Title : Thermal Enhancement of Water-flooding in Medium-Heavy Oil Recovery

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ABSTRACT

Water-flooding in heavy oils is generally not an efficient way of production due to high viscosity of heavy oil compared to water. Therefore, thermal recovery methods are commonly used in heavy oil production. Most thermal methods involve fluid injection to transfer heat further into the reservoir. Hot water-flooding is among these methods. In hot water-flooding, thermal energy will increase oil mobility, and possibly provide a more efficient sweep.

This research investigates the effect of heat on water-flood recovery. An approximate analytical model has been constructed to describe fluid flow and heat transfer, simultaneously. Furthermore, several core flooding experiments have been conducted. These experiments involve regular (isothermal water-flooding at room temperature), and non-isothermal (hot) water-flooding. X-ray Computed Tomography (CT) scans have been also taken during the experiments to detect the movement of the water phase and the stability of the displacement front.

It has been observed from the experiments, that increasing the injection temperature delays water breakthrough, and increases recovery factor of the water-flood. Moreover, due to the decrease in oil viscosity, the pressure drop along the core also decreases with increasing temperature. On the other hand, the movement of the water phase cannot be detected accurately from CT images.
ACKNOWLEDGEMENTS

This project has been completed with great help and support from a number of people. First and foremost, I would like to thank my supervisors Prof. Dr. Pacelli Zitha and Prof. Dr. Ir. Evert Slob for their inspiration on the topic of the project, and great guidance and insightful comments during discussions in the past ten months. Moreover, am grateful to Dr. Patrick van Hemert and Ir. Mohammad Simjoo for their support during the processing of the CT Scan Data.

I want to appreciate the assistance provided by Marc Friebel and Ir. Karel Heller in conducting experiments, and Ing. Ellen Meijvogel-de Koning and Ing. Wim Verwaal for their contributions while taking CT scans.

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Last but not least, I owe my deepest gratitude to my family and my girlfriend, Şeyda. Even though we were physically apart for the duration of this project, they never ceased to support and encourage me, and this project is dedicated to them.
# NOMENCLATURES

## Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>CT</td>
<td>X-Ray Computed Tomography</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>EM</td>
<td>Electromagnetic</td>
</tr>
<tr>
<td>HU</td>
<td>Hounsfield Units</td>
</tr>
<tr>
<td>KI</td>
<td>Potassium iodide</td>
</tr>
<tr>
<td>PEEK</td>
<td>Polyether-ether-ketone</td>
</tr>
<tr>
<td>PV</td>
<td>Pore Volume</td>
</tr>
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</table>

## Latin

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Unit</th>
</tr>
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<tbody>
<tr>
<td>$A$</td>
<td>Coefficient Matrix</td>
<td></td>
</tr>
<tr>
<td>$\vec{B}$</td>
<td>Complex magnetic flux density</td>
<td>T</td>
</tr>
<tr>
<td>$c_o$</td>
<td>Specific heat capacity of oil</td>
<td>J/kg.K</td>
</tr>
<tr>
<td>$c_s$</td>
<td>Specific heat capacity of rock matrix</td>
<td>J/kg.K</td>
</tr>
<tr>
<td>$c_w$</td>
<td>Specific heat capacity of water/aqueous phase</td>
<td>J/kg.K</td>
</tr>
<tr>
<td>$\vec{D}$</td>
<td>Complex electric displacement field density</td>
<td>C</td>
</tr>
<tr>
<td>$dp$</td>
<td>Pressure drop across the sample</td>
<td>Pa</td>
</tr>
<tr>
<td>$\vec{E}$</td>
<td>Complex electric field intensity</td>
<td>N/C</td>
</tr>
<tr>
<td>$F_{eff}$</td>
<td>property function defined by $\rho_o c_o + (\rho_w c_w - \rho_o c_o) f_w$</td>
<td>J/K.m³</td>
</tr>
<tr>
<td>$f_w$</td>
<td>Fractional flow of water</td>
<td>[-]</td>
</tr>
<tr>
<td>$G$</td>
<td>Dimensionless ratio function defined by $\frac{f_w + \alpha}{s_w + \beta}$</td>
<td>[-]</td>
</tr>
<tr>
<td>$H_{air}$</td>
<td>CT number for air</td>
<td>HU</td>
</tr>
<tr>
<td>$H_{ar}$</td>
<td>CT number for dry rock</td>
<td>HU</td>
</tr>
<tr>
<td>$H_{brine}$</td>
<td>CT number for brine</td>
<td>HU</td>
</tr>
<tr>
<td>$H_o$</td>
<td>CT number for oil</td>
<td>HU</td>
</tr>
<tr>
<td>$H_{owr}$</td>
<td>CT number for a voxel during water-flooding</td>
<td>HU</td>
</tr>
<tr>
<td>$H_{wr}$</td>
<td>CT number for fully water/brine saturated rock</td>
<td>HU</td>
</tr>
</tbody>
</table>
Complex magnetic field intensity $\vec{H}$ A/m
Identity matrix $I$
Complex current density $\mathbf{j}$ A/m$^2$
Imaginary unit $j$
Thermal conductivity of oil $K_o$ W/(m.K)
Thermal conductivity of rock matrix $K_s$ W/(m.K)
Thermal conductivity of water/aqueous phase $K_w$ W/(m.K)
Absolute permeability of core sample $k$ D
Relative permeability to oil $k_{ro}$ [-]
Endpoint relative permeability to oil $k_{ro,e}$ [-]
Endpoint relative permeability to water/aqueous phase $k_{ro,w}$ [-]
Sample/core length $L$ m
Length of the sample at which a mobile water phase is present $L_{eff}$ m
Cumulative dimensionless oil recovery $N_{pd}$ [-]
Corey exponent for oil and water $n_o, n_w$ [-]
Total power dissipated $P$ W
Electromagnetic power dissipated in oil $P_{PVU,o}$ W
Electromagnetic power dissipated in rock matrix $P_{PVU,s}$ W
Electromagnetic power dissipated in water/aqueous phase $P_{PVU,w}$ W
Capillary pressure $p_c$ Pa
Heat source term for oil, rock matrix and water/aqueous phase $q_o, q_s, q_w$
Total external source term $Q$ W/m$^2$
Poynting Vector $\mathbf{S}$
Oil saturation $S_o$ [-]
Residual oil saturation $S_{or}$ [-]
Water saturation $S_w$ [-]
Average water saturation behind displacement front $\bar{S}_w$ [-]
Connate water saturation $S_{wc}$ [-]
Temperature of the system $T$ °C
Temperature of oil, rock matrix and water/aqueous phase $T_o, T_s, T_w$ °C
<table>
<thead>
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<th>Symbol</th>
<th>Definition</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_i$</td>
<td>Temperature of the brine injected into the system</td>
<td>°C</td>
</tr>
<tr>
<td>$T_r$</td>
<td>Initial temperature of the core sample at the start of experiment</td>
<td>°C</td>
</tr>
<tr>
<td>$t$</td>
<td>Time</td>
<td>s</td>
</tr>
<tr>
<td>$t_D$</td>
<td>Dimensionless time</td>
<td>[-]</td>
</tr>
<tr>
<td>$u$</td>
<td>Total velocity</td>
<td>m/s</td>
</tr>
<tr>
<td>$u_o, u_w$</td>
<td>Oil and water (aqueous) phase Darcy velocity</td>
<td>m/s</td>
</tr>
<tr>
<td>$v$</td>
<td>Dimensionless property defined by $\frac{u}{\phi}$</td>
<td>[-]</td>
</tr>
<tr>
<td>$W_{id}$</td>
<td>Dimensionless water injected</td>
<td>[-]</td>
</tr>
<tr>
<td>wt%</td>
<td>Weight percentage</td>
<td>[-]</td>
</tr>
<tr>
<td>$x_D$</td>
<td>Dimensionless position</td>
<td>[-]</td>
</tr>
</tbody>
</table>

**Greek**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha_{CT}$</td>
<td>Attenuation coefficient for a voxel</td>
<td>I/m</td>
</tr>
<tr>
<td>$\alpha_{CT,a}$</td>
<td>Attenuation coefficient for air</td>
<td>I/m</td>
</tr>
<tr>
<td>$\alpha_{CT,w}$</td>
<td>Attenuation coefficient for demineralized water</td>
<td>I/m</td>
</tr>
<tr>
<td>$\beta$</td>
<td>Dimensionless property function defined by $\frac{1-\phi \rho_s c_s + \rho_o c_o}{\rho_w c_w - \rho_o c_o}$</td>
<td>[-]</td>
</tr>
<tr>
<td>$\gamma$</td>
<td>Dimensionless property function defined by $\frac{\rho_o c_o}{\rho_w c_w - \rho_o c_o}$</td>
<td>[-]</td>
</tr>
<tr>
<td>$\varepsilon'$</td>
<td>Real part of permittivity</td>
<td>F/m</td>
</tr>
<tr>
<td>$\varepsilon''$</td>
<td>Imaginary part of permittivity</td>
<td>F/m</td>
</tr>
<tr>
<td>$\Lambda$</td>
<td>Eigenvalues</td>
<td></td>
</tr>
<tr>
<td>$\lambda_o, \lambda_w$</td>
<td>Oil and water/aqueous phase mobility</td>
<td></td>
</tr>
<tr>
<td>$\mu_m'$</td>
<td>Real part of magnetic permeability</td>
<td>N/A²</td>
</tr>
<tr>
<td>$\mu_m''$</td>
<td>Imaginary part of magnetic permeability</td>
<td>N/A²</td>
</tr>
<tr>
<td>$\mu_o$</td>
<td>Dynamic viscosity of oil</td>
<td>Pa.s</td>
</tr>
<tr>
<td>$\nu_o$</td>
<td>Kinematic viscosity of oil</td>
<td>mm/s²</td>
</tr>
<tr>
<td>$\rho_o, \rho_s, \rho_w$</td>
<td>Density of oil, rock matrix and water/aqueous phase</td>
<td>Kg/m³</td>
</tr>
<tr>
<td>$\rho_q$</td>
<td>Complex charge concentration</td>
<td>C/m³</td>
</tr>
<tr>
<td>$\sigma'$</td>
<td>Real part of electrical conductivity</td>
<td>S/m</td>
</tr>
<tr>
<td>Symbol</td>
<td>Description</td>
<td>Unit</td>
</tr>
<tr>
<td>--------</td>
<td>-------------------------------------------------------</td>
<td>----------</td>
</tr>
<tr>
<td>$\sigma''$</td>
<td>Imaginary part of electrical conductivity</td>
<td>S/m</td>
</tr>
<tr>
<td>$\sigma_{eff}$</td>
<td>Effective conductivity of the system</td>
<td>S/m</td>
</tr>
<tr>
<td>$\tau$</td>
<td>Dimensionless property defined by $\frac{l}{v}$</td>
<td>[-]</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Porosity</td>
<td>[-]</td>
</tr>
<tr>
<td>$\phi C_{eff}$</td>
<td>Effective volumetric heat capacity of the system</td>
<td>J/m$^3$.K</td>
</tr>
<tr>
<td>$\phi K_{eff}$</td>
<td>Effective thermal conductivity of the system</td>
<td>W/m.K</td>
</tr>
<tr>
<td>$\chi_R$</td>
<td>Right eigenvectors</td>
<td></td>
</tr>
<tr>
<td>$\omega$</td>
<td>Angular frequency</td>
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CHAPTER 1 - INTRODUCTION

Conventional oil represents a large fraction of the daily production of hydrocarbons. The production of such conventional resources has been diminishing steadily and it is estimated that conventional oil could be depleted in about forty years. To minimize the effects of the decrease in production of conventional oil and meet the growing energy demand, unconventional oil recovery methods have been investigated and applied for nearly fifty years. More recently, unconventional oil recovery has become a major focus of oil and gas industry thanks to technological developments and suitable economic conditions (high oil prices).

Unconventional oil resources including heavy oil, extra-heavy oil, bitumen, shale oil and oil sands represent about two-thirds of the total oil reserves in the world (Alboudwarej, et al., 2006). Heavy oil is only about 15% of the total world oil reserves. However, it is one of the easiest to produce as it displays the most similar characteristics as conventional oil.

1.1. LITERATURE REVIEW

The recovery methods for heavy oil can be classified in two main categories: non-thermal and thermal recovery. Water-flooding is among non-thermal recovery methods. During water-flooding, water injected into the reservoir sweeps the oil in the reservoir as it moves through. The efficiency of a water-flooding project depends on three main factors: the mobility ratio between water and oil, heterogeneity of the reservoir and gravity (Dake, 2001). For a stable displacement such that the mobility ratio between the water and oil is lower than unity, water-flooding can be described by Buckley-Leverett theory (Dake, 1978). However, this is not the case in heavy oil reservoirs. Since heavy oil is much more viscous than water, most heavy oil reservoirs have large mobility ratios. Therefore, water travels faster than oil, and bypasses large parts of the reservoir. This viscous fingering phenomenon leads to poor sweep efficiency and low recovery factors.
(Smith, 1992). Nonetheless, water-flooding has been used in heavy oil reservoirs as a primary recovery method due to its simplicity and low cost (Mai and Kantzas, 2009).

The thermal methods remain the main methods for producing heavy oils. The purpose of thermal methods is to increase the mobility of the oil by reducing its viscosity (Farouq Ali, Jones and Meldau, 1997). For an efficient transfer of the thermal energy deep into the reservoir, thermal recovery methods have usually involved fluid injection like hot water-flooding, steam-flooding or cyclic steam stimulation. Hot water-flooding is not widely used due to its relatively large heat losses. Other thermal methods, including electromagnetic (EM) heating and in-situ combustion (fire-flooding), involve the in-situ generation of the thermal energy used to heat the contents of the reservoir (Latil et al., 1980). In the last two decades, EM heating has been the focus both experimental studies (Chakma and Jha, 1992; Hascakir, Babadagli and Akin, 2008) and numerical modeling (Ovalles et al., 2002; Sahni, Kumar and Knapp, 2000). Without a displacing liquid, the heated zone in these methods is limited. This problem is even more significant for high frequency EM heating because the penetration depth of EM waves into the reservoir is inversely proportional to their frequency. In this work, it is proposed that the combination of water flooding with EM heating will provide a better means of recovery as the injected water will act as a secondary heat source to enhance the heated zone, and will carry the heat further into the reservoir.

1.2. RESEARCH OBJECTIVES

The main objective of this work was to investigate both theoretically and experimentally the effect of heating on the efficiency of a water-flood. Firstly, the theories for the isothermal and non-isothermal two-phase flow in porous media were critically reviewed. The Buckley-Leverett flow models have been solved analytically by the method of characteristics. Secondly, core flooding experiments were conducted to compare the cumulative production and efficiency of regular (isothermal) water-flooding at room temperature and hot water-flooding. The displacement of oil during the process was visualized and analyzed quantitatively using X-ray computed tomography (CT) scans taken at different time intervals to map fluid saturations. The
images help to determine saturation evolution, and estimate the position of the water front and breakthrough time.

Initially, it was planned to include an experiment where microwave heating is combined with water-flooding. However, due to the extreme complexity of building an experimental setup that deals with microwave radiation and computerized tomography simultaneously, the EM part of the experiment could not be completed during this project. The materials concerning EM heating are presented in the Appendices.

The remainder of this thesis is organized in four chapters. The second chapter presents the mathematical models for the isothermal and non isothermal water-flooding and their analytical solution. The analytical models are then used to estimate the cumulative oil production with time. The third chapter provides the experimental details, including a brief description of the principles of CT imaging. The fourth chapter presents a discussion of the experimental results including a comparison with the analytical models. Chapter five gives the main conclusions of this study and some recommendations for further work.
CHAPTER 2 - THEORY

To describe the thermal enhancement of water-flooding in medium-heavy oil, two physical aspects were taken into account: (1) two-phase flow and (2) heat transfer between the phases in the system. The fluid flow is described by the combination of the mass balances of the fluid phases (oil and water) and the Darcy’s equation. Depending on the heating mechanism, the heat balance may involve an external source term, such as an electromagnetic heating source. For hot water-flooding, there is no external source. The source of energy in this case is the combination of thermal conduction from hot water into the reservoir (sandstone matrix, oil and immobile water) and the convection caused by the movement of heated fluid phases. Combining multiphase flow and heat transfer yields the mathematical model for the system. These aspects will be explained in further detail below.

2.1. MULTIPHASE FLOW

Let us consider the 1D flow of two incompressible phases (fluid densities are constant), such that gravity effects are negligible (horizontal flow), in a porous medium with constant porosity $\phi$ and permeability. The basic governing equations for this problem include the mass conservation, energy or heat transfer conservation and the Darcy’s equation. The energy conservation will be treated separately in the next subsection. With the above assumptions, mass conservation and Darcy’s equations can be written

$$\phi \frac{\partial S_\alpha}{\partial t} + \frac{\partial u_\alpha}{\partial x} = 0$$  \hspace{1cm} (2.1)

and

$$u_\alpha = -\lambda_\alpha \left( \frac{\partial p_\alpha}{\partial x} \right)$$  \hspace{1cm} (2.2)

where $S_\alpha$ is the saturation, $u_\alpha$ is the Darcy velocity and $\lambda_\alpha$ is the mobility of fluid phase $\alpha$ ($\alpha = o,w$). To complete the basic formulation of the problem the following closure conditions are required
\[ S_w + S_o = 1; \quad p_c = p_o - p_w \]  \hspace{1cm} (2.3)

where \( p_c \) is the capillary pressure.

The mobility of a phase is defined by the ratio of the product of absolute permeability and relative permeability to dynamic viscosity where the relative permeabilities are only functions of saturation. Here the Brooks-Corey relations were used to represent the relative permeabilities. Combining oil and water phases, the total mass balance becomes

\[ \frac{\partial u}{\partial x} = 0. \]  \hspace{1cm} (2.4)

where \( u \) is the total velocity. As the sum of the water and oil saturation is equal to unity during two-phase flow, it is deduced that the total Darcy velocity independent of the location throughout the reservoir. In a situation where the injection velocity is kept constant, the total velocity for the system will also be constant.

### 2.1.1. Fractional Flow

Introducing the fractional flow of water \( f_w \), i.e. the ratio of water flow rate to the total flow rate of the system, the two-phase flow problem can now be described by the mass balance for the water phase as follows (Willhite, 1986)

\[ \phi \frac{\partial S_w}{\partial t} + u \frac{\partial f_w}{\partial x} = 0 \]  \hspace{1cm} (2.5)

where the fractional flow function is given

\[ f_w = \frac{\lambda_w}{\lambda_w + \lambda_o} \left( 1 + \frac{\lambda_o}{u} \frac{\partial p_c}{\partial x} \right). \]  \hspace{1cm} (2.6)

For an isothermal environment, phase mobilities and the capillary pressure are functions of only the water saturation (Craig, 1971). Therefore, the fractional flow term also is a function of water saturation. For non-isothermal flow, phase mobilities are dependent on both the water saturation and viscosity, and the resulting fractional flow term is be a function of water saturation and temperature.
2.2. HEAT TRANSFER

The heat transport during flow was described using an energy conservation equation. To derive this equation in the general case, we need to take into account all three phases present, i.e. the solid rock matrix, oil and water. For the solid matrix which is immobile, heat transfer occurs only by thermal conduction and can be described by the following heat diffusion equation

\[ \rho_s c_s \frac{\partial T_s}{\partial t} = K_s \frac{\partial^2 T_s}{\partial x^2} + \dot{q}_s \]  

(2.7)

where \( \rho_s \) is the density, \( c_s \) is the specific heat capacity, \( T_s \) is the temperature, \( K_s \) is the thermal conductivity of the solid matrix, and \( \dot{q}_s \) is the source term. For EM heating, the source term represents the power dissipated in the solid phase \( (P_{PVI_s}) \). For hot water-flooding the source term is equal to zero.

For the fluid phases, both conduction and convection contribute to the heat transfer. Accordingly the energy conservation equation for a fluid phase can be written

\[ \rho_\alpha c_\alpha \frac{\partial T_\alpha}{\partial t} + \rho_\alpha c_\alpha u_\alpha \frac{\partial T_\alpha}{\partial x} = K_\alpha \frac{\partial^2 T_\alpha}{\partial x^2} + \dot{q}_\alpha. \]  

(2.8)

For an immobile fluid (such as connate water), the heating mechanism is again reduced to conduction. Convection is dominant at early times but at later times diffusion becomes more important (Sumnu-Dindoruk and Dindoruk, 2006).

By assuming that the system is in local thermal equilibrium, i.e. at a given position, the temperatures of different phases are all equal, the overall energy conservation can be described using a single equation obtained by adding the equations (2.7) and (2.8) for both fluid phases. This gives

\[ \phi C_{eff} \frac{\partial T}{\partial t} + F_{eff} u \frac{\partial T}{\partial x} = Q + \phi K_{eff} \frac{\partial^2 T}{\partial x^2} \]  

(2.9)

where \( \phi C_{eff} \) is the effective volumetric heat capacity of the system, \( Q \) is the total energy influx to the system (equal to total power dissipated \( P_{PVI} \) for EM heating), \( \phi K_{eff} \) is the effective
thermal conductivity for the system, and the coefficient $F_{eff}$ is a function of the fractional flow term. These quantities are defined as:

\[
\phi C_{eff} = (1 - \phi)\rho_s c_s + \phi[\rho_o c_o + (\rho_w c_w - \rho_o c_o)S_w] \tag{2.10}
\]

\[
\phi K_{eff} = (1 - \phi)K_s + \phi[K_o + (K_w - K_o)S_w] \tag{2.11}
\]

\[
F_{eff} = \rho_o c_o + (\rho_w c_w - \rho_o c_o)f_w \tag{2.12}
\]

The source term for EM heating is discussed in detail in Appendix B. Note that in the above definitions we have assumed that the densities and specific heat capacity are independent of temperature. This is a reasonable assumption only if the changes of temperature are not too large.

2.3. ANALYTICAL SOLUTIONS

2.3.1. Coupled Problem

From the previous section, the non-isothermal water-flooding can generally be described by the system comprising the fluid flow equation (2.5) and the energy balance (2.9). This is a system of non-linear partial differential equations (PDE) which are first order in time and second order in space. There are no obvious analytical solutions in the general case for this type of system. In order to obtain approximate analytical solutions, further assumptions are made, enabling the simplification of the equations. The most important of these is the neglect of diffusive terms, i.e. the capillary pressure and the thermal conduction terms, in the mass and energy balance equations, respectively. With these assumptions, the system is converted into a first order one, and takes the form of

\[
\begin{cases}
\phi \frac{\partial S_w}{\partial t} + u \frac{\partial f_w}{\partial x} = 0; f_w = \frac{\lambda_w}{\lambda_w + \lambda_o} \\
\phi C_{eff} \frac{\partial T}{\partial t} + F_{eff} u \frac{\partial T}{\partial x} = 0
\end{cases} \tag{2.13}
\]

where clearly, the fractional flow is now only function of phase mobilities, and is thus dependent on water saturation and temperature. The coupled problem in Eq. 2.13 is a quasi-linear system of
partial differential equations. For the analytical solution, it is convenient to put the equations in dimensionless form, using the following dimensionless parameters:

\[
\begin{align*}
v & = \frac{u}{\phi}; \quad \tau = \frac{L}{v}; \quad x_D = \frac{x}{L}; \quad t_D = \frac{t}{\tau}
\end{align*}
\]

where \(x_D\) and \(t_D\) are dimensionless position and time, respectively. Using chain rule of differentiation, the fractional flow term in the first equation of the system is divided into two separate terms dependent on water saturation and temperature, respectively. After these substitutions, the coupled problem becomes

\[
\begin{align*}
\frac{\partial S_w}{\partial t_D} + \frac{\partial f_w}{\partial t_D} \frac{\partial S_w}{\partial x_D} + \frac{\partial f_w}{\partial t_D} \frac{\partial T}{\partial x_D} &= 0; \quad f_w = \frac{\lambda_w}{\lambda_w + \lambda_o} \\
\frac{\partial T}{\partial t_D} + G \frac{\partial T}{\partial x_D} &= 0
\end{align*}
\]

The term \(G\) is the ratio of \(F_{eff}\) to \(C_{eff}\), which are defined by Eqs. 2.12 and 2.10, respectively. Following substitution, this new term can be expressed as

\[
G = \frac{f_w + \gamma}{S_w + \beta}
\]

where \(\gamma\) and \(\beta\) are dimensionless functions of thermal properties and porosity, and are defined by

\[
\begin{align*}
\gamma &= \frac{\rho_o c_o}{\rho_w c_w - \rho_o c_o} \quad ; \quad \beta = \frac{1 - \phi}{\phi} \frac{\rho_o c_o + \rho_o c_o}{\rho_w c_w - \rho_o c_o}
\end{align*}
\]

### 2.3.2. Initial and Boundary Conditions

We consider the case where the core is fully saturated with oil and connate water before waterflooding. During water flooding the oil saturation at the core inlet is equal to the residual oil saturation, so that the water saturation at \(x_D = 0\), is equal to \(1 - S_{or}\). Similarly, the initial temperature throughout the core is equal to the initial core temperature \(T_r\), and at the inlet the temperature is equal to the temperature of the injected water \(T_i\). Initial and boundary conditions are summarized on Table 2-1.
### Table 2-1. Initial and boundary conditions for non-isothermal two phase flow

<table>
<thead>
<tr>
<th>Initial Conditions</th>
<th>Boundary Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>$S_w(x_D, 0) = S_{wc}$</td>
<td>$S_w(0, t_D) = 1 - S_{or}$</td>
</tr>
<tr>
<td>$T(x_D, 0) = T_r$</td>
<td>$T(0, t_D) = T_i$</td>
</tr>
</tbody>
</table>

#### 2.3.3. Analytical Solution for Isothermal Flow

For an isothermal displacement the system reduces to the conservation law regarding fluid flow. The solution to this conservation law is given by the Buckley-Leverett displacement theory. The Buckley-Leverett equation is given as

$$
\left( \frac{dx}{dt} \right)_{S_w} = \frac{u}{\phi} \left( \frac{\partial f_w}{\partial S_w} \right)_t
$$

(2.18)

where $\left( \frac{dx}{dt} \right)_{S_w}$ is the characteristic velocity for any particular water saturation value. Buckley-Leverett theory states each water saturation value moves with a different characteristic velocity that is proportional to the fractional flow derivative. This equation is solved using the method of characteristics coupled with shock-front displacement (Dake, 2001). The resulting saturation profile starts off as a rarefaction wave moving with characteristic velocity until it reaches the shock saturation, and then drops to the initial (connate) water saturation. The shock indicates the position of the water front.

The shock saturation is determined by locating the point at which the shock velocity is maximum. The shock velocity is calculated from the Rankine-Hugoniot condition (Leveque, 2004), and is given as

$$
\frac{\Delta f_w}{\Delta S_w} = \frac{f_w(S_w) - f_w(S_{wc})}{S_w - S_{wc}}.
$$

(2.19)

After determining the shock saturation, the saturation profile at any time is determined by solving the Buckley-Leverett equation for $x$. 

2.3.4. Analytical Solution for Non-Isothermal Flow

Da Mota (1992), Bedrikovetsky (1993), Barkve (1989) Sumnu-Dindoruk and Dindoruk (2006) provided the analytical and general solution to non-isothermal two-phase flow. This study adopted the approach of Sumnu-Dindoruk and Dindoruk, which uses the method of characteristics to solve the quasi-linear system (2.15), which is rewritten here in the following matrix form

\[
\frac{\partial U}{\partial t} + A(U) \frac{\partial U}{\partial x} = 0
\]  

(2.20)

where \( U \) is the state vector whose elements are the dependent parameters, and \( A(U) \) is the square matrix of coefficients defined by

\[
U = \begin{pmatrix} S_w \\ T \end{pmatrix}; \quad A = \begin{pmatrix} \frac{\partial f_w}{\partial S_w} & \frac{\partial f_w}{\partial T} \\ 0 & G \end{pmatrix}
\]  

(2.21)

The method of characteristics can only be applied to the system (2.20) if it is hyperbolic. The nature of the system is determined by the discriminant of the quadratic equation obtained from

\[
|A - \Lambda I| = 0
\]

(2.22)

where \( I \) is the identity matrix. The system is hyperbolic, if the discriminant is positive. This turns out to be the case, as the discriminant is equal to

\[
\left( \frac{\partial f_w}{\partial S_w} + G \right)^2 - 4 \left( \frac{\partial f_w}{\partial S_w} G \right) \left( \frac{\partial f_w}{\partial S_w} - G \right)^2 > 0
\]

(2.23)

The eigenvalues of \( A \), \( \Lambda_1 \) and \( \Lambda_2 \), are equal to the solutions of Eq. 2.22. These values indicate the characteristic curves \( C_+ \) and \( C_- \), and are calculated as

\[
C_+ : \frac{dx}{dt} = \Lambda_1 = \frac{\partial f_w}{\partial S_w} ; \quad C_- : \frac{dx}{dt} = \Lambda_2 = G
\]

(2.24)

The corresponding right-eigenvectors are
As the system has two eigenvalues that are functions of the same parameters, there is a possibility that they coincide at points in space. This will lead to a parabolic degeneracy, at which the system will fail to have a classical solution. Therefore a weak solution should be introduced. The weak solution of a genuinely nonlinear hyperbolic system consists of rarefaction waves that are terminated by shocks. To check whether a field is genuinely nonlinear, the gradient of the eigenvalue of the field is multiplied by the corresponding eigenvector for that field (Toro, 2009). This operation yields

\[ \chi_R^{(1)} \cdot \nabla \Lambda_1 = \frac{\partial^2 f_w}{\partial S_w^2}; \quad \chi_R^{(2)} \cdot \nabla \Lambda_2 = 0 \]  \hspace{1cm} (2.26)

indicating that the temperature evolution is not genuinely nonlinear, but it is linearly degenerate instead. Accordingly, it can be inferred that the temperature anywhere in the system consists of two constant states (Leveque, 2004); i.e. injected water temperature and initial rock temperature in this case, which are separated by a discontinuity, which propagates at a constant speed of \( G \).

However, the evolution of water saturation is more complex, as it is affected by fractional flow derivatives with respect to both saturation and temperature. From downstream (outlet) to upstream, the solution starts with a constant state equal to the connate water saturation. This zone displays the initial conditions, and indicates the zone that is unaffected by the injected fluid. The constant state is terminated by a shock front which is identical to the Buckley-Leverett type front observed in the isothermal case. The solution then continues with a rarefaction wave until the point at which the eigenvalues of the system at the injection temperature \( T_i \) are equal. This point marks the saturation values which are observed at the point that the temperature jumps from its initial value \( T_r \) to the injected value \( T_i \). As soon as the saturation reaches this value, the rarefaction wave transforms into a zone of constant state, which continues until the temperature front. This phenomena is caused because the landing point of the trailing shock caused by the change in temperature moves slower than the rarefaction wave for the same saturation (Sumnu-
Dindoruk and Dindoruk, 2006). The saturation at which the trailing shock is observed is equal to the saturation at which

\[ G(S_w)|_{T=T_l} = G(S_w)|_{T=T_r}. \] (2.27)

At the temperature front, a jump in saturation is observed. The solution then continues as a rarefaction wave until the inlet. The characteristic velocity of this rarefaction is equal to the fractional flow derivative for the injection temperature.

### 2.3.5. Production Estimation

For the isothermal water-flooding the production profile is determined by the classical Welge integration (Dake, 1978). In this approach, the average water saturation in the entire core is determined, and the cumulative dimensionless oil recovery is estimated from

\[ N_{pd} = \bar{S}_w - S_{wc} \] (2.28)

where \( \bar{S}_w \) is the average water saturation inside the core. The average water saturation at breakthrough is determined by drawing a tangent on the fractional flow curve from \( (S_{wc}, 0) \), and extending it to intersect \( f_w = 1 \) (Figure 2.1). The point of intersection is equal to the average saturation at breakthrough.

To determine the production after breakthrough, the saturation value \( S_{w,e} \) is increased with increments of 0.01, and the cumulative oil production is calculated from

\[ N_{pd} = (1 - f_{w,e})W_{id} + (S_{w,e} - S_{wc}) \] (2.29)

where \( f_{w,e} \) is the fractional flow value corresponding to the saturation \( S_{w,e} \), and \( W_{id} \) is the dimensionless water injected into the system up to that point. The dimensionless water injected at any point is calculated from

\[ W_{id} = \frac{1}{\frac{df_w}{dS_w}|_{S_{w,e}}}. \] (2.30)
For determining the production during non-isothermal water-flooding, numerical integration is used. In this approach, the saturation range has been divided into numerous pieces with a step size of 0.0005, and the trapezoidal rule has been used for each interval to determine the area under the rarefaction waves. These values are then combined with the area of the zone of constant state, which is derived using rectangle method. Repeating this operation for different times yields the production evolution for non-isothermal water-flooding. The cumulative dimensionless oil production has been calculated at intervals of one minute in this study.

![Fraction flow curve and tangent](image)

**Figure 2.1.** Fraction flow curve (blue), and the tangent drawn to calculate average saturation at breakthrough

### 2.3.6. Pressure Drop

Assuming that capillary pressure is negligible, the pressure drop for both the oil and water phases are equal, and can be estimated from

\[ \Delta p = \frac{(1 - f_w)L_{\text{eff}} \mu_o}{k k_{ro}} \]  

(2.31)
where $\Delta p$ is the pressure drop across the core, $L_{eff}$ is the length of the sample at which a mobile water phase is present, and $k_{r,o}$ is the relative permeability to oil. At a given time, the fractional flow and relative permeability are calculated from the saturation profile for that time. Similar to the production curves, the pressure drop has been calculated for every minute of water-flooding.
CHAPTER 3 - EXPERIMENTS

This chapter presents the details about the experiments conducted in this project. It discusses the methodology of the experiments to determine the effects of thermal energy on the efficiency of water-flooding. Two types of experiments were performed: isothermal water-flooding and non-isothermal (or hot) water-flooding. All aspects of these experiments will be discussed, including the materials, fluid model, preparation and procedure. The experiments involve CT scans, therefore CT scanning principles and data processing for CT scan data will also be discussed.

3.1. CORE AND COREHOLDER

The properties of the Bentheimer sandstone core samples used to carry out the experiments are shown in Table 3-1. The values for the density and specific heat capacity were obtained from literature (Waples and Waples, 2004). Core porosity was determined using wet porosity method. Each core was encapsulated in 2 mm thick glue to avoid bypassing flow along the sides of the core. The core was placed in a polyether-ether-ketone (PEEK) core-holder to isolate it from any environmental effects.

<table>
<thead>
<tr>
<th>Permeability (D)</th>
<th>Porosity (-)</th>
<th>Diameter (cm)</th>
<th>Length (cm)</th>
<th>Density (kg/m³)</th>
<th>Specific Heat Capacity (J/kgK)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.25 ± 0.30</td>
<td>0.225 ± 0.01</td>
<td>3.96 ± 0.05</td>
<td>17.0 ± 0.10</td>
<td>2640</td>
<td>775</td>
</tr>
</tbody>
</table>

3.2. MATERIALS AND METHODS

A paraffinic medium-heavy oil (Shell Ondina 933) mainly used in medicine was used in the experiments. This refined oil was chosen because of its homogeneity and stable parameters. The aqueous phase consisted with a solution of potassium iodide (KI) in demineralized water. The addition of the KI had two main purposes: (a) enhance the contrast between the aqueous and oleic phases in porous media and (b) prevent any clay swelling or detachment of fines. Vials
containing the KI solutions with different concentrations were prepared and CT scanned to establish the calibration curve (Figure 3.1). The brine containing 3 wt% KI, with an attenuation coefficient almost twice of that of Shell Ondina 933, was chosen for doing the core-floods. The properties of the fluids used to do the experiments are summarized in Table 3-2. There is a viscosity difference of about 1% between the brine and water, but this is neglected due to the low value of water/brine viscosity compared to the oil.

![Figure 3.1. Histogram of CT numbers for different fluid phases](image)

3.2.1. Viscosity-Temperature Relation

To obtain the viscosity-temperature relation, the viscosity of the oil was measured at different temperatures, ranging from 20 to 70°C using a Rheometric Mechanical Spectrometer. The corresponding kinematic viscosity-temperature curve is shown Figure 3.2. The kinematic viscosity at any temperature is determined from the exponential trendline running through this data. The resulting equation to determine kinematic viscosity of oil \( \nu_o \) at a given temperature is

\[
\nu_o = 671e^{-0.0491(T)} \tag{3.1}
\]
Since the change in oil viscosity is has the most influence on the model, the other fluid and rock parameters have been assumed to be constant with changing conditions.

Table 3-2. Properties of fluids used in the experiments

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Density (kg/m³)</th>
<th>Dynamic viscosity at 20°C (Pa.s)</th>
<th>CT number (HU)</th>
<th>Specific Heat Capacity (J/kgK)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shell Ondina 933</td>
<td>876±8.00</td>
<td>0.220±0.0110</td>
<td>-139.5</td>
<td>2000±50.0</td>
</tr>
<tr>
<td>Water</td>
<td>1000±2.00</td>
<td>0.001</td>
<td>0.00</td>
<td>4190±20.0</td>
</tr>
<tr>
<td>3% KI Brine</td>
<td>1020±8.00</td>
<td>0.001</td>
<td>505.0</td>
<td>4170±20.0</td>
</tr>
</tbody>
</table>

Figure 3.2. Experimental kinematic viscosity- temperature data (red) and the trendline (blue) used for viscosity calculation
3.3. EXPERIMENTAL SETUP

The experimental setup used in this study is shown in Figure 3.3. In this setup, the brine is injected into the core at a constant flow rate using a high pressure syringe pump (ISCO pump). This pump is connected to a thermostatic bath, which circulates hot water through the annulus of the pump to heat up the brine. However, due to (relatively) low flow rates used in the experiment, energy transferred by heat convection is not sufficient to maintain the temperature of the brine in the distance that leaves the pump and enters the core. To minimize this heat loss, water from the thermostatic bath is circulated also around the tube that transfers the brine from the pump to the core holder.

![Figure 3.3. The Schematic of the Experimental Setup](image)

During the experiments, the pressure and the temperature were monitored using two pressure transducers and four thermocouples, respectively. A pressure transducer is connected at the inlet of the core holder to determine the pressure of the system, while another transducer is connected at two points of the core (4.35 cm apart) to measure the pressure drop inside the core.
Meanwhile, two of the thermocouples were placed at the inlet and the outlet while the other two were placed inside the core to measure the temperature 4.0 and 13.0 cm away from the inlet. The effluents were collected using a fraction collector to construct an accurate production curve.

The setup was slightly modified by using stainless steel tubing and connectors to ensure that it could withstand higher pressures. In the modified set-up the pressure in the core was controlled using a backpressure regulator connected at the core outlet.

### 3.4. CT SCANNING

X-ray computed tomography was used to determine the average porosity and to map fluid saturations during water flooding. During scanning of the specimens, the intensity of the X-ray beams are attenuated as they cross the sample. The detectors placed oppositely to the X-ray source measure the attenuated intensities of the emerging beams. The data gathered at these detectors are filtered and inverted to reconstruct the spatially resolved attenuation maps, or CT scan images of the scanned object (Du et al., 2008).

#### 3.4.1. Data Acquisition

During two-phase flow, a single attenuation coefficient of a voxel (volume pixel) includes the combined attenuation of the rock, oil and water. After scanning, the attenuation coefficient for each voxel is converted into the Hounsfield Scale by

$$H = 1000 \times \left( \frac{\alpha_{CT}}{\alpha_{CT,w}} - 1 \right).$$  \hspace{1cm} (3.2)

Here $H$ is the converted attenuation coefficient (also called the CT number), $\alpha_{CT}$ is the attenuation coefficient for any pixel, and $\alpha_{CT,w}$ is the attenuation coefficient for demineralized water. The units for CT number are called Hounsfield Units (HU). By definition, the CT numbers for demineralized water and air ($\alpha_{CT,air} = 0$) are 0 and -1000, respectively.
3.4.2. Methodology

The settings used during the scanning procedure are displayed on Table 3-3. The scanner used in this project is a third generation scanner in which the X-ray source and the detectors rotate around the sample (Sharma, Brigham, & Castanier, 1997). For a scanning sequence in this project, the slices are taken parallel to the length of the core. In a sequence, the scanner takes 4 slices simultaneously. The resulting images consists of 512 x 512 pixels, with each one representing the average attenuation coefficient for a volumetric element. To cover as much of the core as possible in an image, the slices are focused on the middle of the core. The slice thickness is 1 mm, so the resulting images cover a width of 3 mm.

To estimate the porosity and water saturation from CT scan data, the contribution of all the solid materials (rock, core holder, tubing, thermocouple etc.) in the scan window must be removed from the images. Therefore, images of the dry core and 100 % water saturated core are also needed, to compare the water-flooding images.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tube current</td>
<td>250 mA</td>
</tr>
<tr>
<td>Tube voltage</td>
<td>140 kV</td>
</tr>
<tr>
<td>Scan mode</td>
<td>Sequential</td>
</tr>
<tr>
<td>Slice thickness</td>
<td>1 mm</td>
</tr>
<tr>
<td>Number of images</td>
<td>4/slice</td>
</tr>
<tr>
<td>Number of slices</td>
<td>4</td>
</tr>
<tr>
<td>Scan time</td>
<td>3 s</td>
</tr>
<tr>
<td>Image reconstruction kernel</td>
<td>B50s medium sharp</td>
</tr>
</tbody>
</table>

3.4.3. Image Processing

To process the images, and calculate properties of the porous specimen, a MATLAB script was developed by the author. The first step of image processing consists of cropping manually the
core from the measured CT scan images. This results in the core being divided in 481 voxels along its length.

After cropping the images, the attenuation coefficient values are converted to CT numbers using Eq. 3.2. The porosity at a location is then calculated from

$$\phi_{CT} = \frac{H_{wr} - H_{ar}}{H_{brine} - H_{air}}$$

(3.3)

where $H_{wr}$ is the CT number for fully water saturated rock, $H_{ar}$ is the CT number for dry rock, $H_{brine}$ is the CT number for the brine and $H_{air}$ is the CT number for air (Akin and Kovcsek, 2003). The oil saturation is determined using

$$S_o = \frac{H_{owr} - H_{wr}}{\phi_{CT}(H_o - H_{brine})}$$

(3.4)

where $H_{owr}$ and $H_o$ are the CT numbers during water-flooding and for the oil phase, respectively. The water saturation is then calculated by simply taking the difference between unity and oil saturation.

### 3.5. EXPERIMENTAL PROCEDURE

The procedure used to conduct the experiments is shown on Figure 3.4. The experiment can be divided into two separate processes; core saturation and core flooding. For core saturation, the core is placed inside a core holder, and the annular space of the core holder is sealed with O-rings. Next, CO₂ was flushed through the core to remove all the air inside. Then, 10 PV brine were injected into the core at a flow rate of 3 cm³/min (this requires nearly 3 hours) to saturate the core: the back pressure was set to 25 bar to ensure complete dissolution of the CO₂ and thus 100% saturation of the core with brine. Subsequently, brine injection continues at different flow rates to determine the core permeability. Using Darcy’s Law, the permeability is calculated from the measured pressure drop at each flow rate. The last part of core saturation is the injection of oil into the core to bring the system to the connate water saturation. The flow rate and the
duration of this process were similar to brine injection. At the end of this process, the initial conditions for water-flooding were established.

![Flow chart explaining the experimental procedure](image)

Water-flooding was carried out at a flow rate of 1 cm³/min and was continued for about 6 PV until the pressure drop over the core was stable. CT scans of the core were taken at different times during water-flooding process to calculate the saturation evolution in the system, and estimate the position of the water front. During core saturation, the temperature of the core and the fluids were equal to the ambient temperature of 21°C. However, the temperature of the injected brine during water-flooding varied at each experiment. In total, three core floods have been conducted for three different brine temperatures: 21 °C (isothermal water-flooding), 35.5°C and 57 °C.
CHAPTER 4 - RESULTS AND DISCUSSIONS

4.1. RELATIVE PERMEABILITY DATA

The relative permeability curves have been determined by using Brooks-Corey model. The parameters used in the construction of these curves were determined by history matching the analytical isothermal model to two-phase experiments. These values are shown in Table 4-1, and the resulting relative permeability curves are presented in Figure 4.1.

Table 4-1. Parameters used to construct the relative permeability curves

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$S_{wc}$</td>
<td>Varies with experiment</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>0.3</td>
</tr>
<tr>
<td>$k_{ro,e}$</td>
<td>0.75</td>
</tr>
<tr>
<td>$k_{rw,e}$</td>
<td>0.05</td>
</tr>
<tr>
<td>$n_o$</td>
<td>2</td>
</tr>
<tr>
<td>$n_w$</td>
<td>4</td>
</tr>
</tbody>
</table>

Figure 4.1. Oil-water (brine) relative permeability curves at 21°C
4.2. CORE FLOODING EXPERIMENTS

The conditions and duration of all three experiments are summarized on Table 4-2. For the isothermal experiment, CT images were only taken during core flooding. Therefore, no saturation profiles could be determined for this experiment. Moreover, the core sample was vertical during core saturation phase and horizontal during core flooding for the first non-isothermal experiment.

4.2.1. Isothermal Water-flooding

In this experiment, the temperature of the rock and the injected brine are assumed to be the same as the difference between them is within experimental error. CT imaging was started 1 minute

<table>
<thead>
<tr>
<th>Property</th>
<th>Isothermal Experiment</th>
<th>Non-isothermal Experiment</th>
<th>Non-isothermal Experiment 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV (ml)</td>
<td>46.8±2.50</td>
<td>49.5±1.25</td>
<td>49.4±0.910</td>
</tr>
<tr>
<td>$\phi$</td>
<td>0.219±0.013</td>
<td>0.232±0.008</td>
<td>0.231±0.007</td>
</tr>
<tr>
<td>k (D)</td>
<td>1.44±0.030</td>
<td>1.18±0.050</td>
<td>1.54±0.005</td>
</tr>
<tr>
<td>Saturated oil (ml)</td>
<td>37.7±1.50</td>
<td>41.7±1.30</td>
<td>42.2±1.50</td>
</tr>
<tr>
<td>Remaining water (ml)</td>
<td>9.10±2.90</td>
<td>8.30±1.80</td>
<td>8.50±1.75</td>
</tr>
<tr>
<td>$S_{wc}$</td>
<td>0.194±0.086</td>
<td>0.167±0.037</td>
<td>0.167±0.036</td>
</tr>
<tr>
<td>$S_{oi}$</td>
<td>0.806±0.086</td>
<td>0.833±0.037</td>
<td>0.833±0.036</td>
</tr>
<tr>
<td>Duration</td>
<td>4 h 44 m 09 s</td>
<td>4 h 42 m 19 s</td>
<td>5 h 4 m 37 s</td>
</tr>
<tr>
<td>$W_{ad}$ (PV)</td>
<td>6.07±0.320</td>
<td>5.70±0.140</td>
<td>6.17±0.110</td>
</tr>
<tr>
<td>$T_r$ ($^\circ$C)</td>
<td>21.3±1.00</td>
<td>21.5±1.00</td>
<td>21.8±1.00</td>
</tr>
<tr>
<td>$T_i$ ($^\circ$C)</td>
<td>21.1±1.00</td>
<td>35.5±1.00</td>
<td>57.1±1.00</td>
</tr>
<tr>
<td>$\mu_o$ at $T_i$ (cP)</td>
<td>209±10.6</td>
<td>103±5.20</td>
<td>36.0±1.80</td>
</tr>
</tbody>
</table>
into brine injection, and scans were taken on twelve occasions. Since there were no scans during core saturation, the images were used to estimate the position of the water front only.

4.2.1.1. **CT images**

CT images for isothermal water-flooding are displayed in Figure 4.2. No clear water-oil displacement front could be observed from these CT images due to a poor contrast between the phases. However, by using the difference between CT numbers of images the water saturation profiles and a position for the water front could be estimated (Figure 4.3).

![CT images](image-url)

Figure 4.2. CT images at different times for isothermal water-flooding. Images were obtained by the subtraction of water-flooding images from the oil saturated image. The water is injected from the left side of the core. The estimation for displacement front at each time has been indicated by the green vertical lines.
Initially the CT numbers during water-flooding are very similar to the numbers of the wet core. Even though the data is noisy, the CT numbers appear to increase near the inlet after 5 minutes. As time passes, the extent of the zone with elevated CT numbers also increases. This corresponds to the movement of the brine with time. As higher density brine invades the core, the CT numbers increase starting from the inlet. The position of the water phase is estimated at the point where the CT numbers decrease to the value of the oil saturated core. This decrease in CT numbers is a gradual one, instead of a shock front; indicating unstable displacement of the oil phase. The estimations for the position of the brine are displayed on Table 4-3.

![Figure 4.3. Differences in CT numbers between water-flooding images and oil saturated image for isothermal water-flooding. The position of the displacement front is determined from the region where the difference between images decrease. The water is injected from the left side (L= 0 cm). Lower numbers suggest that the conditions in the core is similar to the oil saturated core](image)

**4.2.1.2. Production and Pressure Drop**

The production profile for isothermal water-flooding is displayed in Figure 4.4. The recovery factor after injection of about 6 PV brine is about 55 %, and the breakthrough was estimated to have taken place after injection of 0.26 PV of brine. This amount of injection corresponds to 12 minutes. However, this estimation of breakthrough does not seem to agree with the pressure drop data, which reaches its maximum value after just 8 minutes (Figure 4.5). This difference might
be caused from an error in estimating the production delay resulting from the time difference between the moment oil is observed in the production tubing and the moment that this oil drops into the fraction collector.

Furthermore, the estimated time of breakthrough from production and pressure data does not comply with the CT images. In the scan data, no breakthrough is observed even after 20 minutes into the injection. This indicates that CT scan data is not an accurate way to estimate water breakthrough for the isothermal water-flooding experiment.

Table 4-3. Position of the displacement front during isothermal water-flooding

<table>
<thead>
<tr>
<th>Time</th>
<th>Estimated position of the displacement front</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 minute</td>
<td>Indistinguishable</td>
</tr>
<tr>
<td>3 minutes</td>
<td>Indistinguishable</td>
</tr>
<tr>
<td>5 minutes</td>
<td>1.1 cm</td>
</tr>
<tr>
<td>7 minutes</td>
<td>1.7 cm</td>
</tr>
<tr>
<td>9 minutes</td>
<td>3 cm</td>
</tr>
<tr>
<td>10 minutes</td>
<td>3.5 cm</td>
</tr>
<tr>
<td>12 minutes</td>
<td>4.6 cm</td>
</tr>
<tr>
<td>14 minutes</td>
<td>5.9 cm</td>
</tr>
<tr>
<td>16 minutes</td>
<td>7.9 cm</td>
</tr>
<tr>
<td>20 minutes</td>
<td>11.6 cm</td>
</tr>
<tr>
<td>124 minutes</td>
<td>After Breakthrough</td>
</tr>
<tr>
<td>195 minutes</td>
<td>After Breakthrough</td>
</tr>
</tbody>
</table>
Figure 4.4. The recovery factor obtained during isothermal water-flooding.

Figure 4.5. Pressure drop for isothermal water-flooding. The point at which the pressure drop reaches maximum is marked.
4.2.2. Hot water-flooding (35.5°C)

4.2.2.1. CT images

The CT images were taken at seven different times during water-flooding, including the image of the oil saturated core just before water injection commenced. These images are displayed in Figure 4.6. They show the difference between the core during water-flooding and the wet core, with red color indicating that the attenuation in both cases at that voxel is the same. Therefore, it is expected that an increase in red zones will be observed with time. However, as in the isothermal case, a clear front is not visible in the images. Furthermore, a clear displacement front cannot be estimated even with the help of the CT number profiles, as the accuracy of the data is believed to be compromised. A sudden drop in CT numbers is observed 4.5 minutes into water-flooding, which can only be accounted by air getting into the core before water-flooding started (Figure 4.7). Under normal circumstances, the CT numbers should start to increase with the injection of brine (as in the isothermal case).

Figure 4.6. CT images at different times for hot water-flooding at 35.5°C. Images were obtained by the subtraction of water-flooding images from the wet core image. The water is injected from the left side of the core.
Figure 4.7. Differences in CT numbers between wet core image and water-flooding images for hot water-flooding at 35.5°C. The position of the water front is determined from the region where the difference between images increase. The water is injected from the left side (L=0 cm). Lower numbers suggest that the conditions in the core is similar to the wet core. The jump in values after 4.5 min indicate a decrease in the total density of the core, and cause the difference in CT numbers to increase.

4.2.2.2. Saturation Profiles

The average porosity of the sample was calculated as 0.134 from the CT scan data. This values is significantly lower than the value of 0.232 obtained by measuring the volume of brine injected in the core during core saturation. As expected, the presence of air in the system affects the calculation of porosity. Because of the error in porosity calculations, and the discrepancies in CT numbers, no saturation profiles have been constructed for this experiment.

4.2.2.3. Production and Pressure Drop

From the measurement of the effluents, the total recovery rate for this experiment is found out to be about 56%, and the recovery factor at breakthrough is about 40% (Figure 4.8). First water production is observed after 20 minutes, which corresponds to the injection of more than 0.40 PV of brine. This estimation of breakthrough time is not entirely consistent with the pressure drop (Figure 4.9). The pressure drop reaches a maximum a little after 12 minutes, which is 10 minutes earlier than the water breakthrough observed from production. This difference between
estimated breakthrough times indicate a slight problem during effluent collection, which causes a delay in fluid production.

Figure 4.8. The recovery factor obtained during hot water-flooding at 35.5°C

Figure 4.9. Pressure drop for hot water-flooding at 35.5°C. The point at which the pressure drop reaches maximum is marked.
4.2.3. Hot Water-Flooding (57°C)

4.2.3.1. CT Images

Fourteen CT scans, including that of the oil saturated core were taken during the experiment. Similar to the previous cases, no clear water front can be observed from the images, but zones of increased attenuation indicating brine movement can be seen in the images (Figure 4.10). These areas start near the inlet after 8 minutes, and spread throughout the core with time. Due to lack of a clear front, the position of the displacement front is determined from CT number profiles (Figure 4.11). Similar to the isothermal case, the gradual decrease in CT numbers indicate that no shock front is visible, and the mobility ratio continues to be too high for stable displacement. The estimated positions of the displacement front at each time is displayed in Table 4-4. From the images, it is concurred that the breakthrough takes place around 20 minutes into water-flooding.

![CT images at different times for hot water-flooding at 57°C. Images were obtained from the subtraction of water-flooding images from the wet core image. The water is injected from the left side of the core.](image-url)
Figure 4.11. Differences in CT numbers between wet core image and water-flooding images for hot water-flooding at 57°C. The position of the water front is determined from the region where the difference between images increase. The water is injected from the left side (L = 0 cm).

Table 4-4. Position of the water front during hot water-flooding at 57°C

<table>
<thead>
<tr>
<th>Time</th>
<th>Estimated position of the water front</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 minutes</td>
<td>Indistinguishable</td>
</tr>
<tr>
<td>5 minutes</td>
<td>Indistinguishable</td>
</tr>
<tr>
<td>8 minutes</td>
<td>1.35 cm</td>
</tr>
<tr>
<td>11 minutes</td>
<td>3.4 cm</td>
</tr>
<tr>
<td>13 minutes</td>
<td>5.3 cm</td>
</tr>
<tr>
<td>16 minutes</td>
<td>8.9 cm</td>
</tr>
<tr>
<td>20 minutes</td>
<td>16.1 cm or breakthrough</td>
</tr>
<tr>
<td>30 minutes</td>
<td>breakthrough</td>
</tr>
<tr>
<td>60 minutes</td>
<td>breakthrough</td>
</tr>
</tbody>
</table>

The CT images and numbers obtained during the first three hours of the experiment appear to comply with the expectation of increased CT numbers with time. However, an event taking place
between 3 and 4 hours causes a significant decrease in CT numbers near the inlet (Figure 4.12). This is also confirmed by the images, as a zone of decreased attenuation is observed near the inlet (Figure 4.13). Decreased CT numbers indicate the presence of a phase with lower density. Since the system is closed with continuous injection during water-flooding, this sudden decrease in attenuation near the inlet indicates the formation of an air bubble or vapor near the inlet due to heat. The effect of this bubble decreases with time. However, zones of reduced attenuation are still present within the sample at the end of core flooding.

![Graph showing CT number differences](image.png)

Figure 4.12. CT number differences compared to the wet core image for various times. Notice the significant increase in difference after 4 hours of injection (gray line). This corresponds to a decrease in CT numbers. The effect slightly decreases after 5 hours.

### 4.2.3.2. Saturation Profiles

The average porosity calculated from CT images is 0.168. This value is almost 30% smaller than the value calculated from the amount of water injected in the sample during core saturation. To overcome negative effect of this reduced porosity values, saturation profiles were calculated using a fixed average porosity of 0.230.
Figure 4.13. CT images for 16, 60, 120, 180, 240, 300 minutes during hot water-flooding at 57°C. The zones of reduction in attenuation for the last two images are marked with black.

Figure 4.14 shows the calculated water saturation profiles for the first hour of the experiment. The reduction in saturation caused by the water front is clearly visible for the time before breakthrough. However, this drop is not similar to a shock like behavior. Instead a gradual decrease for a few centimeters is observed. This trend is indicative of unstable displacement environment. After the displacement front, the calculated saturation values are similar to ones obtained before water-flooding (0 min curve). On the other hand, the saturation values appear to increase near the middle of the core, and then gradually decrease until it reaches the outlet. These fluctuations in the saturation profile is caused by the heterogeneity of the sample. Same trends can be observed from the images taken during core saturation.

The saturation profiles after the initial displacement shock do not seem to follow the saturation profiles estimated from the analytical model. As the position of the core is fixed during the whole process, high water saturation values indicate that the CT numbers for the fluid phases during water-flooding are different from the estimates calculated from numerous samples.
4.2.3.3. Production and Pressure Drop

The total recovery factor for this experiment was found to be more than 58% (Figure 4.15). From effluent collection, the breakthrough is estimated to occur after about 14 minutes (0.28 PV brine injected), at which 35% of the oil has been recovered. The behavior of the pressure drop is consistent with these observations: the pressure drop reaches a maximum at 16 minutes, indicating a breakthrough around that time (Figure 4.16). As with the two previous experiments, the breakthrough time estimated from image data does not agree with the breakthrough estimation obtained from pressure and production data.

An abnormal behavior is observed in the pressure response after 3 hours, as the pressure first drops suddenly, and then increases rapidly. This discrepancy continues for 15-20 minutes before the pressure drop starts to increase gradually until the end of data acquisition. The time of this anomaly is consistent with the decreased CT numbers observed from the scan data. Therefore, it is thought that this behavior is caused by the gas phase going into the system.
Figure 4.15. The recovery factor obtained during hot water-flooding at 57°C

Figure 4.16. Pressure drop for hot water-flooding at 57°C. The point at which the pressure drop reaches maximum is indicated, and the sudden drop in pressure values are marked in the circle
4.3. COMPARISON OF CORE FLOODING DATA

The production profiles for all experiments are displayed in Figure 4.17. From this figure it is seen that the recovery factor increases as the temperature of the injected brine is increased. However, this increase is not substantial, as the recovery factor for the highest injection temperature is only 2.6% higher than the isothermal case. Furthermore, the increase in recovery factor for injection temperature of 35.5°C is within experimental error: this indicates that for this injection temperature, the thermal energy put into the system is not sufficient for a more efficient sweep. On the other hand, the reason for the lack of increase in the recovery factor might also be due to poorer permeability of the sample (1.18 D compared to 1.44 D of isothermal conditions).

![Production profiles for all core flooding experiments](image)

Figure 4.17. Production profiles for all core flooding experiments

Interesting observations can be made from the comparison of pressure drop responses for the three experiments (Figure 4.18). The time at which the pressure drop reaches a maximum value is an indication of water breakthrough. From the graphs, it is observed that this maximum is delayed as the injection temperature increase. The analytical model for non-isothermal breakthrough suggests that the water front moves faster than the temperature front. This indicates
that the breakthrough should take place at the same time, regardless of the injection temperature. The change in breakthrough disproves this expectation: probably heat is transferred deep into the core, resulting in a decrease in the mobility ratio. This leads to a better sweep efficiency and delays in breakthrough.

It is also observed from data in Figure 4.18 that peak pressure is affected by the temperature. Due to very high mobility ratio during isothermal water-flooding, the pressure drop experienced during the process is high. However, thermal energy reduces mobility ratio and decreases the peak pressure drop. It is observed from the experiments that the pressure drop measured with injection temperature of 35.5°C is lower than that is experienced with 57°C.

![Figure 4.18. Pressure drop responses for core flooding experiments](image)

**4.4. COMPARISON OF EXPERIMENTS WITH ANALYTICAL DATA**

**4.4.1. Temperature Profiles**

Figure 4.19 displays the temperature evolution for various times observed during hot water-flooding with an injection temperature of 57°C. It is clear from this figure that the predicted
temperature profiles does not represent the real temperature evolution accurately. The main reason for this is the heat loss to the surroundings. Due to this heat loss (combined with low energy transfer rate), the temperature inside the sample cannot increase to the initial injection temperature. Instead, a decreasing trend is observed throughout the core. Moreover, the heat loss is more substantial at higher temperatures.

With an injection temperature of 57°C, the measured increase in temperature is 7.6°C, 3.5°C and 1.5°C at the second, third and fourth thermocouples, respectively. The increase in temperature for the first non-isothermal experiment is significantly less: 5.0°C, 2.7°C and 0.7°C.

On the other hand, as time increases, it is observed that the heat is transferred further into the sample than anticipated with the model. These elevated temperature values are caused by heat conduction. As the heated brine moves through the core, some of its energy is conducted to the parts of the sample that were not reached by the hot fluid. The effect of conduction becomes more evident after half an hour into water-flooding, and then becomes ineffective as the injected brine reaches the outlet.

### 4.4.2. Production Curves

The analytical and experimental production curves for each experiment are shown in Figure 4.20. While the predicted production curve for the isothermal case is a really good match with experimental data, the production curves obtained by measuring the effluents for both non-isothermal cases seem to differ. This difference is especially clearer after breakthrough is achieved. The reason for this anomaly is the heat loss. As the overall temperature in the analytical model is estimated to be higher than what is actually observed, a better mobility ratio is obtained in analytical models, which lead to a better sweep efficiency and production. Furthermore, since there is no temperature front found during experiments, the decrease in production rate after breakthrough is more pronounced than the analytical model.
Figure 4.19. Temperature evolution for various times during hot water-flooding at 57°C. The blue curves indicate the temperature evolution estimated from the analytical model, while the green curves are constructed from the temperature measurements measure at each thermocouple.
Figure 4.20. Comparison of production curves calculated from the analytical model with the production data of experiments. Top: isothermal water-flooding; Middle: hot water-flooding at 35.5°C; Bottom: hot water-flooding at 57°C.
4.4.3. Pressure Drop

Even though the behavior of the analytical and experimental pressure drop profiles are similar, the values do not seem to match with each other except the values measured before breakthrough for the second non-isothermal experiment (Figure 4.21). For isothermal water-flooding, the calculated pressures are significantly lower than measured ones. Due to the higher viscosity of the oil phase, the displacement during isothermal water-flooding at room temperature is highly unstable. Low oil mobility will lead to increased pressure drop across the core, which accounts for the difference in pressure drops at room temperature. Meanwhile, the observed breakthrough is faster than estimated as a result of viscous fingering. As the analytical model suggests a more stable, front-like displacement; the estimated breakthrough occurs later than what is actually observed.

For the first non-isothermal experiment, the estimated pressure drop turns out to be higher than the observed values. Even though both values appear to be fairly similar at earlier times, the values start to differ after 12 minutes, when the measure values peak, but estimated values continue to increase. The estimated pressure drop in this case is higher than the pressure drop estimated for isothermal conditions because of the lower permeability of this sample.

Similar pressure values obtained for the last experiment indicate that the displacement during this experiment is similar to the front-like displacement anticipated in the analytical model. The breakthrough time also is similar for these data (16.6 minutes for experimental compared to 16 minutes for analytical).

After the breakthrough, the major difference in pressure profiles is the effect of the temperature front in the analytical model. Due to this secondary front, the pressure decrease after breakthrough is initially gradual during hot water-flooding. Since no temperature front is observed during experiments, the decrease in pressure drop is quite rapid once brine breaks through.
Figure 4.21. Comparison of observed (red) and estimated (blue) pressure drop values. Top: isothermal water-flooding; Middle: hot water-flooding at 35.5°C; Bottom: hot water-flooding at 57°C.
CHAPTER 5 - CONCLUSION AND RECOMMENDATIONS

5.1. CONCLUSIONS

Core flooding experiments have been carried out to investigate the effect of thermal energy for enhancing heavy oil recovery. The results of these experiments have been compared to a simplified analytical model that has been developed to describe hot water-flooding. Analysis of the results led to following conclusions:

- The ultimate recovery factor after water-flooding increases as the temperature of the injected fluid is increased. This increase however, is less than that anticipated from the analytical model. This difference is due to the neglect of heat loss in the analytical model.

- Increasing the temperature at the inlet results in a delay in water breakthrough. Unlike the model suggests, thermal conduction causes an increase in temperature throughout the core. This results in an increase in the oil phase mobility, and leads to delays in breakthrough due to better sweep efficiency.

- Since heat decreases the mobility ratio, pressure response acquired during hot water-flooding experiments are lower than those observed during isothermal water-flooding at room temperature.

- No displacement front or viscous fingering can be observed from the images, and the accuracy of the estimates made from CT numbers are questionable. Furthermore, significantly low porosity values calculated from image data suggests some form of interaction that causes a change in the CT numbers of fluid phases during experiments.
5.2. RECOMMENDATIONS

To follow up research on this topic, some recommendations are made:

- Some important parameters were neglected to construct the analytical model. To extend the model to a more realistic one, it is proposed to use a numerical approach. Including effects such as heat loss, and heat transfer due to conduction will give a more realistic and more comparable model to the results of core flooding experiments.

- Change in injection temperature also causes changes in the fluid model. A quantitative history matching can be conducted to investigate the effects of temperature on parameters such as endpoint permeabilities and Corey exponents.

Due to problems experienced during experimental processes, following recommendations are made to improve the setup:

- It is really important to minimize the heat loss from the pump to the inlet of the core. If this is achieved, the initial water temperature at the thermostatic bath might be set at a lower value than 75°C, decreasing the chance of the formation of air bubbles.

- To see a clear water phase from CT scans, the KI concentration inside the brine can be increased. However, as the CT numbers of the fluid phases appear to change during the experiments, it may be better to change the salt used in the brine. Sodium tungstate (Na₂WO₄) is proposed as an alternate salt.
References


APPENDIX A: ELECTROMAGNETIC HEATING

Electromagnetic (EM) heating is a thermal recovery method where electrical energy acts as the heat source, and this source is generated either within the reservoir or inside the well (Callarotti, 2007). Electromagnetic heating is especially used in zones where the heat loss to the overburden and the well is too high when steam is injected.

EM heating is divided into three categories according to different frequency ranges and heating methods. The first one involves low frequency electric fields (less than 60 Hz). In this type, resistive heating is the dominant method of heating. In the application of this method, wells usually act like electrodes to create a pathway for electric current to flow. This electric current is carried within the formation via the connate water. This method is called Formation Resistive Heating, and it is the most common electromagnetic oil recovery method (Das, 2008). It is essential to maintain this water supply either by water-flooding or keeping the temperature low, since lack of water will prevent the flow of electric currents, resulting in the removal of the heat source.

Another method is induction heating where a wide range of frequencies can be applied depending on the characteristics of the medium (Hascakir, Babadagli and Akin, 2008). In this method, Eddy Currents resulting from the alternating current flowing through conducting metals results in the heating of the material (Sahni, Kumar and Knapp, 2000).

The EM heating method that this project intended to focus on is the third heating method, which is dielectric heating. Dielectric heating is observed in the high frequency range (Radio Frequency and Microwave Frequency). In this type of heating the heat energy will be created by the friction caused during electromagnetic wave propagation. As the wave changes cycle, the molecules within the medium will reverse polarity, and this continuous motion will result in friction and collision between molecules (Hascakir, Babadagli and Akin, 2008). High frequency heating is seldom used in oil fields. The main reason for this is the fact that the penetration depth of electromagnetic waves decreases with increasing frequency. To overcome this problem, EM heating is usually combined with water-flooding. By doing this, the heated aqueous phase will act as a secondary source, and larger penetration depths will be achieved.
Adjustments to Experimental Setup

As the heat source in EM assisted water-flooding is different, some modifications are needed on the setup. An experimental setup has been built for this purpose and is displayed in Figure A.1. The main concern when using EM waves is to direct the waves into the core, and contain them in the system. A conical shaped aluminum waveguide is attached to the magnetron, which serves as the heat source. This waveguide is then connected to a cylindrical shaped aluminum vessel. This vessel contains the sandstone core encapsulated in the PEEK core holder. The whole apparatus is put inside an aluminum chest, which serves as a Faraday Cage and prevents the interference of the microwaves with the X-rays from the CT scanner. The rest of the setup is the same as mentioned in Chapter 3. However, some holes should be drilled on the chest to connect the thermostatic bath, the syringe pump and the fraction collector to the apparatus. Moreover, careful consideration is needed to shield all the holes to prevent leakage of EM waves.
Figure A.1. Experimental setup for EM heating assisted water-flooding
APPENDIX B: POWER AND ELECTRIC FIELD

To calculate the dissipated power and the evolution of the electric field in the system, one must know about Maxwell’s equations. In a time varying field (which is the case in microwaves), the Maxwell’s equations are defined as

\[ \vec{\nabla} \times \vec{E} = -j\omega \vec{B} \]  
\[ \vec{\nabla} \times \vec{H} = \vec{j} + j\omega \vec{D} \]  
\[ \vec{\nabla} \cdot \vec{D} = \rho_q \]  
\[ \vec{\nabla} \cdot \vec{B} = 0 \]  
\[ \vec{D} = \varepsilon(\omega)\vec{E} = [\varepsilon'(\omega) - j\varepsilon''(\omega)]\vec{E} \]  
\[ \vec{B} = \mu(\omega)\vec{H} = [\mu'(\omega) - j\mu''(\omega)]\vec{H} \]  
\[ \vec{j} = \sigma(\omega)\vec{E} = [\sigma'(\omega) - j\sigma''(\omega)]\vec{E} \]

In these equations, \( \vec{E} \) and \( \vec{H} \) are the complex electric and magnetic field intensities, \( \vec{B} \) is the complex magnetic flux density, \( \vec{j} \) is the complex current density, \( \vec{D} \) is the complex electric displacement field density, \( \rho_q \) is the complex charge concentration, and \( \varepsilon, \mu \) and \( \sigma \) are the permittivity, magnetic permeability and the conductivity of the material, respectively. The ‘’ figures associated with these parameters indicate the real parts of the characteristics while “” indicate the imaginary parts (Callarotti, 2007).

The power radiated over an area is defined by the Poynting Vector, \( \vec{S} \). For time varying fields, the Poynting Vector is

\[ \vec{S} \equiv \frac{1}{2}(\vec{E} \times \vec{H}^*) \]

where the asterisk sign denotes the complex conjugate. The power radiated through a volume of \( V \), enclosed by an area of \( A \) can be determined by using Gauss’s Theorem and Eq. 31. The resulting equation is
The balance of power for the indicated volume is obtained by reversing the signs of the integrals in the previous equation. With the reversed signs, the left side of the equation indicates the power radiating inside the volume. “The first two right hand terms represent the power stored in the volume, while the last two terms represent the power dissipated in the volume (Callarotti, 2007).” In a petroleum reservoir (or reservoir sample), the magnetic permeability of the medium is similar to the magnetic permeability of free space, thus, it can be neglected (Callarotti, 2007). With this assumption, the power dissipated per unit volume becomes

\[ P_{PUV} = \frac{1}{2} [\sigma + \omega \varepsilon''] |E|^2 \] 

(B.10)

The total power dissipated for the system can be calculated by multiplying the dissipated power per unit volume with the volume of the system. However, as the system contains three different phases with different dielectric properties, the dissipated power should be defined as the sum of three different terms, where each term indicates the power dissipated inside a different phase. The effect of volume on each phase is described by the water saturation and the porosity. Thus, the total power dissipated becomes

\[ P = (1 - \phi) \frac{[\sigma_s + \omega \varepsilon_s'']}{2} |E|^2 + \phi S_w \frac{[\sigma_w + \omega \varepsilon_w'']}{2} |E|^2 + (1 - \phi) S_w \frac{[\sigma_o + \omega \varepsilon_o'']}{2} |E|^2 \] 

(B.11)

The problem in Eq. 34 is determining the imaginary part of permittivity, which is called the loss factor. The electromagnetic energy will be absorbed within the core during propagation, an assumption of a lossy medium can be made. In a lossy medium, the conductivity is equal to the product of angular frequency and loss factor. Defining an effective conductivity term of

\[ \sigma_{eff} = (1 - \phi) \sigma_s + \phi S_w \sigma_w + (1 - \phi) S_w \sigma_o \] 

(B.12)

the total power dissipated in the system will be equal to \( P = \sigma_{eff} |E|^2 \).