery factor (% of OOIP) and μ of the lognormal EOR production curve, with indication of the total discounted NPV (in M GBP).

1.15 Additional oil produced by EOR

The additional oil produced by EOR activity provides the main income to the project (Figure 6.11). In the Reference scenario, the Claymore field could produce between 80 and 160 MMbbl extra using CO_2-EOR, with an additional 0-20 MMbbl by the extension of primary production, depending on project timing. For the Scott oil field, this is 60-100 MMbbl and 10 MMbbl for extended primary production, for Buzzard 75-130 MMbbl and up to 15 MMbbl for extended primary production. The extended primary production numbers are in general one order of magnitude smaller than CO_2-EOR production numbers, and in many cases 0 (no extension of lifetime).

These numbers are consistent for the LowTax and $LowCO_2$ scenario, indicating that this is physically the maximum feasible, and that there is no economic inhibitor on the production rate. For the Loan scenario though, numbers are on average a little lower, indicating that this scenario poses a limit onto the oil production.

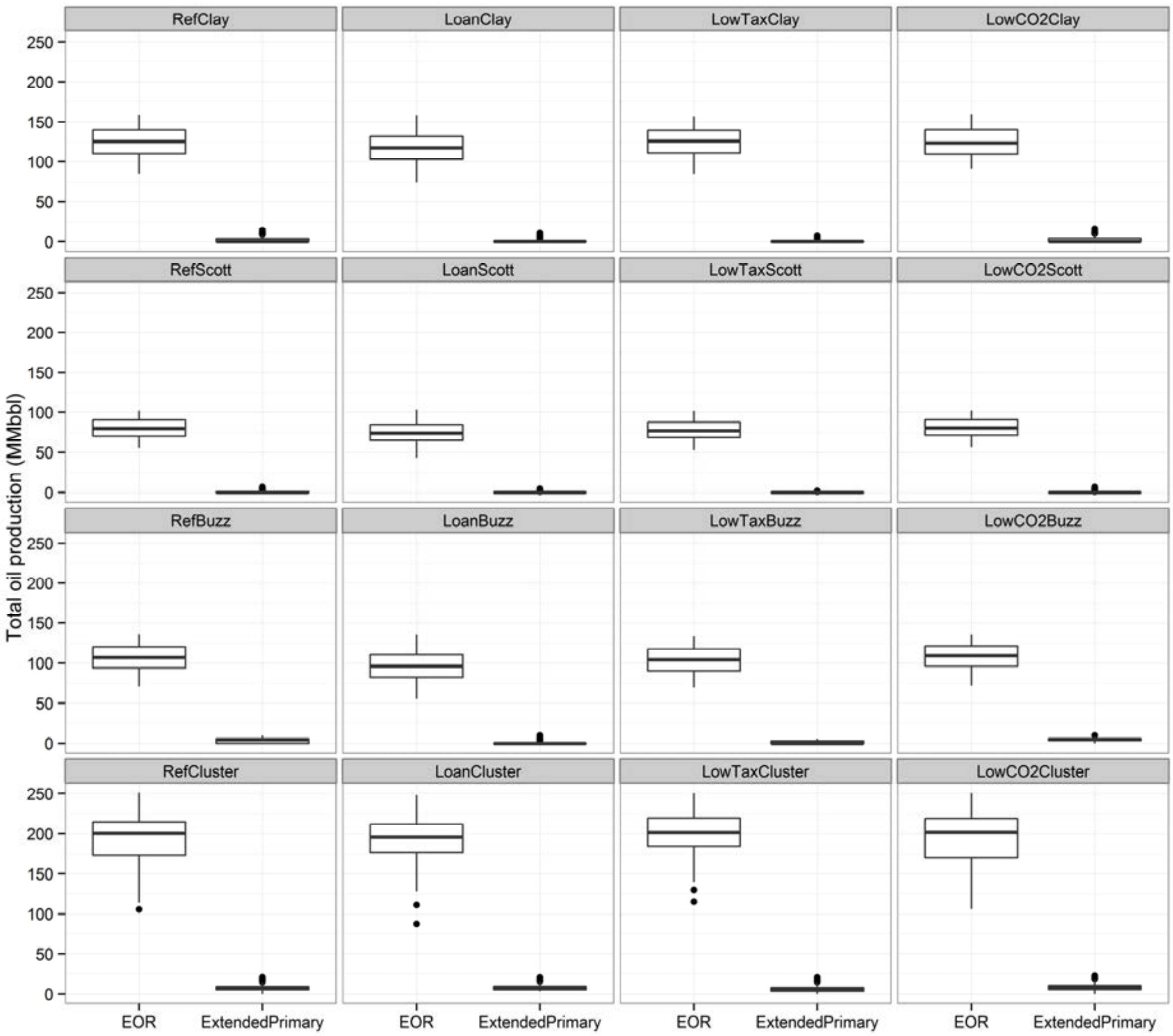

Figure 6.11. Boxplot of the oil produced by EOR activity, and additional oil produced by extension of the primary production. The box corresponds to the 25th and 75th percentile, with an indication of the average. The whiskers extend 1.5 times the range between the first and third quartiles. Other data is plotted as outliers.

1.16 Deferred decommissioning

By applying CO_2-EOR to an existing oil production operation, the lifetime of this original production can be extended. By doing so, the expense of the decommissioning cost, which is a substantial amount (assumed at 15% of capex), can be delayed. This provides a certain gain which is considered as an additional income to the CO_2-EOR project. The value shown in Figure 6.12 is the yearly gain, which ranges from 0 to 3 M GBP/y for the individual fields, and up to 8 M GBP/y for the Cluster.

As the lifetime of the primary production is not always extended by applying EOR, the value of deferred decommissioning is 0 in many Monte-Carlo runs. For the Buzzard field for example, which is the most recent field, the end of primary production does not fall within the timeframe in which PSS IV chooses to apply CO_2-EOR for this field, and no gain is made.

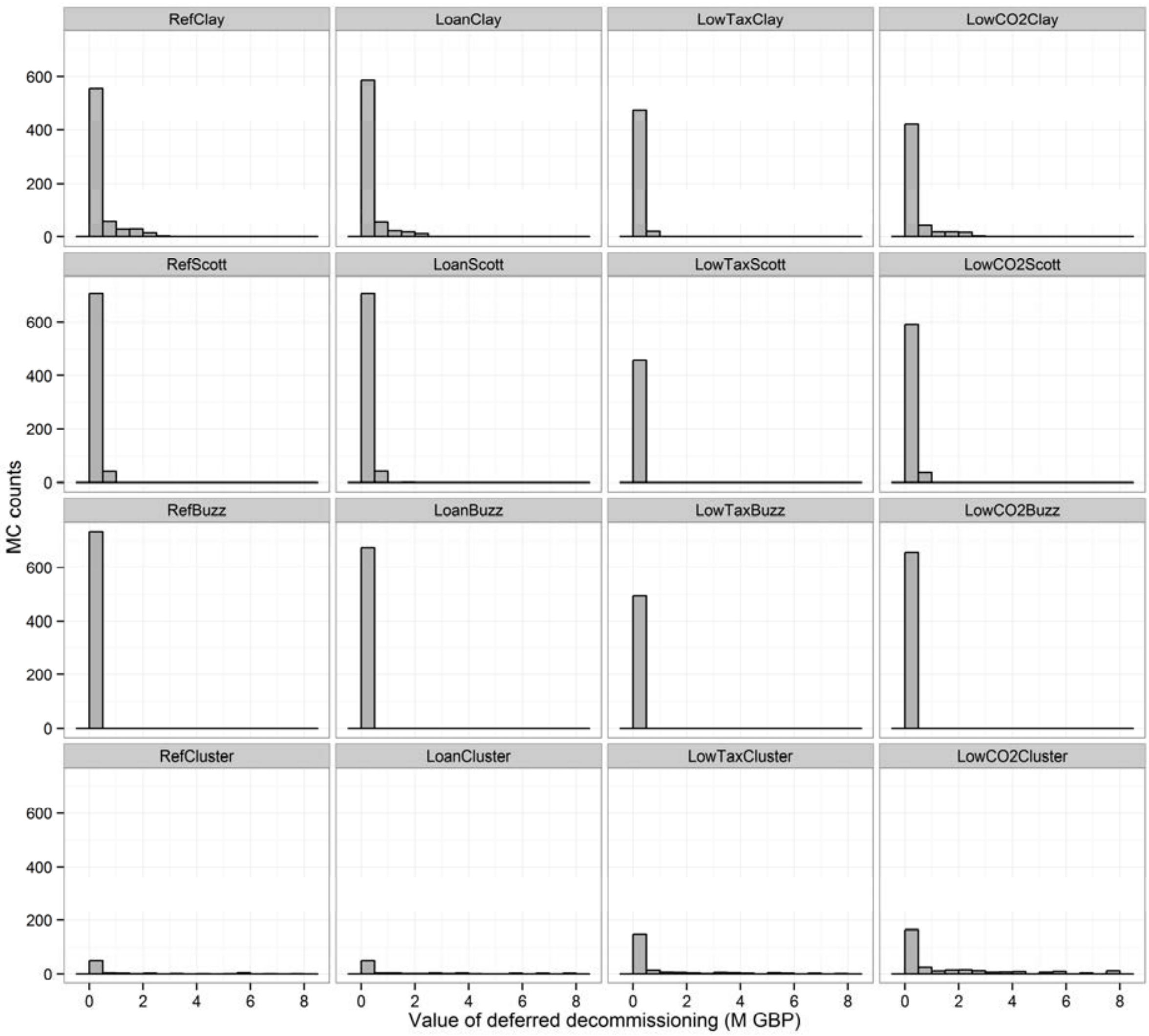

Figure 6.12. Histogram of the value of deferred decommissioning of primary production, by starting a CO_2-EOR project, in M GBP per year.

7. Conclusions

Techno-economic simulations for the application of CO_2-EOR to oil fields in the North Sea are conducted using the PSS IV simulator. The Claymore, Scott and Buzzard oil fields are analysed this way, as well as a small cluster of the Claymore and Scott fields. The results provide an insight in project value to the private owner and the public Treasury, in function of different policy, economic and geological circumstances.

A lowering of the overall tax on profit results in the highest project values, but lowest Treasury income. Out of all incentives that are proposed here, this LowTax scenario appears as the most optimal to stimulate CO_2-EOR in the North Sea. The Supplementary Charge, part of the oil profit tax in the United Kingdom offshore, was recently lowered by 10%, together with a reduction of the PRT. In the current simulations, it was already assumed the PRT would disappear and all oil fields are considered to fall under the same tax regime. The very recent reduction of the Supplementary Charge by 10% is fully in line with our conclusion that a tax reduction is the most effective incentive for introduction CO_2-EOR.

Of all individual fields, the Claymore field has the highest potential regarding total discounted NPV, and Scott the lowest. A sensitivity analysis with four stochastic parameters shows that the oil market price is the primary driver for a successful CO_2-EOR project. The CO_2 acquisition cost has a secondary but significant influence on the NPV. The reservoir geology and its response to enhanced production also clearly influence the project value. The amount of oil producible by EOR, and the reservoirs response and timing, both exert significant influence on the NPV. There is a clear advantage for fields with a high recovery rate and a fast reservoir response.

Table 7.1 Summary of the PSS IV results, with the average discounted total NPV and tax (M GBP), and total oil production (MMbbl), for each field and scenario.

Field		Reference	Loan	LowTax	LowCO$_2$
Claymore	*NPV*	824	716	1053	847
	Tax	1275	1070	1039	1286
	Oil	127	118	125	127
Scott	*NPV*	485	414	596	518
	Tax	800	670	630	824
	Oil	81	75	78	82
Buzzard	*NPV*	739	626	909	786
	Tax	1099	903	876	1136
	Oil	111	98	105	112
Cluster	*NPV*	1514	1299	1796	1572
	Tax	2208	1870	1752	2230
	Oil	200	201	207	200

The deferred decommissioning of primary oil production, as an effect of implementing CO_2-EOR, was also analysed. Only when the EOR project lasts longer than the originally planned decommissioning date of primary production, there is a gain. If this is the case, the is a relatively small, but demonstrable effect, up to a few million GBP per year.

In general, when a CO_2-EOR project is started, the technically maximum possible amount of oil is produced. Only in the Loan scenario, there is an economic limit on the production.

In the current set of simulations, the hurdle rate for the activation of new projects is too low, which results in the activation of too much projects. The simulation results are still valid, especially for the relative influences and interactions of the different (stochastic) parameters and scenarios. However, conclusions regarding a lower cut-off cannot be made at this point.

A number of issues regarding this techno-economic assessment could be addressed in future research. Regarding the PSS IV simulator itself, a cost calibration, including CO_2 transport cost, is necessary for investigating the lower cut-off limits. An extension of the CO_2 cost range will also provide a better insight into the dynamics of this parameter. From an investor's perspective, presenting results in terms of the internal rate of return (IRR) would be of interest. Project flexibility might be an important factor for reducing investment risk, by adding the possibility to adjust to specific circumstances. From this point of view, the possibility to continue storing CO_2 when oil production has ceased, and a possible clustering of CO_2-EOR projects (of which a first attempt was made here) are options that require more fundamental enhancements to the PSS simulator and scenarios.

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