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Abstract

Low salinity water injection is an emerging enhanced oil recovery (EOR) technology, just on the verge of being implemented at full scale at the Clair Ridge field, UK. Clair Ridge will be the world's first offshore deployment of BP's *LoSal* EOR technology. The method will be implemented as a day one, secondary waterflood and is expected to deliver an additional 42 million barrels, at a cost of only 3 $/bbl. Over the last twenty years, there has been a significant growth in the evidence supporting the technology, but there is a limited amount of papers where the profitability of the method is discussed.

Profitability is the primary driver of any project. Thus, the objective of this thesis is to evaluate the profitability of *LoSal* EOR at Clair Ridge, and contribute to an improved insight in to the economics of EOR. This is done by combining both technical and economic aspects of the Clair Ridge project. Through a literature review of the reservoir mechanisms and deployment of EOR projects, three main challenges are identified: technical, managerial and economic.

The economic challenges are further analyzed by calculating the differential cash flow from the Clair Ridge field. The project's net present value (NPV) is also obtained and evaluated. The results indicate that *LoSal* EOR is profitable under the given assumptions and circumstances. Additionally, scenarios including traditional waterflooding and tertiary EOR are investigated to illustrate the added value of *LoSal* EOR. From the observed results, it is clear that *LoSal* EOR is the preferred project.

Finally, the effects of delayed production peak and timing of EOR investments are discussed. Although production curves and cash flows are strongly related, it is found that a delay in production peak has a minor effect on NPV. However, results show that an investment made early in the lifetime of the field has a favorable influence on NPV. Hence, it is strongly recommended to include an EOR strategy from the beginning of the field development.

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Preface

This thesis was written as a part of my Master of Science in Industrial Economics at the University of Stavanger, during spring 2017.

My interest in enhanced oil recovery (EOR) started through my bachelor degree in Petroleum Technology, and was deepened throughout my bachelor thesis where experimental studies of EOR were performed. An emerging EOR method with great potential is low salinity water injection. However, there exist few economic evaluations of this method. This motivated me to combine my knowledge within petroleum technology and economics to investigate this topic.

I would like to take this opportunity to thank my faculty supervisor, Petter Osmundsen. His guidance, input and enthusiasm has been very helpful and motivating throughout the work with this thesis. Special thanks also go to Skule Strand, for introducing me to the Clair Ridge field and always welcoming me to ask questions.

Finally, I would like to thank all my friends at the University of Stavanger, and especially INDØKS, for making these five years the very best.

Abbreviations and Acronyms

$bn	One billion dollars
$mm	One million dollars
b/d	Barrels per day
bbl	US oil barrel
CAPEX	Capital expenditure
COP	Cessation of production
cP	Centipoise
EOR	Enhanced oil recovery
HS	High salinity
HSWI	High salinity water injection
IEA	International energy agency
IOR	Improved oil recovery
LS	Low salinity
LSE	Low salinity effect
LSWI	Low salinity water injection
Mbbl	One thousand barrels
mD	Millidarcy
MMbbl	One million barrels
NPV	Net present value
OOIP	Original oil in place
OPEX	Operational expenditure
PV	Pore volume
PWRI	Produced water re-injection
SWCTT	Single well chemical tracer tests
UKCS	United Kingdom continental shelf

1. Introduction

Profitability is the primary driver of any project. It justifies the project implementation, and governs its processes and design (Hite et al., 2005). For many years, almost any project in the oil and gas industry seemed to be profitable, and with an increasing oil demand, many companies were eager to invest in new technology. Today, alongside falling oil prices, there is no guarantee that projects will be profitable, and companies are less willing to take risks. The main focus is on maximizing the recovery factor from current oil fields, as well as maintaining an economic oil rate (Muggeridge et al., 2014).

In the *Market Report Series: Oil 2017*, the International Energy Agency (IEA) reports that the global oil and gas upstream investment fell by 25 % in 2015, and by another 26 % in 2016. However, 2015 also became the biggest year-on-year growth since the financial crisis, with a growth in demand of 2,0 million b/d. Followed by a very robust growth of 1,6 million b/d in 2016, IEA still expects a steady growth in oil demand. Given this increase in demand, and the fact that the average oil recovery factor per reservoir is only 20 % to 40 %, increasing the amount of oil produced from existing and future fields is essential (IEA, 2017).

Enhanced oil recovery, or simply EOR, seeks to do just that. Conventional methods use reservoir energy and re-pressurizing by gas- and water-injection to recover trapped oil. EOR-methods, on the other hand, alter the reservoir's properties to persuade the rock to give up more of its resources. Low salinity water injection (LSWI) is an EOR-method that floods the reservoir using water with total dissolved solids content less than 5,000 ppm (Robbana et al., 2012). The method is widely known, and over the last twenty years, numerous experimental evidences of increased oil recovery by LSWI have been published. Yet, very few economic evaluations of this method are currently available.

1.1 Objectives

The objective of this thesis is to investigate the profitability of enhanced oil recovery at the Clair Ridge field, UK. The field is selected due to several reasons. First, Clair Ridge is the world's first full-field deployment of BP's *LoSal* EOR water injection technology. Second, the method is adopted as a day one, secondary waterflood, which has several advantages compared to a traditional tertiary EOR processes. Third and finally, the method is expected to be very cost effective with an additional cost of only $3 per barrel. Through differential cash flow analysis, the project's net present value (NPV) is obtained and evaluated. Scenarios including traditional waterflooding and tertiary EOR are also analyzed to illustrate the added value of *LoSal* EOR. Hence, this thesis aims to evaluate the profitability of *LoSal* EOR at Clair Ridge, and contribute to an improved insight in to the economics of EOR.

1.2 The Clair Ridge Field

The Clair field is located 142 miles north of the Scottish mainland and 35 miles west of the Shetland Island. The field extends over an area of 220 km^2, in water depths of 132 m to 155 m. Clair is the largest oil accumulation in the United Kingdom continental shelf (UKCS), and contains over 6 billion barrels of oil in place. Operator of the field is BP (27,62 %), and partners are ConocoPhilips (24 %), Chevron North Sea (19,42 %), Enterprise Oil (18,68 %), Shell Clair UK (9,3 %) and Britoil (0,98 %) (Wilson, 2014).

Clair was originally discovered in 1977, but due to complex conditions such as a tight sandstone reservoir (50 mD average), a relatively viscous oil (3,2 cP) and a harsh North Atlantic environment, the appraisal period was long. Because of the physical size of Clair, the field is developed through a phased approach. Phase one came on stream February 2005, and has up till now produced over 100 billion barrels. The success at Clair Phase 1, paved way for the much larger second phase, Clair Ridge (BP, 2017b).

Clair Ridge is planned to target the part of the field to the north of Clair Phase 1, and is estimated to produce 640 million barrels of oil over a 40-year period. By implementing *LoSal* EOR from day one, an extra 42 million barrels are expected to be recovered cost-effectively from the field during its lifetime. Facilities (two bridge-linked platforms) were installed during 2013-2016, and the first oil is expected in the beginning of 2018 (BP, 2015). Figure 1.1 illustrates the location of the Clair field, and other BP operated fields in the same area.

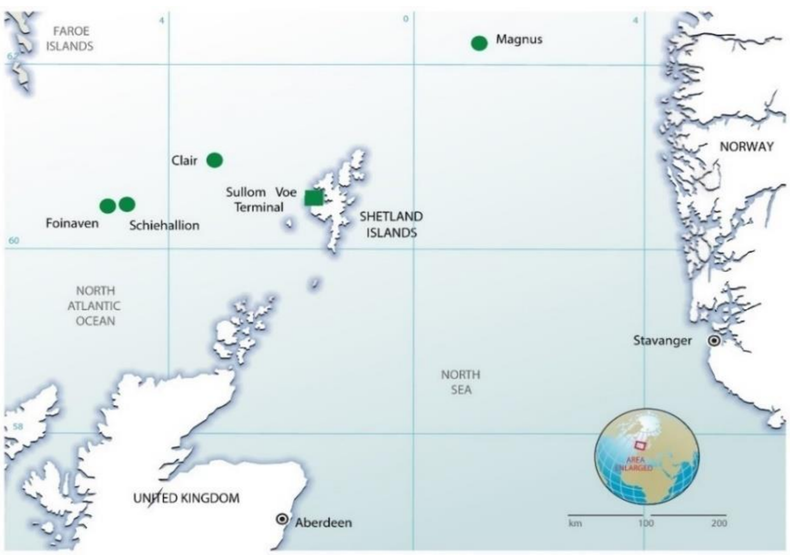


Figure 1.1 *Location of the Clair field and other BP operated fields in the North Sea (BP, 2017b).*

2. Theory

N.B. 1: Sections 2.1.1 and 2.1.2 are retrieved from Layti (2015).

N.B. 2: LoSal EOR is a trademark of BP p.l.c.

2.1 Oil Recovery

Oil recovery is referred to as the processes by which crude oil is extracted from reservoirs beneath the Earth’s surface. The main goal of the process is to produce oil as long as it is environmentally and economically feasible.

2.1.1 Traditional Oil Recovery

Traditionally, oil recovery has been divided into three groups: primary recovery, secondary recovery and tertiary recovery. These groups describe the recovery process in a chronological order.

The initial production stage is primary recovery. Primary recovery results from the use of natural energy existing in a reservoir, as the main source of energy to displace the oil. These natural energy drive mechanisms are solution-gas drive, gas-cap drive, natural water-drive, fluid and rock expansion, and gravity drainage (Green & Willhite, 1998). As the reservoir pressure declines because of production, artificial lift systems such as rod pumps, electrical submersible pumps or gas-lift installations can be implemented. At this production stage, 5 % to 10 % of the original oil in place (OOIP) is recovered (Schlumberger, 2015).

Secondary recovery is the second stage of oil recovery. This stage is traditionally implemented after primary production declines or is too low for economic oil recovery. The main purpose is to re–pressurize the reservoir by adding external energy. This process involves high pressure maintenance by waterflooding or gas injection (Green & Willhite, 1998). Waterflooding gives pressure support to the reservoir to prevent gas production, and to displace the oil by viscous forces (Austad, 2012). Secondary recovery can allow extraction of additional 10 % to 20 % of the oil. After primary and secondary recovery, about two thirds of the original oil in place is left trapped in the reservoir (Van't Veld & Phillips, 2010).

Tertiary recovery, the third stage of production, is applied after secondary recovery processes are ineffective, uneconomical or no longer qualified. The process uses different injectors such as miscible gases, chemicals and/or thermal energy to improve the flow and displace additional crude oil from the reservoir (Green & Willhite, 1998).

2.1.2 Enhanced Oil Recovery

Today, tertiary recovery processes are often referred to, and more accepted as enhanced oil recovery (EOR) processes. Enhanced oil recovery is not restricted to a particular producing life period of the reservoir, and can be initiated with primary or secondary recovery processes (Green & Willhite, 1998).

EOR refers to oil recovery processes other than natural reservoir energy and re-pressurization of the reservoir. The processes involve injection of a fluid or fluids that alter the original properties of the reservoir, and creates favorable conditions for oil recovery. Typical injectors include chemical liquids and gases such as hydrocarbon gases, carbon dioxide, nitrogen, flue gases and/or thermal energy (Green & Willhite, 1998).

The term improved oil recovery (IOR) is also frequently used. IOR refers to any practice used to increase the oil recovery and includes EOR, secondary recovery, infill drilling and horizontal wells (Stosur et al., 2003). Figure 2.1 shows a schematic overview over widely used recovery processes, and the proposed definitions of EOR and IOR.

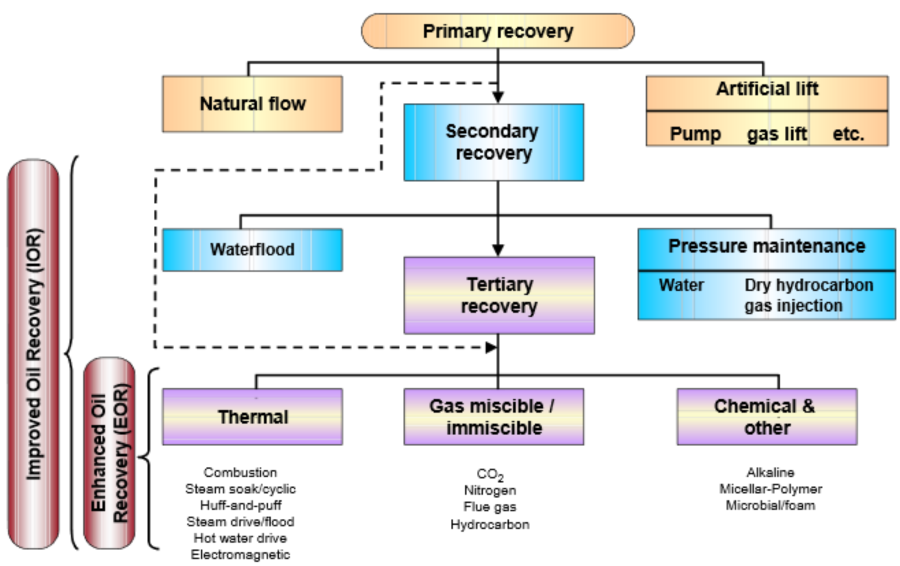


Figure 2.1 *Proposed definitions of the EOR and IOR terms (Stosur et al., 2003).*

Nowadays, conventional oil resources are maturing and new giant oil fields are becoming increasingly difficult to find. There are huge volumes of unconventional hydrocarbons, such as very viscous oil and gas hydrates, but the technologies to recover these resources are either too energy consuming, environmentally sensitive or not ready to be applied in field (Muggeridge et al., 2014). Thus, enhanced oil recovery is essential to maintain the existing oil reserves and improve production rates.

2.1.3 Waterflooding As an EOR Method

Oil and gas are produced by creating pressure gradients within the reservoir that cause the oil and/or gas to flow towards one or more production wells. Normally these pressure gradients are sustained by injecting water or gas into the reservoir through injection wells. Waterflooding physically displaces the oil, and takes its place in the pore space (Muggeridge et al., 2014). The technique has proved to be widely successful over a range of reservoirs and conditions, and is currently the preferred technique for most projects. Waterflooding has also brought solutions to problems regarding water treatment, corrosion control, water handling, sand production and waste water disposal (Wade, 1971).

In a normal waterflooding process, reservoir properties are not altered, thus the recovery method is considered as secondary recovery. However, if the composition of the injected water is modified, e.g. by lowering the salinity or adding chemicals, the initial reservoir properties may change. Therefore, waterflooding may also fall into the EOR category (Torrijos, 2017).

2.1.4 Emerging Enhanced Oil Recovery Technologies

As figure 2.1 illustrates, EOR processes can be classified in three categories: *Thermal, gas miscible/immiscible* and *chemical & others*. However, a fourth category, *emerging processes*, is also often included. Emerging EOR processes include low salinity water injection, microbial EOR, enzymatic EOR and Nano particles, among others. These methods apply rather different mechanisms than the conventional EOR processes to improve oil recovery. Emerging EOR processes also benefit from significantly lower costs per barrel, have a broader applicability and are less complex to implement (Muggeridge et al., 2014).

2.2 Low Salinity Water Injection

As mentioned, one of the emerging enhanced oil recovery technologies is low salinity water injection (LSWI). The purpose of LSWI is to inject water with a reduced salinity (less than 5,000 ppm) to improve oil recovery. LSWI is a relatively new method, yet very attractive due to its simple, inexpensive and environmentally friendly implementation (Dang et al., 2013). However, the method has not yet been implemented in full scale, even though the first experimental evidence of increased oil recovery by low salinity water injection was reported more than twenty years ago. In this section, the proposed mechanisms for LSWI in sandstone reservoirs, and the process of getting *LoSal* EOR from laboratory experiments to full field deployment are presented.

2.2.1 The Low Salinity Effect

Jadhunandan (1990) and Jadhunandan and Morrow (1995) were the first to document the effect of brine composition on waterflooding, and in 1996, Yildiz and Morrow published the first coreflood results. The authors concluded that the composition of the injected water can affect recovery, but that further work was needed to distinguish the relative importance of crude oil, brine and rock chemistry (Yildiz & Morrow, 1996). Trough continuous investigation, the low salinity effect was discovered by Tang and Morrow (1997). In their study of Berea sandstone cores, it was documented that the salinity of the injected brine had a major influence on wettability and oil recovery (Tang & Morrow, 1997). Following, extensive research programs on low salinity water injection have been conducted by Webb et al. (2004) and McGuire et al. (2005). Both programs conducted LSWI single well tests, and similar favorable results were obtained (McGuire et al., 2005; Webb et al., 2004).

Today, it is generally accepted that the reason for this improved oil recovery is due to wettability alteration (Webb et al., 2004). Wettability is closely linked to the distribution of oil and brine in the pores of the rock, and wetting properties are found to play a very important role for the efficiency of waterfloods in reservoirs (Austad, 2012). Reservoirs are defined as water-wet, mixed-wet or oil-wet, and usually the initial wetting is not optimal for oil recovery (Fathi et al., 2011). However, the wettability can be improved (towards more water-wet conditions) by injecting low salinity water.

The proposed mechanisms for this wettability improvement include the low salinity water weakening the polar attraction of crude oil to clay particles in the rock. As the oil migrates through the reservoir rock, polar organic components in the crude oil are adsorbed to the surface (see figure 2.2). In several cases, the mechanism by which polar components involve cation bridges. The low salinity water is able to break these bridges by exchanging the divalent cation (Ca^{2+}, Mg^{2+}) for a monovalent cation such as sodium (Na^{+}). Consequently, the oil molecules are freed to be swept towards the producing wells. This mechanism is referred to as multicomponent ion exchange (MIE) and is illustrated in figure 2.3 (Lager, Webb, Black, et al., 2008; Robbana et al., 2012).

Understanding low salinity water injection is essential to develop a successful EOR method. Still, the mechanisms for the increased production are not well understood. Other proposed low salinity EOR mechanisms include fines migration (Tang & Morrow, 1999), pH variation (McGuire et al., 2005) and the smart water LS mechanism (Austad et al., 2010). Nevertheless, all the interest in the low salinity effect have led to a better understanding, and enabled the world's first full field implementation of low salinity water injection at the Clair Ridge field.

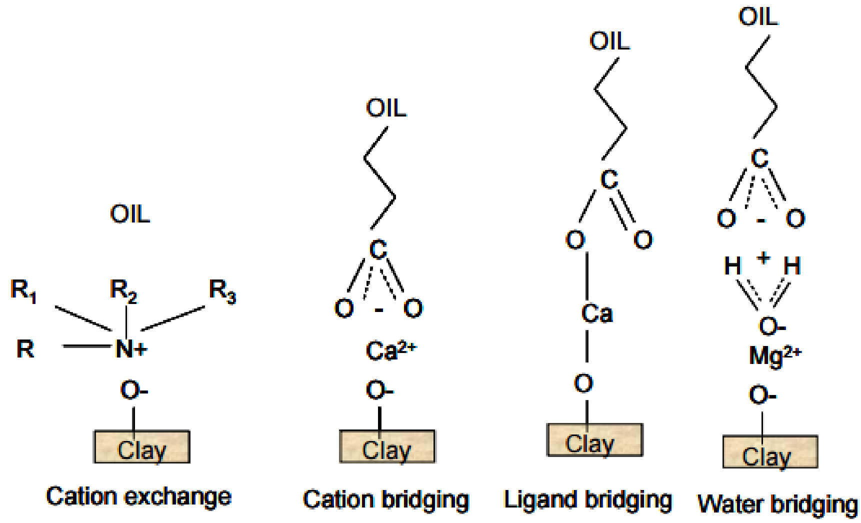


Figure 2.2 *Attraction mechanisms between crude oil and rock surface (Robbana et al., 2012).*

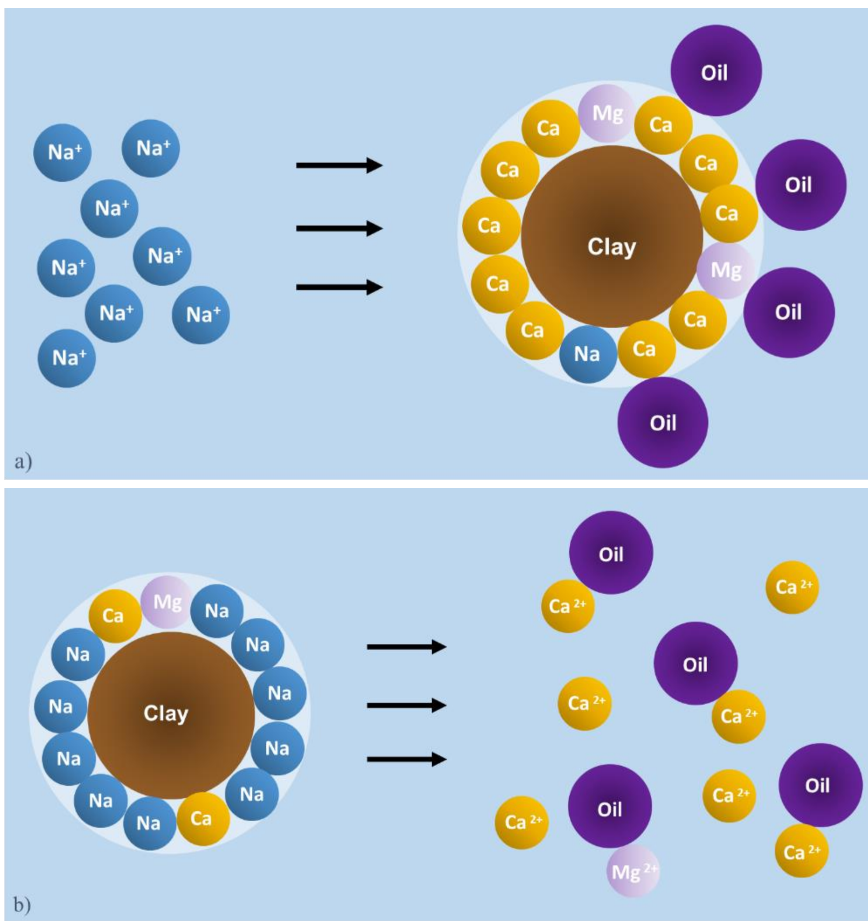


Figure 2.3 *The multicomponent ion exchange mechanism.* ***a)*** *Oil molecules are attracted to the divalent ions (Mg^{2+}, Ca^{2+}) and the clay surface.* ***b)*** *Na^{+}-ions from the injected water replace the divalent cations and release the oil. Re-drawn after (Zekri et al., 2011).*

2.2.2 From Laboratory Research to Field Implementation

BP's low salinity technology is named *LoSal* EOR, and is developed by BP's *Pushing Reservoir Limits* team. The deployment of *LoSal* EOR at Clair Ridge is a combination of a decade of testing in BP's laboratories and oil field trials in Alaska (BP, 2014). Figure 2.4 shows a typical timeline for EOR development projects.

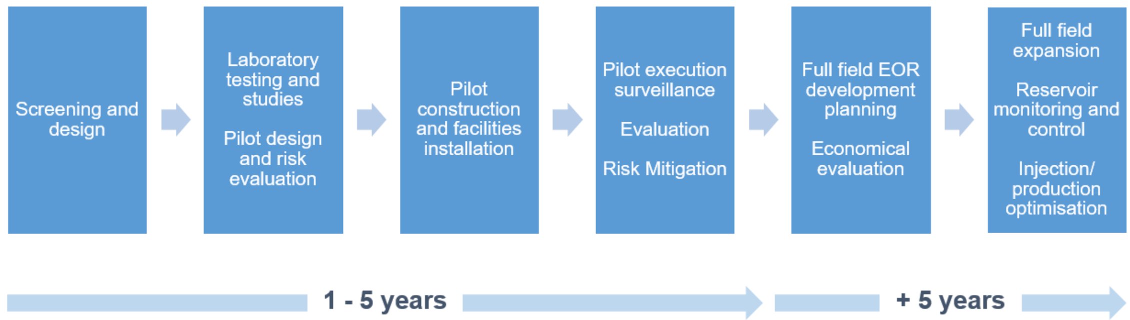


***Figure 2.4** EOR development timeline. Re-drawn after (Maersk Oil, 2017).*

Per figure 2.4, it can take more than 10 years from screening and design of an EOR project to full field expansion. As an example, the confirmation and quantification of the *LoSal* EOR potential began in 2006, and the first oil from the project is expected at the beginning of 2018 (Robbana et al., 2012).

EOR Screening

Choosing an appropriate EOR process for a targeted oil field is a critical decision. Typical screening criteria to be considered include oil viscosity, oil gravity, saturation, formation type, permeability, previous production method, etc. In addition to these reservoir-specific criteria, offshore-specific conditions such as higher costs, remote location, space and weight limitations, and environmental regulations must be included (Kang et al., 2014). Furthermore, an economic screen, where the chosen EOR method is applied to a representative model reservoir, should be conducted (Bondor, 1993).

During the development of Clair Ridge, various EOR schemes, e.g. gas flooding, CO_2 flooding and polymer flooding, were considered and rejected. Since water naturally imbibes into the Clair rock formation, it was concluded that an EOR method based on water would offer the best solution.

A successful LSWI should be designed in such a way that additional oil is generated, while risks such as formation damage and clay swelling are avoided under any condition (Sorop et al., 2013). With limited reservoir information, this could be a challenging and complex process (Green & Willhite, 1998).

Laboratory Testing

Once a suitable EOR scheme is chosen, extensive laboratory testing is initiated. The performance of *LoSal* EOR can be simulated at core, well or sector scale (shown in figure 2.5). At core scale, corefloods under reservoir conditions are performed to understand mechanisms and evaluate displacement behavior of the injected water (Green & Willhite, 1998). Next, single well chemical tracer tests (SWCTT) are conducted to measure residual oil saturation in the near-well region (Huseby et al., 2012). In total, over 50 corefloods and over 15 SWCTTs have been conducted by BP across its portfolio to confirm the performance of *LoSal* EOR (Reddick et al., 2012).

Finally, at the sector scale, fine grid 3D models of pilot area, EOR forecast scenarios and scaling of low salinity parameters are investigated (Rotondi et al., 2014). Robbana et. al (2012) created 48 sector models to analyze *LoSal* EOR at Clair Ridge. Of all the reservoir descriptions tested, 98 % had a positive *LoSal* EOR incremental recovery (Robbana et al., 2012).

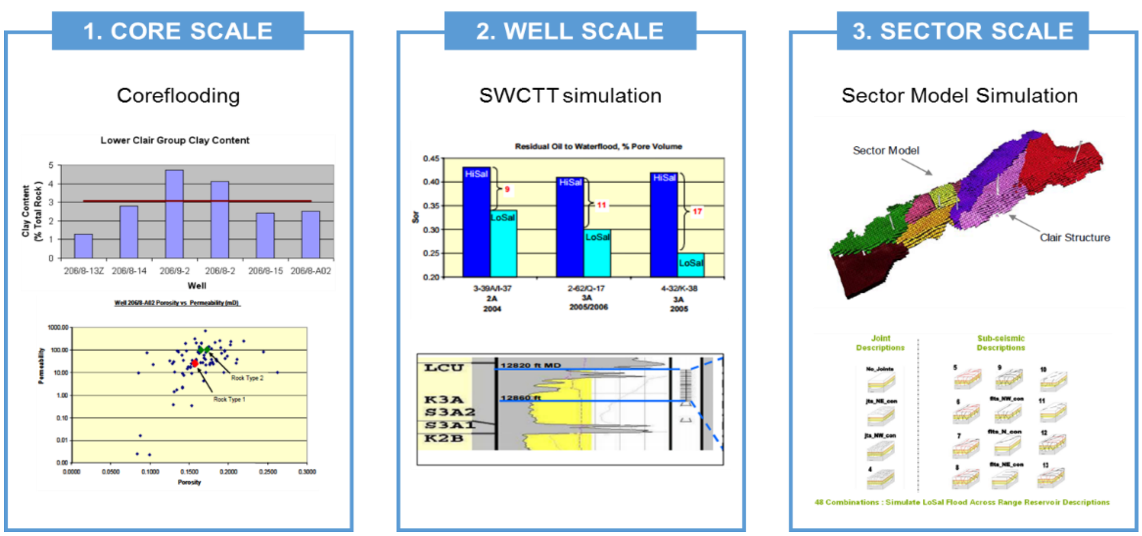


***Figure 2.5** Simulation modelling steps. 1. core scale, 2. well scale and 3. sector scale. Re-drawn after (Rotondi et al., 2014). Example figures are collected from (Robbana et al., 2012; Seccombe et al., 2008).*

Pilot Development and Execution

To gain a better understanding of important parameters and variables a field test or pilot may be necessary. Factors such as injectivity, residual-oil saturation and displacement efficiency can be hard to measure in the laboratory or difficult to deduce from history matching. If these factors are critical for success, a field test is often justified. The results from a pilot can be used to further improve performance models, and in economic studies to help management make smart decisions (Hite et al., 2005).

Prior to the Clair Ridge project, a field trial using *LoSal* EOR at the Edicott Field, Alaska was conducted. The trial confirmed that low salinity water injection works as well at inter-well distances as it does in corefloods and single well chemical tracer tests (Seccombe et al., 2008). A second field trial performed by BP, also concluded that injection of low salinity brine was successful (Lager, Webb, Collins, et al., 2008).

The stages from corefloods in the laboratory to pilots in the field are essential in building confidence and proof for the *LoSal* EOR technology. This is often referred to as the "pyramid of proof", illustrated in figure 2.6.

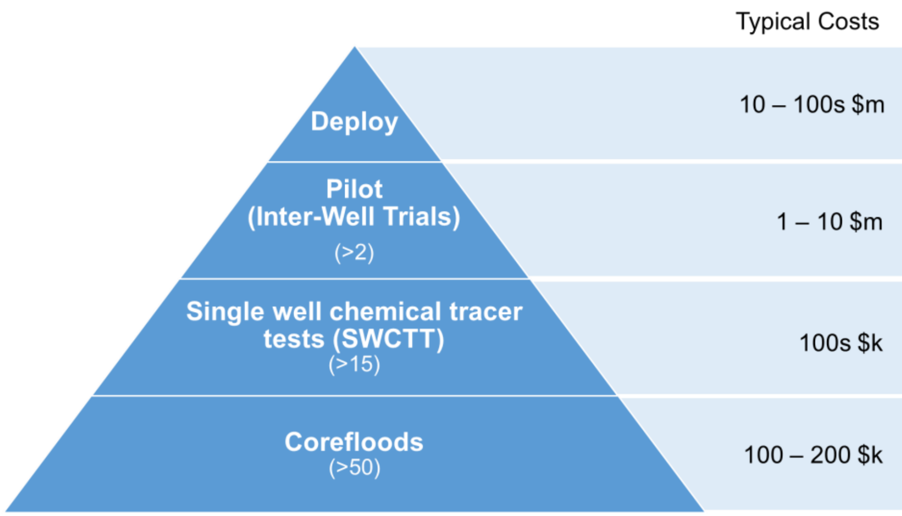


Figure 2.6 *Pyramid of proof and typical costs. Re-drawn after (Reddick, 2012).*

The pyramid of proof illustrates the importance and contribution of each stage in collecting subsurface data and knowledge to enable *LoSal* EOR technology. In addition, the typical costs for each stage are included (Reddick, 2012).

Facilities Installation

When facilities are designed to be installed offshore, all increases in seawater capacity, installed equipment and overall system complexity should be kept to a minimum. The facilities on the Clair Ridge project include two new bridge-linked platforms; a production platform and a utilities platform. Additionally, a new pipeline infrastructure is constructed to connect storage and redelivery facilities on Shetland. To manufacture the low salinity water, desalination facilities based on reverse osmosis with membrane prefiltration are installed (Reddick et al., 2012). Figure 2.7 illustrates the integration of membrane treatment facilities into conventional offshore water injection systems.

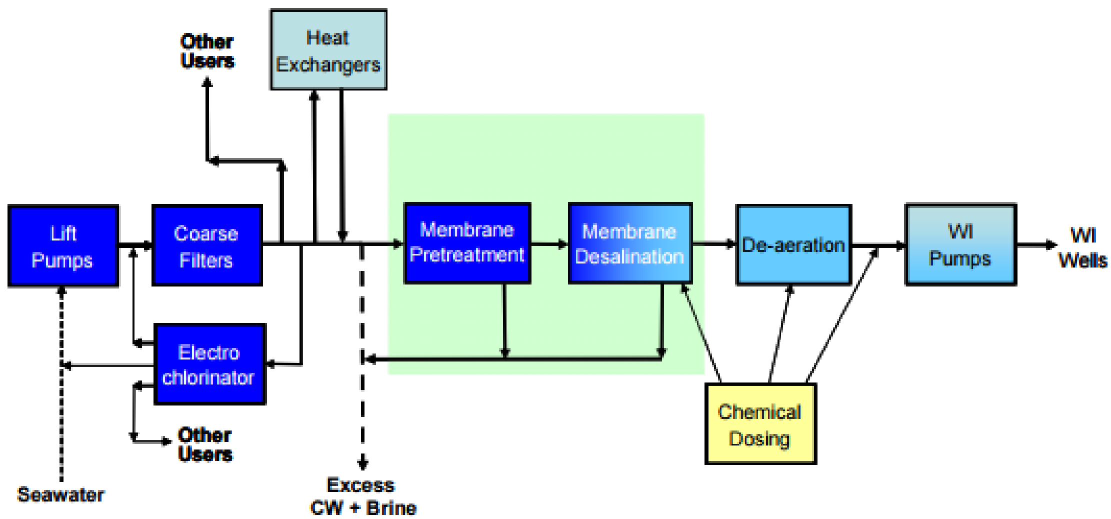


Figure 2.7 *Integration of membrane treatment facilities into conventional offshore water injection systems (Reddick et al., 2012).*

Water is pumped up from the sea, and transported towards membrane pretreatment and membrane desalination where the salinity is reduced. Separated produced water and reduced salinity water streams make it possible to manage the water injection into isolated field segments over time, so that *LoSal* EOR reservoir contact is maximized (Robbana et al., 2012).

Full Field EOR Development

Normally EOR projects are developed as tertiary recovery processes. However, research show that oil recovery in some cases are increased significantly if LSWI is applied as a secondary waterflood (Hamon, 2016). In addition, it is strongly recommended to include an EOR strategy in the development plan of the reservoir in order to get a more efficient EOR project (Strand, 2005).

Clair Ridge will be the first offshore development project to implement *LoSal* EOR as a secondary recovery. Furthermore, the project aims to re-inject produced water into the reservoir, and thus become more environmentally friendly by not disposing any produced water to the sea. (Robbana et al., 2012). Figure 2.8 illustrates the *LoSal* EOR flood segments and injection strategy at Clair Ridge.

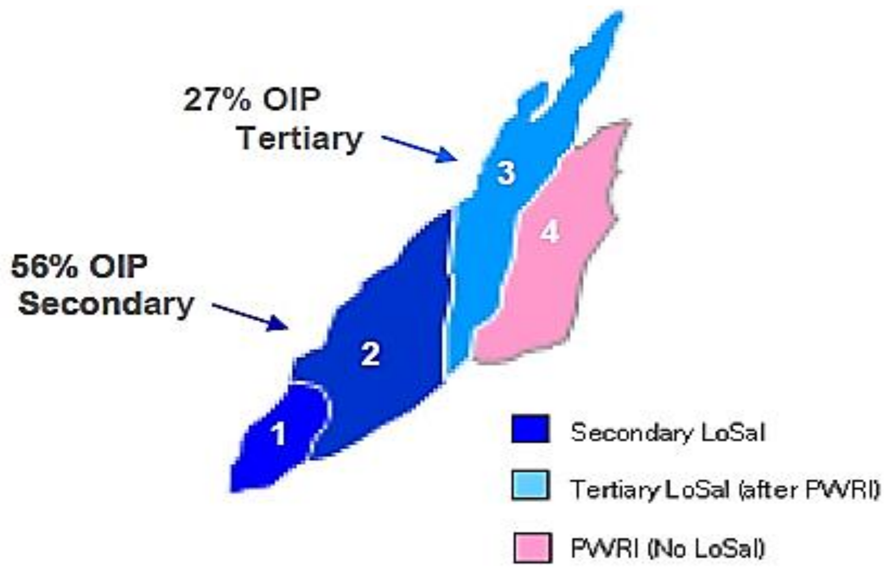


Figure 2.8 *Clair Ridge LoSal flood segments (Robbana et al., 2012).*

From day one of production, segments 1 and 2 will be flooded with low salinity water. Once sufficient *LoSal* water has been injected to deliver secondary EOR, the segments will be switched to produced water re-injection (PWRI). Segment 3 will start with PWRI, and then receive low salinity water after year 2030. Segment 4 will be flooded with produced water throughout the lifetime of waterflood (Robbana et al., 2012).

Finally, even though the most critical part of a project lies in its early phases, the job is not completed once the production valves are turned on. To ensure a successful EOR project, ongoing surveillance of the process is essential. Reliable data, careful quality control, monitoring performance and frequent well reviews play a strong role in achieving production targets (Hite et al., 2005).

2.3 Deployment of EOR Projects

In addition to increased oil recovery and direct economic value, there are several advantages linked to low salinity water injection EOR. First, the method has lower CAPEX and OPEX costs than alternative EOR technologies. Second, risks regarding reservoir souring, formation damage, scaling and corrosion may be reduced (Sorop et al., 2013). Third, by extending the field life of current fields, the need for new field developments may be reduced (Thompson & Goodyear, 2001). Despite these benefits and the fact that EOR methods nowadays are more cost-efficient than ever, the deployment of commercial EOR projects is slow. The main inhibiting factors include technical, managerial and economical challenges (Torrijos, 2017).

2.3.1 Technical Challenges

As described in section 2.2.2, one of the main bottlenecks in the deployment of new technology is transforming the techniques and methods from the laboratory to field implementation (Osmundsen, 2013). There are several reasons for this in EOR projects. Foremost, no single EOR process is applicable to all oil types, and so, several different processes must be developed. Following, oil resources exist in reservoirs of widely varying characteristics. Rock type, structure and other geological parameters are unique for every reservoir, and thus every deployment of an EOR method is unique (Green & Willhite, 1998).

Another major project stopper are the technical challenges related to offshore installation. As mentioned, offshore installations have strict capacity limitations, and reconstructions can be difficult and expensive. In addition, offshore installations have often less injection wells, which causes a greater distance between each well. This can result in a less efficient flooding, and a longer payback period due to the delayed effect of EOR. Offshore projects also require reliable prognoses, but obtaining proper data on reservoir conditions is usually expensive and time-consuming (Søndenå & Henriquez, 2011).

2.3.2 Managerial Challenges and Risks

Low salinity water injection is normally an extension of conventional waterflooding, and thus easier to implement than other EOR methods. However, the screening, designing and executing phases require an increased operator competence and management focus compared to conventional waterflooding (Sorop et al., 2013). Additionally, EOR projects are often held back because the perceived balance between risk and reward is not considered to be competitive compared to other more conventional recovery methods (Thompson & Goodyear, 2001). To overcome this “conservativeness” in applying new technology, long term commitment from management to mature the technology is necessary (Sorop et al., 2013).

Being able to identify and manage risk is an important step in achieving recognition and acceptance towards new technology. Reddick (2012) identified the main risks associated to *LoSal* EOR to be loss of injectivity, operability of desalination facilities and the interface with produced water management. Through a risk management analysis, illustrated in figure 2.9, most of the risks were found to be of relatively low or medium impact and/or frequency. A small number of potentially high impact risks were found. However, these relate to design decisions and become highly manageable with project maturity and definition (Reddick et al., 2012).

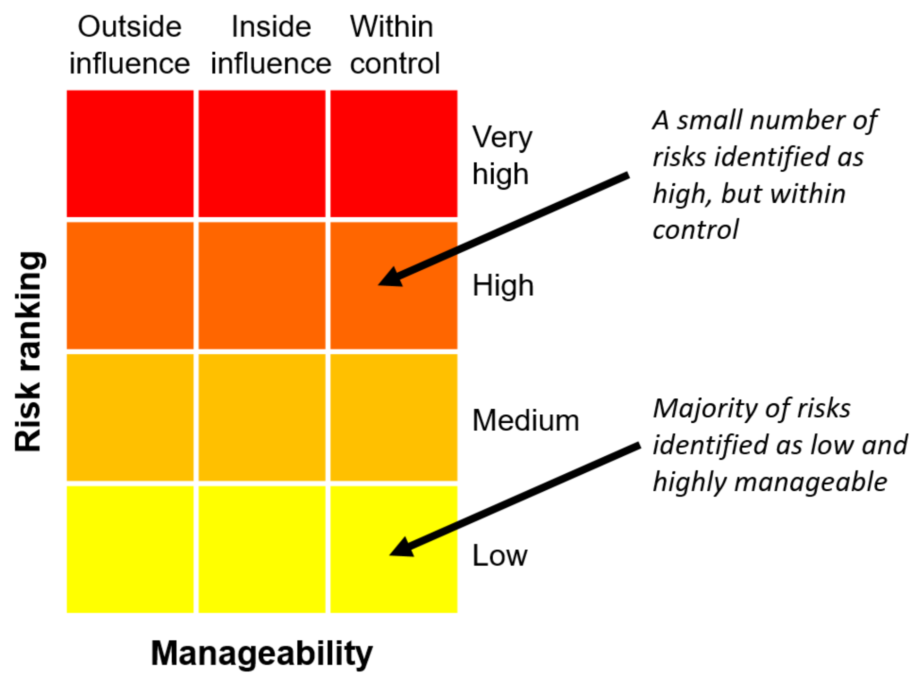


Figure 2.9 *Risk assessment for low salinity projects. Re-drawn after (Reddick et al., 2012).*

2.3.3 Economic Challenges

Besides the internal project economics, the decision on whether to implement EOR is highly dependent on the external market conditions, such as the oil price. As an example of this dependency, most of the EOR processes used today were first introduced in the early 1970s at a time of relatively high oil prices (Muggeridge et al., 2014). Another challenge is that many EOR projects are capital sensitive with high risk of undesirable consequences (Kang et al., 2014).

Onshore EOR projects in the North America have been relatively common for many years, while offshore EOR projects are much less common. Costs of implementing EOR offshore are much higher than in an onshore environment, and this have been one of the main inhibiting factors for EOR in the UKCS (Muggeridge et al., 2014). To overcome the high costs of offshore oil development, the size of the targeted oil fields is generally large. Thus, the amount of recoverable oil using EOR is enormous (Kang et al., 2014). Another positive aspect of offshore EOR implementation is the availability of seawater, which makes waterflooding relatively cheap (Muggeridge et al., 2014).

One more important factor to recognize is that the direct income from the additional oil production due to EOR may not in itself be enough to make a project economic. However, the window created by extended platform life from an EOR project, might create additional recovery from satellite fields, and therefore be profitable (Thompson & Goodyear, 2001).

2.4 Economics of EOR

Today, EOR projects must prove themselves under much more strict criteria than previously (Bondor, 1993). Consequently, in order to be successful, economic studies are performed in parallel with engineering design and performance models (Hite et al., 2005). This ensures that factors that have a significant influence on profitability are given extra attention, so that the project is kept within budget.

2.4.1 How to Measure Profitability?

There are several methods to measure the profitability and to rank multiple projects.

The Time Value of Money

One of the most basic principles of finance is the time value of money: A dollar received today is worth more than a dollar received in the future, because the dollar today can be invested to earn more than a dollar received in the future. This principle is also fundamental in an EOR project since the future oil production rate is translated into future cash flows, which in turn is related to an investment decision in the present (Joshi et al., 1998).

To calculate the present value of money, the cash flow is multiplied by a *discount factor*. The discount factor is given by equation 1 (Joshi et al., 1998):

$$DF_i = \frac{1}{(1+r)^t} \qquad (1)$$

Where r is the discount rate and t is years from now. The discount factor is always less than 1.

If there are a series of delayed cash flows over a given time, their *present value* is (Joshi et al., 1998):

$$PV = \sum_{i=1}^{n} DF_i * C_i \qquad (2)$$

Where C_i is the cash flow at times t_i.

Net Present Value

To make decisions when cash flows are received at different points in time, the net present value (NPV) is calculated. The NPV is obtained by adding the initial cash flow (investments) to the PV formula (equation 2) (Joshi et al., 1998):

$$NPV = C_0 + PV \qquad (3)$$

Where C_0 is the initial cash flow.

A project is said to be profitable if the NPV is larger or equal to zero, and unprofitable if it is less than zero (Albright et al., 2007).

Differential Cash Flow

Cash flow is the yearly net amount of cash moving into and out of a business. To evaluate the profitability of EOR rather than traditional recovery, a differential cash flow analysis is conducted. In a differential cash flow, two mutually exclusive projects are compared by computing the difference in cash flows for each period between the two investments. By using this method, cost savings by choosing one option over another appear as revenue in the annual cash flow (Albright et al., 2007; Damodaran, 2010).

Internal Rate of Return

The internal rate of return (IRR) is the discount rate which makes the NPV equal to zero. Generally, projects with higher IRR are chosen over projects with lower IRR. However, sometimes a project may not have a unique IRR, or not an IRR at all. Thus, NPV is more useful than IRR (Joshi et al., 1998).

3. Method

This chapter describes methods for collecting data, estimating production and calculating cash flows. Figure 5.1 illustrates the steps and approaches used to obtain the results. Finally, some thoughts on uncertainty in the calculations are included.

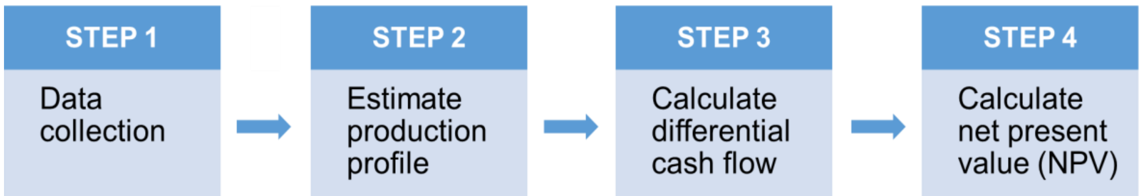


Figure 3.1 *Methodology of analysis.*

3.1 Data Collection

There are a limited amount of papers and reports where the profitability of BP's *LoSal* EOR method is discussed. Thus, obtaining data to investigate the economic potential is even harder. However, Clair Ridge is the world's first full-field deployment of *LoSal* EOR technology, and hence, BP has great interest in displaying it. A search for Clair Ridge on BP's webpage *bp.com* results in 59 articles, while a search for other BP operated fields in the same area, such as Schiehallion and Foinaven (see figure 1.1), only show 33 and 5 results respectively.

More than 500 papers are published on low salinity water injection into sandstone reservoirs to enhance oil recovery, but very few field applications of the technique exist. Clair Ridge is therefore unique, and of great significance if the project successful. Several news articles are written about the project, and a search on *Google Scholar* for Clair Ridge gives more than 100 results. This shows that BP and the *LoSal* EOR technology have gained a lot of attention. However, few articles and papers investigates the economic aspect of the field.

3.2 Production Profiles

First, to study the economic potential of Clair Ridge, production profiles are estimated. The data used in this thesis to develop production profiles are based on historical data from *UK Oil and Gas Authority*, published SPE papers and BP's own statements. Until now, the Clair field (phase one) has produced over 100 million barrels, and reached a plateau of 50,000 barrels per day in 2007. Figure 3.2 shows the monthly oil production in cubic meters from 2004 to 2016.

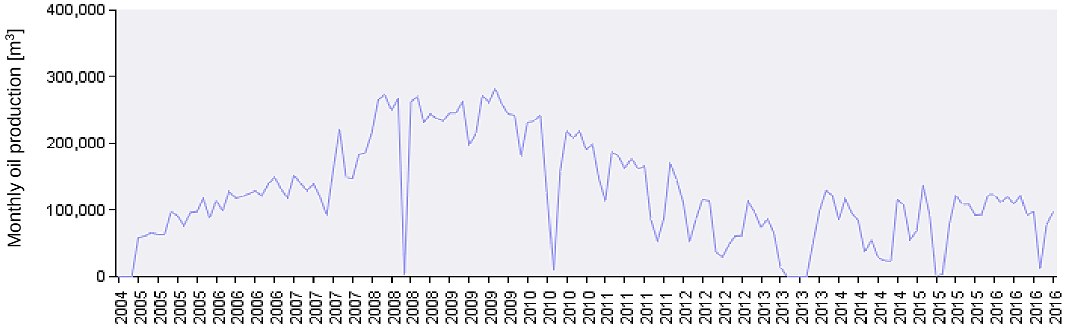


Figure 3.2 *Monthly oil production in m^3 for Clair Ridge (2004-2016)(UK Oil and Gas Authority, 2017).*

Clair Ridge holds more than 640 million recoverable barrels, and is the largest oil accumulation in the UK continental shelf. First oil is expected in 2018, with production growing over four years to more than 100 thousand barrels per day. The employment of *LoSal* EOR technology is expected to result in 42 million additional barrels recovered over the lifetime of the field. It has taken BP over two decades of research to provide the confidence to deploy this technology at Clair Ridge. Several corefloods, well-tests and field trials have been performed to predict field performance from models and simulations (BP, 2014). Figure 3.3 illustrates a fracture-dominated *LoSal* EOR recovery type response, and is used as a base for the production curves in this thesis.

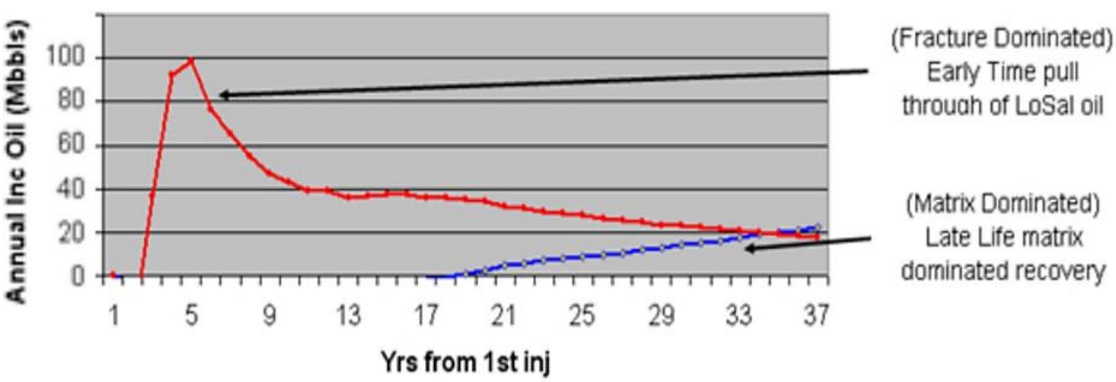


Figure 3.3 *LoSal EOR oil recovery type profiles (Robbana et al., 2012).*

By using *Excel* and the collected data, production curves for different production scenarios at the Clair Ridge field is made. Tables 3.1 and 3.2 summarizes the data used for the calculations.

Table 3.1 Production data for Clair Ridge.

Clair Ridge	
First oil [year]	2018
Expected lifetime [year]	2050
Oil production target [MMbbl]	640
Peak rate [b/d]	100,000

Table 3.2 Production data for LoSal EOR.

LoSal EOR	
Additional recovery [MMbbl]	42
Production peak reached [years after 1st inj.]	4

3.3 Investments and Cash Flows

According to *bp.com*, the company has invested £4.5 billion in the Clair Ridge field (BP, 2011). This represents one of the highest annual investment ever made by BP in the UK North Sea. The project scope includes production, accommodation and drilling facilities on two bridge-linked platforms. In addition, the field will be tied into the existing export systems by new subsea pipelines. The investment also includes $120 million for a desalination unit to produce low salinity water. BP estimates the additional costs associated to producing and injecting low salinity water to be $3 per barrel (Reddick et al., 2012). It is assumed that the investment costs are equally spread over a four-year period starting in 2004, and production costs are kept constant over the lifetime of the field.

To evaluate the profitability of *LoSal* EOR rather than traditional recovery, a differential cash flow with emphasis on net present value (NPV) is calculated. The model is based on a normal discount rate of 10 %. All calculations are done in real terms (2017). Accounting for the expected inflation of 2 %, a real discount rate of 8 % is applied. An oil price of $60 per barrel is assumed. Table 3.3 summarizes the data used in the calculations.

In computing differential cash flow, the project with the larger initial investment normally becomes the project against which the comparison is made (Damodaran, 2010). However, since the cash flows in this thesis are linked to production profiles, the project with larger total production becomes the project against which the comparison is made. Finally, the differential cash flows are used to calculate the NPV as described in section 2.4.1. The decision rule can be summarized as (Damodaran, 2010):

If $NPV_{B\text{-}A} > 0$: Project B is better than project A

$NPV_{B\text{-}A} < 0$: Project A is better than project B

Table 3.3 *Economic data for Clair Ridge.*

Data for NPV analysis	
Investment costs [$bn]	7,1
LoSal investment cost [$mm]	120
Production cost *LoSal* EOR [$/bbl]	3
Oil price [$/bbl]	60
Discount rate [%]	8

3.4 Uncertainty

The lack of theory on the economics of EOR makes it difficult to verify the collected data. Only two papers, SPE 153993 and SPE 161750, directly addressing *LoSal* EOR at Clair Ridge have been published. These papers mainly discuss the technical and operational aspects of the Clair Ridge project.

As previously stated, most data have been collected from BP's own articles and press releases. Even though BP is considered a reliable source, forward-looking statements such as capital expenditure, costs, investments, performance, hydrocarbon production volume etc. may contain errors. BP states in their legal notice and cautionary statement that:

> *"Such statements reflect the views of BP as of the date made with respect to future events and are subject to risks and uncertainties. […] BP disclaims any intention or obligation to update forward looking statements* (BP, 2017c)."

Despite these uncertainties the collected data is quality controlled and compared to several published sources. The obtained results are also verified against similar studies.

Production profiles are also a source of uncertainty. Since no modeling or simulation has been conducted, the profiles are based on forward-looking statements and other assumptions described in section 3.2. This is a weakness since all cash flows are based on these profiles, and thus will be influenced by an error. Yet, it does not exist a satisfactory simulation model for expected production from low salinity water injection today, and so a model based on forecasts is considered to the best alternative for this thesis.

4. Results

The following results of are divided into three main parts. The first part presents the additional production profile and differential cash flow from *LoSal* EOR at Clair Ridge. In the second part, the most realistic option to EOR, a traditional secondary waterflooding, is assessed. Finally, a scenario with tertiary EOR, i.e. high salinity injection followed by a low salinity injection, is evaluated. Corresponding production curves and NPV for each scenario are also presented. All calculations are attached in the appendix.

4.1 Differential Cash Flow, the Profitability of *LoSal* EOR

With the data shown in table 3.2 and assumptions presented in section 3.2, a production curve for the additional oil recovered by *LoSal* EOR, is estimated and presented in figure 4.1.

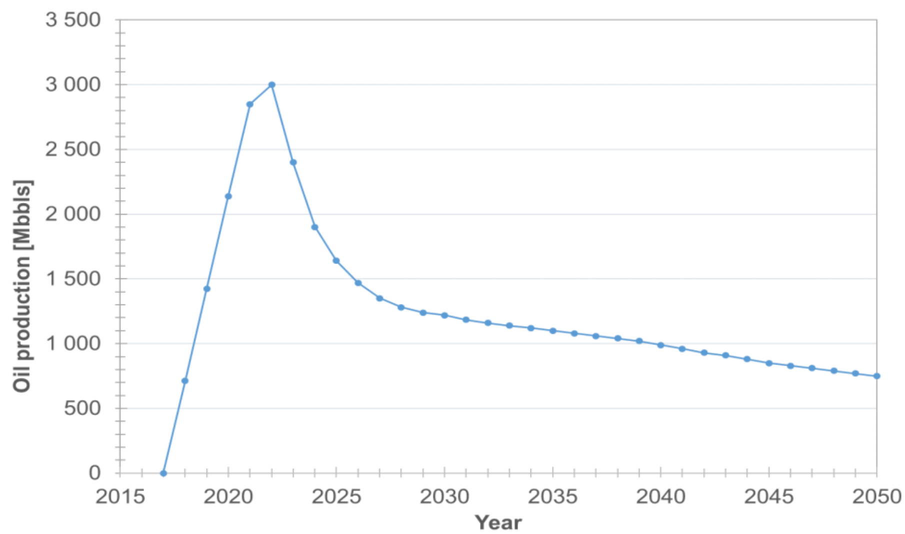


Figure 4.1 *Additional production from LoSal EOR.*

The first oil from the field is expected in 2018, with a projected lifetime till 2050. Starting, the production has a steep increase, until the production peak is reached in 2022. Until this stage, only oil is produced. From 2022, the production significantly declines due to increasing water production. In total, *LoSal* EOR contributes with additional 42 million barrels.

From the additional yearly production, the differential cash flow is calculated. Using only the investment for the *LoSal* EOR facilities, $120 million, and the additional costs of 3 $/bbl, the profitability of EOR alone is obtained. A discount rate of 8 % and oil price of 60 $/bbl, in real terms, have been chosen. Figure 4.2. shows the differential cash flow over time.

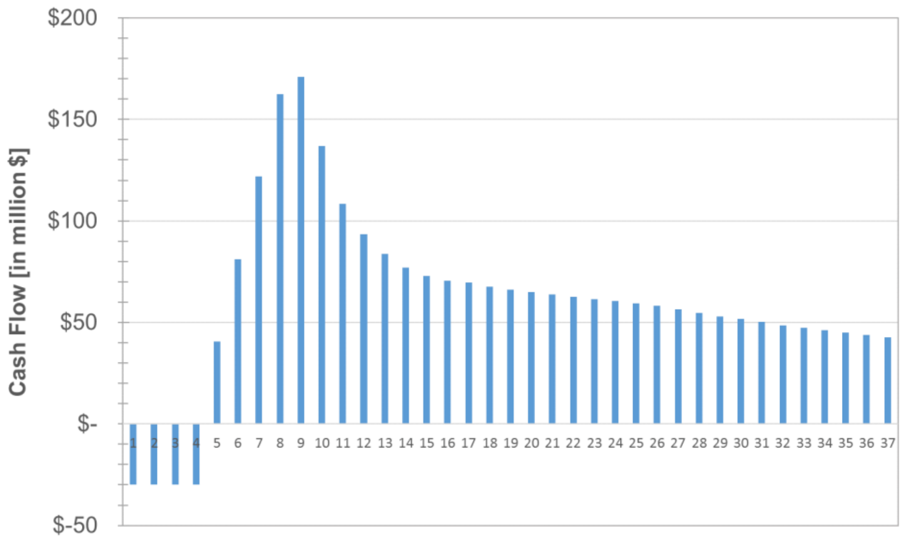


Figure 4.2 *Differential cash flow for LoSal EOR.*

During its first years, the Clair Ridge project has a negative cash flow, but as the production starts, the cash flow is positive throughout the lifetime. The shape of the cash flow columns follows the same shape as the curve in figure 4.1, suggesting that the cash flow is highly dependent on the production curve. From the differential cash flow, net present value of the project can be calculated:

$$\boldsymbol{NPV_{LoSal\ EOR}} = \$\mathbf{697\ 153\ 855}$$

The project is clearly profitable, with a NPV of $697 million.

4.2 Low Salinity Versus High Salinity Injection

In the previous chapter, the profitability of *LoSal* EOR is evaluated based on the difference between implementing *LoSal* EOR and not implementing *LoSal* EOR. In a realistic case, the actual alternative to *LoSal* EOR, would be to perform a conventional high salinity water injection (HSWI). Studies comparing low salinity against high salinity injection show benefits ranging from 5 % to 40 % increased oil recovery based on original oil in place (Webb et al., 2008). Figure 4.3 illustrates a typical secondary high salinity and reduced salinity coreflood.

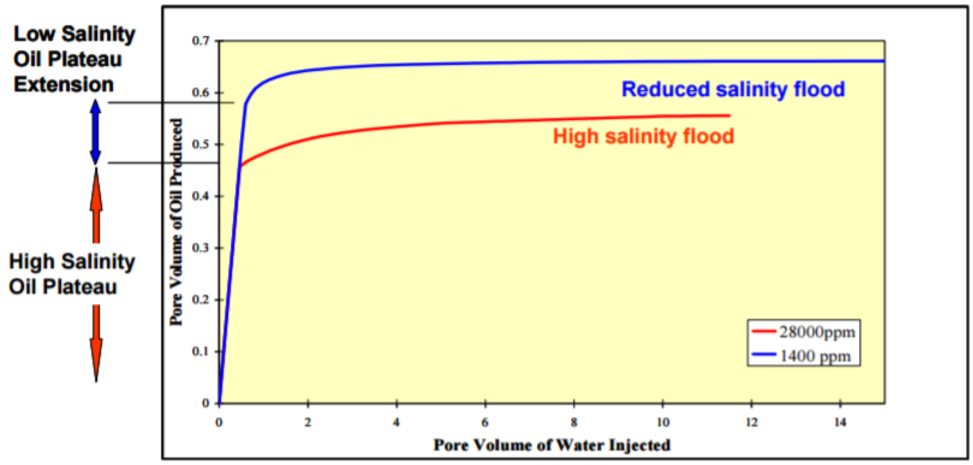
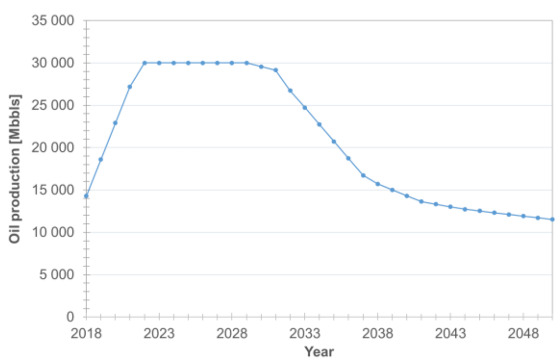


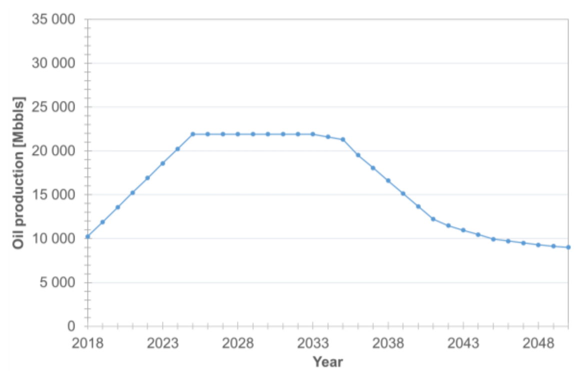
Figure 4.3 *Typical coreflood response – secondary recovery (Robbana et al., 2012).*

The positive effect of low salinity (LS) is clear as the reduced salinity flood curve reaches a higher oil plateau than the high salinity (HS) flood. Even more interesting, is the fact that after 0,5 PV the LS flood has produced 0,58 PV oil, while HS has only produced 0,46 PV. In other words, more oil is produced by injecting the same amount of water during LSWI compared to HSWI.

Based on figure 4.3, production scenarios (a) secondary LSWI and (b) secondary HSWI at Clair Ridge are estimated and presented in figure 4.4.



(a) Low Salinity water injection (*LoSal* EOR)



(b) High salinity water injection

Figure 4.4 *Total production forecast at Clair Ridge.*

Secondary HSWI maintains reservoir pressure, but does not alter the reservoir properties like LSWI, hence the two production curves in figure 4.4 are different. Scenario (a) shows that the oil production reaches a plateau of 30 million bbl/year in 2023, while (b) reaches the plateau in 2025 with a rate of approximately 22 million bbl/year. From the production curves, cash flow and NPV for the two scenarios are calculated. Table 4.1 presents the inputs used.

***Table 4.1** Data used for LSWI and HSWI.*

	LSWI	HSWI	Difference
Investment	\$5,80 billion	\$5,79 billion	\$120 million
Production cost	8 \$/bbl	5 \$/bbl	3 \$/bbl
Total production	682 million bbl	532 million bbl	150 million bbl

Oil price of 60 \$/bbl and discount rate of 8 % (real terms) are applied. The NPVs are:

$$\boldsymbol{NPV_{LSWI}} = \$\mathbf{6\ 063\ 232\ 231}$$

$$\boldsymbol{NPV_{HSWI}} = \$\mathbf{3\ 399\ 233\ 413}$$

Even with very large investments, both NPV_{LSWI} and NPV_{HSWI} are positive. Still, NPV_{HSWI} is 44 % lower than NPV_{LSWI}. Reduction in production and late production peak influence the cash flow for HSWI significantly, even though investments and production costs are reduced compared to LSWI.

Since the two alternatives are mutually excluding, it is clear from the NPV analysis that *LoSal* EOR (LSWI) is the preferred project. To better ascertain the economic benefits of *LoSal*, the differential cash flow is calculated. Figure 4.5 presents the distribution of the additional production from LSWI compared to HSWI.

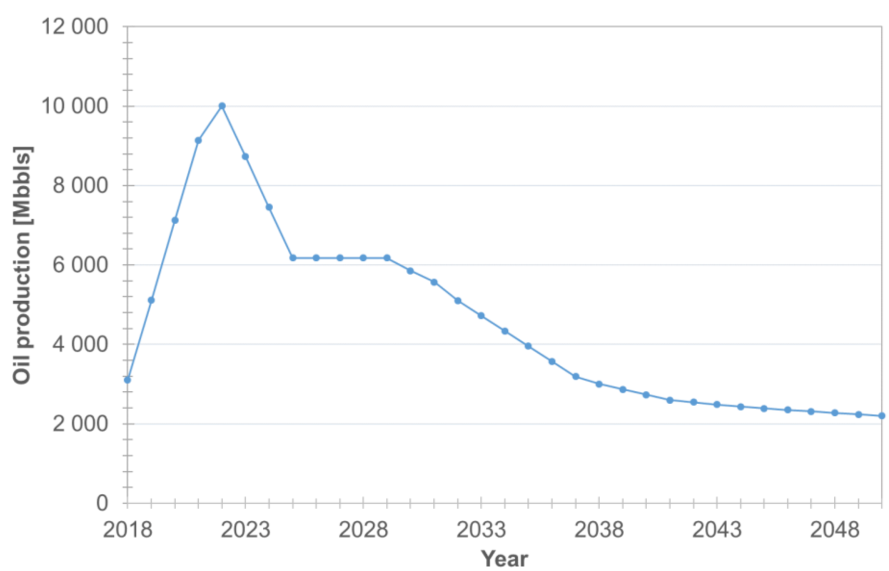


***Figure 4.5** Additional production – Low salinity versus high salinity.*

LSWI recovers 150 barrels more than HSWI. Since LSWI reaches its peak before HSWI, it is assumed that the main contribution comes in the beginning of the lifetime of the field. The peak is followed by a decline until an oil plateau is reached in 2025. From year 2029 the additional production continues to decline.

Furthermore, the differential cash flow (figure 4.6) is calculated using the investment and production costs presented in table 4.1. Oil price of 60 $/bbl and discount rate of 8 % (real terms) are applied.

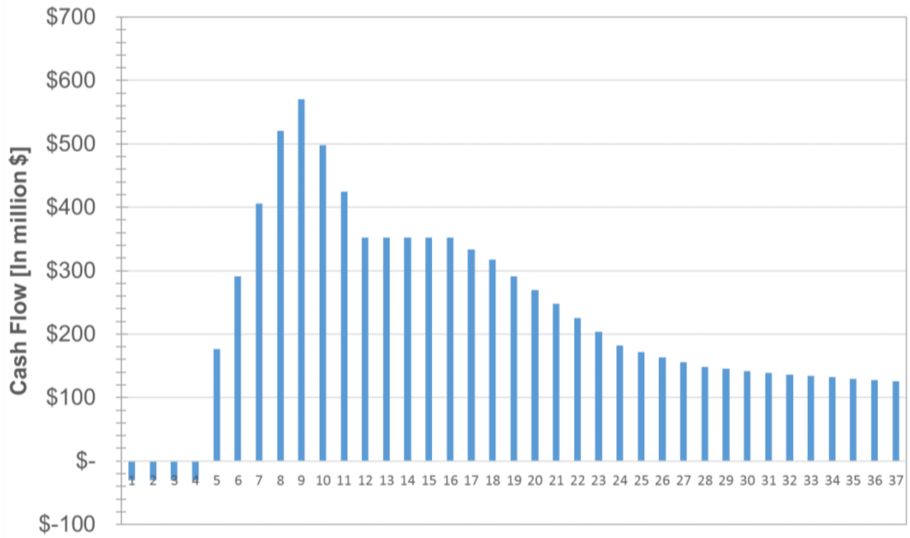


Figure 4.6 *Differential cash flow - Low salinity versus high salinity.*

Again, the curve of the differential cash flow columns follows the production curve (given in figure 4.5). The effect of early production peak is clear, as the cash flow reaches 570 million dollars eight years after first investment. The net present value of the differential cash flow is:

$$\boldsymbol{NPV}_{\boldsymbol{LS\ vs.\ HS}} = \$\mathbf{2\ 867\ 902\ 301}$$

The economic benefits of *LoSal* EOR are clear as the differential NPV when choosing LSWI rather than HSWI is $2,8 billion.

4.3 Secondary Versus Tertiary EOR

The advantage of the Clair Ridge project is that *LoSal* EOR is adopted as a day one, secondary waterflood. Normally, EOR projects are initiated as a tertiary (reduced salinity injection following higher salinity water injection) waterflood when secondary recovery processes are ineffective, uneconomical or no longer qualified. Hamon (2016) states that tertiary LSWI corefloods do not often succeed in increasing significantly the recovery within the two or three first pore volumes of tertiary injection. However, many authors conclude that tertiary LSWI has positive effects, despite wide variation in results (Hamon, 2016). Figure 4.7 illustrates a typical tertiary coreflood response.

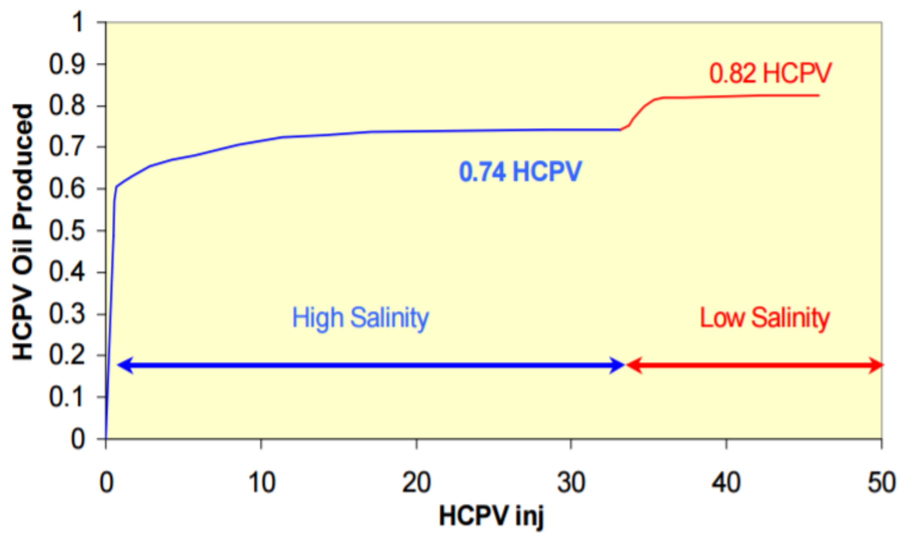


Figure 4.7 *Typical coreflood responses – tertiary recovery (Robbana et al., 2012).*

Figure 4.7 shows that the secondary oil recovery using high salinity water is 0,74 PV. After approximately 34 PV low salinity water is injected, and it takes an additional 2 PV to reach oil plateau of 0,82 PV, corresponding to a LS EOR effect of 9,75 %. This is further used to estimate a production profile (shown in figure 4.8) for Clair Ridge when *LoSal* is implemented as a tertiary EOR method.

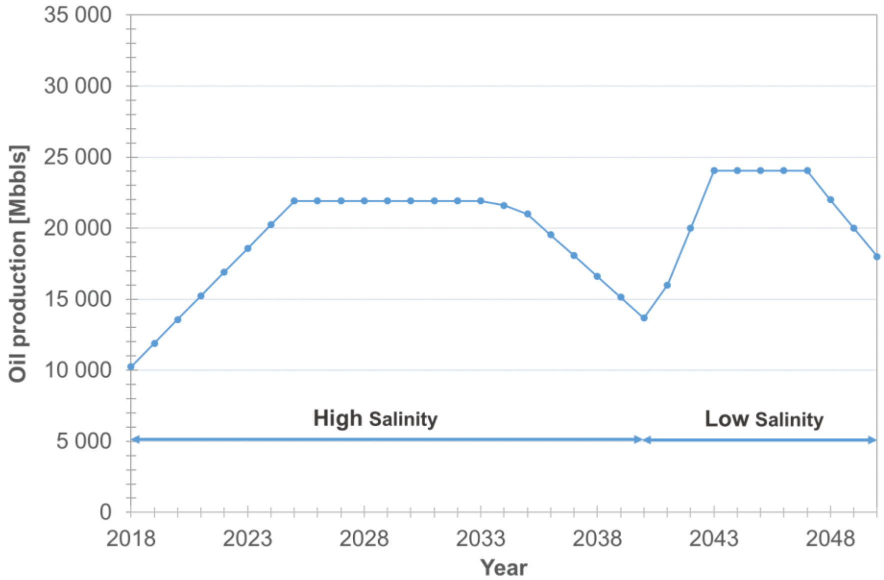


Figure 4.8 *Total production forecast for tertiary EOR at Clair Ridge.*

In a tertiary EOR scenario, HS water is injected from the start and until production starts declining. In 2037 investments are made for *LoSal* EOR facilities ($120 million over four years), and in 2041 the first effects of *LoSal* EOR are shown. The tertiary LSWI increase production up to a production plateau of 24 million bbl. The total production is 645 million barrels. Yearly cash flow (figure 4.9) and NPV are calculated using the corresponding costs for LS and HS as presented in table 4.1.

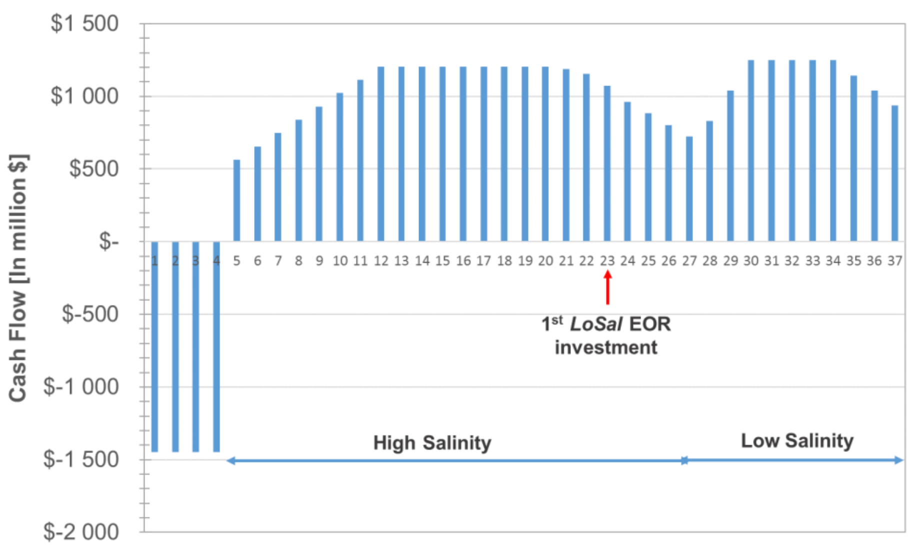


Figure 4.9 *Cash flow for tertiary EOR.*

As for the previous cash flows, the returns are negative in the beginning, until production starts. What differs this cash flow from the others, is that an investment is made late in the lifetime of the field. The effect of investment timing is discussed further in chapter 5.3. The NPV for tertiary EOR at Clair Ridge is:

$$\boldsymbol{NPV_{tertiary\ EOR}} = \$\mathbf{3\ 874\ 799\ 737}$$

$NPV_{tertiary\ EOR}$ shows the value of injection when the production has already started, i.e. when secondary EOR no longer is an option. Once again, the NPV is positive and thus the project is profitable. Nevertheless, $NPV_{tertiary\ EOR}$ is lower than NPV_{LSWI}. In addition, increased costs and stop in production during deployment of tertiary EOR have not been taken into consideration, due to lack of data. This could also affect the prospective returns and result in an even lower NPV.

Further, to evaluate the added value of starting with *LoSal* EOR from day one (secondary EOR), the differential production and cash flow between secondary EOR and tertiary EOR is calculated. Figure 4.10 presents the additional production.

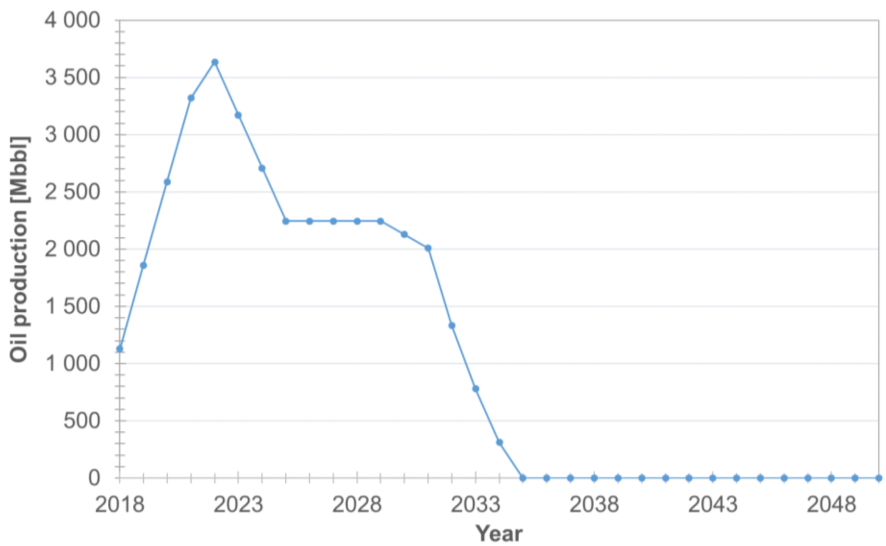


Figure 4.10 *Additional production from secondary EOR compared to tertiary EOR.*

Secondary EOR recovers 37 million barrels more than tertiary EOR. Since the production during tertiary EOR increases towards the end of the field's lifetime, the additional production from secondary EOR must come in the beginning of the differential production. The production reaches its peak in 2022 and decreases until a plateau is reached in 2025. After the production plateau, the production decreases significantly and from 2035 there is no additional production. At this point, the production from tertiary EOR is higher than secondary EOR. From the additional production, the differential cash flow is calculated and presented in figure 4.11.

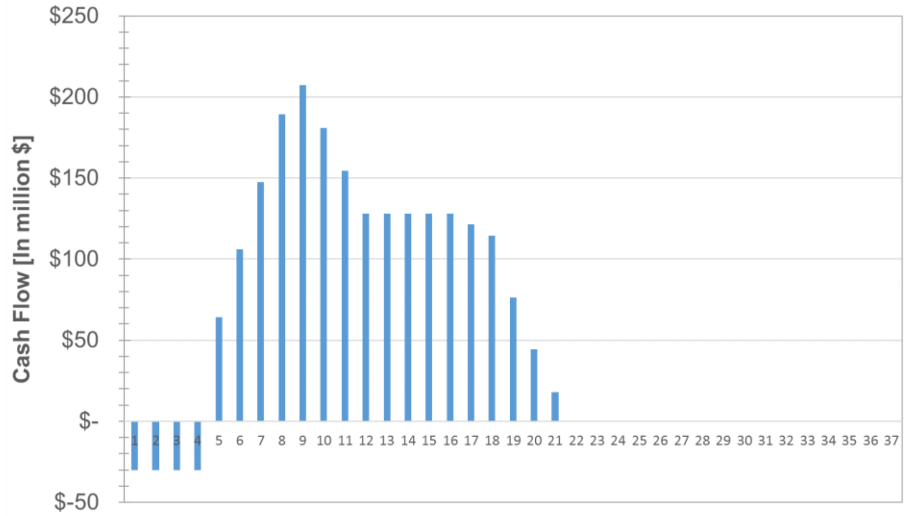


Figure 4.11 *Differential cash flow secondary EOR vs. tertiary EOR.*

Since the additional production (shown in figure 4.10) ends in 2035, the cash flows from this point on also ends. The NPV calculated from this flow is:

$$\boldsymbol{NPV_{secondary\ vs.\ tertiary\ EOR}} = \$\mathbf{764\ 247\ 565}$$

Once more, the NPV is positive with a value of $764 million. This number represents the value gained by starting with *LoSal* EOR from the beginning of the Clair Ridge project.

5. Discussion

5.1 Profitability of *LoSal* EOR

In chapter 4.1 the differential production and cash flow between Clair Ridge development with *LoSal* EOR and without *LoSal* EOR were calculated. The NPV was calculated to be $697 million, which represents the additional profitability BP gains by implementing EOR.

However, there are some uncertainties related to this calculation. *LoSal* EOR at Clair Ridge is expected to deliver an additional 42 million barrels of oil, which represent a 6 % increase in total production. The investment required for *LoSal* facilities at Clair Ridge are $120 million, which represent a 2 % increase in total investment costs. These two factors are both future looking statements, and thus subject to uncertainty and risks. To analyze how sensitive the project is to changes in expected production and investments, a two-way table in *Excel* is made based on the differential cash flow. The result is shown in figure 5.1.

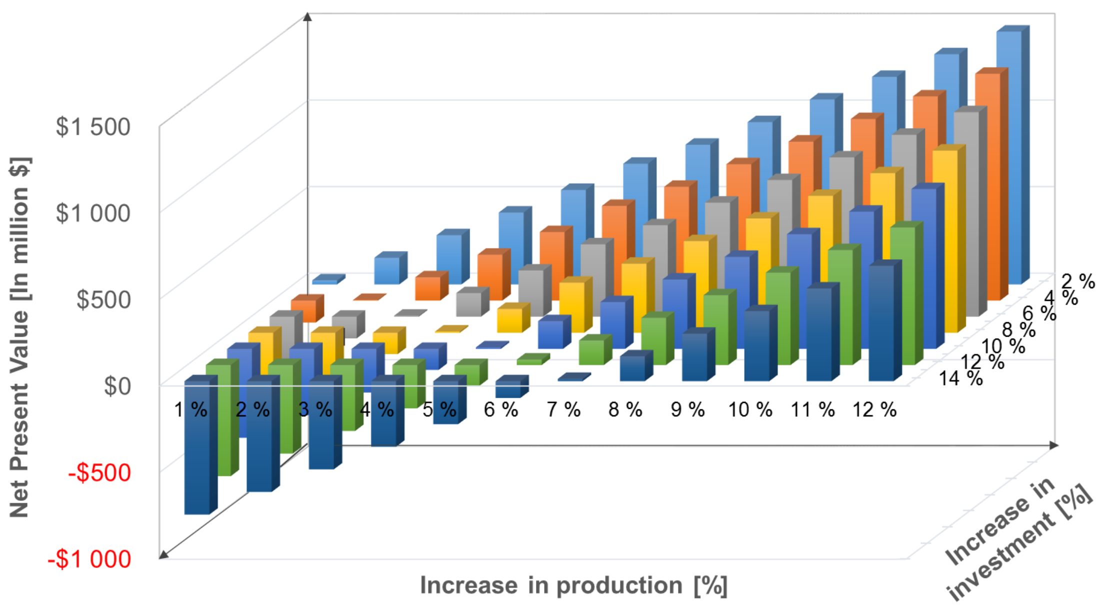


***Figure 5.1** NPV versus increase in additional production and increase in investment costs.*

If the additional production due to *LoSal* EOR is less than 6 %, the chance of a negative NPV increases. If the investment costs simultaneously increase, the probability of an unprofitable project is even higher. In a worst-case scenario, where *LoSal* EOR only contributes with 1 % increase in production and investment costs increase by 14 %, the NPV would be -$770 million.

However, if the additional production is larger than 6 %, the NPV remains positive, even with an increase in investment costs up to 14 %. In fact, of all the 84 cases simulated in figure 5.1, 75 % result in a positive NPV.

5.2 Effects of Delayed Production Peak

As briefly mentioned in chapter 4.1, the results suggest that the cash flow is highly dependent on the production curve. It is essential for most EOR processes that oil is produced quickly and in significant volumes to be economical in the field (Webb et al., 2008). Kemp and Stephen (2015) states that one of the key features of a low salinity waterflood includes modest annual production over a potentially very long period. This is also confirmed in most literature, which suggest that the oil from LSWI would be produced as a long drainage process and not develop into an oil bank. Thus, the long timeframe and large amount of water required, could result in the technology being uneconomical (Webb et al., 2008). To further investigate this issue, two additional *LoSal* EOR production curves with delayed production peaks were made, shown in figure 5.2.

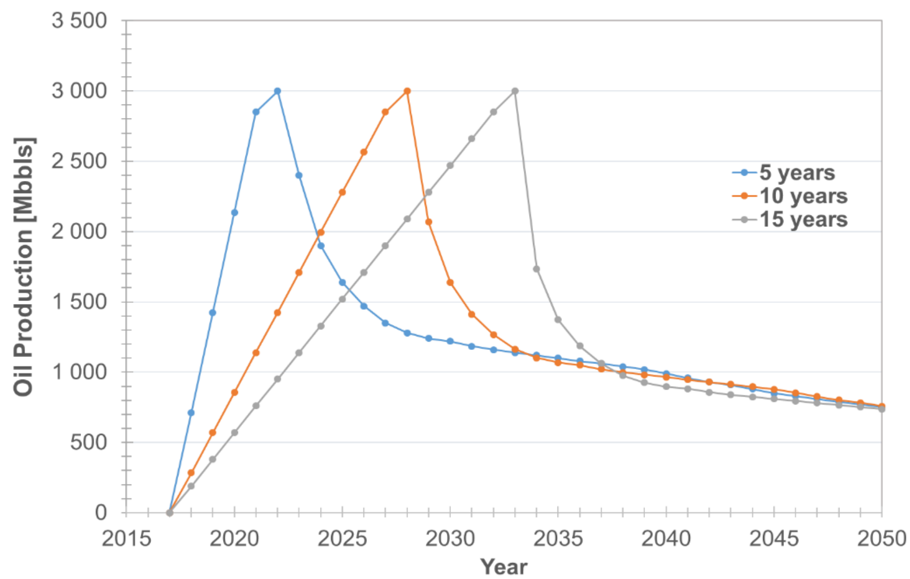


Figure 5.2 *Additional production curves from LoSal EOR with production peak at 5, 10 and 15 years.*

The original production curve for *LoSal* EOR (figure 4.1), has a production peak in year 5 (2022) and a total production of 42 million barrels. To simulate a later oil accumulation, production curves with peak after 10 and 15 years were made. All three curves have the same total production. The NPV was calculated for each scenario, and the effect of the delayed production peak is presented in figure 5.3.

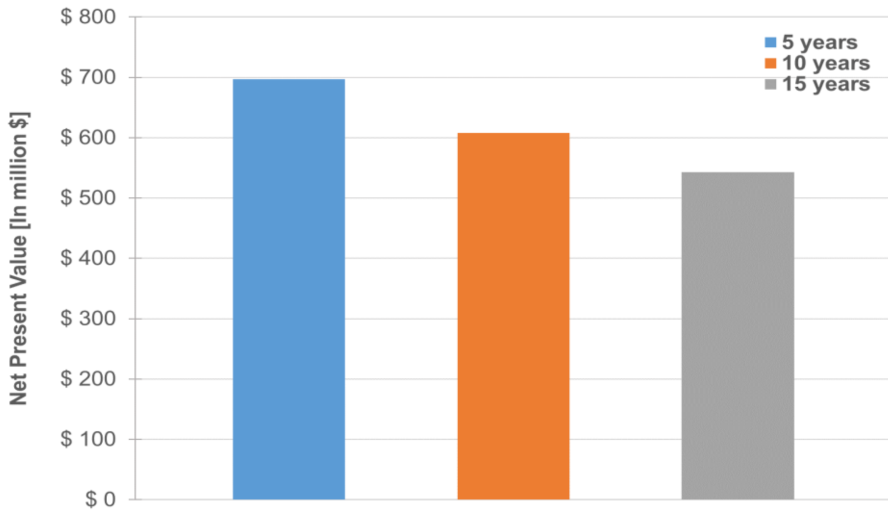


Figure 5.3 *Effects of delayed production peak on NPV.*

As seen from figure 5.3, the NPV becomes lower as the production peak comes later in the lifetime of the field. However, the differences are small, and the NPV is only lowered by 22 % when comparing the 5-year peak and 15-year peak. A reason for these modest changes may be the assumption that all three scenarios produce the same amount of oil. If the delay in production peak also reduced the total production, the differences in NPV could have been more substantial.

Another consequence of modest annual production over an extensive period of time, is a long payback period to the project (Kemp & Stephen, 2015). Payback period is the number of years needed to recover initial investment costs. One of the drawbacks of the payback period method, is that it ignores the time value of money. Therefore, the discounted payback period is also calculated. Figure 5.4 illustrates both payback period and discounted payback period for the three production peak scenarios.

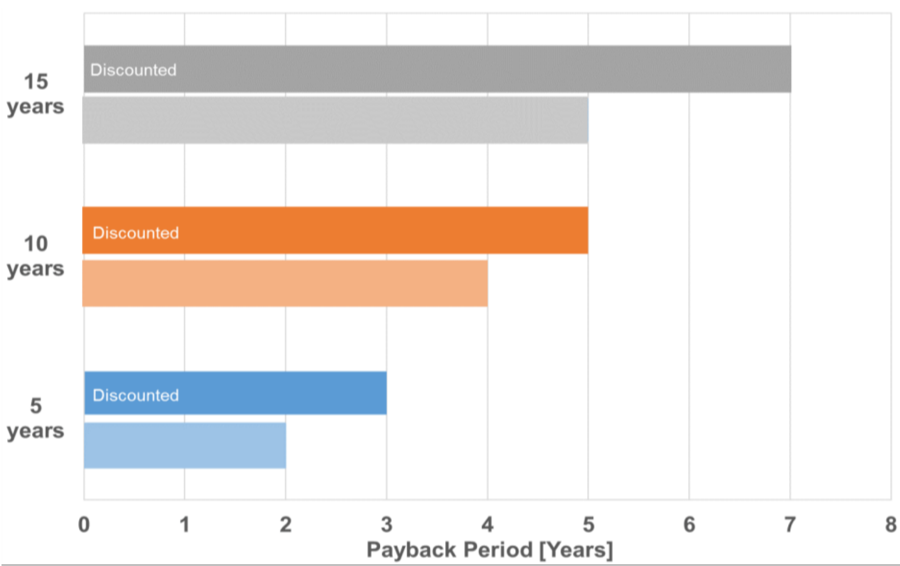


Figure 5.4 *Effects of delayed production peak on payback period and discounted payback period.*

The effect of delayed production peak is more substantial in figure 5.4 than in figure 5.3. It takes three years (discounted) for the 5-year peak scenario to recover its initial investments, while the payback period for the 15-year peak scenario is seven years, representing a 57 % increase. However, the field is expected to produce until 2050 (33 years), and *LoSal* EOR might even extend the lifetime further. Thus, a payback period of seven years is relatively modest.

5.3 Effects of Timing of the EOR Investment

In general, all EOR schemes can extend the lifetime of a field, but to obtain maximum benefit it is essential to commence the investment early in the life of the field. This issue is illustrated by figure 5.5.

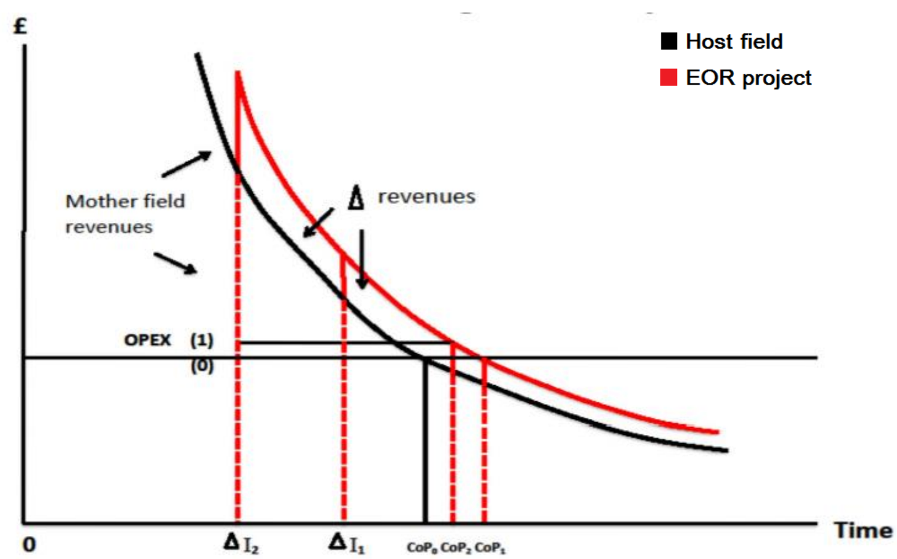


Figure 5.5 *Effects of timing of EOR project (Kemp & Stephen, 2015).*

The figure shows the revenues over time from a host field (black line) and EOR project (red line). As time passes, the revenue from the host field declines, and the field operating costs ($OPEX_0$) with the cessation of production (COP) is at COP_0. By implementing EOR revenue is added, and if there is no extra operating cost, the end of field life will be at COP_1. However, if there are extra operating costs due to EOR ($OPEX_1$), the end of field life will be at COP_2 (Kemp & Stephen, 2015).

Since the production lasts for a relatively long period, the timing of the EOR investment has a major effect. If the investment occurs at ΔI_2 rather than ΔI_1there is significantly more cumulative production, and so prospective returns increase (Kemp & Stephen, 2015).

In chapter 4.3 secondary and tertiary EOR were evaluated. In a secondary EOR process, the initial investment takes place at the time of the initial development of the whole field. This is a great advantage compared to tertiary EOR as the installation of the EOR facilities can be undertaken onshore at a considerably lower cost than an offshore installation later (Kemp & Stephen, 2015).

In addition to the economic benefits of an early EOR investment, there are clear productional advantages of secondary EOR compared to tertiary EOR. Studies showing production of significant incremental oil after a short tertiary injection period are very rare, and the oil is often delayed or produced at a low pace (Hamon, 2016). Torrijos (2017) recently performed experimental studies on secondary low salinity (LS) EOR effect in sandstone cores. Figure 5.6 compares LS oil recovery in secondary mode and LS oil recovery in tertiary mode.

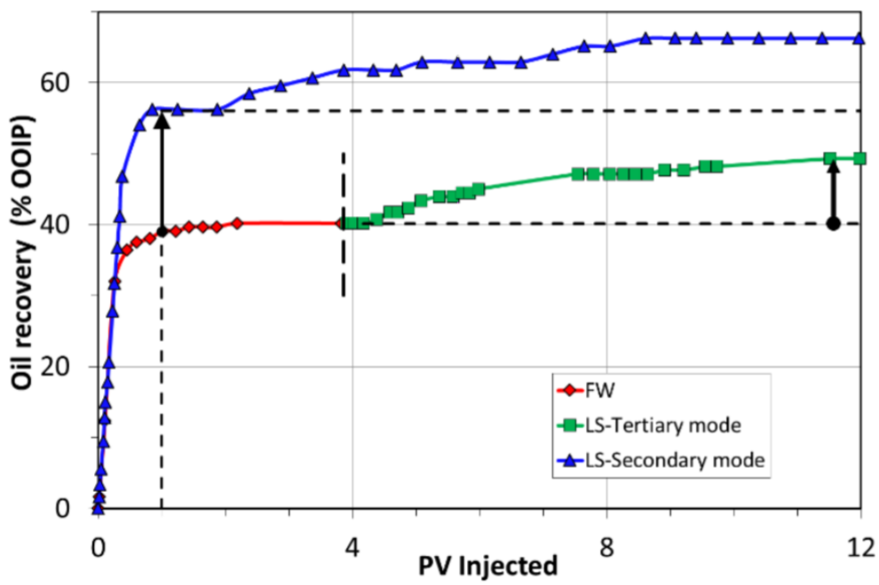


Figure 5.6 *Comparison of LSWI in secondary and tertiary mode (Torrijos, 2017).*

The figure clearly shows that the efficiency of the EOR LS effect is dramatically larger when performed in secondary mode. After only 1 PV injected, the recovery from LS-tertiary mode is 17 % higher than the recovery from formation water (FW) at the same time. Furthermore, after 11 PV injected the secondary LS EOR recovery is still 7 % higher than tertiary LS recovery (Torrijos, 2017).

With these advantages in mind, the NPV from secondary and tertiary EOR at Clair Ridge are compared in figure 5.7.

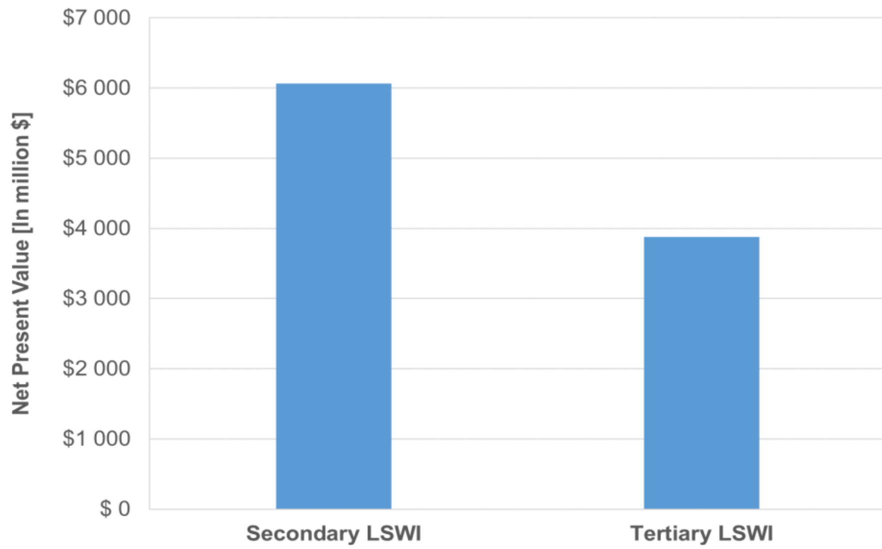


Figure 5.7 *NPV from secondary EOR and tertiary EOR.*

The NPV is decreased by 36 % if *LoSal* is implemented as a tertiary EOR process. This reduction is both due to the technical aspects on reservoir scale and economic aspects of delayed investment costs.

However, there are some disadvantages involved with deploying EOR at an early stage of a reservoir's life. First, there is more risk involved in the beginning of a project, and secondly there is a lack of data availability from the field, which is normally obtained during the secondary stage of recovery (Kokal & Al-Kaabi, 2010).

5.4 Sensitivity of Differential Cash Flow

To analyze the sensitivity of the variable input parameters such as discount rate, production costs and oil price, the Excel tool *One-way Data Table* is used. A one-way data table allows you to investigate how one output variable (in this case NPV) vary as a single input variable (production cost, oil price or discount rate) varies over a selected range of values (Albright et al., 2007). The analysis is performed on the differential cash flow between LSWI and HSWI (presented in section 4.2).

5.4.1 Discount Rate

As described in chapter 3, a constant discount rate of 8 % was chosen. During the lifetime of a project, the discount rate may vary and affect the NPV. Figure 5.8 shows the NPV versus discount rate.

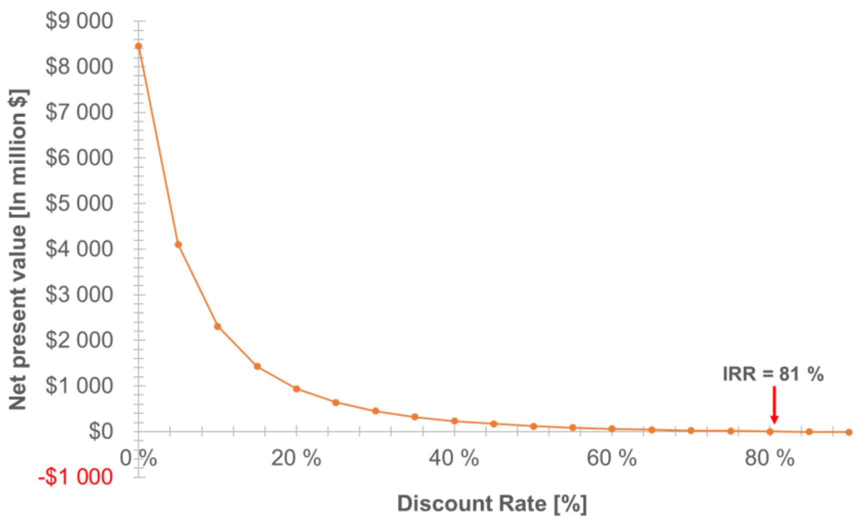


Figure 5.8 *NPV versus discount rate.*

As the discount rate increases, the NPV decreases. The internal rate of return (IRR) is the discount rate that makes a project have an NPV of $0. For this project, the IRR is at a rate of 81 %. This is a relatively high value, suggesting that the project is robust to changes in discount rate.

5.4.2 Production Costs

Production costs include the costs required to operate and maintain wells, related equipment and facilities. In figure 5.9 the NPV is plotted against the differential production costs.

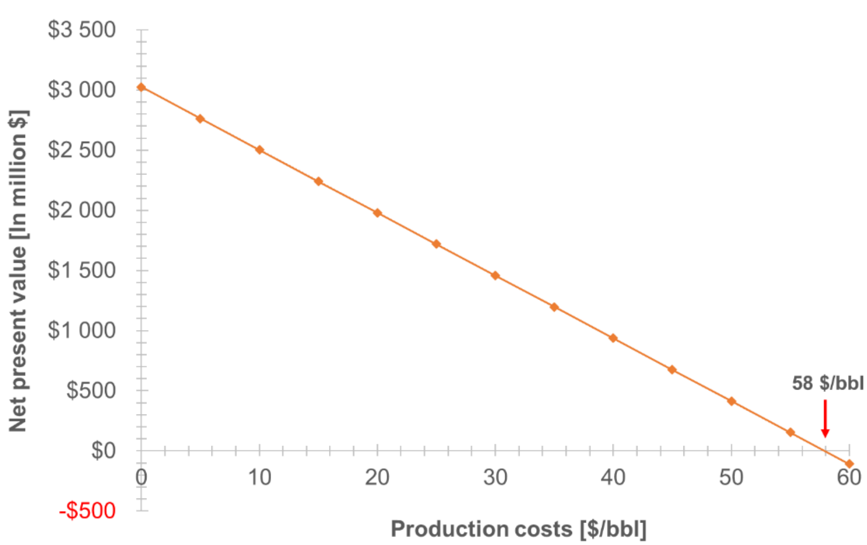


Figure 5.9 *NPV versus production costs.*

As expected, NPV decreases as production costs increase. Figure 5.6 illustrates that the Clair Ridge project tolerates an increase in production costs up to 50 $/bbl and still be profitable. At 58 $/bbl the NPV is equal to zero, and a further increase will cause the NPV to be negative.

However, 3 $/bbl is only the differential cost between LS and HS, and an increase up to 50 $/bbl would affect the *total* production costs significantly. The U.K. has already some of the highest production costs in the world (as seen in figure 5.10), and combined with a decline in production efficiency and low oil prices, an increase in production costs for *LoSal* could be critical.

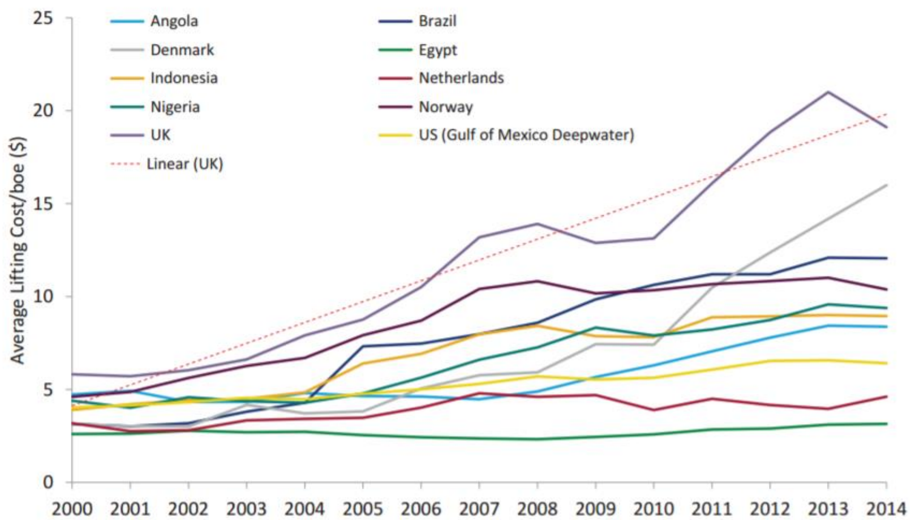


Figure 5.10 *Weighted average lifting costs for UK and other regions (Oil & Gas UK, 2015).*

On the other side, the industry is working hard to address these issues, and IEA reports a significant decrease in costs the last years (IEA, 2017). In their first quarter 2017 report, BP states that average production costs are 7,22 $/bbl which represent an 13 % reduction compared to first quarter 2016 (BP, 2017a).

5.4.3 Oil Price

In 2014, the world experienced a dramatic fall in oil prices. After a long period of sustained high oil prices, the oil price dropped below 30 $/bbl in the beginning of 2016. As of May 10, 2017, the oil price is 46,38 $/bbl, and forecasts suggest that the price will increase again in 2018 (Strandli, 2017). In this thesis, an oil price of 60 $/bbl is assumed, and figure 5.11 illustrates changes in NPV as the oil price varies.

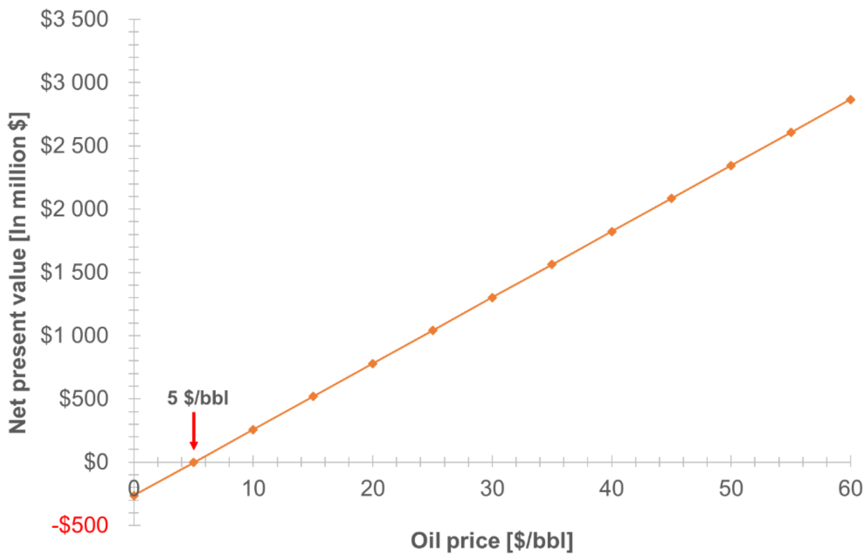


Figure 5.11 *NPV versus oil price.*

As the oil price increases, the NPV also increases. The project will not be profitable if the oil price goes below 5 $/bbl. This suggest that the project can stand relatively low oil prices and still be profitable.

On the other side, there is a strong relationship between EOR investments and oil price. Even though the NPV of Clair Ridge seems to tolerate low oil prices, the whole project might suffer if the oil prices collapse. In the early 1980s there was a huge interest in EOR due to oil price escalation, and in 1986 over 500 EOR projects and research and development investments were initiated. When the oil priced dropped in the1990s and early 2000s, the EOR interest faded out. During the past ten years, the interest has taken hold again as the oil price has increased. Figure 5.12 shows this relationship between EOR projects and oil price. The variation in interest also creates a lag between EOR projects and the price of oil (Kokal & Al-Kaabi, 2010).

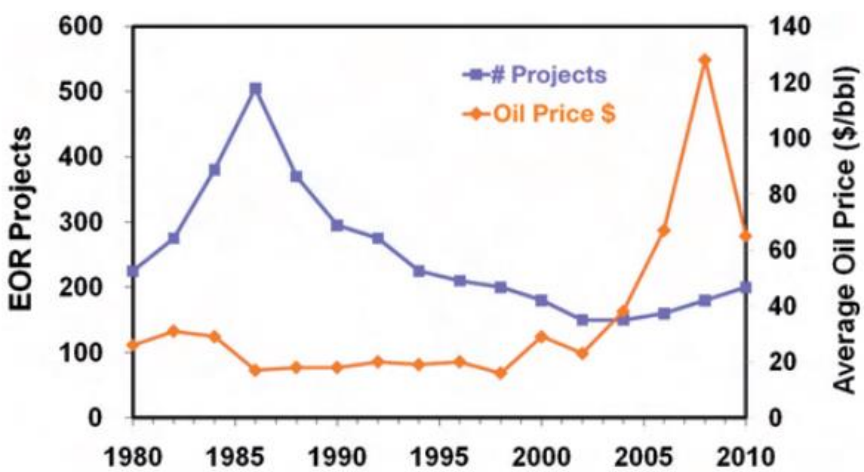


Figure 5.12 *EOR projects and price correlation (Kokal & Al-Kaabi, 2010)*

6. Conclusion

The objective of this thesis is to investigate the profitability of enhanced oil recovery at the Clair Ridge field, UK. This has been done through a differential cash flow analysis of the field and an evaluation of the corresponding net present value. Additionally, two different scenarios at Clair Ridge were analyzed, 1) a traditional waterflooding and 2) tertiary EOR, i.e. high salinity water injection followed by low salinity water injection. Furthermore, the sensitivity of the analysis, the effect of delay in production peak and the effect of investment timing were discussed. The results can be summarized as:

- **Profitability of *LoSal* EOR.** From the differential cash flow, it was found that the project's NPV is $697 million. This indicates that the project will be profitable under the given circumstances. The implementation of *LoSal* EOR is expected to result in a 6 % increase in production and a 2 % increase in investment cost. Through a simulation where the percentage increase in production and costs were varied, 75 % of the cases resulted in a positive NPV.

- **High salinity water injection.** The most realistic option to *LoSal* EOR, is to perform a traditional high salinity waterflooding. It was found that LSWI at Clair Ridge recovers 150 million barrels more than traditional waterflooding. LSWI also resulted in a higher NPV than HSWI. Since the two alternatives are mutually excluding, it becomes clear that *LoSal* EOR is the preferred project. Additionally, a differential cash flow between the two scenarios were calculated. The NPV was calculated to be $2,8 billion, which represent the economic benefit when choosing LSWI rather than HSWI. A sensitivity analysis of the variable inputs in the differential cash flow were also conducted. The results showed that the project is robust to changes in both discount rate, production costs and oil price.

- **Tertiary EOR.** Emerging EOR techniques are typically applied to older fields as the production rate falls or the field becomes uneconomical. Thus, a scenario where *LoSal* was injected in a tertiary mode was studied. The results suggested that the project would still be profitable, however tertiary EOR recovers 37 million barrels less than secondary EOR. A differential cash flow between the two alternatives were calculated, and the NPV was $764 million. This number represents the value gained by starting with *LoSal* form the beginning of the Clair Ridge project.

- **Effect of delayed production peak.** Through the differential cash flow analysis, it was seen that the production curves and cash flows are strongly related. This was further investigated by simulating a delay in the additional production from *LoSal* EOR of respectively 10 and 15 years. Despite the delay, the NPV was not significantly affected, nor was the calculated payback period of each case.

- **Effect of timing of the EOR investment.** To obtain maximum benefit of an EOR scheme, it is essential to commence the investment early in the life of the field. This statement was investigated by comparing secondary EOR, where investment is made in the beginning, and tertiary EOR, where the investment is made later in the lifetime of the field. The results show that investment made early in the lifetime of the field has a favorable influence on NPV. Furthermore, an early EOR investment also has productional advantages, as studies show that the efficiency of EOR is dramatically larger when performed in secondary mode.

Finally, the overall aim of this thesis was to contribute to an improved insight in to the economics of EOR. This is done by combining both technical and economic aspects of the Clair Ridge project. When all aspects of the process are examined, the most critical factors can be identified, and so the probability of a profitable and successful project increases.

6.1 Suggestions for Future Work

- As previously stated, there exist very few economic evaluations of low salinity EOR. To gain more acceptance and knowledge about the economics of EOR, several similar studies should be performed.

- In the sensitivity analysis of the differential cash flow, only one variable was varied at a time. Since the variables may relate, an analysis where several variables are studied simultaneously, could be beneficial.

- From a reservoir surface chemistry point of view, better simulation of the expected production from *LoSal* EOR is needed to gain more confidence in the method.

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A. Appendix

A.1 Production

Differential production – *LoSal* EOR

Year	*Mbbl*	*Year*	*Mbbl*	*Year*	*Mbbl*
2018	713	2029	1240	2040	990
2019	1425	2030	1220	2041	960
2020	2138	2031	1185	2042	930
2021	2850	2032	1160	2043	910
2022	3000	2033	1140	2044	880
2023	2400	2034	1120	2045	850
2024	1900	2035	1100	2046	830
2025	1640	2036	1080	2047	810
2026	1470	2037	1060	2048	790
2027	1350	2038	1040	2049	770
2028	1280	2039	1020	2050	750
					Total production: 42 000 000 bbl

Total production – Secondary high salinity water injection (HSWI)

Year	*Mbbl*	*Year*	*Mbbl*	*Year*	*Mbbl*
2018	10 239	2029	21 915	2040	13 679
2019	11 907	2030	21 915	2041	12 218
2020	13 575	2031	21 915	2042	11 487
2021	15 243	2032	21 915	2043	10 976
2022	16 911	2033	21 915	2044	10 464
2023	18 579	2034	21 605	2045	9 953
2024	20 247	2035	21 294	2046	9 734
2025	21 915	2036	19 523	2047	9 515
2026	21 915	2037	18 062	2048	9 296
2027	21 915	2038	16 601	2049	9 150
2028	21 915	2039	15 140	2050	9 003
					Total production: 531 636 364 bbl

Total production – Secondary low salinity water injection (LSWI/*LoSal* EOR)

Year	*Mbbl*	*Year*	*Mbbl*	*Year*	*Mbbl*
2018	14 300	2029	30 000	2040	14 325
2019	18 600	2030	29 575	2041	13 625
2020	22 900	2031	29 150	2042	13325
2021	27 200	2032	26 725	2043	13025
2022	30 000	2033	24 725	2044	12725
2023	30 000	2034	22 725	2045	12525
2024	30 000	2035	20 725	2046	12325
2025	30 000	2036	18 725	2047	12125
2026	30 000	2037	16 725	2048	11925
2027	30 000	2038	15 725	2049	11725
2028	30 000	2039	15 025	2050	11525
					Total production: 682 000 000 bbl

Differential production - LSWI vs. HSWI

Year	*Mbbl*	*Year*	*Mbbl*	*Year*	*Mbbl*
2018	3 104	2029	6 179	2040	2 737
2019	5 115	2030	5 854	2041	2 603
2020	7 127	2031	5 570	2042	2 546
2021	9 138	2032	5 106	2043	2 489
2022	10 004	2033	4 724	2044	2 431
2023	8 729	2034	4 342	2045	2 393
2024	7 454	2035	3 960	2046	2 355
2025	6 179	2036	3 578	2047	2 317
2026	6 179	2037	3 196	2048	2 279
2027	6 179	2038	3 005	2049	2 240
2028	6 179	2039	2 871	2050	2 202
					Total production: 150 363 600 bbl

Total production – Tertiary EOR (HSWI + LSWI)

Year	***Mbbl***	***Year***	***Mbbl***	***Year***	***Mbbl***
2018	10 239	2029	21 915	2040	13 679
2019	11 907	2030	21 915	2041	16 000
2020	13 575	2031	21 915	2042	20 000
2021	15 243	2032	21 915	2043	24 052
2022	16 911	2033	21 915	2044	24 052
2023	18 579	2034	21 605	2045	24 052
2024	20 247	2035	21 000	2046	24 052
2025	21 915	2036	19 523	2047	24 052
2026	21 915	2037	18 062	2048	22000
2027	21 915	2038	16 601	2049	20000
2028	21 915	2039	15 140	2050	18000
					Total production: 645 805 663 bbl

Differential production – Secondary EOR vs. Tertiary EOR

Year	***Mbbl***	***Year***	***Mbbl***	***Year***	***Mbbl***
2018	1 127	2029	2 245	2040	0
2019	1 858	2030	2 127	2041	0
2020	2 589	2031	2 009	2042	0
2021	3 320	2032	1 335	2043	0
2022	3 634	2033	780	2044	0
2023	3 171	2034	311	2045	0
2024	2 708	2035	0	2046	0
2025	2 245	2036	0	2047	0
2026	2 245	2037	0	2048	0
2027	2 245	2038	0	2049	0
2028	2 245	2039	0	2050	0
					Total production: 36 194 337 bbl

A.2 Cash Flow

Differential cash flow – *LoSal* EOR

Year	*Million $*	*Year*	*Million $*	*Year*	*Million $*
2014	-30	2027	77	2039	58
2015	-30	2028	73	2040	56
2016	-30	2029	71	2041	55
2017	-30	2030	70	2042	53
2018	41	2031	68	2043	52
2019	81	2032	66	2044	50
2020	122	2033	65	2045	48
2021	162	2034	64	2046	47
2022	171	2035	63	2047	46
2023	137	2036	62	2048	45
2024	108	2037	60	2049	44
2025	93	2038	59	2050	43
2026	84				
					NPV: $697 153 855

Total cash flow – Secondary high salinity water injection (HSWI)

Year	*Million $*	*Year*	*Million $*	*Year*	*Million $*
2014	-1 448	2027	1 205	2039	833
2015	-1 448	2028	1 205	2040	752
2016	-1 448	2029	1 205	2041	672
2017	-1 448	2030	1 205	2042	632
2018	563	2031	1 205	2043	604
2019	655	2032	1 205	2044	576
2020	747	2033	1 205	2045	547
2021	838	2034	1 188	2046	535
2022	930	2035	1 171	2047	523
2023	1 022	2036	1 074	2048	511
2024	1 114	2037	993	2049	503
2025	1 205	2038	913	2050	495
2026	1 205				
					NPV: $3 399 233 413

Total cash flow – Secondary low salinity water injection (LSWI/*LoSal* EOR)

Year	*Million $*	*Year*	*Million $*	*Year*	*Million $*
2014	-1 450	2027	1 560	2039	781
2015	-1 450	2028	1 560	2040	745
2016	-1 450	2029	1 560	2041	709
2017	-1 450	2030	1 538	2042	693
2018	744	2031	1 516	2043	677
2019	967	2032	1 390	2044	662
2020	1 191	2033	1 286	2045	651
2021	1 414	2034	1 182	2046	641
2022	1 560	2035	1 078	2047	631
2023	1 560	2036	974	2048	620
2024	1 560	2037	870	2049	610
2025	1 560	2038	818	2050	599
2026	1 560				
					NPV: $6 063 232 231

Differential production - LSWI vs. HSWI

Year	*Million $*	*Year*	*Million $*	*Year*	*Million $*
2014	-30	2027	352	2039	164
2015	-30	2028	352	2040	156
2016	-30	2029	352	2041	148
2017	-30	2030	334	2042	145
2018	177	2031	317	2043	142
2019	292	2032	291	2044	139
2020	406	2033	269	2045	136
2021	521	2034	247	2046	134
2022	570	2035	226	2047	132
2023	498	2036	204	2048	130
2024	425	2037	182	2049	128
2025	352	2038	171	2050	126
2026	352				
					NPV: $2 867 902 301

Total production – Tertiary EOR (HSWI + LSWI)

Year	*Million $*	*Year*	*Million $*	*Year*	*Million $*
2014	-1 448	2027	1 205	2039	803
2015	-1 448	2028	1 205	2040	722
2016	-1 448	2029	1 205	2041	832
2017	-1 448	2030	1 205	2042	1 040
2018	563	2031	1 205	2043	1 251
2019	655	2032	1 205	2044	1 251
2020	747	2033	1 205	2045	1 251
2021	838	2034	1 188	2046	1 251
2022	930	2035	1 155	2047	1 251
2023	1 022	2036	1 074	2048	1 144
2024	1 114	2037	963	2049	1 040
2025	1 205	2038	883	2050	936
2026	1 205				
					NPV: $3 874 799 737

Differential production – Secondary EOR vs. Tertiary EOR

Year	*Million $*	*Year*	*Million $*	*Year*	*Million $*
2014	-30	2027	128	2039	0
2015	-30	2028	128	2040	0
2016	-30	2029	128	2041	0
2017	-30	2030	121	2042	0
2018	64	2031	115	2043	0
2019	106	2032	76	2044	0
2020	148	2033	44	2045	0
2021	189	2034	18	2046	0
2022	207	2035	0	2047	0
2023	181	2036	0	2048	0
2024	154	2037	0	2049	0
2025	128	2038	0	2050	0
2026	128				
					NPV: $764 247 565