INTEGRATION OF NUMERICAL SIMULATION AND WIRELINE FORMATION TESTING MEASUREMENTS FOR PERMEABILITY INTERPRETATION

A Thesis
Submitted to the Faculty of Graduate Studies and Research
In Partial Fulfillment of the Requirements
For the Degree of
Master of Applied Science
In
Petroleum Systems Engineering
University of Regina

By
Min Yang
Regina, Saskatchewan
September, 2013

Copyright 2013: Min Yang
Min Yang, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Integration of Numerical Simulation and Wireline Formation Testing Measurements for Permeability Interpretation*, in an oral examination held on August 30, 2013. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

External Examiner: Dr. Zhigang Chen, Shell Canada Ltd

Supervisor: Dr. Daoyong Yang, Petroleum Systems Engineering

Committee Member: Dr. Farshid Torabi, Petroleum Systems Engineering

Committee Member: Dr. Peng Luo, Petroleum Systems Engineering

Chair of Defense: Dr. Guoxiang Chi, Department of Geology

*Not present at defense*
ABSTRACT

Wireline formation testing (WFT) has gained increasing popularity in the oil and gas industry in the last two decades because of its economical and environmental benefits. Recently, there has been growing interests in using the WFT pumpout transient data to interpret formation permeability and productivity with the conventional pressure transient analysis (PTA). Such an interpretation is based on the assumption of perforating the entire pay zone interval, though it is suspected not to be the case in reality, especially in thick formations where a limited section is sensed by a WFT probe. As for the laminated formations, one challenge to determine thickness is the presence of vertical heterogeneity. In practice, it is extremely difficult to detect such a lamination by running the conventional openhole logs because of their insufficient vertical resolution. Therefore, it is of fundamental and practical importance to quantify the effective formation thickness in thick formation and determine the vertical communication of the lamination to accurately interpret formation permeability with WFT measurements.

In this study, a high-resolution near-wellbore numerical model has been developed to simulate the fluid sampling process together with transient pressures at a flowing WFT probe. This newly developed model is validated analytically and then with the field data from the deepwater Gulf of Mexico. With the inherent noise added, the calculated pressure derivatives are used as a diagnosis tool to determine the effective formation
thickness. As for laminated formations, history matching has been performed with the field data measured by a dual-packer WFT to determine the vertical communication between sublayers and then interpret the permeability for each flow unit. Various cases with lamination located below or at the same level with the dual-packer have been generated to examine the effect of lamination on WFT interpretations.

It is shown from sensitivity analysis that effective formation thickness, which is defined as the maximum vertical thickness in the reservoir being sensed by the WFT device during a test within a given tool resolution, is a strong function of permeability anisotropy, flow rate, porosity and permeability, gauge resolution and probe location. All above-mentioned parameters which increase the effective formation thickness are inclined to obtain the true formation permeability. As for field cases, the permeabilities for two WFT tests, which are performed at two locations in the same well, are interpreted to be 14.0 mD and 10.6 mD, respectively. Such an interpretation reveals the difference in permeability between individual flow units. In a formation where lamination located below the dual packer, radial flow regime will develop when radial length of lamination is greater than the vertical interval and when complete circular shape of lamination is formed. Spherical flow regime is affected greatly by the lamination located the same level with the dual-packer. The integration of packer(s) and observation probes can be used to accurately indicate lamination and flow regimes.
ACKNOWLEDGEMENTS

I would like to express my sincere gratitude to my academic supervisor, Dr. Daoyong (Tony) Yang, for his continuous encouragement, guidance and support throughout my graduate studies.

I also wish to thank the following individuals or organizations for their support and friendship during my MASc studies at the University of Regina:

- My past and present research group members: Dr. Huazhou Li, Dr. Huijuan Sun, Mr. Sixu Zheng, Mr. Yin Zhang, Mr. Feng Zhang, Mr. Chengyao Song, Ms. Xiaoli Li, Ms. Ping Yang, Mr. Deyue Zhou, Mr. Yu Shi, and Mr. Zan Chen;

- Natural Sciences and Engineering Research Council (NSERC) of Canada for Discovery Grants and a Collaborative Research and Development (CRD) Grant to Dr. Yang;

- Faculty of Graduate Studies and Research (FGSR) at the University of Regina for awarding the Faculty of Graduate Studies Scholarship (2012 Fall); and

- Many friends who extended their help and friendship to me during my stay in Regina.
DEDICATION

To my beloved parents, Mrs. Shuli Lu and Mr. Suqian Yang, for their continuous support and endless love.
## Table of Contents

ABSTRACT ................................................................................................................................................. i

ACKNOWLEDGEMENTS .................................................................................................................. iii

DEDICATION ............................................................................................................................................ iv

TABLE OF CONTENTS ..................................................................................................................... v

LIST OF TABLES ...................................................................................................................................... viii

LIST OF FIGURES ................................................................................................................................... ix

NOMENCLATURE .................................................................................................................................... xiv

CHAPTER 1 INTRODUCTION ........................................................................................................... 1

1.1 Wireline Formation Testing ........................................................................................................... 1

1.2 Interpretation of WFT data .......................................................................................................... 3

1.3 Purpose of This Thesis Study .................................................................................................... 5

1.4 Outline of the Thesis ................................................................................................................. 6

CHAPTER 2 LITERATURE REVIEW ............................................................................................... 7

2.1 WFT Development and Applications ...................................................................................... 8

2.2 WFT Pressure Measurements .................................................................................................. 12

2.2.1 Probe-type WFTs ............................................................................................................. 14

2.2.2 Dual-packer WFTs ........................................................................................................... 15

2.2.3 Interval pressure transient testing .................................................................................. 17

2.3 Pressure Transient Analysis .................................................................................................... 19

2.4 Conventional Interpretation Technique ................................................................................... 22
2.4.1 Flow regimes........................................................................................................22
2.4.2 Interpretation constraints...................................................................................25
2.5 Summary.............................................................................................................29

CHAPTER 3 DETERMINATION OF EFFECTIVE FORMATION THICKNESS30

3.1 Numerical Model of Probe-Type WFT.................................................................30
  3.1.1 Reference case.................................................................................................30
  3.1.2 Model validation..............................................................................................39
3.2 Determination of Effective Formation Thickness..............................................47
3.3 Parametric Effect on Permeability Interpretations.............................................51
  3.3.1 Permeability anisotropy ratio........................................................................51
  3.3.2 Probe flow rate.............................................................................................53
  3.3.3 Gauge resolution...........................................................................................57
  3.3.4 Porosity ........................................................................................................60
  3.3.5 Porosity and permeability ..........................................................................63
  3.3.6 Probe location ..............................................................................................66
  3.3.7 Heterogeneous formation............................................................................69
3.4 Summary.............................................................................................................73

CHAPTER 4 EFFECT OF LAMINATIONS ON PERMEABILITY
INTERPRETATION AND PRESSURE BUILDUP DYNAMICS 77

4.1 WFT Field Measurements....................................................................................77
4.2 Numerical Model of Packer-Type WFT ............................................................82
4.3 History matching........................................................................................................... 88
4.4 Effect of Lamination Location......................................................................................... 96
  4.4.1 Lamination located below the packer ................................................................. 96
  4.4.2 Lamination located the same level as the packer ............................................. 107
4.5 Summary.................................................................................................................... 113

CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS............................................. 117
  5.1 Conclusions............................................................................................................. 117
  5.2 Recommendations................................................................................................. 120

REFERENCES.................................................................................................................. 121
LIST OF TABLES

Table 2.1 Comparison of Mini-DST and conventional well testing (Harmawan et al., 2012) ............................................................................................................. 16

Table 3.1 Geometrical and numerical simulation parameters used in the reference case 32

Table 3.2 Petrophysical and fluid properties for the reference case ......................... 36

Table 3.3 Summary of relative permeability and capillary pressure parameters used in the Brooks-Corey equations (Malik, 2008) ......................................................... 43

Table 3.4 Summary of the sensitivity analysis ............................................................ 70

Table 3.5 Permeability distribution under formation thickness of 15 ft and 100 ft ....... 71

Table 4.1 Petrophysical and fluid properties for the base case ................................ 79

Table 4.2 Geometrical and numerical simulation parameters used in the numerical model .......................................................................................................... 83

Table 4.3 Summary of the PVT properties of the OBM filtrate (Malik et al., 2007) ...... 86

Table 4.4 Summary of capillary pressure parameters used in the Brooks-Corey equations (Malik, 2008) ............................................................................................................. 87
LIST OF FIGURES

Figure 2.1 Typical configurations of the MDT tool (Schlumberger, 2006) ...................... 10

Figure 2.2 Configurations of (a) conventional probe-type and (b) packer-type WFT (Schlumberger, 2002) ............................................................................................................. 13

Figure 2.3 Schlumberger’s typical MDT tool configurations for IPTT (Ayan et al., 2001) ....................................................................................................................... 18

Figure 2.4 (a) Schematic of fluid flow around a packer and (b) expected flow regimes in a log-log plot (Al-Amrie et al., 2012) ................................................................. 24

Figure 2.5 Determination of an apparent resolution from a set of test data (Kuchuk, 2009) ....................................................................................................................... 27

Figure 3.1 The 3D view of the numerical model (unit: ft)........................................ 33

Figure 3.2 Schematic of the grid system: (a) side view and (b) top view .................... 34

Figure 3.3 Time sequence of flow rate assumed during the simulations for the reference case ..................................................................................................................... 37

Figure 3.4 Comparison between the analytical solution of transient pressure for a single phase with the simulation results in a radial grid system ......................... 40

Figure 3.5 The measured (a) WFT flowrates and (b) pressures for a well in deepwater Gulf of Mexico ............................................................................................. 44

Figure 3.6 Comparison of measured and simulated transient pressures at the WFT probe ......................................................................................................................... 46

Figure 3.7 Simulated transient pressures as a function of formation thickness for the reference case ......................................................................................................... 48

Figure 3.8 Simulated transient pressures for a 60 ft-thick formation with a noise of 0.01
Figure 3.9 Pressure change together with its derivative as a function of time under various effective formation thickness for the reference case with gauge resolution of 0.01 psi.

Figure 3.10 Simulated transient pressures at the WFT probe for permeability anisotropy of (a) 0.10, (b) 0.25, and (c) 0.50.

Figure 3.11 Derivatives at the WFT probe for permeability anisotropy of (a) 0.10, (b) 0.25, and (c) 0.50.

Figure 3.12 Simulated transient pressures at the WFT probe for probe flow rates of (a) 5 bbl/d, (b) 10 bbl/d, and (c) 20 bbl/d.

Figure 3.13 Derivatives at the WFT probe for probe flow rates of (a) 5 bbl/d, (b) 10 bbl/d, and (c) 20 bbl/d.

Figure 3.14 Pressure change and derivatives at the WFT probe for gauge resolution of (a) 0.01 psi and (b) 0.03 psi.

Figure 3.15 Simulated transient pressure at the WFT probe for porosity of (a) 0.05, (b) 0.20, and (c) 0.40.

Figure 3.16 Pressure change and derivatives at the WFT probe for porosity of (a) 0.05, (b) 0.20, and (c) 0.40.

Figure 3.17 Simulated transient pressure at the WFT probe for combination of (a) porosity of 0.10 with permeability of 5 mD, (b) porosity of 0.15 with permeability of 16 mD, and (c) porosity of 0.20 with permeability of 100 mD.

Figure 3.18 Pressure change and derivatives at the WFT probe for combination of (a) porosity of 0.10 with permeability of 5 mD, (b) porosity of 0.15 with permeability of 16 mD, and (c) porosity of 0.20 with permeability of 100 mD.
permeability of 16 mD, and (c) porosity of 0.20 with permeability of 100 mD

Figure 3.19 Simulated transient pressure at the WFT probe for probe location of (a) 10 ft from the upper boundary, (b) middle of the formation, and (c) 20 ft from the lower boundary .......................................................... 65

Figure 3.20 Pressure change and derivatives at the WFT probe for probe location of (a) 10 ft from the upper boundary, (b) middle of the formation, and (c) 20 ft from the lower boundary .......................................................... 67

Figure 3.21 Pressure change and derivative for Scenarios #1-4 with permeability anisotropy of 0.25 for (a) 15 ft and (b) 100 ft intervals ................................. 72

Figure 3.22 Pressure change and derivative for Scenarios #1-4 with permeability anisotropy of 0.5 for (a) 15 ft and (b) 100 ft intervals ................................. 74

Figure 3.23 Pressure change and derivative for Scenarios #1-4 with permeability anisotropy of 1 for (a) 15 ft and (b) 100 ft intervals ................................. 75

Figure 4.1 Conventional openhole logs over the zone of interest ........................................ 80

Figure 4.2 The measured WFT flowrates and pressures for (a) Tester #1 and (b) Tester #2 in a vertical well, Gulf of Mexico ................................................................. 81

Figure 4.3 Schematic of the grid system: (a) side view and (b) top view .......................... 84

Figure 4.4 Relative permeability curves for (a) Tester #1 and (b) Tester #2 ................. 90

Figure 4.5 Comparison of measured and simulated (a) transient pressures and (b) pressure derivative for Tester #1 with the assumption of impermeable lamination ................................................................. 91

Figure 4.6 Comparison of measured and simulated (a) transient pressures and (b) pressure derivatives for Tester #2 with the assumption of impermeable
lamination........................................................................................................................................92

**Figure 4.7** Comparison of measured and simulated (a) transient pressures and (b) pressure derivative for WFT Tester #1 with the assumption of permeable lamination........................................................................................................................................94

**Figure 4.8** Comparison of measured and simulated (a) transient pressures and (b) pressure derivative for WFT Tester #2 with the assumption of permeable lamination........................................................................................................................................95

**Figure 4.9** Configurations of simulation cases with various lamination dimensions: (a) Case #1-1 (i.e., Base case), (b) Case #1-2 with lamination dimension of $\Delta r = 10.0$ ft, $\Delta \theta = 360^\circ$, (c) Case #1-3 with lamination dimension of $\Delta r = 40.0$ ft, $\Delta \theta = 360^\circ$, (d) Case #1-4 with lamination dimension of $\Delta r = 60.0$ ft, $\Delta \theta = 360^\circ$, (e) Case #1-5 with lamination dimension of: $\Delta r = 300.0$ ft, $\Delta \theta = 360^\circ$, (f) Case #1-6 with lamination dimension of $\Delta r = 300.0$ ft, $\Delta \theta = 90^\circ$, (g) Case #1-7 with lamination dimension of $\Delta r = 300.0$ ft, $\Delta \theta = 180^\circ$, and (h) Case #1-8 with lamination dimension of $\Delta r = 300.0$ ft, $\Delta \theta = 270^\circ$ ........................................... 97

**Figure 4.10** Effect of the radial length of lamination on pressure derivatives with gauge resolution of 0.01 psi........................................................................................................................................99

**Figure 4.11** Effect of angular shape of lamination on pressure derivatives with gauge resolution of 0.01 psi........................................................................................................................................101

**Figure 4.12** Packer and observation probe pressure change together with derivatives of Case #1-1 (Base case) with gauge resolution of 0.01 psi................................. 103

**Figure 4.13** Packer and observation probe pressure change together with derivatives of Case #1-5 with gauge resolution of 0.01 psi......................................................... 104

**Figure 4.14** Packer and observation probe pressure change together with derivatives of
Case #1-3 with gauge resolution of 0.01 psi

Figure 4.15 Configurations of simulation cases with various lamination dimensions: (a) Case #2-1 (i.e., Base case), (b) Case #2-2 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 10.0$ ft, $\Delta \theta = 60^\circ$, (c) Case #2-3 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 10.0$ ft, $\Delta \theta = 120^\circ$, (d) Case #2-4 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 10.0$ ft, $\Delta \theta = 180^\circ$, (e) Case #2-5 with lamination dimension of $\Delta l = 15.4$ ft, $\Delta r = 10$ ft, $\Delta \theta = 120^\circ$, (f) Case #2-6 with lamination dimension of $\Delta l = 40.4$ ft, $\Delta r = 20.0$ ft, $\Delta \theta = 120^\circ$, (g) Case #2-7 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 300$ ft, $\Delta \theta = 120^\circ$, and (h) Case #2-8 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 300$ ft, $\Delta \theta = 360^\circ$

Figure 4.16 Effect of angular shape of lamination on pressure derivatives with gauge resolution of 0.01 psi

Figure 4.17 Effect of distance from wellbore to lamination on pressure derivatives with gauge resolution of 0.01 psi

Figure 4.18 Effect of radial length of lamination on pressure derivatives with gauge resolution of 0.01 psi

Figure 4.19 Packer and observation probe buildup pressure change together with its derivatives of Case #2-1 (i.e., Base case) with gauge resolution of 0.01 psi

Figure 4.20 Packer and observation probe buildup pressure change together with its derivatives of Case #2-8 with gauge resolution of 0.01 psi
# NOMENCLATURE

**Notations**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$B$</td>
<td>Formation volume factor, bbl/STB</td>
</tr>
<tr>
<td>$c_t$</td>
<td>Total compressibility, psi$^{-1}$</td>
</tr>
<tr>
<td>$e_o$</td>
<td>The empirical exponent for oil as defined in Equation [3.5]</td>
</tr>
<tr>
<td>$e_p$</td>
<td>The pore size distribution as defined in Equation [3.6]</td>
</tr>
<tr>
<td>$e_w$</td>
<td>The empirical exponent for water as defined in Equation [3.4]</td>
</tr>
<tr>
<td>$h$</td>
<td>Formation thickness, ft</td>
</tr>
<tr>
<td>$k_h$</td>
<td>Horizontal permeability, mD</td>
</tr>
<tr>
<td>$k_v$</td>
<td>Vertical permeability, mD</td>
</tr>
<tr>
<td>$k_{ro}$</td>
<td>Oil relative permeability as defined in Equation [3.5]</td>
</tr>
<tr>
<td>$k_{ro}^0$</td>
<td>Oil end-point relative permeability as defined in Equation [3.5]</td>
</tr>
<tr>
<td>$k_{rw}$</td>
<td>Water relative permeability as defined in Equation [3.4]</td>
</tr>
<tr>
<td>$k_{rw}^0$</td>
<td>Water end-point relative permeability as defined in Equation [3.4]</td>
</tr>
<tr>
<td>$P_c$</td>
<td>Capillary pressure as defined in Equation [3.6]</td>
</tr>
<tr>
<td>$P_c^0$</td>
<td>The coefficient for capillary pressure as defined in Equation [3.6]</td>
</tr>
<tr>
<td>$r_e$</td>
<td>Reservoir external radius, ft</td>
</tr>
</tbody>
</table>
\( r_w \)  Wellbore radius, ft

\( S_{or} \)  Irreducible oil saturation as defined in Equation [3.3]

\( S_w \)  Water saturation as defined in Equation [3.3]

\( S_w^* \)  Normalized water saturation as defined in Equation [3.3]

\( S_{wr} \)  Irreducible water saturation as defined in Equation [3.3]

\( t \)  Time, hr

\( \Delta r \)  Length of the lamination, ft

\( \Delta \theta \)  Angle of the lamination, °

\( \Delta l \)  Distance from wellbore to lamination, ft

**Greek letters**

\( \sigma \)  Standard deviation

\( \mu \)  Fluid viscosity, cP

\( \phi \)  Porosity, fraction

**Subscript**

\( D \)  Dimensionless
$e$ External boundary

$i$ Initial condition

$wf$ Wellbore flowing

Abbreviations

CQG Combinable quartz gauge

DST Drillstem test

GOR Gas-oil ratio

IPTT Interval pressure transient testing

MDT Modular dynamics formation tester

OBM Oil-based-mud

PTA Pressure transient analysis

RFT Repeat formation tester

VIT Vertical interference testing

WBM Water-based-mud

WFT Wireline formation testing (tester)
CHAPTER 1 INTRODUCTION

1.1 Wireline Formation Testing

As the world strives for additional energy supply, hydrocarbon exploration and production is shifting towards expensive high-risk targets with increasing complexity in rock and fluid properties. Formation evaluation serves as a prerequisite for planning and developing hydrocarbon reservoirs. Physically, formation testing is the final evaluation step before the well is put into production and provides essential information to design the associated well completion and production facilities (Schlumberger, 2006).

Generally, two different technologies can be used for formation testing: conventional well testing and wireline formation testing (WFT) (Schlumberger, 2006). Conventional well testing records formation pressure as a function of time, which can be particularly valuable for estimating formation characteristics such as permeability, reservoir boundaries, and skin factor (Lee, 1982). Although the tested interval is not precisely defined and downhole measurements are limited, the produced fluid volume enables complete evaluation of production potential. WFT is performed mostly in openhole using a cable-operated sonde that can be positioned at a selected depth in the formation to provide accurate measurements of pressure and flowrate, but the produced fluid volume is limited (Schlumberger, 2006).
Compared with the conventional well testing, WFT has gained increasing popularity in oil and gas industry recently because of its economical and environmental benefits (Whittle et al., 2003; Coelho et al., 2005; Daungkawe et al., 2007; Elshahawi et al., 2008; Bertolini et al., 2009). WFT is less expensive than conventional well testing because it avoids the production of hydrocarbons at the surface. Cost benefits also come from more economical downhole equipment, shorter operating time and the avoidance of any surface handling equipment. In addition, there are no problems of fluid disposal and no problems with environmental regulations (Ayan et al., 2001). With the exception of testing reservoir boundaries, the collection of large volumes of fluid samples, or investigating completion efficiency, WFT is able to meet or exceed most well testing objectives in some play types (Elshahawi et al., 2008).

WFT brings special knowledge about reservoir dynamics that no other tools can acquire. In addition to fluid sampling, WFT has been widely and successfully applied over decades to determine pressure gradient, fluid contact, and reservoir compartmentalization (Schlumberger, 2002). Downhole pumping feature of modular wireline tools generates continuous flows without mechanical failure to clean up drilling filtrates as well as obtain flow data. Recently, there has been growing interests in using these extended pumpout flow data to evaluate formation permeability and productivity in hydrocarbon reservoirs, particularly in difficult operation environments (Daungkaew et
al., 2007; Sundaram et al., 2012). Through multiple tests, both horizontal and vertical permeability can be evaluated. By performing measurements at a length scale between cores and the well tests, WFT can be used to quantify the effect of thin layers that are not identified by other techniques. Such thin layers play a vital role in reservoir drainage, controlling gas and waterflood performance (Ayan et al., 2001). Therefore, permeability measurements derived from WFT are able to contribute to reservoir understanding and make an impact on reservoir development.

1.2 Interpretation of WFT data

Since the use of pressure derivative curves is outlined by Bourdet et al. (1983), the combinational use of pressure together with its derivative has imposed a significant impact on analysis of conventional well test as well as WFT. The fundamental for interpretation of WFT pressure measurements is to identify specific transient flow regimes. On a log-log plot of pressure derivative as a function of time, spherical flow is identified by a slope of -0.5, and the radial flow by a stabilized horizontal line (Jackson et al., 2003).

Frimann-Dahl et al. (1998) presented one of the first studies to apply the conventional pressure transient analysis (PTA) technique to WFT data, though the illustrated case used a large probe area. Nowadays, extension of the PTA to data obtained
using wireline formation testers, either a single probe or a dual packer, has been gaining
great popularity in the industry over the last decade (Daungkaew et al., 2007;
Ramaswami et al., 2011; Aguilera et al., 2012; Sundaram et al., 2012).

At present, there are still limitations in interpreting WFT data with conventional
PTA (Ayan et al., 2001). There exists a significant difference in thicknesses interpreted
from a conventional well testing and a WFT measurement (Elshahawi et al., 2008). As
for conventional well test, formation thickness is measured between the top and bottom
of the reservoir due to the fact that pressure transient analysis has been developed based
on the assumption of perforating the entire payzone interval (Elshahawi et al., 2008).
However, it is suspected not to be the case in reality for WFT applications, especially in
thick formations where a limited section is sensed by a WFT probe (Al-Harbi et al.,
2007). Knowing the thickness being sensed by a WFT test is essential for accurate and
reliable permeability determination. Therefore, it is of fundamental and practical
importance to analyze and quantify the effective formation thickness to accurately
interpret the WFT measurements.

As for the laminated formations, one challenge to determine thickness is the
presence of vertical heterogeneity (Daungkaew et al., 2007). Numerous reservoirs are
formed in a depositional environment, resulting in laminated sands with various
percentages of silt and clay beds (Beik et al., 2010). The reservoir sands may be highly
permeable, while the silt and clay laminations affect the reservoir vertical permeability significantly (Daungkaew et al., 2008; Kiatpadungkul et al., 2010). In practice, it is extremely difficult to detect such a lamination by running the conventional openhole logs or well testing because of their insufficient vertical resolution (Daungkaew et al., 2008). Therefore, it is necessary to determine the vertical communication of the lamination in order to accurately interpret formation permeability. In addition, the effect of various configurations of lamination on permeability interpretation should be examined.

1.3 Purpose of This Thesis Study

The purpose of the thesis study is to comprehensively investigate the formation thickness considerations on permeability interpretation by integrating WFT measurements and reservoir simulation. The primary objectives of this study include:

1) To develop a high-resolution near wellbore numerical model to simulate the pumpout flow and pressure buildup dynamics obtained from a WFT device;
2) To validate the newly developed numerical model analytically and then with field data;
3) To determine the effective formation thickness and examine the effects of different parameters on pressure transients as well as effective formation
thickness;

4) To perform history matching with the field data to determine the effective thickness and then interpret the permeability for each flow unit in a laminated formation; and

5) To examine the effect of various configurations of lamination on WFT interpretations.

1.4 Outline of the Thesis

This thesis is composed of five chapters. More specifically, Chapter 1 is an introduction to the thesis topic together with its major research objectives. Chapter 2 provides an updated literature review on the newly developed WFT tools and corresponding interpretation techniques. Chapter 3 presents numerical determination of effective formation thickness together with an extensive sensitivity analysis to examine effect of various parameters on pressure transient response, derivative curves, and permeability interpretation, respectively. Chapter 4 focuses on the effect of laminations on permeability interpretation and pressure buildup dynamics using an actual field case and various synthetic cases. Finally, Chapter 5 summarizes the major scientific findings of this study and provides some recommendations for future research.
CHAPTER 2 LITERATURE REVIEW

Permeability is found to be a quantitative measure of a porous medium’s ability to conduct fluid flow (Kuchuk and Onur, 2003). In practice, permeability is one of the most important parameters that affect fluid flow in porous media and thus the corresponding well and reservoir performance. Measurements of permeability at different scales are useful to assess its spatial variation and effect on fluid production.

Permeability measurements on core samples are made routinely in the laboratory, obtaining absolute permeability corresponding to the smallest scale of measurement. The advantage of such a measurement is that it enables the assessment of spatial variation of permeability along the cored section of the reservoir (Betancourt, 2012). Since core plugs have been relocated to surface and cleaned, the measurement conditions are not the same as those made in-situ. In addition, high operational costs usually limit core data availability to evaluate a reservoir (Zheng et al., 2000).

Well logging measures in-situ porosity and other parameters that are related to the pore size. Permeability can be estimated from these measurements using a suitable empirical relationship, which normally must be calibrated for each reservoir or area against some references, usually cores, to ensure accuracy. The main use of log-derived permeability is to provide continuous estimates in all wells (Al-Harbi et al., 2007).
Well testing evaluates pressure transient response from the largest volume, up to the reservoir boundaries. The analysis of pressure and production history during the tests provides information pertaining to reservoir permeability and volume, which corresponds to a volume in the scale of the drainage area of the well. Well testing is a non-routine job and limited to key wells due to cost and other issues (Ayan et al., 2001; Al-Harbi et al., 2007).

Alternatively, WFT evaluates pressure transient response at an intermediate scale. WFT normally measures effective permeability at a meter scale and in some cases up to several tens of meters. Since the WFT tool has a high vertical resolution and is run typically in openhole conditions, several measurements could be made along the wellbore without requiring additional production hardware (Betancourt, 2012). In practice, none of the existing permeability sources can individually provide the desired permeability information as they emphasize different aspects of the reservoir (Al-Harbi et al., 2007).

2.1 WFT Development and Applications

When the first wireline testing tool was introduced in 1955 (Lebourg et al., 1957), it was primarily used to collect fluid samples and could only collect one sample per trip in a well. The arrival of the repeat formation tester (RFT) in 1975 allowed the repeat pressure measurements during the sampling process (Ayan et al., 1996). In practice, the
RFT offered a limited pressure gauge resolution, while the volume of investigation was relatively small, making it difficult to test rock formations affected by deep mud-filtrate invasion (Angeles, 2009).

The last decades have seen significant improvements in formation testing. The most recent step is the development of the modular dynamics formation tester (MDT) made by Schlumberger. The MDT is equipped with downhole pumping function that allows hours of drawdown without mechanical failure. Meanwhile, thanks to the combinable quartz gauge (CQG), the wireline tools have been significantly improved for accurate pressure measurements. Multi-probe modules enable the MDT to monitor pressure simultaneously as fluid is withdrawn from a separate source.

Other advances have been achieved with spectroscopy modules that determine the composition of downhole fluids in real time at reservoir conditions, which has refined the concept of downhole fluid analysis and extended the downhole fluid characterization (Schlumberger, 2002; Dong et al., 2007). Figure 2.1 shows the typical configurations of the MDT tool, which consists of the following main modules (Schlumberger, 2002):

1) Electronic power module: To convert AC power from the surface to DC power for all modules in the tool;

2) Hydraulic power module: To auto-retract test probes and prevent a stuck-tool situation in the event of a power failure;
Figure 2.1 Typical configurations of the MDT tool (Schlumberger, 2006)
3) Single probe module: To contain the probe assembly, a strain gauge, a high-resolution, quick-response CQG gauge, temperature sensors and a 20 cc pretest chamber;

4) Dual-packer module: To set against the borehole wall and isolate a distance of 3 to 11 ft by using two inflatable packers;

5) Pump-out module: To pump unwanted fluid (mud filtrate) from the formation to the borehole;

6) Sample module: To collect up to six high-quality samples for PVT analysis during a single trip into the well; and

7) Live fluid analyzer module: To analyze and determine the composition of downhole fluids.

All the aforementioned modules extend the applications of WFT to a more complicated environment. Nowadays, the WFT tools are widely used in the following areas (Schlumberger, 2002; Whittle, 2003):

1) To determine formation pressure at points of interest;

2) To interpret pressure gradients for fluid-type identification;

3) To collect multiple formation fluid samples in one trip;

4) To estimate formation permeability (or fluid mobility) and permeability anisotropy;
5) To perform mini-drillstem (DST) and productivity assessment;

6) To conduct in-situ stress and minifrac testing; and

7) To identify zones in hydraulic communication or isolation.

2.2 WFT Pressure Measurements

WFT is performed mostly in openhole using a cable-operated formation tester and sampling tool anchored at a specific depth, while reservoir communication is established through one or more observation probes and sampling probes (Schlumberger, 2006). More specifically, at the beginning of a typical wireline testing, the tool string is anchored stationary at a specific depth and then set a probe or packer against the sandface. A pretest is then performed with the device to not only measure formation pressure, but also confirm the integrity of the seal, preventing pressure communication with wellbore. Pumping rates and pressure transients are recorded during the sampling process as well as the subsequent build-up stage. Once the formation fluids have been pumped out for a sufficient time, the pump is stopped, and a pressure buildup is recorded. Then a final pretest is performed and the probes or packer are retracted. The tool string can be moved to the next station depth (Harmawan et al., 2012; Ramaswami et al., 2012). Figures 2.2a and b describe the conventional probe- and packer-type WFT configuration, respectively.
Figure 2.2 Configurations of (a) conventional probe-type and (b) packer-type WFT (Schlumberger, 2002)
2.2.1 Probe-type WFTs

Probe-type WFTs use hydraulically operated arms to force a packer assembly against the borehole wall. The probe which has a small inflow area with a diameter ranging from 0.5 to 2.0 inches is located in the center of the packer (Elshahawi et al., 2008). The probe extends into the formation and then reservoir fluids are pumped into the equipped chamber. The packer seal, which surrounds the probe, prevents wellbore fluids from mixing with reservoir fluids. The fluids are analyzed downhole, and samples may be captured while pressure is measured using downhole gauges. Fluids are analyzed for purity before being directed to the sample chambers (Ayan et al., 2013). The innovative aspect of the probe-type WFT is to efficiently separate contaminated fluids from pure fluid with minimal contamination (Schlumberger, 2007).

In few cases, concerns about excessive drawdown may limit the flow rate from the probe and hence reduce the utility of this configuration. However, at high mobility and highly under-saturated fluids where flow rate can be maintained close to the maximum value, probes can replace packers with no loss in the ability to estimate the flow unit permeabilities. In practice, probes are usually adopted due to the fast and easy deployment as well as great physical endurance (Elshahawi et al., 2008).
2.2.2 Dual-packer WFTs

A dual packer WFT is a small version of conventional drill stem test (DST) and is usually known as mini-DST (Ayan et al., 2001). Two inflatable packers are positioned in the borehole wall and hydraulically insolate a borehole test interval of approximately 3 ft. Because of large volume interval, pressure drop during drawdown is typically much smaller than that obtained with a probe. Thus, it is easier to ensure that oil is produced above its bubble-point pressure compared to the probe-type WFT. At the same time, the smaller pressure drop during drawdown is also beneficial for the testing of laminated, shaly, fractured, vuggy, unconsolidated or low permeability formations (Schlumberger, 2002).

Mini-DST is gaining increasing popularity in the industry because it avoids the production of hydrocarbons at the surface. The conventional well testing usually ties up expensive equipments for many days or weeks, while it is a major source of safety and environmental risks such as flaring of the produced hydrocarbon gases (Harmawan et al., 2012). A comparison showing the benefits of both conventional well testing and Mini-DST, pertaining to the well of interest, is summarized in Table 2.1 (Harmawan et al., 2012).
Table 2.1 Comparison of Mini-DST and conventional well testing (Harmawan et al., 2012)

<table>
<thead>
<tr>
<th>Item</th>
<th>WFT</th>
<th>Conventional Well Testing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir pressure</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Permeability</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Number of tests</td>
<td>Up to eight tests in one run (preferably less than six); can investigate multiple qualities of sands.</td>
<td>Often limited to one test only. Multiple zones can be tested, but with significant cost increases and operational complexity.</td>
</tr>
<tr>
<td>Fluid samples</td>
<td>Yes, downhole sample with low contamination. Multiple sampling requirements easily handled.</td>
<td>Yes, without contamination. Recombined surface sampling requires long stabilized flow to achieve representative</td>
</tr>
<tr>
<td>Average Cost (10^6 US$)</td>
<td>&lt;1</td>
<td>&gt;11</td>
</tr>
</tbody>
</table>
### 2.2.3 Interval pressure transient testing

Interval pressure transient testing (IPTT) is commonly known as vertical interference testing (VIT), where pressure transient measurements at the sink and observation probes are recorded simultaneously (Kuchuk *et al.*, 2000). **Figure 2.3** illustrates Schlumberger’s MDT tool configurations for interval pressure transient testing. This operation is usually performed with either a dual probe or a dual packer module. The procedure is similar to the conventional interference testing. However, IPTT tests are on a much smaller scale and can be conducted at various positions along the wellbore (Jackson *et al.*, 2000).

The objective of an IPTT is to characterize the vertical and horizontal permeabilities as well as vertical communication between layers, which is of great importance for the overall reservoir development plan, the economics and management of enhanced recovery projects (Kuchuk *et al.*, 2000). However, as for field applications, careful openhole log evaluation with local geology, particular electrical or sonic images, is important for conducting interval tests. Moreover, when testing, a good depth must be achieved and specific zones must be tested at an optimum time. This is because drilling and operational conditions and constraints may not allow us to stay for a long time at a given test location (Kuchuk, 1998).
Figure 2.3 Schlumberger’s typical MDT tool configurations for IPTT (Ayan et al., 2001)
2.3 Pressure Transient Analysis

When WFT was initially introduced, its sole objective was fluid sampling. Recent modular tools allow the permeability determination from the pressure transient analysis. Numerous efforts have been made to develop pressure transient analysis techniques for WFT application approaches together with permeability interpretation techniques. After introducing the pressure transient analysis for WFT applications for the first time, Moran and Finklea (1962) recognized the difference in flow geometry between formation testing and conventional well testing. Based on single-phase flow assumption, they showed that early time flow regime was spherical and late time flow regime was cylindrical flow.

Although WFT was originally used to monitor pressure for fluid sampling purpose, pre-tests allowed for determining permeability and reservoir pressures (Stewart et al., 1979), which was an extension of previous work done by Moran and Finklea (1962). Except for the horizontal permeability, vertical permeability could also be determined with a single probe formation tester (Dussan et al., 1992), though the accuracy of the vertical permeability was not as good as that of the horizontal permeability. As for field practices, however, WFT applications are largely limited by pressure gauge resolution, skin factor, and flowline storage (Brigham et al., 1980; Joseph et al., 1984; Yildiz et al., 1991).

Sophisticated advancement in the WFTs as well as interpretation techniques has
commenced since 1990s. Analytical techniques using pressure derivative curves to recognize various flow regimes introduced by Bourdet et al. (1983) have subsequently had a significant impact on the increased use of pressure transient analysis techniques.

In the late 1990s, the introduction of multi-probe formation testers have improved the determination of permeability and permeability anisotropy at a large scale (Goode et al., 1991; Shan et al., 1993; Badaam et al., 1998; Proett et al., 2000). In addition, the multi-probe formation testers permit the direct determination of both horizontal and vertical permeability in homogeneous formations and potential vertical permeability barriers in laminated formations (Goode et al., 1991). Similarly, a packer formation tester proves to be advantageous over probes when testing shaly, fractured, vuggy and low permeability formations (Ayan et al., 2001). This is mainly because the packer allows higher pumping rates at smaller pressure differentials during drawdown (Pop et al., 1993; Peffer et al., 1997; Onur et al., 2004; Angeles et al., 2007a). In combination with both packers and observation probes, either IPTT or VIT can be performed to improve reservoir characterization, especially the vertical communication between layers (Kuchuk et al., 2000; Jackson et al., 2003).

Numerical simulation pertaining to the WFT have commenced at the same time, while mud-filtrate invasion can be taken into account. The numerical near-wellbore model was initially developed for predicting the time to acceptable levels of
water-based-mud (WBM) filtrate contamination (Akram et al., 1998). Such a numerical model was successfully applied to investigate the characteristics of contamination level and to define the variables governing cleanup process. Ever since, several attempts have been made to improve the numerical model and simulate WFT pressure measurements numerically.

Jackson et al. (2003) proposed an integrated workflow to analyze interval pressure transient tests with a commercial simulator. Liu et al. (2004) developed a three-dimensional (3D) and multiphase numerical model with tool storage and taking skin effects into account. Zazovsky et al. (2008) presented a 3D model of flow in which the wellbore wall was covered by mudcake. In terms of miscible flow, several studies have been reported in oil-based-mud (OBM) environments (Alpak et al., 2008; Malik et al., 2007; 2009a) and in highly-deviated wells (Angeles et al., 2009).

In addition to homogenous reservoirs, simulation of WFT response in heterogeneous reservoir was also performed by Noirot et al. (2011). Malik et al. (2007) first compared field measurements of transient probe pressure against those obtained from numerical simulation. The comparison results indicated that the numerical simulation is a reliability method to verify the internal consistency and reliability of pressure transient measurements. Similarly, history matching of two field examples performed by Angeles et al. (2010) illustrated that simulation is crucial to reproduce the
measured transient pressure and gas-oil ratio (GOR). Mud-filtrate viscosity and radius of invasion are the most dominant properties when attempting to reproduce the early-time portion of pressure transients with numerical simulations. The numerically simulated pressure transients are used for estimation of permeability as well as permeability anisotropy and calculation of spatial sensitivity functions (Angeles et al., 2007b).

2.4 Conventional Interpretation Technique

2.4.1 Flow regimes

Since the use of pressure derivative curves was outlined by Bourdet et al. (1983), the combined use of pressure and pressure derivatives has had a significant impact on analysis of conventional well test as well as wireline formation testing. Frimann-Dahl et al. (1998) presented one of the first studies to apply the conventional pressure transient analysis techniques to wireline formation test data, though the case presented used a large probe area. Spherical flow was often found not to be observed in transient data and the pressure transient response observed was similar to typical response during conventional well testing.

Nowadays, the use of pressure transient data to describe productivity and permeability of the reservoir is considered as a mature technology (Ramaswami et al., 2013). The pressure transient analysis has been widely applied to field WFT data
acquired with probe (Ramaswami et al., 2012) and dual packer configurations (Daungkaew et al., 2007; Mirza et al., 2011; Aguilera et al., 2012; Al-Amrie et al., 2012; Sundaram et al., 2012).

Procedures used for the interpretation of WFT measurements are similar to those used in conventional well testing measurements. The fundamental for interpretation of WFT pressure measurements is to identify specific transient flow regimes. Figures 2.4a and b depict schematic of fluid flow around a packer and the expected flow regimes in a log-log plot, respectively. There are three important flow regimes. The first transient flow regime is a cylindrical radial flow around the well due to the open interval. This regime is usually very short and dominated by the wellbore storage. Subsequently, a pseudo-spherical flow regime may develop before any boundary effect is felt. This flow regime is identified by a negative half slope. Finally, a pseudo-cylindrically radial flow may develop in the system when the flow is restricted by two no-flow boundaries. This flow regime is identified by a stabilized horizontal line with a slope of zero and represents the product of horizontal permeability and reservoir thickness. The pseudo-cylindrical radial flow regime is the same as the infinite acting period for fully completed vertical wells (Jackson et al., 2003).

In assessing the reliability of a WFT measurement, an important characteristic is the existence of a well-established pseudo-cylindrical radial flow regime (Elshahawi et al.,
Figure 2.4 (a) Schematic of fluid flow around a packer and (b) expected flow regimes in a log-log plot (Al-Amrie et al., 2012)
If the formation properties (i.e., porosity, viscosity, and total compressibility of the rock) and the thickness of the formation layer are known, the measurements can be used to estimate horizontal permeability.

### 2.4.2 Interpretation constraints

1) **Formation thickness**

Formation thickness is a parameter that differs significantly by interpreting conventional well testing and wireline formation testing. In a conventional test, formation thickness is measured between the top and bottom of the payzone due to the fact that pressure transient analysis has been developed based on the assumption of perforating the entire payzone interval (Elshahawi et al., 2008). However, it is suspected not to be the case in reality for WFT applications, especially in thick formations where a limited section is sensed by a WFT probe (Al-Harbi et al., 2007).

Knowing spatial distribution of WFT responses is significant for accurate and reliable permeability determination. Angeles et al. (2007) redefined the concept of radius of investigation for formation tester applications. Pressure derivatives calculated from various no-flow boundaries at given radii away from the wellbore are used as the diagnosis tool to quantify the radius of investigation. As such, the radius of investigations determined from pressure derivatives and sensitivity function maps follow each other
closely.

In formations with low permeability streaks, the correct thickness for a WFT test should be the thickness between steaks. The radial flow regime appears more quickly due to these steaks, while the correct thickness for permeability interpretation may be less obvious (Elshahawi et al., 2008). In a laminated reservoir, one challenge to determine formation thickness is the presence of vertical heterogeneity (Daungkaew et al., 2007). Based on a field example, estimation of the flow thickness being sensed by a WFT device was found to be the key to assign permeability and permeability-thickness to an individual flow unit (Ramaswami et al., 2012).

2) *Gauge resolution*

The gauge resolution is the minimum pressure change that can be detected by a pressure gauge sensor (Kuchuk, 2009). Usually after acquiring well test data, the stable part of a drawdown, the last portion of a buildup, or the initial part of an interference test should be plotted at the gauge resolution. As can be seen in Figure 2.5, a set of data is plotted to illustrate the apparent gauge resolution. The standard deviation $\sigma$ of this data displayed is 0.002 psi so that the corresponding apparent resolution is $2\sigma$ (i.e., 0.004 psi). In order to be conservative, $\sigma_{max}$ which is 0.010 psi as shown in the figure should be used for the apparent gauge resolution (Kuchuk, 2009). Gauge resolution depends mainly on
Figure 2.5 Determination of an apparent resolution from a set of test data (Kuchuk, 2009)
the type of gauge used to measure the pressure responses.

Limited efforts have been made to examine the effect of gauge resolution in the WFT applications. Angeles et al. (2007b) re-defined the concept of radius of investigation in WFT applications and pointed out that this concept is affected by the actual resolution of the measurements. As for the pressure transient analysis in WFT applications, Whittle et al. (2003) proposed that the quality of data recorded by WFT tools in low permeability reservoirs (mobility less than about 100 mD/cP) was suitable for pressure transient interpretation, while the resolution of the pressure gauge limited the quality of the data acquired in a high permeability reservoir and thus precluded the transient analysis with good accuracy.

Daungkaew et al. (2004) presented that the small pressure drop which occurs during the short period of the WFT test in a high permeability reservoir was typically of the same magnitude as the resolution of the gauge within the WFT. The measured pressure response cannot provide valid reservoir information and only represents the noise. They concluded that a horizontal permeability of 200 mD was representative of the permeability limit for the use of the pressure transient analysis technique in WFT applications.
2.5 Summary

Due to the economical and environmental considerations, WFT is gaining increasing interest in the oil and gas industry for permeability interpretation. Conventional pressure transient analysis is widely used to interpret the WFT data by combining the pressure and pressure derivatives to recognize the flow regimes. Formation thickness sensed by a WFT device differs significantly with what is defined in pressure transient analysis as well as a conventional well testing. No attempts, however, have been made to determine the formation thickness being sensed by a WFT device in a thick formation as well as a laminated formation during a WFT test, while effect of payzone thickness on the permeability interpretation has not been thoroughly examined. In addition, pressure gauge resolution is seldom considered in the WFT permeability interpretation. It is of practical and fundamental importance to analyze and quantify the effect of formation thickness to accurately interpret the WFT measurements.
CHAPTER 3 DETERMINATION OF EFFECTIVE FORMATION THICKNESS

In this chapter, a numerical model is developed to determine the effective formation thickness and examine its effect on permeability interpretations. A high-resolution near wellbore model is used to simulate the WFT fluid sampling process together with transient pressures at a flowing probe. The calculated pressure derivatives as a function of formation thickness are used as a diagnosis tool to quantify the effective formation thickness for the reference model. Subsequently, sensitivity analysis has been performed to examine the effect of permeability anisotropy, flow rate, gauge resolution, porosity, and probe location on pressure transients and effective formation thickness.

3.1 Numerical Model of Probe-Type WFT

3.1.1 Reference case

Simulation of WFT measurements was performed with a commercial simulator (IMEX, Version 2009.11, Computer Modeling Group Ltd.). It is assumed that a vertical borehole was drilled with the water-based mud (WBM) penetrating through a horizontal layer. The WFT probe is modeled in a 3D radial (cylindrical) coordinate system and is
centered at the axis of the borehole. Simulating the fluid pumpout from the formation is performed by imposing the internal boundary condition with a constant flow rate. Closed or no-flow outer boundary conditions are imposed at the top, bottom and external boundaries, respectively.

Table 3.1 shows the finite difference grid configuration, consisting of 38 non-uniform grids in the radial (r) direction, 25 grids in the azimuthal (θ) direction, and 25 grids in the vertical (z) direction, respectively. Previous studies associated with simulation of WFT probe dynamics assumed a symmetric geometry in the azimuthal direction. Either half of the spatial domain was modeled (McCalmont et al., 2005; Alpak et al., 2008) or a single 180° azimuthal gridblock behind the probe (Malik et al., 2007) was used to minimize the computation time. In this study, a full 3D grid geometry is generated and the azimuthal grid behind the probe is refined as well during the simulation process.

Figure 3.1 depicts the 3D view of the numerical model. The grid size variability is designed not only to represent the probe precisely, but also to analyze flow geometry near the probe accurately. Figure 3.2 illustrates the side and the top views of the grid system with the respect of WFT probe. In the radial direction, the simulator enforces a logarithmic discretization, starting from an initial value of 0.04 ft near the wellbore to 100.00 ft at the external radial boundary. In the vertical direction, the grid thickness
**Table 3.1** Geometrical and numerical simulation parameters used in the reference case

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellbore radius ($r_w$)</td>
<td>ft</td>
<td>0.3</td>
</tr>
<tr>
<td>External radius ($r_e$)</td>
<td>ft</td>
<td>500.0</td>
</tr>
<tr>
<td>Number of grids – radial axis</td>
<td>---</td>
<td>38</td>
</tr>
<tr>
<td>Number of grids – azimuthal axis</td>
<td>---</td>
<td>25</td>
</tr>
<tr>
<td>Number of grids – vertical axis</td>
<td>---</td>
<td>25</td>
</tr>
</tbody>
</table>
Figure 3.1 The 3D view of the numerical model (unit: ft).
Figure 3.2 Schematic of the grid system: (a) side view and (b) top view
ranges from 0.04 ft near the probe to 5.00 ft at the top and bottom boundaries. In the azimuthal direction, the grid angle changes from 8° to 18°. There are 4550 grids in a radius of 1.00 ft around the probe to sufficiently capture flow dynamics in the near-probe region.

At the wellbore, the WFT probe intake opening is modeled as a source or a well in one grid, which is roughly the size of a cube of 0.5 inch on each side. Unless otherwise indicated (e.g., probe location cases), the WFT probe is positioned in the middle of a formation for the reference case. The drawdown sequence enforces a constant production flow rate of 10 bbl/d at the probe during the first one hour, after which the buildup sequence continues for another one hour (see Figure 3.3).

Table 3.2 lists the petrophysical and fluid properties for the reference case. The initial pressure is the pressure at which WFT probe is located. Note that it cannot represent the initial pressure across the formation in the vertical direction due to the fluid gravity effect. In order to replicate the model precisely, the fluid pressure gradient in the reference case is found to be 0.295 psi/ft, corresponding to that of the in-situ density of oil under reservoir conditions. Such fluid pressure gradient has been used to calculate the formation pressures in the vertical direction on the basis of grid thickness.

During the drilling process, the permeable rock formation is hydraulically overbalanced by mud circulation to prevent the well from blowout. Thus, the pressure in...
Table 3.2 Petrophysical and fluid properties for the reference case

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial water saturation</td>
<td>fraction</td>
<td>0.25</td>
</tr>
<tr>
<td>Water compressibility</td>
<td>1/psi</td>
<td>3.16e-6</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>cP</td>
<td>0.45</td>
</tr>
<tr>
<td>Formation porosity</td>
<td>fraction</td>
<td>0.2</td>
</tr>
<tr>
<td>Formation permeability</td>
<td>mD</td>
<td>100</td>
</tr>
<tr>
<td>Formation permeability anisotropy</td>
<td>dimensionless</td>
<td>0.25</td>
</tr>
<tr>
<td>Formation temperature</td>
<td>ºF</td>
<td>140</td>
</tr>
<tr>
<td>Formation compressibility</td>
<td>1/psi</td>
<td>3.9e-6</td>
</tr>
<tr>
<td>Oil gravity</td>
<td>ºAPI</td>
<td>32</td>
</tr>
<tr>
<td>Gas-oil ratio</td>
<td>SCF/STB</td>
<td>1300</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>psi</td>
<td>18000.5</td>
</tr>
</tbody>
</table>
Figure 3.3 Time sequence of flow rate assumed during the simulations for the reference case
the near-wellbore region is higher than the initial pressure, known as supercharging (Yildiz et al., 1991). Some laboratory experiments as well as field experiences have shown that the supercharging effect is negligible in high permeability formations but significant in low permeability formations (Yildiz et al., 1991). In the reference case, supercharging phenomenon is not included in the model because of its high permeability.

Certain efforts have been made to investigate the impact of mud-filtrate invasion on the WFT measurements (Goode et al., 1996; Chang et al., 2005; Gok et al., 2006). The rate of mud-filtrate invasion is found to monotonically decrease as a function of time. In general, it is difficult to calculate the rate of invasion accurately. Moreover, mud filtrate invasion is a complicated process as it involves solid and solute transport and precipitation, wettability alteration, chemical adsorption, and gravity effects (Gok et al., 2006). Therefore, instead of simulating the mud filtrate invasion process, the simulation is initiated with a known radial length of WBM filtrate region symmetrically distributed along the axis of the well (Malik et al., 2007; Alpak et al., 2008; Malik et al., 2009a).

As for simulation, variation of fluid compressibility in the reservoir is considered, while effect of tool (i.e., the probe) flowline storage is not included in the reference case. It is assumed that the sandface flowrate remains constant during flowline drawdown decompression and that the flowline volume is small enough to prevent flow back from the formation during buildup.
3.1.2 Model validation

In this study, two methods have been introduced to validate the numerical model. First, a quick grid quality check has been conducted. The finite difference grid system is validated with the analytical solution of single-phase pressure transient measurements for a radial and closed boundary system, which is represented as follows (Earlougher, 1977),

\[
P_D = -\frac{1}{2} \left( Ei\left( \frac{1}{4t_D} \right) - Ei\left( \frac{1}{4t_{De}} \right) - 4t_{De} \exp\left( -\frac{1}{4t_{De}} \right) \right) \tag{3.1}
\]

\[
t_D = \frac{0.0002637k}{\phi\mu c t_w^2} \tag{3.2a}
\]

\[
t_{De} = \frac{0.0002637k}{\phi\mu c r_e^2} \tag{3.2b}
\]

\[
P_{wf} = P_i - \frac{141.2qB\mu P_D}{kh} \tag{3.2c}
\]

where \( P_D \), \( t_D \), and \( t_{De} \) are dimensionless forms. The dimensionless time is represented by Equation [3.2a] where \( k \) is permeability, \( \phi \) is porosity, \( \mu \) is fluid viscosity, \( c_t \) is total compressibility, and \( r_w \) is the wellbore radius. The dimensionless time based on the external radius of the system is represented by Equation [3.2b] where \( r_e \) is the external radius of the system. The flowing bottom-hole pressure is calculated by Equation [3.2c] where \( P_i \) is initial pressure, \( B \) is formation volume factor, and \( h \) is formation thickness. As can be seen in Figure 3.4, both short time and long time responses indicate
Figure 3.4 Comparison between the analytical solution of transient pressure for a single phase with the simulation results in a radial grid system
an excellent match between the numerical and analytical results.

Subsequently, history matching has been performed to further validate the numerical model. Such validation is checked against the pressure transient measurements with a set of field data from a WFT test in the deepwater Gulf of Mexico, USA. The reservoir temperature and the initial formation pressure are measured to be 140°F and 16066 psi, respectively. According to well logging, the initial water saturation and formation porosity are 0.25 and 0.18, respectively. Analysis of fluid samples, conventional cores and sidewall cores indicate a high-quality crude oil in good reservoir sands with 32 °API gravity and in-situ viscosity of 2.5 cP.

The WFT test was performed with an interval of 20 ft, identified by the openhole logs while the distance between the WFT probe location and the bottom boundary is 7 ft. Because there is no core data available for the well, a Brooks-Corey relationship is assumed to calculate the relative permeability and capillary pressure. According to this model, relative permeability curve and capillary pressure curve are represented as follows (Brooks and Corey, 1964),

\[
S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{or}} [3.3]
\]

\[
k_{rw} = k_{rw}^0 (S_w^*)^{\gamma_w} [3.4]
\]

\[
k_{ro} = k_{ro}^0 (1 - S_w^*)^{\gamma_o} [3.5]
\]
\[ P_c = P_c^0 \sqrt{\frac{\phi}{k}} \left( 1 - S_w^* \right)^{e_w} \]  

[3.6]  

where \( S_w^* \) is the normalized water saturation, \( S_w, S_w^{irr} \), and \( S_o^{irr} \) are water saturation, irreducible water saturation (or connate water saturation), and irreducible oil saturation, respectively. The water relative permeability is represented by Equation [3.4], where \( k_{rw}^0 \) is water end-point relative permeability and \( e_w \) is an empirical exponent for water. The oil relative permeability can be calculated with Equation [3.5], where \( k_{ro}^0 \) is oil end-point relative permeability and \( e_o \) is an empirical exponent for oil. Equation [3.6] is used to determine capillary pressure \( P_c \), where \( P_c^0 \) is the coefficient for capillary pressure and \( e_p \) is the pore size distribution exponent. Table 3.3 summarises the specific parameters used in Brooks-Corey equations (Malik, 2008).

Figure 3.5 depicts the measured pumpout flow rates and the corresponding pressures, respectively. As shown in Figure 3.5a, the test sequence consists of a 7-hour drawdown with a few minor quick buildup tests and a long buildup test. A total of 27707 pairs of data were recorded with flow rate fluctuated between 4.6 to 5.5 cc/s (i.e., 2.5 to 3.0 bbl/d). As can be seen in Figure 3.5b, there exists several (coincidental) shut-in periods during which the pressure was allowed to build up to the initial formation pressure. At the very beginning, the measured pressures are much higher than the initial formation pressure since the drilling mud pressure is maintained higher than the formation pressure to prevent the well from blowout. Such a difference between the mud hydrostatic pressure and the formation pressure...
Table 3.3 Summary of relative permeability and capillary pressure parameters used in the Brooks-Corey equations (Malik, 2008)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empirical exponent for water phase, ( e_w )</td>
<td>2.2</td>
</tr>
<tr>
<td>Empirical exponent for oil phase, ( e_o )</td>
<td>3.0</td>
</tr>
<tr>
<td>End-point for water phase, ( k_{rw}^0 )</td>
<td>0.37</td>
</tr>
<tr>
<td>End-point for oil phase, ( k_{ro}^0 )</td>
<td>0.99</td>
</tr>
<tr>
<td>Empirical exponent for pore-size distribution, ( e_p )</td>
<td>25</td>
</tr>
<tr>
<td>Capillary pressure coefficient, ( P_c^0 )</td>
<td>15</td>
</tr>
</tbody>
</table>
Figure 3.5 The measured (a) WFT flowrates and (b) pressures for a well in deepwater Gulf of Mexico
pressure is called “overbalance” (Yildiz et al., 1991).

A large number of noisy pressure data (see Figure 3.5b) were involved with the drawdown measurements, mainly resulting from the WFT pump displacement. Under the field sampling conditions, a bi-directional positive displacement pump typically displaces the fluctuated rates. In particular, an instant pause in flow rate is observed during a stroke reversal, resulting in an increased pressure. The volume of chamber in a Schlumberger’s MDT pump is 550 cc (Schlumberger, 2002). Since the flow rate is fluctuated in a range of 4.6 to 5.5 cc/s during the measurement in this data set, it takes about 110 seconds for the piston to theoretically move from one end to the other. As for the ultra-deep well in the Gulf of Mexico, however, the piston is always not pushed for the entire stroke due to mechanical operating limit for the packer. This is why there is an abnormally high pressure reading about every 50 seconds.

During the WFT pumping period, the filtrate invasion process is neglected. Pumpout flow rate history is imposed as well input constraints, while the calculated pressures from the simulator need to be matched with the measured values. In this process, the trial-and-error method is adopted to achieve a good match by manually adjusting permeability, permeability anisotropy, and radial length of invasion. As shown in Figure 3.6, there exists a good match between the measured and simulated pressure measurements except those noisy points as previously explained.
Figure 3.6 Comparison of measured and simulated transient pressures at the WFT probe
3.2 Determination of Effective Formation Thickness

The effective formation thickness is defined as the maximum vertical thickness in the reservoir being sensed by the WFT device within a specified tool resolution. The effective formation thickness is determined by the ability of the wireline formation tester to sense pressure variations induced by a petrophysical perturbation. This concept is analogous to that of radius of investigation used in the conventional well testing. It will be relatively easy to determine the effective formation thickness if pressure sensors with a specific gauge resolution is distributed vertically below or above the WFT probe. At a given time during a WFT test, the pressure fluctuation becomes observable from these observation sensors. The distance between these two sensors which are respectively distributed below and above the probe is termed as the effective formation thickness.

In this study, the pressure derivatives calculated as a function of formation thickness are used as a diagnosis tool to determine the effective formation thickness, while the calculation of pressure derivatives are performed with the commercial software (Saphir, Version 4.12, Ecrin). Figure 3.7 describes the simulated pressure transient responses for the reference case at different formation thicknesses. Pressure responses for the formations with different thicknesses are kept to be consistent, while the enlarged view indicates that it would take less time for the thicker formation to build up to the
Figure 3.7 Simulated transient pressures as a function of formation thickness for the reference case
initial pressure after a drawdown process.

As for real field applications, pressure transient measurements are always affected with the inherent noises. Here, in agreement with the accuracy and reliability of most commercially available quartz gauges, a noise threshold of 0.01 psi has been added to simulate the pressure transient measurements, while a zero-mean random Gaussian noise was added to simulate pressure measurements. Figure 3.8 depicts the simulated pressure measurements with 0.01 psi noise for a formation of 60 ft in thickness.

With the added noise, the calculated pressure derivative curves are not as smooth and converging as the theoretical ones. Pressure derivatives become noisy especially after 0.1 hr because the pressure change is very small and close to the gauge resolution at the late time of the buildup test. The formation thickness is increased step by step starting from 60 ft, while its derivative is compared with that of the infinite-thickness formation. The effective formation thickness is determined once its pressure derivative becomes indistinguishable with that of the infinite-thickness formation. The effective formation thickness is calculated at a given time during the WFT buildup test and for a specific pressure gauge resolution.

As for conventional pressure transient analysis, if the formation properties (i.e., porosity, viscosity and total compressibility) and the thickness of the layer are known, the measurements can be used to interpret the product of horizontal permeability and
Figure 3.8 Simulated transient pressures for a 60 ft-thick formation with a noise of 0.01 psi
formation thickness and subsequently calculate horizontal permeability. As such, permeability is always underestimated for thick formations if the effective formation thickness is much less than its true thickness in a given reservoir.

In order to keep the plot clear, only four representative curves are included in Figure 3.9. It takes 0.1 hr and 0.3 hr for the formation thickness of 60 ft and 100 ft to develop the pseudo-cylindrical radial flow regime, respectively. As for the formation thickness of 140 ft and the infinite-thickness, however, the pseudo-cylindrical radial flow regime does not develop during this scenario, while the corresponding pressure derivatives are indistinguishable. Therefore, the effective formation thickness for the reference case is determined to be 140 ft under condition of 0.01 psi gauge resolution.

3.3 Parametric Effect on Permeability Interpretations

3.3.1 Permeability anisotropy ratio

The permeability anisotropy ratio is defined as the ratio of the vertical permeability to the horizontal permeability of the formation, \( k_v/k_h \) (Alpak et al., 2006). In this analysis, three different cases of permeability anisotropy are considered ranging from 0.1 to 0.5. Horizontal permeability for all cases is kept as 100 mD, while vertical permeability is modified correspondingly to obtain different values of permeability anisotropy. As shown
Figure 3.9 Pressure change together with its derivative as a function of time under various effective formation thickness for the reference case with gauge resolution of 0.01 psi
in **Figures 3.10a-c**, the simulation results indicate that the measured drawdown pressures are sensitive to permeability anisotropy. This finding is similar to that documented in the literature (Malik *et al.*, 2007).

The effective formation thickness (see **Figure 3.11**) is increased as permeability anisotropy increases. In the reference case, the effective formation thickness decreases from 150 to 100 ft with permeability anisotropy of 0.1, but increases from 150 to 230 ft with permeability anisotropy of 0.5. As the permeability anisotropy decreases, the decreased vertical permeability acts as a barrier to flow in the vertical direction. The lower the vertical permeability is, the weaker the pressure wave will affect the upper and lower spatial region of the WFT probe. Therefore, a low vertical permeability results in a small effective formation thickness.

### 3.3.2 Probe flow rate

The WFT pumpout flow rates are usually controlled by a number of factors, mostly the pump capacity and well depth (when the mud hydrostatic pressures exceed the tool mechanical operating limit). In this section, a practical pumpout flow rate used for the simulation is consistent with the capacity limits of WFT pump operation. The flow rates in this analysis are varied from 5 to 20 bbl/d. The simulated pressure transient measurements (see **Figure 3.12**) are found to be very sensitive to the pumpout flow rate.
Figure 3.10 Simulated transient pressures at the WFT probe for permeability anisotropy of (a) 0.10, (b) 0.25, and (c) 0.50
Figure 3.11 Derivatives at the WFT probe for permeability anisotropy of (a) 0.10, (b) 0.25, and (c) 0.50
Figure 3.12 Simulated transient pressures at the WFT probe for probe flow rates of (a) 5 bbl/d, (b) 10 bbl/d, and (c) 20 bbl/d
An increase in flow rates leads to a higher pressure differential. This finding is the same as those documented in the literature (Malik et al., 2007).

When the flow rate is increased from 5 to 10, and then 20 bbl/d, the effective vertical thickness is increased from 120 to 150, and then 180 ft (see Figure 3.13). As for the same pumpout duration, the effective formation thickness is dependent on the rate of fluid withdrawn. A higher probe flow rate affects a larger spatial region and therefore increases the effective formation thickness.

### 3.3.3 Gauge resolution

The gauge resolution is the minimum pressure change that can be detected by a pressure gauge sensor (Kuchuk, 2000). Accordingly, gauge resolution of 0.01 psi and 0.03 psi resolution is chosen for performing sensitivity analysis. After two different levels of noise are added to the originally simulated pressure measurements, the corresponding pressure derivative curves are plotted to estimate effective formation thickness under different gauge resolution conditions. Figure 3.14 shows that a small value of gauge resolution can lead to a significant increase in predicting the effective formation thickness. At 0.01 psi gauge resolution (see Figure 3.14a), the pressure derivatives are converging and the effective formation thickness is calculated to be 140 ft, while, at 0.03 psi gauge resolution (see Figure 3.14b), the predicted pressure derivatives become very noisy with
Figure 3.13 Derivatives at the WFT probe for probe flow rates of (a) 5 bbl/d, (b) 10 bbl/d, and (c) 20 bbl/d
Figure 3.14 Pressure change and derivatives at the WFT probe for gauge resolution of (a) 0.01 psi and (b) 0.03 psi
difficulty to determine its effective formation thickness. A smaller value of gauge resolution can be used to detect a smaller pressure change and therefore sense a thicker region. Pressure gauge with high resolution is recommended to obtain high quality of pressure transient measurements as well as true formation permeability. As for the most WFT field applications, the quartz gauge resolution is 0.01 psi (Schlumberger, 2002).

3.3.4 Porosity

In this section, three different cases of formation porosity are considered ranging from 0.05 to 0.40, while formation permeability is kept constant for all cases. Figure 3.15 shows that the measured drawdown pressures are sensitive to formation porosity due to the mud filtrate invasion. The radial lengths of mud-filtrate invasion for all cases are the same. A higher porosity will result in a larger pressure differential because the invaded mud-filtration is more serious. When the porosity is increased from 0.05 to 0.20, and then 0.40, the effective vertical thickness is decreased from 170 to 150, and then 110 ft (see Figure 3.16). For a low porosity, pressure perturbation will be greater than that for a high porosity, assuming that the flow rate of fluid production is kept constant. Therefore, a low porosity results in an increase for the effective formation thickness.
Figure 3.15 Simulated transient pressure at the WFT probe for porosity of (a) 0.05, (b) 0.20, and (c) 0.40
Figure 3.16 Pressure change and derivatives at the WFT probe for porosity of (a) 0.05, (b) 0.20, and (c) 0.40
3.3.5 Porosity and permeability

This sensitivity analysis is performed by simultaneously varying both porosity and permeability, assuming these two parameters are dependent on each other in a sandstone formation based on field experience. Three different combinations of porosity and permeability are considered: 1) porosity of 0.10 with permeability of 5 mD; 2) porosity of 0.15 with permeability of 16 mD; and 3) porosity of 0.20 with permeability of 100 mD. Figure 3.17 depicts transient pressures for these three cases. As can be seen, pressure transient measurements are very sensitive to both porosity and permeability. Note that excessive drawdown (see Figure 3.17a) occurs because of the low permeability. In practice, concerns about excessive drawdown may limit the flow rate from the probe and reduce the utility of the probe configuration. However, for high mobility fluids, probe can be used to estimate the flow unit permeabilities without loss in the ability (Elshahawi et al., 2008).

In previous section, effective formation thickness will decrease with an increase in porosity. As for this combinational analysis, however, with an increase in porosity and permeability, effective formation thickness will increase correspondingly from 80 ft to 100 ft, and then 150 ft (see Figure 3.18). This is due to the interdependence of permeability and porosity, though permeability plays a dominant role for pressure wave propagation in the formation.
Figure 3.17 Simulated transient pressure at the WFT probe for combination of (a) porosity of 0.10 with permeability of 5 mD, (b) porosity of 0.15 with permeability of 16 mD, and (c) porosity of 0.20 with permeability of 100 mD
Figure 3.18 Pressure change and derivatives at the WFT probe for combination of (a) porosity of 0.10 with permeability of 5 mD, (b) porosity of 0.15 with permeability of 16 mD, and (c) porosity of 0.20 with permeability of 100 mD.
3.3.6 Probe location

In previous sections, the WFT probe is located in the middle of the formation. In this section, another two probe locations are considered: one is located 10 ft from the upper boundary and the other is 20 ft from the lower boundary. As can be seen, Figure 3.19 indicates that pressure transient measurements are not very sensitive to the probe locations. When the probe is located 10 ft from the top boundary (see Figure 3.20a), the effective formation thickness is determined to be 85 ft with 10 ft above the probe which is restricted by top boundary and 75 ft below the probe. As can be seen in Figure 3.20b, the effective formation thickness is found to be 150 ft with a symmetric distribution from the probe to both ends if the WFT probe is located in the middle of the formation. When the probe is located 20 ft from the bottom boundary (see Figure 3.20c), the effective formation thickness is calculated to be 95 ft with 20 ft below the probe which was restricted by the bottom boundary and 75 ft above the probe. Note that the radial flow regime can develop only when flow is restricted by both top and bottom boundaries.

At the same time, once the flow is restricted by only one boundary, the derivative slope in the spherical flow regime will be less than -1/2. Meanwhile, the time required for the flow to develop the radial flow regime is a function of the distance between the probe and the farther boundary. For the WFT application in a thick formation larger than 75 ft, the probe should be positioned in the middle of the formation to better define the
Figure 3.19 Simulated transient pressure at the WFT probe for probe location of (a) 10 ft from the upper boundary, (b) middle of the formation, and (c) 20 ft from the lower boundary
Figure 3.20 Pressure change and derivatives at the WFT probe for probe location of (a) 10 ft from the upper boundary, (b) middle of the formation, and (c) 20 ft from the lower boundary
effective formation thickness and to accurately interpret the formation permeability. 

Table 3.4 presents a summary of the sensitivity analysis, while input parameters and corresponding effective formation thickness are also listed.

3.3.7 Heterogeneous formation

As for the heterogeneous formation, it is expressed as layered formations. In all cases, the WFT probe is positioned in the middle of the layered intervals. Table 3.5 describes the permeability distributions in Scenarios #1-4 with a thickness of 15 ft and 100 ft, respectively. Permeability anisotropy with three different values (i.e., 0.25, 0.50 and 1.00) has been considered for each scenario in which a noise threshold of 0.01 psi is added to calculate the corresponding pressure derivatives.

Figure 3.21 depicts the pressure derivatives of Scenarios #1-4 for permeability anisotropy of 0.25. The pressure derivatives can be used to interpret the correct permeability for the formation with 15 ft interval in thickness. The permeability interpreted from the WFT probe measurement is the weighted average of all sub-intervals with different permeability. Although the average permeabilities in Scenarios #2 and #3 (i.e., 10 mD and 8 mD) are very close, it is still easy to find the difference from their corresponding pressure derivative curves (see Figure 3.21a). For the formation with 100 ft interval in thickness, however, the derivative curves of Scenarios #1-3 overlap with
Table 3.4 Summary of the sensitivity analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
<th>Effective formation thickness, ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability anisotropy</td>
<td>dimensionless</td>
<td>0.10</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.25</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.50</td>
<td>230</td>
</tr>
<tr>
<td>Probe flowrate</td>
<td>bbl/d</td>
<td>5</td>
<td>120</td>
</tr>
<tr>
<td></td>
<td></td>
<td>10</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20</td>
<td>180</td>
</tr>
<tr>
<td>Gauge resolution</td>
<td>psi</td>
<td>0.01</td>
<td>140</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.03</td>
<td>80</td>
</tr>
<tr>
<td>Porosity</td>
<td>fraction</td>
<td>0.05</td>
<td>170</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.20</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.40</td>
<td>110</td>
</tr>
<tr>
<td>Porosity and permeability</td>
<td>fraction, mD</td>
<td>0.10, 5</td>
<td>80</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.15, 16</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.20, 100</td>
<td>150</td>
</tr>
<tr>
<td>Probe location</td>
<td>ft</td>
<td>10 ft from the upper boundary</td>
<td>85</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Middle of the formation</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20 ft from the lower boundary</td>
<td>95</td>
</tr>
</tbody>
</table>
Table 3.5 Permeability distribution under formation thickness of 15 ft and 100 ft

<table>
<thead>
<tr>
<th>Layer</th>
<th>15 ft Thickness interval (ft)</th>
<th>Permeability (mD)</th>
<th>100 ft Thickness interval (ft)</th>
<th>Permeability (mD)</th>
<th>Weighted average permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario #1</td>
<td>1 3 20 20 20</td>
<td>14.6</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2 3 5 20 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3 3 20 20 20</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4 3 8 20 8</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>5 3 20 20 20</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario #2</td>
<td>1 3 10 20 10</td>
<td>10.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2 3 5 20 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3 3 20 20 20</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4 3 5 20 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>5 3 10 20 10</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario #3</td>
<td>1 3 7 20 7</td>
<td>8.8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2 3 5 20 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3 3 20 20 20</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4 3 5 20 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>5 3 7 20 7</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario #4</td>
<td>1 3 20 21 20</td>
<td>18.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2 1 5 6 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3 7 20 45 20</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4 1 5 6 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>5 3 20 22 20</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 3.21 Pressure change and derivative for Scenarios #1-4 with permeability anisotropy of 0.25 for (a) 15 ft and (b) 100 ft intervals
each other. Note that the permeability distributions in the middle three sub-intervals in Scenarios #1-3 are almost the same, while total thickness of the middle three sub-intervals is within the defined effective formation thickness. Therefore, the WFT probe data can be employed to accurately determine the average permeability in those three sub-intervals due to the fact that any discrepancy cannot be identified from their derivatives. Similar behaviour is also observed when permeability anisotropy is 0.50 and 1.00 (see Figure 3.22 and Figure 3.23).

3.4 Summary

A high-resolution near-wellbore numerical model has been developed to simulate the WFT fluid sampling process together with transient pressures at a flowing probe. This newly developed model is validated analytically and then with the field data from the deepwater Gulf of Mexico, USA. The calculated pressure derivatives are used as a diagnosis tool to sensitize the impact of the effective formation thickness, which is defined as the maximum vertical thickness in the reservoir being sensed by the WFT device during a test within a given tool resolution.

Sensitivity analysis has subsequently been performed to quantify the effective formation thickness of the tested formation. Pressure transient measurements are found to be sensitive to permeability anisotropy, flow rate, and porosity, while effective formation
Figure 3.22 Pressure change and derivative for Scenarios #1-4 with permeability anisotropy of 0.5 for (a) 15 ft and (b) 100 ft intervals
Figure 3.23 Pressure change and derivative for Scenarios #1-4 with permeability anisotropy of 1 for (a) 15 ft and (b) 100 ft intervals
thickness is a strong function of permeability anisotropy, flow rate, porosity, gauge resolution, and probe location. In addition, permeability interpreted from the WFT probe measurement is the weighted average of all sub-intervals with different permeabilities.
CHAPTER 4  EFFECT OF LAMINATIONS ON  
PERMEABILITY INTERPRETATION AND  
PRESSURE BUILDUP DYNAMICS

In deepwater environments, many reservoirs are formed in a depositional environment, resulting in laminated sands with various percentages of silt and clay beds (Beik et al., 2010). The reservoir sands may be highly permeable, while the silt and clay laminations affect the reservoir vertical permeability significantly (Daungkaew et al., 2008; Kiatpadungkul et al., 2010). In this chapter, history matching has been performed with the field data from deepwater Gulf of Mexico to determine the effective thickness and then interpret the permeability for each flow unit. Subsequently, sixteen cases with various configurations of laminated layers have been generated and examined. The pressure buildup derivatives obtained from both packers and observation probes are used as a diagnosis tool to sensitize the effect of lamination on WFT interpretations.

4.1  WFT Field Measurements

Two WFT tests were performed in a vertical well in the deepwater Gulf of Mexico, which is a vertical exploration well drilled through a water zone with oil-based mud.
(OBM). All the tests were performed with a dual packer WFT and located within an interval of 110 ft. Figure 4.1 shows the petrophysical interpretation of the zone with the conventional openhole wireline logs. The formation consists of sandstone with a silt and clay lamination of 41 ft where limited knowledge is available for the vertical communication between sublayers. According to well logging, formation porosity is measured to be 0.2, while water salinity and in-situ viscosity are 30000.0 ppm and 0.5 cP, respectively.

Table 4.1 lists the petrophysical and fluid properties for the base case. The initial pressure is the pressure at which a WFT packer is located. It cannot represent the initial pressure across the formation in the vertical direction due to the fluid gravity effect. In order to replicate the model precisely, the fluid pressure gradient is taken into consideration in the numerical model, which can be calculated from initial pressures at Testers #1 and #2. Such fluid pressure gradient has been used to calculate the formation pressures in the vertical direction on the basis of grid thickness.

As for Tester #1, the distance between its packer and the top boundary is 8 ft, while it is 84 ft for Tester #2. The distance between the lamination and the top boundary is 28 ft. Figures 4.2a and b illustrate the measured pumpout flowrates and the corresponding pressures for Testers #1 and #2, respectively. As shown in Figure 4.2a, there are step-wise flowrates in drawdown process, followed by a buildup test. As for Tester #2,
Table 4.1 Petrophysical and fluid properties for the base case

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir water density</td>
<td>lb/ft³</td>
<td>61.58</td>
</tr>
<tr>
<td>Water compressibility</td>
<td>1/psi</td>
<td>3.16e-6</td>
</tr>
<tr>
<td>Reservoir water viscosity</td>
<td>cP</td>
<td>0.5</td>
</tr>
<tr>
<td>Formation porosity</td>
<td>fraction</td>
<td>0.2</td>
</tr>
<tr>
<td>Formation temperature</td>
<td>°F</td>
<td>140</td>
</tr>
<tr>
<td>Formation compressibility</td>
<td>1/psi</td>
<td>3.9e-6</td>
</tr>
<tr>
<td>Mud-filtrate viscosity</td>
<td>cP</td>
<td>2.0</td>
</tr>
<tr>
<td>Mud-filtrate density</td>
<td>lb/ft³</td>
<td>49.9</td>
</tr>
<tr>
<td>Initial pressure at WFT Tester #1</td>
<td>psi</td>
<td>18000.5</td>
</tr>
<tr>
<td>Initial pressure at WFT Tester #2</td>
<td>psi</td>
<td>18033.0</td>
</tr>
</tbody>
</table>
Figure 4.1 Conventional openhole logs over the zone of interest
Figure 4.2 The measured WFT flowrates and pressures for (a) Tester #1 and (b) Tester #2 in a vertical well, Gulf of Mexico.
the test sequence consists of a 2.5-hour drawdown with a few minor quick buildup tests
and a long buildup test.

4.2 Numerical Model of Packer-Type WFT

Simulation of WFT measurements is performed with a reservoir simulator (GEM,
Version 2009.11, Computer Modeling Group Ltd.). It is assumed that a vertical borehole
was drilled with the OBM penetrating through a horizontal layer. The dual packer WFT
was modeled in a 3D radial (cylindrical) coordinate system. The numerical model is
adapted from the one validated in Chapter 3. Simulating the fluid pumpout from the
formation is performed by imposing the internal boundary conditions with a constant
flow rate. Closed or no-flow outer boundary conditions are imposed at the top, bottom
and external boundaries, respectively.

Table 4.2 shows the finite difference grid configuration, consisting of 38
non-uniform grids in the radial (r) direction, 24 grids in the azimuthal (θ) direction, and
55 grids in the vertical (z) direction, respectively. Figures 4.3a and b illustrate the side
and the top views of the finite difference grid system. Along the wellbore, the dual packer
interval has a length of 3.28 ft. The drawdown sequence enforces a constant production
rate of 10 bbl/d at the packer during the first one hour, after which the buildup sequence
continues for another one hour. Similar to the methodology adopted in Chapter 3, the
Table 4.2 Geometrical and numerical simulation parameters used in the numerical model

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellbore radius ($r_w$)</td>
<td>ft</td>
<td>0.3</td>
</tr>
<tr>
<td>External radius ($r_e$)</td>
<td>ft</td>
<td>300.0</td>
</tr>
<tr>
<td>Reservoir thickness</td>
<td>ft</td>
<td>110.0</td>
</tr>
<tr>
<td>Number of grids – radial axis</td>
<td>---</td>
<td>38</td>
</tr>
<tr>
<td>Number of grids – azimuthal axis</td>
<td>---</td>
<td>24</td>
</tr>
<tr>
<td>Number of grids – vertical axis</td>
<td>---</td>
<td>55</td>
</tr>
</tbody>
</table>
Figure 4.3 Schematic of the grid system: (a) side view and (b) top view
simulation is initiated with a known radial length of OBM filtrate region symmetrically distributed along the axis of the well (Alpak et al., 2008), which will be adjusted by history matching the field pressure transients.

The OBM contains a mixture of oil, water, and surfactants necessary to maintain the oil-water mixture as an emulsion (Bourgoyne Jr. et al., 1986; La Vigne et al., 1997). Oil is the main component of the OBM and remains immiscible with water phase (Malik, 2008). Under dynamic drilling conditions, drilling mud mixes with the solid particulate matter and formation fluids so that its composition and viscosity can be modified. In addition, due to the high cost of OBM compared to water-based mud (WBM), OBM is often recycled in field operations, thus altering its original composition. Such an adverse situation leads to uncertainty in knowing the exact composition and PVT properties of the OBM (Malik, 2008). OBM composition consists of components from C_{14} to C_{18} which can be lumped into three pseudo-components (i.e., MC_{14}, MC_{16}, and MC_{18}), as shown in Table 4.3 (Malik et al., 2007; 2009b; Beik et al., 2010; Angeles et al., 2011).

A Brooks-Corey (Brooks and Corey, 1964) relationship has been assumed to calculate the relative permeability and capillary pressure curves. Table 4.4 summarizes capillary pressure parameters based on the laboratory measurements performed on core samples acquired in the deepwater Gulf of Mexico (Malik, 2008), while relative permeability curves is adjusted by history matching the field pressure transients.
Table 4.3 Summary of the PVT properties of the OBM filtrate (Malik et al., 2007)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MC\textsubscript{14}</th>
<th>MC\textsubscript{16}</th>
<th>MC\textsubscript{18}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molar concentration</td>
<td>0.6489</td>
<td>0.2145</td>
<td>0.1366</td>
</tr>
<tr>
<td>Critical temperature (°F)</td>
<td>755.1</td>
<td>822.5</td>
<td>878.1</td>
</tr>
<tr>
<td>Critical pressure (psi)</td>
<td>261.8</td>
<td>240.2</td>
<td>224.4</td>
</tr>
<tr>
<td>Acentric factor</td>
<td>0.6257</td>
<td>0.7118</td>
<td>0.7842</td>
</tr>
<tr>
<td>Molecular weight</td>
<td>190</td>
<td>222</td>
<td>251</td>
</tr>
<tr>
<td>Volume shift parameter</td>
<td>0.0792</td>
<td>0.0666</td>
<td>0.0439</td>
</tr>
</tbody>
</table>
Table 4.4 Summary of capillary pressure parameters used in the Brooks-Corey equations (Malik, 2008)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empirical exponent for pore-size distribution, $e_p$</td>
<td>25</td>
</tr>
<tr>
<td>Capillary pressure coefficient, $P_c^0$ (psi·D^{1/2})</td>
<td>15</td>
</tr>
</tbody>
</table>
4.3 History matching

As for WFT field applications, conventional PTA is used to interpret formation permeability. If the formation properties (i.e., porosity, viscosity, and total compressibility of the rock) and the thickness of the layer are known, pressure transients can be used to estimate the horizontal permeability. In this study, PTA and pressure derivatives are calculated with the commercial software (Saphir, Version 4.12, Ecrin). As mentioned previously, vertical permeability in the lamination is unknown, and thus horizontal permeability cannot be correctly interpreted without layer thickness.

In this section, history matching has been performed to determine vertical communication of the laminated layer as well as formation horizontal permeability. Both pressure transients and derivatives are checked against the pressure transient measurements with two sets of field WFT data from the deepwater Gulf of Mexico. During the WFT pumping period, the filtrate invasion process is neglected. Pumpout flow rate history was imposed as well input constraints, while the calculated pressures and derivatives from the simulator need to be matched with the measured values. In this process, the trial-and-error method is adopted to achieve a good match by manually adjusting radial length of invasion, relative permeability and permeability anisotropy.

An impermeable lamination is assumed, implying the effective thicknesses for Testers #1 and 2 are 28.0 ft and 41.0 ft, respectively. Also, horizontal permeability is
adjusted to match the thickness-permeability product. Then radial length of invasion is changed to match the overall trend of the pressure transient measurements, especially the beginning portion which is very sensitive to the concentration of OBM. At the same time, relative permeability curve is tuned to match discrepancy in some specific sections. Then, vertical permeability is changed to match the pressure derivative curve. With the new vertical permeability assigned, radial length of invasion is adjusted again to match the transient pressure measurements.

With the relative permeability curves determined by history matching for Testers #1 and #2 (see Figure 4.4). Figure 4.5 and Figure 4.6 summarize the comparison between the simulated results and field measurements for Testers #1 and #2. Note that, even though the flow rate is constant in Tester #1 (see Figure 4.5a) during certain periods (e.g., from 0.4 to 0.6 hr), the measured pressures increase with time. Such behaviour is attributed to the varying concentrations of the OBM contamination. At the beginning of the test, the transient pressure responses are very sensitive to the mud-filtrate invasion. In this case, the OBM filtrate has a higher viscosity than that of the formation water. Thus, mobility of the sampled fluid increases with time due to the corresponding decrease of viscosity when the formation water is produced by the packer. Similar phenomenon can also be observed in pressure transient response of Tester #2 (see Figure 4.6a). If the lamination is assumed to be permeable, even a permeability anisotropy ratio of 26 cannot
Figure 4.4 Relative permeability curves for (a) Tester #1 and (b) Tester #2
Figure 4.5 Comparison of measured and simulated (a) transient pressures and (b) pressure derivative for Tester #1 with the assumption of impermeable lamination.
Figure 4.6 Comparison of measured and simulated (a) transient pressures and (b) pressure derivatives for Tester #2 with the assumption of impermeable lamination
be used to match the field measurements (see Figure 4.7 and Figure 4.8) due to the fact that flow is hardly restricted by both top and bottom boundaries simultaneously. Such a physically impossible ratio suggests that a vertically impermeable lamination be most appropriate.

Based on the above history matching results, it is found that the lamination is vertically impermeable. The interval of interest consists of two flow units. The effective thickness for Tester #1 is 28.0 ft and its effective horizontal permeability is 14.0 mD. As for Tester #2, the effective thickness and effective horizontal permeability are found to be 41.0 ft and 10.6 mD, respectively. Such an interpretation reveals one advantage of WFT over the conventional well testing in that the former interprets permeabilities between individual flow units, while the latter provides average permeability for the whole interval, though there exists a significant difference in the interpreted thickness. In practice, the conventional test determines the formation thickness from the top to the bottom boundaries of the reservoir. In a laminated reservoir, the formation thickness for a WFT test should be the vertical distance between those with low vertical permeability layers.
Figure 4.7 Comparison of measured and simulated (a) transient pressures and (b) pressure derivative for WFT Tester #1 with the assumption of permeable lamination.
Figure 4.8 Comparison of measured and simulated (a) transient pressures and (b) pressure derivative for WFT Tester #2 with the assumption of permeable lamination
4.4 Effect of Lamination Location

4.4.1 Lamination located below the packer

In order to examine the effect of low vertical permeability lamination on pressure transient responses, a base case and seven cases with various configurations of lamination are generated. The WFT test takes one hour drawdown with flow rate of 10 bbl/d, while the buildup period is varied for different cases. In fact, the testing period of an actual WFT is very short because drilling and operational conditions may not allow a long test time at a given location (Kuchuk, 1998). In the numerical model, a longer buildup period can be used to simulate all possible flow regimes. A dual packer is located 8.0 ft below the top boundary, while three observation probes are assigned in this numerical model. Pressure transient measurements at the packer and observation probes are recorded simultaneously to simulate an interval pressure transient test (IPTT) which is also commonly known as vertical interference test (VIT). Three observation probes are positioned 6.0 ft (above the lamination), 25.0 ft (in the lamination) and 50.0 ft (below the lamination) below the packer, respectively.

The base case model is a homogeneous thick interval without any lamination. As for other cases, a lamination is located in the middle of the interval varied by thickness, shape, and size, though there is a limitation in defining the lamination shape as no local grid refinement is used. Figure 4.9a shows the cross section of the base case, while
Figure 4.9 Configurations of simulation cases with various lamination dimensions: (a) Case #1-1 (i.e., Base case), (b) Case #1-2 with lamination dimension of $\Delta r = 10.0$ ft, $\Delta \theta = 360^\circ$, (c) Case #1-3 with lamination dimension of $\Delta r = 40.0$ ft, $\Delta \theta = 360^\circ$, (d) Case #1-4 with lamination dimension of $\Delta r = 60.0$ ft, $\Delta \theta = 360^\circ$, (e) Case #1-5 with lamination dimension of: $\Delta r = 300.0$ ft, $\Delta \theta = 360^\circ$, (f) Case #1-6 with lamination dimension of $\Delta r = 300.0$ ft, $\Delta \theta = 90^\circ$, (g) Case #1-7 with lamination dimension of $\Delta r = 300.0$ ft, $\Delta \theta = 180^\circ$, and (h) Case #1-8 with lamination dimension of $\Delta r = 300.0$ ft, $\Delta \theta = 270^\circ$
Figures 4.9b-h depict configurations of various interbedded laminations. The red grid color represents vertically permeable sand, while the blue color represents a barrier with vertical permeability of 0.01 mD. The radial length of the lamination is varied to be 10.0 ft (Case #1-2), 40.0 ft (Case #1-3), 60.0 ft (Case #1-4) and 300 ft (Case #1-5) in order to examine the effect on the derivative plots. The shape of the lamination is varied from incomplete circular shapes (Cases #1-6, #1-7 and #1-8) to a complete circular shape (Case #1-5). Here, in agreement with the accuracy and reliability of most commercially available quartz gauges, a noise threshold of 0.01 psi has been added to simulate the pressure transient measurements, while a zero-mean random Gaussian noise is added to simulate pressure measurements.

Figure 4.10 depicts effect of the radial length of lamination on pressure change together with its derivative with gauge resolution of 0.01 psi. Radial flow regime does not develop in the base case, while radial flow regime is fully developed in Case #1-5. Although the lamination is permeable in horizontal direction, its low vertical permeability can act as a barrier or boundary in the vertical direction. As for the base case, spherical flow has developed without restriction of any boundary before 0.01 hr, while, after 0.10 hr, the slope of the derivative curve is changed due to the restriction of the top boundary. There is a distortion in the derivative between 0.01 and 0.10 hr. Such behaviour can be regarded as the transition between different flow regimes resulted from low permeability
**Figure 4.10** Effect of the radial length of lamination on pressure derivatives with gauge resolution of 0.01 psi
anisotropy in the whole interval. This finding is similar to that documented in the literature (Ramaswami et al., 2007).

As for Case #1-3 (blue line), radial flow regime is developed around 0.03 hr and the derivative is dipped down after 0.15 hr, indicating an increase in the permeability-thickness product. In the numerical model, a low-permeability lamination generates a flow unit and thus restricts the radial flow regime. The lamination disappears 40.0 ft away from the wellbore and two flow units merge into a single larger unit. The same trend can also be found in Case #1-4, in which radial flow regime sustains for a longer time because radial length of lamination is 60.0 ft, compared to Case #1-3. This finding is similar to those documented in the literature (Daungkaew et al., 2007). In Case #1-2, radial flow regime does not develop because of the shorter radial length of lamination. It is found from Figure 4.10 that radial flow regime will develop when the radial length of lamination is greater than the vertical reservoir interval.

Figure 4.11 shows the effect of angular shape of lamination on pressure derivatives. Derivatives of Cases #1-6 to 1-8 exhibit a decrease of the permeability-thickness product compared with that of the base case. Such a decrease corresponds to the low vertical permeability lamination. The magnitude of the decrease in Case #1-6 is smaller than that of Cases #1-7 and 1-8 since the laminated volumes are different. These incomplete circular shapes of lamination (Cases #1-6, 1-7, and 1-8) affect the derivative trend, while
Figure 4.11 Effect of angular shape of lamination on pressure derivatives with gauge resolution of 0.01 psi
only the complete circular shape of lamination (Case #1-5) restricts the flow and results in the radial flow regime. It is found from Figure 4.10 and Figure 4.11 that radial flow regime can be developed when radial length of lamination is greater than vertical reservoir interval and a complete circular shape of lamination is formed.

In the numerical model, three observation probes are assigned at different depths to monitor pressure transients together with the packer. In several cases, the pressure transients in packer and observation probes are similar. Therefore, only three representative cases are selective to study the packer and observation probes pressure behaviour. Figure 4.12 illustrates pressure change and derivatives obtained from the packer and observation probes for Case #1-1 (i.e., Base case). Note that pressure derivatives for the packer and Probe #1 are smoother than those of the Probes #2 and #3 because the pressure change is very small at the later time for these two probes. The pressure derivative normally becomes noisy once the pressure change is closer to the gauge resolution. There is a time lag in pressure responses between the packer and observation probes. As for observation probes, pressure change becomes visible later than that of the packer, while pressure derivative for Probe #1 becomes visible first due to its closest distance between the packer and Probe #1.

As for Case #1-5 (see Figure 4.13), pressure derivatives for the dual packer and Probe #1 exhibit the same radial flow stabilization, while no valid derivatives can be
Figure 4.12 Packer and observation probe pressure change together with derivatives of Case #1-1 (Base case) with gauge resolution of 0.01 psi
Figure 4.13 Packer and observation probe pressure change together with derivatives of Case #1-5 with gauge resolution of 0.01 psi
calculated for Probes #2 and #3. This is mainly because the dual packer and Probe #1 are located in the same flow unit. However, the lamination in Case #1-5 functions as a vertical barrier in the whole interval and there is no vertical communication above and below the lamination. In this case, great care should be taken in the proper modeling and calibration of these tests prior to arriving at this conclusion, as the lack of signal may also be a manifestation of too large a distance between the devices for the environment, or an insufficient drawdown achieved on the flowing probe (Ramaswami et al., 2013).

Similarly, the dual packer and Probe #1 exhibit same pressure response in Case #1-3 (see Figure 4.14) because they are located in the same flow unit. Pressure derivative of Probe #2 becomes visible at about 0.15 hr, while those of the packer and Probe #1 dip down at the same time after sustaining a radial flow regime. At about 0.15 hr, pressure wave encounters the boundary of lamination where the vertical barrier disappears. With a relatively high horizontal permeability, pressure change can be observed in Probes #2 and #3. Therefore, pressure response can be observed in the observation probe when a partially sealing lamination exists if the dual packer and observation probe are located in different flow units.
Figure 4.14 Packer and observation probe pressure change together with derivatives of Case #1-3 with gauge resolution of 0.01 psi
4.4.2 Lamination located the same level as the packer

In previous cases, all the laminations are located below the dual packer. In this section, the laminations are positioned in the same depth with the dual packer. Similarly, a base case and seven cases with various configurations of lamination are generated. The WFT test takes one hour drawdown with flow rate of 10 bbl/d. The base case model is a homogeneous flow unit restricted by the top boundary and a low vertical permeability barrier. As for other cases, a lamination is located in the same depth with the dual packer varied by shape, size and distance from the wellbore. Figure 4.15a shows the cross section of the base case, while Figures 4.15b-h depict configurations of the interbedded lamination in other simulation cases. The red grid color represents vertically permeable sand, while the blue color represents a barrier with vertical permeability of 0.01 mD. The shape of the lamination is varied between incomplete circular shapes (Cases #2-2, #2-3, and #2-4). The distance from wellbore to lamination is varied from 4.7 ft (Case #2-3) to 15.4 ft (Case #2-5) and 40.4 ft (Case #2-6). The radial length of the lamination is varied to be 10.0 ft (Case #2-3) and 300.0 ft (Cases #2-7 and #2-8).

Figure 4.16 illustrates the effect of angular shape of lamination on pressure derivatives. The spherical flow regime in the Base case is developed around 0.002 hr and the slope of the spherical flow regime is a negative half slope line followed by a radial flow regime. However, the derivatives of Cases #2-2, #2-3, and #2-4 exhibit a hump
Figure 4.15 Configurations of simulation cases with various lamination dimensions: (a) Case #2-1 (i.e., Base case), (b) Case #2-2 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 10.0$ ft, $\Delta \theta = 60^\circ$, (c) Case #2-3 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 10.0$ ft, $\Delta \theta = 120^\circ$, (d) Case #2-4 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 10$ ft, $\Delta \theta = 180^\circ$, (e) Case #2-5 with lamination dimension of $\Delta l = 15.4$ ft, $\Delta r = 10$ ft, $\Delta \theta = 120^\circ$, (f) Case #2-6 with lamination dimension of $\Delta l = 40.4$ ft, $\Delta r = 20.0$ ft, $\Delta \theta = 120^\circ$, (g) Case #2-7 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 300$ ft, $\Delta \theta = 120^\circ$, and (h) Case #2-8 with lamination dimension of $\Delta l = 4.7$ ft, $\Delta r = 300$ ft, $\Delta \theta = 360^\circ$
Figure 4.16 Effect of angular shape of lamination on pressure derivatives with gauge resolution of 0.01 psi
during spherical flow, which corresponds to the lamination near the dual packer WFT. The magnitude of the hump in Case #2-3 is larger than that in Case #2-2 as the volume of lamination in Case #2-3 ($\Delta \theta = 120^\circ$) is larger than that in Case #2-2 ($\Delta \theta = 60^\circ$). As for the Case #2-4 ($\Delta \theta = 180^\circ$), with the largest lamination volume, the hump is the most evident. After 0.10 hr, radial flow regimes in all cases develop due to the disappearance of laminations.

**Figure 4.17** plots the effect of distance from wellbore to lamination on pressure derivatives. The derivative of Case #2-3 exhibits a hump at about 0.001 hr, while the humps in derivative of Case #2-5 and Case #2-6 exhibit at about 0.01 hr and 0.20 hr, respectively. This is due to fact that the distance between the wellbore and lamination in Case #2-3 is closer than those in Cases #2-5 and #2-6.

**Figure 4.18** displays the effect of radial length of lamination on pressure derivatives. The spherical flow regime is affected dominantly by the lamination, while the radial flow regime is also affected with large lamination volume. With the increase of the lamination volume, derivative of Case #2-8 exhibits a less permeability-thickness product. In this situation, the pressure transient may be mistakenly interpreted as radial flow regime if the true radial flow is not observed, resulting in underestimating of horizontal permeability.

In the numerical model, an observation probe is positioned 6.0 ft below the packer
Figure 4.17 Effect of distance from wellbore to lamination on pressure derivatives with gauge resolution of 0.01 psi
Figure 4.18 Effect of radial length of lamination on pressure derivatives with gauge resolution of 0.01 psi
to monitor pressure transients together with the packer. **Figure 4.19** shows pressure change and derivatives obtained from the packer and observation probe for Case #2-1 (i.e., Base case). For the observation probe buildup response, there is a delay in pressure response with that of the packer. After the delay, the late time derivative is the same for both packer and observation probe measurements. This finding is consistent with what is observed in previous cases.

As for Case #2-8 (see **Figure 4.20**), there is a time lag in pressure responses between the packer and the observation probe. As mentioned previously, within the limited buildup time, pressure transient in the packer could be mistakenly interpreted as radial flow. However, pressure response of the observation probe does not display the same behaviour with that of the packer, indicating true radial flow will be developed after 1.0 hr. The true permeability for the flow unit should be between values from packer and observation probe. Therefore, observation probes are strongly recommended in a WFT test to accurately identify the flow regimes.

### 4.5 Summary

History matching has been performed with the field data from deepwater Gulf of Mexico to determine the effective thickness and then interpret the permeability for each flow unit. As for the field case, effective water horizontal permeabilities for Testers #1
Figure 4.19 Packer and observation probe buildup pressure change together with its derivatives of Case #2-1 (i.e., Base case) with gauge resolution of 0.01 psi
Figure 4.20 Packer and observation probe buildup pressure change together with its derivatives of Case #2-8 with gauge resolution of 0.01 psi
and #2 are found to be 14.0 mD and 10.6 mD, respectively, which reveals the difference in permeability between individual flow units. In addition to the Base case, fourteen cases with various configurations of laminated layers have been generated and examined, while the pressure buildup derivatives obtained from both packers and observation probes are used as a diagnosis tool to sensitize the effect of lamination on WFT interpretations.

As for the lamination located below the dual packer WFT, radial flow regime develops when the radial length of the laminated layers with low vertical permeability is greater than the vertical formation interval and a complete circular shape of lamination is formed in a thick formation. As for the lamination located the same level with dual packer, spherical flow regime is affected by the lamination greatly. In all cases, observation probes are strongly recommended in a WFT test to identify the communication between flow units and to accurately recognize the flow regimes.
CHAPTER 5  CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

In this thesis study, a high-resolution near-wellbore numerical model has been developed to simulate the WFT fluid sampling process together with transient pressures at a flowing probe. This newly developed model is validated analytically and then with the field data from the deepwater Gulf of Mexico. With the inherent noise added, the calculated pressure derivatives are used as a diagnosis tool to determine the effective formation thickness, which is defined as the maximum vertical thickness in the reservoir being sensed by the WFT device during a test within a given tool resolution. Sensitivity analysis has been subsequently performed to examine the effects of different parameters on pressure transients as well as effective formation thickness.

As for laminated formations, history matching has been performed with the field data obtained with a dual-packer WFT from the deepwater Gulf of Mexico to determine the vertical communication between sublayers and then interpret the permeability for each flow unit. Sixteen cases with various configurations of laminations have been generated and examined, while the pressure derivatives obtained from either packers or observation probes are used as a diagnosis tool to sensitize the effect of lamination on WFT interpretations.
The major conclusions that can be drawn from this thesis study are summarized as follows:

1) Pressure derivatives calculated as a function of formation thickness can be used as a tool to accurately determine the effective formation thickness. As for the reference case in this study, effective formation thickness is determined to be 140 ft under condition of 0.01 psi gauge resolution.

2) It is shown from sensitivity analysis that pressure transient measurements obtained from a WFT probe are found to be sensitive to permeability anisotropy, flow rate, porosity and permeability. Higher permeability anisotropy, porosity, and permeability lead to a lower pressure differential, while a higher flowrate leads to a higher pressure differential.

3) Effective formation thickness is a strong function of permeability anisotropy, flowrate, porosity, gauge resolution and probe location. Higher permeability anisotropy, flowrate, porosity, and gauge resolution increase the effective formation thickness. It is recommended that the WFT probe be positioned in the middle of the formation to avoid any restriction of no-flow boundary. All above-mentioned parameters which increase the effective formation thickness are inclined to obtain the true formation thickness.

4) As for the field cases, two WFT tests (i.e., Tester #1 and Tester #2) are
performed at two locations in the same well. The effective thickness for Tester #1 is 28.0 ft and its effective water horizontal permeability is 14.0 mD. As for Tester #2, the effective thickness and effective horizontal permeability are 41.0 ft and 10.6 mD, respectively. Such an interpretation reveals the difference in permeability between individual flow units.

5) In a formation where lamination located below the dual packer, radial flow regime will develop when radial length of lamination is greater than the vertical reservoir interval and when complete circular shape of lamination is formed. As for the lamination located at the same level with dual packers, spherical flow regime is affected by the lamination greatly.

6) It is recommended that observation probes be positioned in or below the lamination layer to accurately define the vertical communication of lamination as well as its configuration. The same flow regimes will be exhibited by packer(s) and observation probes, indicating that they are located in the same flow unit. The integration of packer(s) and observation probes can be used to accurately identify the flow regimes.

7) The permeability interpreted from the WFT probe measurement is the weighted average of all subintervals with different permeabilities.

8) Numerical simulation indicates that low vertical permeability results in a distortion in derivatives, particularly during the transition between flow
regimes.

9) Mud-filtrate invasion affects the early-time behaviour of pressure transients because of the associated changes in fluid viscosity and compositions.

5.2 Recommendations

Based on this thesis study, the following recommendations for future studies are made:

1) Mud-filtrate invasion process should be simulated to accurately capture the mud-filtrate distribution along the wellbore by imposing a decreasing invasion rate. Also, such an invasion model is recommended to take the overbalance pressure, formation damage, and mud cake properties into account.

2) Pressure transients obtained from observation probes should be used in history matching to further determine the vertical permeability of the tested interval.

3) This thesis study considers immiscible mud-filtrate (i.e., WBM filtrate invades the oil zone, and OBM filtrate invades the water zone) in all the numerical simulations. Application of miscible mud-filtrate (e.g., OBM filtrate invades the oil zone) is suggested for future consideration.
REFERENCES


Angeles, R. Simulation and Interpretation of Formation-Tester Measurements Acquired in the Presence of Mud-Filtrate Invasion, Multiphase Flow, and Deviated Wellbores. Ph.D. Dissertation, University of Texas at Austin, Austin, TX, 2009.


Ayan, C., Hafez, H., Hurst, S., Kuchuk, F., Peffer, J., Pop, J., and Zeybek, M.


of Texas at Austin, Austin, TX, 2012.


Harmawan, I., Kabir, C.S., Habib, S., Kennedy, J. Henson, J., and Minhas, H. Integrating


Kuchuk, F.J. Interval Pressure Transient Testing With MDT Packer-Probe Module in


Liu, W., Hidebrand, A., Lee, Jaedong., and Sheng, J. High-Resolution Near-Wellbore

Malik, M. *Numerical Simulation and Interpretation of Formation-Tester Measurements Acquired in the Presence of Mud-Filtrate Invasion*. Ph.D. Dissertation, University of Texas at Austin, Austin, TX, 2008.


Simulator. Paper SPE 95885, presented at the SPE Annual Technique Conference and Exhibition, Dallas, TX, October 9-12, 2005.


Peffer, J., O’Callaghan, A., and Pop, J. In-Situ Determination of Permeability Anisotropy and Its Vertical Distribution–A Case Study. Paper SPE 38942, presented at the SPE Annual Technique Conference and Exhibition, San Antonio, TX, October 5-8,


Ramaswami, S., Hows, M., Frese, D., Dong, C., and Elshahawi, H. Pressure Transient Data from Wireline Formation Testers: When and How to Use It? Paper SPE 164733, presented at the North Africa Technical Conference and Exhibition, Cairo,
Egypt, April 15-17, 2013.


