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## Oil and Gas Governance and Efficiency Study

Output 1 Report: Review of Policy and Regulatory Frameworks for Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR)

**FINAL**



March 2017

Amec Foster Wheeler Environment  
& Infrastructure UK Limited



**FINAL**

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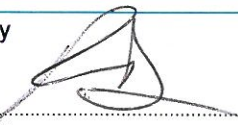
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## Executive summary

The Brazilian Ministry of Mines and Energy (MME) and the Brazilian National Agency of Oil, Natural Gas and Biofuels (ANP) have recognised the need for prioritising improved oil recovery and have sought to take advantage of UK expertise and UK Continental Shelf (UKCS) experience regarding Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR).

Supported by the Foreign and Commonwealth Office (FCO) Brazilian Board, under the FCO 2016/17 Prosperity Fund, Amec Foster Wheeler has undertaken a study into the policy and regulatory framework for EOR and IOR and the range of EOR and IOR technologies to identify lessons to be learnt to help support improved recovery rates in mature oil fields and potentially benefit new offshore basins in Brazil.

The two outputs of the study are:

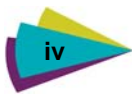
- ▶ Output 1 (this report): A report containing a review and analysis of the policy and regulatory framework for EOR and IOR on the UKCS to identify relevant approaches to reduce cost, extend field life and improve recovery from Brazilian mature oil fields; and
- ▶ Output 2: A report containing a review of EOR and IOR in the UKCS (and wider EU) covering the different technologies used (e.g. thermal, gas injection, chemical), the reservoir factors affecting recovery, other requirements (e.g. infrastructure, logistics, environment), investment (and the return on investment) with guidance on possible applicability to the Campos Basin.

The Output 1 and 2 reports follow the completion of a scoping stage. A draft Scoping Report provided the proposed scope of the study, the technologies to be considered, the likely geographic extent of data sources and case studies to be used. This was revised following comments from the FCO and ANP.

This report contains:

- ▶ Definitions of EOR and IOR;
- ▶ The identification, description and review of the existing policy and regulatory framework that operates in the UKCS (and the wider Europe) as it relates to EOR and IOR;
- ▶ A review of UK's (and any wider European) improved recovery initiatives (including links between Carbon Capture and Storage (CCS) and EOR);
- ▶ An analysis of the barriers to IOR/EOR deployment and the identification of measures to overcome them;
- ▶ Recommendations, guidance and measures for policy, regulatory and initiatives to support the use of EOR and IOR in Brazil; and
- ▶ Recommendations for any areas of further study.

A glossary of terms and acronyms is also provided.



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# 1. Introduction

This chapter provides an introduction to this report which presents the findings of research into the policy and regulatory framework in the UK and Europe for Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR). The chapter provides an overview of the project and the reasons for its commission, outlines the purpose of this report, the approach taken to completing the research and the structure of the rest of the report.

## 1.1 Overview

- 1.1.1 Following the substantial and sustained decrease in the price of crude oil from more than \$100 dollar a barrel in June 2014 to \$46 in July 2016<sup>1,2</sup>, the economic challenges of exploration and production have increased significantly and there is international interest in reducing costs and improving efficiency and margins.
- 1.1.2 Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR) provide a range of technologies that increase the recovery of the remaining oil reserves in existing mature basins (brownfields) with recovery factors (RFs) potentially increasing up to 70%<sup>3</sup>, extending the life of existing oil production assets. Successful EOR and IOR can therefore play a significant role in maximising economic recovery from mature basins, not merely by significantly increasing the volume of recovery, but by extending field life, supporting job provision, helping stimulate field redevelopments and deferring decommissioning activities.
- 1.1.3 Campos basin was responsible for 65% of Brazilian oil and gas production in December 2015. It has an estimated 22 billion barrels (bn bbl) reserves. It has similarities with the UK Continental Shelf (UKCS). Both are mature basins with new exploration plays and substantial opportunities in maximising brownfield recovery. However, the RF for the UKCS is projected to be 46%<sup>4</sup> whereas the projected RF of sandstone and carbonate reservoirs in the Campos Basin is approximately 27.5% and 14.3% respectively<sup>5</sup>.
- 1.1.4 Given the current economic challenges and the low RFs, the Brazilian Ministry of Mines and Energy (MME) and the Brazilian National Agency of Oil, Natural Gas and Biofuels (ANP) have recognised the need for prioritising improved recovery and have sought to take advantage of UK experience and UKCS expertise. Supported by the FCO Brazilian Board, under the FCO 2016/17 Prosperity Fund, Amec Foster Wheeler has been appointed to complete a study into the policy and regulatory framework for EOR and IOR and the range of EOR and IOR technologies to identify lessons to be learnt to help support improved recovery rates in mature oil fields such as Campos and potentially benefit new offshore basins, such as Santos.

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<sup>1</sup> New York Times (2016), Oil Prices: What's Behind the Drop? Simple Economics by Clifford Krauss, July 27, 2016

<sup>2</sup> NB, at the time of writing (8.3.17) the oil price is \$52.74 a barrel (see <http://www.macrotrends.net/2566/crude-oil-prices-today-live-chart>)

<sup>3</sup>Toole ST, Grist DM. 2003 Oil and gas recovery behaviour in the UKCS basins. In Proc. Offshore Europe Conf., Aberdeen, UK, 2–5 September 2003. Tulsa, OK: Society of Petroleum Engineers. (doi:10.2118/83982-MS) and McGuire PL, Spence AP, Redman RS. 2001 Performance evaluation of a mature miscible gasflood at Prudhoe Bay. SPE Reservoir Eval. Eng. 4, 318–326. (doi:10.2118/59326-MS)

<sup>4</sup> DECC (2010), [https://www.whatdotheyknow.com/request/uk\\_north\\_sea\\_oil\\_fields\\_ultimate](https://www.whatdotheyknow.com/request/uk_north_sea_oil_fields_ultimate)

<sup>5</sup> ANP (2016), Enhanced Oil Recovery Methods (EOR) and Improved Oil Recovery (IOR) in Brazil (presentation provided to Amec Foster Wheeler by ANP, August 2016)



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1.1.5 The purpose<sup>6</sup> of the project is as follows:

- ▶ To identify, describe and evaluate the different technologies for EOR (including, but not limited to thermal, gas injection, CO2 injection, microbial and chemical) and IOR (including, but not limited to 4D seismic, infill drilling wells, topside improvement and new subsea technologies) used on the UKCS (and the wider Europe) and the reservoir characteristics and other factors affecting recovery rates;
- ▶ To review the existing and planned use of EOR and IOR to help maximise the economic recovery of the UKCS (and other offshore basins in Europe), including consideration of policies, initiatives, incentives and regulatory frameworks;
- ▶ To identify, describe and evaluate the barriers to EOR/IOR deployment and how to overcome them, with a view to identifying the lessons that can be learnt that are applicable to maximise economic recovery in mature basins in Brazil;
- ▶ To identify and provide recommendations for any further aspects of study that need to be addressed to support the widespread application of EOR and IOR in Brazil; and
- ▶ To facilitate the transfer of knowledge and experience from the UK to Brazil to build capacity of relevant staff in MME and ANP in relation to the policy, regulatory and technological aspects of EOR/IOR.

1.1.6 The two outputs of the project will be as follows:

- ▶ Output 1 (this report): A report containing a review and analysis of the policy and regulatory framework for EOR and IOR on the UKCS to identify relevant approaches to reduce cost, extend field life and improve recovery from Brazilian mature oil fields; and
- ▶ Output 2: A report containing a review of EOR and IOR in the UKCS (and wider Europe) covering the different technologies used (e.g. thermal, gas injection, chemical), the reservoir factors affecting recovery, other requirements (e.g. infrastructure, logistics, environment), investment (and the return on investment) with guidance on possible applicability to the Campos Basin.

## 1.2 Purpose of this Report

1.2.1 This report sets out the findings of the research used to complete Output 1. Specifically, it will:

- ▶ Define EOR and IOR and identify the technologies that have been included within the study;
- ▶ Outline the factors that have been considered in the study that influence recovery (including but not limited to microscopic attributes, reservoir characteristics and field constraints);
- ▶ Outline the policies, initiatives, incentives and regulatory frameworks that operate in the UKCS (and the wider Europe) as it relates to EOR and IOR;
- ▶ Outline the UK's (and any wider European) improved recovery initiatives (and including any links between CCS and EOR);
- ▶ Provide an analysis of the barriers to IOR/EOR deployment and the identification of measures to overcome them;
- ▶ Provide recommendations, guidance and measures for policy, regulatory and initiatives to support the use of EOR and IOR in Brazil; and
- ▶ Provide recommendations for any areas of further study.

1.2.2 The structure of the remaining chapters of this Output 1 Report (as outlined in Section 1.4) will address the above requirements.

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<sup>6</sup> Amec Foster Wheeler, Revised Terms of Reference, 17<sup>th</sup> June 2016

## 1.3 Approach

- 1.3.1 Terms of Reference (ToR) for the project were agreed with the FCO and ANP (June 2016). This set out the following stages and tasks for the project:
- ▶ Stage 1: Scoping;
  - ▶ Stage 2: Data Gathering, Analysis, Assessment and Reporting;
    - ▶ Task 2.1: Data Gathering;
    - ▶ Task 2.2 EOR and IOR Policy, Regulatory and Initiatives Review;
    - ▶ Task 2.3 EOR and IOR Technologies Review;
  - ▶ Stage 3: Workshop (to facilitate information exchange, skills transfer and capacity building).
- 1.3.2 The Scoping Report was completed in draft and finalised with the FCO and ANP in October 2016 and fulfilled the “Stage 1” requirements for the project.
- 1.3.3 The completion of this Output 1 Report corresponds to Task 2.2 of the ToR and builds on the completion of a Scoping Report.
- 1.3.4 The study relates to EOR and IOR activities on the UKCS and, where appropriate, the wider EU.
- 1.3.5 Publicly accessible information, peer reviewed research and industry case studies have been used to identify, define and describe EOR and IOR used in this report. Sources have included:
- ▶ Studies for the UK government, regulators and agencies related to the use of EOR and IOR to maximise recovery (including, but not limited to, the 2014 Wood Review, the UK Government’s Strategy for Maximising Economic Recovery, the Oil and Gas Authority (OGA) EOR Strategy, the OGA Delivery Programme and relevant PILOT initiatives (formerly the UK Oil and Gas Taskforce));
  - ▶ Written evidence, transcripts of committee meetings and reports from the UK House of Commons and House of Lords e.g. House of Commons Energy and Climate Change Committee report into Carbon Capture and Storage (with particular reference to EOR);
  - ▶ Academic reports, Society of Petroleum Engineers (SPE) and European Association of Geoscientists and Engineers (EAGE) conference papers and peer reviewed publications on EOR and IOR;
  - ▶ Research, case studies and guidance produced by PILOT;
  - ▶ Case studies provided by the oil and gas industry (including, but not limited to Oil and Gas UK (OGUK), Subsea UK, East of England Energy Group (EEEGR) and individual companies);
  - ▶ Other sources of information (such as trade journals); and
  - ▶ Key UK stakeholders (covering representatives from government, regulators, industry and academia);
- 1.3.6 As part of the study, a limited number of stakeholders from government, regulators, industry and academia have been contacted.
- 1.3.7 The analysis of the information has been used to support the development of an appropriate suite of recommendations relevant to the Brazilian context.



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## 1.4 Structure of the Report

1.4.1 The remainder of this report is structured as follows:

- ▶ **Section 2: Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR)** which provides an overview of the different EOR and IOR technologies and processes;
- ▶ **Section 3: Factors Affecting Recovery** which provides an outline of those factors that influence oil recovery (including but not limited to microscopic, reservoir and field characteristics);
- ▶ **Section 4: UKCS Policy and Regulatory Framework for EOR and IOR** which provides an outline of the key UK policies and strategies (including the Wood Review, the Strategy for Maximising Economic Recovery, the UK EOR Strategy), the principal statutes (the Infrastructure Act 2015) and the work of PILOT;
- ▶ **Section 5: European Policy and Regulatory Framework for EOR and IOR** which provides an outline of the policy and regulatory frameworks at the European Union (EU) level, regional level (marine Conventions) and at the level of individual countries (i.e. Norway, Denmark and The Netherlands);
- ▶ **Section 6: Barriers to the Deployment of Oil Recovery** which provides an overview of the commercial, physical, organisational and environmental barriers to the deployment of oil recovery and measures to overcome the identified barriers; and
- ▶ **Section 7: Recommendations** provides proposed recommendations for possible policy, regulatory and initiatives to support the use of EOR and IOR in Brazil.

## 2. Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR)

This chapter provides an overview of the phases of oil development and production and the role of EOR and IOR in oil recovery. It then outlines the different EOR and IOR technologies and processes that have been considered in the study.

### 2.1 Overview

2.1.1 Oil development and production can comprise three phases; **primary**, **secondary**, and **tertiary** (or enhanced) recovery.

#### Primary Recovery

2.1.2 Between 5 and 20 percent of the available oil in a reservoir is recovered during the primary recovery phase, as the natural reservoir pressure forces oil into the wellbore. This can stem from several individual, or a combination of, mechanisms including liquid and rock expansion, expansion of gases, gravity drainage and water influx. The natural expulsive forces present in a given reservoir depend on rock and fluid properties, geologic structure and geometry of the reservoir, as well as on the rate of oil and gas production.

#### Secondary Recovery

2.1.3 Typically, anything applied beyond primary recovery falls under the umbrella of “Improved Oil Recovery” (IOR). Secondary recovery techniques tend to be employed when the natural reservoir energy has been depleted and the oil production rate has decreased, however they are also used to accelerate production.

2.1.4 Secondary recovery utilises a wide range of techniques to increase oil recovery above that achievable by natural depletion alone. Generally, this can involve the injection of water or natural gas to maintain the reservoir pressure; driving oil to a production wellbore, helping to sustain higher production rates and extend the productive life of the reservoir<sup>7 8 9</sup> The injectant is usually chosen to displace and not mix with the reservoir oil (i.e. it is ‘immiscible’ with the existing oil). In gas re-injection, a common variant of secondary recovery, natural gas produced during extraction is re-injected into the reservoir’s gas cap, which overlies the oil, driving the oil downwards and towards the production wellbore. Water flooding is usually targeted at the margins of the reservoir, to push (or sweep) the oil towards the wellbore.<sup>10</sup> Secondary recovery may also include artificial lift technologies, subsea pumping and reservoir stimulation. It also refers to ‘better’ engineering and project management such as identifying volumes of oil that have been bypassed during water injection using seismic surveying and then drilling new wells to access those oil pockets.<sup>11</sup>

<sup>7</sup> US Department of Energy (2016) Enhanced Oil Recovery. Available from <http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery> [Accessed August 2016].

<sup>8</sup> Terry, R. (2001) Enhanced Oil Recovery. Encyclopaedia of Physical Science and Technology 3rd Edition, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

<sup>9</sup> U.S. Department of the Interior and U.S. Geological Survey (2015) Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO<sub>2</sub>-EOR)—A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO<sub>2</sub>-EOR Associated with Carbon Sequestration. Available from <http://pubs.usgs.gov/of/2015/1071/pdf/ofr2015-1071.pdf> [Accessed August 2016].

<sup>10</sup> International Energy Agency (2015) *Storing CO<sub>2</sub> through Enhanced Oil Recovery*. Available from [https://www.iea.org/publications/insights/insightpublications/Storing\\_CO2\\_through\\_Enhanced\\_Oil\\_Recovery.pdf](https://www.iea.org/publications/insights/insightpublications/Storing_CO2_through_Enhanced_Oil_Recovery.pdf) [Accessed August 2016].

<sup>11</sup> Muggeridge, A. et al (2013) Recovery rates, enhanced oil recovery and technological limits in Philosophical Transactions of the Royal Society (307), 2006. <http://rsta.royalsocietypublishing.org/content/372/2006/20120320> [accessed Aug 2016].

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Consequently, it is often considered a general term that applied to improved oil recovery by any means.<sup>12</sup>

- 2.1.5 Following implementation of the secondary recovery phase, it is estimated that oil recovery is generally in the range of 20 to 40 percent of the original oil in place<sup>13</sup>. In consequence, a significant percentage of residual oil remains in the reservoir following secondary recovery. This can be because the reservoir oil has not been in contact with the displacing fluid, or because of the capillary forces that exist between oil, water and the porous rock.<sup>14</sup>

### Tertiary Recovery

- 2.1.6 Tertiary recovery forms the basis of EOR and refers to the process of producing liquid hydrocarbons by methods other than the conventional use of reservoir energy, artificial lift or reservoir repressurising schemes with gas or water.<sup>15</sup> It is therefore used to recover this residual oil once natural reservoir energy has been depleted (primary recovery) and where secondary techniques become ineffective. In addition to maintaining pressure and sweeping oil to the production wellbore (as in secondary recovery), EOR aims to alter the properties of the oil and/or reservoir rock, or alter flow patterns in the reservoir.
- 2.1.7 Applications are chosen to interact with the formation rock/fluids to alter the oil/water density or viscosity, change the “wettability” of the reservoir rock, or plug high-permeability flow paths in the reservoir.<sup>16</sup>
- 2.1.8 EOR is a term that is sometimes used synonymously with IOR. EOR is considered to be one step further, but is still thought of as a subset of IOR, which encompasses a wider scope of methods.
- 2.1.9 The US Department for Energy (2016) estimates that EOR techniques have the potential to produce 30 to 60 percent, or more, of a reservoir’s original oil in place<sup>17</sup>. In terms of the UKCS, the UK Oil and Gas Authority (OGA) estimates that the theoretical maximum (un-risked) total EOR potential is approximately 6,000 million stock tank barrels (mstb) of oil, which assumes that the optimal EOR project will be carried out on each field where it is applicable.<sup>18</sup>
- 2.1.10 The relationship between the different phases and the technologies are illustrated in the Error! Reference source not found..

<sup>12</sup> International Energy Agency (2015) Storing CO2 through Enhanced Oil Recovery. Available from [https://www.iea.org/publications/insights/insightpublications/Storing\\_CO2\\_through\\_Enhanced\\_Oil\\_Recovery.pdf](https://www.iea.org/publications/insights/insightpublications/Storing_CO2_through_Enhanced_Oil_Recovery.pdf) [Accessed August 2016].

<sup>13</sup> US Department of Energy (2016), Enhanced Oil Recovery. <http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery> [accessed Aug 2016].

<sup>14</sup> Meyer, J.P. (2007), Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology. Prepared for the American Petroleum Institute. <http://www.api.org/~media/files/ehs/climate-change/summary-carbon-dioxide-enhanced-oil-recovery-well-tech.pdf> [accessed Aug 2016].

<sup>15</sup> Terry, R. (2001) Enhanced Oil Recovery. Encyclopaedia of Physical Science and Technology 3rd Edition, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

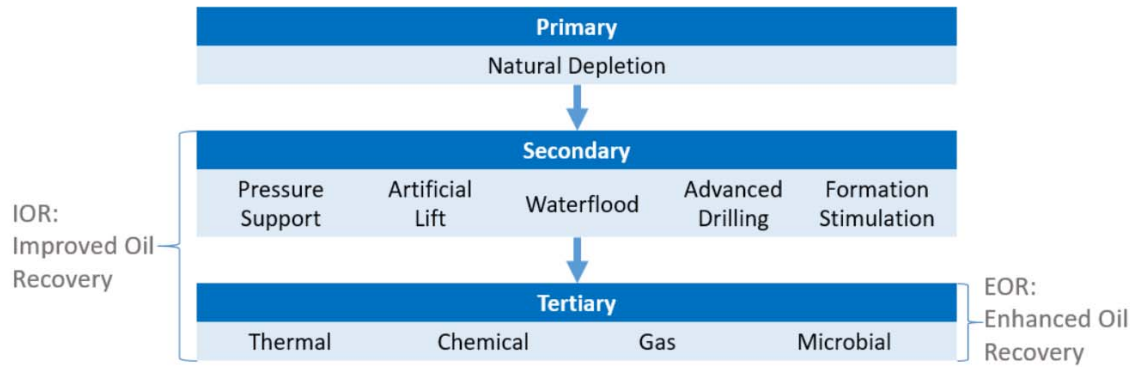
<sup>16</sup> U.S. Department of the Interior and U.S. Geological Survey (2015) *Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO2-EOR)—A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO2-EOR Associated with Carbon Sequestration*. Available from <http://pubs.usgs.gov/of/2015/1071/pdf/ofr2015-1071.pdf> [Accessed August 2016].

<sup>17</sup> US Department of Energy (2016) *Enhanced Oil Recovery*. Available from <http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery> [Accessed August 2016].

<sup>18</sup> Oil and Gas Authority (2016), Enhanced Oil Recovery (EOR) Strategy [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/540028/OGA\\_EOR\\_Strategy.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/540028/OGA_EOR_Strategy.pdf) [accessed Aug 2016].

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Figure 2.1 Relationship between different phases of oil recovery and technologies



Source: Generated Flow Diagram

2.1.11 The next two subsections provide further details on EOR and IOR technologies.

## 2.2 Enhanced Oil Recovery (EOR)

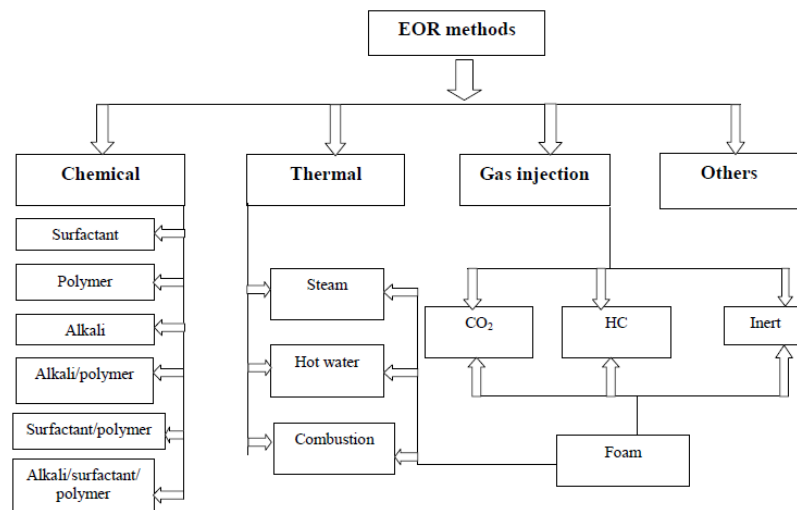
2.2.1 EOR processes can be classified into four categories:

- ▶ Chemical flooding processes;
- ▶ Thermal processes;
- ▶ Gas injection (miscible flooding processes); and
- ▶ Other (including water alternating gas (WAG), foam assisted WAG and microbial processes).<sup>19</sup>

2.2.2 Each category contains further subsections as illustrated by **Figure 2.2**.

Figure 2.2 EOR process classification

Figure 2 Simplified classification of EOR methods



Source: Speight, J (2016), Introduction to Enhanced Recovery Methods for Heavy Oil and Tar Sands, 2nd Edition, Gulf Professional Publishing

<sup>19</sup> Terry, R. (2001) Enhanced Oil Recovery. *Encyclopaedia of Physical Science and Technology 3rd Edition*, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

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- 2.2.3 The type of EOR technology suitable depends on the characteristics of a given oil reservoir and its state of depletion. The following sections describe the technologies associated with each process listed above.

## 2.3 Chemical Flooding Processes

- 2.3.1 Chemical flooding relies on the addition of one or more chemical compounds to an injected fluid (usually water) either to reduce the interfacial tension (IFT) between the reservoir oil and/or make the water viscosity match that of the oil (polymers) to improve the sweep efficiency of the injected fluid. Chemical flooding has been an option for EOR since the mid-1960s.
- 2.3.2 The four principal chemical flood technologies are: polymer flooding; alkali flooding; surfactant flooding; and then combinations of these technologies.

### Polymer flooding

- 2.3.3 This technology involves the addition of large-molecular-weight water soluble polymers to water to increase viscosity and improve macroscopic sweep and so improve the effectiveness of a conventional water flood. Polymers (such as acrylamide) are usually added to the water in concentrations ranging from 250 to 2000 parts per million (ppm). In a flooding application, the increased viscosity will alter the mobility ratio between the injected fluid and the reservoir oil, leading to better vertical and areal sweep efficiencies and thus higher oil recoveries.<sup>20</sup>

### Alkali flooding

- 2.3.4 Alkaline flooding involves the use of aqueous solutions of alkali chemicals including, for example, sodium hydroxide, sodium silicate, and sodium carbonate. These react with constituents present in some crude oils or at the rock/crude oil interface to form detergent-like or surfactant-type materials which reduce the ability of the formation to retain the oil. These chemicals enhance oil recovery by lowering surface tension, reversing rock wettability or emulsifying oil.<sup>21</sup>

### Surfactants

- 2.3.5 Surfactants reduce the interfacial tension between the oil and water phase and also alters the wettability of the reservoir rock to improve oil recovery.

### Combination flooding

- 2.3.6 The chemical processes of polymer, surfactant and alkali flooding can be combined with a synergistic effect on oil recovery. This combination flooding includes alkaline-surfactant (AS), alkali-polymer (AP) or alkaline-surfactant-polymer (AST).

#### Alkaline-surfactant-polymer flooding

- 2.3.7 Alkaline surfactant polymer (ASP) flooding aims to improve microscopic displacement efficiency by reducing the IFT between the water and oil through the addition of a surfactant to the water, while matching the oil and water mobility through the addition of polymer. Alkali is also added to the water to reduce adsorption of the surfactant onto the pore walls and to control the local salinity to ensure minimum IFT. It can also alter the rock wettability.

#### Alkaline-polymer flooding

- 2.3.8 In alkaline-polymer flooding, alkaline reaction with crude oil results in soap generation, wettability alteration, and emulsification; and polymer provides the required mobility control. The combination

<sup>20</sup> Terry, R. (2001) Enhanced Oil Recovery. *Encyclopedia of Physical Science and Technology 3rd Edition, vol. 18*. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

<sup>21</sup> Speight, J. (2016) Introduction to Enhanced Recovery Methods for Heavy Oil and Tar Sands (2nd Edition)

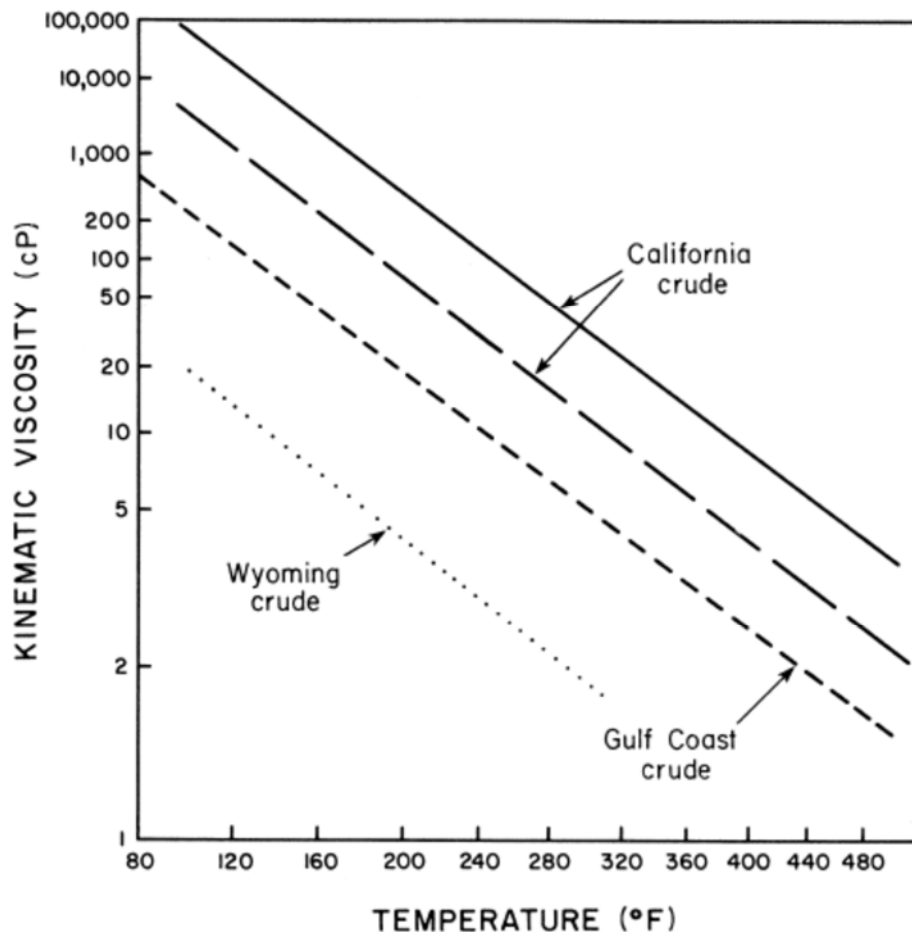
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of alkaline and polymer flooding can have three variations: (1) alkaline injection followed by polymer injection (A/P), (2) polymer injection followed by alkaline injection (P/A), and (3) alkaline and polymer co-injection (A+P).<sup>22</sup>

## 2.4 Thermal Processes

2.4.1 The viscous nature of oil from reservoirs containing heavy, low-grade crude oils means that only a small proportion of the recovery oil is produced during primary and secondary recovery processes. As the viscosity of oil decreases with increased temperature, increasing its temperature (by 100–200°F over the normal reservoir temperature – see **Figure 2.3**) can therefore enhance oil flow.

Figure 2.3 Typical viscosity–temperature relationships for several crude oils



Source: Terry (2001).

2.4.2 In this context, thermal methods of EOR raise the temperature of the reservoir, thereby stimulating oil flow to a producing well. There are three main types of thermal recovery; steam simulation, steam drive, and in situ combustion.

<sup>22</sup> Sheng, J.J. (2011) Modern Chemical Enhanced Oil Recovery - Theory and Practice. Elsevier.



**FINAL****Steam cycling**

- 2.4.3 Steam cycling involves the injection of 5000–15,000 bbl of high-quality steam. The well is then shut in, and the steam is allowed to soak the area around the injection well (typically over a 1 to 5 day period) which condenses to hot water.<sup>23</sup> The increase in heat reduces the surface tension, increases the permeability of the oil and improves the reservoir seepage conditions. The heated oil may also vaporise and then condense forming improved oil. The process is normally repeated to a point that is economically feasible.

**Steam drive**

- 2.4.4 In this process, steam is injected into several injection wells while the oil is produced from other wells. Once the oil viscosity is reduced by the increased temperature, it can flow more readily to the producing wells. The steam moves through the reservoir and comes in contact with cold oil, rock, and water. As the steam comes in contact with the cold environment, it condenses and a hot water bank is formed. This hot water bank acts as a water flood and pushes additional oil to the producing wells.

**In situ combustion**

- 2.4.5 In situ combustion involves the ignition of oil followed by a continuous injection of air, or other gas mixture with high oxygen content, to maintain the flame front. As the fire burns, it moves through the reservoir towards the production wells. Heat from the fire reduces oil viscosity and helps to vaporise reservoir water to steam. The steam, hot water, combustion gas and a bank of distilled solvent all act to drive oil in front of the fire toward production wells.<sup>24</sup>
- 2.4.6 There are three methods of in situ combustion: dry forward; reverse; and wet combustion, although the 'wet' combustion process is the primary method of conducting combustion EOR. In wet combustion, injected air is replaced by water once the flame front is established which in-turn vaporises to steam that moves through the reservoir and displaces the oil.

**2.5 Gas Injection (Miscible Flooding Processes)**

- 2.5.1 Miscible flooding refers to the injection of miscible gases such as hydrocarbon gas, carbon dioxide (CO<sub>2</sub>), or inert gas, such as nitrogen under high pressure into the reservoir. Miscible gas injection improves microscopic displacement efficiency by reducing or removing the IFT between the oil and the displacing fluid (the miscible gas). When used after a water flood this has the effect of re-establishing a pathway for the remaining oil to flow through and results in a very low residual oil saturation (2% has been measured in reservoir cores recovered from gas swept zones). The drawback of this process is that the gas is both less viscous and less dense than the oil. The choice of the selected gas will depend on what is available and the reservoir conditions.

**Carbon dioxide flooding**

- 2.5.2 CO<sub>2</sub> is the most commonly used gas in miscible flooding. CO<sub>2</sub> flooding involves the injection of CO<sub>2</sub> into the reservoir which is miscible with the oil. As CO<sub>2</sub> mixes and dissolves with the oil, it causes the oil volume to increase and its viscosity to reduce, enabling the CO<sub>2</sub> to displace the oil from the rock pores and facilitating sweep into the production wellbore.<sup>25</sup>
- 2.5.3 Often, CO<sub>2</sub> floods involve the injection of volumes of CO<sub>2</sub> alternated with volumes of water; water alternating gas or WAG floods although sometimes the two fluids are injected simultaneously (termed SWAG).

<sup>23</sup> Terry, R. (2001) Enhanced Oil Recovery. *Encyclopedia of Physical Science and Technology 3rd Edition*, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

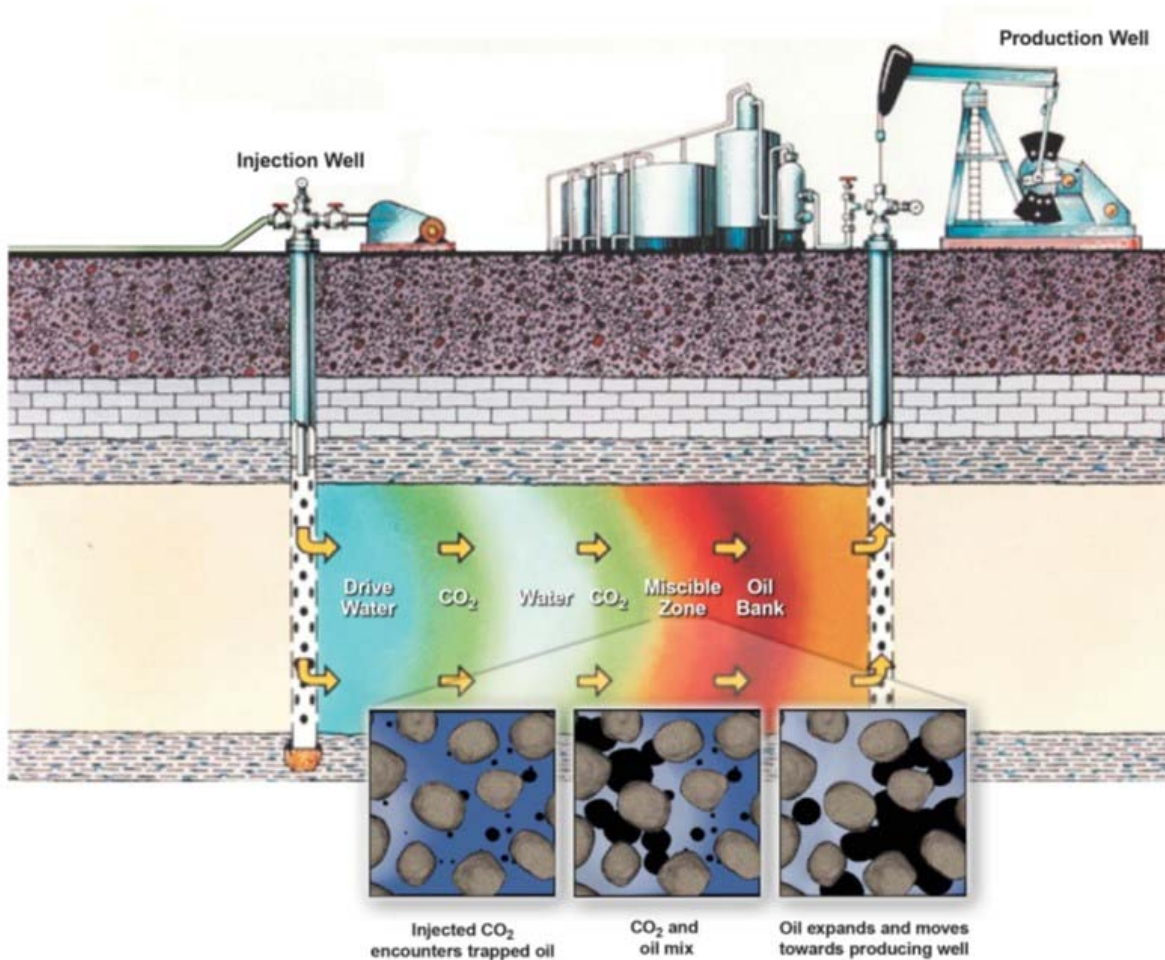
<sup>24</sup> Terry, R. (2001) Enhanced Oil Recovery. *Encyclopedia of Physical Science and Technology 3rd Edition*, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

<sup>25</sup> US Department of Energy (2010) *Carbon Dioxide Enhanced Oil Recovery*. Available from [https://www.netl.doe.gov/file%20library/research/oil-gas/CO2\\_EOR\\_Primer.pdf](https://www.netl.doe.gov/file%20library/research/oil-gas/CO2_EOR_Primer.pdf) [Accessed August 2016].

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- 2.5.4 This approach helps to mitigate the tendency for the lower viscosity CO<sub>2</sub> to finger its way ahead of the displaced oil<sup>26</sup>. Vertical sweep efficiency is also improved as water, being heavier than oil, tends to slump towards the bottom of the reservoir while the gas, being lighter, rises to the top.
- 2.5.5 **Figure 2.4** provides an illustration of how CO<sub>2</sub> and water can be used to flush residual oil from a subsurface rock formation between wells.

Figure 2.4 Carbon dioxide flooding



Source: US Department of Energy (2010).

- 2.5.6 Oil displacement by CO<sub>2</sub> flooding requires specific conditions concerning reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition. As the reservoir temperature increases (and the CO<sub>2</sub> density decreases), or as the oil density increases (as the light hydrocarbon fraction decreases), the minimum pressure needed to attain oil/CO<sub>2</sub> miscibility increases. Below some pressure (known as minimum miscibility pressure), CO<sub>2</sub> and oil will no longer be miscible with low pressure reservoirs needing to be re-pressurised through water injection.

<sup>26</sup> Terry, R. (2001) Enhanced Oil Recovery. *Encyclopedia of Physical Science and Technology 3rd Edition*, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

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- 2.5.7 In these applications, between one-half and two-thirds of the injected CO<sub>2</sub> returns with the produced oil. This is then usually re-injected into the reservoir to minimise operating costs with the remainder trapped in the oil reservoir by various means. Over the life cycle of the EOR project, the CO<sub>2</sub> injection and recovery cycles are repeated many times, with smaller amounts of new CO<sub>2</sub> added to the project in each cycle. The recycling process and retention of CO<sub>2</sub> in the oil reservoir raises the potential for carbon capture and storage as a means of tackling climate change, although most of the CO<sub>2</sub> based EOR projects in current operation utilise naturally occurring CO<sub>2</sub> that is extracted from underground specifically for EOR purposes.
- 2.5.8 Cyclic CO<sub>2</sub> stimulation, also known as the “huff-and-puff” method, is a single-well operation, which is developing as a method of rapidly producing oil. Similar to the cyclic steam process, CO<sub>2</sub> is injected into an oil reservoir, the well is shut in for a time, providing for a “soak period,” then is opened, allowing the oil and fluids to be produced. The dissolving of the CO<sub>2</sub> increases the volume of the oil and reduces the oil’s viscosity, allowing the oil to flow more easily toward the well. The process can also be used in heavy oil reservoirs by high-pressure injection of CO<sub>2</sub> to facilitate miscibility between the oil and CO<sub>2</sub>, and in cases where thermal methods are not feasible.<sup>27</sup>

**Nitrogen flooding**

- 2.5.9 Nitrogen flooding can be used to recover ‘light oils’ that are capable of absorbing added gas under reservoir conditions, are low in methane, and at least 5,000 feet deep to withstand the high injection pressure necessary for the oil to mix with the nitrogen without fracturing the producing formation. When nitrogen is injected into a reservoir, it forms a miscible front by vaporizing lighter oil components. As the front moves away from the injection wells, its leading edge goes into solution, or becomes miscible, with the reservoir oil. Continued injection moves the bank of displaced oil toward production wells. Water slugs are injected alternately with the nitrogen to increase the sweep efficiency and oil recovery. Nitrogen can be manufactured on site at relatively low cost by extraction from air by cryogenic separation, and being totally inert it is noncorrosive.

**Liquefied petroleum gas miscible slug**

- 2.5.10 Displacement by miscible slug usually refers to the injection of some liquid solvent that is miscible upon first contact with the resident crude oil. In particular, this process uses a slug of propane or other liquefied petroleum gas (2 to 5% PV [pore volume]) tailed by natural gas, inert gas, and/or water. Thus, the solvent will bank oil and water ahead of it and fully displace all contacted oil.<sup>28</sup>

**Enriched gas**

- 2.5.11 In the enriched gas process, a slug of methane enriched with ethane, propane, or butane (10 to 20% PV) and tailed by lean gas and/or water is injected into the reservoir. When the injected gas contacts virgin reservoir oil, the enriching components are slaked from the injected gas and absorbed into the oil.

**High pressure lean gas**

- 2.5.12 This process involves the continuous injection of high pressure methane, ethane, nitrogen, or flue gas into the reservoir. The lean gas process, similar to enriched gas, involves multiple contacts between reservoir oil and lean gas before forming a miscible bank. However, there is a difference in the enriched gas process where light components condense out of the injected gas and into the oil, then intermediate hydrocarbon fractions (C<sub>2</sub> to C<sub>6</sub>) are stripped from the oil into the lean gas phase.

<sup>27</sup> US Department of Energy (undated) *Miscible Recovery*. Available from <https://www.netl.doe.gov/file%20library/research/oil-gas/enhanced%20oil%20recovery/other/bwmr.pdf> [Accessed August 2016].

<sup>28</sup> Al-Anazi, B.D. (2007) *Enhanced Oil Recovery Techniques and Nitrogen Injection*. Available from <http://csegrecorder.com/articles/view/enhanced-oil-recovery-techniques-and-nitrogen-injection> [Accessed August 2016].

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## 2.6 Water Alternating Gas (WAG)

- 2.6.1 Due to high capital costs when installing gas injection systems, a more economically viable solution was developed which involves injection of gas and water alternatively, this is commonly referred to as water alternating gas (WAG). The WAG process entails injecting a slug of gas into the reservoir followed by water which serves as the "chasing fluid". This cycle is repeated as determined by the operator.
- 2.6.2 The process essentially involves two steps: (1) gas is first injected above the MMP (in miscible or MWAG operations) which causes the oil to swell, reducing its viscosity, (2) water is then injected as a means of flushing out newly mobilised oil. The interfacial tension between gas and oil is lower than for water to oil and this enables the oil to be displaced by the gas which would not have been accessible by water alone. WAG thus improves the efficiency of both microscopic and macroscopic displacement.
- 2.6.3 WAG helps to reduce the tendency for the lower viscosity gases to finger their way ahead of the displaced oil. Vertical sweep efficiency is also improved as water, being heavier than oil, tends to slump towards the bottom of the reservoir while the gas, being lighter, rises to the top. Typically WAG injection is used after waterflood operation as it helps to drive the residual oil saturation down even further. The typical improved oil recovery (IOR) potential for WAG injection when compared with water injection is quoted in the literature at 5-10%.
- 2.6.4 Many authors have suggested comprehensive classification of the WAG processes which includes: MWAG (miscible), IWAG (immiscible), HWAG (hybrid), FAWAG (Foam Assisted), SWAG (simultaneous) and SSWAG (selective).<sup>29</sup>

### Foam Assisted WAG (FAWAG)

- 2.6.5 In the FAWAG process foam is used to shut off gas routes and increase sweep efficiency. Foam is either generated at surface or in the reservoir and acts as a barrier for the tailing gas. This prevents gas from bypassing the oil and breaking through to the producer too early. The desired effect is that more injected gas is held in the reservoir to dissolve and mobilise oil deposits.

### Simultaneous WAG (SWAG)

- 2.6.6 In Simultaneous WAG, water and gas are injected at the same time. Water and gas are mixed at the surface before injection through a single well. In SSWAG, water is injected at the top of the reservoir formation and gas is injected at the bottom of the formation via a single dual completion well. The difference in water and gas densities will provide a sweeping mechanism in which water tends to sweep hydrocarbons downward and the gas tends to sweep the hydrocarbons upward.

## 2.7 Microbial Processes

- 2.7.1 Microbial Enhanced Oil Recovery (MEOR) is a biologically based technology, which aims to manipulate the function or structure, or both, of microbial environments existing in oil reservoirs. This can involve the injection of microbes and/or nutrients into the reservoir to improve recovery. The microbes consume the nutrients to multiply and produce beneficial metabolites. They can produce biopolymers, bio-surfactants, gases, and acids which can all contribute to improved recovery. They may also form biofilm that clogs pores which can also benefit overall recovery. Selective plugging can result in a lower permeability of thief zones and thus increase the sweep of the water flood. Research is required to ensure that the reservoir is capable of sustaining the microbial population. This includes consideration of such factors as temperature, pH, salinity, and pore size.

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<sup>29</sup> J.R. Christensen (1998), International Petroleum Conference and Exhibition of Mexico, Review of WAG Field Experience

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## 2.8 Emerging EOR Techniques

- 2.8.1 The EOR technologies (miscible gas/WAG and chemical flooding) for improving microscopic displacement and macroscopic sweep have been around for a number of decades but significant technical, operational and economic difficulties continue to limit their application and effectiveness.
- 2.8.2 In consequence, new technologies have been developed over recent years that aim to improve recovery using rather different mechanisms from those used by the traditional EOR techniques. They benefit from significantly lower cost per incremental barrel, have broader applicability, are less dependent on detailed characterisation of the reservoir rock and fluids and are less complex to implement. These techniques are low-salinity water flooding and deep reservoir flow diversion.

### Low-salinity water injection

- 2.8.3 Low-salinity water injection improves microscopic displacement efficiency by modifying the reservoir wettability. Most oil reservoir rocks have a heterogeneous or 'mixed' wettability. The effect of the low-salinity water is to make these rocks slightly more (but not completely) water wet as it progresses through the reservoir. This has the effect of mobilising more of the oil behind the displacement front and increasing recovery.

### Deep reservoir flow diversion

- 2.8.4 Deep reservoir flow diversion is a technique for improving macroscopic sweep efficiency. Flow diversion by polymers in the reservoir adjacent to the injection well could be very successful, however, in many cases cross-flow in the high-pressure gradient environment near the well can also mean that the diverted water will soon flow back. Chemical treatments placed deep in the reservoir are not so vulnerable to this and benefit from the diversion of fluid in the interval between the injection well and the reduced permeability zone.

## 2.9 Improved Oil Recovery (IOR)

- 2.9.1 IOR encompasses EOR, but is wider in scope. For the purposes of this study, IOR is taken to include:
- ▶ Pressure support and water flood;
  - ▶ Artificial lift technologies;
  - ▶ Reservoir modelling, simulation and monitoring;
  - ▶ Advanced drilling and well technologies;
  - ▶ Subsea processing; and
  - ▶ Topside modifications.

### Pressure Support and Water Flood

#### Water Flood and Injection Pressure Support

- 2.9.2 Seawater or formation water is injected to either the flanks of a reservoir or the water leg. Depending on the shape and properties of the reservoir this may serve as mainly a water flood or a pressure support application. During water flood, injected water displaces residual oil and encourages it towards the wellbore. During pressure support, the volumes of produced fluid are replaced with injected water in an attempt to maintain the reservoir at a sufficient pressure to prolong production. When a reservoir is above its bubble point pressure, this is easier to maintain, due to a lack of highly compressible gas.

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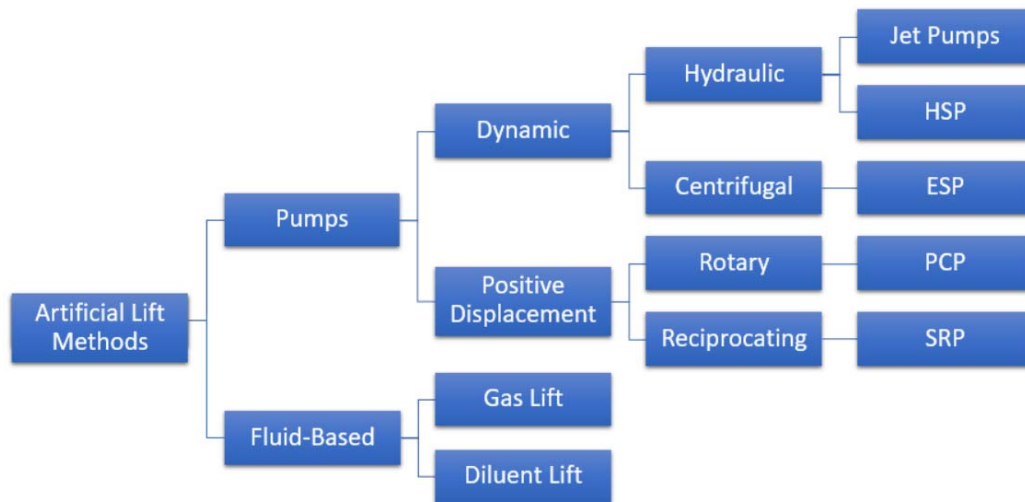
**Gas Injection Pressure Support**

2.9.3 Produced gas or imported gas is injected into the reservoir in the crestal regions. The effect of this is to squeeze the oil column and push oil down toward the wellbore. Commonly this scheme is used when there are strict anti-flaring laws to abide by, if there is no viable export route or no natural pressure support is available (e.g. an aquifer). The injected gas serves to replace the volumes of the produced fluids to boost the reservoir pressure.

**Artificial Lift Technologies**

2.9.4 Artificial lift is the process by which artificial methods are used to increase the flow of liquids through a production well. Generally this is achieved by the use of a mechanical device inside the well or by decreasing the weight of the hydrostatic column in the well. Artificial lift is needed in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface, but is commonly used in naturally flowing wells to increase the flow rate above what would flow naturally.

Figure 2.5 Artificial Lift Methods



HSP: Hydraulic Submersible Pump  
ESP: Electrical Submersible Pump

PCP: Progressive Cavity Pump  
SRP: Sucker Rod Pump

Source: Generated Flow Diagram

**Gas Lift**

2.9.5 Gas lift has been widely used to improve oil recovery rates for decades. Pressurised gas is injected down the annulus of a well, into lower sections of the tubing string. Valves are strategically placed along the tubing to allow gas to flow from the annulus into the tubing. These “unloading” valves are designed to open once a predetermined differential pressure is reached. Gas mixes with the tubing fluid reducing the static pressure of the column. Gas rises through the tubing due to buoyancy effects and carries the fluids with it. This subsequently increases the drawdown pressure on the reservoir, enabling formation fluid to enter the wellbore.

**Diluent Lift**

2.9.6 Diluent lift operates on similar principles to that of gas lift. Light oils or condensates are injected through subsurface injection valves into the tubing string. As the light oil mixes with the heavier oil or water in the well, it reduces the overall density of the fluids. This reduction in fluid density causes the back pressure on the reservoir to decrease, once again increasing the drawdown and allowing the reservoir to produce into the wellbore.

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### Suction Rod Pump (SRP)

- 2.9.7 The suction rod pump was the first artificial lift technique to be used on an oil field. The SRP is a surface operated pump which is usually powered by an electric motor or gas engine. The surface unit is connected to the downhole pump with a polished rod called a "Sucker Rod". The sucker rod moves up and down through a "Stuffing Box" mounted on the wellhead. The stuffing box seals against the rod and prevents surface leaks of liquids and gas. As the rod moves, oil is either sucked into or pushed out of the pump to surface.

### Progressive Cavity Pump (PCP)

- 2.9.8 The progressive cavity pump is a positive displacement pump. Fluids are transmitted through the pump via a series of small and discrete cavities surrounding a helical rotor. As the rotor turns these cavities move, but their shape remains unchanged. Liquid is hereby carried through these cavities along the length of the pump. The number of cavities and length of the pump are directly related to the discharge pressure. So for a higher discharge pressure more cavities will be used.

### Electrical Submersible Pump (ESP)

- 2.9.9 The ESP is an electrically powered centrifugal pump placed downhole in the well. A high voltage, three phase electrical supply powers the pumps. Downhole cables run the length of the well to the ESP, connecting it to the power supply. ESPs work by mechanically increasing the drawdown on the wellbore by pressurising the fluid column about it. They are usually multi-staged in design and form part of the overall tubing string.

### Hydraulic Submersible Pump (HSP)

- 2.9.10 HSPs operate similarly to ESPs in that a centrifugal (or piston or turbine type) pump is placed downhole to pump fluid to the surface. However in place of an electrical supply and cables are a "power fluid" and hydraulic lines. High pressure fluid is pumped from surface into the well and drives the motors of the HSP. The power fluid then commingles with the oil downstream of the pump to be produced to surface. HSPs also have the added benefit of being able to send hot power fluid down the well, which can aid in recovering viscous crudes.

### Jet Pump

- 2.9.11 Jet pumps also utilise a power fluid, but have no moving parts. The Jet pump is driven by a nozzle and Venturi valve. High pressure power fluid is directed down the tubing to the nozzle, where the pressure energy is converted to kinetic energy. When the Venturi valve causes the pressure of the power fluid to drop, this low pressure fluid entrains production fluid at the throat of the pump. A diffuser then reduces the fluid's velocity and increases its pressure, allowing the commingled fluid to flow to the surface.

## Reservoir Modelling, Simulation and Monitoring

- 2.9.12 Through reservoir modelling, operators are able to predict oil and gas reservoir behaviour, supporting decisions relating to the well location, the number of wells required, optimal completion, need for artificial lift and forecast production, prior to investment.<sup>30</sup> Ongoing reservoir management can also support the implementation of EOR methods.
- 2.9.13 Models can be constructed using well logs, seismic surveys and production history. A reservoir characterisation study forms the first part of the development of a reservoir model and is followed by reservoir simulation of flow of fluids within the reservoir over its production lifetime. In some cases, a single "shared earth model" is used for both purposes.<sup>31</sup>

<sup>30</sup> Bridger, T. (2012), 'Enhancing EOR through reservoir modelling'. Offshore. <http://www.offshore-mag.com/articles/print/volume-72/issue-8/geology-geophysics/enhancing-eor-through-reservoir-modeling.html> [accessed Sept 2016].

<sup>31</sup> PetroWiki (2016), Basic elements of a reservoir characterization study. [http://petrowiki.org/Basic\\_elements\\_of\\_a\\_reservoir\\_characterization\\_study](http://petrowiki.org/Basic_elements_of_a_reservoir_characterization_study) [accessed Sept 2016].

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- 2.9.14 Modelling approaches and methods of data acquisition are wide-ranging and include seismic surveys, pressure surveys, tracer surveys and electromagnetic surveys<sup>32</sup>. Three-dimensional seismic imaging is now mainstream practice in the industry for exploration and with reservoir modelling can support “virtual drilling” to help optimise the number and placement of wells.<sup>33</sup> In addition to 3D seismic, 4D seismic can be highly effective in mapping and monitoring fluid movements. By acquiring new seismic data after a period of production, it is possible to observe the movement of gas and water in the reservoir and obtain an image of where the hydrocarbons were produced – and where there are any left.<sup>34</sup>
- 2.9.15 Tracers allow fluid movement to be tracked by tagging injection fluids with inert chemical or radioactive compounds, and these can be used to help to estimate the amount of oil in a reservoir and identify reservoirs that are specifically suited for EOR operations. Injection of a selection of partitioning tracers, combined with frequent sample analysis of produced fluids, provides information suited for estimation of residual oil saturation. Tracers can also be used to evaluate and optimise the application of EOR chemicals in a reservoir.<sup>35</sup>
- 2.9.16 Electromagnetic (EM) induction offers a greater depth of investigation than conventional logging tools and is sensitive to fluid content. Cross well EM induction surveys investigate the region between wells, filling an intermediate role between high-resolution well logs and lower resolution surface measurements.<sup>36</sup>
- 2.9.17 Ongoing reservoir monitoring, including downhole, subsea and topside monitoring, can play an important role in improving operational costs and drilling efficiency. Permanent reservoir monitoring (PRM) is in its infancy but over the past decade several major fields have served as testing grounds for permanent installations.<sup>37</sup> PRM enables operators to decrease field risk by providing a better image of the nature of subsea reservoirs during extraction operations. As monitoring equipment is constantly onsite, an oil company is able to better manage oil reservoirs throughout the reservoir's lifecycle. PRM systems are fixed with fibre-based data capability enabling improved data communication between the PRM system and the operator].<sup>38</sup>

**Advanced Drilling and Well Technology**

- 2.9.18 Advanced drilling methods can be employed to improve oil recovery. Potential drilling methods include:
- ▶ **Infilling drilling:** the addition of wells in a field that decreases average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, the shifting well patterns alter the formation-fluid flow paths and increase sweep to areas where greater hydrocarbon saturations exist;<sup>39</sup>

<sup>32</sup> INTSOK (undated), Improved Oil Recovery – an overview.

[http://www.ccop.or.th/eppm/projects/16/docs/Keynote\\_Eva\\_Improved%20oil%20recovery%20-%20an%20overview%20%5BCompatibility%20Mode%5D.pdf](http://www.ccop.or.th/eppm/projects/16/docs/Keynote_Eva_Improved%20oil%20recovery%20-%20an%20overview%20%5BCompatibility%20Mode%5D.pdf) [accessed Sept 2016].

<sup>33</sup> IBM (2010), Smarter oil and gas exploration with IBM. [http://www-07.ibm.com/innovation/au/shapingourfuture/downloads/smarter\\_oil\\_gas\\_exploration.pdf](http://www-07.ibm.com/innovation/au/shapingourfuture/downloads/smarter_oil_gas_exploration.pdf) [accessed Sept 2016].

<sup>34</sup> Statoil (2016) Permanent cables increase oil recovery.

[http://www.statoil.com/en/TechnologyInnovation/OptimizingReservoirRecovery/Pages/2012\\_13Dec\\_Permanent\\_Reservoir\\_monitoring.aspx](http://www.statoil.com/en/TechnologyInnovation/OptimizingReservoirRecovery/Pages/2012_13Dec_Permanent_Reservoir_monitoring.aspx) [accessed Sept 2016].

<sup>35</sup> Husebya, O. Sagen, J. Viig, S. and Dugstad, O. (2013), ‘Simulation and interpretation of inter-well tracer tests’. EPJ Web of Conferences. [http://www.epj-conferences.org/articles/epjconf/pdf/2013/11/epjconf\\_tracer6\\_03003.pdf](http://www.epj-conferences.org/articles/epjconf/pdf/2013/11/epjconf_tracer6_03003.pdf) [accessed Sept 2016].

<sup>36</sup> Al-Ali, Z. (2009), Looking Deep into the Reservoir. Oilfield Review Summer 2009: 21, no. 2.

[https://www.slb.com/~media/Files/resources/oilfield\\_review/ors09/sum09/looking\\_deep.pdf](https://www.slb.com/~media/Files/resources/oilfield_review/ors09/sum09/looking_deep.pdf) [accessed Sept 2016].

<sup>37</sup> Detomo, R. (2014), Permanent monitoring enhances life of field reservoir management. Oil and Gas Journal. <http://www.oqj.com/articles/print/volume-112/issue-10/special-report-geophysics-update/permanent-monitoring-enhances-life-of-field-reservoir-management.html> [accessed Sept 2016].

<sup>38</sup> Global Marine Systems (2016), The growing importance of permanent reservoir monitoring.

<http://www.globalmarinesystems.com/news/the-growing-importance-of-permanent-reservoir-monitoring.html> [accessed Sept 2016].

<sup>39</sup> Schlumberger (2016), Oilfield Glossary. <http://www.glossary.oilfield.slb.com/> [accessed Sept 2016].



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- ▶ **Horizontal wells:** high-angle wells (with an inclination of generally greater than 85°) drilled to enhance reservoir performance by placing a long wellbore section within the reservoir. The advantages of horizontal wells include: reduced water and gas coning; increased production rate; reduced pressure drop around the wellbore; lower fluid velocities around the wellbore; reduction in sand production; and larger and more efficient drainage patterns leading to increased overall reserves recovery;<sup>40</sup>
- ▶ **Multilateral wells:** comprise of more than one wellbore drilled from and connected to a main bore. This improves reservoir production by accessing multiple production zones or by increasing the contact between the wellbore a formation with minimal increase in drilling and completion costs;<sup>41</sup>
- ▶ **Formation Fracturing:** a viscous fluid is pumped down the well into the completion interval at a sufficiently high pressure to overcome rock stresses. The fluid then causes existing and new fractures to grow and propagate through the formation. Proppant is added to the fluid prior to its injection. Fractures are filled with this proppant and hold the fractures open when the stress of the fluid is removed. This increases the potential drainage area of a well, accessing tight pockets of oil;
- ▶ **Formation Acidising:** matrix acidising is may be used to remove wellbore damage. Specifically formulated fluids (though commonly HF or HCl based) are pumped into the reservoir. The acid dissolves the sediments and mud blocking up the pores after drilling thereby increasing its permeability. The effect on a sandstone reservoir is to dissolve material lining the pore, however if the same technique is applied to a carbonate reservoir the natural pore size of the formation increases due to its reactivity. This is commonly used in conjunction with fracturing to access even more of the reservoir; and
- ▶ **Through Tubing Rotary Drilling:** involves drilling side-tracks in existing producers and injectors, enabling new reservoir sections to be reached without having to remove the existing 'x-mas tree', the completion or the production casing.<sup>42</sup>

2.9.19 Well IOR technologies can include:

- ▶ **Downhole instrumentation and control systems:** the use of downhole devices to monitor operation from the surface to improve flow or injection without having to perform a well intervention;
- ▶ **Downhole oil-water separators:** separate oil and water in the well bore, enabling water to be pumped directly to an injection formation without ever coming to the surface. This can lower costs and improve environmental protection. This technology has two primary components - an oil/water separation component and one or more pumps. Two basic methods of separation (hydrocyclones and gravity separation) have been employed in commercial units; and<sup>43</sup>
- ▶ **Artificial lift:** as described in paragraph 2.9.4 – 2.9.11.

<sup>40</sup> PetroWiki (2016), Horizontal Wells. [http://petrowiki.org/Horizontal\\_wells](http://petrowiki.org/Horizontal_wells) [accessed Sept 2016].

<sup>41</sup> Flatern, R. (2016), 'Multilateral Wells'. Oilfield Review 2016. [http://www.slb.com/resources/oilfield\\_review/~media/Files/resources/oilfield\\_review/defining\\_series/Defining-Multilateral-Wells.ashx](http://www.slb.com/resources/oilfield_review/~media/Files/resources/oilfield_review/defining_series/Defining-Multilateral-Wells.ashx) [accessed Sept 2016].

<sup>42</sup> Statoil (2014), Through tubing drilling and completion. <http://www.statoil.com/en/technologyinnovation/optimizingreservoirrecovery/advanceddrilling/through%20tubing%20drilling/pages/through-tubingdrilling.aspx> [accessed Sept 2016].

<sup>43</sup> US Department of Energy (undated), Factsheet – Downhole Separation. <https://www.netl.doe.gov/research/coal/crosscutting/pwms/tech-desc/downsep> [accessed Sept 2016].

**FINAL****Subsea Processing**

- 2.9.20 Subsea processing is the application of hydrocarbon processing equipment at the seafloor, enabling the separation of produced fluids into gas and liquid—or gas, oil, and water—for individual phase transport and disposal (in the case of water). The liquid stream can be pumped to a central facility for final processing whilst the gas stream can be transported under natural pressure or pressure boosted (compressed) to the host facility.<sup>44</sup>
- 2.9.21 Subsea processing can increase recoverable reserves through more effective field management, improve well productivity through higher pressure drawdown, help overcome challenges associated with operations in deepwater areas and extend reservoir life. Additionally, the reduction in size, or possibly the elimination altogether of the otherwise required topside facility, can significantly reduce both capex and opex, thus making subsea processing a high-value investment.<sup>45</sup>
- 2.9.22 Subsea processing can encompass a number of different processes to help reduce the cost and complexity of developing an offshore field. The main types of subsea processing include subsea water removal and reinjection or disposal, single-phase and multi-phase boosting of well fluids, sand and solid separation, gas/liquid separation and boosting, and gas treatment and compression.<sup>46</sup>

**Topside Modifications**

- 2.9.23 On regular occasion, in order to utilise a proposed IOR/EOR scheme, topside modifications are required to existing platform installations. Examples of situations which may arise include:
- ▶ The installation and/or retrofitting of the latest technology in an attempt increase the overall reliability of a process train to subsequently reduce downtime;
  - ▶ Increasing the handling capacity of a “less” desirable product (e.g. produced water, gas) by upgrading e.g. the gas compression system, gas dehydration system, hydrocyclone throughput, etc;
  - ▶ Installing/upgrading gas compression and water pump capacity, which can benefit the development by removing process constraints or enabling the application of other IOR schemes (such as water or gas injection);
  - ▶ Upgrading the pump system to increase its discharge pressure, enabling IOR by means of fracturing the reservoir formation; and
  - ▶ Upgrading the chemical injection system can improve recovery by assuring the flow through the system and preventing excessively long shutdown periods (when mitigating against wax, scale, hydrate, asphaltene, etc.).
- 2.9.24 However, when considering topsides modifications, the tendency is focused on improving the “economic recovery” of a field by means of extending the life of a platform or removing process constraints. This can then mean that they provide a means of accelerating the production of oil from the reservoir and may not actually extract any additional reserves, *per se*. A caveat is that increasing gas compression and water pumping capacity for injection programmes can and do extract extra reserves, but this can also be considered as a means of “enabling” actual IOR operations. Ultimately, the only widely recognised topsides modification which can truly be considered to unlock additional reserves is to drop the separator pressure and switch to low pressure operations. In doing this the overall back pressure on the system is reduced and recovery is enhanced.

<sup>44</sup> PetroWiki (2015), Subsea Processing Benefits. [http://petrowiki.org/index.php?title=Subsea\\_processing\\_benefits&printable=yes](http://petrowiki.org/index.php?title=Subsea_processing_benefits&printable=yes) [accessed Sept 2016].

<sup>45</sup> McKee, M. et al (2013) Subsea Processing Comes of Age. Offshore. <http://www.offshore-mag.com/articles/print/volume-73/issue-3/subsea/subsea-processing-comes-of-age.html> [accessed Sept 2016].

<sup>46</sup> Rigzone (undated), How Does Subsea Processing Work? [http://www.rigzone.com/training/insight.asp?insight\\_id=327](http://www.rigzone.com/training/insight.asp?insight_id=327) [accessed Sept 2016].

## 2.10 Summary

- 2.10.1 EOR involves injecting a fluid/gas into an oil reservoir to recover residual oil once natural reservoir energy has been depleted (primary recover) and where secondary techniques become ineffective thereby increasing oil recovery. It can be used to improve pore scale displacement and sweep. EOR processes can be classified into four categories:
- ▶ Chemical flooding processes;
  - ▶ Thermal processes;
  - ▶ Gas injection (miscible flooding processes); and
  - ▶ Other (including water alternating gas (WAG), foam assisted WAG and microbial processes).
- 2.10.2 IOR applies to improvements in oil recovery achieved via better reservoir understanding and overall field management. It is a term that is sometimes used synonymously with EOR. However, it has a wider scope than EOR and includes 'better' engineering and project management such as identifying volumes of oil that have been bypassed during water injection using seismic surveying and then drilling new wells to access those oil pockets.<sup>47</sup> In consequence, it is often considered a general term that implies improved oil recovery by any means with EOR considered a subset of IOR. IOR is taken to include:
- ▶ Pressure support and water flood;
  - ▶ Artificial lift technologies;
  - ▶ Reservoir modelling, simulation and monitoring;
  - ▶ Advanced drilling and well technologies;
  - ▶ Subsea processing; and
  - ▶ Topside modifications.
- 2.10.3 EOR in conjunction with IOR are used to address and improve recovery factors at a range of scales: microscopic, macroscopic (reservoir) or field scale. The application of EOR and IOR can significantly increase the recovery of OIP.

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<sup>47</sup> Muggeridge, A. Cockin, A. Webb, K. Frampton, H. Collins, I. Moulds, T. Salino, P. (2013) Recovery rates, enhanced oil recovery and technological limits in *Philosophical Transactions of the Royal Society* (307), 2006. Available from <http://rsta.royalsocietypublishing.org/content/372/2006/20120320> [Accessed August 2016].

### 3. Factors Affecting Recovery

The following section outlines those factors that will influence oil recovery (including but not limited to microscopic, reservoir and field characteristics).

#### 3.1 Overview

- 3.1.1 Production profiles differ from field to field due to high geological variability between reservoirs. Production rates are influenced by a number of factors, such as reservoir geometry (primarily formation thickness and reservoir continuity), reservoir pressure, reservoir depth, rock type and permeability, fluid saturations and properties, extent of fracturing, number of wells and their locations, and development plan<sup>48</sup>. Not all oil can be recovered from a reservoir, with the ratio of recoverable oil to estimated oil in place referred to as the recovery factor.
- 3.1.2 The ultimate average recovery factor for oilfields, on a worldwide basis, is approximately 35%<sup>49</sup> with the remaining oil left behind in the reservoir when production ends. On the UKCS specifically, the average recovery factor from oil fields after primary and secondary recovery is projected to be approximately 46% at end of field life.<sup>50</sup> For Brazil, whilst estimates vary, the recovery factor for offshore fields it is likely to be in the order of 20%.<sup>51</sup>
- 3.1.3 Between 5 and 20 percent of the available oil in a reservoir is recovered during the primary recovery phase as the natural reservoir pressure forces oil into the wellbore. This can stem from several individual, or a combination of, mechanisms including liquid and rock expansion, solution gas, gas-cap expansion, gravity drainage and water influx. The natural expulsive forces present in a given reservoir depend on rock and fluid properties, geologic structure and geometry of the reservoir, as well as on the rate of oil and gas production.
- 3.1.4 With secondary recovery, various techniques can be used to recover oil from depleted or low-pressure reservoirs with incremental recovery ranging from 20 to 40%<sup>52</sup>. Secondary recovery techniques include, of example, the use of pumps on the surface or submerged (electrical submersible pumps), to bring oil to the surface or increasing reservoir pressure by water injection or gas injection. EOR (or tertiary recovery) can improve this further.
- 3.1.5 The factors affecting recovery can be considered by the scale at which they operate: microscopic, macroscopic (reservoir) or field scale.<sup>53</sup> **Figure 3.1** illustrates how these factors relate to each other. This chapter briefly outlines how these, and key other factors, influences oil recovery. Guidance on possible applicability to sedimentary basins in Brazil is explored in the report for Output 2 of this project.

<sup>48</sup> Speight, James G. (2016). Introduction to Enhanced Recovery Methods for Heavy Oil and Tar Sands (2nd Edition). Elsevier.

<sup>49</sup> Labastie, A. (2011) En Route: Increasing Recovery Factors: A Necessity. Society of Petroleum Engineers.

<sup>50</sup> Oil & Gas Authority (2016) Enhanced Oil Recovery (EOR) Strategy.

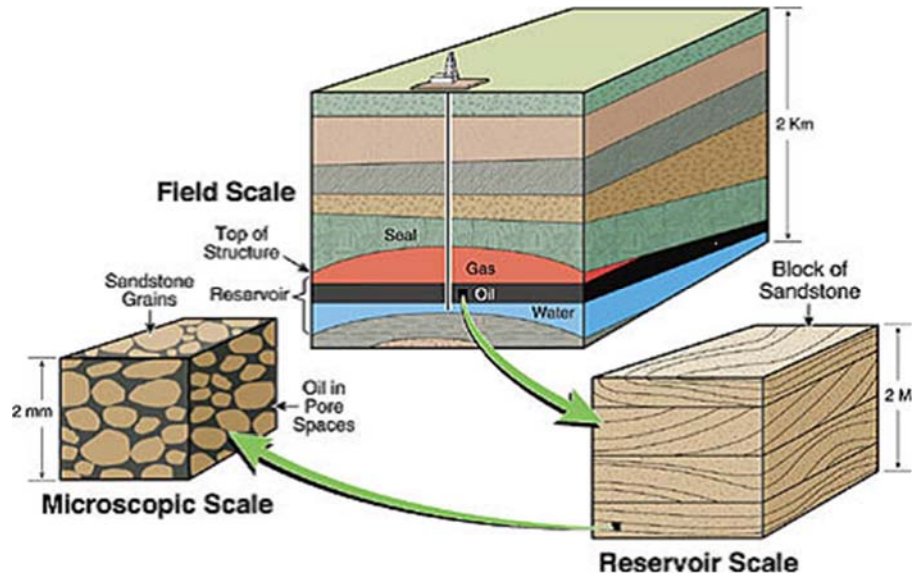
<sup>51</sup> Alvarado, V and Manrique, E (2010), Enhanced Oil Recovery: An Update Review in Energies 2010, 3, 1529-1575; doi:10.3390/en3091529

<sup>52</sup> US Department of Energy (2016) *Enhanced Oil Recovery*. Available from <http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery> [Accessed August 2016].

<sup>53</sup> Zitha, P., et al. (2011) Increasing hydrocarbon recovery factors. Society of Petroleum Engineers, Online, Available from: <http://www.spe.org/industry/docs/recoveryfactors.pdf> [Accessed 31/08/2016]

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Figure 3.1 Different scales of factors involved in hydrocarbon production



Source Zitha, P., et al. (2011) Increasing hydrocarbon recovery factors. Society of Petroleum Engineers, Online, Available from: <http://www.spe.org/industry/docs/recoveryfactors.pdf> [Accessed 31/09/2016]

- 3.1.6 The relationship between the microscopic, macroscopic and field level factors and the recovery factor can be expressed through an equation (although this specifically relates to the use of water and gas flooding EOR)<sup>54</sup>:

$$RF = E_{ps} \times E_s \times E_d \text{ and } E_c$$

- 3.1.7 Where:

- ▶ RF is the recovery factor which is defined as the volume of oil recovered over the volume of oil initially in place (OIIP), both measured at surface conditions;
- ▶  $E_{ps}$  is microscopic displacement efficiency - microscopic sweep efficiency at a pore scale;
- ▶  $E_s$  is macroscopic sweep efficiency - what fraction of the rock is swept both areally and vertically on a field wide scale;
- ▶  $E_d$  is the connected volume factor – the proportion of the total reservoir volume connected to wells (e.g. the field may be compartmentalized by faults or layering). The type, number, and placement of wells to achieve optimum reservoir drainage requires detailed knowledge of reservoir geology; and
- ▶  $E_c$  is the economic efficiency factor - considering the physical and commercial constraints on field life such as how much production/recovery is lost through curtailment of well, plant, or infrastructure life for design performance, integrity, or economic reasons.

<sup>54</sup> Muggerridge, A et al (2014) Recovery rates, enhanced oil recovery and technological limits. Phil. Trans. R. Soc. A 372 20120320

## 3.2 Factors Influencing Microscopic Displacement

- 3.2.1 Microscopic displacement efficiency is a measure of the efficiency of the displacing fluid in mobilising the residual oil once the fluid has come in contact with the oil. It is influenced by:
- ▶ Relative permeability:

When two or more fluid phases are present, the saturation of one phase affects the permeability of the other(s), and relative permeability have to be considered.
  - ▶ Rock wettability:

Wettability refers to the tendency for a solid to prefer one fluid over another. The wettability of the reservoir rock is affected by its mineralogy, the crude oil composition, the connate waste composition and the pore size distribution. Rock surfaces can be either oil-wet or water-wet, depending on the chemical composition of the fluids.<sup>55</sup>
  - ▶ Interfacial tension and surface tension:

Interfacial or surface tension occurs when two phases are present, and is a function of pressure, temperature, and the composition of each phase. These phases can be gas/oil, oil/water, or gas/water.
  - ▶ Capillary pressure:

The capillary pressure in a porous medium is a function of the chemical composition of the rock and fluids, the pore size distribution and the saturation of the fluids in the pores.
- 3.2.2 Approaches to increasing microscopic displacement efficiency focuses on ways to reduce capillary effects, by reducing the oil–water (or gas) interfacial tension, and modify the rock wettability to the optimum mixed wettability state.

## 3.3 Factors Influencing Macroscopic Displacement

- 3.3.1 Factors influencing macroscopic displacement efficiency, a measure of the efficiency of the displacing fluid in contacting the oil-bearing parts of the reservoir, includes:
- ▶ Mobility ratio:

The mobility ratio is the mobility of displacing fluid divided by the mobility of the displaced fluid. Mobility ratio is one of the most important parameters of a miscible displacement and has a profound influence on macroscopic sweep efficiency.
  - ▶ Viscous fingering:

Viscous fingering can occur when the interface of two fluids bypasses sections of a reservoir as it moves along, creating an uneven, or fingered, profile. This can result in an inefficient sweeping action that can bypass significant volumes of recoverable oil and, in severe cases, an early breakthrough of water into adjacent production wellbores.
  - ▶ Gravity segregation:

Macroscopic sweep may also be affected by gravitational segregation. This occurs more often in gas–oil rather than water–oil displacements because of the higher density contrast between gas and oil. Due to its lower density, gas tends to rise above oil and then flow rapidly along the top of the reservoir in an unstable gravity tongue because of its low viscosity. This can result in very early gas breakthrough and poor vertical sweep efficiency.

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<sup>55</sup> Speight, James G. (2016). Introduction to Enhanced Recovery Methods for Heavy Oil and Tar Sands (2nd Edition). Elsevier.

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▶ Reservoir geological heterogeneity:

The macroscopic sweep efficiency is influenced principally by the geological heterogeneity in the reservoir, which control the spatial distribution of porosity and permeability.

### 3.4 Field Scale Factors

3.4.1 Examples<sup>56</sup> of field scale factors affecting offshore EOR implementation include:

- ▶ Higher transportation costs of wastes and resources e.g. injectant due to remote location of offshore fields;
- ▶ Limited waste disposal options;
- ▶ Access to injectants (e.g., CO<sub>2</sub>);
- ▶ Power, weight and space restrictions limiting retrofitting of existing offshore facilities to accommodate processing facilities for EOR applications and storing additional fluids;
- ▶ Development and operational costs including, for example, field development and equipment expenditures, operating & maintenance costs, and injection material costs (**Figure 3.2** illustrates the range of cost elements to be considered for an EOR project).<sup>57</sup> On the UKCS, the costs of implementing EOR schemes offshore, rather than knowledge of the technology, is considered a key factor inhibiting implementation of EOR schemes; and<sup>58</sup>
- ▶ Risk – EOR projects are high risk with the initiation of EOR projects often dependent on the preparedness and willingness of investors to manage EOR risk and economic exposure, and the availability of more attractive investment options.<sup>59</sup>

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<sup>56</sup> Kang, P. S., Lim, J. S., & Huh, C. (2016). Screening criteria and considerations of offshore enhanced oil recovery. *Energies*, 9(1), [44].

<sup>57</sup> Zekri, A. Y. and Jerbi, K. K. (2002). Economic Evaluation of Enhanced Oil Recovery. *Oil & Gas Science and Technology - Rev. IFP*, Vol. 57, No. 3, pp. 259-267

<sup>58</sup> Kemp A G & Stephen L (2014) The Economics of Enhanced Oil Recovery (EOR) in the UKCS and the Tax Review. North Sea Study Occasional Paper 129 Aberdeen University. Online, Available from: [www.abdn.ac.uk/research/acreef/documents/Working\\_papers/nsp-129.pdf](http://www.abdn.ac.uk/research/acreef/documents/Working_papers/nsp-129.pdf) [Accessed 31/08/2016]

<sup>59</sup> Alvarado, V & Manrique, E. (2010). *Enhanced Oil Recovery - Field Planning and Development Strategies*. Elsevier.

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Figure 3.2 Cost elements of EOR miscible projects

COST ELEMENTS	EXPLANATION OF COST ELEMENTS	COST DETERMINATION
Field development expenditures		
Drilling and completion	Drill sufficient new production wells to provide the required acre spacing; drill sufficient injection wells to provide the injection pattern.	Number of new production and injection wells drilled; costs vary by depth and region.
Workover and conversion	Bring existing production and injection wells to acceptable quality.	Number production and injection wells that need workover; variable by age of latest field development costs vary by depth and region.
Equipment expenditures		
Well, lease, and field production equipment	Install equipment necessary to operate new production wells.	Number of new production wells drilled; costs vary by depth and region.
Injection equipment	Install equipment necessary to operate new injection wells.	Number of new production and injection wells drilled. Costs vary by depth and region.
Separation and compression equipment	Install sufficient equipment to produce maximum yearly requirement for recycle indicants.	Maximum pore volume injection per year.
Operating and maintenance costs		
Normal operating and maintenance costs	Cover normal daily operation, surface repair and maintenance, and subsurface repair, maintenance and services (include artificial lift of primary production).	Normal production and injection wells. Costs vary by depth and region.
Incremental injection operating and maintenance costs	Cover incremental operating and maintenance costs due to injection operation and increased fluid handling.	Number and injection wells. Costs vary by depth and region.
Injection material costs		
Purchased injacants	Inject the specified reservoir pore volume of recycle indicants over the determined time period.	Amount of pore volume; cost of injacants variable by source, purchased or recovered (see unit costs for injacants miscible).
Recycle injection fluids	Inject reservoir pore volume of recovered injectant from production (per injection schedule for recycle injectant).	
Other costs		
Field study, engineering, and supervision	Provide research, development, and management support to the project.	Include in general and overhead costs.

Source: Alvarado, V & Manrique, E (2010) Enhanced Oil Recovery: An Update Review Energies, 3(9), 1529-1575



## 4. UKCS Policy and Regulatory Framework for EOR and IOR

This chapter outlines the UKCS policy and regulatory framework for EOR and IOR.

### 4.1 Overview

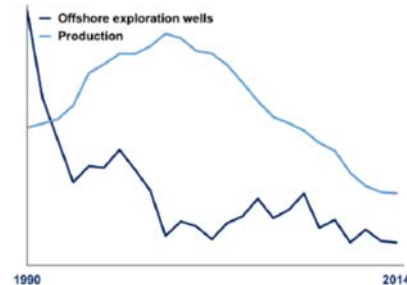
UK Government policy and regulation with respect to EOR and IOR has been framed by the wider context of the Maximising Economic Recovery review, the resulting Maximising Economic Recovery (MER) Strategy and legislation (Infrastructure Act 2015 and Energy Act 2016) to establish a new arms-length regulator and the recently published EOR Strategy. The following provides a brief review of these aspects of UK policy and regulation and highlights those areas that will be subject to further consideration in the subsequent study.

### 4.2 Maximising Economic Recovery

#### The Wood Review

4.2.1 In June 2013 the UK Secretary of State for Energy and Climate Change asked Sir Ian Wood to conduct an independently led review of UKCS oil and gas recovery, specifically looking at how economic recovery could be maximised. This was in response to the fact that oil and gas exploration and production on the UKCS was (and still is) facing a range of issues, including (but not limited to):

- ▶ **Mix of plays:** as a mature offshore basin, the UKCS contains a mix of diverse offshore plays, numbering some 300 fields in total. This contrasts with the 1970s and 1980s where a small number of fields were the dominant source of production;
- ▶ **Mix of operators:** fields have been increasingly operated by a mix of companies, far more interdependent than before, operating assets that could be more than 30 years old (and in some cases exceeding their originally intended design life);
- ▶ **Declining investment:** UK oil and gas industry anticipated that UKCS investment would halve from the record high of £14 billion in 2013 in the remainder of the decade unless new developments were matured;
- ▶ **Declining exploration activity:** In 2012 and 2013, there was a sharp fall in exploration activity meaning that less than 150 million had been discovered. The discoveries that were made were generally smaller than in the past and more expensive to exploit. This contrasted with 1.4 billion barrels of oil equivalent (boe) being discovered in the previous decade (between 2005 and 2008); and
- ▶ **Declining efficiency:** Production efficiency has fallen from 80% in 2002 to 70% in 2010 and 60% in 2012.



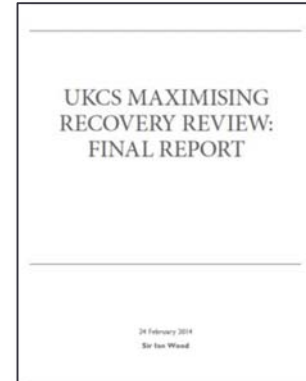
4.2.2 The combination of these factors led to a fall in production of 38 per cent between 2010 and 2013. This was a substantial increase in the rate of decline which had been around 7% per annum since a production peak of 4.6 million barrels of oil equivalent per day (boepd).

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4.2.3 This meant that the UK produced approximately 500 million boe less in the 3 year period. An estimated 360 million boe of this decrease was due to a substantial reduction in production efficiencies. Despite this, the Wood Review estimated that there *'could be a further 12 to 24 billion boe that could be produced, with ultimate recovery in a large part dependent on how well the UK manages the overall development of the remaining resources'*.

4.2.4 Following evidence gathering and the completion of an interim report, the Wood Review published its final report on the 24th February 2014.<sup>60</sup> The Wood Review identified the reasons behind the market trends:

- ▶ The lack of focus on maximising economic recovery in the UK;
- ▶ The lack of fiscal policy stability consistent with the challenges in UKCS maturity;
- ▶ The need to change the government stewardship model to one that reflects the changes in the UKCS and the complexity of business and operating models;
- ▶ The decreasing quality of asset stewardship which needs to be arrested to address the rapid fall in production efficiency. Under investment in assets and the insufficient uptake of IOR and EOR was identified as an important contributory factor;
- ▶ The lack of collaboration and cooperation between operators, increasing costs, delays and poorer recovery rates; and
- ▶ The inadequate implementation of existing strategies such as exploration, infrastructure and decommissioning leading to sub-optimal outcomes.



4.2.5 It made four key recommendations to maximise economic recovery from the UKCS:

- i. 'Government and industry to develop and commit to a new strategy for Maximising Economic Recovery from the UKCS (MER UK).'**
  - ▶ *A new Regulator should be established and, in conjunction with HM Treasury and Industry should develop an over-arching Strategy for delivering MER UK, adopting a cohesive tripartite approach.*
- ii. Create a new arm's length body charged with effective stewardship and regulation of UKCS hydrocarbon recovery and maximising collaboration across the Industry.**
  - ▶ *DECC should create a new independent body, responsible for operational regulation of the UKCS, focused on supervising the licensing process and maximising economic recovery of the UK's oil and gas reserves in the short, medium and long terms.*
- iii. The new body should take additional powers to facilitate implementation of MER UK.**
  - ▶ *To underpin delivery of the new MER UK strategy, Government should fully utilise its existing powers and take a series of additional powers and sanctions, for example establishing a clear system of (private) informal and (public) formal warnings which could ultimately lead to the loss of operatorship and then licence.*
- iv. Develop and implement important Sector Strategies.**
  - ▶ *The new body should work with Industry to develop and implement the six sector strategies outlined in the Wood Review (covering exploration, asset stewardship, regional development, infrastructure, technology and decommissioning), along with suggested actions.'*

<sup>60</sup> Wood, I et al (2014) *UKCS Maximising Economic Recovery: Final Report*

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- 4.2.6 The report concluded that full and rapid implementation of the recommendations could deliver 3-4 billion barrels of oil equivalent more than would otherwise be recovered over the next 20 years, worth over £200bn.

**The Government's Response**

- 4.2.7 In July 2014, the Government published its response<sup>61</sup> to the Wood Review. It accepted all of the Review's recommendations and provided further detail on its commitment to fully implement them. Specifically:
- ▶ It committed to establishing a new Maximising Economic Recovery Strategy based on a tripartite approach from industry, a new regulator and HM Treasury;
  - ▶ It committed to establishing a new arms-length regulator, the Oil and Gas Authority (OGA). Amongst its duties, the OGA will be responsible for maximising the economic recovery of oil and gas from onshore and offshore, including the UKCS;
  - ▶ It committed to ensuring that the OGA has the range of additional regulatory powers to give effect to the Maximising Economic Recovery Strategy; and
  - ▶ It committed the OGA to develop the new sector strategies (covering exploration, asset stewardship, regional development, infrastructure, technology and decommissioning). The Technology Strategy included reference to IOR and EOR.
- 4.2.8 Section 36 of the Infrastructure Act 2015, enacted on the 12<sup>th</sup> February 2015, placed a duty of the Secretary of State to produce one or more strategies for enabling the principal objective of "maximising the economic recovery of UK petroleum to be met".
- 4.2.9 Subsequently on the 1<sup>st</sup> April 2015, the OGA was established as an Executive Agency. It is the Government's view however that an executive agency is not the best long-term structure for the OGA, arguing that it would be better established as a government company which will '*give the Authority greater operational independence from Government*'<sup>62</sup>. In addition to its MER responsibilities, the OGA's duties include the licensing, exploration and development functions work previously undertaken by DECC.

**The MER Strategy**

- 4.2.10 On 28<sup>th</sup> January 2016, the first MER UK Strategy<sup>63</sup> was published jointly by DECC and the OGA. It provides the OGA with additional powers to maximise economic recovery of oil and gas from beneath UK waters, including the ability to issue enforcement notices and financial penalties, and to revoke licences for clear or persistent breaches of the MER UK Strategy. The MER UK Strategy is a legal document containing obligations with which those bound by it will be required to comply. These include: the OGA, petroleum licence holders, operators appointed under those licences, the owners of upstream petroleum infrastructure, and those planning and carrying out the commissioning of upstream petroleum infrastructure.
- 4.2.11 The MER UK Strategy sets out a 'Central Obligation' reflecting the legislation to ensure that:



*'Relevant persons must, in the exercise of their relevant functions, take the steps necessary to secure that the maximum value of economically recoverable petroleum is recovered from the strata beneath relevant UK waters.'*

<sup>61</sup> DECC (2014) *Government Response to Sir Ian Wood's UKCS: Maximising Economic Recovery Review*, July 2014

<sup>62</sup> DECC and OGA (2015) *Oil and Gas Authority Framework Document*, 1 April 2015, p 2.

<sup>63</sup> DECC and OGA (2016) *The Maximising Economic Recovery Strategy for the UK*, March 2016

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- 4.2.12 The MER UK strategy also establishes a series of legal and financial safeguards to ensure that the strategy implementation does not lead to any party breaking the law, investing in activities that do not make a satisfactory return, delay investment or lead to a loss of confidence of investors in oil and gas exploration and production projects in relevant UK waters. Specifically it states:
- '2. No obligation imposed by or under this Strategy permits or requires any conduct which would otherwise be prohibited by or under:*
- a. any legislation, including legislation relating to competition law, health, safety or environmental protection; or*
- b. the common law, including the OGA's duty to act reasonably.*
- 3. No obligation imposed by or under this Strategy requires any person to make an investment or fund activity (including existing activities) where they will not make a satisfactory expected commercial return on that investment or activity.....*
- 4.2.13 Items 4 and 5 concerning the safeguards to compensate for loss and to ensure contributions to invest in infrastructure or to fund activity wholly or partly for the benefit of another relevant person or persons are *'fair and reasonable'*.
- 4.2.14 A final safeguard sets out the importance of benefits outweighing costs when considering obligations arising from the Strategy:
- 6. No obligation imposed by or under this Strategy requires any conduct (including investment or funding activity) where the benefits to the UK deriving from that conduct are outweighed by the damage to the confidence of investors in oil and gas exploration and production projects in relevant UK waters.'*
- 4.2.15 The Strategy also sets out Supporting Obligations and Required Actions and Behaviours, which are binding (like the Central Obligation). The Supporting Obligations cover exploration, development, asset stewardship, technology and decommissioning.
- 4.2.16 There are a number of the Supporting Obligations that could be considered of relevance to EOR and IOR (namely):
- ▶ Under Asset Stewardship: Owners and operators of infrastructure must ensure that it is operated in a way that facilitates the recovery of the maximum value of economically recoverable petroleum from (as applicable); and
  - ▶ Under Technology: Relevant persons must ensure that technologies, including new and emerging technologies, are deployed to their optimum effect, in maximising the value of economically recoverable petroleum that can be recovered from relevant UK waters.
- 4.2.17 The MER UK Strategy also provided for the OGA to *'produce a plan or plans which set out its view of how any of the obligations in this Strategy may be met'*.
- 4.2.18 In March 2016, the OGA produced a Corporate Plan, covering the five year period from 2016 to 2021. This describes the OGA's priorities and plans, the development of the sector strategies and provisional targets. Improving asset stewardship is identified as an OGA priority within the Corporate Plan, reflecting the MER UK Supporting Obligations. Under this priority, the OGA has a target for EOR of 250 million barrels of oil equivalent (mmbœ). The Corporate Plan also commits the OGA to:
- ▶ Developing and issuing an EOR strategy to industry by the end of June 2016; and
  - ▶ Delivering a strategy to facilitate recovery of up to 250 mmbœ of additional reserves through polymer, low salinity water-flood activity and other secondary recovery opportunities.

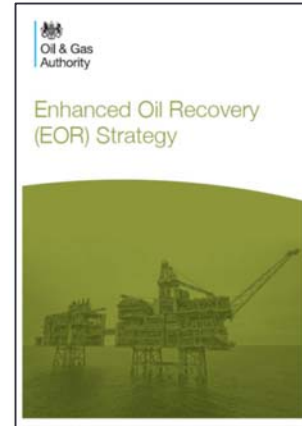
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## 4.3 UK EOR Strategy

4.3.1 In response to the OGA Corporate Plan requirements and the MER UK Strategy commitments, the OGA published its EOR Strategy<sup>64</sup> on 22<sup>nd</sup> July 2016.

4.3.2 The aim of the EOR Strategy is to help deliver EOR projects in the UKCS and this strategy supports both the MER UK Strategy and the OGA Corporate Plan. Its priorities are:

- ▶ Driving economic development of 250 mmboe incremental reserves primarily through polymer EOR over the next decade<sup>65</sup>;
- ▶ Supporting existing EOR projects to ensure readiness for future projects; and
- ▶ Demonstrating a proven offshore operation of low salinity EOR and progressing further opportunities by encouraging evaluations for all new projects.



4.3.3 The EOR Strategy identifies some of the principal barriers to implementing EOR projects as:

- ▶ Incomplete subsurface understanding (e.g. pore scale and sweep);
- ▶ Supply of secure, low-cost injectant, in particular for miscible gas EOR;
- ▶ Cost of building EOR facilities or redevelopment of existing brownfield assets; and
- ▶ Concerns over EOR economics.

4.3.4 Drawing on the work of the PILOT EOR Work Group (see **Section 4.6**), the OGA consulted with a number of UKCS operators and concluded that there is significant EOR potential. An estimate, validated by operators, was that the theoretical maximum (un-risked) total EOR potential of the UKCS is approximately 6,000 million stock tank barrels (mmstb) of oil. This assumed that the optimal EOR project will be carried out on each field where it is applicable. The economic (or risked) EOR potential was determined based on the application of BP global experience (both onshore and offshore), considering pore scale, sweep, drainage and cut off. The economic (or risked) EOR potential is estimated at between 10% to 20% of the maximum (un-risked) amount (so in the range 600 to 1,200 mmboe).

4.3.5 Whilst there are a number of EOR techniques available, the EOR Strategy seeks to prioritise three based on their potential and a view on their suitability and applicability in the UK offshore environment. These are:

- ▶ Chemical EOR (polymer and surfactant);
- ▶ Low salinity water flooding; and
- ▶ Miscible gas injection (either hydrocarbon or CO<sub>2</sub>).

4.3.6 The EOR Strategy commits the OGA to supporting the take up of EOR by:

- ▶ Working with operators and supply chain to support existing polymer EOR projects and ensuring readiness for future projects;
- ▶ Demonstrating a proven offshore operation of low salinity EOR by 2021 and encouraging evaluations for all new projects; and

<sup>64</sup> OGA (2016) *Enhanced Oil Recovery (EOR) Strategy*

<sup>65</sup> The target of 250 mboe in the EOR strategy was a judgement by the OGA on the recovery potential of those EOR projects likely to proceed within the Strategy timeframe. Whilst pragmatic, it should not be viewed as unduly limiting and there remains the potential for a wider ambition for RF across the UKCS (reflecting the PILOT EOR Work Group Report that 'Increasing the deployment of EOR in the North Sea will help achieve the overall goal of increasing average recovery factors in the UKCS to over 50%').

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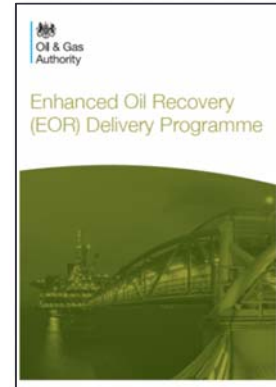
- ▶ Advancing the next tranche of EOR technologies and developing a framework for their economic implementation.

4.3.7 The EOR Strategy also commits the OGA to complete a delivery programme which will be reviewed and updated as appropriate.

## 4.4 UK EOR Delivery Programme

4.4.1 The OGA published its EOR Delivery Programme in December 2016<sup>66</sup>. It provides in more detail how and when the near-term priorities in the EOR Strategy will be delivered. It identifies eight EOR Delivery Programme areas, aligned to the obligations in the MER UK Strategy and the principles and expectations outlined in the Asset Stewardship Strategy:

- ▶ **Existing EOR Projects** – actions to ensure current polymer and low salinity EOR projects are progressed in line with their Field Development Plans (FDPs), for example through support to identified EOR pilots;
- ▶ **MER for future EOR projects** – actions to ensure EOR opportunities are identified early enough in field life cycle to maximise economic recovery, for example through early EOR screening for regulatory approval in draft FDPs;
- ▶ **Workgroups and industry partnerships** – actions to ensure that EOR technology and implementation lessons are shared, for example through the development of EOR technology specific workgroups;
- ▶ **Technology development and deployment** – actions to ensure that EOR technologies are developed and deployed, for example through developing and trialling new polymer chemical systems to improve polymer injectivity;
- ▶ **Creating value – improving economics** – actions to ensure the economics of marginal EOR projects do not stifle investment, for example through detailed EOR economic evaluations for current projects including all cost assumptions and predicted incremental recovery profiles used;
- ▶ **Advance next EOR and support CO<sub>2</sub> storage** – actions to ensure that, while prioritising polymer and low salinity EOR, other EOR technologies are not missed, for example through developing and use of low cost microbial EOR;
- ▶ **Knowledge management** – actions to improve EOR awareness and knowledge transfer, for example through creating and managing an OGA EOR library for EOR technologies; and
- ▶ **Communication and stakeholder plans** – actions to ensure investment in EOR projects is not limited by lack of senior industry leadership buy-in to the deployment of EOR technology, for example by developing and implementing a clear stakeholder plan.



4.4.2 For each programme area, the following information is provided in the Delivery Programme:

- ▶ Objective;
- ▶ Inputs;
- ▶ Activities;
- ▶ Responsibilities; and

<sup>66</sup> OGA (2016) Enhanced Oil Recovery (EOR) Delivery Programme, December 2016

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## ▶ Deliverables.

4.4.3 The activities in the EOR Delivery Programme will be monitored by a joint industry/OGA task group and reviewed annually by the MER UK Asset Stewardship Board and updated as necessary.

4.4.4 The actions under the objectives for existing and future EOR projects highlight the importance of FDPs to increase EOR use. Guidance<sup>67</sup> has been provided to operators on what to include in the FDP with regard to EOR (our underlining):

*'The approach taken by the Department is to ensure that, at the planning stage, the Licensees have examined those options which are most likely to secure the full recovery of the economic reserves of the area. In most cases the preferred commercial option will achieve this but....cases can arise where wider UK interests and commercial interests differ. In such circumstances the Department will, in discussion with the operator, wish to obtain a full appreciation of the commercial factors and constraints involved, and explain why it believes wider UK interests are not being served by a particular option.'*

*In examining Field Development Plans for new fields, and significant departures proposed from authorised Plans for existing fields, the Department will in particular wish to be satisfied that the approach agreed does not lead to the permanent loss of reserves which could otherwise be recovered economically. In looking at the wider picture, the Department focuses on those options which are most likely to secure maximum economic recovery of hydrocarbon reserves from the reservoir in question, taking into account other potential reserves in the area.'*

4.4.5 The OGA will now also ensure that in preparation of FDPs, the appropriate level of EOR modelling and screening has been completed and future EOR forecasts (production/capital expenditure/operating expenditure) are presented.

## 4.5 Tax and Financial Incentives

4.5.1 The Oil Taxation Act 1975 and the Corporation Tax Act (CTA) 2010 provide the basis for most of the taxation which applies to companies extracting oil and gas from the UK and the UKCS. The differing taxes are:

- ▶ **Ring Fence Corporation Tax (RFCT)** on the profits arising from 'oil extraction' or the 'acquisition, enjoyment or exploitation of oil rights' in the UK or UKCS. RFCT is calculated in the same way as Corporation Tax, but with the addition of a 'ring fence' that treats these activities as a separate trade. The ring fence prevents taxable profits from oil and gas extraction being reduced by losses from other activities or by excessive interest payments;
- ▶ The **Supplementary Charge (SCT)** is also charged on the same basis as RFCT;
- ▶ **Petroleum Revenue Tax (PRT)** is a field based tax, deductible as an expense against RFCT and SCT; and
- ▶ **Value Added Tax.**

4.5.2 The Finance Act 2016 has amended section 1 of the Oil Taxation Act 1975 to reduce the rate of PRT from 50% to 0%, to amend section 330 of CTA 2010 to reduce the rate of the supplementary charge from 30% to 10%, and to enable HMRC to amend the cluster area and investment allowance by secondary legislation to extend the definition of 'relevant income' and to make any amendments in consequence of, or in connection with, this extension.

4.5.3 These changes reflected the conclusions of a 2014 HM Treasury review<sup>68</sup> of the oil and gas fiscal regime. The review recognised that the government would need to reduce the overall tax burden on the industry over time to maximise economic recovery. The review concluded that the government should keep the rate of PRT under review and consider reducing the rate when fiscal conditions allow, to level the playing-field between investment opportunities in fields which are

<sup>67</sup> BEIS (2013) *Guidance on the Content of Offshore Oil and Gas Field Development Plans*, Appendix 3 Maximising Economic Recovery

<sup>68</sup> HM Treasury (2014) *Driving investment: a plan to reform the oil and gas fiscal regime*, December 2014

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- subject to PRT and opportunities in other fields and ensure key assets attract the right level of investment. A reduction in the rate of PRT from 50% to 35% was announced at Budget 2015 and further reduced in the Finance Act 2016.
- 4.5.4 In 2009, the UK Government introduced field allowances, as an incentive for the development of commercially marginal oil and gas fields. The field allowance reduces the amount of adjusted ring fence profits on which the SCT is charged. A qualifying field is one whose development consent is granted after 22<sup>nd</sup> April 2009, categorised as follows (the gross amount of the field allowance is in brackets):
- ▶ Small field (£150m);
  - ▶ Ultra-heavy oil field (£800m);
  - ▶ Ultra high pressure/high temperature field (£800m);
  - ▶ Deep water gas field (£800m);
  - ▶ Extra deep water field (up to £3bn); and
  - ▶ Shallow water gas field (£500m).
- 4.5.5 The Finance Act 2012 substantially expanded the application of field allowances through the introduction of a Brown Field Allowance (BFA). The BFA applies to the development of new, previously un-accessed, reserves in an existing field and has a maximum allowance of £250m (or £500m in a PRT paying field). It is through the BFA that UK government seeks to support the take up of EOR and IOR projects.
- 4.5.6 The 2015 Budget also announced the introduction of the cluster area and investment allowance. However, legislation to date has not covered tariff income, owing to the complexities of identifying and apportioning capital expenditure between infrastructure owners and users, and insufficient transparency around the commercial arrangements in place.
- 4.5.7 The University of Aberdeen completed an analysis<sup>69</sup> of the prospective returns to investments for a number of EOR projects operating in the UKCS in 2015. The analysis indicated that any returns were *'likely to be quite modest... Total costs per barrel are relatively high, the production profiles typically exhibit modest annual volumes over a very long period of time'*. The research proposed, for the purpose of an investment allowance, to expand the definition of capital expenditure to include purchase costs of EOR inputs such as polymers and gas. The accompanying illustrative modelling demonstrated that whilst the extra incentives were modest, they could provide a worthwhile stimulus. The research noted a possible correlation in the USA where EOR schemes are common with the presence of special tax credits for the Federal income tax in conjunction with tax incentives at state level.
- 4.5.8 The restriction of the eligibility of the investment allowance to the conventional definition of capital expenditure means that the incentives to invest in polymer flood and miscible gas schemes are significantly reduced. If the objective of the allowance is to incentivize the EOR activity it is arguable that it should be available for the purchase costs of the polymers and gas.
- 4.5.9 The OGA have commented on the current taxation and incentive regime that:
- ▶ Overall tax burden will need to fall as the basin matures in line with MER UK;
  - ▶ The UK Government will need to consider wider economic benefits of oil and gas production; and
  - ▶ The UK Government will need to take account of the global competitiveness of the UKCS.

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<sup>69</sup> Kemp, A and Stephen, L (2015), The Economics of EOR Schemes in the UK Continental Shelf (UKCS), SPE-175470-MS



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## 4.6 PILOT EOR

- 4.6.1 PILOT (formerly the Oil and Gas Taskforce) is a partnership between the UK oil and gas industry, and government. PILOT seeks to foster cooperation between partners to deliver quicker, smarter and sustainable energy solutions to secure the long-term future of the UKCS and ensure full economic recovery of our hydrocarbon resources.
- 4.6.2 The aim of PILOT has been to:
- ▶ Focus on delivery of actions that will improve the competitiveness of the UK oil and gas industry;
  - ▶ Deliver the PILOT 2010 vision, which will contribute to the longer term security of energy supply; and
  - ▶ Promote continued dialogue between government and industry.
- 4.6.3 Following a focus on efforts to increase North Sea recovery, a PILOT EOR Work Group was established in 2012.

### PILOT EOR Work Group

- 4.6.4 The PILOT EOR Work Group was set up to co-ordinate industry and government attempts to tackle the principal barriers to implementing EOR projects: incomplete subsurface understanding; supply of secure, low cost injectants; retrospective brownfield implementation of EOR; and project economics. It sought to address the challenge that “*we take more oil out of the North Sea than we leave behind*”.<sup>70</sup>
- 4.6.5 The Work Group was made up of:
- ▶ A Senior Industry Sponsor: BP’s North Sea Regional President;
  - ▶ A core technical working group comprising of staff from DECC, Oil & Gas UK (the representative body for the UK’s offshore oil and gas industry) and BP; and
  - ▶ Participants from a number of operators in the UK North Sea who are actively looking for EOR opportunities within their portfolios.
- 4.6.6 The objective of the PILOT EOR Work Group was to ‘*provide a clear view of the EOR prize in the UKCS, to identify candidate EOR projects, and to begin to scope potential development solutions including identifying collaboration opportunities between field groups*’. A three phase programme was developed to:
- ▶ Systematically screen all UKCS fields for EOR potential;
  - ▶ Engage industry and look for synergies by geography/geology/EOR type and collaborative opportunities to progress EOR understanding, and
  - ▶ Where possible, initiate EOR projects with operators and/or suppliers.

### Screening

- 4.6.7 The remaining EOR potential in the North Sea was mapped on a field-by-field basis using a spreadsheet based EOR screening tool (SENEOR). For each field with reserves >20 million barrels, the tool was used to map the application of differing EOR technologies against the following ten screening criteria (derived from work by the Department of Petroleum and Geosystems Engineering at the University of Texas in Austin):
- ▶ Depth;

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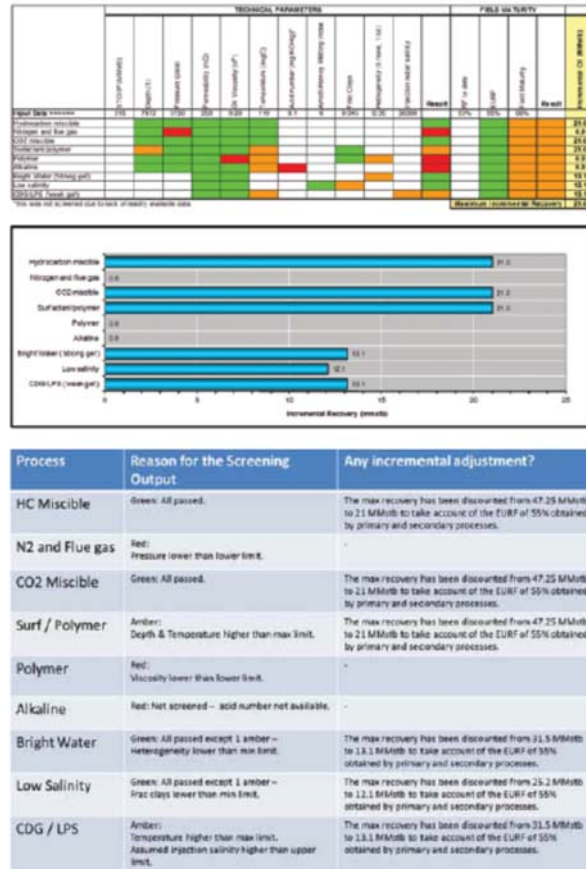
<sup>70</sup> PILOT and DECC (2014), *PILOT EOR Work Group Report summarising 2012 - 2013 Activities*, April 2014

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- ▶ Pressure;
- ▶ Permeability;
- ▶ Oil viscosity;
- ▶ Temperature;
- ▶ Acid number;
- ▶ Wettability;
- ▶ Fraction of clays;
- ▶ Heterogeneity factor; and
- ▶ Injection water salinity.

4.6.8 The presentation of the outputs of the screening were based on a “traffic light” system. The value of each parameter was scored red, amber or green for each process in the particular reservoir (reflecting a subjective judgement). The scores for the individual parameters were then aggregated to give an overall red, amber or green score for each process in the particular reservoir. An example output from SENEOR for a field is presented in **Figure 4.1**.

Figure 4.1 Example SENEOR field output



4.6.9 Over 100 North Sea fields were screened as part of this exercise. The outputs from SENEOR were checked with the respective operators and their comments addressed as part of the finalisation of the screening.

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- 4.6.10 As a result of this screening exercise, the UK validated the estimate of EOR potential on a UKCS wide basis, demonstrating that the overall theoretical EOR potential is estimated to be approximately 6 billion barrels of oil (see **Table 4.1**). Note: the EOR potential figures shown in **Table 4.1** are not additive, as different EOR techniques can be considered as viable options for the same reservoir.

Table 4.1 UKCS estimated EOR potential

EOR Process	Estimated EOR Potential (mmstb)
Miscible hydrocarbon flood	5,400
Miscible CO2 injection	5,700
Surfactant/Polymer (Chemical EOR)	4,800
Polymer	2,100
Low Salinity Waterflood	2,000

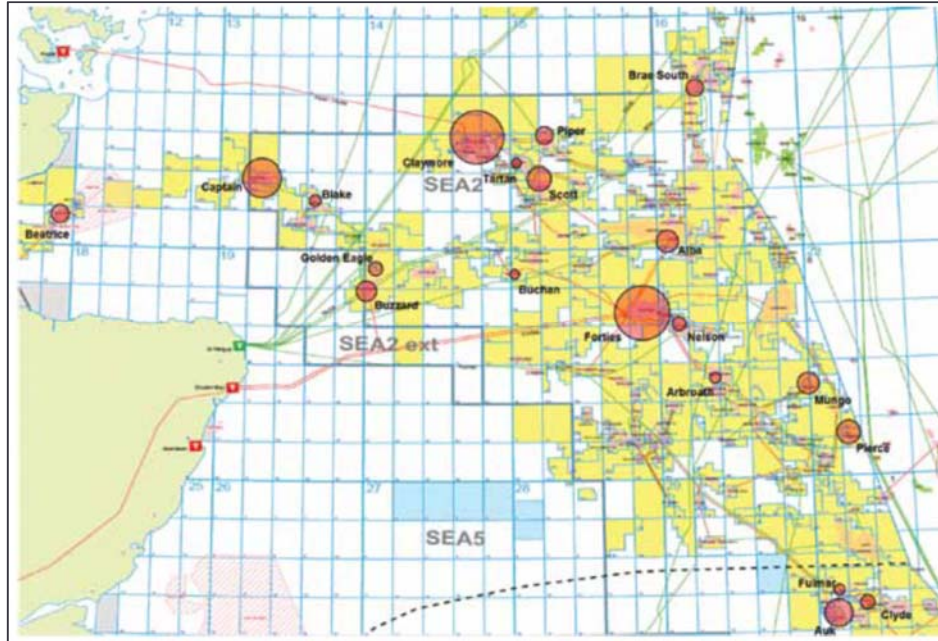
- 4.6.11 The individual field EOR estimates and the "grand totals" for each EOR technique for the North Sea, are the basis for the theoretical maximum (unrisked) EOR potential, quoted in the final Wood Review and subsequently, the OGA EOR Strategy. Based on experience and following consideration of a range of recovery factors such as pore scale, sweep, drainage and cut off, the PILOT Work Group stated that 'one fifth of the theoretical maximum is probably more realistic'. In consequence, the economic (or risked) EOR potential was estimated to be between 10% and 20% of the maximum (un-risked) amount (so in the range 600 to 1,200 mmbob).

#### Identifying Opportunities for EOR Technologies

- 4.6.12 The individual field EOR estimates were used to focus more detailed discussions between the lead Department and the respective field operators about EOR scope.
- 4.6.13 Maps were also developed for all the fields screened showing the distribution of EOR potential in the central North Sea (**Figure 4.2**).

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Figure 4.2 Distribution of EOR potential (the diameter of each circle is proportional to EOR potential)



4.6.14 The 'bubble-maps' were used to identify "EOR clusters" of nearby fields where there was scope for cooperation between operators to potentially reduce project development costs. Examples of this could include sharing of offshore facilities between more than one EOR project, or by agreement to share data from laboratory testing of EOR potential. The clusters whilst a logical approach to take advantage of synergies and proximity was not subsequently included in the UK EOR strategy. This reflected 2 factors:

- ▶ Fall in oil price and need to focus on EOR technologies that were low cost; and
- ▶ Outcomes of Low Salinity research and the less favourable returns (due to presence of clays affecting sweep); however there were also issues in terms of the evaluation of the opportunity.

4.6.15 The results of the EOR screening process identified three EOR processes that had good potential, in particular if a cooperative approach to EOR development in the North Sea was undertaken:

- ▶ Low Salinity Waterflood;
- ▶ Chemical EOR (polymer & surfactant flooding); and
- ▶ Miscible Gas Injection (both hydrocarbon gas and carbon dioxide).

4.6.16 There were good North Sea exemplars of existing or planned EOR projects for all three technologies (low salinity EOR – Clair Ridge; polymer EOR – Captain; miscible gas – Magnus) which provided confidence that further successful projects could be delivered.

4.6.17 Industry workshops were held on each of these technologies and actions taken to resolve specific challenges. For example, for Low Salinity Waterflood EOR, there was a lack of readily available information on how to best design a low salinity coreflood screening test, which was resolved through the provision of expert workshop who developed a protocol.

#### Initiate Actions for Implementation of EOR Technology

4.6.18 The PILOT Work Group led the development of distinct work programmes for Low Salinity Waterflood EOR, Chemical EOR and Miscible Gas Injection to promote increased cooperation between operators in looking for viable EOR projects.

**FINAL****In Conclusion**

- 4.6.19 At the end of the 2013-14 year, the proposed approach outlined in the 2014 PILOT report was overtaken by the fall in oil price, and as such, the programme identified was replaced with the more targeted agenda outlined by the Wood Review. However, both the Wood Review and the EOR Strategy have made use of the PILOT work and it is considered an essential pre-requisite to have the evidence in place to inform the direction of the Strategy.

**4.7 Summary**

- 4.7.1 Given the recent adoption of the MER UK Strategy and the OGA EOR Strategy, it would be premature to conclude on the extent to which the Strategies have influenced operators EOR activities. Indeed EOR and IOR have been used in the North Sea since the early 1970s, and so the presence of any Strategy is clearly not a pre-requisite to such activity taking place. However, the operating environment in the North Sea has changed, affecting asset management, investment and views on commercial risk which in turn has affected exploration and production. The UK Government's recent policy and regulatory work has built on an intentionally collaborative approach, fostered through the PILOT programme, aiming to address such issues and deliver EOR projects that will contribute to maximising economic recovery, whilst providing a framework for supported innovation. So whilst an EOR Strategy was not necessary in the past, given the changes and the maturity of oil and gas fields, its presence, the manner of its development and its widespread ownership should ensure that it has a lasting effect.

## 5. European Policy and Regulatory Framework for EOR and IOR

This chapter outlines the approach taken by other countries in Europe towards a policy and regulatory framework for EOR and IOR.

### 5.1 Overview

- 5.1.1 In the sections below, the policy and regulatory frameworks are described at the EU level, regional level (marine Conventions) and at the level of individual countries (i.e. Norway, Denmark and The Netherlands).
- 5.1.2 Whilst there are no unifying policies on EOR or IOR in the EU, EOR and IOR techniques are covered both directly and indirectly through several Directives and regulations, in particular in relation to the emerging legal framework for Carbon Capture and Storage (CCS) for greenhouse gas abatement purposes. Whilst the purpose of the CCS Directive is to support the safe, secure and sustainable sequestration of carbon dioxide, it also covers aspects that are relevant to CO<sub>2</sub> injection EOR when combined with the storage of CO<sub>2</sub> in depleted oil and gas fields.

### 5.2 Legislation and Regulation

- 5.2.1 In the table below, the main pieces of EU legislation and regulation that are relevant to EOR and IOR projects are described.

Table 5.1 Overview of EU legislation, regulation and guidance for EOR and IOR, in order of relevance

Legislation, regulation or guidance	Relevance to offshore EOR and IOR
Carbon Capture and Storage Directive (2009/31/EC)	<p>The Directive makes legal provisions for Carbon Capture and Storage (CCS). This involves the sequestration of gaseous CO<sub>2</sub> in geological formations. Preamble 20 to the EU CCS Directive states that Enhanced Hydrocarbon Recovery (EHR) is not in itself included in the scope of this Directive, but that the provisions of the Directive will apply where EHR is combined with geological storage of CO<sub>2</sub>:</p> <p><i>“Enhanced Hydrocarbon Recovery (EHR) refers to the recovery of hydrocarbons in addition to those extracted by water injection or other means. EHR is not in itself included in the scope of this Directive. However, where EHR is combined with geological storage of CO<sub>2</sub>, the provisions of this Directive for the environmentally safe storage of CO<sub>2</sub> should apply. In that case, the provisions of this Directive concerning leakage are not intended to apply to quantities of CO<sub>2</sub> released from surface installations which do not exceed what is necessary in the normal process of extraction of hydrocarbons, and which do not compromise the security of the geological storage or adversely affect the surrounding environment. Such releases are covered by the inclusion of storage sites in Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community which requires surrender of emissions trading allowances for any leaked emissions.”</i></p> <p>There are several guidance documents available that support the implementation of the CCS Directive<sup>71</sup>.</p>
Emissions Trading Scheme Directive (2003/87/EC)	CO <sub>2</sub> capture, transport and storage operations are covered by the EU Emissions Trading Scheme. EOR operations cannot secure the benefits of the Emissions Trading Scheme.

<sup>71</sup> [https://ec.europa.eu/clima/policies/lowcarbon/ccs/implementation\\_en](https://ec.europa.eu/clima/policies/lowcarbon/ccs/implementation_en)

Legislation, regulation or guidance	Relevance to offshore EOR and IOR
Recommendation (2014/70/EU) outlining the minimum principles that should be adhered to when using hydraulic fracturing	However, vented and fugitive emissions from EOR operations are covered by the Directive, which requires surrender of allowances for leaked emissions.  This complements existing legislation which covers oil and gas production by making provisions specifically for hydraulic fracturing (HF). In 2016 the effectiveness of this recommendation was reviewed <sup>72</sup> . In the review, it was mentioned that there has been an increase in the usage of enhanced recovery techniques across Europe <sup>73</sup> . The Commission concluded that similar risk management measures that should be in place for such practices as for HF. Member States are required to report the measures that they have applied in response to the Recommendation on an annual basis.
Offshore Safety Directive (2013/30/EC)	The Directive harmonises and enhances EU Member States regulatory frameworks for safety in offshore oil and gas production. It stipulates safety requirements that oil and gas operators must achieve, including reporting and risk assessments (overseen by Member State Competent Authorities (MSCAs)), but does not instruct operators on how to achieve these requirements. It covers safety practices related to all offshore oil and gas techniques, including EOR and IOR (but it does not explicitly mention IOR or EOR).
Best Available Technology (BAT) guidance document on upstream hydrocarbon exploration and production <sup>74</sup>	The Commission is currently in the early stages of developing a guidance document which describes the best environmental technologies that should be applied for each process in onshore and offshore oil and gas production, including enhanced recovery. The main driver behind the guidance document is to improve protection of the environment. The identification of best practice in the document should serve as guidance for operators and competent authorities to draw upon when planning changes and investments as well as permitting activities across the EU. The guidance document will be a non-binding tool designed to assist operators and competent authorities with this objective in mind.
Environmental Impact Assessment Directive (2014/52/EU)	The EIA Directive requires public and private projects over a certain size to produce an environmental statement (ES) before the project begins, outlining the likely significant environmental effects associated with the project and measures that will be put in place to avoid, minimise, reduce, mitigate or compensate for such effects. An EIA is mandatory for all oil and gas projects exceeding 500t/day oil or 500,000m <sup>3</sup> /day gas. Below this threshold, it is the responsibility of the Member State to screen the project and determine whether the project is likely to have a significant effects on the environment necessitating whether an EIA is to be required. In an ES, any likely significant effects related to the use of EOR or IOR must be considered. There are also specific guidance documents for conducting EIAs for unconventional oil and gas projects <sup>75</sup> .
Environmental Liability Directive (2004/35/EC)	The ELD applies the 'polluter pays principle' to prevent and remediate environmental damage. It covers damage to water and species or natural habitats that occurs within each Member States Exclusive Economic Zone (EEZ), which extends up to 200miles offshore. This therefore covers damages incurred from any emissions to water during application of EOR or IOR offshore in an EU Member State.
Waste Framework Directive (2008/98/EC)	The WFD places a mandatory responsibility on oil and gas operators to treat and dispose of their waste appropriately. This includes any wastes produced through EOR or IOR.
Regulation (1907/2006) concerning the Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH)	REACH requires manufacturers and importers of chemicals to evaluate the risk arising from the use of chemicals and to manage such risks. Key elements of REACH include registration requirements, whereby it is compulsory to register the manufacture or import of chemicals in quantities of one tonne or more per annum. Substances of extremely high concern are also subject to authorisation. A procedure of restriction is put in place by REACH, setting out restrictions relating to the use of a substance or an outright ban. The use of some chemicals for EOR and IOR may therefore be restricted or prohibited by REACH.

<sup>72</sup> [http://ec.europa.eu/environment/integration/energy/pdf/Report\\_com\\_2016\\_794.pdf](http://ec.europa.eu/environment/integration/energy/pdf/Report_com_2016_794.pdf)

<sup>73</sup> 11 Member States (MS) confirming they had granted authorisation for plans involving the use of enhanced recovery techniques

<sup>74</sup> [http://ec.europa.eu/environment/integration/energy/hc\\_bref\\_en.htm](http://ec.europa.eu/environment/integration/energy/hc_bref_en.htm)

<sup>75</sup> [http://ec.europa.eu/environment/integration/energy/pdf/guidance\\_note.pdf](http://ec.europa.eu/environment/integration/energy/pdf/guidance_note.pdf)

**FINAL****Research and funding**

- 5.2.2 Below is an overview of the main EU research and funding initiatives for EOR and IOR techniques (including CCS), in chronological order:
- ▶ Between 1985 and 2001 the European Commission initiated a variety of European R&D projects on IOR technologies such as foam assisted WAG, polymer flooding and steam injection<sup>76</sup>. These were funded through programmes targeting energy innovation and a reduction in reliance on imported oil and gas;
  - ▶ In 2006 the JRC published a study exploring the potential of EOR using CO<sub>2</sub> in Europe<sup>77</sup> and in the North Sea<sup>78</sup>. This concluded that CO<sub>2</sub> EOR could be viable for several European oil fields, particularly when optimised for CO<sub>2</sub> sequestration with a reasonable price for carbon in place;
  - ▶ In 2008, the EU agreed to set aside 300 million Emission Unit Allowances from the New Entrant Reserve (NER) under the EU Emissions Trading Scheme (ETS) Directive to demonstrate CCS and innovative renewable energy technologies. In 2014 the White Rose CCS project in the UK was funded with EUR 300m through this scheme. However, funding for the project from the UK Government was withdrawn in 2015 as a consequence of the cancellation of the CCS competition capital fund and in 2016 development consent was refused by the UK Secretary of State. It is therefore unclear whether the project will ever be delivered;
  - ▶ In 2009 the Commission established the CCS Demonstration Project Network. It brings together industry and the public sector to accelerate the deployment of commercial scale CCS. This includes CCS-EOR; and
  - ▶ Between 2012 and 2016 the Commission commissioned several studies that investigated the risks and impacts of unconventional oil and gas production. The latest 2016 study also investigated the risks and impacts of enhanced recovery technologies<sup>79</sup>. These studies were used to establish whether existing oil and gas legislation was suitable for unconventional oil and gas extractions and the application of enhanced recovery technologies. The findings informed Recommendation 2014/70/EU.

**5.3 Regional level**

- 5.3.1 There are several Conventions related to offshore oil and gas extraction (including the application of EOR/IOR techniques) that apply to regions in Europe. The primary objective of all these Conventions is environmental protection. This is because marine pollution is the most significant trans-boundary issue faced by the offshore oil and gas industry. These regional Conventions described here (including how they relate to EOR/IOR) are the Convention for the Protection of the Marine Environment of the North-east Atlantic (OSPAR), the Helsinki Convention (HELCOM), the Barcelona Convention and the Bucharest Convention.

**OSPAR Convention**

- 5.3.2 A key legislative instrument in northern Europe is the 1992 Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR Convention). It is managed by the OSPAR Commission and represents 15 signatory nations. OSPAR provides decision making on goals and targets for pollution, emissions and other environmental impacts which are then subsequently included in national legislation. The EU is an OSPAR Contracting Party and therefore is involved in the sharing of guidance and other types of information between OSPAR and the other regional convention fora in Europe. The offshore industry has, over the years, taken a collaborative approach to working with OSPAR and to implementing environmental management as part of their

<sup>76</sup> [http://cordis.europa.eu/project/rcn/5075\\_en.html](http://cordis.europa.eu/project/rcn/5075_en.html)  
[http://cordis.europa.eu/result/rcn/20297\\_en.html](http://cordis.europa.eu/result/rcn/20297_en.html)  
[http://cordis.europa.eu/project/rcn/15442\\_en.html](http://cordis.europa.eu/project/rcn/15442_en.html)

<sup>77</sup> <http://publications.jrc.ec.europa.eu/repository/bitstream/JRC32102/P2005-277=EUR21895EN=PUBSY%20Request%202102.pdf>

<sup>78</sup> <http://www.co2.no/download.asp?DAFID=55&DAAID=4>

<sup>79</sup> [http://ec.europa.eu/environment/integration/energy/uff\\_studies\\_en.htm](http://ec.europa.eu/environment/integration/energy/uff_studies_en.htm)



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operations. In 2007 amendments to the Convention were adopted to allow the storage of CO<sub>2</sub> in geological formations under the seabed. This included the storage as part of EOR<sup>80</sup>.

**HELCOM**

- 5.3.3 HELCOM (Baltic Marine Environment Protection Commission - Helsinki Commission) is the governing body of the Convention on the Protection of the Marine Environment of the Baltic Sea Area, known as the Helsinki Convention<sup>81</sup>. HELCOM was established over forty years ago to protect the marine environment of the Baltic Sea from all sources of pollution through intergovernmental cooperation. This includes provisions for the environmental management of offshore oil and gas extractions. Its scope includes EOR and IOR activities, but it does not make any specific reference to them.

**Barcelona Convention**

- 5.3.4 The Barcelona Convention was adopted in 1976 to prevent and abate pollution in the Mediterranean Sea. There are 22 contracting parties<sup>82</sup>. The Barcelona Convention and its protocols, together with the Mediterranean Action Plan (MAP), form part of the United Nations Environment Programme (UNEP) Regional Seas Programme. The Convention covers all activities in the sea, including oil and gas extractions. Its scope includes EOR and IOR activities, but the Protocols do not make any specific reference to them.

**Bucharest Convention**

- 5.3.5 The Convention on the Protection of the Black Sea Against Pollution (Bucharest Convention) was signed in Bucharest in April 1992, and ratified by all six legislative assemblies of the Black Sea countries<sup>83</sup>. The objective of the Convention is to prevent, reduce and control the pollution in the Black Sea in order to protect and preserve the marine environment and to provide legal framework for co-operation and concerted actions to fulfil this obligation. The Convention does not make any specific reference to EOR and IOR activities.

**5.4 Country level**

- 5.4.1 This section provides an overview of domestic policy and regulation for EOR and IOR techniques for Norway and two EU Member States (MSs): The Netherlands and Denmark. The policy and regulatory framework in the UK is discussed in detail in **Section 3** and therefore it is not repeated here. Offshore production in these countries (including the UK) make up the vast majority of European offshore oil and gas production<sup>84</sup>. It is therefore considered that these countries have the most developed offshore policy and regulatory frameworks, beyond those enforced at an EU and regional level.

**Norway**

- 5.4.2 Norway has produced oil and gas since 1971. All hydrocarbon production is related to subsea deposits, and the oil and gas exploration and production activities primarily take place offshore on the Norwegian Continental Shelf (NCS).
- 5.4.3 A broad range of companies carry out oil and gas activities on the NCS. In the beginning, only a few major international oil companies operated on the shelf, but today there are more than 70 companies involved in exploration, production and infrastructure.

<sup>80</sup> [www.ospar.org/documents?d=7050](http://www.ospar.org/documents?d=7050)

<sup>81</sup> The Contracting Parties are Denmark, Estonia, the EU Finland, Germany, Latvia, Lithuania, Poland, Russia and Sweden.

<sup>82</sup> Albania, Algeria, Bosnia and Herzegovina, Croatia, Cyprus, Egypt, the European Community, France, Greece, Israel, Italy, Lebanon, Libya, Malta, Monaco, Montenegro, Morocco, Slovenia, Spain, Syria, Tunisia, Turkey

<sup>83</sup> <http://www.blacksea-commission.org/convention.asp>

<sup>84</sup> <http://euoag.jrc.ec.europa.eu/node/63>

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- 5.4.4 Since 1975, gas has been injected to increase recovery on the Norwegian shelf. On the NCS, the expected average recovery rate from oil fields is 46 per cent (comparable to the UKCS); however, for some fields (such as Statfjord) it is as high as 66%.
- 5.4.5 Two relevant instruments in relation to context of this note are the Petroleum Act and the Pollution Control Act. **The Petroleum Act** (Act No. 72 of 29 November 1996 relating to petroleum activities) provides the general legal basis for the petroleum activities on the NCS. Pursuant to the Petroleum Act and the Petroleum Regulations (Regulation No. 653 of 27 June 1997), production licences (exclusive rights for qualified oil companies to explore for and produce oil and gas in defined areas on the Norwegian Continental Shelf) are awarded under competition in dedicated licensing rounds. **The Pollution Control Act** (Act No. 6 of 13 March 1981 concerns environmental protection, waste management and reduction) gives the legal basis for environmental regulations and permits.
- 5.4.6 The Norwegian government works closely with industry and academia on research related to EOR and IOR. **The Norwegian Petroleum Directorate (NPD)** is a specialist government directorate and administrative body. The primary task of the NPD is to contribute to improved recovery from producing fields. It provides guidance on all aspects of oil and gas exploration and production, including guidelines<sup>85</sup> for a plan for development and operation of a petroleum deposit (PDO). These guidelines include reference to methods for improving recovery and require that 'a plan for potential studies of such methods should also be included' within the PDO.
- 5.4.7 The NPD funds and brings together research efforts from both academia and industry. This includes the joint Norwegian-Danish chalk research co-operation, known as the Joint Chalk Research (JCR). The JCR builds on research on the NCS from the early 1970s which marked the beginning of improved oil recovery (IOR) efforts to improve initial RFs of c20% in carbonate basins<sup>86</sup>. Established in 1980, the JCR brought together the Danish and Norwegian governments with multiple oil companies to share and collaborate on research focusing on the whole chalk basin at the southern end of the NCS. The program has been judged a success, and sharing information has proved to be inexpensive compared to research by an individual company. The current IOR research project (JCR-7) of the JCR centres around formations in the North Sea of very tight chalk, from which it is very difficult to recover oil<sup>87</sup>. The project utilises technical expertise of the participating oil companies, and in some of the sub-projects the JCR-group is cooperating with various universities.
- 5.4.8 Recently, the NPD has become interested in CO<sub>2</sub> EOR. Studies carried out by the NPD in 2012 and 2016 on fields in the North Sea, indicated a large potential for additional oil recovery through CO<sub>2</sub> injection, with an increase in recovery factor of between 5-12%<sup>88</sup>. Each year, the NPD awards a prize to the most innovative IOR project in the Norwegian Continental Shelf (NCS). The NPD has also been involved in establishing two important research groups on IOR that cut across industry and academia: the **IOR Centre at Stavanger University** and the **Forum for Reservoir Characterisation, Reservoir Engineering and Exploration Technology Cooperation (FORCE)**. Together, they are also responsible for overseeing the Norwegian national petroleum technology strategy (OG21).<sup>89</sup>
- 5.4.9 The IOR Centre at the University of Stavanger<sup>90</sup> was set up in partnership with the International Research Institute in Stavanger. It is funded by both the Norwegian government and industry. Its research includes both physical experimentation and modelling. The findings are used to assist the oil companies in performing field pilots. Important R&D areas include:
- ▶ Macroscopic reservoir sweep efficiency – Use of water diverting agents (polymers, gels, silicate) to improve macroscopic sweep efficiency and manage water production, use of foam to improve hydrocarbon gas- or CO<sub>2</sub> – injection performance;

<sup>85</sup>NPD (2010) Guidelines for plan for development and operation of a petroleum deposit (PDO) and plan for installation and operation of facilities for transport and utilisation of petroleum (PIO). February 2010.

<sup>86</sup><http://www.npd.no/en/Topics/Improved-Recovery/Temaartikler/Long-live-chalk/>

<sup>87</sup><http://jointchalkresearch.org/>

<sup>88</sup><http://www.npd.no/Global/Norsk/2-Tema/Lagring-og-bruk-av-CO2/GHGT13-paper.pdf>

<sup>89</sup>[http://www.og21.no/prognostikk-og21/Home\\_page/1253962785326](http://www.og21.no/prognostikk-og21/Home_page/1253962785326)

<sup>90</sup><http://www.uis.no/research-and-phd-studies/research-centres/national-ior-centre-of-norway/>

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- ▶ Rock/fluid and geo-mechanical properties in carbonate rocks;
  - ▶ Microscopic sweep efficiency – Technical Potential, recovery and transport mechanisms of surfactants, low salinity, and CO<sub>2</sub>-flooding; reduction of capillary forces; phase behaviour; core floods and modelling; and
  - ▶ Pore scale mechanisms – Modelling of fluids distribution, and impact of formation wettability and capillary pressure on oil recovery.
- 5.4.10 In April 2017, the IOR Centre will host the 19<sup>th</sup> edition of the European Symposium on IOR, in partnership with the European Association of Geoscientists and Engineers (EAGE). The event will consist of seminars and lectures on IOR research topics.
- 5.4.11 FORCE<sup>91</sup> was established by the NPD in 1995 to stimulate industrial cooperation for improved oil and gas recovery and improved exploration between oil and gas companies and authorities in Norway. The forum improves collaboration by sharing knowledge through network groups and by enabling the establishment of cross company piloting projects through project groups. Improved oil and gas recovery is one main areas for research and technology development within FORCE. Research is organised and experienced are shared through a technical committee, network groups and project groups.
- 5.4.12 Norway's technology strategy for the petroleum sector (OG21)<sup>92</sup> was established in 2001 by the IOR Centre and FORCE to identify technology priorities for efficient and environmentally responsible petroleum activities on the Norwegian continental shelf. OG21 describes a concerted national effort to strengthen research, development, demonstration and commercialisation of technologies that can solve challenges for the petroleum industry. The latest strategy was published in November 2016 and highlights EOR as one of the ten priority areas for technological development<sup>93</sup>. Specific research needs for EOR/IOR are mentioned, such as the improvement of sweep efficiency and the identification of environmental friendly EOR chemicals. Public funding of petroleum research is mainly organized through the research programmes PETROMAKS 2 and DEMO 2000 by the Research Council of Norway. These programmes contribute to achieve the goals set in the OG21 strategy. Oil companies, universities, research institutions, suppliers and governments cooperate through OG21 to develop and implement the national technology strategy for Norway.

**The Netherlands**

- 5.4.13 Oil and gas have been produced from the subsurface of the Netherlands for more than half a century. More than 470 gas fields have been discovered, some 250 of which are currently producing. The Groningen gas field is by far the largest; all the other fields are therefore called 'small fields'. Of the total of 50 oil fields discovered, some 15 are currently producing.
- 5.4.14 The Dutch Mining Act ("Mijnbouwwet") regulates the mining and storing of substances, as well as the extraction of oil and gas. In a 2008 evaluation of the Dutch Mining Act it was noted that the Mining Act is unclear on whether CO<sub>2</sub> used for EOR should fall into the category of "facilitating substance to the mining process, or whether the injection of CO<sub>2</sub> should be considered as a storage activity".
- 5.4.15 Since September 2011, existing Dutch legislation has been adapted to incorporate the requirements of the EU Directive on the geological storage of carbon dioxide (2009/31/EC, see Section 5.2). Alterations have been made to the Dutch Mining Act, Decree and Regulation.
- 5.4.16 The explanatory memorandum to the Act amending the Mining Act sheds some light on the role of CO<sub>2</sub> in Enhanced Hydrocarbon Recovery. It explains that a permit is not required for the storage of CO<sub>2</sub> in situations where CO<sub>2</sub> is used as a "facilitating substance" to the extraction of oil or gas. The term "facilitating substance" does not explicitly appear in the Mining Act, but the memorandum

<sup>91</sup> <http://www.force.org/>

<sup>92</sup> [http://www.og21.no/prognett-og21/Home\\_page/1253962785326](http://www.og21.no/prognett-og21/Home_page/1253962785326)

<sup>93</sup> [http://www.og21.no/prognett-og21/Nyheter/New\\_OG21strategy\\_New\\_technology\\_could\\_result\\_in\\_petrolium\\_worth\\_billions\\_and\\_reduce\\_CO2\\_emissions/1254022660471?lang=en](http://www.og21.no/prognett-og21/Nyheter/New_OG21strategy_New_technology_could_result_in_petrolium_worth_billions_and_reduce_CO2_emissions/1254022660471?lang=en)

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- states that “on the ground of Article 25(2) of the Mining Act, (it) will be decided by means of Decree (which substances will be classified as ‘facilitating substances’ and therefore fall outside of the general mining regime”. This should be read in the context of Article 25(2) of the Mining Act, which states that substances may be exempt, by way of Decree, from the general obligation to obtain a storage permit. The memorandum further explains that if CO<sub>2</sub> is used as a ‘facilitating substance’, the operator may not make use of the emissions trading scheme. If CO<sub>2</sub> is stored underground, partly for the benefit of storing CO<sub>2</sub> and partly to promote oil or gas extraction, then for the part that will be permanently stored the operator must obtain a storage permit. For the permanently stored CO<sub>2</sub> the operator will fall within the emissions trading system<sup>94</sup>.
- 5.4.17 When storing CO<sub>2</sub> in the Dutch subsurface, a storage permit is required. During the CATO-2 national research program (Dutch national R&D programme for CO<sub>2</sub> capture, transport and storage), a “best practice” guidance document was developed which describes the process of application for a storage project<sup>95</sup>.
- 5.4.18 Since 2010, two special schemes have been in place to encourage the exploration for and development of oil and gas reserves. These are the ‘Investment allowance for marginal offshore gas fields’ and the ‘Fallow Acreage Covenant’ to promote exploration for and development of oil and gas reserves and storage of substances in the Dutch part of the continental shelf. The covenant is a non-binding agreement that allows licence holders to voluntarily surrender all or part of that licence to a third party.

**Denmark**

- 5.4.19 Denmark has produced oil and gas from the Danish part of the North Sea since 1972. It is estimated to have the following hydrocarbon reserves: 623m m<sup>3</sup> of oil (of which 414m m<sup>3</sup> has already recovered) and 278.5bn m<sup>3</sup> of gas (of which 168bn m<sup>3</sup> has been recovered). In 2015 production was from in 19 oil and gas fields in the Danish part of the North Sea. Mærsk Olie og Gas is the operator for 15 fields, while DONG is the operator of three fields and Hess the operator of one field<sup>96</sup>.
- 5.4.20 There is a long standing history of funding and arranging cooperation on IOR research in Denmark. This includes organisations such as the Danish Energy Agency, academic institutes, oil companies, NGOs and consultants. The most significant government funded program is the joint Norwegian-Danish chalk research co-operation, known as the Joint Chalk Research (JCR), as described in paragraph 5.4.7.
- 5.4.21 In 2014 the Danish Hydrocarbon Research and Technology Centre was opened at the Technical University of Denmark (DTU). The centre develops new knowledge, ideas and methods for increasing the extraction of oil and gas in the North Sea. The petroleum facility has attracted researchers of a high calibre from both Denmark and abroad, and has set up partnerships across research institutions and with the industry. IOR research programmes include “Advanced Water Flooding” and a joint industry and university funded project on optimising oil production by Novel technology integration – well flow modelling (OPTION)<sup>97</sup>. The funding for these initiative focuses on flagship programmes, which involve demonstrations of the commercial uses of different EOR and IOR technologies. The Centre relies heavily on access to industry data, knowledge and people. This is provided by partners from industry such as Maersk.
- 5.4.22 The Danish Technology Institute (DTI) is a non-profit organisation that is conducting research into the applications of EOR in Danish fields. <sup>98</sup> They are sponsored by both the Danish Government and Industry.

<sup>94</sup> Macropy et al., 2013. Legal Status of CO<sub>2</sub> – Enhanced Oil Recovery. UCL Carbon Capture Legal Programme. [www.sccs.org.uk](http://www.sccs.org.uk)

<sup>95</sup> Permitting needs for CCS operations in the Netherlands. CATO2-WP4.2-D04. <https://www.co2-cato.org/publications/library/1/permitting-needs-for-ccs-operations-in-the-netherlands>

<sup>96</sup> Danish Energy Agency, 2016, Resources and Forecasts, August 2016

<sup>97</sup> <http://www.cere.dtu.dk/research-and-projects/phd-projects/optimizing-oil-production-by-novel-technology-integration---well-flow-modeling>

<sup>98</sup> <http://www.dti.dk/services/enhanced-oil-recovery/33727>

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## 5.5 Summary

- 5.5.1 There are a range of policies and regulatory frameworks that affect EOR and IOR activities in Europe and a number of joint government and industry initiatives that illustrate the benefits of collaboration.
- 5.5.2 At a European Union level the application of EOR and IOR technologies is regulated through several pieces of legislation and regulation. Notably, this includes the CCS Directive (for CO<sub>2</sub> EOR coupled to CCS only), the Emissions Trading Scheme (ETS) Directive, the Offshore Safety Directive and Recommendation 2014/70/EU on hydraulic fracturing (which also discusses enhanced recovery technologies). There is no unifying policy or strategy for EOR/IOR in the EU, but there have been multiple research projects and initiatives related to EOR and IOR funded by the European Commission:
- ▶ Between 1985-2001, these focused on R&D for EOR/IOR technologies;
  - ▶ From 2006 until present there has been a focus on CO<sub>2</sub>-EOR coupled to CCS, both through research into its potential in Europe and investment in demonstration projects; and
  - ▶ Since 2012 the European Commission has funded research into the environmental risks and impacts of unconventional oil and gas extractions, which has included IOR and EOR techniques.
- 5.5.3 At a regional level in Europe, several Conventions are in place for the offshore oil and gas industry, each with the objective of environmental protection. Their Protocols apply to all aspects of offshore oil and gas production and extraction, including the application of EOR and IOR technologies. These Conventions include the OSPAR Convention (North East Atlantic), the Helsinki Convention (Baltic Sea), the Barcelona Convention (the Mediterranean) and the Bucharest Convention (the Black Sea).
- 5.5.4 At a country / Member State level, the countries with the most developed EOR/IOR policy and regulation are Norway, the Netherlands and Denmark. Of these three, Norway can be considered to be the leader in EOR/IOR policy. A summary of EOR/IOR policy and regulation in these countries is provided below:
- ▶ In **Norway**, the petroleum regulatory framework is based on two key instruments: The Petroleum Act (1996) and The Pollution Control Act (1981). The Norwegian government works closely with industry and academia to foster research efforts on EOR and IOR. Salient initiatives include the Joint Chalk Research (JCR), the IOR Centre at Stavanger University, the Forum for Reservoir Characterisation, Reservoir Engineering and Exploration Technology Cooperation (FORCE) and the Norwegian technology strategy for the petroleum sector (OG21). Each year, the Government also awards a prize to the most innovative IOR project in the Norwegian Continental Shelf;
  - ▶ In **Denmark**, there is a long standing history of collaboration on IOR/EOR research between government, industry and academia. This includes the joint Danish-Norwegian Joint Chalk Research (JCR). In 2014 the Danish Hydrocarbon Research and Technology Centre opened at the Technical University of Denmark. The centre pioneers R&D research into EOR and IOR technologies, and is partly funded by government and industry. The Danish government also funds EOR research conducted by the Danish Technology Institute (DTI), a non-profit organisation; and
  - ▶ In **The Netherlands**, the Dutch Mining Act is the primary legal instrument that control oil and gas production. It includes provisions for the geological storage of CO<sub>2</sub> in depleted oil and gas fields as a result of CO<sub>2</sub> EOR. The government has developed guidance documents which outline best practices for the permit applications for such projects.

## 6. Barriers to the Deployment of Oil Recovery

This chapter identifies the key barriers to deployment of oil recovery and proposes measures that could be implemented to overcome them.

### 6.1 Overview

6.1.1 World oil production by EOR methods represents around 3 million barrels of oil per day compared to total daily oil production of ~85 million barrels.<sup>99</sup> At approximately 3.5%, the contribution EOR makes to total oil production is therefore low (despite the benefits and observable results the application of EOR methods can deliver) and indicates that significant barriers exist to the deployment of EOR processes worldwide.

6.1.2 Norway's Oil and Gas Technology Strategy (OG21)<sup>100</sup> provides a useful starting point for understanding the factors which could influence decisions relating to EOR deployment. It identifies the following key barriers to technology development and application across the oil and gas sector generally (see also **Figure 6.1**):

- ▶ technologies' full potential not harvested;
- ▶ high perceived risks;
- ▶ contractual barriers;
- ▶ high societal value, but lower business value;
- ▶ piloting and first use challenges;
- ▶ Norwegian Continental Shelf (NCS) structural challenges;
- ▶ competence and organisational capability;
- ▶ lack of standardisation/standards; and
- ▶ leadership and commitment.

6.1.3 The UK EOR Strategy<sup>101</sup>, meanwhile, identifies the following barriers specific to the implementation of EOR projects:

- ▶ incomplete subsurface understanding (e.g. pore scale and sweep);
- ▶ supply of secure, low-cost injectant, in particular for miscible gas EOR;
- ▶ cost of building EOR facilities or redevelopment of existing brownfield assets; and
- ▶ concerns over EOR economics.

6.1.4 Reflecting the factors identified in OG21 and the UK EOR Strategy, and taking into account a review of relevant literature, the sections that follow explore the barriers to EOR deployment in more detail and identify a range of measures that could be implemented to help overcome them.

Figure 6.1 Barriers to Technology Development and Implementation in the Oil and Gas Sector<sup>100</sup>



<sup>99</sup> Kokal, N. and Al-kaabi, A. (2010) *Enhanced oil recovery: Challenges & Opportunities*. Available from [https://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwiliqrLue7RAhVLGsAKHQiBCLYQFgqIMAA&url=http%3A%2F%2Fwww.firstmagazine.com%2FDownloadSpecialistPublicationDetail\\_466.ashx&usq=AFQjCNGC2v8V5j\\_iQgde3vO2y2-u1YMOvQ](https://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwiliqrLue7RAhVLGsAKHQiBCLYQFgqIMAA&url=http%3A%2F%2Fwww.firstmagazine.com%2FDownloadSpecialistPublicationDetail_466.ashx&usq=AFQjCNGC2v8V5j_iQgde3vO2y2-u1YMOvQ) [Accessed January 2017].

<sup>100</sup> OG21 (2016) *Oil and Gas for the 21<sup>st</sup> Century: Strategy Document*. Available from [http://www.og21.no/prognett-og21/Home\\_page/1253962785326](http://www.og21.no/prognett-og21/Home_page/1253962785326) [Accessed January 2017].

<sup>101</sup> OGA (2016) *Enhanced Oil Recovery (EOR) Strategy*.

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For the purposes of this review, the barriers to deployment have been considered under the following broad headings:

- ▶ commercial barriers;
- ▶ physical barriers;
- ▶ organisational barriers; and
- ▶ environmental barriers.

## 6.2 Commercial Barriers

### Barrier Description

- 6.2.1 The principal factor driving decisions relating to the deployment of EOR concerns capital expenditure and financial return. EOR deployment can represent a significant investment in terms of both installation (for example, topside modifications and costs associated with the construction of storage facilities) and operational costs (for example, costs related to the supply of injectant). The preparation time of an EOR project can also be as long as 6 to 10 years before field scale production begins. This is in order to allow for design, pilot testing and, ultimately, full-scale deployment<sup>102</sup>. This extended lead-in means that the rate of financial return usually takes place over a longer time period when compared to conventional production. Together, the high upfront and operational costs associated with EOR deployment and the comparatively long time period over which a financial return can be expected to be realised create uncertainty and risk to investment decisions which can affect the attractiveness of EOR projects.
- 6.2.2 The various cost elements of EOR projects have already been illustrated in **Figure 3.2** of this report and include, for example, the drilling of new injection wells and equipment expenditure during installation and the purchase/recycling of injectants during operation. An important financial constraint associated with EOR technologies is also the loss of production during platform modification<sup>103</sup>. Kemp and Stephen (2014) highlight that costs associated with the supply of injectant used in EOR can be particularly important noting that in polymer flood schemes in the UKCS, injectant can constitute between 80%-90% of total operating costs.<sup>104</sup> Similarly, the supply of CO<sub>2</sub> in EOR schemes involving CO<sub>2</sub> flooding can amount to 25% to 50% of the cost per barrel of oil produced<sup>105</sup>.
- 6.2.3 The economic viability of an EOR project can be determined by calculating the Net Present Value (NPV) of a scheme, based on capital expenditure (CAPEX), the operational cost (OPEX), the price of injectants, the price of oil, the extent of the reserve and the duration of the project. However, it is the price of oil that is likely to have the greatest influence on economic viability and be the principal factor driving investment decisions (with CAPEX and OPEX being secondary factors).<sup>97</sup> Research by Vesna *et al* (2014) suggests that the minimum oil price for profitable oil production by EOR methods is 60 USD/barrel<sup>106</sup>.

### Measures to Overcome the Barrier

- 6.2.4 Measures to encourage the take-up of EOR have been predominantly fiscal and, more specifically, focused on tax allowances. In the US, for example, tax relief has been provided to companies

<sup>102</sup> Trung, P., Quang, P., Anh, L. (2015) Motivating Enhanced Oil Recovery (EOR) Projects in Vietnam – A Regulatory Approach. *In Perovietnam (6)/2015*.

<sup>103</sup> IEA Environmental Protection Ltd (2016) *Regional Assessment of the Economic Barriers to CO<sub>2</sub> Enhanced Oil Recovery in the North Sea, Russia and GCC States*.

<sup>104</sup> Kemp, A., and Stephen, L. (2014) *The Economics of Enhanced Oil Recovery (EOR) in the UKCS and the Tax Review*. Available from [https://www.abdn.ac.uk/research/acreef/documents/Working\\_papers/nsp-129.pdf](https://www.abdn.ac.uk/research/acreef/documents/Working_papers/nsp-129.pdf) [Accessed January 2017].

<sup>105</sup> Global CCS Institute (undated) *Summary of Costs for CO<sub>2</sub>-EOR*, available from <https://hub.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-co2-enhanced-oil-recovery-10> [Accessed January 2017].

<sup>106</sup> Vesna, K.M., Leković Branko, L., Dušan, D. (2014) Factors Influencing Successful Implementation of Enhanced Oil Recovery Projects. *Underground Mining Engineering* 25 (2014) 41-50.

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- specifically for EOR schemes.<sup>104</sup> As highlighted in **Section 4.5**, the UK Government has also sought to reduce the overall tax burden on industry to maximise economic recovery. This has included the introduction of a Brownfield Allowance (BFA) against Supplementary Charge (SC) that applies to the development of new, previously unassessed reserves and through which the UK Government seeks to support the take-up of EOR projects.
- 6.2.5 Research by Kemp and Stephen (2014)<sup>104</sup> has examined the efficiency of several types and rates of tax incentives in the context of the UKCS. They conclude that an uplift allowance for SC related to investment and operating costs is likely to produce incentives which perform reasonably efficiently. They also note that the provision of an uplift relating to operating costs is unusual, but, given the very high costs involved in purchasing polymers and gas for schemes which are promising in the context of the UKCS, there is a case for an uplift relating to these product requirements.
- 6.2.6 Overall, a review of tax incentives is considered critical to informing policy on EOR. This should include sensitivity testing to reflect changes to the price of oil and injectants.
- 6.2.7 Whilst tax incentives have been the principal mechanism used by governments to encourage EOR deployment, there exists a range of other fiscal measures that can be implemented to increase economic viability. These may include (*jnter alia*) grants, take-off agreements, and bonds to finance EOR schemes<sup>107</sup> as well as private equity investment (as supported in OG21). Measures that seek to reduce the up-front installation and ongoing operating costs associated with EOR projects could also have a significant impact on commercial viability. In this regard, the UK EOR Strategy and EOR Delivery Programme<sup>108</sup> place a strong emphasis on cost reduction and the creation of a competitive, robust supply chain (including, in particular, for injectants).
- 6.2.8 Reducing the costs associated with EOR installation and operation could be achieved through a transition towards standardised technologies and materials and stimulus to promote innovation including public funding for research and development (this could support the development of subsea technologies which have the potential to minimise downtime normally associated with topside modifications for EOR, for example<sup>105</sup>). With specific regard to CO<sub>2</sub> EOR, there may also be an opportunity to offer the free delivery of this injectant in exchange for free storage (as part of a wider CCS scheme)<sup>109</sup>.

## 6.3 Physical Barriers

### Description

- 6.3.1 **Chapter 3** of this report has identified a range of physical factors that can influence the rate of recovery from reservoirs including: relative permeability, rock wettability, interfacial and surface tension and capillary pressure (factors influencing microscopic displacement); and mobility ratio, viscous fingering, gravity segregation and reservoir geological heterogeneity (factors influencing macroscopic displacement). These characteristics also influence whether EOR is feasible, the type of method that can be deployed, the recovery rate projected and, ultimately, economic viability. It follows that a detailed understanding of reservoir characteristics must be first established in order to determine the appropriate reservoir management strategy. Ongoing monitoring is also required during/ after execution of EOR to assist performance evaluation and subsurface model calibration. However, obtaining this information can be complex, time/resource intensive and costly, typically requiring detailed reservoir modelling including 4D/ time-lapse seismic and horizontal wells to ensure effective well placement and successful EOR execution.

<sup>107</sup> Falwell, P. (2013) *State Policy Actions to Overcome Barriers to Carbon Capture and Sequestration and Enhanced Oil Recovery*. Available from <https://www.c2es.org/publications/state-policy-actions-overcome-barriers-carbon-capture-sequestration-enhanced-oil-recovery> [Accessed January 2017].

<sup>108</sup> OGA (2016) *Enhanced Oil Recovery (EOR) Delivery Programme*, December 2016.

<sup>109</sup> Reid, W. (2015) *A Selective Literature Review of CO<sub>2</sub> EOR in the UK North Sea Continental Shelf*. Available from <https://www.thecrownstate.co.uk/media/501905/ei-literature-review-of-co2-eor-in-the-uk-north-sea-continental-shelf.pdf> [Accessed January 2017].



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- 6.3.2 Alongside reservoir characteristics, physical barriers can also relate to the availability of resources and associated infrastructure to support EOR projects. This is particularly pertinent for offshore schemes given the remoteness of some fields. In the UKCS, for example, the availability of hydrocarbon gas and CO<sub>2</sub> and the lack of an established supply network for these injectants is seen as a significant barrier to miscible gas EOR projects whilst uncertainty with regard to CO<sub>2</sub> accumulations and the long distance between CO<sub>2</sub> sources and oil producing areas has been assessed as a barrier to the up-take of CO<sub>2</sub> EOR in Russia<sup>103</sup>.

**Measures to Overcome the Barrier**

- 6.3.3 The early compilation of data regarding the status and characteristics of fields can be used to help identify a target play in one or more fields that could be the focus for a dialogue with the operator. This could identify realistic opportunities in a given play in a given field acting to encourage take-up and help 'de-risk' investment decisions. In this context, a range of studies have been undertaken to identify screening criteria that can be applied to crude oil and reservoir properties and to help establish requirements for specific technologies. **Figure 6.1**, for example, shows screening criteria derived for miscible, chemical and thermal EOR processes.

Figure 6.1 Example Screening Criteria for EOR Processes

Process	Oil gravity (°API)	Oil viscosity (cP)	Oil saturation (%)	Formation type	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temp (°F)
<b>Miscible</b>								
Hydrocarbon	>35	<10	>30	Sandstone or carbonate	15-25	— <sup>a</sup>	>4500	— <sup>a</sup>
Carbon dioxide	>25	<12	>30	Sandstone or carbonate	15-25	— <sup>a</sup>	>2000	— <sup>a</sup>
Nitrogen	>35	<10	>30	Sandstone or carbonate	15-25	— <sup>a</sup>	>4500	— <sup>a</sup>
<b>Chemical</b>								
Polymer	>25	5-125	— <sup>b</sup>	Sandstone preferred	— <sup>a</sup>	>20	<9000	<200
Surfactant-polymer	>15	20-30	>30	Sandstone preferred	>10	>20	<9000	<200
Alkaline	13-35	<200	— <sup>b</sup>	Sandstone preferred	— <sup>a</sup>	>20	<9000	<200
<b>Thermal</b>								
Steamflooding	>10	>20	>40-50	Sand or sandstone with high porosity	>10	>50	500-5000	— <sup>a</sup>
Combustion	10-40	<1000	>40-50	Sand or sandstone with high porosity	>10	>50	>500	— <sup>a</sup>

<sup>a</sup> Not critical but should be compatible.

<sup>b</sup> Ten percent mobile oil above waterflood residual oil.

Source: Terry (2011)<sup>110</sup>.

- 6.3.4 For each play, average reservoir properties and ranges can be tabulated along with fluid properties, OIIP, areal closure, historic and current well count including type (deviated vs horizontal; producer vs injector). A reservoir management strategy for each play can then be identified (water and/or gas injection) together with any other reservoir drive mechanism(s). An initial field assessment could also help to establish the availability of injectants and the infrastructure necessary to implement EOR schemes and, through clustering, identify where there is scope for cooperation between operators to share infrastructure such as onshore facilities. Ongoing evaluation of operational EOR projects and the dissemination of survey results is also important in order to consolidate learning, identify technological solutions and help refocus attention on the opportunity.

As an example, the PILOT EOR Working Group systematically screened UKCS fields for EOR potential using a spreadsheet-based EOR screening tool (SENEOR) (see **Section 4.6** of this report for further information). As a result of this screening exercise, the UK validated the estimate of EOR potential on a UKCS wide basis, demonstrating that the overall theoretical EOR potential is estimated to be approximately 6 billion barrels of oil. The results of the EOR screening process also identified

<sup>110</sup> Terry, R. (2001) Enhanced Oil Recovery. *Encyclopaedia of Physical Science and Technology 3rd Edition*, vol. 18. Robert A. Meyers Ed., Academic Press (2001) pp 503-518.

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three EOR processes that had good potential, in particular if a cooperative approach to EOR development in the North Sea was undertaken:

- ▶ Low Salinity Waterflood;
- ▶ Chemical EOR (polymer & surfactant flooding); and
- ▶ Miscible Gas Injection (both hydrocarbon gas and carbon dioxide).

## 6.4 Organisational Barriers

### Description

6.4.1 Alongside the commercial and physical barriers outlined above, there are also organisational barriers to the deployment of EOR. These organisational barriers principally concern industry focus on immediate recovery and short term profits and a lack of capacity and knowledge to support EOR delivery.

#### Focus on immediate recovery

6.4.2 Related to the commercial barriers discussed in **Section 6.2**, capital intensive projects such as EOR that require a long lead-in have not traditionally been favoured by operators. This reflects the commercial risk associated with such projects and also a focus on immediate oil recovery driven by short term profits as opposed to ultimate recovery.<sup>99</sup>

6.4.3 The long-term nature of most EOR schemes can pose a continuity challenge on projects. This favours larger operators who have greater resources often with research and development laboratories and technical personnel who provide an initial bridge from scientific theory and laboratory investigation to possible field application. In addition, large international operators will take a long-term view and will often have access to lower cost proving grounds.

#### Capacity and knowledge

6.4.4 As highlighted above, EOR projects can be complex compared to conventional recovery methods, requiring skilled professionals to deliver them and to address any technological barriers in specific fields. Whilst there is considerable US experience of EOR projects, and of EOR projects onshore (including in Brazil), there remains challenges associated with transferring technologies and capability due in particular to different geological conditions, infrastructure and economic conditions<sup>103</sup>.

6.4.5 A lack of capacity, capability and knowledge can therefore act as a constraint to the development and implementation of EOR offshore and may also affect the success of a project's implementation. In this regard, Kang *et al* (2016) state that "*personnel training and mindset is important for all offshore EOR processes, because offshore EOR applications are rare compared with conventional oil production (primary and secondary oil recovery). New skills, including a different operating philosophy, management technique, closer surveillance, quality control, and new processes/equipment must be developed.*"<sup>56</sup>

6.4.6 EOR methods also present a number of technical challenges. For example, Kang *et al* (2016) highlight that, in particular, space and weight limits on the platform can cause difficulty in installing processing facilities for EOR applications, and in storing injection and produced fluids. Terry (2001), meanwhile, identifies a number of method-specific technological and operational problems associated with the application of EOR projects. These are summarised in **Table 6.1**.

Table 6.1 EOR Technical and Operational Difficulties

EOR Method	Technical Problems	Operational Problems
Miscible Processes	<ul style="list-style-type: none"> <li>Poor mobility.</li> </ul>	<ul style="list-style-type: none"> <li>Corrosion of equipment and tubing</li> <li>Separation and recycling of the miscible flooding agent.</li> <li>Securing gas supplies.</li> </ul>
Chemical Processes	<ul style="list-style-type: none"> <li>Screening chemicals to optimise the microscopic displacement efficiency.</li> <li>Making contact with the oil in the reservoir.</li> <li>Maintaining good mobility.</li> </ul>	<ul style="list-style-type: none"> <li>Treatment of water used to make up the chemical systems.</li> <li>Mixing the chemicals to maintain proper chemical compositions.</li> <li>Plugging the formation with particular chemicals such as polymers.</li> </ul>
Thermal Processes	<ul style="list-style-type: none"> <li>Poor sweep efficiencies.</li> <li>Loss of heat energy to unproductive zones underground.</li> <li>Poor injectivity of steam or air.</li> </ul>	<ul style="list-style-type: none"> <li>The formation of emulsions.</li> <li>The corrosion of injection and production tubing and facilities.</li> <li>Adverse environmental impacts.</li> </ul>
Microbial Processes	<ul style="list-style-type: none"> <li>Detailed knowledge of reservoir characteristics required.</li> <li>Reservoir brines can inhibit the growth of the microorganisms.</li> </ul>	None identified.

Source: Adapted from Terry (2001)<sup>10</sup>.

## Measures to Overcome the Barrier

### Focus on immediate recovery

- 6.4.7 Overcoming organisational barriers to EOR requires a shift in mind-set from conservative, risk avoidance to one of empowered, opportunity realisation. Whilst this can in part be driven through the implementation of fiscal measures, Trung *et al* (2015)<sup>102</sup> set out (in the context of Vietnam) that effective government policies must also address the long term commitment of the operator. They recommend that Vietnamese government policies and regulations should focus on the ultimate recovery of a field, rather than on immediate short term profits in order to help optimise recovery. They state that this could be achieved through direct measures such as compulsory lifecycle planning that requires operators to consider and propose EOR programmes. In this regard, one of the UK EOR Strategy and Programme activities is to introduce early EOR screening for regulatory approval of draft Field Development Plans (FDPs) in order to make EOR part of the regulatory approval process for FDPs and to place an obligation on operators to justify why EOR is not being used.

### Capacity and knowledge

- 6.4.8 Turning to the issue of capacity and knowledge constraints to EOR deployment, piloting and the establishment of working groups can provide an opportunity to build industry capacity and address technological barriers through collaboration and shared experience. The UK PILOT EOR Work Group, for example, was set up to co-ordinate industry and government attempts to tackle the principal barriers to implementing EOR projects (see **Section 4.6** of this report for further information). The UK EOR Strategy and Programme, meanwhile, include specific activities designed to drive operator collaboration including the establishment of working groups, creation of a shared EOR library and development of an inventory of EOR projects.
- 6.4.9 Annual operator conferences can also be a platform for knowledge sharing, helping to address technical challenges and develop an industry-wide perspective on EOR. This working model is successfully employed in Norway in an annual Reservoir Management Conference at which a prize is awarded to recognise the best contribution to realising maximum recovery from Norwegian reservoirs through EOR/ IOR. Despite commercial sensitivities, there is a keen competitive interest among operator staff and academics. It also provides a useful forum where projects are interrogated

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- on an annual basis by peers in other organisations making for informative exchange of ideas and regular peer challenge.
- 6.4.10 Ongoing research and development is critical and in this regard, OG21 recommends that public funding for research and development be increased in order to:
- ▶ address technology needs that are otherwise not addressed due to market imperfections;
  - ▶ cover basic research and early phases - phases for which industry research and development funding is challenging;
  - ▶ stimulate development of technologies which could have high rewards, but which fall short due to high development costs or risks; and
  - ▶ address technologies which offer high societal rewards, but which are less attractive to private enterprises due to factors such as different return requirements and/or license/project portfolio limitations and challenges.
- 6.4.11 Brazil is understood to have considerable onshore EOR test experience which provides an invaluable information source. Beyond the state level, opportunities could also be explored to share research and development on EOR internationally (it is understood that Brazil has bilateral agreements with other states in this regard).

## 6.5 Environmental Barriers

### Description

- 6.5.1 Concerns relating to the environmental impacts of EOR projects, whether real or perceived, can be a constraint to their deployment in terms of the public perception of a project and the willingness of regulators to permit schemes. The potential causes of environmental impacts common across all EOR technologies include:
- ▶ transit spill - spills which may occur when material is being prepared at, or transported to, the field site;
  - ▶ onsite spills - spills which may occur at the field site from surface lines and/or storage facilities;
  - ▶ well system failure - escape of materials which may occur from failure of the injection or producing well due to casing leaks or channelling;
  - ▶ reservoir migration - fluid may migrate outside of the confining limits of a reservoir through fractures or through a well bore which interconnects reservoirs; and
  - ▶ operations - the effects caused by routine activities and by the support facilities and activities associated with EOR production including disposal of spent material, consumption of site-associated natural resources, discharge emissions, fugitive emissions and off site supply and support efforts.<sup>111</sup>
- 6.5.2 The type and magnitude of the resulting potential impact is dependent on the technology employed and the environmental sensitivity of a specific field. Zoveidavianpoor and Jalilav (2014)<sup>112</sup> have, however, summarised the potential environmental impacts common across different EOR technologies as including:

<sup>111</sup> Office of Technical (1978) *Enhanced Oil Recovery Potential in the United States*. Available from [https://www.princeton.edu/~ota/disk3/1978/7807\\_n.html](https://www.princeton.edu/~ota/disk3/1978/7807_n.html) [Accessed January 2017].

<sup>112</sup> Zoveidavianpoor, M. and Jalilav, M. (2014) *Qualitative Analysis of Enhanced Oil Recovery: Impacts on Air, Surface Water and Groundwater*. International Conference on Chemical, Environment & Biological Sciences (CEBS-2014) Sept. 17-18, 2014 Kuala Lumpur (Malaysia)

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- ▶ air quality impacts (dust, engine exhaust, off-well gases, gas-flaring combustion products, particulates, SO<sub>2</sub>, CO<sub>2</sub>, NO<sub>x</sub>, H<sub>2</sub>S and hydrocarbons) associated with the use of chemicals/CO<sub>2</sub>, accidental spills and equipment leaks as well as indirect impacts related to, for example, the production of chemicals and power generation;
- ▶ water quality impacts related to accidental spills, well failure and reservoir leakage;
- ▶ induced seismicity caused by injections;
- ▶ noise emissions related to the use of compressors and other equipment used; and
- ▶ ecological impacts, associated with disturbance, emissions to air and changes in water quality.

6.5.3 Where technologies are new to a region or field there may be increased uncertainty relating to potential environmental impacts and which could increase the difficulty of gaining regulatory approval for a scheme. A study by Carruthers (2014)<sup>113</sup> on the potential environmental impacts of EOR involving CO<sub>2</sub> in the UKCS, for example, states that “*The oil and gas industry has been operating in the UKCS for over forty years with the experiences of these operations incorporated into national legislation and international agreements. CO<sub>2</sub>-EOR does not yet have this legacy in the UK and as such it is uncertain how similarly it will be regulated, with respect to environmental regulations, compared to oil and gas*”. However, it is important to recognise that many of the potential impacts associated with the deployment of EOR are similar to those of conventional oil production. Although activities may be intensified during the application of EOR, it is therefore reasonable to assume that any associated impacts can be managed to an acceptable level through standard industry practice and regulatory requirements.

**Measures to Overcome the Barrier**

- 6.5.4 Whilst the range of potential environmental impacts associated with EOR implementation are well-known and are likely to be manageable, there remains limited recent study in this area. Further, where technologies are employed that are novel to an area, there may be uncertainty and permitting risk.
- 6.5.5 Research, drawing largely on recent US experience of EOR but also from the North Sea and onshore EOR could be a vehicle for wider stakeholder involvement and help to address any perceived concerns with regard to the environmental impacts of EOR. The findings of this research could also usefully inform any future regulatory review and guidance for the sector. This is critical in ensuring that necessary regulations are in place to permit EOR projects, which may be particularly important for processes that include CCS<sup>107</sup>.

**6.6 Summary**

- 6.6.1 Due to the high costs associated with the implementation of EOR projects, barriers to deployment are principally commercially driven with investment decisions being strongly influenced by the prevailing price of oil. However, the barriers to EOR deployment are not purely financial and there exists a range of other secondary factors that are also important to consider.
- 6.6.2 **Table 6.2** summarises the barriers identified in the preceding sectors together with the measures that could be adopted to help overcome them. These measures have informed, and where appropriate, are expanded upon further, in the recommendations contained in **Section 7** of this report.

<sup>113</sup> Carruthers, K. (2014) *Environmental Impacts of CO<sub>2</sub>-EOR The Offshore UK Context*. Available from <http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP4-Environmental-Impacts.pdf> [Accessed January 2017].

Table 6.2 Summary of barrier and measures

Barrier	Measure
<b>Commercial Barriers</b>	
High capital expenditure and long term financial return.	<ul style="list-style-type: none"> <li>Review tax incentives to encourage EOR take-up. This should include sensitivity testing to reflect changes to the price of oil and injectants.</li> <li>Investigate other economic stimulus to encourage EOR deployment including grants, take-off agreement and bonds.</li> <li>Seek to reduce installation and operational costs associated with EOR deployment including through a transition towards standardised technologies and materials and funding for research and development.</li> </ul>
<b>Physical Barriers</b>	
Incomplete understanding of reservoir characteristics and costs associated with evaluation and ongoing monitoring.	<ul style="list-style-type: none"> <li>Undertake early basin-wide screening to identify EOR potential and suitability.</li> <li>Identify EOR methods with most potential and undertake further evaluation of viability.</li> <li>Undertake ongoing monitoring during and post implementation and disseminate results to consolidate learning.</li> </ul>
Availability of injectant and supporting infrastructure.	<ul style="list-style-type: none"> <li>Undertake early field assessment to establish the availability of injectants and supporting infrastructure including clustering opportunities.</li> </ul>
<b>Organisational Barriers</b>	
Operator focus on immediate recovery and short term profit.	<ul style="list-style-type: none"> <li>Introduce early EOR screening as part of the approval process for Field Development Plans (or equivalent).</li> <li>Ongoing liaison and engagement with operators.</li> </ul>
Lack of capacity and knowledge.	<ul style="list-style-type: none"> <li>Investigate the potential for piloting EOR schemes.</li> <li>Establish EOR working groups to share knowledge and experience and to co-ordinate action to address economic and technical challenges related to specific EOR technologies.</li> <li>Develop a shared library of information on EOR including an inventory of EOR projects.</li> <li>Establish an annual operator conference in order to share knowledge and experience.</li> <li>Explore the potential for research and development funding to address technological challenges and reduce costs/risks.</li> <li>Review international and Brazilian EOR experience and explore opportunities for knowledge sharing.</li> </ul>
<b>Environmental Barriers</b>	
Potential environmental impacts of EOR and associated permitting risk.	<ul style="list-style-type: none"> <li>Undertake research on the potential environmental impacts of EOR, drawing on recent US, North Sea and onshore experience.</li> <li>Review the effectiveness of existing regulatory frameworks for EOR.</li> </ul>

## 7. Recommendations

This final chapter outlines proposed recommendations for possible policy, regulatory and initiatives to support the use of EOR and IOR in Brazil

### 7.1 Brazilian Legislative and Policy Context

- 7.1.1 Successful EOR and IOR can play a significant role in maximising economic recovery from mature basins, not merely by significantly increasing the volume of recovery, but by extending field life, supporting job provision, helping stimulate field redevelopments and deferring decommissioning activities.
- 7.1.2 Whilst there has been substantial use of EOR and IOR in Brazil onshore, there has been more limited use offshore<sup>114</sup>. Its application has been dominated by one operator (Petrobras), with techniques used including chemical, miscible and thermal methods.
- 7.1.3 The principal regulations that have been used to encourage the take up of EOR and IOR in Brazil are:
- ▶ **ANP Regulation nº 17/2015** – Plan of Development (PoD) which establishes the technical data and other information that must be presented to ANP so that the plans can be evaluated and approved. Information about IOR and EOR projects are considered in the PoD scope:
 

*‘The exploitation strategy in which the Development Plan is based must aim at maximizing the recovery of in-situ resources, present in each Field Reservoir, according to the best economic principles and according to the Best Practices of the Oil Industry.*

*The Development Plan must have an enhanced recovery studies schedule throughout the Production Phase, aiming at increasing the recovery of Oil and Natural Gas Reservoirs.’*
  - ▶ **ANP Regulation nº 100/2000** – Annual Production Forecast within the context of a five year horizon, allowing the monitoring and supervision of production, injection, etc. In this context the supervision of the forecast resulting from the implementation of IOR and EOR activities is included; and
  - ▶ **ANP Regulation nº 123/2000** – Annual Activities and Budget Forecast which provides a schedule of activities to be implemented over a five year horizon, allowing the monitoring and supervision of the projects. In this context the monitoring of IOR and EOR activities is included.
- 7.1.4 The PoD requirements mirror the requirements concerning FDPs and EORs outlined in the UK guidance on FDPs, focusing on *‘those options which are most likely to secure maximum economic recovery of hydrocarbon reserves from the reservoir in question, taking into account other potential reserves in the area’*. The requirements for forecasting also find echoes in the activities of the OGA.
- 7.1.5 The legislative framework to establish ANP was provided by Act No 9.478/97 (Petroleum Law) and implemented by Decree No 2.455/98, as the oil industry regulator, under the MME, in the form of special agency member of Indirect Federal Administration. ANP main responsibilities relate to petroleum exploration and production and concern the implementation of national policy, regulation and licensing of exploration, development and production activities and the facilitation of research and adoption of new technologies. In its separation from MME and the scope of its activities, the creation of ANP anticipated by nearly two decades the creation of the UK’s OGA (established under the Infrastructure Act 2015). Reflecting the UK government’s acceptance of the Wood

<sup>114</sup> ANP (2016) Enhanced Oil Recovery Methods (EOR) and Improved Oil Recovery (IOR) in Brazil, presentation provided to Amec Foster Wheeler from Vitor Jose Campos Bourbon, 26.8.16

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- Review recommendations however, the OGA has a clear responsibility to maximise the economic recovery of oil and gas from onshore and offshore, including the UKCS.
- 7.1.6 Whilst there are then similarities between the principal agencies responsible for oil and gas in Brazil and the UK, and commonalities in the treatment of EOR and IOR in regulations, at present there is no Brazilian equivalent to the MER UK Strategy and the OGA EOR Strategy. The MER UK Strategy and OGA Strategy have been developed to address the changes in operating environment, asset management, investment and exploration and production. Whilst these factors may differ when considering exploration and production activities in Brazil, there is clear scope for ANP (and MME) to establish a high level strategy with the principal objective of securing a lasting increase in the recovery rates in Brazilian offshore basins.
- 7.1.7 ANP commented in their trip to the UK that they were particularly interested in the more collaborative approach to working between regulator, industry and researchers, fostered in the UK and Europe. For example:
- ▶ UK – the PILOT work, built on collaboration between industry and government (with working groups comprised of both) was instrumental in building widespread ownership for the OGA EOR strategy. A key element in the process was the validation of the initial screening of the 100 fields by operators;
  - ▶ Norway – the Norwegian national petroleum technology strategy (OG21) fosters cooperation between oil companies, universities, research institutions, suppliers and governments to develop and implement the national technology strategy for Norway. The NPD award of an annual prize to the most innovative IOR project in the NCS celebrates research excellence, raises the profile and ensures widespread interest and awareness of new advances. That it combines with an annual Reservoir Management Conference heightens the opportunities for dissemination; and
  - ▶ Denmark – the Danish-Norwegian Joint Chalk Research (JCR) and the government and industry funded Danish Hydrocarbon Research and Technology Centre provides research into EOR and IOR technologies. This combines industry expertise with the research of various universities.
- 7.1.8 Reflecting on the response of the UK and the other European countries to the challenges of maximising economic recovery and the ambition to take more oil out than is left behind, whilst some of the drivers may be different to Brazil, the outcome (to improve RF) is the same. In consequence, there are clear benefits to ensuring a collaborative approach to the development and implementation of strategy for EOR and IOR in Brazil.

## 7.2 Recommendations

- 7.2.1 To foster this approach, the following key recommendations are made:
1. Consider whether a high level review of barriers to EOR is needed to provide initial impetus;
  2. Establish the evidence base for intervention; and
  3. Consider developing and implementing an EOR and IOR Strategy.

R1: Consider whether a high level review of barriers to EOR is needed to provide initial impetus

- 7.2.2 Reflecting on UK's approach to the development of the EOR Strategy, ANP are asked to consider whether it is important, as a pre-requisite, to undertake the equivalent of the Wood Review in the UK, but applied to the Brazilian context. This would be a credible, objective high level study presenting an independent analysis of the issues of low recovery in Brazil's offshore basins. This could be industry, academic or politically led but would aim to achieve (as it did for the UK) a



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consensus on the range of policy, regulator and industry interventions needed to maximise economic recovery.

**R2: Establish the evidence base for intervention**

- 7.2.3 Any intervention to increase recovery will need to be based on credible evidence.
- 7.2.4 There is potential for a series of steps to be completed in order to establish the evidence base. The following are proposed for ANPs consideration:
1. Review the various EOR initiatives that have been trialled or just evaluated for the Campos basin fields and based on the analysis, identify those EOR technologies that afford greatest theoretical potential.
  2. Develop a screening tool for EOR technologies based on consideration of the following (or similar) factors (informed by relevant research):
    - a. Depth;
    - b. Pressure;
    - c. Permeability;
    - d. Oil viscosity;
    - e. Temperature;
    - f. Acid number;
    - g. Wettability;
    - h. Fraction of clays;
    - i. Heterogeneity factor;
    - j. Injection water salinity.

The parameters of each criterion and any weighting to be given will need to be determined. In this regard further reference could be made to the SENEOR tool used in the UK.
  3. Complete basin wide screening of potential EOR technologies.
  4. Complete a field level screening of EOR technologies (for fields where reserves are greater than an agreed threshold amount).
  5. Validate the findings of the field level screening with operators and confirm scale of unrisks EOR opportunity. Prioritise the unrisks potential EOR opportunities by factors such as scale, timeframe, infrastructure requirements and investment needed.
  6. For those prioritised EOR opportunities, consider developing a reservoir management strategy for each play. An initial field assessment could also help to establish the availability of injectants and the infrastructure necessary to implement EOR schemes and, through clustering, identify where there is scope for cooperation between operators to share infrastructure such as onshore facilities.
  7. Focusing on those prioritised EOR opportunities provide an assessment of the scale of the risks (Economic) EOR potential (broken down by field and EOR technology).
- 7.2.5 If ANP agree to the overall approach, who will undertake the screening will need to be agreed at the outset. Consideration will need to be given to whether the UK approach of a specific working group comprising of members drawn from industry and government should be repeated. As an alternative, ANP could consider inviting field operator's team to help build up a database on each

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productive/prospective reservoir, which outlines the limits of each EOR method and confirms their applicability to a specific reservoir type. In this way a prioritised list could also be developed.

### R3: Consider developing and implementing an EOR and IOR Strategy

- 7.2.6 Based on the evidence base, established in response to Recommendation 2, the ANP could then give consideration to the development of an EOR Strategy. Key features of the Strategy could include:
- ▶ **Objectives** – to focus on maximising recovery (in order to ensure the focus is on the long term ultimate recovery of a field, rather than the short term recovery);
  - ▶ **Targets** – provide quantified time limited targets for the increase in recovery rates (so for example, aiming to increase final recovery rates from the Campos Basin by 10% within 10 years or to ensure recovery rates on the Campos Basin are increased to align with international averages within 15 years). Alternatively (or in addition) there is the potential to establish a separate target for all new fields (to ensure that have higher recovery rates than current) with potential also to focus on specific technologies; and
  - ▶ **Actions** – with measures that could include:
    - ▶ New Schemes
      - Implementation of any EOR schemes identified through the prioritisation process.
      - Ensure that the PoDs include EOR to maximise the recovery of in-situ resources, consistent with international best practice.
    - ▶ Research and New Technologies
      - Encourage technology providers and operators to develop and deploy low-cost EOR.
      - Investigate the potential for piloting EOR technologies drawing on Brazilian on-shore experience.
      - Actively support emerging technology Joint Industry Projects (JIPs) engaging global knowhow.
    - ▶ Incentives
      - Review tax incentives to encourage EOR take-up.
      - Investigate other economic stimulus to encourage EOR deployment including grants, take-off agreement and bonds.
      - Seek to reduce installation and operational costs associated with EOR deployment including through a transition towards standardised technologies and materials and funding for research and development.
    - ▶ Knowledge and learning
      - Establish EOR working groups to share knowledge and experience and to co-ordinate action to address economic and technical challenges related to specific EOR technologies.
      - Develop a shared library of information on EOR including an inventory of EOR projects.
      - Consider examining other offshore EOR activities in other operating environments (which have potentially common offshore geologies). E.g. Polymer Injection in a Deep Offshore Field (Dalia/Camelia Field), Angola

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- Establish an annual operator conference in order to share knowledge and experience. This could build on the proposed 2 day workshop, scheduled by ANP for March 2017.
- Consider establishing an award for the most innovative and effective EOR technologies.
- Establish links with international and overseas bodies who can provide support and insight. NB the OGA offered to provide ongoing support on the promotion of EOR, and there are potential opportunities to attend a variety of international conferences, e.g. SPE's Tulsa EOR Conference, IEA EOR Workshop and Symposium, EAGE IOR Conference.
- Explore the potential for research and development funding to address technological challenges and reduce costs/risks.

7.2.7 In developing the approach, a few key reflections from UK experience were:

- ▶ The importance of pragmatism – the UK EOR strategy was developed during a period of price uncertainty – and focused on achievable targets;
- ▶ Applicability - The risked evaluation of potential EOR was based on BP onshore and offshore experience drawn largely from sandstone environments. There is possibility that offshore risked estimates could be lower for Brazil than those identified in the PILOT report (so less than the 10-20% of unrisked estimate); and.
- ▶ UK experience was informed by industry practice. For example, BP trialled technologies onshore before taking them offshore which in the view of stakeholders informs understanding and resolution of issues. Brazil has considerable onshore EOR test experience across EOR technologies so there is potential to build on this approach.

7.2.8 If a strategy is developed, consideration would also need to be given to aspects of monitoring, progress reporting and communication of outcomes.

## Glossary

AGR	Associated Gas Reinjected
ANP	Brazilian National Agency of Oil, Natural Gas and Biofuels
AP	Alkali-Polymer
AS	Alkaline-Surfactant
ASP	Alkaline-Surfactant-Polymer
BLP	Bridge-Linked Platform
Bn bbl	Billion barrels
Boe	Barrels of oil equivalent
Brown Field Allowance (BFA)	Brown Field Allowance is a tax allowance that reduces the amount of adjusted ring fence profits on which the Supplementary Charge (SCT) and is used to encourage the development of new, previously un-accessed, reserves in an existing field.
CCS	Carbon Capture & Storage
Chemical Flood EOR	The addition of one or more chemical compounds to an injected fluid (usually water) either to reduce the interfacial tension between the reservoir oil and/or make the water viscosity match that of the oil (polymers) to improve the sweep efficiency of the injected fluid. The four principal chemical flood technologies are: polymer flooding; alkali flooding and surfactant flooding (and then combinations of these technologies)
CRA	Corrosion Resistant Alloy
CoP	Cessation of Production
DECC	Department of Energy and Climate Change (DECC became part of Department for Business, Energy & Industrial Strategy (BEIS) in July 2016)
EAGE	European Association of Geoscientists and Engineers
EEEGR	East of England Energy Group
EM	Electromagnetic
Enhanced Oil Recovery (EOR)	The process of producing liquid hydrocarbons by methods other than the conventional use of reservoir energy and reservoir repressurising schemes with gas or water.
EU	European Union
FAWAG	Foam Assisted Water Alternating Gas
FCO	Foreign & Commonwealth Office
FDP	Field Development Plan
FEED	Front End Engineering & Design
FPSO	Floating Production, Storage and Offloading
FPS	Forties Pipeline System
GOR	Gas-Oil Ratio
Gravity segregation	The tendency of fluids to stratify into different layers because of gravity forces. In gravity segregation, the heaviest fluid settles near the bottom and the lightest fluid rises to the top.
GVF	Gas Vapour Fraction
HPAM	Hydrolysed Polyacrylamide
ICD	Inflow Control Device
Immiscible	Two (or more) liquids incapable of being mixed to form a homogeneous substance. The fluids separate into two phases with an interface between them. For example, oil and water are immiscible.
Improved Oil Recovery (IOR)	Any activity that increases oil production and increases the recovery factor. This sense can also include, for example, enhanced oil recovery methods, infill drilling, hydraulic fracturing, and drilling horizontal and multilateral wells. Term is sometimes used synonymously with EOR.
Interfacial tension (IFT)	A property of the interface between two immiscible phases and is the force that holds the surface of a particular phase together. When the phases are both

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	liquid, it is termed interfacial tension; when one of the phases is air, it is termed surface tension. Surfactant molecules preferentially position themselves at the interface and thereby lower the interfacial tension.
IWAG	Immiscible Water Alternating Gas
MEOR	Microbial Enhanced Oil Recovery
MER	Maximising Economic Recovery
MER UK	Maximising Economic Recovery from the UKCS
MGI	Miscible Gas Injection
Microbial Enhanced Oil Recovery (MEOR)	A biological based technology involving the manipulation of the function or structure, or both, of microbial environments existing in oil reservoirs to improve recovery.
Miscible Flooding EOR	The injection of miscible gases such as hydrocarbon gas, carbon dioxide (CO <sub>2</sub> ), or inert gas, such as nitrogen under high pressure into the reservoir.
Mmboe	Million barrels of oil equivalent
MME	Brazilian Ministry of Mines and Energy
MMP	Minimum Miscible Pressure
Mmstb	Million stock tank barrels
Mobility ratio	The mobility of a fluid is defined as its relative permeability divided by its viscosity. Mobility combines a rock property, permeability, with a fluid property, fluid viscosity.
MPR	Micellar Polymer
MWAG	Miscible Water Alternating Gas
NCS	Norwegian Continental Shelf
NGL	Natural Gas to Liquids
NPD	Norwegian Petroleum Directorate
NPF	Norsk Petroleumsforening
OGUK	Oil Gas UK
OGA	Oil and Gas Authority
OIIP	Oil Initially in Place
OWC	Oil Water Contact
Permeability	The ability of a substance to allow another substance to pass through it, especially the ability of a porous rock, sediment, or soil to transmit fluid through pores and cracks. Geologic permeability is usually measured in millidarcies.
PILOT	Organisation (formerly the Oil and Gas Taskforce) that facilitates the partnership between the UK oil and gas industry, and government.
Play	
PLT	Production Logging Tool
PRM	Permanent Reservoir Monitoring
PRT	Petroleum Revenue Tax (PRT) of 50%, and is a field based tax, deductible as an expense against RFCT and SCT.
PV	Pore Volume
PWRI	Produced Water Reinjection
RF	Recovery Factor which is the ratio of recoverable oil and / or gas to estimated oil and / or gas in place in reservoir expressed as a percentage. Determined by a various factors such as reservoir dimensions, pressure, nature of hydrocarbons, and field development plan.
RFCT	Ring Fence Corporation Tax (RFCT) at the rate of 30% on the profits arising from 'oil extraction' or the 'acquisition, enjoyment or exploitation of oil rights' in the UK or UKCS.
Rock wettability	Wettability is the tendency of one fluid to spread on, or adhere to, a solid surface in the presence of other immiscible fluids. Wettability refers to the interaction between fluid and solid phases. In a reservoir rock the liquid phase can be water or oil or gas, and the solid phase is the rock mineral assemblage.
ROI	Return on Investment
SAG	Surfactant Alternating Gas
SAGE	Scottish Area Gas Evacuation

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Saturation	Saturation is a direct measure of the fluid content of the porous rock. It therefore directly influences the hydrocarbon storage capacity of the reservoir.
SCT	Supplementary Charge (SCT) occurs at a rate of 32%, charged on the same basis as RFCT.
SPE	Society of Petroleum Engineers
SSWAG	Selective Simultaneous Water Alternating Gas
SVT	Sullom Voe Terminal
SWAG	Selective Simultaneous Water Alternating Gas
Sweep Efficiency	A measure of the effectiveness of an enhanced oil recovery process that depends on the volume of the reservoir contacted by the injected fluid. The volumetric sweep efficiency is an overall result that depends on the injection pattern selected, off-pattern wells, fractures in the reservoir, position of gas-oil and oil/water contacts, reservoir thickness, permeability and areal and vertical heterogeneity, mobility ratio, density difference between the displacing and the displaced fluid, and flow rate.
TDS	Total Dissolved Solids
Thermal EOR	Techniques to raise the temperature of the reservoir, thereby stimulating oil flow to a producing well.
TLP	Tension Leg Platform
ToR	Terms of Reference
TVD	True Vertical Depth
UF	Ultra-Filtration
Viscous fingering	A condition whereby the interface of two fluids, such as oil and water, bypasses sections of reservoir as it moves along, creating an uneven, or fingered, profile. Fingering is a relatively common condition in reservoirs with water-injection wells. The result of fingering is an inefficient sweeping action that can bypass significant volumes of recoverable oil and, in severe cases, an early breakthrough of water into adjacent production wellbores.
WAG	Water Alternating Gas
WoS	West of Shetlands
WI	Water Injectors
UKCS	United Kingdom Continental Shelf

