Quantitative Analysis of Multi-Phase Flowback From Multi-Fractured Horizontal Wells

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Quantitative Analysis of Multi-Phase Flowback From Multi-Fractured Horizontal Wells

by

Jesse Daniel Williams-Kovacs

A THESIS
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Thesis Abstract

Due to a decline in conventional reserves, particularly in North America, recent development has focused on low to ultra-low permeability unconventional reservoirs. Due to the low permeability of these plays, extensive hydraulic fracturing is required for commercial production. As a result of this growing trend, operators are looking for new methods to characterize hydraulic fractures, especially early in the well life. Several authors have identified high frequency flowback data as an early-time method for fracture characterization.

This dissertation starts with, and builds on, two publications by Clarkson and Williams-Kovacs (2013a) and Clarkson and Williams-Kovacs (2013b), which set the ground work for quantitatively analyzing flowback from multi-fractured horizontal wells (MFHWs) completed in shale gas and light tight oil (LTO) reservoirs respectively.

First a new shale gas model was developed to better capture the physics of the flowback problem. The tool was built using a similar conceptual model to that assumed by Clarkson and Williams-Kovacs (2013b) for LTO applications, although significant modifications were required to account for the complexities of shale gas reservoirs. A focus was also placed on stress-dependant porosity/permeability as a result of fracture closure during flowback. Although this new model yielded comparable results to the model developed by Clarkson and Williams-Kovacs (2013a) in the case study presented herein, by better capturing the physics of the problem the new model is applicable to more cases and creates a much improved platform for further development.

Secondly, the LTO model developed by Clarkson and Williams-Kovacs (2013b) was expanded to account more complex problems, such as stage-by-stage flowback, multi-well analysis and multi-layer flowback for wells contacting multiple productive intervals. These
advances of the base model greatly broaden the applicability of the developed methods to many of the complexities faced by operators in unconventional formations, particularly with advancements in completion technology and development strategies currently being employed in these formations.

Thirdly, stochastic simulation and several assisted history-matching techniques were applied to an LTO data set to quantify the uncertainty in key fracture parameters and to optimize the history-match for the most accurate estimation of key fracture parameters. Application of stochastic simulation allows the operator to determine realistic bounds for future potential well performance while assisted history-matching leads to significantly improved results.

Fourthly, several LTO case studies were conducted to address topics such as assessment of the potential economic value of conducting flowback analysis, and development of a modified model for analyzing flowback from LTO wells completed with an oil-based fracture fluid. Numerical simulation was also conducted to confirm the sequence of flow-regimes interpreted from field data. These case studies validate the simple analytical models developed, quantify the value to operators for applying such methods as well as demonstrate extensions which are required to analyze flowback from many modern completions.

Lastly, a salinity model was developed to compliment the flow models primarily to confirm fracture surface area and volume. It is possible that this model could be applied in place of detailed flow modeling if enough of the key transport parameters can be accurately estimated. The flow simulation was successfully validated using the developed salinity model.
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Dedication

I would like to dedicate this work to all of my friends, family and colleagues who have supported me throughout my life and helped me become the individual that I am today.

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Table of Contents

Thesis Abstract ........................................................................................................................................... ii
Acknowledgements ......................................................................................................................................... iv
Dedication ...................................................................................................................................................... vi
Table of Contents ........................................................................................................................................ vii
List of Tables ............................................................................................................................................... xii
List of Figures ............................................................................................................................................... xiv
List of Symbols, Abbreviations and Nomenclature ...................................................................................... xxii

CHAPTER ONE: INTRODUCTION ................................................................................................. 1
  1.1 Problem Description ......................................................................................................................... 2
  1.2 Literature Review .............................................................................................................................. 3
    1.2.1 Flow Modeling ............................................................................................................................ 4
    1.2.1.1 Rationalization for Developing Quantitative Analysis Methods ........................................... 4
    1.2.1.2 Single-Phase Analysis ............................................................................................................ 4
    1.2.1.3 Multi-Phase Analysis ............................................................................................................ 7
    1.2.1.4 Other Flow-Based Analysis .................................................................................................. 21
    1.2.1.5 Summary of Existing Methods for Flow-Based Analysis ................................................... 21
    1.2.2 Salinity Modeling ....................................................................................................................... 23
    1.2.2.1 Experimental Studies Investigating Recovered Fluid Salinity ............................................. 23
    1.2.2.2 Flowback Field Results ......................................................................................................... 33
    1.2.2.3 Flowback Salinity Models ...................................................................................................... 35
    1.2.2.4 Summary of Existing Methods for Flow-Based Analysis ................................................... 43
    1.2.3 Other Relevant Literature .......................................................................................................... 44
  1.3 Objectives .......................................................................................................................................... 45
  1.4 Organization of Dissertation ............................................................................................................ 46

CHAPTER TWO: CONCEPTUAL MODEL AND ANALYSIS PROCEDURE ....... 49
  2.1 Conceptual Model ............................................................................................................................. 49
  2.2 Sequence of Flow-Regimes Associated with the Conceptual Model ............................................... 54
    2.2.1 LTO Conceptual Model ............................................................................................................ 55
    2.2.2 Initial LTO Flowback Analysis Approach Using “Flowback Analysis Tool” (“FLOAT”) ......... 58
      2.2.2.1 BBT Single-Phase RTA ....................................................................................................... 59
    2.2.3 BBT Analytical Modeling ......................................................................................................... 61
      2.2.3.1 Transient Radial Flow ........................................................................................................ 61
      2.2.3.2 Fracture Depletion .............................................................................................................. 62
    2.2.4 ABT Analytical Modeling ......................................................................................................... 63
  2.3 Basic and Significant Modifications Made by the Author ................................................................. 67
    2.3.1 Shale Gas Flowback Tool (FAT) ............................................................................................... 67
    2.3.2 LTO Flowback Tool (FLOAT) .................................................................................................... 67
      2.3.2.1 Jones (1975) ....................................................................................................................... 69
      2.3.2.2 Aguilera (1999) .................................................................................................................. 69
      2.3.2.3 Weighted Average ............................................................................................................. 70
    2.3.3 Tight and Shale Gas Conceptual Model ..................................................................................... 73
  2.4 Analysis Procedure ............................................................................................................................ 75
CHAPTER FIVE: ANALYSIS OF STAGE-BY-STAGE, MULTI-WELL AND MULTI-LAYER FLOWBACK FROM MULTI-FRACTURED HORIZONTAL WELLS

5.1 Abstract ................................................................................................................................................. 191
5.2 Introduction ............................................................................................................................................ 192
5.3 Objective ................................................................................................................................................ 193
5.4 Theory and Methods ............................................................................................................................... 194

5.4.1 Conceptual Model of Inter-Well and Inter-Stage Communication During Flowback ................................................................................................................................................................. 194
5.4.2 Conceptual Model For Multi-Layer Flowback ..................................................................................... 203
5.5 Analysis Procedure ................................................................................................................................. 204
5.6 Case Studies ........................................................................................................................................... 205

5.6.1 Case Study 1: Stage-by-Stage Simulated Example Without Communication ........................................ 205
5.6.1.1 Raw Data and Diagnostic Plots ........................................................................................................ 207
5.6.1.2 Rate-Transient Analysis of BBT Data ............................................................................................ 210
5.6.1.3 Analytical Modeling of BBT Water Data and ABT Multi-Phase Data .................................................. 214

5.6.2 Case Study 2: Multi-Well Field Example ........................................................................................... 218
5.6.2.1 Raw Data and Diagnostic Plots ........................................................................................................ 222
5.6.2.2 Rate-Transient Analysis of BBT Data ............................................................................................ 225
5.6.2.3 Analytical Modeling of BBT Single-Phase Data and ABT Multi-Phase Data .......................................... 226

5.6.3 Case Study 3: Multi-Layer Flowback ................................................................................................. 234
5.6.3.1 Raw Data and Diagnostic Plots ........................................................................................................ 236
5.6.3.2 Rate-Transient Analysis of BBT Data ............................................................................................ 237
5.6.3.3 Analytical Modeling of BBT Single-Phase Data and ABT Multi-Phase Data ......................................... 239

5.6.3.4 Post-Flowback Build-Up Test Analysis ........................................................................................... 241
5.7 Discussion ............................................................................................................................................. 243
5.7.1 Collection of Stage-by-Stage Flowback Data ...................................................................................... 243
5.7.2 Impact of Assumed Fracture Geometry .............................................................................................. 246
5.7.3 Handling Direct Communication Between Producing Layer ............................................................. 249
5.8 Summary .............................................................................................................................................. 250
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.5</td>
<td>Analysis Procedure</td>
<td>321</td>
</tr>
<tr>
<td>7.6</td>
<td>Field Example</td>
<td>322</td>
</tr>
<tr>
<td>7.6.1</td>
<td>Raw Data</td>
<td>323</td>
</tr>
<tr>
<td>7.6.2</td>
<td>Salinity History-Match</td>
<td>324</td>
</tr>
<tr>
<td>7.7</td>
<td>Discussion</td>
<td>327</td>
</tr>
<tr>
<td>7.8</td>
<td>Summary</td>
<td>329</td>
</tr>
<tr>
<td>Appendix 7.1</td>
<td>– Alternate Derivation of EFR Equation</td>
<td>329</td>
</tr>
</tbody>
</table>

CHAPTER EIGHT: CONTRIBUTIONS, CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK | 333  |
| 8.1     | Contributions and Conclusions | 333  |
| 8.2     | Future Research and Recommendations | 337  |
| 8.2.1   | Flowback Data Gathering and Operations | 337  |
| 8.2.2   | Flowback Modeling | 340  |
| 8.3     | Other Considerations | 346  |

REFERENCES | 348  |

COPYRIGHT PERMISSION | 369  |
| Chapter Three | 369  |
| Chapter Four | 370  |
| Chapter Five | 371  |
| Chapter Six | 373  |
List of Tables

Table 3.1 — Dietz Shape Factors and Skin Factors ......................................................... 91
Table 3.2 — Input Parameters For Analytical Simulation For Case Study 1 ...................... 102
Table 3.3 — Parameters Solved From Each BBT RTA Technique for Case Study 1 ........... 107
Table 3.4 — Input Parameters for Field Example (Case 2) .................................................. 113
Table 3.5 — Comparison of History-Match Parameters from the Two Flow Models ........... 118
Table 4.1 — Input Parameters for Flowback Field Example ............................................... 143
Table 4.2 — Parameters Solved From Each BBT RTA Technique ..................................... 147
Table 4.3 — Key History-Match Parameters for Flowback Simulation ................................. 149
Table 4.4 — Input Distributions/Ranges For Monte Carlo Simulation and Assisted History- 
Match ing ............................................................................................................................. 152
Table 4.5 — Stochastic History-Match Parameters ................................................................ 155
Table 4.6 — Average Values of Top 5 Monte Carlo Simulations ......................................... 156
Table 4.7 — Initial Guesses for Assisted History-Matching Parameters ............................... 161
Table 4.8 — Initial Guesses and Final Solutions for Attempt #1 using EXCEL’s GRG Non- 
Linear Solver ......................................................................................................................... 162
Table 4.9 — Initial Guesses and Final Solutions for Attempt #2 using EXCEL’s GRG Non- 
Linear Solver ......................................................................................................................... 163
Table 4.10 — Input Parameters for Excel’s Single-Objective Evolutionary Solver ............... 166
Table 4.11 — Optimal Match Parameters for Excel’s Single-Objective Evolutionary Solver .. 167
Table 4.12 — Input Parameters for Excel’s Single-Objective Evolutionary Solver ............... 168
Table 4.13 — Best Match Parameters for Excel’s Single-Objective Evolutionary Solver ....... 168
Table 4.14 — Input Parameters For GAPS Multi-Objective Genetic Algorithm ................. 171
Table 4.15 — GAPS Multi-Objective Genetic Algorithm Generation 100 Results .................. 174
Table 4.16 — Input Parameters for Palisade’s Single-Objective Genetic Algorithm .............. 177
Table 4.17 — Best Match Parameters For Evolver’s Single-Objective OptQuest Algorithm ... 178
List of Figures

Fig. 2.1 — Conceptual model of fracture geometries (assuming circular fracture shape) used in flowback modeling. Scenario 1 and 2 represent cases corresponding to the formation of simple bi-wing planar fractures, while Scenario 3 and 4 represent cases corresponding to the formation of a complex fracture network consisting of a primary fracture zone and secondary (induced or reactivated) fracture zone. Modified from Williams-Kovacs and Clarkson (2013a). .......................................................... 52

Fig. 2.2 — Conceptual model of fracture geometries (assuming rectangular fracture shape) used in flowback modeling. A half-element of symmetry is shown (with plane of symmetry parallel to the horizontal well in the vertical plane). Modified from Williams-Kovacs and Clarkson (2013a). ........................................................................ 53

Fig. 2.3 — Illustration of the common flow-regimes observed during flow-back of fracturing fluids from multi-fractured horizontal wells completed in tight oil reservoirs. Flow-regimes in a) (cross-section view of single fracture) and b) (plan view of single fracture) are transient radial (flow-regime, FR 1) and boundary-dominated flow (FR 2) of single-phase fracturing fluid (assumed to be water in this case), which are identified with a rate-normalized pressure derivative (c). These flow-regimes correspond to flow only in the fracture, prior to breakthrough of formation fluids. The flow-regime in d) (cross-section view of single fracture) and e) (plan view of single fracture) corresponds to transient linear flow of formation fluid (assumed to be only oil) to the fracture, identified with a rate-normalized pressure derivative (f). Note at this stage, multi-phase flow (water and oil) occurs in the fracture ABT. The BBT ($x_{f_BBT}$) and ABT ($x_{f_ABT}$) fracture half-lengths are assumed to be different. The water RNP’ plots (c,f) were derived using an analytical model. Modified from Clarkson and Williams-Kovacs (2013b). .......................................................... 57

Fig. 2.4 — Workflow for application of analytical model. Modified from Williams-Kovacs and Clarkson (2016). .................................................................................................................. 65

Fig. 2.5 — Fracture compressibility using the Aguilera (1999) method. For reference, the curve derived for 31% fracture porosity used in the examples in this paper is shown. ....... 70

Fig. 2.6 — Illustration of (possible) flow-regimes observed during flowback of fracturing fluids from MFHWs completed in tight or shale gas reservoirs. Single-phase flow-regimes in a) (cross-section view of single fracture) and b) (plan view of single fracture) are transient radial (FR 1) and fracture depletion (boundary-dominated) flow (FR 2) of fracturing fluid (assumed to be water in this case), which are identified with a RNP derivative (c). These flow-regimes correspond to flow only in the fracture, prior to breakthrough of formation fluids. FR 3 in d) (cross-section view of single fracture) and e) (plan view of single fracture) corresponds to transient linear flow of formation fluid (shown to be multi-phase water and gas) to the fracture coupled with multi-phase fracture depletion. Below desorption pressure, gas may also be sourced to the primary fracture network via desorption. The BBT ("$x_{f_BBT}$") and ABT ("$x_{f_ABT}$") fracture half-
lengths are assumed to be different. The water RNP’ plots (c,f) were derived using an analytical model. Modified from Clarkson and Williams-Kovacs (2013b).

Fig. 2.7 – Basic analysis procedure for analyzing flowback data from all reservoir types.

Fig. 3.1 — Plots for interpolating between known shape factor and shape factor skin values.

Fig. 3.2 — Conceptual model for transient linear flow coupled with fracture depletion and the associated MBE (Eqn. 3.44-346 below).

Fig. 3.3 — Workflow for application of analytical model. Modified from Williams-Kovacs and Clarkson (2014).

Fig. 3.4 – Summary of procedure for analyzing flowback data and forecasting long-term production using flowback parameter estimates (steps 1-4) and comparing flowback derived parameter estimates with other data sources (step 5).

Fig. 3.5 — Diagnostic plots used to identify flow-regimes associated with flowback data: a) fluid production rate and flowing pressure data; b) RNP and RNP’ plot; c) Fetkovich type-curve plot; and d) GWR vs. cumulative gas produced. Synthetic data were generated using an analytical simulator (see Table 2 for inputs). Water and flowing pressure data shown in a) is analyzed in plots b) – d). The RNP’ plot shows an early radial flow period (~0.1 days), followed by a storage signature (~2.6 days), prior to formation fluid breakthrough after ~2.7 days. All times are in MBT, as shown on the plots, which has the effect of stretching time. These flow-regimes are confirmed on the Fetkovich type-curve. Immediately ABT, flow approaches multi-phase depletion, although as the contribution from linear flow increases (with declining fracture pressure) a positive deviation can be identified.

Fig. 3.6 — Rate-transient analysis of synthetic flowback data: a) rate-normalized pressure derivative plot shown for reference to select data to be analyzed with each specialty plot; b) radial flow plot used to analyze single-phase fracture transient radial flow data; c) FMB plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots. Water and flowing pressure data is analyzed in all plots. Deviation from depletion signature late in time, shown in Fig. 3.6a,c,d results from breakthrough of formation fluid from matrix to the fractures.

Fig. 3.7 — Plots used in analytical model history-matching: a) production rates of water and gas; b) cumulative production of water and gas; c) model-predicted matrix (formation fluid) contribution; d) fractional-flow plot; and e) convergence of fracture pressure and flowing pressure over time.

Fig. 3.8 – Flowback data: a) gas rates and choke settings; and b) water rates and bottom-hole flowing pressures. Flowback lasted approximately 40 hours, followed by a shut-in/buildup test.
Fig. 3.9 – GWR vs. cumulative gas production. A ½-slope indicating multi-phase fracture depletion is shown for reference. .......................................................... 115

Fig. 3.10 – Plots used in analytical model history-matching: a) production rates of water and gas; b) cumulative production of water and gas; c) GWR; and d) fractional-flow plot. .... 116

Fig. 3.11 – Relative permeability curves used in analytical model history-match: a) matrix relative permeability curves; and b) fracture relative permeability curves..................... 116

Fig. 3.12 – Comparison between original and modified model history-match: a) rate match; and b) cumulative production match................................................................. 117

Fig. 3.13 – 2-phase type-curve matches (gas): a) Fetkovich type-curves; and b) Pratikno-Blasingame type-curves. Data falling down the harmonic stem (b = 1) suggests 2-phase depletion....................................................................................... 119

Fig. 3.14 – 2-phase FMB analysis (gas). Data falling along a straight-line suggests 2-phase fracture depletion. .......................................................................................... 119

Fig. 3.15 – Online production data: a) rate and calculated sandface flowing pressure; b) gas RNP and RNP’; and c) linear derivative. The diagnostics suggest that the majority of the data comes from a linear flow-regime, which is assumed to be early linear flow....... 121

Fig. 3.16 – Linear flow analysis on online production data to estimate effective fracture half-length........................................................................................................ 121

Fig. 3.17 – Model history-match and forecast of online production data using parameters solved from flowback and actual calculated sandface flowing pressure. ................. 122

Fig. 3.18 – History-match to long-term production using multi-phase flowback model: a) rate match; b) cumulative production match. For reference the history-match using the single-phase model (Fig. 3.17) is also shown. ................................................................. 123

Fig. 3.19 – Comparison of MBE drivers indicating dominant fracture and desorption compressibility........................................................................................................ 127

Fig. 3.20– History-matches using skin instead of stress-dependent permeability: a) production rates of water and gas; b) skin changes used in the modeling............... 128

Fig. 3.1.1 — Conceptual model for linear flow solution......................................................... 132

Fig. 4.1 – Summary of procedure for analyzing flowback data using deterministic, stochastic and assisted history-matching techniques. ....................................................... 135

Fig. 4.2 – Flowback data: (a) water, oil and gas rate, as well as bottom-hole flowing pressure and GOR; and (b) water RNP and RNP’.................................................. 144
Fig. 4.3 – Rate-transient analysis of BBT single-phase data: a) water RNP and RNP’ plot; b) early radial flow analysis; c) flowing material balance; and c) Fetkovich type-curve. ................................................................. 147

Fig. 4.4 – Deterministic flowback match: (a) water, oil and gas production rates; and (b) cumulative water, oil and gas........................................................................................................................................... 148

Fig. 4.5 – Stochastic flowback history-match: (a) water production rates; (b) cumulative water production; (c) oil production rates; (d) cumulative oil production; (c) gas production rates; and (d) cumulative gas production.................................................................................................................. 156

Fig. 4.6 – Stochastic flowback history-match parameter distributions: (a) fracture permeability; (b) breakthrough pressure; (c) BBT half-length; (d) Corey oil relative permeability exponent, n’; (e) Corey water relative permeability exponent, m’. .......................................................... 158

Fig. 4.7 – Gradient solver flowback history-match: (a) water production rates; (b) cumulative water production; (c) oil production rates; (d) cumulative oil production; (c) gas production rates; and (d) cumulative gas production.................................................................................................................. 164

Fig. 4.8 – Evolver™ SO GA results: (a) by equivalent generation, showing both the equivalent generation average and minimum; (b) by progression step; and (c) by trial, also showing the minimum achieved value. .................................................................................................................................................. 170

Fig. 4.9– Pareto diagram for flowback history-match: a) generations grouped into sets of 10 generations showing significant scatter in the first 10 generations; b) generations grouped into sets of 5 generations starting at generation 11; c) every 10th generation to show advancement of Pareto Front over time; d) every 10th generation between Generation 50 and Generation 100 to demonstrate convergence on the ultimate Pareto Front. The single best solution is shown with a star. .................................................................................................................. 173

Fig. 4.10 – GAPS MO Generation 100 flowback history-match parameter distributions: (a) fracture permeability; (b) breakthrough pressure; (c) BBT half-length; (d) Corey oil relative permeability exponent, n’; (e) Corey water relative permeability exponent, m’. .......................................................... 175

Fig. 4.11 – Evolver’s SO OptQuest results: (a) by equivalent generation showing both the equivalent generation average and minimum; (b) by progression step; and (c) by trial also showing the minimum achieved value. .................................................................................................................................................. 179

Fig. 4.12 – Flowback history-match using different algorithms: a) water rate match; b) cumulative water production match; c) oil rate match; d) cumulative oil production match; e) gas rate match; and f) cumulative gas produced match. .................................................................................................................................................. 181

Fig. 4.13 – Flowback key history-match parameters found using different algorithms: a) fracture permeability; b) BBT half-length; c) Breakthrough Pressure; d) oil relative permeability exponent, n’; e) water relative permeability exponent, m; and f) Total OF value. .................................................................................................................................................. 182

xvii
Fig. 5.1 – Cross-sectional schematic representation of the compartmentalized reservoir approach with cross-flow from Compartment 1 to Compartment 2. Adapted from Payne (1996).

Fig. 5.2 – Cross-sectional schematic representation of compartmentalized reservoir approach for communicating fractures of adjacent wells during flowback.

Fig. 5.3 – Example pressure profile for two communicating wells which are stimulated and brought on flowback at different times.

Fig. 5.4 – Schematic showing all possible communications for a four well pad with equal length and equally spaced wells.

Fig. 5.5 – Cross-sectional schematic representation of compartmentalized reservoir approach for communicating fractures within a single-well during flowback.

Fig. 5.6 – Plan view schematic representation of compartmentalized reservoir approach for communicating fractures between multiple wells during flowback.

Fig. 5.7 – Conceptual model for multi-layer scenario in Case Study 2. The fracture fully penetrates Layer 1 but only partially penetrates Layer 2.

Fig. 5.8 – Summary of procedure for analyzing stage-by-stage and multi-well flowback data.

Fig. 5.9 — Schematic of simulated example for stage-by-stage flowback.

Fig. 5.10 — Diagnostic plots used to identify flow-regimes associated with flowback data: a) water production rate for each stage and the commingled data (note that stages 2-5 overlay each other); b) RNP’ plot for the commingled data; c) RNP’ plot for stage 1; and d) RNP’ plot for stages 2-5. Synthetic data were generated using an analytical simulator (see Table 1 for inputs). Water data shown in a) is analyzed in plots b) – d). The commingled RNP’ plot illustrates the difficulty in identifying flow-regimes from commingled data, where the stages are in different flow-regimes at different times, as identified on the stage-by-stage plots.

Fig. 5.11 — Rate-transient analysis of commingled before-breakthrough water flowback data: a) RNP’ plot used for reference to select data to be analyzed with each specialty plot; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots.

Fig. 5.12 — Rate-transient analysis of stage 1 before-breakthrough water flowback data: a) RNP’ plot used to identify flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots.
Fig. 5.13 — Rate-transient analysis of Stage 1 before-breakthrough water flowback data: a) RNP’ plot used to identify flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots. .......................................................... 214

Fig. 5.14 — History-matching using analytical model: a) commingled production rates; b) commingled cumulative production; a) stage 1 production rates; b) stage 1 cumulative production a) stage 2-5 production rates; b) stage 2-5 cumulative production. Note than only a single stage is shown for stages 2-5 (all equivalent). .......................................................... 216

Fig. 5.15 — Primary raw data plots used to identify flow behavior and well communication during Flow 1: a) Well 1 water rate and flowing pressure; b) Well 1 hydrocarbon rate, choke size and GOR; c) Well 2 water rate and flowing pressure; and d) Well 1 hydrocarbon rate, choke size and GOR. Minimal single-phase data is seen in both wells at the onset of flowback. Communication is evident in the rate and pressure response of both wells upon the onset of flowback of Well 2. This primary communication was also seen during stimulation. .................................................................................................. 224

Fig. 5.16 – Production data associated with flowback (Flow 1 and Flow 2) for Case Study 3: a) Well 1; and b) Well 2.......................................................... 225

Fig. 5.17 — Flwing material balance to estimate before-breakthrough contacted fracture fluid-in-place: 1) Well 1; and 2) Well 2. Fluid-in-place is estimated at ~ 5,200 STB for Well 1 and ~ 6,300 STB for Well 2. Parameters may be in error due to very short single-phase flow period. .................................................................................................. 226

Fig. 5.18 – Analytical history-match for Well 1 during Flow 1 of Case Study 3: a) production rate of all 3 phases without communication; b) cumulative production of all 3 phases without communication; c) production rate of all 3 phases with communication; and d) cumulative production of all 3 phases with communication........................................... 228

Fig. 5.19 – Analytical history-match for Well 2 during Flow 1 of Case Study 3: a) production rate of all 3 phases without communication; b) cumulative production of all 3 phases with communication; c) production rate of all 3 phases without communication; and d) cumulative production of all 3 phases with communication........................................... 229

Fig. 5.20 — Communication between Well 1 and Well 2: a) differential pressure between fracture networks; 2) phase-specific communication factors; and c) fluid transfer rate and cumulative fluid transferred for each phase. .......................................................... 232

Fig. 5.21 – Analytical history-match for Well 2 during Flow 2 of Case Study 3: a) production rate of all 3 phases without communication; and b) cumulative production of all 3 phases without communication........................................... 234

Fig. 5.22 – Production data and diagnostic plots associated with flowback data for Case Study 3: a) fluid production rate and flowing pressure data; and b) RNP and RNP’ plot with respect to water. .......................................................... 237
Fig. 5.23 – Rate-transient analysis for Case Study 3: a) water RNP and RNP’ illustrating identified flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) FMB plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots. Deviation from straight-line behavior on the FMB and from the harmonic stem on the Fetkovich type-curve marks the onset of breakthrough. .................................................. 238

Fig. 5.24 – Analytical model history-match for Case Study 3: a) single-layer match - production rate of all 3 phases; b) single-layer match - cumulative production of all 3 phases; c) multi-layer match - production rate of all 3 phases; b) multi-layer match - cumulative production of all 3 phases. .............................................................................. 240

Fig. 5.25 – Interpreted build-up test diagnostic conducted following flowback for Case Study 3. .................................................................................................................. 242

Fig. 6.1 – Summary of procedure for analyzing flowback data and forecasting long-term production using flowback parameter estimates (steps 1-4) and comparing flowback derived parameter estimates with other data sources (step 5). .................................................. 255

Fig. 6.2 – Production data and diagnostic plots associated with flowback data for Case Study 1: a) fluid production rate and flowing pressure data; and b) water RNP and RNP’ plot. 258

Fig. 6.3 – Rate-transient analysis for Case Study 1: a) water RNP and RNP’ illustrating identified flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots. ............. 260

Fig. 6.4 – Analytical model history-match for Case Study 1: a) production rate of all 3 phases; and b) cumulative production of all 3 phases. ................................................................. 261

Fig. 6.5 – Numerical simulation of long-term production for Case Study 1 using parameters estimated from quantitative flowback analysis. ............................................................................. 262

Fig. 6.6 – History-match of long-term monthly production data for Case Study 1 using numerical simulation forecast based on flowback-derived parameters. ....................... 263

Fig. 6.7 – Flowback data: (a) water, oil and gas rate, as well as bottom-hole flowing pressure and GOR; and (b) water RNP and RNP’. ................................................................. 267

Fig. 6.8 – Rate-transient analysis for Case Study 2: a) water RNP and RNP’ illustrating identified flow-regimes; b) linear flow plot used to analyze single-phase fracture transient data; c) square root of time plot to analyze single-phase transient data; c) FMB plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots. .................................................. 269

Fig. 6.9 – Analytical model history-match for Case Study 1: a) production rate of all 3 phases; and b) cumulative production of all 3 phases. ................................................................. 271
Fig. 6.10 – Microseismic fracture mapping: a) map view; b) plan view of the vertical array; and c) plan view of the horizontal Array ................................................................. 273

Fig. 6.11 – Calibrated hydraulic fracture modeling showing propped and created fracture height .................................................................................................................. 273

Fig. 6.12 – Production data and diagnostic plots associated with flowback data for Case Study 4: a) case with differentiated oil streams; b) case with a single oil stream consisting of both fracture and formation fluid; and c) RNP and RNP’ derivative for total oil stream ........................................................................................................ 278

Fig. 6.13 – Rate-transient analysis for Case Study 4: a) water RNP and RNP’ illustrating identified flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) FMB plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots ...................................................................................... 279

Fig. 6.14 – Analytical model history-match for Case Study 4: a) production rate of oil and gas phases; and b) cumulative production of oil and gas phases; and c) GOR ........................................ 281

Fig. 6.15 – Plan view schematic of 2-D simulation model. Modified from Zanganeh et al. (2015) ......................................................................................................................... 283

Fig. 6.1.1 – Steps associated with converting properties of fracture oil from measured conditions to base conditions (step 1). The iterative loop is handled using Newton’s method ...................................................................................................................... 288

Fig. 6.1.2 – Steps for converting fracture oil properties from base conditions to reservoir conditions and then to calculate required PVT properties (step 2) ........................................ 289

Fig. 7.1 – Conceptual model used in the derivation of the salinity model. The fractures are assumed to consist of simple planar fractures surrounded by an enhanced fracture region which is then bound by an unstimulated matrix ......................................................... 298

Fig. 7.2 – Water data associated with the first 3 days of the flowback (primarily the BBT period): a) water rate; and 2) water salinity ......................................................................................... 324

Fig. 7.3 – Water salinity history-match: a) shut-in period and BBT flow; and b) BBT flow only ......................................................................................................................... 326
# List of Symbols, Abbreviations and Nomenclature

## Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABT</td>
<td>After-breakthrough</td>
</tr>
<tr>
<td>BBT</td>
<td>Before-breakthrough</td>
</tr>
<tr>
<td>BT</td>
<td>Breakthrough</td>
</tr>
<tr>
<td>CBM</td>
<td>Coalbed methane</td>
</tr>
<tr>
<td>CDF</td>
<td>Cumulative distribution function</td>
</tr>
<tr>
<td>CEC</td>
<td>Cation exchange capacity</td>
</tr>
<tr>
<td>CVFD</td>
<td>Control volume finite difference</td>
</tr>
<tr>
<td>DDA</td>
<td>Dynamic drainage area</td>
</tr>
<tr>
<td>DFIT</td>
<td>Diagnostic fracture injection test</td>
</tr>
<tr>
<td>DRP</td>
<td>Dynamic relative permeability</td>
</tr>
<tr>
<td>E&amp;P</td>
<td>Exploration and production</td>
</tr>
<tr>
<td>EFR</td>
<td>Enhanced fracture region</td>
</tr>
<tr>
<td>EGP</td>
<td>Early gas production</td>
</tr>
<tr>
<td>EUR</td>
<td>Estimated ultimate recovery</td>
</tr>
<tr>
<td>FMB</td>
<td>Flowing material balance</td>
</tr>
<tr>
<td>FR</td>
<td>Flow-regime</td>
</tr>
<tr>
<td>GA</td>
<td>Genetic algorithm</td>
</tr>
<tr>
<td>GOR</td>
<td>Gas-oil-ratio</td>
</tr>
<tr>
<td>GRG</td>
<td>Generalized reduced gradient</td>
</tr>
<tr>
<td>GWR</td>
<td>Gas-water-ratio</td>
</tr>
<tr>
<td>IFFIP</td>
<td>Initial fracture fluid-in-place</td>
</tr>
<tr>
<td>LGP</td>
<td>Late gas production</td>
</tr>
<tr>
<td>LTFD</td>
<td>Laplace Transform finite difference</td>
</tr>
<tr>
<td>LTO</td>
<td>Light tight oil</td>
</tr>
<tr>
<td>MBE</td>
<td>Material balance equation</td>
</tr>
<tr>
<td>MBT</td>
<td>Material balance time</td>
</tr>
<tr>
<td>MC</td>
<td>Monte Carlo</td>
</tr>
<tr>
<td>MDH</td>
<td>Miller-Dyes-Hutchinson</td>
</tr>
<tr>
<td>MINC</td>
<td>Multiple interacting continua</td>
</tr>
<tr>
<td>MFHW</td>
<td>Multi-fractured horizontal well</td>
</tr>
<tr>
<td>MO</td>
<td>Multi-objective</td>
</tr>
<tr>
<td>NSGA</td>
<td>Nondominated sorting genetic algorithm</td>
</tr>
<tr>
<td>OF</td>
<td>Objective function</td>
</tr>
<tr>
<td>IFFIP</td>
<td>Initial fracture fluid-in-place</td>
</tr>
<tr>
<td>IGIP</td>
<td>Original gas-in-place</td>
</tr>
<tr>
<td>PDA</td>
<td>Production data analysis</td>
</tr>
<tr>
<td>PDF</td>
<td>Probability density function</td>
</tr>
<tr>
<td>PTA</td>
<td>Pressure Transient Analysis</td>
</tr>
<tr>
<td>RNP</td>
<td>Rate-normalized pressure</td>
</tr>
<tr>
<td>RNP'</td>
<td>Rate-normalized pressure derivative</td>
</tr>
<tr>
<td>RTA</td>
<td>Rate-transient analysis</td>
</tr>
<tr>
<td>SO</td>
<td>Single-objective</td>
</tr>
<tr>
<td>SRV</td>
<td>Stimulated reservoir volume</td>
</tr>
</tbody>
</table>
Western Canadian Sedimentary Basin

XRD X-ray diffraction
XRF X-ray fluorescence

Field Variables

\( a \) Fracture Spacing, cm
\( A \) Fracture surface area, acres or area of the block of interest (EFR), m\(^2\)
\( A_{\text{com}} \) Cross-sectional area of communication, ft\(^2\)
\( b \) FMB intercept during flowback
\( b' \) Fracture aperture width, μm
\( \dot{b} \) Intercept of radial flow plot during flowback
\( \ddot{b} \) Intercept of linear flow superposition plot or square root of time plot during flowback
\( B_{g} \) Gas formation volume factor, reservoir volume to surface volume
\( B_{o} \) Oil formation volume factor, reservoir volume to surface volume
\( B_{w} \) Water formation volume factor, reservoir volume to surface volume
\( c \) Kozeny-Carmen constant, dimensionless
\( C_{\text{block}} \) Concentration of salt in the block of interest (EFR), kg/m\(^3\)
\( c_{f} \) Fracture (or formation) compressibility, psi\(^{-1}\)
\( c_{p} \) Proppant compressibility, psi\(^{-1}\)
\( C_{pf}/C_{f} \) Primary fracture concentration, kg/m\(^3\) or ppm
\( C_{m} \) Matrix concentration, kg/m\(^3\) or ppm
\( c_{nf} \) Natural fracture compressibility, psi\(^{-1}\)
\( c_{o} \) Oil compressibility, psi\(^{-1}\)
\( C_{s} \) Saturation concentration for salt, kg/m\(^3\) or ppm
\( c_{t} \) Total compressibility, psi\(^{-1}\)
\( c_{t}^* \) Total compressibility including desorption effects, psi\(^{-1}\)
\( C_{TL} \) Volume correction factor due to temperature, bbl/STB
\( C_{PL} \) Volume correction factor due to pressure, bbl/STB
\( C_{xy} \) Communication factor between compartments x and y, scf/D/psi\(^2\)/cp (gas) or STB/D/psi (oil)
\( C_{TPL} \) Volume correction factor due to temperature and pressure, bbl/STB
\( d \) Proppant diameter, μm or diffusion layer thickness in the block of interest (EFR), m
\( D \) Diffusion coefficient of salt in water, m\(^2\)/s
\( D' \) Rate-dependent skin factor, 1/(MSCF/D)
\( D_{ef} \) Effective diffusion coefficient of salt in water in porous media, m\(^2\)/s
\( D_{o} \) Open media diffusion coefficient of salt in water, m\(^2\)/s
\( D_{e} \) Exponential skin decline factor, 1/D
\( f \) Impedance or constriction factor in porous media, dimensionless
\( F_{c} \) Fracture conductivity, md-ft
\( F_{g} \) Fractional flow of gas, dimensionless
\( F_{o} \) Fractional flow of oil, dimensionless
\( F_{p} \) Scaled compressibility factor, psi\(^{-1}\)
\( G_{i} \) Original gas-in-place in the fracture network, MSCF
\( h \) Net pay, ft
\( h_{f} \) Fracture height, ft
$J$  Flux, kg/(m²s)
$k$  Absolute Permeability, md
$k_l$  Component of the Brunner and Tolloczko dissolution rate constant, (m²s⁻¹)
$k_d$  Dissolution rate constant, s⁻¹ or kg/(m²s)
$k_f$  Effective permeability of the fracture network, md
$k_g$  Effective permeability to gas ($k_g = kk_{rg}$), md
$k_m$  Absolute matrix permeability, md
$k_o$  Effective permeability to oil ($k_o = kk_{ro}$), md
$k_p$  Precipitation rate constant, s⁻¹
$k_{rg}$  Relative permeability to gas, dimensionless
$k_{ro}$  Relative permeability to oil, dimensionless
$k_{rg}'$  Gas relative permeability endpoint, dimensionless
$k_{ro}'$  Oil relative permeability endpoint, dimensionless
$k_{rw}$  Relative permeability to water, dimensionless
$k_w$  Effective permeability to water ($k_w = kk_{rw}$), md
$K_0$  Coefficient 0 of correlation for $\alpha_{60}$, kg²/m³ °F
$K_1$  Coefficient 1 of correlation for $\alpha_{60}$, kg/m³ °F⁻¹
$K_2$  Coefficient 2 of correlation for $\alpha_{60}$, °F⁻¹
$n$  Number of hydraulic fracture
$n'$  Exponent relating variable porosity and permeability, dimensionless
$n''$  Corey oil or gas relative permeability constant - matrix, dimensionless
$m$  Slope of the flowing material balance during flowback
$m$  Slope of radial flow plot during flowback
$m$  Slope of linear superposition or square root of time plot during flowback or mas, kg
$m'$  Corey water relative permeability constant - fracture, dimensionless
$m''$  Corey water relative permeability constant - matrix, dimensionless
$m(p)$  Real gas pseudo-pressure, psi²/cp
$m(p)_L$  Liquid pseudo-pressure accounting for non-static permeability, psia
$m'(p)$  Real gas pseudo-pressure accounting for non-static permeability, psi²/cp
$m'_{salt}$  Mass of salt in the block of interest (EFR), kg
$m'_{p}$  Mass of salt in the primary fractures
$p$  Pressure, psia
$p*$  Extrapolated initial reservoir pressure, psia
$p_h$  Fracture healing pressure, psia
$p_k$  Net stress on the fractures, psia
$p_L$  Langmuir pressure, psia
$q_g$  Gas production (surface) flow rate, MSCF/D
$q_o$  Oil production (surface) flow rate, STB/D
$q_w$  Water production (surface) flow rate, STB/D
$Q_g$  Cumulative gas production (surface), MMSCF or MSCF
$Q_o$  Cumulative oil production (surface), STB
$Q_w$  Cumulative water production (surface), STB
$r_e$  Drainage radius, ft
$r_d$  Dissolution rate, kg/(m³s)
$r_p$  Precipitation rate, kg/(m³s)
<table>
<thead>
<tr>
<th>Variable</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>( r_w )</td>
<td>Wellbore radius, ft</td>
</tr>
<tr>
<td>( r_{wa} )</td>
<td>Apparent wellbore radius ( (r_{wa}=r_w e^{-s}) ), ft</td>
</tr>
<tr>
<td>( s )</td>
<td>Skin factor, dimensionless</td>
</tr>
<tr>
<td>( s_c )</td>
<td>Convergence skin for rectangular fracture geometry, dimensionless</td>
</tr>
<tr>
<td>( s(t) )</td>
<td>Time-dependent skin factor, dimensionless</td>
</tr>
<tr>
<td>( s_{CA} )</td>
<td>Drainage area skin or skin factor caused by non-radial drainage area, dimensionless</td>
</tr>
<tr>
<td>( s_{hmin} )</td>
<td>Minimum horizontal stress, psi</td>
</tr>
<tr>
<td>( s_{hmax} )</td>
<td>Maximum horizontal stress, psi</td>
</tr>
<tr>
<td>( s_{max} )</td>
<td>Maximum skin value, dimensionless</td>
</tr>
<tr>
<td>( S_w )</td>
<td>Water saturation, dimensionless</td>
</tr>
<tr>
<td>( S_w^* )</td>
<td>Normalized water saturation, dimensionless</td>
</tr>
<tr>
<td>( t )</td>
<td>Time, days or hours</td>
</tr>
<tr>
<td>( T )</td>
<td>Reservoir temperature, °C/F or fracture tonnage (tonnes)</td>
</tr>
<tr>
<td>( T_{C,68} )</td>
<td>Temperature in IPTS-68 basis, °C</td>
</tr>
<tr>
<td>( T_{F,68} )</td>
<td>Temperature in IPTS-68 basis, also known as ( T^* ), °F</td>
</tr>
<tr>
<td>( T_{C,90} )</td>
<td>Temperature in ITS-90 basis, °C</td>
</tr>
<tr>
<td>( T_{F,90} )</td>
<td>Temperature in ITS-90 basis, °F</td>
</tr>
<tr>
<td>( t_c )</td>
<td>Liquid material balance time, days</td>
</tr>
<tr>
<td>( t_{ca} )</td>
<td>Material balance pseudo-time corrected for desorption and non-static permeability and porosity, days</td>
</tr>
<tr>
<td>( t_{cal} )</td>
<td>Material balance pseudo-time for liquid accounting for non-static porosity and permeability, days</td>
</tr>
<tr>
<td>( t_{al} )</td>
<td>Pseudo-time for liquid accounting for non-static porosity and permeability, days</td>
</tr>
<tr>
<td>( t_a )</td>
<td>Pseudo-time for gas accounting for non-static porosity and permeability, days</td>
</tr>
<tr>
<td>( t_{a,LS} )</td>
<td>Linear superposition pseudo-time for gas accounting for non-static porosity and permeability, days</td>
</tr>
<tr>
<td>( t_{a,RSL} )</td>
<td>Radial superposition pseudo-time for liquid accounting for non-static porosity and permeability, days</td>
</tr>
<tr>
<td>( V )</td>
<td>Volume, ( m^3 )</td>
</tr>
<tr>
<td>( V_b )</td>
<td>Bulk volume, ( m^3 )</td>
</tr>
<tr>
<td>( V_L )</td>
<td>Langmuir volume, scf/ton</td>
</tr>
<tr>
<td>( V_f )</td>
<td>Fracture volume, Bbl</td>
</tr>
<tr>
<td>( V_w )</td>
<td>Volume of water, ( m^3 )</td>
</tr>
<tr>
<td>( V_p )</td>
<td>Pore volume, ( m^3 )</td>
</tr>
<tr>
<td>( w )</td>
<td>Single-objective weighting factors, dimensionless</td>
</tr>
<tr>
<td>( w_c )</td>
<td>Width of the communication plane, ft</td>
</tr>
<tr>
<td>( w_{EFR} )</td>
<td>Width of the enhanced fracture region, m</td>
</tr>
<tr>
<td>( w_f )</td>
<td>Fracture width, ft</td>
</tr>
<tr>
<td>( x_e )</td>
<td>Inter-well spacing, ft</td>
</tr>
<tr>
<td>( x_f )</td>
<td>Fracture half-length, ft</td>
</tr>
<tr>
<td>( y_e )</td>
<td>Half of reservoir length or stage spacing, rectangular reservoir geometry, ft</td>
</tr>
<tr>
<td>( Z )</td>
<td>Gas deviation factor, adjusted to account for desorption effects, dimensionless</td>
</tr>
<tr>
<td>( Z^* )</td>
<td>Gas deviation factor, adjusted to account for desorption effects, dimensionless</td>
</tr>
</tbody>
</table>

**Greek Variables**

\( \alpha_{60} \) | Thermal expansion factor, °F^{-1} |

xxv
\[ \beta \] Time-dependent diffusion coefficient constant, \( m^3/kg \)

\[ \gamma \] Permeability modulus, \( \text{psi}^{-1} \)

\[ \gamma_o \] Oil gravity, \(^\circ\)API

\[ \delta_{60} \] Temperature shift value, \(^\circ\)F

\[ \Delta_t \] Temperature correction, \(^\circ\)C

\[ \Delta_T \] Difference between reservoir and base temperature, \(^\circ\)F

\[ \Lambda \] Difference

\[ \gamma \] Permeability modulus, \( \text{psi}^{-1} \)

\[ \mu_g \] Gas viscosity, \( \text{cp} \)

\[ \mu_g \] Gas viscosity, \( \text{cp} \)

\[ \mu_w \] Water viscosity, \( \text{cp} \)

\[ \rho_{60} \] Oil density at standard conditions, \( \text{kg}/m^3 \)

\[ \rho^* \] \( \rho_{60} \) in IPTS basis, \( \text{kg}/m^3 \)

\[ \rho_o \] Oil density, \( \text{c}/cm^3 \) or \( \text{kg}/m^3 \)

\[ \rho_b \] Bulk density of shale, \( g/cm^3 \)

\[ \tau \] Scaled Temperature, \( ^\circ\)C

\[ \tau_f \] Fracture Tortuosity, dimensionless

\[ \sigma \] Shape factor

\[ \Theta \] Porosity, fraction

\[ \omega \] Surface renewal rate, \( m^3/s \)

**Dimensionless Variables**

\[ b_{Dpss} \] Dimensionless pseudosteady-state constant

\[ F_{cD} \] Dimensionless fracture conductivity

\[ q_D \] Dimensionless rate

\[ q_{Dd} \] Dimensionless decline rate

\[ r_{eD} \] Dimensionless wellbore radius; \( (r_{eD}=r_e/r_w) \) for radial flow type-curves, and \( (r_{eD}=r_e/x_f) \) for hydraulically-fractured well type-curves

\[ t_D \] Dimensionless time

\[ t_{Dd} \] Dimensionless decline time

\[ t_{Dpss} \] Dimensionless time at beginning of single-phase fracture depletion

\[ t_{DA} \] Dimensionless time based on \( A \)

\[ T_{Dwf/2} \] Dimensionless based on half the primary fracture width

\[ t_{Dxf} \] Dimensionless time based on \( x_f \)

**Superscripts**

\[ - \] Pore-volume average (overbar)

\[ * \] Altered variable

**Subscripts**

\[ 1 \] Tank 1, Stage 1, Well 1 or Layer 1

\[ 2 \] Tank 2, Stage 2, Well 2 or Layer 2

\[ ABT \] After-breakthrough

\[ accum \] Part of mass accumulation term

\[ BBT \] Before-breakthrough
Block  Block of interest (EFR)
BT  Breakthrough
D  Dimensionless variable
Dd  Dimensionless decline variable
eff  Effective
EFR  Enhanced fracture region
f  Fracture
g  Gas
i  Initial, iteration or element i
in  Part of mass in term
irr  Irreducible
j  Element j
nf  Natural fractures
m  Matrix
O  Oil
out  Part of mass out term
s  Surface controlled reaction
salt  Associated with mass of salt in the EFR or primary fractures
sc  Standard conditions
sink  Part of the mass sink term
source  Part of the mass source term
t  Transport controlled reaction
T  Total
w  Water or well
wf  Sandface
x,y  Elements x and y
Chapter One: Introduction

In this introductory chapter, a brief introduction to unconventional reservoirs and characterization methods, as well as their timelines for providing confident estimates of key fracture properties, will be summarized. The problem description, objectives and organization of the dissertation will then be given.

Due to declining conventional reserves, particularly in North America but also globally, the industry has begun to focus on the development of unconventional resources. Unconventional resources are difficult to produce compared to conventional reservoirs and therefore require advanced drilling, completion/stimulation and/or production strategies to achieve economic success. There are several types of unconventional reservoirs including oilsands, coalbed methane (CBM), gas hydrates, tight oil/gas and shale oil/gas. In recent years, the focus has been on the development of the oilsands, tight oil/gas and shale oil/gas, with tight/shale reservoirs being the focus of this research.

The most common method for developing these tight reservoirs is with MFHWs and therefore development of analysis methods to characterize the generated fractures has received significant attention in the past decade. The most common approach applied for fracture characterization has been the assessment of long-term online production data using a combination of straight-line techniques, type-curves and simulation (analytical and numerical). Although highly effective, these methods often require a minimum of 6-12 months of production history to accurately characterize fracture properties. This has led operators to seek new methods for the early characterization of hydraulic fractures to allow prediction of long-term performance as quickly as possible, and to make changes to the current drilling program if necessary. Methods such as microseismic hydraulic fracturing monitoring, hydraulic fracture
modeling and welltest analysis have gained traction in the industry, but these methods have issues that could lead to misleading results in tight rock. For example, microseismic data interpretation often leads to significant over-estimation of fracture half-length. This is because microseismic events created during the fracturing process do not indicate the location where an effective fracture has been created, and to what extent the fracture is propped allowing it to be conductive. Hydraulic fracture modeling addresses some of these issues by providing an estimate of created and propped fracture half-length, although understanding which part of the fracture will be effective remains uncertain. Further these models are typically developed to model fractures from a vertical wellbore with planar geometry, and therefore, may not be accurate for many MFHWs. Classic welltesting techniques such as build-up tests are often not economically viable in tight reservoirs due to the long shut-in time required to achieve radial flow which is required to decouple fracture half-length and matrix permeability.

1.1 Problem Description

Due to the issues associated with the currently available characterization techniques, both industry and academia have continued to explore new methods for the characterization of hydraulic fracture properties. Recently, several authors have identified carefully gathered, high-resolution flowback (production test) rates and pressures as one possible method for characterizing hydraulic fracture properties, such as conductivity and half-length, using a limited data set which is collected on essentially every MFHW.

Flowback periods immediately following fracture stimulation can be used quantitatively to characterize hydraulic fractures, and in some cases, the reservoir. However, analyses of this data are not commonly reported. Flowback of fracturing and formation fluids after stimulation of a
well is a routine operation performed on hydraulically-fractured wells, and is necessary to condition the well for long-term performance (Crafton and Gunderson, 2007). This operation is particularly critical for MFHWs completed in shale gas reservoirs where massive volumes of stimulation fluid are injected into the formation, of which usually only a small percentage is recovered. Such stimulations are also becoming popular in tight gas and tight oil reservoirs as a result of their success in shale gas reservoirs. Crafton (2008) has discussed the need for careful management of flowback procedures to prevent degradation of well performance – in particular, he noted that aggressive flowback followed by shut-in prior to cleanup can be particularly damaging.

Flowback analysis is the focus of this work with the goal of accurately characterizing hydraulic fractures using a limited data set. This dataset has largely been ignored by industry possibly due to the multi-phase flow nature of the problem, and the possibility of early-time data being dominated by wellbore storage. Note that calculations on several reservoirs of different types has shown that wellbore volume only makes up a very small portion of wellbore+fracture volume and as a result it can be assumed that total volume is equal to fracture volume, with minimal impact of wellbore storage.

1.2 Literature Review

In recent years there have been a number of publications on quantitative flowback analysis, primarily focusing on shale gas but also on tight gas and tight oil. Literature reviewed for this dissertation falls into two primary categories: 1) flow modeling; and 2) salinity modeling.
1.2.1 Flow Modeling

Flow modeling will be discussed first and can be further divided into multiple categories: 1) rationalization for developing quantitative analysis methods; 2) single-phase analysis; and 3) multi-phase analysis.

1.2.1.1 Rationalization for Developing Quantitative Analysis Methods

Kinnon and Williams-Kovacs (2017) conducted a study investigating some common indicators used in industry in attempt to predict long-term well performance, at least qualitatively. This study started by investigating the simplest indicators attempting to correlate peak flowback rate to peak online rate as well as 30 and 90 day average rates and estimated ultimate recovery (EUR). No correlation was found when considering these simple parameters. In the next phase of the study, reservoir (matrix or hydraulic fracture) and flowing pressures were incorporated and yet no correlation was found. This study indicated that many of the simplistic ways that operators have incorporated flowback data may be misleading and lead to poor decision making. From this analysis it was concluded that quantitative flowback analysis was required to get an indication of long-term productivity from very early-time flowback data. This study sets the stage for the work conducted in this dissertation.

1.2.1.2 Single-Phase Analysis

Some of the earliest works in quantitative flowback analysis were conducted by Crafton and his co-authors (Crafton 1998; Crafton 2008; Crafton 2010; Crafton and Gunderson, 2006; Crafton and Gunderson, 2007). Crafton’s method for quantitatively analyzing flowback data from tight gas wells involves plotting the Reciprocal Productivity Index on a Miller-Dyes-
Hutchinson (MDH) semi-log plot and drawing a straight-line through the early-time data (assumed to be transient radial flow in the fractures). From the straight-line, permeability-thickness of the fracture and effective wellbore radius (effective fracture length) can be determined (Crafton, 1997). There are three primary issues with the techniques developed by Crafton and his co-authors: 1) lack of application of diagnostic plots for correct flow-regime identification; 2) the extremely short-duration single-phase flow, especially in gas cases; and 3) early-time transient flow within the fractures is extremely short, particularly with high permeability fractures. With conventionally measured flowback data, rates and pressures are typically collected hourly, while transient flow in the fracture system may only last for 10’s of seconds for high permeability fractures (Wylie and Streeter, 1982). As a result, data must be gathered at ultra-high frequency (20+ data points per minute or more) to allow quantitative analysis. Although this is technologically feasible, it is not practically feasible for the vast majority of wells. Even collected at this frequency, it is likely that the majority of single-phase data corresponds to wellbore/fracture storage (depletion), rather than transient flow in the fractures, and therefore the developed models are not directly applicable. Note that fracture storage is significantly greater than wellbore storage in most cases, allowing the assumption that the majority of fluid resides in the hydraulic fracture system, rather than the wellbore.

An additional study conducted on early-time single-phase flowback data is that of Abbasi et al. (2014). In that work, the authors developed a straight-line relationship between rate-normalized pressure (RNP) and material balance time (MBT) for application during early-time depletion within the fracture network. From the straight-line, fracture permeability and the fracture storage coefficient can be determined. This technique was applied to both tight oil and tight gas scenarios, although application in tight gas cases may be limited as a result of
deficiency 1 discussed above in relation to Crafton’s work. Abbasi et al. considered water-dominated flow early in the flowback period where gas saturation, and therefore gas production, is limited and has a relatively minor impact on total compressibility. A similar approach was used by Fu et al. (2017) with a focus on oil applications; in that work, they demonstrated the importance of estimating fracture compressibility for determining fracture volume, since fracture compressibility is often several orders of magnitude higher than water compressibility, and therefore is the primary driver for early single-phase production. The authors also developed a technique for estimating fracture compressibility using a combination of Diagnostic Fracture Injection Test (DFIT) data and a correlation developed by Aguilera (1999) which was developed for natural fractures with various levels of mineral fill. The correlation developed by Aguilera was also used in this dissertation and was first applied to hydraulic fractures by Williams-Kovacs and Clarkson (2013c). They also attempted to relate the fracture pore volume to key fracture design parameters. From this analysis the authors concluded that increasing total injected volume and tighter perforation cluster spacing typically leads to a larger effective fracture volume. Further, they concluded that increasing proppant concentration per perforation interval may increase created fracture volume to a limit, after which it may decrease effective fracture volume before ultimately stabilizing. Finally, the authors investigated soaking time, which led to inconclusive results. The overall trend was controlled by a single well which had the longest soaking time, and the smallest effective fracture volume, with the remainder of the wells being highly scattered. Only soaking times between a couple of hours and six days were considered, with the majority of wells having less than two days of shut-in time. It would be fruitful to extend this study to wells with a much larger range of soaking periods in an attempt to determine whether there is a positive or negative impact on effective fracture volume and productivity;
many authors have hypothesized the impact with no conclusive statistical evidence provided. It is likely that the correlation between soaking time and long-term productivity is highly formation dependant.

In summary, early-time single-phase flowback analysis represented the first and most simplistic form of flowback analysis and provided the foundation for research on the topic, similar to long-term online analysis. This analysis can be highly effective when flow-regimes are correctly identified, although they have often been misinterpreted in the literature leading to potentially erroneous results. Additional complexities such as estimating hydraulic fracture compressibility make this analysis more challenging than similar applications to online production.

1.2.1.3 Multi-Phase Analysis

In addition to the work on early-time single-phase flow in the fracture system described above, several authors have recently developed models for analyzing multi-phase flowback data. Some of the initial work on multi-phase flowback analysis was carried out by Clarkson and Williams-Kovacs, first focusing their attention on shale and tight gas before switching their focus to LTO as a result of a shift in commodity prices to favour liquids-rich production. Clarkson and Williams-Kovacs (2013a) developed the first model for analyzing production from shale wells where both water and gas production are present from the onset of the flowback period. Their analytical approach for shale gas wells was to treat flowback analogously to highly cleated, commercial coalbed methane wells, where the only source of gas is from instantaneous desorption. An extension of this model to tight gas presented by Williams-Kovacs and Clarkson (2013c) assumed that free gas could be instantaneously sourced to the fractures from the
surrounding matrix. The focus of this work was on the initial fracture/wellbore multi-phase depletion flow-regime. Post-depletion data was modeled using methods for forecasting long-term single-phase production from ultra-low permeability gas wells coupled with continued depletion of water from the fracture network. The limitations of this approach will be discussed in detail in Chapter Four. Clarkson et al. (2014) (originally published as Clarkson 2013c with further model details) then developed a model for analyzing three-phase (water, oil and gas) flowback from LTO wells using a different model framework, which was eventually applied to shale gas flowback, as will be discussed in Chapter Three. In this approach the before-breakthrough (BBT) single-phase fracture fluid only production was analyzed first, followed by multi-phase after-breakthrough (ABT) data. In their base model, which assumed a circular fracture shape, the BBT flow-regimes were assumed to be a brief period of radial flow within the fractures, followed by a longer period of single phase fracture depletion. ABT the primary flow-regime observed is a coupled flow-regime which is a combination of transient flow from the matrix (single or multi-phase) coupled with multi-phase fracture depletion. As suggested by the authors, as well as Crafton (2008), phase breakthrough leads to a reduction in effective fracture half-length. Although these methods provided an excellent starting point they did not consider some key aspects of the physics of the flowback problem including fracture closure which will be discussed in Chapter Three. Many additional constraints and improvements were also made to the model which will be discussed in greater detail in Chapters Two, Three and Four. These improvements, leading to the existing suit of tools, were later expanded to more complex situations such as multi-well flowback and oil fracs in LTO reservoirs, which will be discussed in Chapter Five and Six.
Alkouh et al. (2013) demonstrated a method for estimating initial fracture fluid-in-place (IFFIP) from gas flowback data using the RNP and RNP derivative (RNP’), for both early-time single-phase and multi-phase flowback data. The primary uncertainty in this model is total system compressibility, which the authors assume to be water + formation compressibility during single-phase flow and approximately equal to gas compressibility upon breakthrough of formation fluids. This technique assumes that fracture storage is the dominant flow-regime both before- and- after breakthrough of formation fluids. The method is analogous to the BBT flowing material balance (FMB) approach used in this dissertation. For the technique to be applicable after formation fluid breakthrough, fracture depletion must still be the dominant flow-regime. This is largely consistent with observations obtained in the current study, although a modified pseudopressure definition accounting for the relative permeability of water would be required to accurately analyze this flow-regime, which was not considered by Alkouh et al. (2013). Application of a modified pseudopressure would make this technique analogous to the 2-phase FMB used for analyzing multi-phase CBM reservoirs and also in this work for ABT flow-regime confirmation, although a history-match of water saturation is required (Clarkson and Williams-Kovacs, 2013a) to allow for this correction.

Xu et al (2015a) identified two flow periods in flowback data from Horn River shales (demonstrated to be significantly naturally fractured), which they defined as Early Gas Production (EGP) and Late Gas Production (LGP) using a log-log plot of Gas-Water Ratio (GWR) vs. Time. Those authors hypothesized that the mechanism for gas in the fracture system at early time is counter-current imbibition of water and redistribution of free gas initially in the natural fractures during the shut-in period prior to flowback. This effect would be particularly substantial in wells with an extended shut-in period. The authors assumed that the EGP region
corresponds to free gas expansion in the natural fractures, whereas the LGP corresponds to the onset of gas transfer from the matrix to the fracture network. In a case study presented by Cugnart et al. (2017) on the Vaca Muerta shale, a v-shaped behaviour in the GWR plot, comparable to that observed by Xu et al. (2015), was observed. However in the Cugnart et al. study, ~7 hours of water-only production was observed at the onset of the flowback period prior to the onset of gas production, suggesting that there is no initial gas saturation in the fractures and therefore creating further uncertainty as to the cause of this v-shaped behaviour. The EGP region was modelled by Xu et al. (2015a) and Xu et al. (2016a), whereas the LGP region was modeled by Ezulike and Dehghanpour (2014), Ezulike and Dehghanpour (2015) and Xu et al. (2015b). Xu et al. (2015a) used material balance calculations (early-time straight-line on a conventional p/Z plot) to demonstrate that the fractures act as a closed system during the EGP period, suggesting the dominant flow-regime is fracture depletion. The authors also developed a straight-line material balance approach for determining initial gas-in-place (IGIP) in the fractures. This method required an assumption of initial gas saturation in the fractures. Using an iterative approach, and a combination of the results of the p/Z material balance analysis and the developed straight-line material balance approach, a best fit value of initial gas saturation and initial fracture volume could be determined. One issue with this technique is an unexpected non-zero intercept is observed in most field cases, which the authors attribute to a “skin effect” resulting from ignoring several data points at the onset of flowback. In a follow-up paper Xu et al. (2016a) developed a straight-line technique analogous to that demonstrated by Abbasi et al. (2014) to model early-time multi-phase depletion in the fractures, although using the concept of dynamic relative permeability (DRP) proposed by Ezulike and Dehghanpour (2014). In the DRP model, relative permeability is related to time using an empirical equation to account for multi-
phase flow in the fracture system. From the straight-line on a plot of \textit{RNP vs. pseudotime} (modified to account for relative permeability), initial gas saturation, leak-off percentage, effective fracture volume and a dimensionless fracture parameter including fracture permeability and effective half-length can be determined. One issue with this technique, is a certain degree of non-linearity is seen in all of the field cases presented by the authors, suggesting that the physics of the problem have not been adequately captured, possibly due to the assumptions associated with the development of the DRP term. Further, the authors ignored the impact of desorption as a driving force in the MBE, both in modeling and straight-line analysis, which several authors have shown to be the dominant material balance mechanism during both flowback (ex. Clarkson and Williams-Kovacs, 2013a) and online (post-flowback) production (ex. Seidle, 1999) from organic-rich shale reservoirs. It is possible that this is not significant in the particular area and intervals of the Horn River Basin that were studied, although a MBE of a form comparable to that used by King (1993) would likely yield more meaningful results in many shale gas applications. The authors also presented an empirical correlation for estimating the transition time from EGP to LGP.

Ezulike and Dehghanpour (2014) modeled the LGP period identified by Xu et al. (2015a) as a multi-phase transient flow period by applying the concept of DRP to the linear dual-porosity model developed by Bello and Wattenbarger (2010) for single-phase flow. The model developed by the authors ignores the impact of fracture depletion, which has been identified as a primary flow-regime using diagnostic plots in the current study (and other previous studies discussed above), and therefore may not honor the physics of the flowback problem in many reservoirs. Further, these authors also ignore desorption as an important material balance mechanism,
although again this may not be significant in the particular area (and intervals) of the Horn River Basin studied.

Ezulike and Dehghanpour (2015) extended the multi-phase dual porosity model first proposed by Ezulike and Dehghanpour (2014) to allow for history-matching both flowback and post flowback data. They then use the parameters estimated from flowback to constrain and improve upon parameters estimated from post-flowback data. During flowback they rationalize the use of a dual-porosity model by assuming that secondary fractures are filled with water and are not contributing to gas production and therefore a significant increase in effective half-length is required to history-match long-term production data using a dual-porosity model. Several modifications were made to the model for post-flowback analysis in order to improve the history match. Initially using the same assumptions as used when analyzing flowback data long-term gas production was significantly underestimated. When the impacts of multi-phase effects and secondary fractures (through the use of a triple-porosity model) were taken into account, an improved late time history-match was achieved, although the equivalent fracture volume was significantly higher than that observed from flowback. Ultimately an increase in compressibility to account for desorption during long-term production leads to the best history-match, although also the largest equivalent half-length. There are several deficiencies that can be observed in this work. Most critically, it is unclear how the flowback data is used to guide long-term production data analysis (PDA) as several additional mechanisms are required and significantly different effective fracture half-lengths are estimated both during and after flowback. This is significantly affected by allowing the secondary fractures to be active during long-term production which significantly increases the stimulated volume. Further, although post-flowback desorption is partially accounted for by changing compressibility, it does not account for the actual desorbed
gas volume. Another deficiency of the model is that the authors identify a unit slope in the production data (which is analyzed by Ezulike et al., 2016 – see below) corresponding to fracture depletion, yet the model being applied does not predict a unit slope at any point during the production profile. In addition to the flow modeling conducted, the authors also present a relatively strong correlation between load fluid recovery and effective fracture pore volume and flowback sequence, as well as between cumulative water production and effective fracture pore volume. A very weak correlation between effective fracture pore volume and total injected volume was also presented. They attribute the first two correlations to communication between multiple wells on the pad, which is one of the scenarios addressed in this dissertation and seems to be a reasonable conclusion, although communication effects are ignored in their modeling procedure.

Xu et al. (2015b) also developed a material balance technique for analyzing LGP analogous to the technique developed by Xu at al. (2015a) but now considering the fracture system as an open tank rather than a closed tank during EGP. As with the predecessor paper, the ultimate goal of the workflow is to estimate initial fracture volume. The technique requires an iterative procedure and the application of four plots to solve for the four drive mechanisms responsible for two-phase flowback. The authors only show one field case to validate their model making it difficult to judge its applicability as a whole. The largest downside of technique is that a linear approximation is used to estimate the gas influx from the matrix to the fractures which may not be applicable in all shale gas reservoirs. Even in the field case presented, some non-linearity exists in the gas influx profile. Many factors can impact gas influx including the volume of gas stored in the matrix system, fracture geometry, pressure difference between the matrix and the
fractures and gas desorption. A tight rock physics-based influx equation will be applied in Chapter Three which accounts for these key factors.

Ezulike et al. (2016) developed a simple straight-line method for estimating fracture pore volume for shale gas wells that exhibit a period of unit slope which falls between the early transient flow period and the late transient flow periods during multi-phase flow. In their relationship, RNP is inversely proportional to fracture pore volume and total compressibility. The authors use a combination of the generalized reduced gradient method (GRG) and evolutionary algorithms in order to decouple the involved parameters. The GRG algorithm is used to find a possible optimal combination of the unknown parameters and then the evolutionary algorithm is used to generate the probability density function (PDF) and cumulative distribution function (CDF) associated with the unknown parameters. Although the approach of decoupling parameters is unique, the GRG algorithm has been shown by many authors to get trapped in local optima rather than finding the true global optimum, and therefore, this approach could be strengthened by using a more rigorous algorithm such as a genetic algorithm (GA) which typically will find the near optimal. With the exception of the application of assisted parameter estimation algorithms, this approach is very similar to FMB applied by Clarkson et al. (2014), although this analysis focused on single-phase fracture depletion prior to the breakthrough of formation fluids. This model contradicts the model presented by Ezulike (2015) for analyzing the same data set.

Xu et al. (2016b) conducted a study to compare the estimated effective half-length from microseismic with the results using the technique of Ezulike and Dehghanpour (2014), Xu et al. (2015b), Xu et al. (2016a) and Ezulike et al. (2016). Generally the half-length values estimated by the flowback techniques are significantly lower than the microseismic-interpreted half-length,
as would be expected because microseismic provides an indication of where a seismic event was recorded as a result of the hydraulic fracture treatment, although gives no indication of effective or propped half-length. In one anomalous case, the flowback model developed by Xu et al. (2016b) estimates a half-length longer than microseismic, which makes the analysis questionable. A comparison of the estimated fracture volume using the four flowback techniques was also performed. The method developed by Ezulike and Dehghanpour (2014) consistently estimates a significantly lower fracture volume than the other techniques. The authors attribute this to fracture closure since this model is analyzing later-time flowback data. The three techniques used to analyze EGP show significant variability in several wells (up to 50%). This is likely due to varying assumptions in the derivation of the models and suggests that the physics of the flowback model are not consistently accounted for in the different models.

Zhang and Ehlig-Economides (2014) conducted an investigation into the load recovery of shale gas wells. Although this work makes no attempt to estimate key fracture properties, it is included here due to the fact that it makes use of a similar diagnostic plot (log-log plot of Water-Gas Ratio vs. Cumulative Gas Produced) used in many of the other works on shale gas reservoirs and provides some interesting insights to the mechanisms controlling production during load fluid recovery. This study also investigates longer term flow than most of the flowback studies, as the authors were also investigating the cause of water production several years after the stimulation treatment and identify any problems which may impact future production. The two main shales investigated in this paper are the Horn River Basin and the Barnett Shale. In the Horn River Basin, 15 wells were studied. In all 15 wells an early-time $-\frac{1}{2}$ slope was observed, while in 8 of the wells a later time negative unit slope was observed. In each of these 8 wells the transition volume is similar at approximately 200 MMscf. The
observed trend fits with the experimental work conducted by Mahadevan and Sharma (2003) which suggested that water-block cleanup occurs as a result of two mechanisms: 1) immiscible displacement of water by the flowing gas; and 2) evaporation of water by flowing gas that becomes undersaturated as the pressure decreases. As a result, the \(-\frac{1}{2}\) was interpreted as displacement, while the negative unit slope was interpreted as evaporation. The displacement flow-regime was shown to be fairly short, while the evaporation flow-regime often lasted for several months. This is supported by the field data which suggests that the evaporation flow-regime occurs primarily while water falls within its solubility limit. One of the wells showed a slope significantly greater than -1 which the authors attributed to liquid loading issues in the wellbore. Interpretation of both seismic and microseismic on this well suggest that the well trajectory passes through a fault which may have been contacted by one of the hydraulic fractures which may be leading to the excess water production. In the Barnett Shale, 17 wells with highly variable completions strategies were investigated. Early in time, all 17 wells fall along a \(-\frac{1}{2}\) slope, although a very high WGR was observed in long-term production. One possible interpretation provided by the authors is that well interference was occurring when well spacing is small, transferring water from the recently stimulated well to the well which has already been on production via the natural or induced fractures. Another possible interpretation is that fractures have grown into the underlying Ellenburger Karst, which is a water-bearing carbonate formation. This second interpretation is likely in several of the wells which have a total load fluid recovery significantly larger than pumped volume. An investigation of the wells which showed no evidence of well interference or contact with another water-bearing formation demonstrated only a \(-\frac{1}{2}\) slope trend indicating a displacement flow-regime, while the WGR remained above the water solubility level justifying the absence of the negative unit slope late in
time. As a result, it is possible that load fluid recovery may continue. In both formations a weak but positive correlation between load fluid recovery and cumulative gas production was observed and ultimate load fluid recovery was typically significantly higher than the 25% or less often reported by operators.

Kurtoglu et al. (2015) demonstrated a flow-regime based approach for analyzing flowback data with the goal of estimating fracture conductivity via bilinear flow and reservoir connectivity via linear flow. In this work, the single-phase diffusivity equation is modified to account for simultaneous flow of water, oil and gas. The study adopted the multi-phase formulations developed by Kazemi et al. (2014), which assume flow from the matrix to natural fractures, natural fractures to the hydraulic fractures and finally from the hydraulic fractures to the wellbore. Equations for analysis of both multi-phase bilinear and linear flow were presented by Kazemi et al. (2014). Analysis was conducted on both flowback and long-term production data. Stimulated Reservoir Volume (SRV) drainage during flowback is limited to fractures in the vicinity of the wellbore, while the end of linear flow from long-term production characterizes the ultimate drainage boundary. Field cases were conducted on both the Eagle Ford and Bakken Shales, with each case study comparing a well pair investigating three main effects: 1) stage spacing; 2) well orientation; and 3) efficiency of refracturing. As expected, in each of the cases the SRV grows between the flowback and online production period as the pressure transient moves toward the ultimate drainage area boundary. The main issue with this technique for application to flowback data is the lack of clear diagnostic slopes on the plot of RNP vs. Time during the flowback period. Rarely was the expected ¼-slope of bilinear flow and the expected ½-slope of linear flow observed; rather the diagnostic slopes are force-fit to the data to allow analysis. As a result, it is unclear whether the behaviour expected by the authors is actually
occurring in the field. If the incorrect flow-regime is analyzed on a straight-line plot, the results are often erroneous. This work may have benefitted from the application of the RNP’ with MBT which has been shown to provide better diagnostic information and a clearer flow-regime interpretation.

Yang et al. (2016) developed a semi-analytical model for history-matching multi-phase flowback data from shale gas wells. In this model, two-phase flow is allowed in both the matrix and fracture network. The approach models the matrix analytically, while the fractures are solved numerically under the assumption of pseudo steady-state flow in the fractures. This model uses the node analysis approach to discretize the complex fracture network into a given number of segments depending on the complexity of the fracture system. The model is extended from single-phase flow to multi-phase flow by iteratively correcting the relative permeability to gas and water phases and capillary pressure for each fracture segment with fracture depletion. The authors also conducted a series of sensitivity studies and concluded that: 1) initial gas saturation and fracture conductivity may have a significant impact on peak gas rate and dewatering time; 2) fracture spacing had little impact on the generated type-curves, suggesting that interference between fracture clusters may be minimal during flowback (likely highly dependent on extent of created/reactivated natural fractures); 3) observed flow-regimes and length of flow-regimes is highly dependent on fracture geometry; and 4) the v-shape behavior on the GWR vs. Cumulative Gas Production, which has been identified in several (although not all – ex. Williams-Kovacs and Clarkson, 2016) shale gas formations (ex. Yang et al., 2015) is likely caused by gas and water supply from the natural fractures and their flow dynamics which are controlled by relative permeability. This is an alternate explanation than that provided by Xu et al. (2015a). The main deficiency of this model is the need for a detailed understanding of
fracture geometry in order to derive meaningful fracture parameters. Gravity effects are also ignored, although this is the case with all flowback work not conducted using a numerical simulator. A similar model was presented by Jia et al. (2017a), although in this study steady-state flow in the fractures is not assumed. This model will be discussed in greater detail in Chapter Three.

Kanfar and Clarkson (2016) developed an approach for analyzing both flowback and long-term online production data from gas condensate wells using numerical simulation combined with a multi-objective (MO) GA to derive key fracture and reservoir parameters. The authors rigorously modeled flowback data using a triple-porosity system (matrix, primary hydraulic fractures and induced/natural fractures) using the multiple interacting continua approach (MINC - Pruess, 1985). The model also includes multiple water trapping mechanisms (permeability jail, capillary pressure and gravity segregation). This is likely the most rigorous method developed to date, although it is also the most computationally intensive. The model could be more rigorous by including coupled flow-geomechanical simulation, although this would add additional computational intensity.

Clarkson et al. (2016) developed a semi-analytical model for history-matching flowback and early-time production from multi-fractured horizontal tight oil wells using the dynamic drainage area (DDA) concept which was first applied by Clarkson and Qanbari (2016) for history-matching long-term oil and gas production data. In this model, the DDA concept is applied to two regions: a primary hydraulic fracture region and enhanced fracture region (or unstimulated region). The primary deficiencies of this approach at its current stage of development is the inability to model a third region (a primary fracture, an enhanced fracture region, EFR, and an unstimulated region), and the restriction to two-phase flow (oil and water) making it
inappropriate for use below the bubble point. The authors have indicated that both deficiencies are easily handled within their framework and will be addressed in future work. In a follow-up paper Clarkson et al. (2017) extended this concept by integrating a simple fracture model developed by Valko (2001) to estimate fracture half-length and fracture width and applied the DDA concept to model leakoff during fracture propagation and the subsequent shut-in period. By modeling leakoff, the authors are able to estimate initial fracture pressure, depth of penetration of fracture fluid and matrix properties immediately surrounding the fractures which have been impacted by the hydraulic fracture stimulation. This paper provided a proof of concept and outlined many steps for future work in fine-tuning the technique. The vast majority of field studies discussed above make assumptions about the initial conditions on flowback, which leads to uncertainty in the analysis.

Jia et al. (2017b), a Laplace domain Hybrid model was developed to account for inter-well communication through the primary and secondary fractures. In this work the Laplace Transform Finite Differences (LTFD) method is used to model fracture flow which is dynamically coupled with the analytical matrix model derived using the line-source function in the fracture domain. This work represents an extension to the multi-well flowback model which will be discussed in Chapter Five. In this work an analysis of the “pseudo single-phase data” of the first well during the early-time flowback data where the water-phase is dominant and the second well had not yet been brought on production was used to provide an initial estimate of primary and secondary fracture properties to guide the multi-phase simulation.

In one final work (Jia et al., 2017c) developed a model similar to that presented by Jia et al. (2017a) for shale gas reservoirs, but instead focused on tight oil reservoirs with a rectangular
fracture geometry. Both of these models use a basic framework similar to Jia et al. (2017b). This model will be discussed in further detail in Chapter Six.

1.2.1.4 Other Flow-Based Analysis

Jones et al. (2014) have attempted to estimate initial reservoir pressure from flowback data, given the complexities of pre- and post-fracture build-up tests in unconventional wells. With this approach, reservoir pressure is estimated from the sandface flowing pressure upon breakthrough of formation fluid into the fracture. This technique is similar to the breakthrough pressure concept used in the current study, although this pressure may still be elevated from initial reservoir pressure, as a result of near-fracture super-charge caused by stimulation (essentially a mini waterflood), depending on the pre-flow shut-in time.

1.2.1.5 Summary of Existing Methods for Flow-Based Analysis

In summary, in recent years there have been a large number of studies conducted developing techniques for quantitatively analyzing flowback from MFHWs. Generally speaking these fall into three main categories: 1) material balance; 2) straight-line analysis; and 3) simulation (analytical, semi-analytical and numerical). These methods typically increase in complexity in the order listed and have rarely been combined, which can significantly improve the quality of key parameter estimates by demonstrating consistency between analysis techniques. A brief summary of the studies discussed in detail above and some of their key deficiencies is provided below:

- Authors have studied both single-phase flow prior to the breakthrough of formation fluids and multi-phase analysis following the breakthrough of formation fluids.
• The majority of work conducted has been on dry shale gas reservoirs, although recently commodity price differentials have directed some authors to focus investigation on gas condensate and tight oil applications.

• The majority of the early studies on quantitative flowback analysis focused on single-phase BBT fracture-fluid only data which simplifies the analysis. These studies were primarily based on straight-line techniques based on assumptions of which flow-regime was dominating the flowback period without the use of diagnostic plots.

• The majority of attempts to apply straight-line techniques to multi-phase flow have been hindered by simplifying assumptions which is the likely cause of non-linearity commonly observed in applications to simulation and field data.

• Analysis methods that combine several steps including diagnostic plots for flow-regime identification, straight-line and type-curve analysis and simulation (as applied in this dissertation) likely offer the best results. These methods follow a workflow which is commonly applied to the analysis of long-term online production data.

• Some of the semi-analytical techniques presented recently in the literature which build upon the work presented in this dissertation provide a reasonable compromise of simple analytical techniques and rigorous numerical solution. These techniques are far less time consuming than numerical simulation but are able to analyze more complex fracture geometries more accurately than simple analytical techniques.

• In addition to estimating key fracture properties, some authors have attempted to extract initial reservoir pressure from flowback data, although formation pressure may be overestimated using these methods.
1.2.2 Salinity Modeling

There have been three main fields of research considering flowback salinity including: 1) using experimental data to infer mechanisms for increased salinity; 2) using field data to infer mechanisms for increased salinity; and 3) modeling salinity response to characterize hydraulic fracture or reservoir parameters. As with flowback flow modeling, the majority of work presented in the literature has focused on shale gas reservoirs. Although the focus of this work (Chapter Seven) is on salinity modeling, it is important to understand existing experimental and field-based studies in order to understand the key mechanisms which should be included into a salinity model for a specific reservoir and therefore both lab and field-based studies will be thoroughly reviewed.

1.2.2.1 Experimental Studies Investigating Recovered Fluid Salinity

Recently, flowback chemical analysis has been a complementary approach for evaluating fracturing operations and characterizing reservoir properties. Understanding the source of flowback salts and the mechanisms controlling water chemistry is important but also challenging due to the complexity of water-rock reactions, especially in shale reservoirs (Zolfaghari et al., 2015). Several authors have conducted lab experiments to better understand the origins of flowback salts.

Blaunch et al. (2009) conducted a geochemical and lithologic laboratory and field study in an attempt to identify the source of high salt content found in flowback water from the Marcellus Shale. By examining produced brines from other off-setting conventional formations they concluded that brine originated as an evaporated seawater which has since been diluted. The chemistry of this water was then impacted by diagenetic affects such as dolomitization and other
rock-water interactions leading to the present day water chemistry. The authors concluded four potential origins of salt in flowback water: 1) primary dissolution of autochthonous salts (rocks for which dominant constituents have been formed in situ) – salt must be observable in subsurface samples of the Marcellus and the cations and anions typical of evaporate minerals should be present; 2) primary dissolution of allochthonous salts (have formed from hydrogeological emplacement and subsequent crystallization in fractures and pores) – identified from observation of fracture/pore filling with evaporate minerals and not requiring a hypersaline or evaporate depositional setting since the origin would be from outside the formation of interest; 3) encroachment of basinal brine – direct dynamic communication of brine into the hydraulic fracture network sourced from external zones, where well-to-well composition would be expected to be highly variable, as not all treatments will breach water-bearing zones; 4) mobilization of hypersaline connate water – mobilization or solubilisation of immobile, highly saline, connate water held in place by capillary pressure or encapsulation, varying from direct solubilisation of solid-phase salt, and requiring a water phase to be present in the formation. A combination of the above is also possible. In addition, by looking in detail at samples from one well stimulated with fresh water using a Piper diagram, it was concluded that, if fresh water was pumped (as was in this well), dissolution of Marcellus salts is the primary mechanism. If returned fracture water is reused, mixing with brine from offsetting formations may be dominant. To validate the Piper diagram results, subsurface core was analyzed for residual salts. Thin sections, XRD and chemical analysis was conducted on two core intervals spaced approximately 80 ft apart to determine which type of salt was found in place. Ultimately the authors also selected sections of the core which appeared to show layers of salt. Comparison of the analysis of scrapings from the salt layers along with samples from the bulk core around the salt layers
suggested that the salt was consistent with natural autochthonous salt obtained along bedding planes. Despite the findings of the study, the authors were unable to completely rule out mixing or direct inflow from the Oriskany aquifer as a source of high flowback salinity. Of note Haluszczak et al. (2013) hypothesized that these salt layers may have been a result of precipitation upon extracting the core from the well. Further Barbot et al. (2013) pointed out that no other studies in the Marcellus Shale had reported salt layers which may support the hypodissertation of Haluszczak et al. (2013) or salt layers may be isolated to certain parts of the formation. With the absence in Br data presented in the paper it is difficult to evaluate potential halite contribution (Rowan et al., 2015).

Josh et al. (2012) conducted a study, in which samples were analyzed for quantitative mineralogy using XRD and XRF, for clay chemical reactivity via cation exchange capacity (CEC) and for grain size using centrifugation, as well as a variety of other tests to determine the quality of a shale for potential to be a shale gas resource. Of particular interest to this study, which has not been investigated by other authors for the purpose of flowback salinity, is CEC (i.e. clay-mineral leaching – Keller and Da-Costa, 1989) with clay minerals. The CEC is related to the mobile ions liberated onto the clay mineral surface and can severely impact the ion-transfer rate (Zolfaghari et al., 2016). CEC tends to be higher in swelling-prone clays such as smectite and can have a significant impact on flowback water composition and the overall salinity response in time.

Ghanbari et al. (2013) conducted an experimentally-based study in an attempt to explain the cause of wells with low initial water production and high initial gas production and those with high initial water production and low initial gas production. The study was conducted on the three members of the Horn River Basin Shale. They attributed the distinction to imbibition
results measured in the lab as well as possible fracture patterns. The study also attempted to explain the increase in *Flowback Salinity vs. Time* using diffusion data measured in the lab combined with fracture complexity and alteration of the samples when brought in contact with fresh water, as modeled by Zolfaghari et al. (2016). In this study, deionized water was used for both measurement of imbibition rate and to measure the change in conductivity as well as different ion quantities with time. In the final phase of the study, the inductively coupled plasma (ICP) method was used to detect and quantify dissolved ions in water. The authors also used a correlation between barium concentration in time as an indicator that ion transfer was coming from the matrix as barium is absent in all surface fluids. XRD analysis suggested that there was no barium in the bulk shale samples, leaving the only source of barium to be salt precipitated in natural fractures. Based on this observation, the authors conclude that barium content in flowback water is positively correlated with fracture complexity. In the same study, the authors also investigated the impact of exposure of samples to deionized water and concluded that bringing the two in contact induced microfractures in the core and led to disintegration. The authors attributed this phenomenon to the clay content in the shale samples. To conduct their ion diffusion tests, the authors measured observed water conductivity and attributed this change to ion transfer from the matrix to the fractures. The authors also stated that advection and diffusion are the main controls on ion transfer out of the matrix, where advection is pressure-dependant and diffusion is concentration gradient-dependant. In their experimental studies, water flow was slow and in the opposite direction of ion transport and therefore ion transport was attributed primarily to diffusion. Diffusion is highly dependent on porosity (tortuosity) where higher porosity leads to higher values of diffusion coefficient as a result of lower tortuosity and a decrease in surface interactions. Two out of the three shale members demonstrated a single
straight-line relationship starting from the origin on plots of Conductivity and Imbibed Volume/Surface Area vs. Square Root of Time. This straight-line relationship suggests that the transport process can be described by a one-dimensional linear diffusion equation. The third member showed two straight-line relationships, the first being steeper, which was attributed to faster imbibition/diffusion through the higher permeability micro-fractures, and the second having a shallower slope, interpreted as imbibition/diffusion through the tight matrix once the microfractures were filled with water. These observations support the hypodissertation that the effective diffusion coefficient is higher through more permeable microfractures than through the tight matrix as would be as expected. This work was expanded upon by Ghanbari and Dehghanpour (2015) who investigated the impact of imbibition and diffusion both parallel and perpendicular to bedding as well as under confinement. From their results, the authors concluded that imbibition and diffusion rate were significantly higher parallel to bedding than perpendicular to bedding. Further, confinement led to greater reductions in imbibition rate and diffusion rate parallel to bedding rather than perpendicular to bedding. The observed results varied greatly from shale member to shale member. These results are particularly important in highly heterogeneous laminated formations such as most shales and suggest that both imbibition and diffusion are dominated by the direction parallel to bedding. These impacts would be less significant in more homogenous rocks such as sands and siltstones.

Haluszczak et al. (2013) conducted a geochemical evaluation of flowback brine from Marcellus Shale gas wells in Pennsylvania. The authors used several ion cross-plots and other basic observations to conclude that 1) high salinity late-stage flowback water did not occur primarily due to dissolution; 2) the chemistry of late-stage flowback water was similar to that produced from conventional oil and gas wells tapping permeable formations ranging in age from
Ordovician to Devonian; 3) the Cl-Br relation indicated that late flowback waters developed from highly saline brine evaporated from salt water into the stage of halite dissolution, and then diluted and mixed with seawater, freshwater and injected fluid; 4) late stage flowback water contains high quantities of radium and barium and therefore unhealthy levels may appear in drinking water without proper disposal.

A similar study conducted by Barbot et al. (2013), also for the Marcellus Shale, produced some notably different results. Although the Cl-Br relationship shows a similar trend to that demonstrated by Haluszczak et al. (2013), other cross-plots and temporally-dependent data demonstrate that other mechanisms are likely at play, particularly in the early-stages of well flowback. The authors hypothesize that this may be related to the quality of the fracturing fluid and/or chemical reactions occurring with the formation.

Another geochemistry and isotope-based study was conducted on the Marcellus Shale by Rowan et al. (2015), although this study is more focused on the source of long-term produced solutes rather than being restricted to the flowback period. The δ¹⁸O values and relationships between Na, Cl and Br suggest that once composition has stabilized, produced water is natural formation water, the salinity of which originated primarily from seawater concentrated by evaporation. The fairly rapid transition from injected water to chemically and isotopically distinct water, while recovering <50% of load fluid, suggests that significant load fluid is lost to the formation through imbibition. Again this study varies from that of Haluszczak et al. (2013) by looking at multiple samples collected from each well throughout the well life. The origin of salts produced over the long-term (>~1year) is not well agreed upon. The study of Blauch et al. (2009) suggests that the primary source is halite dissolution, while other studies such as that by Haluszczak et al. (2013) and Barbot et al. (2013), suggest that the increase in longer-term
flowback salt results primarily from mixing with formation brines. An additional study by Striolo et al. (2012) suggests that the source of long-term salt production comes from injected fluid mobilizing ions adsorbed onto clay minerals. Many authors including Englander (2012a,b) and Striolo et al., (2012) suggest that the majority of water stored in the Marcellus Shale is immobile and believe that produced water is in fact coming from overlying and underlying formations. Ratios of radiogenic isotopes, such as $^{228}\text{Ra}/^{226}\text{Ra}$ investigated by Rowan et al. (2015), and $^{87}\text{Sr}/^{86}\text{Sr}$ (Chapman et al., 2012; Capo et al., 2014), help to identify a relatively narrow band corresponding to water produced from the Marcellus Shale versus adjacent formations, and can be used to rule out contributions of adjacent formations. Simple observation of salinity and key ions including Na, Cl and Br from three wells suggest that these components tend to increase for at least 200 days before beginning to stabilize. Considering ratios of these ions has allowed investigators to differentiate between formation water salinity resulting from evaporative concentration of seawater past the threshold of halite saturation and onset of precipitation or alternatively from the dissolution of halite. As seawater evaporates, halite precipitation removes Na and Cl ions in a 1:1 mole ratio, allowing Na and Cl concentrations to remain at the halite solubility threshold until nearly complete evaporation. Alternatively, Br is almost entirely excluded from the lattice of halite and other mineral phases allowing it to become increasingly concentrated with time. As a result, brines formed from halite dissolution tend to be very low in Br, whereas evaporated seawater is enriched in Br (Stroesell and Carpenter, 1986; McGaffrey et al., 1987; Walter et al., 1990). Halite dissolution yields Na/Br and Cl/Br ratios that increase along the same trend away from seawater, and therefore where samples plot compared to this trend can act as an indicator as to whether salinity is derived from seawater evaporation, halite dissolution or another unrelated source. Studies by those such as Sanders (1991) found no
viable alternative to increasing Br concentration other than seawater evaporation. Oxygen and hydrogen isotopes provide a secondary indicator of seawater evaporation as the heavier isotopes $^{18}$O and $^2$H are progressively concentrated in residual brine. Beyond a certain point when TDS exceeds ~ 4 times seawater values this trend is reversed (Sofer and Gat, 1972, 1975; Holser, 1979; Kharaka and Hanor, 2007). From the late time grab samples collected later in the well lives the majority of data fell along the seawater evaporation trend, while in the time-series samples a shift in ratios with time suggested that early samples were primarily fracture fluid returned to the well and approached formation water composition over time. These results suggest that concentration of formation brine is primarily attributed to seawater evaporation and mixing with a more dilute fluid. Further, samples were enriched in Ca and depleted in Mg, which is consistent with brines derived by evaporation of seawater which has been altered by commonly occurring diagenetic reactions. Next, considering the isotope data gathered, a rapid initial increase in TDS and $\delta^{18}$O suggests a mixing trend is the dominant mechanism for producing high salinity water. Further, due to the rate of increase, it further suggests that imbibition is occurring to remove injected water from the fractures and the high capillary pressure of small pores makes it difficult for this water to be released as reservoir pressure depletes with production. Isotope enrichment to the observed extent of time cannot be attributed to rock-water interactions (specifically halite dissolution) at reported reservoir temperatures. Subsequent, more gradual shifts, are interpreted to be continued mixing. Grab samples collected over a longer period of time demonstrate a different trend suggesting that other mechanisms may be coming into play over time. In this study, the ratio of $^{228}$Ra/$^{226}$Ra was also used as an indicator that Marcellus produced water is significantly different than water in adjacent zones. Without long-term water production history showing cumulative produced water exceeding
injected water it is difficult to conclude whether there is mobile formation water or not in the Marcellus. The authors suggest that any formation water contribution is likely coming from the pre-existing natural fracture network if present.

Zolfaghari et al. (2015b) conducted a study, which builds upon the study of Zolfaghari et al. (2014, 2015a) investigating the interplay of shale-water interactions, to evaluate the source of ions and factors controlling flowback water chemistry in the Horn River Basin Shales. In this study, the intact water samples are tested over the flowback period for their electrical conductivity, total salt concentration, pH, dissolved oxygen and individual ion concentrations. The intact water samples were also digested in acid and analyzed for ions to account for precipitated salts. Furthermore, XRD was used to characterize rock composition and two extraction methods were used to characterize the nature of the leachable ions in the shale rock samples including acid digestion and sequential ion-extraction. From analysis of the undigested samples, the electrical conductivity and mass of flowback salts (after evaporation) for wells in each of the three shale formations in the Horn River Basin were measured over time. Interestingly the Muskwa and Otter Park water samples showed similar behaviour where conductivity and concentration first increased before reaching a plateau, while the Evie samples showed a continuous increase of both measurements throughout the flowback period. Individual ion concentrations for Na\(^{+}\), K\(^{+}\), Ca\(^{2+}\) and Ba\(^{2+}\) were also measured over time for both the intact and acid-digested water samples. Due to the presence of precipitated salts, the acid-digested samples consistently had a higher concentration, although both sets of concentrations generally increased over time for all cations. The concentrations of each cation were then compared between each of the three formations over time. The ratios for each of the formations were vastly different, although it was commonly observed that the concentration of monovalent ions
(Na$^+$ and K$^+$) remained relatively constant over time, while the divalent ions (Ca$^{2+}$ and Ba$^{2+}$) fluctuated more in time. Further, the ion concentrations for the divalent ions were higher than those of the monovalent ions, which may be due to the surface charge density of these ions. The increased charge density also increased the chance of creating complex ions and precipitate in the intact flowback water, leading to higher ion ratios between the intact and digested samples. XRD was then conducted on the rock samples, which identified very different compositions with the Otter Park samples having a quartz content more than double that of the Evie samples, while the clay content in the Otter Park samples was approximately one third that of the Evie samples. Of significance, no barium was identified in the samples. In order to determine the ability of deionized water to leach minerals out of the rock samples acid digestion was conducted in both fresh and washed samples. Concentrations of the main mono and divalent cations in the shale samples for both the Otter Park and Evie were determined to allow comparison with the water samples. As suggested by Essington (2005) the monovalent ions were easier to leach out of the shale samples than the divalent cations, again associated with their surface charge density and its impact on selectivity for the negatively charged clay surface. The results of the produced water testing were found to be counter-intuitive with rock mineral testing with Na$^+$ being the dominant ion found in water samples, while K$^+$ was the dominant ion found in rock samples. As a result of the discrepancy, sequential ion-extraction was conducted to determine how easily each of the major cations could be detached from the shale samples. It was determined that the monovalent ions were most loosely attached which could be the cause of K$^+$ being the dominant cation in shale samples, while Na$^+$ is the dominant cation in flowback water with Na$^+$ being the more easily detachable ion of the two. In-situ formation brine and dissolution of precipitated salts are another potential source of these dominant ions (Haluszczak et al., 2013, Zolfaghari et al., 2014).
Dissolution may be enhanced over time as increased mineral concentration in the fracture fluid decreases the activity coefficient of ions by increasing the ionic strength of flowback water.

1.2.2.2 Flowback Field Results

Bearinger (2013) proposed a theoretical model based on field evidence which considered multiple mechanisms involving the interaction of the injected fracture fluid with reservoir rock and formation fluid. The model suggests that a different chemical signature can be expected for wells containing only induced hydraulic fractures than those that contain a stimulated natural fracture network, where fractures are open prior to stimulation and contain connate water and reservoir fluid. The paper is focused on the Horn River Basin, but also shows some results from the Eagle Ford Shale. The author attributes the increase in salinity during flowback to three main processes: 1) solid dissolution (ex. halite); 2) mixing with connate water; and 3) ion diffusion and exchange/leaching from pore water to fracture water. In formations containing large quantities of halite and sylvite, like some areas of the Marcellus Shale, dissolution can lead to the liberation of large quantities of highly soluble compounds such as NaCl and KCl to create an abundance of sodium, potassium and chloride ions in produced water (Blauch et al., 2009). In the absence of precipitated salts, other processes control the increase in salinity. In reservoirs lacking natural fractures, exposure to connate water will be minimal and confined to contact with the matrix pores which typically make up less than 5% of the fracture surface (freshly broken rock will not be coated with connate water), while in open natural fractures the area coated with connate water may be in excess of 75%. Due to the lack of mobile water in most shales (caused by low relative permeability and other factors), ion diffusion tends to be the dominant process for ion accumulation from connate water. The slope of the rise in salinity is controlled by contact
with connate water and hydraulic fracture aperture. Ultimately produced water will approach connate water composition (although lower) and a salinity plateau will be achieved which depends on the bulk volume of connate water, stimulated natural fracture aperture which impacts pore water mixing and diffusion from the matrix to the fractures. It was also proposed that with continued production of gas and diminishing production of injected water, water of condensation would ultimately begin to dilute the flowback water concentration, although this has not been demonstrated with field data. Examples from the Evie and Muskwa Shale members were presented and showed that salinity first increases rapidly and then continues to increase at a reduced slope on a plot of Salinity vs. Cumulative Water Production. The examples also demonstrate significantly different signatures for the two shale members. The mechanisms controlling flowback salinity can be inferred by looking at ion ratios. For example: 1) dissolution favours highly soluble NaCl and KCl; 2) diffusion moves sodium and potassium ions faster than calcium and magnesium ions; 3) formation clay and permeability (cation exchange); 4) mixing is driven by connate water composition and contact; 5) surface area to volume ratio (significantly higher for natural fractures) and; 6) cation exchange of illite and other clays. The author presents plots of both Salinity and Chloride Ions vs. Cumulative Water Produced and Ca/Na vs. Cumulative Water Produced for both the Evie and Muskwa members. In both shales, the overall salinity and Ca/Na ratio increases quickly followed by a transition to a more gradual increase. The author attributes the change in slope in the two plots to initial flowback water being produced primarily from propped hydraulic fractures, while the remainder is recovered primarily from stimulated natural fractures similar to the study by Ghanbari et al. (2013) discussed above. Further, over time pressure in the fracture network decreases leading to precipitation of calcium carbonate in the casing or fracture network which would contribute to the decrease in slope.
Step reductions in tracer returns at the same cumulative water production point as the inflection point on the salinity and Ca/Na plots discussed above suggest greater contact with connate water and diffusion into the rock matrix. As a result of the lack of produced water from most shale formations, conventional measurements of ion concentrations in connate water is relatively unknown and therefore stable isotopes on hydrogen and oxygen were used. Unfortunately isotope values were not measured on the injected water and are unknown in the connate water. Some reasonable end points for the injected water were taken from two surface water studies conducted in the area by Gibson et al., (1993) and Bell et al., (2002), while it was assumed that the connate water should be close to the Devonian seawater modified by water released from mineral transformations which were taken from Rostron et al. (2000). Both the Evie and Muskwa members fall along mixing lines with the potential end members suggesting an increase in contribution of connate water over time. The work conducted by Bearinger suggests that transport coefficients are likely time-dependant.

1.2.2.3 Flowback Salinity Models

In recent years several models have been developed for varying purposes and of varying complexity. Some of these models are simple analytical models which treat salt as a single component, while others use complex numerical methods to match individual ions.

Gdanski et al. (2007) developed a numerical flow model to match water and hydrocarbon production during the flowback period and added a chemistry layer to the model to trace the movement of ions such as sodium, potassium, chloride, sulphate, etc. during both shut-in and production. Prior to dealing with the composition problem, an adequate match to water and hydrocarbon is required. The ionic composition of the flowback water can then be matched by
adjusting various parameters that may affect how water is recovered from the reservoir. Flow and salinity modeling yields information about relative permeability curves, capillary pressure curves and some fracture structure details (specifically what percentage of the fracture is productive).

Gdanski et al. (2010) improved upon the simulator constructed by Gdanski et al. (2007). In addition to improvements to the simulator, microseismic, DFIT and post-fracture pressure-transient analysis (PTA) analysis were also used to further constrain the solution. From microseismic, created fracture height and length were estimated. From DFIT analysis, the authors were able to estimate formation pressure and permeability. With the PTA analysis of a very short 16 hour build-up test, the authors were able to develop a “line of solutions” on a log-log plot of $k_g \phi_g \Delta P^2$ vs. $x_f$ using an expression originally developed by Cinco (1982) for an infinite acting conductive fracture, where $k_g$ is reservoir permeability to gas, $\phi_g$ is gas filled porosity, $\Delta P$ is average drawdown pressure and $x_f$ is fracture half-length) which could be used to constrain the variability in key fracture and reservoir parameters. Their combination of flow and compositional analysis of flowback fluid also yielded a similar “line of solutions”. The authors also developed a method using ion dilution ratios to determine what percentage of the produced water was fracture water for use in formations with mobile water. This method also helped to constrain fracture half-length since multiple PTA analysis methods suggested an infinite conductivity fracture. Ultimately the authors concluded that flow analysis on its own was not sufficient to determine key fracture properties and that compositional matching as well as a variety of other techniques were required to constrain the solution. A similar approach was also used by Vazquez et al. (2013) for determining formation properties between an injector and a producer well.
Fakcharoenphol et al. (2013) and Fakcharoenphol et al. (2014) developed similar flow and transport models for predicting water and hydrocarbon rates as well as salt concentration of produced water. Fakcharoenphol et al. (2013) derived a triple porosity model for application to shale gas reservoirs where there was a fracture component, an organic component and an inorganic component, while Fakcharoenphol et al. (2014) developed a similar dual porosity model for shale oil wells. The mathematical models include osmotic pressure, gravity and capillary effects, with osmotic pressure being a key addition over other simulators and assumes that high-clay shale sediments act as a semi-permeable membrane with low membrane efficiency. The triple porosity shale gas model is essentially a more advanced version of the dual porosity shale oil model with additional connections with the additional porosity system. For the purpose of this discussion, the focus will be on the salinity component of the dual porosity shale oil model. The matrix and fractures are modeled separately as with other dual porosity models. In the matrix, accumulation is equal to the combination of salt transport from the matrix to the fractures via advection (pressure diffusion and osmosis) and pseudo steady-state diffusion where the effective diffusion coefficient is dependent on membrane efficiency. In the fractures, salt is transported by both advection and transient diffusion. There are also source terms associated with transport of salt out of the matrix by advection and diffusion and a sink term that could correspond to production to the well. These terms are then combined to yield an equation for salt accumulation in the fractures. In the tight oil paper, the authors assume constant water salinity in the fractures and use the model to demonstrate how osmotic pressure can lead to enhanced oil production. Alternatively, different boundary conditions could be used to predict salinity of produced water as was done in the shale gas paper.
Vazquez et al. (2014) conducted a study in which a numerical flow and reactive transport model were used to attempt to identify the source of high salinity in flowback water with the main two mechanisms being the dissolution of salts and the breaching of deep saline aquifers through fracturing. In the model, fracture fluid was injected into an open hydraulic fracture at which point it was transported through the fracture and brought in contact with the matrix allowing a number of geochemical reactions to occur, namely dissolution of sulphate and carbonate minerals and multi-component competitive ion exchange, followed by production back to the well. The study considered four wells from the Permian Basin. Because flowback rates were not available, ion concentrations were compared against Cl, since Cl is thought to not be a very reactive ion and therefore can be treated as a conservative ion. Cross plots of Na, Mg, Ca, SO₄ and Cl suggest that Na follows a perfect mixing line, while Mg and Ca follow a reasonably linear trend although may be influenced by other mechanisms, whereas SO₄ tends to be far more nonlinear suggesting other mechanisms are dominant. Based on the observed flowback compositions, in-situ brine composition was estimated and then refined during history-matching. History-matching of the four wells suggested that Na, Mg and Ca could reasonably be matched by only considering mixing, whereas dissolution was required to history match SO₄. Overall the study concluded that a combination of both dissolution and mixing were required to accurately match flowback composition.

Merry et al. (2015) developed a material balance model based on the dissolution of salt from salt-sealed natural fractures which have been observed in multiple shale plays including the Haynesville, Marcellus and Horn River Basin. The model was designed to mimic the behaviour of the salt-sealed fracture porosity, shale matrix porosity and fracture pore volume dissolved by leaked off fracture fluid during the fracture stimulation, soaking period, flowback and long-term
online production. The authors hypothesized that the phenomena often attributed to stress-dependant permeability, which leads to a significantly shorter than expected apparent transient flow period, may in fact be due to (at least in part) the vaporization of salt-saturated residual water leading to the deposition of salt crystals. The model is developed to be applicable to any formation that has a dissolvable mineral volume, measurable salt concentration in flowback water, inferred distribution of minerals in the formation and an inferred fracture geometry (or SRV). The model assumes that salinity of the secondary fractures increases over time due to the dissolution of minerals in the secondary fractures, while the salinity of the primary fractures increase due to diffusion from the secondary fractures. The model can ultimately be used to determine the total area contacted by the fractures and load fluid recovered solely by displacement from formation gas and ultimate load fluid recovery which would include both displaced water and water produced as water vapour due to gas production. Empirical evidence was provided to rationalize the displacement and vaporization flow-regimes similar to what was shown by Zhang and Ehlig-Economides (2014). One drawback of the model is that it is only applicable to formations with salt-sealed natural fractures and assumes that total fracture area (propped + secondary fractures) remains constant in time which likely leads to an over-estimate of the actual results due to fracture closure with drawdown.

Balashov et al. (2016) developed a transient multi-component diffusion model based on the assumption that salt components diffused from in-situ brine (capillary-bound or free) into 1 mm wide hydraulic fractures spaced at one per meter which are initially filled with low salinity fracturing fluid. The model is designed to predict flowback salinity and individual ions to better prepare for water recycling and disposal efforts and focuses specifically on the Marcellus Shale, although could likely be applied to other similar shale formations. The model is derived under
the assumption that transport is significantly faster in the fractures than in the matrix and therefore concentration of fracture water is spatially constant in the fractures and therefore the problem of interest is the transient diffusion out of a planar porous sheet into a stirred solution of limited volume. Mathematically this is equivalent to the problem of diffusion out of a stirred solution of limited volume into a planar sheet (Crank, 1980). In the model the boundary condition at the hydraulic fracture is derived by conducting a mass balance on fluid leaving the fracture. The authors also conducted a mass balance to determine what percentage of salt accessed by a given well needed to be mobilized to yield the mass of produced salt. For their calculations they assumed that the bulk rock matrix was 2% saturated with capillary-bound or free brine (estimated from porosity and water saturation from petrophysical analysis) at an initial concentration determined from the calibrated model. From this calculation it was determined that only 0.1-0.2% of the salt in the initial brine accessed needed to be mobilized to explain the level of salt production at the surface. Simulation runs with the model suggested that it took approximately one year for salt concentration to reach 90-95% of its steady-state value. The model was used to successfully model total dissolved solids (TDS) from several Marcellus Shale wells.

Zofaghari et al. (2016) developed two methods for determining fracture aperture size distribution in the form of a PDF using basic salinity measurements. The premise of their models are that early low salinity water production comes from the large aperture primary fractures, while later in the flowback period higher salinity water is produced primarily from the smaller aperture secondary fractures. Unlike primary fractures, the secondary fractures have associated connate water which can readily mix with fracture water and a larger surface area-to-volume ratio leading to a higher salinity (Ghanbari et al., 2013). Each of the two methods
developed by the authors assume the formation of a network of slit-shaped fractures and assume that salt is transported from the matrix to the fractures and that this transport can be described by Fick’s first law of diffusion. Further, the models assume that concentration in the \( i \)th fracture can be considered negligible compared to the matrix concentration throughout the flowback period, that matrix concentration is constant (matrix acts as an infinite salt source during the relatively short flowback period), and that inflow from the matrix and that total fracture volume is known. The two developed methods assume that a plot of \( \text{Salt Concentration vs. Cumulative Produced Water} \) can be interpreted as a basis for the CDF of fracture aperture size under the assumption that total fracture volume is known. The derivative of the CDF then yields the PDF which can be interpreted as a fracture aperture size distribution. The first approach gives the volumetric fraction as a PDF of fracture aperture, while the second method considers a bundle of fractures in series to derive the PDF. The two methods yield PDF’s of a similar form, although the results between the two are quite variable. Based on the results presented by the authors, this variability becomes more significant with greater fracture complexity. The results are also highly dependent on the diffusion coefficient as well as the effective distance from which salt is sourced from the matrix to the fractures. The biggest limitations of the models are that they assume that salt is sourced purely by diffusion and that all other mechanisms (i.e. mixing of fracture water with formation water, dissolution and cation exchange) are accounted for in the selection of the diffusion coefficient and matrix concentration. Further, the model assumes a constant diffusion coefficient for a single component, although in reality the produced flowback water contains multiple ions which have different diffusion coefficients and whose concentrations can be impacted by different mechanisms (i.e. clay mineral leaching and cation-exchange capacity). As the authors point out, the model could be improved by accounting for individual ions and the
mechanisms which impact their produced concentration. Such an analysis would require a far more complex model, like that presented by Gdanski et al. (2010).

Seales et al. (2016) coupled an ion-transport and halite-dissolution model with a fully-implicit dual-porosity numerical simulator to investigate the excess solutes often found in flowback water and to predict the concentrations of sodium and chloride ions in produced brine. A series of sensitivities were conducted, although the model was not used to match or extract properties from field data. The results of this analysis concluded that mixing alone between injected fracture water and highly-concentrated in-situ brine could not describe that rapid increase in water salinity during flowback, and therefore, it was assumed that mineral dissolution must play an important role in flowback water salinity. The study concluded that ~ 6 times as many ions could be sourced from dissolution than mixing alone. The study also concluded that halite-dissolution was impacted by temperature, but not to an extent that it would significantly impact the amount of sodium and chloride detected at the wellhead. The authors concluded that reactions other than halite-dissolution were likely occurring within the formation, although these were not modelled. The authors ruled out diffusion of dissolved ions as a major source of salinity because high permeability fractures are the main conduit for flow in shale gas reservoirs and velocity in these fractures tends to be high and therefore this mechanism was not incorporated in the model. This assumption relies on pervasive natural or created secondary fracturing in the reservoir, which is not the case with all reservoirs, especially some sand and siltstone reservoirs.
1.2.2.4 Summary of Existing Methods for Flow-Based Analysis

In summary, in addition to flow-modeling some authors have recognized the wealth of information which can be gathered from the salinity response of water produced during the flowback period. Three main areas of research have been investigated: 1) laboratory studies to infer the mechanisms for increasing produced water salinity; 2) field studies to infer mechanisms for increasing produced water salinity; and 3) modeling the salinity response of produced water in attempt to extract key reservoir and fracture parameters. The findings from both laboratory and field studies have been used to generate models to predict the salinity response of produced water. A brief summary of the studies discussed in detail above and some of their key deficiencies is provided below:

- The majority of work conducted has been on shale gas reservoirs. These reservoirs are unique from a salinity perspective due to the presence of clays and other components of the shale matrix which lead to unique rock-water interactions not present in many other unconventional reservoirs. Further, vaporization of formation water as a result of gas, rather than liquids-rich reservoir fluids, may also contribute to the enhanced rock-water interactions seen in these reservoirs,

- A variety of laboratory techniques have been applied including imbibition and diffusion studies, ion analysis, isotope analysis, thin sections, XRD and XRF.

- Field studies have been used primarily to upscale and support findings from laboratory experiments.

- Six potential sources of salinity in flowback water have been identified including dissolution of autochthonous and allochthonous, encroachment of brine from adjacent formations or production is formation water, mobilization or solubilisation of hypersaline
connate water, mixing of injected water and formation water and cation exchange/leaching from the surface of clay minerals. The mechanisms controlling produced water salinity vary significantly from formation to formation depending on matrix composition.

- The flowback models presented in the literature have varied greatly in complexity with some studies considering salt as a single component and some going further to consider individual salt ions.

- Many of the models developed have been designed to act as stand-alone analysis techniques only considering the salinity response including studies focus on steady-state diffusion, transient diffusion and material balance methods focusing on shales with salt sealed natural fractures. In many cases these models would benefit from being coupled with fluid flow analysis as a complimentary technique.

- The most comprehensive models presented in the literature were conducted by Gdanski and his co-authors which coupled flow and geochemical simulation in order to simultaneously history-match fluid flow and individual ion production. Although these models are comprehensive, they also rely on numerical simulation which can be incredibly time-consuming when attempting to history-match both flow and ion data particularly if many wells need to be analyzed.

**1.2.3 Other Relevant Literature**

There has been a wide variety of studies that have primarily used numerical simulation to investigate factors impacting load fluid recovery and the impact of various parameters such as capillary pressure, drawdown and shut-in period on load fluid and hydrocarbon recovery.
Although these studies provided some interesting insights when developing the models discussed in this dissertation, they are not directly relevant and therefore will not be reviewed in detail. Readers are directed to the following papers for detailed investigations into parameters affecting load fluid recovery and both early-time and long-term hydrocarbon production. Relevant references include Gdanski et al. (2006), Wang (2008), Gdanski and Walters (2010), Cheng (2012), Agarwal and Sharma (2013), Bertoncello et al. (2014), Fakcharoenphol et al. (2014), Deen et al. (2015), Zanganeh et al. (2015) and Kim et al. (2016). Although this list is not comprehensive, it guides the reader to many relevant references on these topics.

1.3 Objectives

From this literature review it can be seen that quantitative flowback analysis is quickly gaining popularity as an early-time fracture characterization method, which is being followed closely by industry as operators look for new methods to estimate key fracture properties particularly early in the well life. It can also be seen that many approaches have been taken by different authors suggesting that this is a new field with a critical need for ongoing research. As a result, this dissertation represents a valuable piece of work from both an academic and industry perspective. The objectives of this research are as follows:

1. Improve upon the methods for flowback analysis which have been presented in the literature.

2. Improve upon the flowback analysis techniques developed by Clarkson and Williams-Kovacs (2013a) and Clarkson et al. (2014) by further constraining models using tools such as fractional flow curves to improve the reliability of the results.
3. Develop new methods and tools for analyzing flowback from shale gas wells to improve upon the physics of the model presented by Clarkson and Williams-Kovacs (2013a).

4. Apply Monte Carlo (MC) simulation and a variety of assisted history-matching techniques (with a focus on evolutionary algorithms) to aid in quantifying the uncertainty in key fracture parameters and also determining the optimal parameters for history-matching the available production data.

5. Expand upon the LTO flowback analysis tool (FLOAT) developed by Clarkson and Williams-Kovacs (2013b) for application to more complex scenarios such as stage-by-stage, multi-well and multi-layer flowback.

6. Present several additional LTO case studies which focus on the economic impact of conducting quantitative flowback analysis, investigate different fracture shape assumptions and develop new methods for analyzing flowback from LTO wells stimulated with an oil-based fracture fluid.

7. Develop a salinity model to match the increasing flowback water salinity commonly observed in order to confirm the results of flow analysis during the flowback period. This model could also be applied in the absence of flow modeling to estimate fracture surface area assuming that enough of the mass transport parameters can be estimated from laboratory experiments.

1.4 Organization of Dissertation

This dissertation is divided into eight chapters which largely follow the seven objectives outlined above,
Chapter One provides a brief introduction to unconventional resources, followed by an overview of the problem description, a detailed literature review and description of the objectives of the dissertation.

Chapter Two describes the conceptual models used in this work as well as an overview of the basic modifications which were made to the tools developed by Clarkson and Williams-Kovacs (2013a) for shale gas wells, and by Clarkson et al. (2014) for LTO wells. A summary of the tool originally developed for analyzing LTO flowback will be presented as this framework presents the basis of both the LTO model used in this dissertation and the shale gas model developed in Chapter Three.

Chapter Three presents a new model for analyzing flowback from dry shale gas wells. This new model includes concepts which were applied by Clarkson and Williams-Kovacs (2013a) and Clarkson et al. (2014) as well as several extensions to improve upon the physics of the flowback problem.

Chapter Four discusses the application of MC simulation and assisted history-matching algorithms to assist in quantifying the uncertainty associated with key fracture parameters and seeking optimal values of the key history-match parameters.

Chapter Five describes the modifications which have been made to the tool developed by Clarkson and Williams-Kovacs (2013b) to account for more complex flowback problems including stage-by-stage, multi-well and multi-layer scenarios with case studies being presented for all three of these scenarios.

Chapter Six demonstrates several additional LTO case studies, each of which is unique. The four case studies demonstrated present the economic advantage of conducting quantitative flowback analysis, the impact of assumed fracture shape on estimated fracture parameters, an
extension of the LTO flowback tool for analyzing wells completed with an oil-based fracture fluid and numerical validation of the modeled flow-regime.

Chapter Seven describes the development and application of a salinity model which can be used to confirm fracture surface area and volume determined from the flow model and can either be used in unison with the flow models for parameter confirmation or as a free standing tool for estimating fracture surface area and volume if enough of the key mass transfer parameters can be accurately estimated from laboratory or field data.

Chapter Eight presents key conclusions and recommendations for future work.
Chapter Two: Conceptual Model and Analysis Procedure

2.1 Conceptual Model

For flowback, hydraulic fractures are conceptualized as tanks of varying shape and geometry. A diagram of this conceptual model showing a circular fracture shape with four different fracture geometries is shown below in Fig. 2.1, while the same conceptual models are presented for a rectangular fracture shape in Fig. 2.2. Elliptical shaped fractures have also been considered as in Williams-Kovacs and Clarkson (2013a), although this will not be shown here. In this diagram the well is assumed to be hydraulically fractured in multiple stages, with multiple perforation clusters per stage. The same geometries can also be induced using different completion techniques (i.e. open-hole ball-drop systems) as in Williams-Kovacs and Clarkson (2013b). The following are possible fracture geometries seen in multi-fractured horizontal wells (illustrated in Fig. 2.1 and 2.2):

1. Single discrete bi-wing planar fracture developing from each fracture stage (high permeability/high porosity fractures).
2. Single discrete bi-wing planar fracture developing from each perforation cluster (high permeability/high porosity fractures).
3. Complex fracture network developing from each perforation cluster (low permeability/low porosity fractures).
4. Complex fracture network developing along entire horizontal wellbore (low permeability/low porosity fractures).
Fracture geometry can be selected based on evidence provided by microseismic data, advanced hydraulic fracture modeling, knowledge of historical fracture performance in the area, evaluator experience, or by a trial and error process. Microseismic is the only method which provides a direct demonstration of fracture geometry without requiring any assumptions.

Initially Clarkson and Williams-Kovacs (2013a) only considered scenario three for analyzing shale gas flowback data. In this scenario, a complex fracture network consisting of a primary fracture network and a secondary fracture network is formed. It is further assumed that the primary fracture network contains proppant and mobile water while the secondary fracture network contains no proppant, immobile water and gas. A similar conceptual model was used by Fan et al. (2010) to explain low load fluid recoveries in the Haynesville Shale. This model was most applicable to shale gas wells at the time when stage spacing was relatively large such that the complex fracture networks from each stage were unlikely to overlap. As industry has continued to down space stages, scenario four has become a more realistic outcome, which could also occur from hydraulic fracturing in naturally fractured reservoirs.

As research progressed into assessing flowback from tight sand and siltstone reservoirs, with a focus on LTO, scenario one and two were also added to the models because planar fracture geometries were interpreted from microseismic for those reservoir types.
Hydraulic Fracture Geometry Models – Circular Fractures

Geometry #1: Single Discrete Bi-Wing Fracture Developing From Each Stage

Geometry #2: Single Discrete Bi-Wing Fracture Developing From Each Perf Cluster

Geometry #3: Complex Fracture Network Developing From Each Perf Cluster

Geometry #4: Complex Fracture Network Developing Along Entire Horizontal Wellbore
Fig. 2.1 — Conceptual model of fracture geometries (assuming circular fracture shape) used in flowback modeling. Scenario 1 and 2 represent cases corresponding to the formation of simple bi-wing planar fractures, while Scenario 3 and 4 represent cases corresponding to the formation of a complex fracture network consisting of a primary fracture zone and secondary (induced or reactivated) fracture zone. Modified from Williams-Kovacs and Clarkson (2013a).

Hydraulic Fracture Geometry Models – Circular Fractures

Geometry #1: Single Discrete Bi-Wing Fracture Developing From Each Stage

Geometry #2: Single Discrete Bi-Wing Fracture Developing From Each Perf Cluster

Geometry #3: Complex Fracture Network Developing From Each Perf Cluster
Fig. 2.2 — Conceptual model of fracture geometries (assuming rectangular fracture shape) used in flowback modeling. A half-element of symmetry is shown (with plane of symmetry parallel to the horizontal well in the vertical plane). Modified from Williams-Kovacs and Clarkson (2013a).

Note that for flowback Fracture Geometry #1 and #2, fracture width is assumed to be the total width of the planar fractures, whereas in Fracture Geometry #3 and #4 fracture width is assumed to be the width of the perforation clusters and assumes 100% cluster efficiency. The latter can be adjusted if a spinner survey or other method is conducted to determine which perforation clusters are effective or knowledge of typical perf cluster efficiency for the given reservoir is available (i.e. from previous wells in the immediate area). Note that some operators are currently using a geometric well design, meaning that the perforation clusters are evenly spaced along the wellbore. In such cases cluster spacing would be altered in Fig 2.1 and Fig. 2.2 to reflect this design,
2.2 **Sequence of Flow-Regimes Associated with the Conceptual Model**

The initial model developed by Clarkson and Williams-Kovacs (2013a) compared flowback from shale gas wells to long-term production from CBM wells. This was due to the resemblance of data between shale gas flowback and log-term CBM production; in both cases, water starts at peak rate and declines throughout the production period, while gas starts at a low rate, inclines and peaks, followed by a decline period. In most CBM reservoirs gas is typically primarily sourced from desorption. This behaviour is often modeled using a two-phase pseudo steady-state tank model (multi-phase depletion). The application of a series of diagnostic plots developed by Ilk et al. (2010) on a limited flowback dataset suggested that the dominant flow-regime appeared to be multi-phase fracture depletion and therefore a two-phase tank model was the basis of the initial flowback model developed by Clarkson and Williams-Kovacs (2013a). The interpretation of the diagnostic slopes by Ilk et al. (2010) have not been proven mathematically. This would be a useful piece of future work. This model worked relatively well for the cases analyzed although an increased Langmuir Volume \( V_L \) was required to introduce enough gas into the system. This model also did not account for any single-phase fracture fluid production at the onset of the flowback period, which was not observed in the early shale gas wells analyzed. After reviewing the flowback data from a significant number of shale gas, tight gas and LTO wells worldwide, a new conceptual model was developed which is the basis of the work conducted in this dissertation.
2.2.1 LTO Conceptual Model

The conceptual model used in the development of the analytical tools for flowback analysis of tight oil wells is given in Fig. 2.3 and was initially introduced by Clarkson and Williams-Kovacs (2013b) to address the limitations of the initial shale gas model described above. The initial production on flowback is assumed to occur only in the fracture, and consists of just fracturing fluid (BBT); of the two possible flow-regimes (FR 1 and FR 2) observed during this period (Fig. 2.3a-c), fracture depletion (boundary-dominated flow within the fracture while fracture pressure remains elevated above formation pressure) appears to be the most common, as can be identified with the RNP’ plot (Fig. 2.3c). This fracture depletion flow-regime can be used to obtain an estimate of the IFFIP, which combined with fracture porosity and fracture geometry information, can be used to derive a fracture half-length ($x_{f, BBT}$). Although not commonly observed with a high degree of certainty in our experience, with the resolution of data available (maximum of 1 data point every 15 minutes), transient flow in the fractures may be used to derive a first pass estimate of fracture conductivity from the first few data points. With higher data collection frequency it would be more probable to observe this flow-regime, although it may be extremely short, especially with high conductivity fractures. As discussed previously, Wylie and Streeter (1982) suggested this flow-regime may only last 10’s of seconds. Although the primary focus of this work is on circular fractures where the expected transient flow-regime would be radial flow, transient elliptical or linear flow in the fracture may be observed depending on the exact fracture dimensions (i.e. $x_f/h_f$) (Al-Kobaisi et al., 2006). In the presence of ultra-high frequency flowback data (on the order of several data points per minute depending on fracture conductivity) transient flow within the fractures can be observed and this early-time transient flow-regime may be diagnostic and could assist in constraining fracture shape for
analytical modeling. Microseismic and fracture modeling can also provide guidance on fracture shape. As mentioned previously, each of these fracture shapes (and therefore early-time flow-regimes) have been incorporated into the developed tools to allow for better versatility.

After a short period (< 1 day to several days), formation fluids breakthrough to the fracture (Fig. 2.3a,b) and multi-phase flow (fracturing + formation fluids) occurs in the fracture and possibly the formation (ABT). In Fig. 2.3d,e, an undersaturated oil is assumed, with no free-gas liberated in the formation or fracture, so oil is the only hydrocarbon phase flowing in the reservoir. This assumption is accurate when flowing pressure is held above the bubble point which is commonly the case during at least the initial part of the flowback period. Once the flowing pressure drops below the bubble point, gas flow will eventually occur in the formation and fractures, and hence it is possible to have three-phase flow of gas-oil-water, with mixing of fracturing fluids and formation fluids in the fracture. 3-phase flow goes beyond the scope of this work. It is also possible that formation water will flow into the fracture ABT, which is illustrated in Fig. 2.3, although due to the short duration of flowback, and the low permeability of the rock being analyzed, the initial mobile saturation is assumed to stay constant throughout the flowback period. ABT, a coupled flow-regime is observed, which is a combination of transient linear flow from the matrix to the fractures and multi-phase depletion within the fracture network. Note that ABT of hydrocarbons to the fracture, the effective length of the fracture may be reduced ($x_{f,ABT}$), as initially discussed by Crafton (2008) for tight gas reservoirs. The work of Crafton (2008) suggests that the reduction in half-length from the breakthrough of gas may be more significant than that caused by the breakthrough of oil, possibly due to the mobility ratio of the fluids. Note that the reductions in effective half-length discussed are not associated with relative permeability which is rigorously accounted for in the model.
Fig. 2.3 — Illustration of the common flow-regimes observed during flow-back of fracturing fluids from multi-fractured horizontal wells completed in tight oil reservoirs. Flow-regimes in a) (cross-section view of single fracture) and b) (plan view of single fracture) are transient radial (flow-regime, FR 1) and boundary-dominated flow (FR 2) of single-phase fracturing fluid (assumed to be water in this case), which are identified with a rate-normalized pressure derivative (c). These flow-regimes correspond to flow only in the fracture, prior to break-through of formation fluids. The flow-regime in d) (cross-section view of single fracture) and e) (plan view of single fracture) corresponds to transient linear flow of formation fluid (assumed to be only oil) to the fracture, identified with a rate-normalized pressure derivative (f). Note at this stage, multi-phase flow (water and oil) occurs in the fracture ABT. The BBT (x_{f,BBT}) and ABT (x_{f,ABT}) fracture half-lengths are assumed to be different. The water RNP’ plots (c,f) were derived using an analytical model. Modified from Clarkson and Williams-Kovacs (2013b).

The sequence of flow-regimes modeled during flowback is consistent with what was presented by Larsen and Hegre (1991) for PTA of MFHWs with transverse circular fractures in the absence of storage. Song and Ehlig-Economides (2011) noted that fracture storage may precede transient linear flow to the hydraulic fractures. In this work, a focus will be placed on the transitional flow-regime (FR 3), which is typically too short to be clearly observed in daily or
less frequent flow data (as is typically recorded during long-term production) and is often referred to as a clean-up period.

The sequence of flow-regimes depicted in Fig. 2.3 have been validated using numerical simulation by Williams-Kovacs et al. (2015) as well as Zanganeh et al. (2015), and will be demonstrated in Chapter Six of this dissertation.

2.2.2 Initial LTO Flowback Analysis Approach Using “Flowback Analysis Tool” (‘FLOAT’)

FLOAT v1 was primarily developed by Dr. Christopher R. Clarkson at the University of Calgary with the assistance of the author. After some modifications by the author the model were presented by Clarkson and Williams-Kovacs (2013b) and later by Clarkson et al. (2014). The mathematical model development, in its initial form, of the base analytical model will be summarized here. This model assumed the formation of bi-wing planar fractures with a circular cross-section, with one fracture being generated at each stage (Fracture Geometry #1 of Fig. 2.1), and constant half-length both before and after the breakthrough of formation fluids. Three main categories of analysis exist:

1. BBT single-phase RTA
2. BBT analytical modeling
3. ABT analytical modeling
2.2.2.1 BBT Single-Phase RTA

BBT single-phase analysis is conducted using diagnostic plots to guide flow-regime identification, straight-line analysis to estimate key hydraulic fracture properties and type-curves to confirm the parameters estimated from straight-line analysis.

2.2.2.1.1 Fracture Depletion

The general equation for the FMB assuming static porosity and permeability is given by the following:

\[
\frac{q_w}{p_{fi}-p_{wf}} = m \frac{q_w}{c_{t,BBT}|p_{fi}-p_{wf}|} + b
\]  

(2.1)

Where, \( m \) is the slope, \( b \) is the y-intercept \( q_w \) is water flow rate, \( p_{fi} \) is initial fracture pressure, \( \overline{p_f} \) is average fracture pressure, \( p_{wf} \) is sandface flowing pressure, \( Q_w \) is cumulative water produced and \( c_{t,BBT} \) is total compressibility BBT.

A straight-line extrapolation through the single-phase fracture depletion data yields IFFIP from the y-axis and an estimate of fracture conductivity (fracture permeability with an assumption of fracture width) from the x-axis if a value of skin is available. Using the FMB, IFFIP and initial fracture permeability are estimated as follows:

\[
IFFIP = \frac{b}{-m}
\]  

(2.2)

\[
k_f = 141.2B_o\mu_o \left[ \ln \left( \frac{r_w}{r_{wa}} \right) - 0.75 \right] \frac{b}{w_{ft}}
\]  

(2.3)

Where,

\[
r_{wa} = r_w \exp(-s) \text{ and } r_e \text{ is equal to fracture half-length which was originally assumed to be constant both before and after the breakthrough of formation fluids.}
\]
2.2.2.1.2 Transient Radial Flow

Assuming the primary transient flow-regime in the fracture is transient radial flow, this data may be analyzed using the radial flow superposition plot, which in its general form, assuming static porosity and permeability, is:

\[
\frac{P_m - P_{wf}}{q_w} = \hat{m}t_{RSL} + \hat{b}
\]  

(2.4)

Where,

\[
t_{RSL} = \sum_{j=1}^{n} \left( \frac{q_j - q_{j-1}}{q_n} \right) \log(t_n - t_{j-1})
\]  

(2.5)

Using the radial superposition plot, fracture permeability (or conductivity) and skin can be determined using Eqn. 2.6 and 2.7, which were defined by Hager and Jones (2001).

\[
k_f = \frac{162.6\theta_w\mu_w}{m_wf}\]  

(2.6)

\[
s = 1.1513 \left[ \frac{b}{m} - \log_{10} \left( \frac{k_f}{\phi_1\mu_1c_{1f}r_{BT}^2} \right) + 3.23 \right]
\]  

(2.7)

The Fetkovich type-curve is then used to confirm the results derived from the FMB and linear superposition plot, as this type-curve was developed for infinite acting radial flow followed by boundary-dominated flow, where the time function used for the data is liquid material balance:

\[
t_{cal} = \frac{q_w}{q_{wL}}
\]  

(2.8)

For type-curve analysis, assuming radial drainage, the altered definition of \( q_D \) and \( t_D \) for liquid analysis are as follows:

\[
q_D = \frac{141.2q_w\mu_w\theta_w}{kh[p_{BT} - P_{wf}]}
\]  

(2.9)

\[
t_D = \frac{0.00634k_w[q_{cal}]}{(\phi\mu_wc_1r_D^2)}
\]  

(2.10)
For the Fetkovich (1980) type-curves, the following dimensionless decline variables were used:

\[ q_{Dd} = q_D \left[ \ln \left( \frac{r_e}{r_{wa}} \right) - 1/2 \right] \]  \hspace{1cm} (2.11)

\[ t_{Dd} = \frac{2t_D}{\left[ (r_e/r_{wa})^2 - 1 \right] \left[ \ln \left( \frac{r_e}{r_{wa}} \right) - 1/2 \right]} \]  \hspace{1cm} (2.12)

The use of MBT (which converts the data to an equivalent constant rate case) causes fracture depletion data to fall down the harmonic stem on the Fetkovich type-curve and a positive deviation suggests the breakthrough of formation fluids.

### 2.2.3 BBT Analytical Modeling

The BBT flow-regimes (FR 1 and FR 2 in Fig. 2.3) are assumed to be transient radial flow followed by single-phase fracture depletion, assuming the fracture fluid is water, and mobile water saturation is 100% in the fractures.

#### 2.2.3.1 Transient Radial Flow

1. Dimensionless time \((t_{Dpss})\) to reach pseudo steady-state is calculated as in Golan and Whitson (1996) as:

   \[ t_{Dpss} = 0.177 \left( \frac{r_e}{r_{wa}} \right)^2 - 0.234 \left( \frac{r_e}{r_{wa}} \right) \]

2. For \(t_D < t_{Dpss}\), the transient form of the radial-flow equation is used. The equation provided by Golan and Whitson (1996) was used to calculate \(t_D\) \(\left( t_D = \frac{0.00634kt}{\phi \mu_w c_T r_{wa}} \right)\) and Eqn. 2.9 is used to convert back to dimensional rate. The approximate numerical curve fits to the transient portion of the van Everdingen and Hurst solution, as provided by Edwardson et al. (1962) were used:

   For \(t_D < 200\):
For \( t_D > 200 \):

\[
q_D = \frac{26.7544 + 43.5537t_D^{0.5} + 13.3813t_D + 0.492949t_D^{1.5}}{47.4210t_D^{0.5} + 35.5372t_D + 2.60967t_D^{1.5}}
\]  

(2.13)

For \( t_D \leq 0.01 \) the following van Everdingen and Hurst approximation was used:

\[
q_D = \frac{3.90086 + 13.3813t_D[\ln(t_D) - 1]}{t_D[\ln(t_D)]^2}
\]  

(2.14)

2.2.3.2 Fracture Depletion

For \( t_D \geq t_{D_{pss}} \), the pseudo steady-state radial-flow equation (2.16) is coupled with the water material balance equation (MBE) (2.17) to model single-phase fracture depletion. Alternatively a material balance simulator such as that used by Clarkson and McGovern (2005) can be used in which case skin is inherently accounted for. Both methods yield the identical model.

\[
q_w = \frac{k_{w,f}r_f[\bar{p}_f - p_{w,f}]}{141.2 \mu_w B_w \ln \left(r_e/r_{w,f} \right) - 0.75 + s}
\]  

(2.16)

Where, \( r_e = \chi_f \) (see Fig. 2a-b), \( \bar{p}_f \) is the average pressure in the fracture, \( w_f \) is total fracture width and \( s \) is a skin factor. Average pressure within the fracture BBT is modeled using the MBE shown below in Eqn. 2.17.

\[
\bar{p}_f = p_{fi} - \frac{Q_{w,f} B_w}{V_f c_{L,BBT}}
\]  

(2.17)

Where, \( \bar{p}_f \) is average fracture pressure, \( p_{fi} \) is initial fracture pressure, \( Q_{w,f} \) is cumulative water production from the fracture, \( c_{L,BBT} \) is total compressibility and \( V_f \) is effective (mobile) fracture volume.
2.2.4 ABT Analytical Modeling

Once $p_f$ reaches breakthrough pressure ($p_{BT}$) linear flow of oil and formation water (if present) is assumed to occur from the matrix adjacent to the fracture into the fracture (see Fig. 2.3d-e). Stress sensitivity of the formation is ignored in this model, although could easily be incorporated. For oil, the equation used to simulate inflow is the bounded transient linear flow solution of Wattenbarger et al. (1998):

$$\frac{1}{q_D} = \frac{\pi \left( \frac{y_c}{4} \right)}{\Sigma_{odd} \exp \left[ -\frac{n^2 \pi^2 (\frac{x_f}{y_c})^2}{4} t_{DXF} \right]}$$

(2.18)

Where:

$$\frac{1}{q_D} = \frac{k_o h [p_{BT} - p_f]}{141.1 \mu_o \rho_o \mu_o}$$

(2.19)

$$t_{DXF} = \frac{0.00633 k_r o}{(0 \mu_c) x_f^3}$$

(2.20)

Where, $k_o$ is effective permeability to oil in the formation and $x_f$ is total fracture half-length. Versions of 2.18-2.20 can also be used to simulate the inflow of water, accounting for water properties and effective permeability for water. For this analysis, matrix pressure and saturation are assumed constant due to the short nature of flowback and the low permeability of the formations of interest.

Flow of water and oil to the well from the fracture is again described by the BDF equation (written below for oil), but now accounting for relative permeability variation:

$$q_g = \frac{k_f k_{ro} w_f [p_f - p_{w_f}]}{141.1 \mu_o \rho_o \ln(r_e/r_w) - 0.75 + s}$$

(2.21)

Where, $k_{ro}$ is relative permeability to oil in the fracture (effective permeability to oil is given by: $k_o = k_f k_{ro}$). Eqn. 2.21 is also used to describe flow for water ABT, but accounting for relative permeability to water. ABT, $p_f$ is again calculated with a MBE which accounts for inflow and outflow of water and oil from the fractures (from the formation and into the wellbore). For this application a two-phase version of Eqn. 2.7 is used to calculate $p_f$ which is
shown in Eqn. 2.22 and the material balance for calculating average water saturation in the fractures is given by Eqn. 2.23.

\[
\bar{p}_f = p_{fi} - \frac{(Q_{w,f}-Q_{w,m})B_w+(Q_{o,f}-Q_{o,m})B_o}{v_f c_{t,ABT}} 
\]  
(2.22)

\[
\bar{S}_w = S_{wi} - \frac{(Q_{w,f}-Q_{w,m})B_w}{v_f} 
\]  
(2.23)

Where, \(Q_{o,f}\) is cumulative oil produced from the fracture, \(Q_{o,m}\) is cumulative oil inflow from linear flow, \(B_o\) is oil formation volume factor, \(\bar{S}_w\) is average water saturation, \(Q_{w,m}\) is cumulative water inflow from the matrix, \(Q_{w,f}\) is cumulative water production from the fracture, \(B_w\) is water formation volume factor \(c_{t,ABT}\) is total compressibility.

Relative permeability curves for water and gas are assigned to the fracture to calculate effective phase permeability as a function of water saturation. In this work Corey relative permeability curves are used which are normalized such that only mobile saturation, \(S_w^*\), is considered. These equations are shown below.

\[
S_w^* = \frac{(S_{wi}-S_{wr})}{(1-S_{wi})} 
\]  
(2.24)

\[
k_{ro} = k_{ro}^t (1 - S_w^*)^{n_t} 
\]  
(2.25)

\[
k_{rw} = (S_w^*)^{n_t} 
\]  
(2.26)

Where, \(S_w^*\) is refered to as \(\bar{S}_w\) for the remainder of this dissertation. The basic workflow for the application of the analytical model is shown below if Fig. 2.4.
As can be seen from Fig. 2.4, history-matching flowback data is an iterative process which is driven by the calculated (or preferentially measured) bottom-hole flowing pressure. In order to achieve an accurate history-match, the following primary parameters are adjusted:

1. Fracture permeability (conductivity)
2. Fracture half-length
3. Breakthrough pressure
4. Oil and water relative permeability curves for the fractures
Although practical, there are several drawbacks to FLOAT v1 including the following:

1. Fracture half-length is constant both BBT and ABT making it impossible in most cases to adequately match both BBT and ABT water data.

2. Only a circular fracture shape with a single simple bi-wing planar fracture being generated from each fracture stage is assumed.

3. Difficulty estimating fracture permeability and porosity in the absence of ultra-high frequency flowback data which allows clear identification and estimation of fracture conductivity. Fracture porosity is assigned based on simple rules of thumb for planar fractures (typically high permeability and high porosity).

4. Fracture closure is not accounted for (pressure-dependant permeability and porosity for the fractures).

5. Uncertain and constant fracture compressibility.

6. No method in place for constraining fracture relative permeability curves which are one of the most significant unknowns in quantitative flowback analysis.

7. Only accounts for water-based fractures in LTO reservoirs (not oil-based fractures which are becoming common in many unconventional formations).

8. Assumes under-saturated oil production (flowing pressure above the bubble point).

9. Assumes a single deterministic solution which may or may not be optimal.

10. Only applicable to single well, single layer commingled analysis.

11. Limited number of case studies analyzed.
2.3 Basic and Significant Modifications Made by the Author

The overall template of the tools have not been significantly modified since FLOAT v1, although several key contributions by the author are worth noting which address drawbacks 1, 2, 3 and 5. Deficiencies 4, 6 and 8 will be addressed in the development of the of the new shale gas model in Chapter Three and have also been incorporated into FLOAT v2 which is used in the remainder of this dissertation. Deficiency 7 will be addressed in Chapter Six by accounting for oil-based fractures in LTO reservoirs. Deficiency 8 will be discussed in Chapter Eight as a topic for future work. Deficiency 9 will be accounted for in Chapter Four through the application of Monte Carlo (MC) simulation and other assisted history-matching techniques. Deficiency 10 will be addressed in Chapter Eight by extending the well to stage-by-stage, multi-well and multi-layer flowback scenarios. Finally, deficiency 11 has been addressed by looking at LTO data sets from several LTO plays in North America for different operators, some of which will be demonstrated in Chapter Six.

2.3.1 Shale Gas Flowback Tool (FAT)

As discussed previously, this model was fully redesigned after assessing significantly more flowback data. These changes were described briefly in the conceptual model section of this chapter and will be elaborated upon in Chapter Three. All of the modifications made to the LTO flowback tool described below were also included in the new shale gas model development.

2.3.2 LTO Flowback Tool (FLOAT)

Likely the most significant addition to the tool made by the author was the introduction of variable half-length between BBT and ABT flow. When a single half-length was used
throughout the flowback period it was consistently noticed that the slope on the FMB line had to be steepened away from the data to match ABT half-length, and in this was reflected in modeling by significantly under-estimating BBT water production. This change significantly improves history-matching, particularly to the water phase, although also had an impact on the history-match to oil due to the changing calculation of fracture pressure. An additional significant addition is the incorporation of several additional fracture shapes and geometries. In the initial work only a single simple bi-wing planar fracture with circular geometry, developing from each fracture stage was considered. Due to the growing use of microseismic and the ability for different fracture geometries to develop even in the same formation (as a result of different completions/stimulation methods and other factors such as heterogeneity) it is crucial to be able to analyze fractures of different geometries and shapes. Both rectangular and elliptical fracture shapes were added to the model, as well as complex fracture network scenarios.

Another significant issue identified by Clarkson and Williams-Kovacs (2013b) for the LTO case is the impact of fracture compressibility. Since fracture compressibility is a property that is not commonly measured, it is important to estimate it as accurately as possible. In this dissertation four possible fracture compressibility models were introduced: 1) Jones (1975) equation for estimating fracture compressibility; 2) Aguilera (1999) graphical method for estimating fracture compressibility of natural fractures with varying calcite cement fill (analogous to proppant); 3) weighted average method using Aguilera method to estimate compressibility of the un-propped fracture in combination with proppant compressibility, using porosity as the weighting factor; and 4) manual input method using lab data. The details of the first 3 of these techniques will be briefly summarized below.
2.3.2.1 Jones (1975)

Jones (1975) originally developed a model for natural fracture compressibility, which can also be applied to hydraulic fractures. The model is shown in Eqn. 2.27 below:

\[ C_f = \frac{-1}{p_k \ln(p_k/p_h)} \]  

(2.27)

Where, \( p_k \) is net stress on the fractures and \( p_h \) is fracture healing pressure.

2.3.2.2 Aguilera (1999)

Aguilera (1999) derived a variety of natural fracture compressibility curves using the work of Jones (1975) and Tkhostov et al. (1970) as a basis for varying levels of mineral matter fill, ranging from 0-50%. In this work mineral matter fill is used as a proxy for proppant fill (i.e. Mineral Matter Fill = 1-\( \Phi_f \)). Aguilera (1999) only derived curves for up to 50% mineral matter fill (50% void space), although this can be extrapolated to (1-\( \Phi_f \)) for the hydraulic fracture of interest. To use this method an estimate of net stress on the fractures (i.e. net overburden pressure) and fracture porosity is required. In Fig. 2.5 the (1-\( \Phi_f \)) curves is derived using a fracture porosity of 31%, which was assumed for each of the examples assuming a planar fracture geometry in this work. This has been shown to be a reasonable value for simple bi-wing planar fractures (Valko, 2001).
2.3.2.3 Weighted Average

The weighted average technique calculates fracture compressibility as the porosity-weighted average of open natural fracture compressibility calculated using the method of Aguilera (1999) and proppant compressibility, which is shown below in Eqn. 2.28.

\[ C_f = \phi C_{nf} + (1 - \phi)C_p \]  
\[ (2.28) \]

Each of the estimation methods have their strengths and weaknesses, although none of the techniques have been developed directly for proppant-filled hydraulic fractures and therefore error may still exist in the estimation process. This is an important piece of future work. A sensitivity analysis to fracture compressibility was shown by Williams-Kovacs and Clarkson (2013c). Aguilera (1999) has also stressed the importance of incorporating the pressure dependence of the compressibility of natural fractures into the analysis (increasing compressibility with decreasing pressure and increasing time) and therefore this has also be incorporated into this tool as an optional feature. Variable fracture compressibility, which is calculated using an explicit formulation (fracture compressibility is solved using the pressure from the previous time-step), is only thought to be significant during single-phase water
depletion, prior to the breakthrough of formation fluids, although can also be incorporated for ABT flow. It is difficult to rationalize using dynamic fracture compressibility when estimates are being used, although if the necessary data is available this should be incorporated into the analysis.

Another issue that arises is the selection of the relative permeability curves for the fractures. To assist in constraining relative permeability, fractional flow theory was incorporated in this work. From fractional flow theory, an estimate of $\frac{k_{rw}}{k_{ro}}$ as a function of time from the rate data can be derived and plotted alongside $\frac{k_{rw}}{k_{ro}}$ from the relative permeability curves selected against $S_w$ calculated from analytical simulation. These curves will have a similar shape and should overlay each other in cases where a reasonable set of relative permeability curves have been selected. Since $S_w$ from this simulator is a function of the selected relative permeability curves, this is an iterative process; although it does not directly identify the correct relative permeability curves, it does constrain the selection, which has been found useful by the authors. The details of generating these curves from fractional flow theory will be discussed in Chapter Three specifically for shale gas but the same methodology can be applied to LTO cases.

Another difficulty that typically arises (in part due to the lack of quality transient flow data at the onset of flowback) is the estimation of fracture porosity and permeability. To at least partially reduce this problem several constraints were introduced into the model. For Geometry #1 and #2 above (high porosity, planar fractures) a modified Kozeny-Carmen equation has been used to estimate fracture permeability as a function of fracture porosity and proppant diameter. This equation was originally developed for sand packs, which are analogous to planar fractures. For Fracture Geometry #3 and #4 (complex low porosity and permeability fracture network), the
scenario is analogous to highly cleated CBM reservoirs. In this case the matchstick model (Reiss, 1980), which has been used in commercial CBM plays, has been applied to relate fracture porosity and permeability to fracture spacing \((a)\) and aperture width \((b)\). In both cases a fracture tortuosity factor \((\tau_f)\) factor has been applied to account for the non-ideal behavior of hydraulic fractures (Chen, 2005). The modified Kozeny-Carmen equation is shown below in Eqn. 2.29, while the matchstick model is shown in Eqn. 2.30 and 2.31.

\[
k_f = \frac{c}{\tau_f} \left( \frac{d^2 \phi_f^2}{(1-\phi_f)^2} \right)
\]  

\[
\phi_f = \frac{b'}{5a}
\]  

\[
k_f = \frac{0.416(1000\phi_f)b'^2}{\tau_f}
\]

Where, \(c\) is the appropriate Kozeny constant, \(d\) is proppant diameter, \(a\) is fracture spacing in \(mm\) and \(b'\) is fracture aperture width in \(\mu m\).

Another key issue associated with porosity and permeability, is the impact of stress (pressure) dependant porosity and permeability in the fractures. It is hypothesized that during flowback, fracture permeability will often decrease as a function of time due to fracture closure as load fluid is produced. This is analogous to the reduction in cleat permeability in CBM wells as fracture pressure decreases during production. Recently, authors including Clarkson et al. (2012b) have also incorporated stress-dependent permeability into the long-term production data analysis of shale gas wells in highly over-pressured formations (i.e. Haynesville shale). Due to the dynamics of the problem this concept is highly applicable to flowback analysis, particularly in cases where the shut-in period between stimulation and flowback is short or wells are flowed back aggressively creating high stress on freshly created and propped fractures. It is likely that
proppant embedment/crushing are two of the causes for the reduction in fracture porosity and permeability in addition to fracture closure and elimination of fracture fluid propped fractures. The models used for stress-dependant porosity and permeability will be discussed in Chapter Three as part of the shale gas model development.

2.3.3 Tight and Shale Gas Conceptual Model

The conceptual model used for analyzing tight gas reservoirs is equivalent to that of the LTO conceptual model shown above in Fig. 2.3 except with oil being replaced by gas. The modified conceptual model applied to shale gas cases is very similar to that applied to LTO wells with several shale-specific modifications. In this work, shale gas is the focus over tight gas, with tight gas being an area of future research. The primary modification is that gas is not only sourced to the fractures via instantaneous desorption when fracture pressure falls below desorption pressure and also transient linear flow from the matrix to the fractures. Experience from looking at a significant number of cases suggests that assuming instantaneous desorption appears to be reasonable, particularly when a significant amount of secondary fracturing is present (comparable to the assumption used in most highly-cleated commercial CBM wells). Note that desorption will not initiate until reservoir pressure drops below desorption pressure and therefore desorption may not occur from the onset of flowback in all shale gas reservoirs. The combined sourcing method is also consistent with observations from many field cases where a near-depletion signature is seen on diagnostics ABT, although an additional source is required to provide the system with enough gas immediately following breakthrough to adequately history-match flowback data. Over time, as desorbed gas depletes around the fracture face and a gas saturation is established within the secondary fracture network (or the matrix if a complex
fracture network is not formed), the linear flow component becomes dominant; this will be demonstrated in a simulated example in Chapter Three. The conceptual model used for analyzing flowback data from shale gas wells is shown below (Fig. 2.6). This conceptual model assumes the formation of a single planar fracture formed per stage, which is also applicable for the different fracture geometries shown above in Fig. 2.2. Note that the BBT period for gas wells tends to be significantly shorter than for LTO wells and in many cases is not observed, particularly shale cases (as has been observed by several authors).

Fig. 2.6 — Illustration of (possible) flow-regimes observed during flowback of fracturing fluids from MFHWs completed in tight or shale gas reservoirs. Single-phase flow-regimes in a) (cross-section view of single fracture) and b) (plan view of single fracture) are transient radial (FR 1) and fracture depletion (boundary-dominated) flow (FR 2) of fracturing fluid (assumed to be water in this case), which are identified with a RNP derivative (c). These flow-regimes correspond to flow only in the fracture, prior to breakthrough of formation fluids. FR 3 in d) (cross-section view of single fracture) and e) (plan view of single fracture) corresponds to transient linear flow of formation fluid (shown to be multi-phase water and gas) to the fracture coupled with multi-phase fracture depletion. Below desorption pressure, gas may also be sourced to the primary fracture network via desorption. The BBT (“$x_{F,BBT}$”) and ABT (“$x_{F,ABT}$”) fracture half-lengths
are assumed to be different. The water RNP’ plots (c,f) were derived using an analytical model. Modified from Clarkson and Williams-Kovacs (2013b).

Again, models for rectangular and elliptical-shaped fractures have also been developed for shale gas cases.

2.4 Analysis Procedure

The analysis procedure for analyzing oil and gas flowback data is very similar, although key differences will be noted during the presentation of the analysis procedure. There are 3 primary steps to analyzing flowback data using the methods used in this work, after converting surface pressures to bottom-hole pressures using a multi-phase wellbore model. In this work IHS® Harmony™ (Gray’s correlation) has been used to convert surface pressures to sandface pressures. These models can lack accuracy in some cases, particularly during flowback due to the presence of multi-phase flow, sand production and a rapidly changing wellbore environment. This makes collection of downhole flowing pressures desirable for quantitative analysis, although no such data has been analyzed to date. The three main steps include: 1) raw data and diagnostic plots to assess data quality and determine which flow-regimes are available for analysis; 2) rate-transient analysis (RTA) on single-phase BBT data to estimate BBT half-length and fracture conductivity; 3) deterministic history-match to confirm results of BBT RTA and determining key properties ABT. The basic analysis procedure is summarized in Fig. 2.7 and is discussed in further detail below. In later chapters additional steps will be added to the basic analysis procedure.
1. Diagnostic plots. In all applications there are diagnostic plots which can be analyzed to identify or infer flow-regimes both BBT and ABT. BBT, two diagnostic plots are employed to guide interpretation: 1) water RNP; and 2) water RNP’. The RNP’ plot has been found to be most useful for flow-regime identification and will be the primary BBT diagnostic plot discussed in this work. On the water RNP’ plot, a unit slope is indicative of single-phase fracture depletion, as is commonly the only flow-regime seen prior to hydrocarbon breakthrough. A deviation from the unit slope suggests hydrocarbon breakthrough and the transition into combined fracture depletion/transient linear flow. In cases with ultra-high frequency flowback data the initial transient flow-regime is likely to be identifiable (radial, linear or elliptical flow). ABT several diagnostic plots, as suggested by Ilk et al. (2010), are employed to guide interpretation. The primary plot of interest used in this work is the plot of GWR or GOR vs. Cumulative Gas or Oil Production, where a \( \frac{1}{2} \)-slope is thought to be indicative of fracture depletion. A positive deviation from \( \frac{1}{2} \)-slope indicates linear flow from the matrix to the fractures becoming more dominant than multi-phase depletion in the fractures. As discussed above Zhang and Ehlig-Economides (2014) suggested that the mechanism for this positive deviation may result from vaporization of water by gas later in time, although this would not explain the trend seen in tight oil reservoirs. This ABT diagnostic has primarily been used in shale gas cases where instantaneous desorption is a
significant gas sourcing mechanism, although a similar signature can be observed in LTO wells (not shown in this dissertation). This occurs since transient inflow is initially minor due to the low pressure differential between the fractures and the formation making depletion the dominant signature; over time, however, the influence of matrix inflow becomes more significant as fracture pressure declines.

2. *Rate-Transient Analysis.* Several specialty straight-line plots are used to assist in analytical history-matching: 1) FMB; and 2) transient flow analysis (radial, linear or elliptical). The FMB is used to estimate BBT fracture storage volume and hydraulic fracture half-length after the application of constraints on fracture shape and geometry (particularly fracture shape, fracture width and porosity), where analysis is conducted on the fracture depletion data identified on the diagnostic plots (as a unit-slope on the RNP’ plot) straight-line. Deviation (flattening) from this unit-slope straight-lines caused by the breakthrough of formation fluids. Radial, linear and elliptical flow analysis all provide an estimate of fracture conductivity but can only be used accurately if the flow-regime is clearly identified. If the frequency of data does not allow for clear identification, radial flow is typically assumed and the first few data points on the radial flow plot can be fit to provide a first pass indication of potential fracture conductivity. After trial and error history-matching, as will be discussed in the next section, this early-time flow-regime may be re-evaluated assuming a different flow-regime.

3. *Deterministic History-Matching.* Deterministic history-matching is used to assess the applicability of the developed flowback model and select which of the fracture geometries shown in Fig. 2.1 best represent the data.

   a) *BBT Single-Phase Analysis.* As mentioned previously, FR 2 and FR 3 shown above
are the two flow-regimes most commonly seen in flowback data acquired with common gathering frequency, although FR 1 may also be seen for a small number of points or in cases where higher frequency data is recorded. The modeling methods used in this work use a combination of transient and pseudo steady-state techniques which have been applied for other unconventional resources. For transient radial flow, FR 1 is modeled using the approach of Edwardson et al. (1962) to describe mud circulation and has since been used to model transient radial flow of several reservoir types. For transient linear flow the approach of Wattenbarger et al. (1998) is used with the fracture acting as the reservoir of interest. For transient elliptical flow the approach of Cheng et al. (2009) is used, again where the fracture is the reservoir of interest. FR 2 is modeled using the pseudo steady-state flow equation for water to represent fracture depletion while fracture pressure remains elevated from formation pressure.

b) FR 3 is modeled as a combination of transient linear flow (again using the approach of Wattenbarger et al. 1998), where the reservoir of interest is now the matrix, and multi-phase fracture depletion occurs requiring relative permeability curves for the fractures. Relative permeability curves may also be required for the matrix if multi-phase flow is occurring.

A comprehensive summary of this analysis procedure in the context of a simulated example was presented by Clarkson and Williams-Kovacs (2013b) for an LTO case and will not be reproduced in this work, although the analysis procedure will be demonstrated in the context of a simulated example for a shale gas case in Chapter Three. This simulated example shows all of
the same features as that presented by Clarkson and Williams-Kovacs (2013b) with the addition of some of the shale-specific components discussed at the beginning of Chapter Three.
Chapter Three: A Modified Approach For Modeling Two-Phase Flowback From Multi-Fractured Horizontal Shale Gas Wells

3.1 Abstract

This chapter will expand on the analytical flowback analysis model presented by Clarkson and Williams-Kovacs (2013a) and modified by Williams-Kovacs and Clarkson (2013a). These works presented a data-driven pseudo-analytical modeling approach for quantitatively analyzing two-phase flowback to estimate key fracture properties including fracture conductivity and half-length. In the early attempts to model flowback from shale gas wells, multi-phase depletion from the fracture network was assumed to be the primary flow-regime. More recently, three flow-regimes have been observed in flowback data depending on data frequency: 1) transient flow of fracture fluid within the fracture network prior to breakthrough of formation fluids (rarely seen in shale gas); 2) single-phase depletion of water within the fracture network (also rarely seen); and 3) coupled formation and fracture flow following breakthrough of formation fluid. In this work, FR 1-3 are modeled rigorously. FR 3 is the focus of this study and will be modeled using a coupling of transient linear flow of gas from the matrix to the fractures with multi-phase depletion within the fracture network (conceptually more realistic than previous attempts). Further, dynamic fracture porosity and permeability are incorporated to better represent the physics of the problem and a modified MBE is developed to account for additional drive mechanisms (fracture closure in addition to desorption and gas expansion). Finally, a modified pseudo-pressure and pseudo-time are applied to BBT single-phase RTA and ABT multi-phase RTA (conducted after analytical simulation using pressure and saturation dependent outputs from simulation) to improve both parameter estimates (BBT) and flow-regime confirmation (ABT). The new model is compared to the previous model using a field case study.

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2 Data-driven pseudo-analytical means that the model was based on the flow-regimes observed in the field rather than being developed from first principles.
3.2 Introduction

For over a decade, operators have been developing shale gas reservoirs. What started as a phenomena in the United States has turned into a giant global resource. Much like other unconventional resources, shale gas reservoirs must be extensively hydraulically fractured to allow for commercial production. As a result, operators are seeking new methods to characterize hydraulic fractures, particularly early in the well life.

Several authors have developed methods for analyzing flowback from shale gas wells as was demonstrated in the literature review in Chapter Two. In fact this resource type has received the most attention in the flowback analysis literature, being driven primarily by shale gas plays in North America, although recently such methods have been used in other global shale plays.

3.3 Problem Statement and Objectives

In this chapter, a new method for analyzing multi-phase flowback from shale gas wells was developed which improves upon the early shale gas flowback methods developed by Clarkson and Williams-Kovacs (2013a) and the follow-up paper. The conceptual approach that those authors used for analysis was to treat flowback analogously to production of water and gas from highly-cleated commercial coalbed methane (CBM) wells – their focus was on an early-time apparent fracture + wellbore multi-phase storage (depletion) period. Post-storage flow was modeled using methods designed for single-phase shale gas cases (post-cleanup) combined with continued depletion of fracture water from the fracture network. In these papers, early-time single phase data (prior to the breakthrough of formation fluids) was not considered and the transition from depletion-flow in the fracture network to formation linear flow was not modeled. Clarkson et al. (2014), two predecessor papers (Clarkson and Williams-Kovacs, 2013b; Williams-Kovacs and Clarkson (2013c), demonstrated that these flow-regimes are important in modeling flowback from tight oil wells and are also likely critical in tight and shale gas cases. In addition to these conceptual issues, it was consistently observed that an elevated Langmuir Volume ($V_L$) or extended free gas contribution zone was required to incorporate enough gas into
the fracture system to match flowback data. This is addressed in the current chapter. A detailed comparison of the models will be presented in the Discussion section.

The objectives of the current chapter are to provide: 1) a rigorous method for analyzing and history-matching early-time single-phase data; 2) a modified method to explicitly model gas contribution from the matrix using an approach similar to what was proposed by Clarkson et al. (2014) and the predecessor papers for analyzing flowback from LTO wells; 3) incorporate a modified MBE to account for fracture closure as a mechanism for flowback; and 4) improve the physics of the model by accounting for pressure-dependent porosity and permeability during flowback as a result of fracture closure. The flowback analysis and analytical forecasting methodology will be described below in the context of a simulated example, and then applied to a field case. For the field case, a comparison with the early shale gas flowback model is presented. Flowback results from the field case will also be briefly compared to RTA results for long-term online production data.

3.4 Analytical Model Development and Other Analysis Techniques Used

In this work, several techniques have been applied for quantitatively analyzing two-phase flowback from MFHWs completed in shale into a tool known as FAT. The following techniques will be discussed below:

1. BBT single-phase RTA
2. BBT analytical modeling
3. ABT analytical modeling
4. ABT two-phase RTA

The fourth step comes from the predecessor tools link to previous work conducted on CBM reservoirs. These methods use multi-phase RTA using the results of analytical simulation which in the presence of pure depletion can be used to confirm parameters solved from history-matching. Although the newly developed model does not start with the assumption of pure
multi-phase depletion, these plots still demonstrate the dominance of a multi-phase depletion signature ABT before linear flow becomes more dominant later in the flowback period.

### 3.4.1 BBT Single-Phase RTA

Three BBT RTA techniques are used in this work: 1) FMB; 2) transient flow analysis (circular and rectangular fracture shapes are presented in this dissertation); and 3) type-curves (either transient radial to boundary-dominated flow – Fetkovich type-curve; or transient linear followed by boundary-dominated flow – Wattenbarger type-curve). Although all of these cases analyzed in this chapter use the assumption of circular fracture shape, the equations associated with rectangular shaped fractures will also be demonstrated and have been applied to several industry case studies including a case study in Chapter Six. A version of the model has also been developed for elliptical shaped fractures, although this will not be shown here. The general equation for the FMB accounting for stress-dependent porosity and permeability is given by the following:

\[
\frac{q_w}{m(p_{fi})_L - m(p_{wf})_L} = m \frac{\phi_{fi}}{\phi_f(p_f)} c_{BBT} \frac{Q_w}{p_{fi} - p_{wf}} + b \tag{3.1}
\]

Where, \( m \) is the slope, \( b \) is the y-intercept \( q_w \) is water flow rate, \( m(p)_L \) is liquid pseudo-pressure accounting for pressure-dependent permeability, \( p_{fi} \) is initial fracture pressure, \( \bar{p}_f \) is average fracture pressure, \( p_{wf} \) is sandface flowing pressure, \( Q_w \) is cumulative water produced, \( c_{BBT} \) is total compressibility BBT, \( \phi_f(\bar{p}_f) \) is the fracture porosity at the current pressure, and \( \phi_{fi} \) is the fracture porosity at initial fracture pressure.

A straight-line extrapolation through the single-phase fracture depletion data yields IFFIP from the y-axis and an estimate of fracture conductivity from the x-axis if a value of skin is available. Using the FMB, IFFIP and initial fracture permeability are estimated as follows:

\[
IFFIP = \frac{b}{-m} \tag{3.2}
\]

\[
k_{fi} = 141.2B_o\mu_o \left[ \ln \left( \frac{r_e}{r_{wa}} \right) - 0.75 \right] \frac{b}{w_{fr}} \tag{3.3}
\]
Where,

\[ r_{wa} = r_w \exp(-s) \] and \( r_e \) is equal to BBT half-length for a circular fracture shape.

For a rectangular geometry at the onset of fracture depletion, the total skin is equal to the convergence skin, \( s_C \), resulting from the distortion of flow lines from linear to radial around a horizontal wellbore (not present in fully penetrating vertical fractures) and any enhanced permeability, \( s' \), which may occur close to the wellbore as a result of higher proppant concentrations. This presents the opposite effect of choked fracture skin which can be caused by proppant crushing and embedment near the wellbore as a result of high drawdown on the fractures. Convergence skin comes from the x-intercept of the linear superposition plot or square root of time plot (see below). The total skin is given by Eqn. 3.4.

\[ s = s_C + s' \] (3.4)

Liquid pseudo-pressure is defined as:

\[ m(p)_L = \frac{1}{k_{fi}} \int_0^p k_f(p) dp \] (3.5)

Where, \( k_f(p) \) is the average fracture permeability at the current pressure, and \( k_{fi} \) is the permeability at initial pressure. All pressure-dependent properties in BBT RTA are calculated with a simple water material balance, using fracture volume determined from the FMB and actual water rate data (similar to Eqn. 3.35 below). The analogous definition for gas, which is modified for pressure-dependent permeability, is given by Eqn. 3.6. The same definition was used by Behmanesh et al. (2014).

\[ m^*(p) = \frac{2}{k_{fi}} \int_0^p \frac{k_f(p)p}{\mu \rho g} dp \] (3.6)
3.4.1.1 Transient Radial Flow – Circular Shaped Fractures

Assuming the primary transient flow-regime in the fracture is transient radial flow, this data may be analyzed using the radial flow superposition plot, which in its general form, accounting for changing fracture porosity and permeability is:

\[
\frac{m[p_{fr}] - m[p_{wf}]}{q_w} = \dot{m}t_{a,RS} + b \quad (3.7)
\]

Where,

\[
t_{a,RS} = \sum_{j=1}^{n} \frac{(q_{j} - q_{j-1})}{q_n} \log(t_{aL,n} - t_{aL,j-1}) \quad (3.8)
\]

And,

\[
t_{at} = \frac{\rho_f}{k_f} \int_{0}^{t} \frac{k_f(p)}{\varrho_f(p)} dt \quad (3.9)
\]

The analogous definition for gas, which is modified for pressure-dependent porosity and permeability, is given by:

\[
t_{a} = \left(\frac{\varrho_f \mu_w c_w}{k_f}\right) \int_{t}^{\infty} \frac{k_f(p)}{\varrho_f(p) \mu_w c_w} dt \quad (3.10)
\]

In Eqn. 3.9 and 3.10, properties in the integral are evaluated at the average fracture pressure. Desorption is also included in the total compressibility calculation. These definitions of pseudo-time are the same as those used by Behmanesh et al. (2014) in the presence of stress-dependent porosity and permeability for both liquid and gas cases.

Using the radial superposition plot, initial fracture permeability (or conductivity) and skin can be determined using Eqn. 3.11 and 3.12, which were defined by Hager and Jones (2001).

\[
k_{f1} = \frac{162.6 \theta w \mu w}{m w f r} \quad (3.11)
\]

\[
s = 1.1513 \left[ \frac{b}{m} - \log_{10} \left( \frac{k_{f1}}{\varrho_f \mu_w c_w T_{BRT}} \right) + 3.23 \right] \quad (3.12)
\]
The Fetkovich type-curve is then used to confirm the results derived from the FMB and radial superposition plot as this type-curve was developed for transient radial to boundary-dominated flow, where the time function used is liquid MBT or material balance pseudo-time (shown below to account for variable porosity and permeability).

\[
t'_{cal} = \frac{q_{fi} 1}{k_{fi} q_w} \int_0^t \frac{k_f \rho}{q_f(p)} \, dt
\]  
(3.13)

For type-curve analysis, assuming radial drainage, the altered definition of \( q_D \) and \( t_D \) for liquid analysis are as follows:

\[
q_D = \frac{141.2 q_w u_w \theta_w}{k_f \rho_f [m_l(p_{Rf}) - m_l(p_{w_f})]}
\]  
(3.14)

\[
t_D = \frac{0.00634 k_f t'_{cal}}{(\theta_{w_c})^{1/2} \phi_{a}}
\]  
(3.15)

For the Fetkovich (1980) type-curves, the following dimensionless decline variables are used:

\[
q_{Dd} = q_D [\ln(r_e/r_{wa}) - 1/2]
\]  
(3.16)

\[
t_{Dd} = \frac{2t_D}{[(r_e/r_{wa})^2 - 1][\ln(r_e/r_{wa}) - 1/2]}
\]  
(3.17)

The use of material balance pseudo-time (constant rate equivalent solution) causes fracture depletion data to fall down the harmonic stem and a positive deviation suggests the breakthrough of formation fluids.

### 3.4.1.2 Transient Linear Flow – Rectangular Shaped Fractures

Note that in the case of rectangular shaped fractures, a short transient radial flow period may be observed prior to transient linear flow, although this has not been modeled here. If the primary transient flow-regime in the fracture is transient linear flow, two alternate plots may be used to analyze this data: 1) linear flow superposition plot; and 2) square-root of time plot. The
linear superposition plot in its general form, accounting for changing fracture porosity and permeability is:

$$\frac{m(p_f)_{L} - m(p_w)_{L}}{q_w} = \dot{m} t_{a,LSL} + \dot{b}$$  \hspace{1cm} (3.18)

Where,

$$t_{a,LSL} = \sum_{j=1}^{n} \left( \frac{(q_j - q_{j-1})}{a_n} \sqrt{t_{aL,n}^* - t_{aL,j-1}^*} \right)$$  \hspace{1cm} (3.19)

Using the linear superposition plot, initial fracture permeability (or conductivity) can be determined using Eqn. 3.19, which were defined by Lee et al. (2003).

$$k_{fi} = \left( \frac{4.064 B_w}{m h_w f_T/2} \right)^2 \left( \frac{\mu_w}{\sigma C_T} \right)_{i}$$  \hspace{1cm} (3.20)

The square root of time plot takes a similar form to the linear superposition plot:

$$\frac{m(p_f)_{L} - m(p_w)_{L}}{q_w} = \dot{m} \sqrt{t_{c,LSL}} + \dot{b}$$  \hspace{1cm} (3.21)

Where, \( t_{c,LSL}^* \) is material balance pseudotime time which is repeated below from Fig. 3.12:

$$t_{c,LSL}^* = \frac{\Theta f l_{1}}{k f l q_{w} \int_{0}^{t} \frac{k_{f}(p)q_{w}}{\Theta f(p)} dt}$$  \hspace{1cm} (3.22)

Based on the square root of time plot, initial fracture permeability (or conductivity) can be determined as demonstrated by Wattenbarger et al. (1998).

$$k_{fi} = \left( \frac{31.3 B_w}{m h_w f_T/2} \right)^2 \left( \frac{\mu_w}{\sigma C_T} \right)_{i}$$  \hspace{1cm} (3.23)

On both plots, a positive intercept is related to a convergence skin effect defined as follows:

$$s_c = \frac{b k_{fi} w f_T}{141.2 B_w q_w \mu_w}$$  \hspace{1cm} (3.24)

The Wattenbarger type-curve is then used to confirm the results derived from the FMB and linear superposition plot/square root of time plot as this type-curve was developed for linear to boundary-dominated flow, where the time function used is liquid MBT or material balance
pseudo-time as defined above. Again a deviation from the depletion stem suggests the breakthrough of formation fluids from the matrix to the fractures.

For type-curve analysis, assuming linear drainage, the altered definition of \( q_D \) and \( t_D \) for liquid analysis are as follows:

\[
q_D = \frac{141.2 q_{w,alt} \mu_w B_w}{k \phi h [m_L(p_{fr}) - m_L(p_{wf})]} \\
t_{DWF/2} = \frac{0.00634 k_w \phi_c L}{(\theta \mu_w c_t)(w_{fr}/2)^2}
\]

Where, water rate, \( q_{w,alt} \), is modified to account for the skin effect if present. To simplify the application of this type-curve the x and y-axis are modified to give only one curve per case instead of a family of curves (Wattenbarger et al., 1998). This is achieved by using the following variable transformations:

\[
\left( \frac{x_f}{w_{fr}/2} \right) q_D = \left( \frac{x_f}{w_{fr}/2} \right) \frac{141.2 q_{w,alt} \mu_w B_w}{k \phi h [m_L(p_{fr}) - m_L(p_{wf})]} \\
t_{Dx_f} = t_{DWF/2} \left( \frac{w_{fr}/2}{x_f} \right)^2
\]

### 3.4.2 BBT Analytical Modeling

The BBT flow-regimes (FR 1 and FR 2 in Fig. 2.6) are assumed to be transient radial or linear flow followed by single-phase fracture depletion, assuming the fracture fluid is water and water saturation is 100% in the fractures. Radial flow will first be considered as the primary flow-regime, followed by the assumption of transient linear flow.

#### 3.4.2.1 Transient Radial Flow – Circular Shaped Fractures

1. Dimensionless time (\( t_{Dpsa} \)) to reach pseudo steady-state is calculated as in Golan and Whitson
(1996) as: \( t_{Dpss} = 0.177 \left( \frac{r_e}{r_{wa}} \right)^2 - 0.234 \left( \frac{r_e}{r_{wa}} \right) \).

2. For \( t_D < t_{Dpss} \), the transient form of the radial-flow equation is used. The equation provided by Wattenbarger et al. (1998) modified for stress-dependent porosity and permeability was used to calculate \( t_D \left( t_D = \frac{0.00634k_t^{*IL}}{\theta \mu_w c r_{wa}^2} \right) \) and Eqn. 3.13 is used to convert back to dimensional rate.

The approximate numerical curve fits to the transient portion of the van Everdingen and Hurst solution, as provided by Edwardson et al. (1962) were used:

For \( t_D < 200 \):

\[
q_D = \frac{26.7544 + 43.5537t_D^{0.5} + 13.3813t_D + 0.492949t_D^{1.5}}{47.4210t_D^{0.5} + 35.5372t_D + 2.60967t_D^{1.5}}
\]

For \( t_D > 200 \):

\[
q_D = \frac{3.90086 + 13.3813t_D[ln(t_D)-1]}{t_D[ln(t_D)]^2}
\]

For \( t_D \leq 0.01 \) the following van Everdingen and Hurst approximation was used:

\[
q_D = \frac{1}{\sqrt{\pi t_D}}
\]

3.4.2.2 Transient Linear Flow – Rectangular Shaped Fractures

1. Dimensionless time \( t_{Dpss} \) to reach pseudo steady-state is calculated as in Wattenbarger (1998) as: \( t_{Dpss} \left( t_{Dpss} = 0.25 \left( \frac{x_{f,BBT}}{w_{RT/2}} \right)^2 \right) \).

2. For \( t_D < t_{Dpss} \), the transient form of the linear-flow equation is used. The equation provided by Wattenbarger et al. (1998) modified for stress-dependent porosity and permeability was used to calculate \( t_{DW_{RT/2}} \left( t_{DW_{RT/2}} = \frac{0.00634k_w t_{cal}}{(\theta \mu_w c)_{(w_{RT/2})^2}} \right) \) and Eqn. 3.24 is used to convert back to dimensional rate. The empirical curve fit to the analytical solution derived by Bello and Wattenbarger et al. (2010) for infinite acting linear flow in the presence of convergence skin
under constant bottomhole flowing pressure conditions was used. This is equivalent to the solution presented by Wattenbarger et al. (1998) for a vertical fracture fully penetrating a vertical well in which convergence to the wellbore is not present.

\[
\frac{1}{q_D} = \frac{\pi}{2\sqrt{t_{DW ft}/t_D}} + \frac{2\pi S_c}{\sqrt[0.8]{t_{DW ft}/t_D} S_c} \tag{3.32}
\]

Some authors (ex. Nobakht and Mattar, 2012) have questioned whether the skin term is variable under constant bottomhole flowing equations based on the results of a large number of field cases. Under this assumption, Eqn. 3.31 simplifies to:

\[
\frac{1}{q_D} = \frac{\pi}{2\sqrt{t_{DW ft}/t_D}} + 2\pi S_c \tag{3.33}
\]

### 3.4.2.3 Fracture Depletion – Circular Fracture Shape

For \( t_D \geq t_{Dps} \), the pseudo steady-state radial-flow equation (3.34) is coupled with the water material balance equation (MBE) (3.35) to model single-phase fracture depletion. Alternatively a material balance simulator such as that used by Clarkson and McGovern (2005) can be used in which case skin is inherently accounted for. Both methods yield the identical model.

\[
q_w = \frac{k_{fi w ft}[\ln(\overline{p_f}) - m(p_w)]}{141.2 \mu_w d_w \ln(r_e/r_w - 0.75 + s(t))]} \tag{3.34}
\]

Where, \( r_e = x_{i,BBT} \) (see Fig. 2a-b), \( \overline{p_f} \) is the average pressure in the fracture and \( s(t) \) is a skin factor which may be time-dependent. Pressure within the fracture BBT is modeled using the MBE shown below in Eqn. 3.34.

\[
\overline{p_f} = p_{fi} - \frac{Q_{w,f} B_w}{V_{f,BBT}(\overline{p_f}) c_{l,BBT}} \tag{3.35}
\]

Where, \( \overline{p_f} \) is average fracture pressure, \( p_{fi} \) is initial fracture pressure, \( Q_{w,f} \) is cumulative water production from the fracture, \( c_{l,BBT} \) is total compressibility and \( V_{f,BBT}(\overline{p_f}) \) is effective fracture volume prior to breakthrough, which may be a function of pressure as a result of pressure-dependent porosity.
3.4.2.4 Fracture Depletion – Rectangular Fracture Shape

The pseudo steady-state flow equation shown in Eqn. 3.34 can be modified to account for different fracture shapes by using a shape factor skin. The generalized pseudo steady-state flow equation is given below.

\[
q_w = \frac{k_f w_f r_f [m(p_f) - m(p_w)]}{14.2 \mu_w \phi_w \ln(r_e/r_w) - 0.75 + s(t) + S_{CA}}
\]  

(3.36)

Where, \(S_{CA}\) is a skin factor caused by non-radial geometries. Various skin factors have been presented in the literature (i.e. Golan and Whitson, 1996). The shape factors and skin factors for circular, square and rectangular shaped fractures with different ratios of \(x_f/(h_f/2)\) are shown below in Table 3.1.

<table>
<thead>
<tr>
<th>Geometry</th>
<th>Shape Factor, (C_{A})</th>
<th>Skin, (S_{CA})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circle</td>
<td>31.620</td>
<td>0.000</td>
</tr>
<tr>
<td>Square</td>
<td>30.883</td>
<td>0.012</td>
</tr>
<tr>
<td>Rectangle (2:1)</td>
<td>21.837</td>
<td>0.185</td>
</tr>
<tr>
<td>Rectangle (4:1)</td>
<td>5.379</td>
<td>0.886</td>
</tr>
<tr>
<td>Rectangle (5:1)</td>
<td>2.361</td>
<td>1.298</td>
</tr>
<tr>
<td>Rectangular (10:1)</td>
<td>0.100</td>
<td>3.352</td>
</tr>
</tbody>
</table>

The following plot which shows trend lines between each derived value was used to derive the shape factor and shape factor skin for any rectangular geometry. Note that alternatively a polynomial fit or cubic spline algorithm could be used to connect the derived data points, although the impact on the application would be minimal.
Fig. 3.1 — Plots for interpolating between known shape factor and shape factor skin values.

For a rectangular fracture shape individual fracture half-length is calculated using $x_{fi} = \frac{A}{4hf}$, where $A$ is fracture drainage area and $hf$ is the fracture height (often constrained to the net pay of the formation which is the assumption used in most analytical model development for online production data). Total fracture half-length is then given by $x_{ft} = \sum_{i=1}^{n} x_{fi}$, where $n$ is the total number of fractures created (often assumed to be equal to the number of stages executed). From the above discussion it is clear that history-matching with a rectangular fracture shape is more complicated than with a circular fracture shape since the shape factor skin becomes an additional history-match parameter unless fracture height is set equal to net pay at which point BBT half-length can be determined from the FMB and the ratio of $x_{f}/(hf/2)$ can be determined and used in modeling. Note it is highly unlikely that fracture height will be constrained to the net pay thickness unless strong fracture barriers exist above and below the formation of interest which is rare in the majority of unconventional formations which may lead to an over-estimate of fracture properties and will be demonstrated in Chapter Six.

3.4.2.5 Accounting for Stress-dependant Permeability and Porosity.

As discussed previously, it is common that fractures will close during the flowback period leading to a loss is conductivity and volume. Pressure-dependent fracture permeability is modeled using the Yilmaz and Nur approach (Yilmaz et al. 1991):
\[ k_f(\bar{p}_f) = k_{f,i}e^{(\bar{p}_f-p_{f,i})} \]  

(3.36)

Where, \( \gamma \) is the permeability modulus. The reduction in fracture volume is accounted for by using pressure-dependent porosity using an equation similar to Eqn. 3.36. A similar formulation could be used to reduce fracture width as the well is flowed back and likely better represents the fracture closure problem. This is a topic of future work.

\[ \phi_f(\bar{p}_f) = \phi_{f,i}e^{c_f(\bar{p}_f-p_{f,i})} \]  

(3.37)

Where, \( c_f \) is the fracture compressibility. Jones (1975) developed a correlation for relating the change in porosity and permeability by combining Lamb’s equation (Lamb, 1932) for flow through a narrow duct with Darcy’s equation for fluid flow in porous media. The idealized correlation assumes that flow only occurs through the fracture and the fracture has uniform width with no tortuosity. A generalized form of the equation is shown below in Eqn. B-23. Using the above assumptions Jones (1975) calculated \( \hat{n} = 3 \), which has been used by Mavor and Gunter (2006) for application to CBM reservoirs, although both Jones (1975) and Tonnsen and Miskimins (2011) have suggested that \( \hat{n} \) may be significantly higher (up to 12 or even much higher) in non-ideal cases. Specialized geomechanical testing would be required to accurately determine \( n' \) for a specific set of conditions.

\[ \frac{k(p)}{k_i} = \left( \frac{\phi(p)}{\phi_i} \right)^{\hat{n}} \]  

(3.38)

By substituting Eqn. 3.35 and 3.36 in to Eqn. 3.37 a useful expression relating \( \gamma \) to \( c_f \) can be derived:

\[ \gamma = \hat{n} \times c_f \]  

(3.39)

### 3.4.3 ABT Analytical Modeling

Once \( \bar{p}_f \) reaches \( p_{GR} \), linear flow of gas and formation water (if present) is assumed to occur from the matrix adjacent to the fracture into the fracture (see Fig. 2.6d-e). In cases where
multiple primary fractures are created per stage, the observed linear flow during flowback is likely the linear flow between created fractures which may last a matter of weeks or months before transitioning to linear flow towards the fracture stage. Gas is also sourced instantaneously to the fractures by desorption which is accounted for in the MBE. For gas, the equation used to simulate inflow is the bounded transient linear flow solution of Wattenbarger et al. (1998):

\[ \frac{1}{q_D} = \frac{\pi (y_e)}{4} \sum_{k=0}^{\infty} \frac{\sum_{n=1}^{\infty} y_e n^2 r_f^2 \exp\left(-\frac{n^2 r_f^2 x^2}{4 y_e}\right)}{t_{Dxf}} \]  

(3.40)

Where:

\[ \frac{1}{q_D} = \frac{k_g h [\bar{m}(p_{gr}) - \bar{m}(\bar{p})]}{1424 q_0 T} \]  

(3.41)

\[ t_{Dxf} = \frac{0.00633 k_g f}{(\rho \mu c)^{1/2} r_f} \]  

(3.42)

Where, \( k_g \) is effective permeability to gas in the formation (\( k_g = k_{ro}k_m \)). Total compressibility is modified for adsorption to allow application to shale gas wells. Versions of Eqn. 3.40 to 3.42, modified for liquid flow presented in Chapter Two, are used to describe inflow of formation water to the fractures, accounting for water properties and effective permeability. Note that convergence skin can be accounted for using the same skin term presented in Eqn. 3.32 or Eqn. 3.33 for infinite acting transient linear flow.

Flow of gas and oil to the well from the fracture is again described by the BDF equation (written below for gas for any fracture shape), but now accounting for relative permeability variation:

\[ q_g = \frac{k_{fg} k_{rg} \bar{w}_{gr} [\bar{m}(p_{gr}) - \bar{m}(p_{wr})]}{14247 [\ln(r_e/r_w) - 0.75 + s(t) + S_{CA}]} \]  

(3.43)

Where, \( r_e = x_{f,ABT} \) and \( k_{rg} \) is relative permeability to gas in the fracture. For the case of rate-dependent skin \( s(t) = D'q_g \) and Eqn. 3.43 becomes Forchheimer’s equation. Eqn. 3.36 is also used to describe flow for water ABT, but accounting for relative permeability to water. For this analysis, matrix saturation is assumed constant due to the short nature of flowback and the low
permeability of the formations of interest. Matrix pressure is solved using a simple material balance equation similar to that shown in Eqn. 2.22 and Equation 2.23 below.

ABT, $p_f$ is again calculated with a material balance, but now accounting for inflow of formation fluids to the fracture (desorption of gas near the fracture face and linear flow of water and gas) and outflow of water and gas to the well. This material balance is shown conceptually in Fig. 3.2 to demonstrate the coupling between matrix and fracture flow.

![Fig. 3.2 — Conceptual model for transient linear flow coupled with fracture depletion and the associated MBE (Eqn. 3.44-346 below).](image)

For this application a modified version of the King (1993) MBE is used, which accounts for both free and adsorbed gas. The MBE was modified to account for linear inflow of both water and gas into the fracture network. A “gas injection” term ($Q_{g,m}$) has been added to the material balance to account for linear inflow of gas. The modified MBE is shown below in Eqn. 3.44, with the corresponding relationship for saturation including a “water injection” term ($Q_{w,m}$) shown in Eqn. 3.46.

$$Q_{g,f} - Q_{g,m} = \frac{A_w f_f f_i z_{sc} T_{sc}}{p_{sc} T} \left( \frac{p_{BT}}{Z_{BT}} - \frac{p_f}{Z_f} \right)$$  \hspace{1cm} (3.44)
Where:

\[
Z^* = \frac{z}{[1-c_f(p_f-p_{BT})](1-S_w) + \frac{z T \phi c V_L \rho_g}{S_{sc} T \phi (p_L+p) \phi_f}}
\]

(3.45)

\[
\overline{S_w} = \frac{S_{wI}[1+c_w(p_f-p_{BT})] + \frac{5.165(q_{w,m}-B_w q_{w,f})}{A_w \phi_f}}{[1-c_f(p_f-p_{BT})]}
\]

(3.46)

Where, \(Q_{g,f}\) is cumulative gas produced from the fracture, \(Q_{g,m}\) is cumulative gas inflow from linear flow, \(A\) is fracture drainage area, \(T\) is temperature, \(Z^*\) is the modified gas compressibility factor, \(\overline{S_w}\) is average water saturation, \(V_L\) is Langmuir volume, \(P_L\) is Langmuir pressure, \(\phi_{fI}\) is initial fracture porosity, \(c_w\) is water compressibility, \(Q_{w,m}\) is cumulative water inflow from the matrix, \(Q_{w,f}\) is cumulative water production from the fracture and \(B_w\) is water formation volume factor. Water saturation change in the fracture is also calculated using material balance and accounts for linear inflow of water (Eqn. 3.46). Relative permeability curves for water and gas are assigned to the fracture to calculate effective phase permeability as a function of water saturation. In this work, Corey relative permeability curves are used which are normalized such that only mobile saturation is considered. These equations were shown in the previous chapter for the oil and water case.

This model can be additionally constrained by relating fracture porosity and permeability and by confirming that the selected relative permeability curves are consistent with the fractional flow seen during flowback. The application of the Kozeny-Carmen model for planar fractures and the Matchstick model for complex fractures was discussed in detail in Chapter Two. The use of fractional flow theory to constrain fracture relative permeability curves was briefly discussed as well although the mathematical details will be provided here. The fractional flow of gas is given by the following:

\[
F_g = \frac{q_g}{q_g + q_w}
\]

(3.47)
Where, $q_g$ and $q_w$ are the flow rate of water and gas respectively at reservoir conditions, where the flow rates for the two phases must have consistent units. Based on $F_g$, an expression for $\frac{k_{rw}}{k_{rg}}$ can be derived:

$$\frac{k_{rw}}{k_{rg}}, data \approx \frac{k_{w, eff}}{k_{g, eff}} = \frac{\mu_w}{\mu_g} \left( \frac{1-F_g}{F_g} \right)$$

(3.48)

Similarly from the Corey-style relative permeability model:

$$\frac{k_{rw}}{k_{rg}}, model = \frac{k'_{rg} (1-S_w)^{n'}}{s_w^{m'}}$$

(3.49)

$\frac{k_{rw}}{k_{rg}}, data$ and $\frac{k_{rw}}{k_{rg}}, model$ are then plotted against $\bar{S}_w$, which is solved analytically from Eqn. 3.43 as a function of time. A similar curve shape and reasonable history-match suggests that the relative permeability curves selected for history-matching are an adequate representation of the recorded water and gas rate data.

The basic workflow for the application of the analytical model is equivalent to what was shown in the previous chapter although the equation numbers have been replaced with the corresponding equations in this chapter shown below in Fig. 3.3.
The primary outputs of the model are equivalent to what was shown in the previous chapter. Note that all the modifications and extensions presented above have also been incorporated into FLOAT, significantly improving the functionality of the tool as compared to v1 which was discussed previously in this chapter.

### 3.4.4 ABT Two-Phase Analysis

In Clarkson and Williams-Kovacs (2013a) and the follow-up paper, two-phase versions of production type-curves and FMB were used to confirm flow-regimes used in analytical
modeling. Using the methods described in Clarkson et al. (2012a) and Clarkson (2013), saturation- and pressure-dependent outputs obtained from the analytical model were used to calculate pseudovariables and dimensionless variables for use in RTA. This type of transformation is required to analyze two-phase data using methods developed assuming single-phase flow and has been used on gas data in two-phase CBM wells. In this work, since pure two-phase depletion is not assumed in the fractures, these methods cannot be used quantitatively for parameter confirmation. Instead these methods will be applied to confirm that there is a strong depletion component, as indicated by the near \( \frac{1}{2} \)-slope on the log-log plot of \( \text{GWR} \) vs. \( \text{Cumulative Gas Produced} \). Depletion is indicated by data falling along a straight-line on the FMB plot and also by data falling down the depletion stem on both the Fetkovich and Pratikno-Blasingame type-curves. For type-curve analysis, assuming radial drainage, the altered definition of \( q_D \) and \( t_D \) for gas analysis are as follows:

\[
q_D = \frac{\tau}{0.000703 k_g h [m^*(p_{BT}) - m^*(p_{wf})]} q_g \tag{3.50}
\]

\[
t_D = \frac{0.00634 k_g}{(\varphi_{fg} c_f^*)} r_w^2 - t_{ca}^* \tag{3.51}
\]

Where \( c_f^* \) is total compressibility modified for adsorption, \( r_{wa} \) is the apparent wellbore radius \( (r_{wa} = r_e e^{-s}) \), assuming circular drainage area, and \( s \) is skin. \( k_g \) is effective permeability to gas, which is a function of water saturation. \( t_{ca}^* \) (material balance pseudo-time), accounting for variable porosity and permeability, is approximated by Eqn. 3.52. This is similar used by Clarkson and Williams-Kovacs (2013a) although also accounts for changes in stress-dependent porosity and permeability.:
Where, $G_i$ is IGIP in the fracture system. For the Fetkovich (1980) type-curves, the dimensionless decline variables shown in Eqn. 3.16 and 3.17 are used in this case as well.

For the Pratikno-Blasingame (Pratikno et al., 2003) type-curves, the following dimensionless decline variables are used:

$$q_{Dd} = q_D b_{DPSS} \quad (3.53)$$

$$t_{Dd} = \frac{2\pi}{b_{DPSS}} t_{DA} \quad (3.54)$$

$$t_{DA} = \frac{0.00634 k_g}{(\phi \mu_g c_f^*) A} t_{ca}^* \quad (3.55)$$

In Eqn. 3.53, $b_{DPSS}$ is a pseudosteady-state parameter that depends on $F_{CD}$ and $r_{eD}$ (correlation derived in Pratikno et al. 2003), which in turn are defined as:

$$F_{CD} = \frac{k_{fwRT}}{k_m x_f} \quad (3.56)$$

$$r_{eD} = \frac{r_e}{x_f} \quad (3.57)$$

Where, $k_m$ is the formation permeability. Since there are different type-curve sets for each value of $F_{CD}$, $F_{CD}$ must be defined. The two-phase FMB is obtained by plotting the following as y- and x-axis variables, which is comparable to what Clarkson and Salmachi (2017) for undersaturated CBM reservoirs but also accounts for stress-dependent porosity in the x-axis.

$$y = \frac{k_{rg} \phi_w [m^* (p_{BT}) - m^* (p_{wf})]}{q_g} \quad (3.58)$$

$$x = G_l \frac{\phi_f (\bar{p}_T)}{\phi_f (\bar{p}_T)} \frac{m(p_{BT}) - m(p_{T})}{m(p_{BT}) - m(p_{WF})} \quad (3.59)$$
## 3.5 Analysis Workflow and Methods

The analysis procedure used by the authors for quantitatively analyzing flowback data consists of five primary steps: 1) raw data and diagnostic plots to assess data quality and determine flow-regimes, respectively; 2) RTA of BBT data to estimate hydraulic fracture properties (BBT fracture half-length and fracture conductivity); 3) history-match with analytical simulation to estimate hydraulic fracture properties; 4) forecast long-term production using parameters estimated from flowback; and 5) compare flowback-derived fracture parameter estimates from RTA of online production data and other data sources once available. This analysis procedure is comparable to that presented in Chapter Two, although two additional steps have been added to the analysis procedure. Stochastic simulation or assisted history-matching steps could also be incorporated into the workflow as will be shown in Chapter Four, although this was not applied in this chapter. The analysis procedure is shown graphically in Fig. 3.4.

![Flowchart of Analysis Workflow](image)

**Fig. 3.4** – Summary of procedure for analyzing flowback data and forecasting long-term production using flowback parameter estimates (steps 1-4) and comparing flowback derived parameter estimates with other data sources (step 5).

Some of the new/unique features of the model will first be presented using a simulated example, with all model details discussed previously. For this demonstration, a gas well was simulated with the analytical model developed in this work using parameters such that both BBT and ABT data is present. A water-based fracture fluid, a single circular bi-wing planar fracture per stage and constant fracture porosity and permeability were assumed. The inputs associated with the simulation are provided in Table 3.2 and the raw data is shown below in Fig. 3.5a.
Table 3.2 — Input Parameters For Analytical Simulation For Case Study 1

<table>
<thead>
<tr>
<th>Fracture Properties</th>
<th>Parameter Value</th>
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</thead>
<tbody>
<tr>
<td>Initial Fracture Pressure (psia)</td>
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</tr>
<tr>
<td>Initial Water Saturation (%)</td>
<td>100</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
<td>31</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
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</tr>
<tr>
<td>Fracture Relative Permeability</td>
<td>Straight-lines (n’ and m’ = 1)</td>
</tr>
<tr>
<td>Fracture Compressibility (psi⁻¹)</td>
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</tr>
<tr>
<td>Number of Hydraulic Fractures</td>
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<tr>
<td>Individual Hydraulic Fracture Width (ft)</td>
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<tr>
<td>Total Hydraulic Fracture Width (ft)</td>
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<table>
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<td>Matrix Porosity (%)</td>
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<td>Initial Mobile Gas Saturation (%)</td>
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<tr>
<td>Initial Mobile Water Saturation (%)</td>
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<tr>
<td>Matrix Relative Permeability</td>
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<tr>
<td>Formation Compressibility (%)</td>
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<tr>
<td>Matrix Permeability (md)</td>
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<td>Reservoir Temperature (°F)</td>
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</table>

<table>
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<td>Formation Water Salinity (ppm)</td>
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<tr>
<td>%CO₂</td>
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<tr>
<td>%H₂S</td>
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</table>

<table>
<thead>
<tr>
<th>Shale Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Langmuir Volume (scf/ton, in-situ)</td>
<td>100</td>
</tr>
<tr>
<td>Langmuir Pressure (psia)</td>
<td>500</td>
</tr>
<tr>
<td>Shale Density (g/cm³)</td>
<td>2.5</td>
</tr>
</tbody>
</table>

3.5.1 Raw Data and Diagnostic Plots

The methods used for BBT flow-regime identification during flowback are analogous to those used for PTA and long-term RTA. The two BBT diagnostics used include log-log plots of RNP \( RNP = \frac{m(p_i)_{L} - m(p_{wf})_{L}}{q_w} \) and its derivative, \( RNP' = \frac{d\left[\frac{(m(p_i)_{L} - m(p_{wf})_{L})}{q_w}\right]}{d\ln(t_{cal}')} \), with respect to water against MBT or material balance pseudo-time (Clarkson and Beierle, 2011;
Suitable type-curves (ex. Fetkovich, 1980 which is consistent with FR 1 and FR 2 discussed in Chapter Two) can also be used to confirm flow-regime identification using parameter estimates from BBT RTA (Fig. 3.5c). Pseudo-pressure and pseudo-time are used to account for stress-dependent porosity and permeability (if present). Further, MBT or material-balance pseudotime was used to convert the variable rate data to an equivalent constant rate scenario, resulting in a unit slope for depletion data on the RNP’ plot and depletion data falling down the harmonic stem on the Fetkovich type-curve. Water rate data was also normalized by pressure drop when using the Fetkovich type-curves, as these type-curves were derived for constant pressure production. Some interesting observations can be made when comparing Fig. 3.5b,c to similar plots presented in Clarkson and Williams-Kovacs (2013c) for a simulated tight oil flowback, particularly pertaining to the ABT data. In Fig. 3.5b the ABT slope of the RNP and RNP’ plot change far less significantly following breakthrough, and in Fig. 3.5c the deviation from the depletion stem (b=1) is less dramatic. These trends occur due to the significant instantaneous sourcing component assumed in the shale gas model, while hydrocarbon is only sourced via linear flow in the tight oil model, resulting in a less apparent deviation from depletion behavior.

One additional diagnostic plot which has been found to be useful in assessing ABT data from gas wells is the log-log plot of GWR vs. Cumulative Gas Produced (Fig. 3.5d). Ilk et al. (2010) suggested that a $\frac{1}{2}$-slope on this plot is indicative of multi-phase fracture depletion, and therefore, an approximate half-slope suggests that fracture depletion (and a significant instantaneous sourcing component) is important during this flow period. Fig. 3.4d shows that when gas first breaks through from the formation, data falls essentially down a $\frac{1}{2}$-slope as linear inflow is insignificant (because the difference between formation pressure and fracture pressure is small). Over time, as the pressure driving force for linear flow increases, gas sourced by this means becomes more significant and the plot becomes non-linear. Interestingly a similar result can be seen in LTO cases where linear flow is the only source of oil suggesting that this behaviour is not completely controlled by the instantaneous sourcing via desorption which is present in the shale gas model.
Fig. 3.5 — Diagnostic plots used to identify flow-regimes associated with flowback data: a) fluid production rate and flowing pressure data; b) RNP and RNP’ plot; c) Fetkovich type-curve plot; and d) GWR vs. cumulative gas produced. Synthetic data were generated using an analytical simulator (see Table 2 for inputs). Water and flowing pressure data shown in a) is analyzed in plots b) – d). The RNP’ plot shows an early radial flow period (~0.1 days), followed by a storage signature (~2.6 days), prior to formation fluid breakthrough after ~2.7 days. All times are in MBT, as shown on the plots, which has the effect of stretching time. These flow-regimes are confirmed on the Fetkovich type-curve. Immediately ABT, flow approaches multi-phase depletion, although as the contribution from linear flow increases (with declining fracture pressure) a positive deviation can be identified.

3.5.2 Rate-Transient Analysis of BBT Water Data

In cases where single-phase BBT data is present, quantitative RTA can be conducted to derive a preliminary estimate of key fracture properties (fracture conductivity and BBT half-length). Prior to analysis, fracture shape and geometry as well as estimates of fracture width, fracture proppant pack porosity, fracture compressibility, and initial fracture pressure at the onset of flowback are required. Water PVT properties must also be determined; common correlations have been used in the developed model.
RTA is conducted according to the BBT flow-regimes identified in Fig. 3.5b. To assist in demonstrating the analysis procedure, the RNP/RNP’ plot is reproduced in Fig. 3.6a. The different flow-regimes identified are analyzed using their corresponding specialty (straight-line) plots, which were described in detail by Clarkson and Beierle (2011) for tight gas and Clarkson (2013) for shale gas and CBM reservoirs. Pressure-dependent permeability is accounted for using a modified formulation of pseudopressure and pseudotime (where applicable) and pressure dependent porosity is accounted for using pseudotime and a modified definition of normalized cumulative production. Transient radial flow (FR 1) can be analyzed using the radial flow superposition plot (Fig. 3.6b) to derive a total fracture conductivity ($F_{cT}$), which for a multi-fractured horizontal well with planar fractures, $F_{cT} = \sum_{j=1}^{n} (k_f w_f)_{j}$, where $(k_f w_f)_{j}$ is the individual fracture conductivity. Knowing the total fracture width [$w_{fT} = \sum_{j=1}^{n} (w_f)_{j}$], the average fracture proppant pack permeability can be calculated. From the radial flow plot, $F_{cT} \sim 420 \text{ md} \cdot \text{ft}$, with skin very near zero (as simulated). Combined with the total fracture width estimate (0.42 ft), an average fracture permeability can be derived (1,000 md). Fracture depletion (FR 2) is then analyzed using the FMB plot (Fig. 3.6c) to obtain an estimate of mobile fracture fluid-in-place ($\sim 20,000 \text{ STB}$, as simulated), which is assumed to represent the total mobile fluid contained in the fractures BBT. Some of this fluid may be trapped following breakthrough of formation fluids. Combined with fracture shape, fracture porosity (31%) and total fracture width (0.42 ft), BBT fracture half-length can be estimated from fluid-in-place, which is $\sim 525 \text{ ft}$ in this case (again as simulated). The FMB plot can also be used to estimate $F_{cT}$, given skin from the radial flow plot and using the y-intercept, which yields a similar result to radial flow analysis. Although the Fetkovich type-curves can also be used to estimate $F_{cT}$, the
minimal amount of transient radial flow data makes a unique match impossible. Instead this plot is used to confirm flow-regime and parameter estimates derived from the previous analysis steps (Fig. 3.6d).

Fig. 3.6 — Rate-transient analysis of synthetic flowback data: a) rate-normalized pressure derivative plot shown for reference to select data to be analyzed with each specialty plot; b) radial flow plot used to analyze single-phase fracture transient radial flow data; c) FMB plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots. Water and flowing pressure data is analyzed in all plots. Deviation from depletion signature late in time, shown in Fig. 3.6a,c,d results from breakthrough of formation fluid from matrix to the fractures.

Parameters estimated from quantitative RTA are provided in Table 3.3.
Table 3.3 — Parameters Solved From Each BBT RTA Technique for Case Study 1

<table>
<thead>
<tr>
<th></th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Radial Flow Plot</td>
<td></td>
</tr>
<tr>
<td>Fracture Conductivity, $F_{ct}$ (md-ft)</td>
<td>420</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>1,000</td>
</tr>
<tr>
<td>Flowing Material Balance</td>
<td></td>
</tr>
<tr>
<td>Fracture Fluid-In-Place (STB)</td>
<td>20,000</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{f, BBT}$ (ft)</td>
<td>525</td>
</tr>
<tr>
<td>Fracture Conductivity, $F_{ct}$ (md-ft)</td>
<td>420</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>1,000</td>
</tr>
<tr>
<td>Fetkovich Type-Curve</td>
<td></td>
</tr>
<tr>
<td>$x_f/r_{wa}$</td>
<td>~ 1,000</td>
</tr>
<tr>
<td>Fracture Conductivity, $F_{ct}$ (md-ft)</td>
<td>420</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>1,000</td>
</tr>
</tbody>
</table>

3.5.3 Analytical Modeling of BBT Water Data and ABT Multi-Phase Data

3.5.3.1 Model Description

The analytical model developed in this work was designed to match fracture and formation fluid production data associated with the conceptual model presented in the previous chapter. The developed model is briefly described below.

The model developed assumes that the hydraulic fractures in a MFHW can be treated as separate tanks summed together to form a single-effective volume where inter-stage communication can be ignored (Chapter Five describes modifications to account for inter-stage communication). Tank dimensions are defined in Fig. 1.1 for the circular case and porosity and permeability of the fractures are assigned to the tanks. In the absence of any method to assign production to each fracture, all fractures are assumed to be equivalent and only average properties can be estimated.

The BBT (single-phase) fracture fluid production is modeled as transient radial flow within the fracture followed by fracture depletion (BDF within the fracture while fracture pressure remains elevated from formation pressure). The model used to history-match this data was discussed previously in this chapter. During this flow period, a single-phase water MBE is used
to estimate fracture pressure. Although circular fractures have been assumed in this work, non-circular shapes can be accounted for using a shape-factor in the BDF solutions. Transient flow solutions are also available in the literature for non-circular shapes. As mentioned previously these have also been incorporated into the developed tool and were described previously in this chapter.

Inflow from the matrix begins once average fracture pressure drops below the $p_{BT}$ specified in the model. Breakthrough pressure is typically elevated above initial formation pressure as a result of water injection during stimulation. Certain phenomena including counter-current imbibition may cause some gas to be present in the fracture network, prior to breakthrough pressure (ex. Ezulike and Dehghanpour, 2014 and Xu et al., 2015a). This scenario can be accounted for by setting initial gas saturation in the fractures to be greater than 0 and initial fracture pressure to be greater than breakthrough pressure. Once formation fluids breakthrough, multi-phase flow occurs in the hydraulic fractures and possibly in the formation. ABT, gas is sourced to the hydraulic fractures by a combination of instantaneous desorption near the fracture face and transient linear flow. Desorption is accounted for in the fracture material balance, while linear flow is modeled using the equations presented by Wattenbarger et al. (1998) and also contributes to the MBE. Total fracture half-length ($x_{fT}$) used in the matrix inflow model is taken as a summation of the individual fracture half-lengths ABT $[x_{fT} = \sum_{j=1}^{n} (x_{f_j})]$. Flowing pressure in the linear inflow model is set equal to fracture pressure, which will approach sandface flowing pressure over time. Effective permeability to water and gas for matrix flow is set by relative permeability curves and input mobile water and gas saturations (assumed to be constant during flowback). In many tight gas and shale gas applications, BBT data is not observed and modeling proceeds by history-matching the ABT flow-regimes.

Within each hydraulic fracture tank, ABT, multi-phase flow of water and gas to the horizontal well is described with BDF equations, with flowing pressure at the well defined in the model, and average pressure in the fracture calculated with material balance. A modification to the MBE presented by King (1993) is used to estimate fracture pressure during the multi-phase flow period, which was discussed in the previous chapter.
Relative permeability curves for water and gas are assigned to the fracture to calculate effective phase permeability as a function of water saturation. Pressure-dependent permeability in the fractures is accounted for using the method of Yilmaz et al. (1991). Pressure-dependent porosity is accounted for within the MBE. Pressure dependent porosity and permeability can be related using a method proposed by Jones (1975) for use in naturally fractured reservoirs. Gravity segregation and imbibition are ignored in the modeling process.

The model is driven by the calculated (or measured) bottom-hole flowing pressure and history-matching is an iterative procedure with the primary inputs being adjusted are fracture permeability, BBT and ABT fracture half-length, stress-dependent permeability modulus, breakthrough pressure and gas and water relative permeability curves for the fractures. The primary objective of the history-matching procedure is to derive estimates of fracture permeability and half-length.

Once an adequate history-match has been achieved, saturation and pressure-dependent outputs from the analytical model are used in the calculation of pseudo-variables and dimensionless variables for application of two-phase RTA techniques on ABT data. These methods were described by Clarkson et al. (2012a) and Clarkson (2013) for application to CBM wells. In this work, two-phase versions of the Fetkovich (Fetkovich, 1980) and Pratikno-Blasingame (Pratikno et al., 2003) type-curves and FMB are used to confirm that a signature approaching depletion is achieved. On the type-curves, multi-phase data would be expected to fall near the depletion stem, while on the FMB plot data would be expected to fall along a nearly straight-line. In this application, these plots cannot be used to confirm key fracture parameter estimates, as was done in Clarkson and Williams-Kovacs (2013a) and the follow-up papers since pure multi-phase depletion is not assumed in the conceptual model. Steps 4 and 5 of the procedure will be demonstrated in the field case.
3.5.3.2 Model Application

The developed model is used to generate production profiles for both water and gas in order to history-match flowback data. Primary inputs for the model are given in Table 3.1 and initial estimates for $x_{f,BBT}$ and $F_{CT}$ are obtained from BBT RTA as described above. These two parameters, along with $x_{f,ABT}$, breakthrough pressure, fracture relative permeability and matrix permeability serve as the primary parameters adjusted for history-matching. History-matching is conducted primarily using semi-log plots of rate and cumulative production vs. time (Fig. 3.7a,b). Water and gas production from the matrix is also shown below in Fig. 3.7c. The fractional flow plot (Fig. 3.7d), where model predicted $k_{rw}/k_{rg}$ is plotted against the same value obtained from field-data using fractional flow theory (see model derivation above), is used to constrain fracture relative permeability curves. Finally, in Fig. 3.7e it can be seen that over the 20 day flowback period simulated that fracture pressure converges towards flowing pressure. Eventually fracture pressure will become equal to flowing pressure as discussed above, although the relative permeability effect will continue to inhibit the fractures from having infinite conductivity until all water is produced or leaks off into the formation.
3.6 Field Example

The field example presented in this paper is a MFHW drilled in the dry gas window of the Marcellus Shale. Additional wells on the pad have also been analyzed to confirm model applicability, although will not be shown in this chapter. To protect operator confidentiality,
well location, reservoir and completion information has been withheld. A summary of the fracture treatment is presented below:

- Hydraulically fractured with slickwater in 12 stages, with 3 perforation clusters per stage (all assumed to be effective – 36 primary fracture networks formed).
- Perforation clusters placed with approximately 100 ft spacing, with 15 shots over a 3 foot interval.
- Approximately 6,800 STB of fluid and 125 T of proppant pumped per stage.

Prior to the analyzed flowback, 2,239 bbls of load fluid (~2.7% of total load) were recovered during drill out of plugs with coil tubing following stimulation, after which the well was shut-in for approximately 3 weeks prior to flowback monitoring with a test separator. The build-up data was analyzed in Clarkson and Williams-Kovacs (2013a), which largely indicated the expected sequence of flow-regimes for a MFHW completed in a tight formation (wellbore storage followed by linear flow as the only reservoir flow-regime). Rate and pressure data was gathered hourly for approximately 40 hours during flowback.

Inputs common to the different flowback analysis techniques are shown below in Table 3.4. Note that in this case, an elevated Langmuir Volume was not required, which was used by Clarkson and Williams-Kovacs (2013a) and the follow-up paper. This additional gas is instead accounted for by linear inflow from the formation (more consistent with the physics of the problem). Initial reservoir pressure (and matrix permeability) was estimated from $p^*$ obtained from a pre-fracture DFIT test, which was also set equal to initial fracture pressure and breakthrough pressure since multi-phase flow is seen from the onset of the flowback period. Further, a circular fracture shape with a complex fracture network with no overlap between stages (Fracture Geometry #3 in Fig. 2.2) was assumed, as with previous analysis of the data set.
**Table 3.4 — Input Parameters for Field Example (Case 2)**

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<tr>
<th>Fracture Properties</th>
<th>Parameter</th>
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<tbody>
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<td>Initial Fracture Pressure (psia)</td>
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<tr>
<td>Initial Water Saturation (%)</td>
<td>97</td>
<td></td>
</tr>
<tr>
<td>Primary Fracture Porosity (%)</td>
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<td></td>
</tr>
<tr>
<td>Fracture Compressibility (psi$^{-1}$)</td>
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<td></td>
</tr>
<tr>
<td>Number of Hydraulic Fracture Stages</td>
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<td></td>
</tr>
<tr>
<td>Primary Fracture Network Width Per Stage (ft)</td>
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<td></td>
</tr>
<tr>
<td>Total Primary Fracture Width (ft)</td>
<td>108</td>
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<td>Reservoir Properties</td>
<td>Parameter</td>
<td>Value</td>
</tr>
<tr>
<td>Formation Pressure (psia)</td>
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<td></td>
</tr>
<tr>
<td>Net Pay (ft)</td>
<td>120</td>
<td></td>
</tr>
<tr>
<td>Initial Mobile Gas Saturation (%)</td>
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<tr>
<td>Initial Mobile Water Saturation (%)</td>
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<td>Matrix Porosity (%)</td>
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<td>Formation Water Salinity (ppm)</td>
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<td>Shale Properties</td>
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</tr>
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<td>Langmuir Volume (scf/ton, in-situ)</td>
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<tr>
<td>Langmuir Pressure (psia)</td>
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</tr>
<tr>
<td>Shale Density (g/cm$^3$)</td>
<td>2.5***</td>
<td></td>
</tr>
</tbody>
</table>

*Assumed to be equal to total perforation width (100% cluster efficiency)

**Assumed to be complex fracture network permeability (derived from DFIT analysis)

***Indicated by lab tests

### 3.6.1 Raw Data and Diagnostic Plots

In Fig. 3.8, the expected rate/pressure-time signature is seen with gas rate starting at a low rate and inclining towards a plateau before declining and water rate and flowing casing pressure largely declining throughout the flowback period (analogous to multi-phase CBM wells, although rate flattens late in time likely due to linear inflow from the formation – see below). Also from the plots, it is apparent that multi-phase flow is present from the onset of the flowback
period and therefore BBT analysis will not be completed. This may be due to the fact that fracture pressure is able to dissipate due to the extended shut-in prior to the flowback period or possibly breakthrough occurs within the first hour of flowback and therefore is not identifiable given the frequency of data collected. Another possible explanation is counter-current imbibition during the pre-flowback shut-in, as suggested by Ezulike and Dehghanpour (2014) and Xu et al. (2015a), although the expected v-shape on the GWR plot is not observed as was suggested by these authors. Gas rate and choke sizes are shown in Fig. 3.8a, while water rate and calculated bottom-hole flowing pressures are shown in Fig. 3.8b. Casing pressures were recorded at the surface and IHS’s Harmony™ wellbore model (Gray’s correlation) was used to calculate sandface flowing pressure.

Following the procedure presented in the previous section, the next step is to identify flow-regimes present during the flowback period using key diagnostic plots. Since no BBT data is available, the primary diagnostic plot used is the log-log plot of GWR vs. Cumulative Gas Production (Fig. 3.9). On this plot, a ½-slope is shown for reference which would indicate multi-phase fracture depletion. In this case, the majority of data falls close to the ½-slope with deviation only beginning to occur near the end of the flowback period. This effect would become more noticeable if the flowback period were longer (see Fig. 3.5d in the simulated example). Fig. 3.9 is consistent with the observations that were used to develop the ABT model presented above.
3.6.2 Analytical Modeling of ABT Multi-Phase Data

Given that no BBT data was observed in the field, the next step is to apply the analytical model discussed above to history-match the flowback data using the procedure outlined previously in order to estimate key fracture properties (Fig. 3.10). From this analysis, the two primary parameters of interest are the fracture permeability and half-length, which were estimated to be 6.5 md and 193 ft respectively. Fig. 3.9c shows the history-match of the GWR vs. Cumulative Gas Production plot, which gives an indication of the combined history-match quality to the two phases. In addition, fractional flow theory (Fig. 3.10d) is used to confirm that the relative permeability curves used for the fracture (Fig. 3.11b) are reasonable. Although a good history-match is achieved, it is suggested that stochastic history-matching be conducted to understand the uncertainty in key fracture parameter estimates. Such analysis was presented by Williams-Kovacs and Clarkson (2013a) using the previous model, and will not be repeated in this paper. Another option is to apply an automated history-matching procedure, such as a GA, to confirm the results achieved from manual history-matching. This will be investigated in Chapter Four for LTO cases.
Fig. 3.10 – Plots used in analytical model history-matching: a) production rates of water and gas; b) cumulative production of water and gas; c) GWR; and d) fractional-flow plot.

Fig. 3.11 – Relative permeability curves used in analytical model history-match: a) matrix relative permeability curves; and b) fracture relative permeability curves.

The history-match achieved using the modified model can also be compared to the history-match achieved using the previous model. A comparison of key parameters determined from the
two models is given in Table 3.5 below and the two are compared graphically in Fig. 3.12. From Fig. 3.12 it can be seen that the history match for gas is similar in both cases, while the water match is similar for ~ 1 day. After 1 day, the previous model under-predicts water rate, while the modified model provides a good match throughout the flowback period. The deviation between the two water matches will increase with time as linear inflow from the formation provides pressure support to the fracture. To better show the deviation of the two models with time, the time axis is expanded to 3 days, rather than 2 days above. Based on observations from this well, as well as others, it has been demonstrated that long-term water recovery is underestimated using the previous model (Williams-Kovacs, 2014). From Table 3.5 it is seen that the key history-match parameters (fracture permeability and half-length) are similar in the two cases, although a pressure-dependent porosity and permeability are required with the modified model, as would be expected during flowback as the hydraulic fractures are closing on the proppant. Note that as with the simulated case fracture pressure begins to converge on flowing pressure over time, although this will not be shown with the flowback or long-term online production.

![Comparison between original and modified model history-match: a) rate match; and b) cumulative production match.](image-url)
Table 3.5 — Comparison of History-Match Parameters from the Two Flow Models

<table>
<thead>
<tr>
<th>Input Parameter</th>
<th>Modified Model</th>
<th>Original Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary Fracture Network Permeability (md)</td>
<td>6.5</td>
<td>4.5</td>
</tr>
<tr>
<td>ABT Half-Length, $x_{ABT}$ (ft)</td>
<td>193</td>
<td>193</td>
</tr>
<tr>
<td>Primary Fracture Network Permeability (md)</td>
<td>6.5</td>
<td>4.5</td>
</tr>
<tr>
<td>Permeability-Porosity Exponent (dimensionless)</td>
<td>25</td>
<td>0</td>
</tr>
<tr>
<td>Variable Primary Fracture Network Porosity</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Langmuir Volume (scf/ton, in-situ)</td>
<td>100</td>
<td>150</td>
</tr>
<tr>
<td>Langmuir Pressure (psia)</td>
<td>500</td>
<td>500</td>
</tr>
</tbody>
</table>

3.6.3 ABT Rate-Transient Analysis

Finally, to confirm that multi-phase fracture depletion is a dominant flow-regime, pseudopressure-normalized gas rate data can be transformed onto type-curves using saturation and pressure-dependent outputs from the analytical simulator match as inputs into the dimensionless variables of the type-curves (Fig. 3.13), using the approach of Clarkson et al. (2012b). In this case there is no transient data to analyze, and the data falls almost entirely down the (harmonic or near harmonic) depletion stem, corresponding to depletion of the fractures. Some deviation away from the depletion stem is seen throughout the flowback period, suggesting there is contribution from linear flow from the formation. FMB analysis (Fig. 3.14) also confirms this finding (majority of the data falls along a nearly straight-line), where extrapolation provides a reasonable estimate of IGIP associated within the fractured region, even though pure depletion is not evident.
Fig. 3.13 – 2-phase type-curve matches (gas): a) Fetkovich type-curves; and b) Pratikno-Blasingame type-curves. Data falling down the harmonic stem (b = 1) suggests 2-phase depletion.

Fig. 3.14 – 2-phase FMB analysis (gas). Data falling along a straight-line suggests 2-phase fracture depletion.

Note, that a more rigorous hybrid model was developed for analyzing shale gas flowback by Jia et al. (2017a) and was applied to this data set, achieving similar results for fracture permeability and half-length further suggesting that this relatively simple approach can be highly effective. This model is analogous to Jia et al. (2016b) which was discussed previously in which the matrix is modeled analytically, while the fractures are modeled numerically using the LTFD method, although communication is not considered in the shale gas model at this time.
3.6.4 Comparison With Online Rate-Transient Analysis and Modeling

The final step (steps 4 and 5 above) in the analysis is to assess the quality of flowback-estimated fracture parameters by analyzing available online production data for the well (~120 days). Two methods will be used: 1) quantitative RTA of online production data (early linear flow analysis); and 2) history-matching online production data with the total fracture half-length (cylinder radius multiplied by number of fracture stages) associated with the fracture stages, using a simple analytical linear-to-boundary model which was originally applied in the literature for tight gas wells (Wattenbarger et al., 1998). The first step when looking at online production data is to look at the raw data and diagnostic plots, as was done with the flowback data. Raw data is shown in Fig. 3.15a, while the RNP and RNP’ plot (with respect to gas) is shown in Fig. 3.15b and the linear derivative with respect to gas is shown in Fig. 3.15c. From Fig. 3.15a it can be seen that gas is the dominant phase, although some water production is reported (likely continued depletion from the fracture network) for ~60 days. From Fig. 3.15b, it can be seen that the majority of the data on both the RNP and RNP’ fall along a ½-slope separated by a factor of two. The most likely interpretation for this behavior from a MFHW completed in an ultra-tight shale formation is transient linear flow from the matrix perpendicular to the fractures. A 0-slope is also seen on the linear derivative plot, again suggesting transient linear flow. Early in time there is deviation from linear flow behavior, likely due to a skin effect which is commonly observed in shales (ex. Nobakht and Clarkson, 2012). Using the information in Fig. 3.15, quantitative RTA can be applied. In this case, transient linear flow is analyzed using the linear flow superposition plot shown in Fig. 3.16. From this analysis, total fracture half-length is estimated at 2,328 ft, which is in excellent agreement with the flowback estimate (2,316 ft).
Fig. 3.15 – Online production data: a) rate and calculated sandface flowing pressure; b) gas RNP and RNP’; and c) linear derivative. The diagnostics suggest that the majority of the data comes from a linear flow-regime, which is assumed to be early linear flow.

Fig. 3.16 – Linear flow analysis on online production data to estimate effective fracture half-length.

As further confirmation of the total half-length estimated from flowback data, online production data was history-matched using the single-phase linear-to-boundary model discussed in the previous chapter (Fig. 3.17). Reservoir and fluid properties are taken from Table 3.3,
while fracture parameters are taken from Table 3.4. Surface flowing pressures were converted to sandface conditions using a wellbore model similar to with the flowback data. From the figure, a good history-match is achieved for the portion of the online production period exhibiting linear flow. Note that the linear-to-boundary model provides a conservative forecast because it is assumed that the well will go into depletion immediately after fracture interference with no contribution from beyond the fracture tips. If online production data is not available, flowback parameter estimates can be used to generate a forecast by assuming a reasonable flowing pressure profile. The flowback model discussed herein can also be used to match long-term gas and water production using a similar procedure to that described above for further confirmation of parameters estimated during the short flowback period (Fig. 3.18). For comparison, the single-phase match is also shown. From the plot it can be seen that the two matches are comparable throughout the available production history (also yield similar parameters), although the single-phase model begins to over-predict the multi-phase flowback model production after ~1 year due to the presence of fracture fluid remaining in the fracture network (not shown). For modeling long-term production with the flowback model, the model was reinitialized with fracture pressure equal to the extrapolated pressure from the post-flowback build-up test and the fracture saturation from the end of the flowback period. Other inputs were held constant throughout the long-term production period. It is clear that there is still value in applying the classic single-phase models when trying to predict long-term production, but the flowback model better handles the physics of flowing against a fracture filled with water and the relative permeability effect within the fracture network.

![Case 2 - Online Rate History-Match Using Flowback Parameters](image)

Fig. 3.17 – Model history-match and forecast of online production data using parameters solved from flowback and actual calculated sandface flowing pressure.
For completeness, the equations for single-phase RTA of a gas well and the conceptual model are given in Appendix 3.1

### 3.7 Discussion

In this chapter, a modified method for quantitatively analyzing two-phase (water and gas) flowback from MFHWs completed in gas shales was developed. The objective of this analysis is to estimate key fracture properties including conductivity and half-length immediately following stimulation (less than 2 weeks of production test data). This methodology includes RTA of BBT data prior to analytical simulation of both BBT and ABT data. An analogous analysis using online production data often requires six months to a year of production before fracture properties can be accurately estimated. Although short-duration data is considered, analysis of a significant number of tight and shale gas wells indicates that flowback parameter estimates are typically consistent with estimates from long-term online production data (particularly in gas cases).
Several modifications were made to the models presented in the predecessor papers (Clarkson and Williams-Kovacs, 2013a and Williams-Kovacs and Clarkson, 2013a,b) to better represent field data. The primary modifications include: 1) rigorous modeling of transient radial flow in the fracture and single-phase fracture depletion prior to formation fluid breakthrough; 2) modeling of a fully-coupled FR 3 to account for the transition from fracture depletion to transient linear flow in the matrix; 3) use of a modified MBE to account for fracture closure as an important mechanism during flowback; and 4) incorporation of pressure-dependent porosity and permeability to account for fracture closure during the flowback period.

In the previous papers by the authors modeling flowback from tight and shale gas wells, BBT data was not considered because the majority of cases analyzed are in multi-phase flow from the onset of the flowback period (including the field case presented in this paper). Conversely, other authors including Crafton and Gunderson (2006) and Abbasi et al. (2014) have demonstrated the potential to observe and analyze BBT single-phase flow data in some tight gas plays. By extension it would be expected that a similar observation could be made in some shale gas plays. It is expected that the presence of BBT data will depend on shut-in time, data gathering frequency and reservoir/stimulation properties. Ezulike and Dehghanpour (2014) and Xu et al., (2015a) presented mechanisms for immediate gas production in Horn River Basin shales, including counter-current imbibition during extended shut-in periods, which may lead to significant gas saturation in the fractures at the onset of flowback, without pressure-driven inflow from the matrix. This phenomena has not been observed by the authors and is likely formation-specific, although this scenario could be modeled using the model presented in this paper by defining an initial gas saturation in the fractures with breakthrough pressure below initial fracture
pressure. It is expected that in most cases considered by the authors that gas breakthrough occurs very quickly (less than one hour) and is therefore not seen in hourly flowback data.

In addition, it was consistently observed, when using the previous model, that an elevated Langmuir Volume was required to incorporate enough gas into the fracture system to match flowback data. It was originally believed that this was due to the fact that a CBM-type model was used, which does not account for free-gas storage in the matrix and therefore $V_L$ needed to be elevated to be consistent with total gas content (Williams-Kovacs and Clarkson, 2013a). Williams-Kovacs and Clarkson (2013a) attempted to incorporate free gas in the matrix into the MBE, although data still could not be adequately matched using the lab-determined Langmuir isotherm. After looking at diagnostics plots (primarily the GWR vs. Cumulative Gas Produced) for a significant number of tight and shale gas cases, it was concluded that pure two-phase depletion is likely not occurring and instead gas is being sourced instantaneously at the fracture face as well as by linear flow in the adjacent secondary fracture network or matrix. This is more realistic than assuming that gas can be sourced instantaneously from free-gas in the ultra-tight matrix surrounding the fracture network and it is sensible that linear flow will begin as soon as there is a pressure differential between the matrix and fractures. Incorporation of linear flow immediately following formation fluid breakthrough is consistent with the model developed by Clarkson et al. (2014) and the predecessor papers for modeling flowback in tight oil wells and appears to better represent field data from the tight and shale gas cases considered.

An alternative MBE was also used in the modified model to better account for the physics of flowback. In the previous works the Clarkson and McGovern MBE (Clarkson and McGovern, 2005) was used. This MBE assumes that rock and water compressibility are negligible compared to desorption and gas compressibility. The assumption of negligible rock
compressibility is reasonable for the matrix, which typically has compressibility on the order of $10^{-6}$ psi$^{-1}$. In flowback applications, where the porous medium analyzed is now a closing fracture, this may not be a reasonable assumption. Compressibility of a closing fracture may be as high as $10^{-4}$ psi$^{-1}$ (Aguilera, 1999, Clarkson and Williams-Kovacs, 2013c and Williams-Kovacs and Clarkson, 2013c), which is on the high end of both desorption and gas compressibility. The magnitude of fracture compressibility will depend on the length of the shut-in and reservoir/stimulation parameters. Williams-Kovacs and Clarkson (2013c) also suggested that hydraulic fracture compressibility is likely variable (decreasing) during the flowback period as the fractures close and as the net stress on the fractures increases with production (consistent with Aguilera, 1999), although this is not considered in this work for simplicity. As a demonstration, Fig. 3.19 provides a comparison of the magnitude of the different components of total compressibility assuming a fracture compressibility of $10^{-4}$ psi$^{-1}$, with the other assumptions of the field case presented above. It can be observed that fracture compressibility is comparable to desorption compressibility throughout the flowback period and is significantly higher than effective gas compressibility since gas saturation is low in the primary fracture network throughout the flowback period. It can also be seen that water compressibility accounts for less than 2% of the total compressibility throughout the flowback period and can be ignored in most cases. This observation is consistent with Jensen and Smith (1997), Seidle (1999) and Clarkson and McGovern (2005).
In this chapter, an emphasis was placed on the incorporation of pressure-dependent porosity and permeability in the fracture system. Although pressure-dependent permeability was incorporated in the models presented in the predecessor papers, it was ignored in the modeling of field data. It is likely that, as the fractures close on the proppant with declining fracture pressure, both porosity and permeability will continually decrease until the fractures have fully closed. Non-static porosity and permeability are incorporated into the current model using modified pseudo-pressure and pseudo-time functions as well as modifications to the MBE. Each of these two phenomena are used in the field case presented.

An alternative modeling approach can also be applied which incorporates a variable positive skin in place of stress-dependent porosity/permeability. **Fig. 3.20a** demonstrates two skin-based modeling methods: 1) exponentially increasing skin to account for fracture damage as a result of early production under high drawdown (mathematical formulation: \( s(t) = s_{max}[1 - e^{-D_s t}] \); where \( D_s \) is the exponential skin decline factor); and 2) rate-dependent skin using Forchheimer’s equation to account for inertial effects due to high gas velocity in the fractures. A time-dependant skin was also used by Clarkson et al. (2013) to account for factors.
including changes in fracture conductivity (i.e. damage resulting from high drawdown), convergence flow into the horizontal well, non-Darcy or turbulent flow in the fractures and fracture face skin (i.e. liquid dropout near the fracture face or cleanup of drilling induced damage). This method provides more freedom as many potential effects can be modeled together, although it also does not provide insight into exactly which mechanisms are in play. Each approach leads to a comparable history-match and accompanying parameters as the base match, although the interpretation of stress-dependent porosity/permeability (presented in the body of the paper) due to fracture closure seems to be (physically) the most reasonable explanation. Due to multi-phase flow and relatively low production per fracture (<500 MSCF/D/fracture) the case with rate-dependent skin is conceptually the least likely.

Fig. 3.20– History-matches using skin instead of stress-dependent permeability: a) production rates of water and gas; b) skin changes used in the modeling.

Although the history-match and associated parameters are comparable to those presented from the previous model (Clarkson and Williams-Kovacs, 2013a), the modified approach better accounts for the physics of the flowback problem and incorporates observations from significantly more flowback cases. The modified approach also accounts for many of the
limitations of the previous approach and therefore the contributions of this paper are considered to be significant.

In addition to the field example presented here, this technique has been validated through application to a significant number of field cases in a variety of global shale plays. One particular study of interest, comparing this technique to long-term production data analysis, was conducted by Cugnart et al. (2017) on the Vaca Muerta Shale in Argentina. In that study, the authors found a good correlation between fracture half-length and SRV permeability estimated from flowback and online production data analysis as was seen in the case study presented above.

3.8 Summary

In this chapter, a modified method for quantitatively analyzing two-phase flowback from multi-fractured horizontal shale gas wells to estimate key fracture properties was presented. Techniques were demonstrated for analyzing both BBT (if available) and ABT data to estimate fracture conductivity (proppant pack permeability) and half-length. In this method, it is assumed that gas is sourced to the fracture network through a combination of instantaneous methods (i.e. desorption similar to highly cleated CBM wells) from the permeable fractured zone near the primary hydraulic fractures and linear flow from the tight matrix or secondary fractures. Instantaneous sourcing appears to be dominant early in time, with linear flow becoming more influential as fracture pressure decreases and sorbed gas near the fracture face is produced and can no longer be sourced instantaneously. A water-based fracturing fluid is assumed and water can also be sourced to the primary fracture network through linear flow if multi-phase linear
flow occurs in the matrix. The main conclusions that can be drawn from chapter include the following:

- The new method developed better represents the physics of the flowback problem than previous studies.
- Stress-dependant permeability and porosity as a result of fracture closure may be important during flowback particularly when post-stimulation shut-ins are short or flowback strategies are aggressive. These affects can be mimicked with a time-dependant skin although this seems like a less likely explanation of the observed phenomena.
- Flowback parameter estimates are in line with those from classical single-phase RTA and modeling of longer-term online production.
- The flowback model developed can be used to history-match long-term production and will eventually deviate from the single-phase model as a result of reduced fracture conductivity to gas as a result of the stimulation fluid.
- Fracture closure may be an important driving mechanism during shale gas flowback, especially in shale formations where significant desorption is absent or desorption pressure is significantly lower than initial reservoir pressure.
- The developed model could be extended to analyze tight gas flowback data.

Appendix 3.1 – Long-Term RTA and Analytical Modeling

Assuming the primary transient flow-regime during the first few months of online production is transient linear flow (from the matrix to the fractures), these data may be analyzed using the
linear flow superposition plot, which in its general form (accounting for non-static matrix porosity and permeability and desorption) is:

$$\frac{m^* (p_l) - m^* (p_{wf})}{q_w} = \tilde{m} t_{a,LS}^* + \tilde{b} \quad (3.1.1)$$

Where:

$$t_{a,LS}^* = \sum_{j=1}^{n} \frac{(q_j - q_{j-1})}{q_n} (t_{a,n}^* - t_{a,j-1}^*)^{1/2} \quad (3.1.2)$$

$$\sqrt{k_m x_{fT}}$$ may be obtained from the slope of the linear flow plot - assuming static matrix permeability, as was done in Fig. 3.18:

$$\sqrt{k_m x_{fT}} = \frac{200 \rho T}{h \sqrt{\mu g c_i^*}} \times \frac{1}{m^*} \quad (3.1.3)$$

If $k_m$ can be estimated from other sources (i.e. DFIT, core analysis, end of linear flow using distance of investigation etc.), $x_{fT}$ may be calculated explicitly.

If an estimate of total fracture half-length can be obtained from the flowback data as described above, then a forecast can be generated for the well, provided some additional information. In this work a simple linear-to-boundary model is used for the forecast (assuming no contribution from beyond the SRV). The equations for forecasting this model were given in the previous chapter. For completeness a sketch of the model for a single fracture stage is shown below in Fig. 3.1.1. Note that in many cases fracture half-length will exceed fracture spacing,
although the classic representation used by many authors (i.e Wattenbarger et al., 1998) is shown in Fig. 3.1.1.

**Fig. 3.1.1 — Conceptual model for linear flow solution.**
4.1 Abstract

In this Chapter, the methods developed by Clarkson et al. (2014) are used to analyze flowback data, which involves modeling flow both before and after the breakthrough of formation fluids. Despite the versatility of these techniques, achieving an optimal combination of parameters is often difficult with a single deterministic analysis. Because of the uncertainty in key model parameters, this problem is an ideal candidate for uncertainty quantification and advanced assisted history-matching techniques, including MC simulation and genetic algorithms (GAs) amongst others. MC simulation, for example, can be used for both the purpose of assisted history-matching and uncertainty quantification of key fracture parameters.

In this work, several techniques are tested including both single-objective (SO) and multi-objective (MO) algorithms for history-matching and uncertainty quantification, using an LTO field case. The results of this analysis suggest that many different algorithms can be used to achieve similar optimization results, making these viable methods for developing an optimal set of key uncertain fracture parameters. An indication of uncertainty can also be achieved, which assists in understanding the range of parameters which can be used to successfully match the flowback data.

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1 This chapter presents a modified version of: Williams-Kovacs and Clarkson. 2018. Stochastic Modeling and Assisted History-Matching Using Multiple Techniques of Multi-Phase Flowback from Multi-Fractured Horizontal Light Tight Oil Wells. Paper SPE 189786 accepted to the SPE Canada Unconventional Resources Conference held in Calgary, Alberta, 13-14 March.
4.2 Introduction

In recent years, as a result of low gas prices and relatively high oil prices, many producers have turned their attention to LTO reservoirs as a means of producing commercial wells. Much like shale gas reservoirs, LTO reservoirs are typically very low in permeability and require extensive hydraulic fracturing to allow for commercial production.

Although the majority of the literature has focused on shale gas reservoirs there has been a substantial amount of research conducted in analyzing flowback from LTO wells. These methods have been applied to LTO plays across North America.

4.3 Objective

The objective of the current work is to apply MC simulation both for uncertainty quantification as well as assisted-history matching purposes. Several other SO and MO techniques for assisted history-matching (focusing on evolutionary algorithms) are tested to determine the ability of each algorithm to identify the global minimum and therefore output the most realistic set of key uncertain fracture parameters. Results of the application of a gradient-based algorithm are presented to demonstrate how these techniques are insufficient in optimization of complex problems, unless the initial guess is closer to the absolute minimum than any local minima in the search space. Application of several evolutionary algorithms suggest that these algorithms are useful for this application, assuming a suitable search space is defined. Discussion will also be provided on how to speed up the performance of these algorithms making them more applicable for wide-spread use by industry.
4.4 Analysis Procedure

The basic analysis procedure for analyzing multi-phase flowback from MFHWs was given in Chapter Two. In this chapter, additional analysis steps are added for stochastic simulation and application of assisted history-matching techniques. The emphasis of this work is on the final 2 steps of the analysis procedure in which a variety of algorithms are used in an attempt to find the optimal solution and quantify uncertainty in key fracture parameter estimates. The first three steps, however, will also be demonstrated in the context of the field example, as these steps assist in setting up the search space for the stochastic simulation and assisted history-matching.

Fig. 4.1 – Summary of procedure for analyzing flowback data using deterministic, stochastic and assisted history-matching techniques.

4.4.1 Algorithms Used

In this work, six different algorithms were tested for the purpose of uncertainty quantification and assisted history-matching. The methods applied in this chapter include: 1) MC MO simulation (Palisade® @RISK™); 2) Microsoft® Excel’s SO Gradient-based (GRG2) algorithm (GRG Nonlinear Solver); 3) Microsoft® Excel’s SO Evolutionary Solver; 4) Palisade® Evolver’s SO GA; 5) GAPS MO GA (based on the NSGA-II – non-dominated sorting genetic algorithm) algorithm; and 6) Palisade® Evolver’s SO OptQuest™ algorithm. Each algorithm will be briefly discussed here, with more details available in the literature.
There are two main characteristics of all of these algorithms: 1) the OF; and 2) constraints. The OF is the key parameter that one is attempting to minimize or maximize (minimization in this case). Constraints are relationships which must be satisfied for a solution to be considered acceptable. The OFs used in this work are sum of squares OFs comparing measured water and oil rate with modeled rate. Cumulative production OFs can also be introduced to further constrain the problem. The OFs used in this work will be discussed in the coming sections. Since there are no hard constraints which are applicable to this problem, the only constraints used will be the input ranges of uncertain parameters, which will also be discussed in the coming sections.

4.4.1.1 Monte Carlo Simulation

Traditional deterministic analysis techniques combine single-point estimates of key input variables to provide a single-point estimate of the result. This type of analysis assumes that the true values of all inputs are known in order to derive an accurate solution. Often these single-point estimates may differ greatly from the actual result and can lead to negative outcomes such as financial loss. In the majority of real-life problems, certainty in all parameters is rarely the case; while some variables may be known precisely or can be estimated with a reasonable degree of accuracy (ex. from lab testing or other methods), others may contain a high degree of uncertainty (Palisade Corporation, 2015a). Stochastic simulation provides a platform to incorporate the uncertainty of inputs in order to derive a range of possible outcomes. This provides the analyst with vastly more information about the problem and assists in making smart decisions in which both the potential upside and downside are understood. Using these techniques in essence is similar to running hundreds or thousands of what-if scenarios.
simultaneously, while removing the often time-consuming and/or biased human component. Further, the results are presented in a manner in which they can easily be interpreted. The key components of a stochastic simulation include: 1) defining uncertain variables using a probability distribution; 2) defining key output variables; 3) running a series of simulations using an appropriate sampling technique (MC or Latin Hypercube); 4) developing a distribution of suitable output parameters using an OF. In this work, MC simulations were conducted using Palisade Corporation’s @RISK™ add-in for Microsoft® Excel™. As mentioned previously, MC simulation is conducted in such a way that multiple objectives are considered.

4.4.1.2 Microsoft® Excel’s GRG Non-Linear Solver (GRG2 Gradient-Based Algorithm)

This technique is based on the Generalized Reduced Gradient 2 (GRG2) algorithm which is an extension of a version of the GRG code developed by Lasdon et al. (1978) and is a SO algorithm. The solver combines a graphical user interface and algebraic modeling language for linear, nonlinear and integer programs and is integrated into the host spreadsheet as closely as possible (Arun and Tayo, 2014). These techniques are generally applied to smooth problems (i.e. smooth in both the OF and constraints), although these methods are often applied unwisely to optimization problems that do not meet the smoothness criteria (Laguna, 2011). These algorithms are “downhill” in nature and therefore tend to get trapped in the closest local minima surrounding the initial guess and struggle to escape these local minima. Application of a good initial guess (i.e. the deterministic solution) or the multi-restart technique, in which the algorithm is started from multiple randomly generated starting points, can allow these algorithms to find the absolute minima rather than being trapped in local minima in the vicinity of the starting point.
4.4.1.3 Microsoft® Excel’s Evolutionary Solver

The version of the Evolutionary Solver available in the standard version of Excel™ is a SO algorithm developed by Frontline Solvers® (2014). Although the exact workings of the solver are not available in the literature or from the developer, much like other GAs, this algorithm retains a population of solutions, although this is a steady-state GA (rather than a generational GA) meaning that only one solution is replaced by a better solution at each model iteration. This GA operates on a time-based constraint in which the algorithm has a set amount of time to find a better solution than the existing best solution and outputs a single best solution. As a result of the time-based nature of this GA, the longer maximum time without improvement defined by the user gives the algorithm a better chance of locating the absolute minimum, although the technique is designed to find a “good” solution rather than the optimal solution (the two may be equivalent or at least similar).

As with other GAs there are four main steps applied within the algorithm: 1) Selection; 2) Crossover/Mating; 3) Mutation; and 4) Replacement. Frontline Solver’s (2014) offers a variety of other more advanced algorithms which combine the simple GA with classical optimization techniques, other evolutionary algorithms as well as Tabu Search and Scatter Search which may lead to better ultimate solutions. These advanced versions were not tested in this work.

4.4.1.4 Palisade® Evolver’s Genetic Algorithm

Palisade® Evolver’s GA is a SO GA which contains 5 potential solving methods: 1) Recipe; 2) Order; 3) Grouping; 4) Budget; and 5) Project. The Recipe method is the default method and is designed to be used when parameter values can be varied independently and can be applied to
the majority of optimization problems, especially when the relationship between the adjustable variables are not well understood, or cannot be handled better by one of the other techniques. In this work, the Recipe solving technique is used. The GA used in Evolver™ is unique, much like that used in Microsoft® Excel’s Evolutionary Solver, in that it uses a steady-state approach, meaning that only one organism is replaced at a time rather that the entire generation. According to Palisade Corporation (2015b), this method has been shown to work as well or better than the generational method, although no evidence is provided in their literature. When comparing the results of Evolver’s GA with other GA’s that use the generational approach, the number of “equivalent generations” can be set by constraining the number of trails to be equal to the size of the population multiplied by the desired number of generations. Parallelization is also utilized by the program to improve computational efficiency. The same four general steps of a GA are applied in this algorithm as were applied in Excel’s Evolutionary Solver. This algorithm is designed to find the global minima. A uniform crossover scheme is used by this algorithm, meaning that half of the parameters of the child come from each parent.

4.4.1.5 GAPS Multi-Objective Genetic Algorithm (Based on NSGA-II Algorithm)

GAPS is a MO GA based on the NSGA-II algorithm developed by Deb et al. (2002). As a MO GA, the algorithm is designed to account for objective conflict and yields a Pareto Front of solutions which are all mathematically equivalent. If a single optimal solution is desired, then the user must select the solution along the Pareto Front which is most applicable to the problem being solved. The NSGA-II algorithm is an extension of the NSGA algorithm developed by Srinivas and Deb (1994). The basis of the algorithm is the nondominated sorting procedure,
hence the name of the algorithm. The modified algorithm was developed to handle the main criticisms of the original algorithm, and offers the following benefits over the original algorithm:

- Utilizes a faster method for nondominated sorting.
- Preserves elitism, meaning that the best solutions are maintained without modification.
- Incorporates a parameter-less diversity preservation mechanism to replace the need for a sharing parameter, which is the traditional mechanism for maintaining diversity.
- Utilizes parallelization to improve solution speed by allowing calculations to be spread out over multiple processors.

There are two key concepts to the algorithm, being: 1) nondominated sorting; and 2) diversity preservation and follows the same general concept of the other GAs discussed above, although is generational in nature. This algorithm has been shown to work well for three OFs (Kanfar and Clarkson, 2016), although it generally begins to fail as further objectives are added in complex problems (four or more in this particular problem). To handle this deficiency, the U-NSGA-III algorithm was developed by Seada and Deb (2015). This algorithm uses a continuous single-point crossover scheme, meaning that crossover occurs at randomly chosen points and the two children get the genetic material from either side of the crossover point.

4.4.1.6 Palisade® Evolver’s OptQuest Algorithm

OptQuest™ is a “black box” optimizer first developed by Glover et al. (1996) to find the global optimum solution. The algorithm is not totally context-independent because the selection of the solution representation gives some information to the optimization algorithm. The model allows the user to represent solutions as a mixture of continuous, discrete, integer, binary,
permutation and other specialized variables which provides the optimizer with some information about the system. The software ultimately chooses solvers based on the characteristics of the optimization model (pure or mixed, constrained or unconstrained and deterministic or stochastic). The optimizer is based in Scatter Search, but also uses the principles of Tabu Search, an Artificial Neural Network and other methods in attempt to derive a global optimum solution more rapidly. Scatter Search is an optimization algorithm comparable to a GA.

4.5 Field Example

A full analysis demonstrating each step of the analysis procedure (shown in Fig. 4.1) will be provided. The application of the first three steps is similar to what was demonstrated for a shale gas well in Chapter Three. One MFHW from a 3-well pad in a LTO play in the Western Canadian Sedimentary Basin (WCSB) will be analyzed, although the other two wells on the pad, as well as other wells in the area and other LTO plays in North America, have also been analyzed using this procedure. This well was previously analyzed by Clarkson et al. (2014), but using a deterministic approach. To protect operator confidentiality, well location and reservoir and completion information has been withheld. A summary of the completion and stimulation performed is given below:

- Cased-hole completion
- Hydraulically fractured with hybrid water fracs in 18 stages using plug and perf technology (single perforation cluster per stage)
- Fracture stages spaced at ~ 330 ft
- 1,350 STB of fracture fluid and 45 T of proppant pumped per stage
Assessing the microseismic collected on this well (shown in Chapter Six), the assumption of circular bi-wing planar fractures appears to be reasonable and will be used in this analysis. Preceding the flowback data used for this analysis, plugs were drilled out with coil tubing following stimulation, after which the well was placed on flowback monitoring through a test separator. Rate and pressure data was gathered every 15 minutes for approximately 300 hours during flowback following a 12 day shut-in period.

Input common to the different flowback analysis techniques are shown below in Table 4.1. Note that the individual hydraulic fracture width is approximately twice what is expected for a simple bi-wing planar fracture (0.25 in/stage). This is likely due to some fracture complexity (or possibly multi-planar fractures) which could not be resolved at the microseismic level. This will be discussed further in Chapter Seven.
4.5.1 Raw Data and Diagnostic Plots

Water, oil and gas rates as well as bottom-hole flowing pressure and GOR are shown below in Fig. 4.2a, while water RNP and RNP’ are shown in Fig. 4.2b.

**Table 4.1 — Input Parameters for Flowback Field Example**

<table>
<thead>
<tr>
<th>Fracture Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Fracture Pressure (psia)</td>
<td>5,000</td>
</tr>
<tr>
<td>Initial Water Saturation (%)</td>
<td>100</td>
</tr>
<tr>
<td>Fracture Porosity (proppant pack) (%)</td>
<td>31</td>
</tr>
<tr>
<td>Fracture Compressibility (psi⁻¹)</td>
<td>1 x 10⁻⁴</td>
</tr>
<tr>
<td>Number of Hydraulic Fractures</td>
<td>18</td>
</tr>
<tr>
<td>Individual Hydraulic Fracture Width (ft)</td>
<td>0.0417</td>
</tr>
<tr>
<td>Total Hydraulic Fracture Width (ft)</td>
<td>0.75</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Pressure (psia)</td>
<td>3,700</td>
</tr>
<tr>
<td>Net Pay (ft)</td>
<td>197</td>
</tr>
<tr>
<td>Matrix Porosity (%)</td>
<td>4</td>
</tr>
<tr>
<td>Initial Mobile Oil Saturation (%)</td>
<td>99</td>
</tr>
<tr>
<td>Initial mobile water saturation (%)</td>
<td>1</td>
</tr>
<tr>
<td>Formation Compressibility ( psi⁻¹)</td>
<td>4 x 10⁻⁶</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.0003</td>
</tr>
<tr>
<td>Reservoir Temperature (°F)</td>
<td>140</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Water Salinity (%)</td>
<td>50,000</td>
</tr>
<tr>
<td>Formation Water Salinity (%)</td>
<td>200,000</td>
</tr>
<tr>
<td>Oil Gravity (°API)</td>
<td>52</td>
</tr>
<tr>
<td>Gas-Oil-Ratio (scf/stb)</td>
<td>1,250</td>
</tr>
<tr>
<td>Bubble-Point Pressure (psia)</td>
<td>2,858</td>
</tr>
<tr>
<td>Gas Gravity (air = 1)</td>
<td>0.747</td>
</tr>
</tbody>
</table>
From Fig. 4.2a it can be observed that flowback initiates with more than 2 days of single-phase water production (fracture fluid) prior to the breakthrough of hydrocarbons (formation fluid). Hydrocarbons breakthrough at just after 2 days, with an initial oil rate of ~ 36 STB/D. For about the first 6 days of hydrocarbon production (8 days total), the GOR is approximately constant at 1,250 scf/STB which is equal to the solution gas level. At ~ 8 days there is a rapid drop in flowing pressure (resulting from a rapid decrease in choke size) below the bubble-point followed by a rapid increase in GOR suggesting a breakthrough of gas into the fractures. Therefore, only the first 8 days of production were considered for this analysis as this is the period where production is under two-phase (water + oil) flow in the formation and fractures (the tool cannot currently model three-phase flow). Over the first 8 days of production, water rate and bottom-hole flowing pressure generally decline, while the hydrocarbon rate generally increases following breakthrough as would be expected from a formation with minimal mobile water and constantly decreasing bottom-hole flowing (and fracture) pressure. From Fig. 3.2b, BBT flow-regimes can be identified using the RNP’ curve from the period of single phase production. The first flow-regime interpreted is a short period of transient radial flow within the
fractures (0-slope), which appears to last until ~ 0.1 days of MBT, although the data is scarce and noisy during this period making it difficult to conclude this flow-regime identification with a significant degree of certainty. From ~ 0.1 days to ~ 3 days of MBT a clear period of fracture depletion (unit-slope) is identified up until breakthrough. ABT, the derivative is non-linear in nature, as would be expected as multiple flow-regimes are occurring, although a depletion-like signature remains dominant.

Casing pressures were converted to sandface pressures using a wellbore model, and initial formation pressure was estimated from $p^*$ obtained from a DFIT test which also yielded the estimate of matrix permeability. The GOR and bubble-point pressure are defined based on PVT analysis of the reservoir fluid from a group of off-setting wells. Initial fracture pressure was determined by a trial and error process conducted by Clarkson et al. (2014) and was maintained for this analysis.

4.5.2 Rate-Transient Analysis of BBT Single-Phase Data

To assist with the history-matching process, RTA is applied to the flow-regimes identified in Fig. 4.2b (repeated in Fig. 4.3a). Radial flow analysis, which is shown in Fig. 4.3b, is used to analyze FR 1 and estimate fracture conductivity (permeability). Delimiters are shown to highlight the interpreted period of radial flow. Using the slope of the radial flow plot, fracture permeability is estimated to be ~ 3,500 md, assuming a fracture width of 0.5 in/fracture with a small negative skin. The negative skin may be a result of maximum proppant concentration near the wellbore as discussed previously. The FMB, which is shown in Fig. 4.3c, is used to assess FR 2 and estimate BBT fracture volume and fracture half-length. From the x-intercept of the plot, the total fracture volume is estimated to be approximately 24,000 STB, and
the BBT fracture half-length to be ~ 441 ft per stage, assuming a circular fracture shape and a fracture width of 0.5 in/fracture. From the y-intercept an additional measure of fracture permeability can be derived to be ~ 3,400 md, assuming a fracture width of 0.5 in/stage. The total calculated fracture volume is approximately equal to the total volume injected during the fracture stimulation, suggesting that the majority of pumped fluid has been converted into effective fracture volume (prior to hydrocarbon breakthrough). This conversion percentage is higher than expected even for a well with minimal natural fracturing (as inferred from microseismic and experience in the formation of interest), and may result from the impact of the other two wells being stimulated on the same pad prior to flowback of the well. These values will be used in the deterministic history-matching process. Finally, the fracture parameters estimated from radial flow analysis and the FMB can be confirmed by using the Fetkovich type-curve (Fig. 4.3d) which is designed for analyzing radial to boundary-dominated flow behaviour. Because MBT is used in the calculation of $t_{Dd}$, fracture depletion data falls down the harmonic stem, with a positive deviation indicating the breakthrough of formation fluid.
Fig. 4.3 – Rate-transient analysis of BBT single-phase data: a) water RNP and RNP* plot; b) early radial flow analysis; c) flowing material balance; and c) Fetkovich type-curve.

Parameters estimated from quantitative RTA of this flowback data are provided in Table 4.2.

| Table 4.2 — Parameters Solved From Each BBT RTA Technique |
|---------------------------------|-----------------|
| Radial Flow Plot                | Parameter Value |
| Fracture Conductivity, $F_{ct}$ (md-ft) | 2.625           |
| Fracture Permeability (md)      | 3,500           |
| Flowing Material Balance        | Parameter Value |
| Fracture Fluid-In-Place (STB)   | 24,000          |
| BBT Half-Length, $x_{bbt}$ (ft)  | 411             |
| Fracture Conductivity, $F_{ct}$ (md-ft) | 2.550           |
| Fracture Permeability (md)      | 3,400           |
| Fetkovich Type-Curve            | Parameter Value |
| $x_{f}/r_w$                     | ~ 1000          |
| Fracture Conductivity, $F_{ct}$ (md-ft) | 2.625           |
| Fracture Permeability (md)      | 3,500           |
4.5.3 Deterministic History-Match

Deterministic history-matching was first conducted to validate the application of the conceptual model to this dataset, confirm selection of a fracture shape and geometry model, and confirm RTA-derived parameters for BBT fracture properties. For this analysis, a circular shape with a single bi-wing fracture being generated from each stage was selected for simplicity, as was done by Clarkson et al. (2014), under the assumption that cylinder radius is equal to fracture half-length.

The history-matches, guided by the BBT RTA-derived parameters are provided in Fig. 4.4. The deterministic history-match was not significantly changed from what was presented by Clarkson et al. (2014), although minor improvements were made. Note the deterministic history-match is shown here in black to maintain continuity of this match throughout the chapter.

![Deterministic Rate Match](#)

**Fig. 4.4** – Deterministic flowback match: (a) water, oil and gas production rates; and (b) cumulative water, oil and gas.

From Fig. 4.4 it can be seen that the deterministic history-match to water is very good throughout the eight days of flowback modeled, while the hydrocarbon match is very good for
the first 6.5 days at which point it begins to significantly underestimate production. After conducting the first 3 stages of the analysis procedure, the remainder of the chapter will focus on the stochastic simulation and assisted history-matching component of the procedure which is the main contribution of this chapter.

The key history-match parameters are given in Table 4.3 (assumed to be fracture permeability, cylinder radius (fracture half-length) BBT and ABT of formation fluid, breakthrough pressure and the Corey relative permeability exponents for oil and water in the fractures). Matrix relative permeability coefficients were assumed to be 2 for oil and water formation fluid, although due to the very high mobile oil saturation, these curves have minimal impact on the analysis.

<table>
<thead>
<tr>
<th>History-Match Parameter</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,500</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
</tr>
<tr>
<td>BBT Half-Length, (x_{f,BBT}) (ft)</td>
<td>441</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
</tr>
<tr>
<td>ABT Half-Length, (x_{f,ABT}) (ft)</td>
<td>425</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>3,825</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, (n')</td>
<td>1.2</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, (m')</td>
<td>5.0</td>
</tr>
</tbody>
</table>

From Table 4.3, it can be seen that the fracture half-length decreases following the breakthrough of formation fluids, as expected. A ~ 7% decrease in drainage radius (~ 4% decrease in effective half-length) was observed and this was applied during stochastic simulation and assisted history-matching to reduce the number of uncertain parameters. In many cases the reduction in half-length as a result of breakthrough can be significantly larger. Further,
breakthrough pressure was set slightly higher than formation pressure to account for the supercharge effect associated with high-rate injection. Matrix relative permeability exponents were set to two for both water and oil throughout.

4.5.4 Stochastic Simulation and Assisted History-Matching

In this section, the results from multiple stochastic and assisted history-matching techniques will be discussed. As mentioned previously, the algorithms used include: 1) MC simulation (Palisade® @RISK™); 2) Microsoft® Excel’s Gradient-based (GRG2) algorithm (GRG Nonlinear Solver); 3) Microsoft® Excel’s Evolutionary Solver; 4) Palisade® Evolver’s GA; 5) GAPS MO GA (based on the NSGA-II) algorithm; and 6) Palisade® Evolver’s OptQuest™ algorithm. The results of each individual technique will be discussed followed by a comparison of the results of each of the techniques. As discussed previously, only the first 8 days of flow data were analyzed because, during this flow period, the flowing pressure remains above the bubble point, and therefore only two-phase flow exists in the matrix and fractures. During this period, the GOR is also relatively constant, as would be expected for flow above the bubble point.

4.5.4.1 Monte Carlo Simulation

As discussed previously, stochastic history-matching can be a multi-step process, with multiple refinement stages. For example, two sets of MC simulations were conducted in the presented example. Following the first stage, inputs including fracture compressibility and matrix properties were held constant for the final set of simulations, which will be discussed here. Further refinement stages could be conducted using information from past runs to adjust
input distributions and increase the number of success cases. The parameter distributions for the first refinement stage are shown below in Table 4.4. Because enough data was not available to construct proper input distributions, uniform distributions were used for each parameter between a reasonable low and high value. In some cases, the high and low value were constrained by physical limits (i.e. the upper limit of half-length, the lower limit of $n'$ and $m'$ and breakthrough pressure) whereas other limits were set at a reasonable range and then adjusted following the screening stage of iterations. The input parameter ranges were also further constrained by the initial screening phase of simulations (500,000 iterations with significantly wider parameter ranges), as well as reasonable limits on the uncertain parameters. The initial screening phase was used to rule out outlier matches which occurred with minimal frequency. The same limits were used for the application of the assisted-history matching techniques, which will be discussed in the following section. This analysis is comparable to that conducted by Williams-Kovacs and Clarkson (2013c), although the number of uncertain parameters were reduced from 10 to 5, placing the focus on the most important parameters. Using this approach allows reasonable coverage of the sample space with a smaller number of iterations. Williams-Kovacs and Clarkson (2013c) conducted significantly less simulations than would be needed to cover the sample space, although the purpose of that work was to demonstrate the purpose and application of MC simulation to history-matching flowback data from MFHWs.
The following objective functions (OFs) were used in either the MC simulations, assisted history-matching algorithms or both. The OFs take the form of sum of squared residuals for the rate and cumulative production of the water and oil phases. Because the well is flowed above the bubble point throughout the analysis period of the flowback, and the GOR is relatively constant at approximately the solution gas level, the gas phase is not considered and is effectively lumped in with the oil phase.

**Water Rate OF:**

$$OF_{qw} = \sum_{i=1}^{n} \left( q_{w,\text{data}} - q_{w,\text{sim}} \right)^2$$ (4.1)

Where, $n$ is the number of data points collected during the portion off the flowback data being analyzed for each phase.

**Oil Rate OF:**

$$OF_{qo} = \sum_{i=1}^{n} \left( q_{o,\text{data}} - q_{o,\text{sim}} \right)^2$$ (4.2)

**Cumulative Water OF:**

$$OF_{Qw} = \sum_{i=1}^{n} \left( Q_{w,\text{data}} - Q_{w,\text{sim}} \right)^2$$ (4.3)

---

**Table 4.4 — Input Distributions/Ranges For Monte Carlo Simulation and Assisted History-Matching**

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Distribution Type</th>
<th>Low Value</th>
<th>High Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>Uniform</td>
<td>3,000</td>
<td>4,000</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>Uniform</td>
<td>10</td>
<td>14*</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{BBT}$ (ft)</td>
<td>Uniform</td>
<td>372</td>
<td>441*</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>Uniform</td>
<td>3,700</td>
<td>4,100</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, $n'$</td>
<td>Uniform</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, $m'$</td>
<td>Uniform</td>
<td>1</td>
<td>10</td>
</tr>
</tbody>
</table>

* Upper bound on fluid in place given assumptions of fracture shape, width and porosity
Cumulative Oil OF:
\[ OF_{Q_o} = \sum_{i=1}^{n} (Q_{o,data} - Q_{o,sim})^2 \] 
(4.4)

Summed Rate OF:
\[ OF_{q_e} = \sum_{i=1}^{n} \left[ w_w (q_{w,data} - q_{w,sim})^2 + w_o (Q_{o,data} - Q_{o,sim})^2 \right] \] 
(4.5)

Where,
\[ w_w + w_o = 1 \] 
(4.6)

The summed rate OF given by Eqn. 4.5 is used for the SO algorithms. There are however two issues associated with using summed OFs: 1) objective conflict leading to erroneous results; and; 2) weighting can have a significant impact on the results of the algorithm. In this work, a 1:1 weighting was used for direct comparison to the MO algorithms (equivalent to using \( w_w = w_o = 0.5 \)).

Alternate criteria, such as those applied by Williams-Kovacs and Clarkson (2013a,c), could also be used if a reasonable baseline deterministic match is not available. In these two papers, the authors used an \( R^2 \) value of each phase (in terms of rate) greater than 0.9 (as suggested by Oudinot et al., 2005) and a total cumulative production for each phase within 10% (as suggested by Roadifer et al., 2003) for each phase to determine a successful match. This approach was shown to be relatively successful in the studies by Williams-Kovacs and Clarkson (2013a,c). However, some successful solutions in both cases were found where a high \( R^2 \) value existed but the match was poor, due to the inherent nature of \( R^2 \) as a match fit indicator, especially when dealing with highly nonlinear problems with a large number of data points. For the current study, 100,000 iterations are conducted, and fairly strict criteria were enforced to obtain a
successful match, including the following (solution has to be better than the deterministic solution for both phases):

- $OF_{q_w} < OF_{q_w,\text{deterministic}}$
- $OF_{q_o} < OF_{q_o,\text{deterministic}}$
- $OF_{Q_w} < OF_{Q_w,\text{deterministic}}$
- $OF_{Q_o} < OF_{Q_o,\text{deterministic}}$

Using all four of these criteria, only 79 matches were found (~ 0.1%), while if only the two rate criteria were used, as is usually done with the assisted history-matching techniques, ~10x the number of matches were found (~ 1%). Based on these results, it is clear that the random behaviour of MC simulation is not particularly efficient in finding optimal solutions, making the use of modern assisted history-matching techniques desirable, particularly when a deterministic solution is not available. For the remainder of this chapter, only the two rate OFs will be used in the application of all algorithms, because adding more OFs can often cause these algorithms to converge slowly and creates further objective conflict, potentially leading to finding a less desirable solution. The parameters for the deterministic match, as well as the best 5 matches (in order of increasing OF value) when considering the summation of the two OFs, are shown below in Table 4.5 along with the mean, standard deviation and P10/P90 ratio of the 861 acceptable matches.
Table 4.5 — Stochastic History-Match Parameters

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Deterministic</th>
<th>Match 1</th>
<th>Match 2</th>
<th>Match 3</th>
<th>Match 4</th>
<th>Match 5</th>
<th>Mean</th>
<th>Std. Dev.</th>
<th>P10/P90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,500</td>
<td>3,225</td>
<td>3,184</td>
<td>3,167</td>
<td>3,159</td>
<td>3,216</td>
<td>3,425</td>
<td>254.41</td>
<td>1.23</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
<td>13.82</td>
<td>13.73</td>
<td>13.97</td>
<td>13.78</td>
<td>13.67</td>
<td>13.52</td>
<td>0.37</td>
<td>1.07</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{f, BBT}$ (ft)</td>
<td>440</td>
<td>438</td>
<td>436</td>
<td>440</td>
<td>437</td>
<td>436</td>
<td>432</td>
<td>6.01</td>
<td>1.04</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
<td>12.83</td>
<td>12.75</td>
<td>12.97</td>
<td>12.79</td>
<td>12.69</td>
<td>12.54</td>
<td>1.41</td>
<td>1.04</td>
</tr>
<tr>
<td>ABT Half-Length, $x_{f, ABT}$ (ft)</td>
<td>425</td>
<td>422</td>
<td>420</td>
<td>424</td>
<td>421</td>
<td>420</td>
<td>417</td>
<td>5.79</td>
<td>1.04</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>3,825</td>
<td>4,093</td>
<td>4,096</td>
<td>4,058</td>
<td>4,099</td>
<td>4,089</td>
<td>4,024</td>
<td>56.75</td>
<td>1.04</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, $n'$</td>
<td>1.20</td>
<td>1.44</td>
<td>1.44</td>
<td>1.35</td>
<td>1.42</td>
<td>1.51</td>
<td>1.40</td>
<td>0.12</td>
<td>1.26</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, $m'$</td>
<td>5.00</td>
<td>4.81</td>
<td>5.04</td>
<td>5.31</td>
<td>6.10</td>
<td>5.25</td>
<td>5.31</td>
<td>1.41</td>
<td>2.03</td>
</tr>
<tr>
<td>Total Objective Function (millions)</td>
<td>41.5</td>
<td>35.4</td>
<td>35.4</td>
<td>35.5</td>
<td>35.6</td>
<td>35.7</td>
<td>39.2</td>
<td>0.14</td>
<td>1.10</td>
</tr>
</tbody>
</table>
Fig. 4.5 – Stochastic flowback history-match: (a) water production rates; (b) cumulative water production; (c) oil production rates; (d) cumulative oil production; (e) gas production rates; and (d) cumulative gas production.

For later comparison to the assisted history-matching results, the average of the top five iterations were assumed to represent the best solution found using MC simulation, as each of these solutions have a total OF within 1% of each other. The values for each of the uncertain parameters are provided in Table 4.6. The average summed rate OF is ~ 14% lower than the deterministic solution.

<table>
<thead>
<tr>
<th>Table 4.6 — Average Values of Top 5 Monte Carlo Simulations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uncertain Parameter</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{f,BBT}$ (ft)</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
</tr>
<tr>
<td>ABT Half-Length, $x_{f,ABT}$ (ft)</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, $n'$</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, $m'$</td>
</tr>
<tr>
<td>Total Objective Function (millions)</td>
</tr>
</tbody>
</table>

The parameter distributions generated from the stochastic history-matching exercise are provided in Fig. 4.6. $R^2$ values are shown to indicate the lognormal nature of the output.
distributions, and the deterministic and mean values are provided for reference. Note that the parameter distribution for BBT drainage area is not provided because the focus is on the half-length calculated from the drainage area (using the assumed shape and geometry constraints), since half-length is one of the key parameters controlling long-term production of the well.
From Table 4.5 and Fig. 4.6 it can be seen that the range of values used to match the flowback data is fairly small (P10/P90 ≤ 2). Further it can be seen that the average values of the 861 successful matches are within 5% of the deterministic match, with the exception of the relative permeability exponents ($n' = 17\%$ and $m' = 6\%$), which are sensitive to small changes due to the small magnitude of their values. Some key results to point out are as follows:

- Fracture permeability covers the entire input distribution, suggesting that fracture permeability may fall outside the search space. However, very few matches beyond the selected range were found during the screening phase.

- Breakthrough pressures, including the deterministic match, are greater than reservoir pressure estimated from DFIT analysis. Values (other than the deterministic match) also fell near the upper limit of 4,100 psia, suggesting a better match to the available data could be achieved using a breakthrough pressure of 4,100 psia. However, experimentation with a variety of fracture parameters suggested that breakthrough pressures greater than 4,100 psia led to model breakthrough significantly earlier than the BBT in the actual data, which led to setting the upper limit at the selected value. 4,100 psia still yields a breakthrough earlier than the data – however, the fact that flow initiates at ~ 36 STB/D, which is higher than other similarly completed wells on the same pad, suggests that some early-time hydrocarbon data may not have been recorded. An improved late-time match was observed with earlier breakthrough. Overall the results suggest a near fracture supercharge of up to 10% following an 11 day shut-in between stimulation and
the onset of flowback in which the bridge plugs were milled out. The supercharge has been shown to be much higher in some formations depending on factors such as the stimulation pumped, shut-in time between stimulation and flowback and other reservoir and fluid properties.

- BBT half-length values fell in the range of 413 to 441 ft suggesting that a BBT half-length less than 400 ft is unlikely and that a high degree of fracture efficiency was achieved.
- Fracture relative permeability exponents to oil fall in a tight band between 1.1 and 1.6, suggesting minimal potential variability in this parameters.
- Fracture relative permeability exponents to water are far less constrained than those to oil falling between 2.1 and 9, although are significantly higher than those to oil. This has been observed in nearly all wells analyzed using these methods. In this case it can be seen that the values between the P10 (3.5) and P90 (7.2) follow a lognormal distribution and yield a P10/P90 ratio of ~ 2. 20% of the solutions fell outside this range and may be considered as outliers.

4.5.4.2 Assisted History-Matching

In addition to the MC simulation approach demonstrated above, five assisted history-matching algorithms were applied in an attempt to find the best possible history-match to the same flowback data set discussed above. Two types of algorithms were used in this analysis (gradient-based and evolutionary) with a total of five techniques being tested: 1) Microsoft® Excel’s SO Gradient-based (GRG2) algorithm (GRG Nonlinear Solver); 2) Microsoft® Excel’s SO Evolutionary Solver; 3) Palisade® Evolver’s SO GA; 4) GAPS MO GA (based on the
NSGA-II) algorithm; and 5) Palisade® Evolver’s SO OptQuest™ algorithm. For this analysis, the lower and upper bounds given above in Table 4.3 are used as constraints on the algorithms, and no further constraints were applied. The same initial guesses for the uncertain parameters (Table 4.6) are used to seed each of the algorithms, although many evolutionary algorithms do not require an initial guess as they generate an initial population based on the constraints in the uncertain parameters. Most available evolutionary algorithms are implemented in a way that the initial guess will be a member of the first population. As was discussed previously, and as will be demonstrated below, the initial guess is critical to achieving good results from the GRG algorithm because these algorithms will tend to find the closest local minima in the OF (downhill nature of the algorithm). The initial guesses were selected based on the following criteria:

- Fracture permeability – RTA of early-time flowback data suggested a maximum fracture permeability of ~ 3,500 psia (as was used in the deterministic history match) and therefore a slightly lower value was selected for this application.
- Breakthrough pressure – DFIT analysis suggested an initial reservoir pressure of ~ 3,700 psia and therefore a 200 psia supercharge effect was assumed (~ 5%).
- Drainage area – set based on results of the FMB in the deterministic analysis.
- Relative permeability exponents – straight-line relative permeability curves were assumed as may be expected for homogeneous perfectly planar fractures under ideal flowing conditions.
The results of each algorithm will be discussed, followed by a comparison of the results of each algorithm, as well as the average results of the top five MC simulations.

4.5.4.2.1 Microsoft® Excel’s GRG Nonlinear Solver

As discussed previously, the initial guess is critical to the quality of the result using this type of algorithm due to the “downhill” nature of the algorithm and tendency to get trapped in local minima. This impact will be demonstrated in this section. Due to the deficiencies of this algorithm in solving complex problems with multiple minima, a poor result was expected using the initial guesses shown in Table 4.7. However, it was interesting to determine whether a reasonable quality initial guess (i.e. the deterministic solution) could be used to converge on the absolute minimum and ultimately find an optimized solution. This is of interest because these algorithms run very quickly compared to GAs due to their simplistic nature, and are built directly into Microsoft® Excel™, allowing for fast and simple application following the deterministic history-matching exercise. To test the capacity of the algorithm for solving this problem, two runs were completed. In the first run the initial guesses shown in Table 4.8 were used, and in the second run, the deterministic solution (see Table 4.2) was used. In both cases the algorithm

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,100</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>13.96</td>
</tr>
<tr>
<td>BBT Half-Length, x_f_BBT (ft)</td>
<td>440</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
</tr>
<tr>
<td>ABT Half-Length, x_f_ABT (ft)</td>
<td>424</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>3,900</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, n’</td>
<td>1</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, m’</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 4.7 — Initial Guesses for Assisted History-Matching Parameters
converged to a solution very quickly, given the speed of the tool being used, suggesting very few iterations were required to locate a minima, although the exact iteration count is not provided by the standard version of Excel™ unless the algorithm is stopped at each iteration (which was not done in this case). The initial guess and final solution for the two sets of input parameters are provided in Table 4.8 and Table 4.9, with the solutions being compared to actual data and the deterministic history-match in Fig. 4.7.

**Attempt #1: Using the Same Initial Guess as the Other Assisted History-Matching Techniques**

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Initial Guess</th>
<th>Final Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,100</td>
<td>3,000</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
<td>14</td>
</tr>
<tr>
<td>BBT Half-Length, x_L_BBT (ft)</td>
<td>441</td>
<td>441</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td>ABT Half-Length, x_L_ABT (ft)</td>
<td>425</td>
<td>425</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>3,900</td>
<td>3,911</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, n’</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, m’</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Total Objective Function (millions)</td>
<td>42.8</td>
<td></td>
</tr>
</tbody>
</table>
Attempt #2: Using Deterministic Solution as Initial Guess

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Initial Guess</th>
<th>Final Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,500</td>
<td>3,102</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
<td>14</td>
</tr>
<tr>
<td>BBT Half-Length, (x_f_{BBT}) (ft)</td>
<td>441</td>
<td>441</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td>ABT Half-Length, (x_f_{ABT}) (ft)</td>
<td>425</td>
<td>425</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>3,825</td>
<td>4,099</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, (n')</td>
<td>1.2</td>
<td>1.45</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, (m')</td>
<td>5</td>
<td>5.61</td>
</tr>
<tr>
<td>Total Objective Function (millions)</td>
<td>34.7</td>
<td></td>
</tr>
</tbody>
</table>
From Table 4.7 and 4.8 it can be seen that the final solutions yield a 4% higher summed rate of flow than the deterministic solution when using the initial guesses shown in Table 4.6, while the optimal solution using the deterministic match as the initial guess yields a 16% reduction in the
summed rate of which equates to an ~2% improved result over any of the MC simulations. From Fig. 4.7 it can be seen that Attempt #1 yields a very poor history-match, especially to the hydrocarbon phases, while Attempt #2 yields an excellent history-match to all three phases. As will be seen in the coming sections, the gradient solver replicated the results of the evolutionary algorithms when seeded with the deterministic history-match as an initial guess. This suggests that no local minima exist between the deterministic solution and the absolute minimum. Further, this type of method may be used to optimize a history-match once a reasonable deterministic solution is found, although additional testing would be required to further substantiate this claim.

4.5.4.2.2 Microsoft® Excel’s Evolutionary Solver

In this section the results of the Excel’s Evolutionary Solver will be demonstrated. This Solver algorithm is the first of two SO GAs which will be tested in this work. This solver also uses several classical optimization methods to attempt to improve upon the solutions found by the GA, thus making it a hybrid GA. As discussed previously, details of how Excel’s Evolutionary Solver works are not readily available and very little assistance was provided by the developer to help understand exactly which techniques are employed. Given that this is a time-based, rather than a generation-based algorithm, the exact number of iterations conducted is unknown, although the algorithm converged significantly faster than the other algorithms tested, suggesting that significantly fewer 10,000 iterations were conducted in finding the best solution. The input parameters used for this algorithm are shown below in Table 4.10. A mutation rate of 15% was selected for all GAs, as this was preprogrammed into the version of the GAPS algorithm which was used in this work. A population size of 100 was used for all of the
population-based algorithms based on the suggestions of Kanfar and Clarkson (2016). Max time without improvement was set to a high value to give the algorithm sufficient time to search for a better solution given the calculation speed of the spreadsheet-based tool used in this work (~ 30 seconds/iteration). Based on the values provided in Table 4.9, and the approximate run speed of the spreadsheet, ~ 300 iterations were allowed to find an improved solution, and the algorithm terminated once a maximum change of the combined OF falls below 0.01%. In this case it is unclear whether the algorithm terminates based on the time or convergence criteria. The same convergence criteria were used with Palisade’s algorithms, which will be discussed in a coming section.

| Table 4.10 — Input Parameters for Excel’s Single-Objective Evolutionary Solver |
|---------------------------------|--------|
| Mutation Rate (%)               | 15     |
| Population Size                 | 100    |
| Max Time Without Improvement (s) | 10,000 |
| Convergence Criteria for Max Change (%) | 0.01   |

As with other SO algorithms, a single best solution is found by the algorithm. The parameters resulting from the optimization are found in Table 4.11 and the resulting combined OF is ~ 16% lower than that of the deterministic match.
4.5.4.2.3 Palisade® Evolver’s Genetic Algorithm

In this section the results of Palisade® Evolver’s SO GA will be demonstrated. Evolver™ is the second SO GA used in this work. Much like Excel’s Evolutionary Solver, Evolver™ uses a steady-state approach, which the company has found to work as well or better than the generational approach. Further, given that this is a proprietary commercial tool, details on the exact workings of the algorithm are not readily available. Based on the information provided by the developer, the algorithm operates in a manner comparable to a basic GA, although several specialty operators are included to improve the results of the algorithm. The algorithm is trial-based rather than generational-based, and therefore to mimic the generational approach used by the GAPS MO GA, 10,000 trials were conducted (equivalent to 100 generations with a population of 100). A convergence criteria for maximum change in the OF is also used as an input for termination of the algorithm, although this was not achieved. The input parameters used for this algorithm are shown below in Table 4.12. A cross-over rate of 50% is used as this is the default setting in the program, meaning that each child receives half of its genes from each parent. Changing the cross-over rate could significantly impact algorithm performance and can be changed during an optimization run.

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,156</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
</tr>
<tr>
<td>BBT Half-Length, x_f_BBT (ft)</td>
<td>441</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
</tr>
<tr>
<td>ABT Half-Length, x_f_ABT (ft)</td>
<td>225</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>4,098</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, n’</td>
<td>1.46</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, m’</td>
<td>5.66</td>
</tr>
<tr>
<td>Total Objective Function (millions)</td>
<td>34.7</td>
</tr>
</tbody>
</table>

Table 4.11 — Optimal Match Parameters for Excel’s Single-Objective Evolutionary Solver
As with other SO algorithms, a single best solution is found by the algorithm. The parameters resulting from the optimization are given in Table 4.13, and the resulting combined OF is ~ 16% lower than that of the deterministic match.

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,102</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{f,bbt}$ (ft)</td>
<td>425</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
</tr>
<tr>
<td>ABT Half-Length, $x_{f,abt}$ (ft)</td>
<td>4,099</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>14</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, $n'$</td>
<td>1.45</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, $m'$</td>
<td>5.61</td>
</tr>
<tr>
<td>Total Objective Function (millions)</td>
<td>34.7</td>
</tr>
</tbody>
</table>

The best solution was found in the 7,455\textsuperscript{th} trial, although only 245 trials were required to get within less than 1\% of the best solution, suggesting that significantly fewer trials could have been run for this particular scenario. Fewer trials, however, would limit the search extent of the algorithm, which may lead to poor results in some cases, as the majority of the early trials produce significantly higher OF numbers. Fig. 4.8\textbf{a} shows the average and minimum OF for the
100 equivalent generations (100 trials is equal to 1 generation). From the average curve the steady-state nature of the algorithm becomes apparent. Unlike a generational GA, where you would expect to see the generational average decrease over time, in this case the average decreases for approximately 15 equivalent generations before beginning to fluctuate between 37 million and 47 million for the remaining 85 equivalent generations. From the minimum curve it can be seen that a value within 1% of the minimum is found (within the third equivalent generation) and remains relatively constant for the remainder of the equivalent generations. This result can be seen by plotting the algorithm’s improvement progress (Fig. 4.8b). The logarithmic x-axis is used to better show the optimization progression. Lastly, Fig. 4.8c provides the OF value per trial, and it can again be seen that values approaching the minimum are found quite quickly and continue to be found throughout the remainder of the optimization.
4.5.4.2.4 GAPS Multi-Objective Genetic Algorithm

In this section, the results of the only MO GA tested will be demonstrated. This is the GAPS algorithm developed by Mohammed Kanfar for the Tight Oil Consortium at the University of Calgary, and is based on the NSGA-II algorithm as discussed previously. The benefits of using MO algorithms were discussed previously, so in this section, the focus will solely be on the results of the algorithm. Although it is common practice in the application of GAs to run half the number of generations as the population size, in this application an equal number of generations and populations were conducted to allow the algorithm to “dig deeper” towards an absolute
minimum. Note that larger population sizes allow the algorithm to explore further in the search space. The impact of running more generations will be discussed below. The algorithm was run with 100 generations with populations of 100 following the recommendations of Kanfar and Clarkson (2016), who ran 50 generations with populations of 100 in a similar application using numerical rather than analytical simulation (for a total of 10,000 runs). The input parameters used for this algorithm are shown given in Table 4.14.

<table>
<thead>
<tr>
<th>Table 4.14 — Input Parameters For GAPS Multi-Objective Genetic Algorithm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mutation Rate (%)</td>
</tr>
<tr>
<td>Population Size</td>
</tr>
<tr>
<td>Number of Generations</td>
</tr>
<tr>
<td>Number of Iterations</td>
</tr>
</tbody>
</table>

As is the case with all MO Gas, the final generation does not converge to a single solution, but instead converges to a Pareto Front of nondominant mathematically-equivalent solutions. In this case, the Pareto Front is convex in nature, which suggests that two phase rate objectives are conflicting (a straight-line would suggest non-conflicting OFs). To converge on a single best solution, the solutions were filtered, removing solutions that have an OF higher than a certain threshold (with the threshold being continuously reduced until only several solutions remained around the corner point of the Pareto Front), and then visual inspection was used to pick the final solution. There are currently no methods available in the literature for selecting the single best solution, and therefore an approach similar to that used by Kanfar and Clarkson (2016) was used in this application due to the similarity of the problems. The evolution of the Pareto Front from generation to generation will first be investigated. The advancing Pareto Front is shown in Fig. 4.9. Fig. 4.9a provides the final generation, along with the other generations being shown in
groups of ten generations. From this plot it can be seen that there is a large amount of scatter in the first 10 generations, but by the second ten generations convergence on the ultimate Pareto Front begins. For the Pareto Front, a semi-log presentation was chosen with the oil rate OF being on a log scale, while the water rate OF is plotted on a Cartesian scale, as this was found to best demonstrate the results in this case (however a Cartesian plot will be used in Fig. 4.9b-d). In Fig. 4.9b, the first ten generations are eliminated and the remaining 90 generations are broken into groups of 5. Form this plot it can be seen that there is consistent improvement for approximately 50 generations prior to converging on the ultimate Pareto Front. This can also be seen in Fig. 11c, which shows every tenth generation starting at Generation 10. Finally, in Fig. 4.9d, the final 50 generations are shown and it can be seen that there is no obvious improvement beyond 50 generations and therefore the population to generation ratio of two used by Kanfar and Clarkson (2016) as well as many others when applying GAs is suggested for future applications of this algorithm. This will reduce runtime by 50% without having a significant impact on the final generation results. The single best solution selected using the method described above is shown with a star in Fig. 4.9d, and it can be seen that this point is near the corner point of the Pareto Front, suggesting relatively equivalent trade-off between the two objectives. From Fig. 4.9 it can also be seen that the average value of the water rate OF is ~ 20x greater than that for the oil rate OF. This is due to the fact that water rates are much larger than the oil rates, and therefore visually similar deviations in rate will be approximately an order of magnitude higher. This information could have been used with the SO algorithms to reduce potential bias towards achieving a better water than hydrocarbon history-match, although an equal weighting appears to still be effective for this problem based on the results of the proceeding and following sections.
Fig. 4.9– Pareto diagram for flowback history-match: a) generations grouped into sets of 10 generations showing significant scatter in the first 10 generations; b) generations grouped into sets of 5 generations starting at generation 11; c) every 10th generation to show advancement of Pareto Front over time; d) every 10th generation between Generation 50 and Generation 100 to demonstrate convergence on the ultimate Pareto Front. The single best solution is shown with a star.

Next, generation 100 will be investigated in greater detail, focusing primarily on the extent of variability in the key parameter estimates during this final generation. The parameters corresponding to the best match and the average, standard deviation and P10/P90 ratio for Generation 100 are given in Table 4.15. The best match leads to a summed OF which is ~ 16% lower than that of the deterministic match. The parameter distributions generated from the stochastic history-matching exercise are shown below in Fig. 4.10. R² values are provided to
indicate the lognormal nature of the output distributions, and mean values are shown for reference. The deterministic and best match values are also provided.

The results for generation 100 will now be investigated in further detail.

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Optimal Match</th>
<th>Average</th>
<th>Std. Dev.</th>
<th>P10/P90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3.136</td>
<td>3.584</td>
<td>290</td>
<td>1.24</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>13.98</td>
<td>13.99</td>
<td>0.21</td>
<td>1.00</td>
</tr>
<tr>
<td>BBT Half-Length, x_{f,BBT} (ft)</td>
<td>440</td>
<td>440</td>
<td>0.20</td>
<td>1.00</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>12.99</td>
<td>12.99</td>
<td>0.01</td>
<td>1.00</td>
</tr>
<tr>
<td>ABT Half-Length, x_{f,ABT} (ft)</td>
<td>424</td>
<td>424</td>
<td>0.20</td>
<td>1.00</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>4,099</td>
<td>4,093</td>
<td>0.01</td>
<td>1.00</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, n'</td>
<td>1.45</td>
<td>1.50</td>
<td>0.03</td>
<td>1.05</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, m'</td>
<td>5.87</td>
<td>7.89</td>
<td>1.57</td>
<td>1.57</td>
</tr>
</tbody>
</table>
Fig. 4.10 - GAPS MO Generation 100 flowback history-match parameter distributions: (a) fracture permeability; (b) breakthrough pressure; (c) BBT half-length; (d) Corey oil relative permeability exponent, \( n' \); (e) Corey water relative permeability exponent, \( m' \).

From Table 4.15 and Fig. 4.10 it can be seen that the range of values used to match the flowback data in Generation 100 are fairly small (P10/P90 < 2). Some key results to point out are as follows:
Fracture permeability covers the entire input distribution, again suggesting that fracture permeability may fall outside the search space. Four “tiers” of fracture permeability can be identified on the plot with the best match falling in the lowest tier (< 3,200 md) and the deterministic match falling near the P50 value.

Again, breakthrough pressures, including the deterministic match, are greater than reservoir pressure estimated from DFIT analysis. All values, including that from the best match, fell at the upper end of the input distribution at ~ 4,100 psia, while the deterministic match was quite a bit lower at 3,825 psia (which does not fall on the distribution for Generation 100).

BBT half-length values fell in a tight band at ~ 440 ft with both the best match value and deterministic match falling in this range.

Fracture relative permeability exponents to oil fall in a tight band between 1.4 and 1.6 suggesting minimal potential variability in this parameter. The best match value fell towards the lower end of this range, although was significantly higher than deterministic value of 1.2 which falls outside the Generation 100 distribution.

As seen previously, fracture relative permeability exponents to water are far less constrained than those to oil falling between 5.8 and 10, although are consistently significantly higher than those to oil. This has been observed in nearly all wells analyzed using these methods. The best match value falls toward the lower limit of the distribution, while the deterministic match falls below the Generation 100 distribution.

4.5.4.2.5 Palisade Evolver’s OptQuest™ Algorithm
In this section the results of Palisade Evolver’s OptQuest\textsuperscript{TM} will be demonstrated. Much like Evolver’s GA, this is a SO algorithm. This algorithm has it’s basis in Scatter Search which draws many similarities to GAs, although also includes integer programming, Tabu Search and an Artificial Neural Network to improve its results and efficiency, as discussed previously. The algorithm is trial-based much like Evolver’s GA. In this case, since there is no basis for comparison of the algorithm, the maximum number of trials was set to a very large value (100,000) allowing the convergence criteria for maximum change in the OF to control the termination of the optimization. The input parameters used for this algorithm are shown below in Table 4.16.

<table>
<thead>
<tr>
<th>Table 4.16 — Input Parameters for Palisade’s Single-Objective Genetic Algorithm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Number of Iterations</td>
</tr>
<tr>
<td>Convergence Criteria for Max Change (%)</td>
</tr>
</tbody>
</table>

As with other SO algorithms a single best solution is found by the algorithm. The parameters resulting from the optimization are found in Table 4.17 and the resulting combined OF is \(~ 16\%\) lower than that of the deterministic match.
In this particular case, 33,756 trials were required to reach the set criteria, although a value with a combined OF within 1% of the optimal value was found in 13,421 trials which equates to a ~60% reduction in optimization time, although many significantly higher OF values were found in the final 20,000 trials. To allow comparison with the GAs, the results were filtered into “equivalent generations” of 100 trials. Fig. 4.11a provides the average and minimum OF for the 338 “equivalent generations” (the 338th “equivalent generation only contains 56 trials). From the average curve, the differences between OptQuest’s performance and a generational GA become apparent. Unlike a generational GA, where one would expect to see the generational average go down over time, in this case the average decreases for approximately 10 “equivalent generations” prior to stabilization with four groups of “equivalent generations” with significantly higher values which occur when the algorithm tries radically different areas of the search space. This is characteristic of a Scatter Search Algorithm which utilizes Tabu Search and an Artificial Neural Network to stop the algorithm from going back to areas of the search space which either have, or are expected to yield inferior solutions. From the minimum curve, it can be seen that a value within 1% of the minimum is found in the 133rd “equivalent generation” and remains relatively constant for the remainder of the “equivalent
generation.”

<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>3,148</td>
</tr>
<tr>
<td>BBT Drainage Area (Ac)</td>
<td>14</td>
</tr>
<tr>
<td>(x_c,\text{BBT} \ (\text{ft}))</td>
<td>441</td>
</tr>
<tr>
<td>ABT Drainage Area (Ac)</td>
<td>13</td>
</tr>
<tr>
<td>(x_c,\text{ABT} \ (\text{ft}))</td>
<td>425</td>
</tr>
<tr>
<td>Breakthrough Pressure (psi)</td>
<td>4,099</td>
</tr>
<tr>
<td>Corey Oil Exponent - Fracture, (n')</td>
<td>1.46</td>
</tr>
<tr>
<td>Corey Water Exponent - Fracture, (m')</td>
<td>5.65</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>34.7</td>
</tr>
</tbody>
</table>
generations”. This result can be seen by plotting the algorithms improvement progress which is shown in Fig. 4.11b. Lastly, Fig. 4.11c shows the OF value per trial, and it can again be seen that values approaching the minimum are found quite quickly and continue to be found throughout the remainder of the optimization. The same impact can be seen as in the “equivalent generation” case in Fig. 4.11.

Fig. 4.11 – Evolver’s SO OptQuest results: (a) by equivalent generation showing both the equivalent generation average and minimum; (b) by progression step; and (c) by trial also showing the minimum achieved value.

4.5.4.3 Summary of Results

In the previous sections the results of several techniques including: 1) Deterministic Analysis; 2) MC MO simulation (Palisade® @RISK™); 3) Microsoft® Excel’s SO Gradient-
based (GRG2) algorithm (GRG Nonlinear Solver); 4) Microsoft® Excel’s SO Evolutionary Solver; 5) Palisade® Evolver’s SO GA; 6) GAPS MO GA (based on the NSGA-II) algorithm; and 6) Palisade® Evolver’s SO OptQuest™ algorithm were discussed individually. In this section the results of the different techniques will be compared. In Fig. 4.12 the history-match to both the water and oil phases is shown for each of the techniques, while in Fig. 4.13 the key parameters and total OF’s are provided. The results from Excel’s GRG Nonlinear Solver have not been included as this required manipulation of the initial guess to achieve an acceptable history-match (although its key match parameters will be discussed below).
Fig. 4.12 – Flowback history-match using different algorithms: a) water rate match; b) cumulative water production match; c) oil rate match; d) cumulative oil production match; e) gas rate match; and f) cumulative gas produced match.
Fig. 4.13 – Flowback key history-match parameters found using different algorithms: a) fracture permeability; b) BBT half-length; c) Breakthrough Pressure; d) oil relative permeability exponent, \( n' \); e) water relative permeability exponent, \( m \); and f) Total OF value.

From Fig. 4.12 it can be seen that the deterministic match matches the early-time hydrocarbon production better than the other algorithms, although it provides a far less superior late time match to the two hydrocarbon phases. The late-time hydrocarbon match can be
improved further by increasing breakthrough pressure, although it was determined that this leads to premature breakthrough by the model and therefore an upper limit of 4,100 psia was enforced. It can also be seen that the water match from each of the solving techniques is similar. Further the hydrocarbon rate profiles for all but the deterministic history-match look similar. Additional key observations are presented below:

- Fracture permeability ranges from 3,102 md to 3,190 md with the lowest value coming from Evolver’s GA and the highest coming from the average of the top five MC simulations. Each of the algorithms find a fracture permeability ~ 350 md lower than the deterministic match (~ 10% difference). The percent variability from the five algorithms is approximately is ~ 2.5% when compared to the deterministic match.

- Breakthrough pressure approaches the upper limit for each of the five algorithms and is significantly higher than the deterministic match (~ 7%). An earlier breakthrough yields a better late-time oil match, which is where oil rates are highest and therefore have greatest potential to add to the OF value. This is also the piece of data were the deterministic solution deviates most from the measured data. As mentioned previously, a breakthrough pressure of greater than 4,100 psia leads to premature breakthrough, although also yields a better late-time history-match. A breakthrough pressure of 4,100 psia suggests a 10% supercharge of the formation directly surrounding the fractures which results from pumping the fracture at significantly higher pressures than formation pressure (mini water flood effect).

- BBT half-length is nearly constant using each of the six techniques, ranging from 437-441 ft which is to be expected given the rather definitive results of the FMB shown.
above. The deterministic history-match used the same BBT half-length as the four main assisted history-matching techniques.

- Oil relative permeability exponent shows almost no variability from the five algorithms ranging from 1.43-1.46. This is ~ 20% higher than the value used in the deterministic history-match.

- Water relative permeability exponent shows slightly more variability from each of the five algorithms, ranging from 5.30-5.87. Each of the algorithms predicted a water exponent exceeding that of the deterministic history-match by an average of ~ 4%. The percent variability from the five algorithms is approximately is ~ 11.4% when compared to the deterministic match.

- The total OF for the four assisted history-matching algorithms were nearly identical, ranging from 34.7-35.4 million. The average of the top five MC simulations was ~ 2% higher than the other assisted history-matching techniques. The five different algorithms improved the total OF from 14.7-16.4%, although this suggests that the deterministic match still falls within the +/- 20% range often accepted in industry in this particular case.

The above results demonstrate that each of the algorithms find a very similar optimal value for each of the key parameters suggesting that this likely represents the global optimum. After reviewing the total OF, it is clear that there is significant benefit to applying these algorithms once bounds on key parameters can be estimated. Another interesting observation is that the deterministic history-match yielded values within 10% of the optimal values for three out of the five uncertain parameters. The only exceptions are the relative permeability exponent to oil
water, which varied by ~ 20% and ~ 11% respectively. This higher differential can be attributed to the low values of these exponents, making them particularly sensitive when calculating percent difference (although the absolute value was within 0.25 and 0.66 of the average optimal values respectively).

Based on the results shown above, it would be expected that application of Excel’s GRG Non-Linear Solver with the use of multi-restart mode would likely yield the same results. This was not tested to its full extent in this analysis, although using the deterministic history-match as an initial guess led to similar parameters as those solved by the other algorithms. This result suggests that the multi-restart method would likely be successful in this problem and also demonstrates that there is no local minima between the deterministic match and global optimum.

4.6 Discussion

The basis of this work is the tool developed by Clarkson et al. (2014) for analyzing multi-phase (water, oil and gas) flowback data from MFHWs following hydraulic fracture stimulation to estimate key fracture properties such as effective fracture half-length and fracture permeability. The base tool, with the modifications discussed previously, was then used to conduct a deterministic history-match. Following the deterministic history-match, MC simulation was used to determine the variability in the key history-match parameters which can be used to effectively match the data (rate OF for oil and water lower than the deterministic match). Once this analysis was conducted, the results of the best MC simulations were compared to the results of several assisted history-matching techniques in an attempt to find the global optimum (which corresponds to the “true” fracture parameters, assuming the model and other hard inputs are correct). Algorithm complexity varied from Excel’s GRG Non-Linear
Solver, which is based on GRG, to SO and MO GAs, and an algorithm known as OptQuest\textsuperscript{TM} which combines several optimization techniques into a single algorithm. It was demonstrated that each technique could essentially locate the same optimal set of parameters, suggesting that this corresponds to the absolute minimum rather than a local minima, which in turn led to a significant improvement in history-matching over the deterministic analysis. Despite the versatility of the methods described, there are several areas which warrant further discussion.

Two of the biggest challenges when applying MC simulation and other assisted history-matching techniques are: 1) selecting which variables to consider unknowns; and 2) developing an input distribution for the unknowns. These methods are typically most successful and converge faster when the number of inputs is limited to the minimum possible number with the smallest range to minimize the search space for the algorithm. In the case of flowback analysis, there are many uncertain inputs making this a difficult problem to solve using these methods, and therefore it is important to select the most important parameters as uncertain (i.e. fracture half-length and conductivity), while assuming that some less critical inputs that are constant (i.e. initial fracture pressure and fracture porosity). The next challenge is developing an input distribution for the uncertain parameters (particularly for MC simulation). In an ideal scenario, the input distributions can be developed from existing data allowing for greater precision and ultimately better output results, although this requires a significant amount of analogous data. For some scenarios, such as history-matching long-term production from wells with a significant number of analogs which have all been analyzed, this is feasible. Further, in many cases parameters such as matrix permeability have been demonstrated extensively in the literature to show a lognormal distribution. Unfortunately this is not the case with flowback analysis, where the data set is generally limited, or in many cases non-existent, due to the very new nature of
industry interest in analyzing this data and lack of widespread (although rapidly growing) application. For example, the basic techniques used in this work have been applied by several companies including in an SPE paper written by Cugnart et al. (2017). Due to a lack of data for developing an input distribution, a simple uniform distribution was used in this work for the 5 selected input parameters, where the distribution range was limited as much as possible using available offset analysis as well as the deterministic history-match. As these methods gain further traction in industry, and are applied to more wells, developing better input distributions will likely be possible making the application of these methods more versatile.

Another challenge is determining an acceptable number of iterations (i.e. the number of generations and population size in the GAPS algorithm) to allow achieving reasonable results while minimizing run time to make the application of the techniques to a large number of wells more feasible. In this dissertation, the purpose was to demonstrate the applicability of the different techniques used, and therefore run time was not a consideration, although this will become more important as these techniques continue to gain traction in industry. In this case, other than the Excel™ Solver methods, each technique required multiple days of run time making the techniques not practically applicable to a large number of wells. Further, the tool is still in the research phase, and could be made significantly more efficient (~ 1 iteration per second comparable to other similar commercial tools), which would also help to significantly reduce run time. Trying to determine an acceptable number of iterations is an area of future work which will require application to more than the several wells which have been analyzed using these techniques.

In this chapter, it was demonstrated that Excel’s GRG Non-Linear Solver is highly ineffective when a relatively generic initial guess is used, as this algorithm will find the closest
local minima to the initial guess. When the deterministic solution was used as the initial guess, the algorithm converged to parameters similar to the other techniques applied, suggesting there is no local minima between the deterministic solution and the optimal solution. This may not always be the case, and in some applications a complete deterministic analysis may not be conducted prior to applying an assisted history-matching algorithm. The convergence speed of this algorithm makes it ideal, although its application clearly has limitations. One solution is to apply the multi-restart techniques discussed previously, where the algorithm will run for a series of different initial guesses in attempt to find the global minima. It is likely that a substantial number of restarts would be required to find the optimal solution for the flowback problem, and therefore extensive testing would be required before confidently applying this technique and determining how its run time compares to the other algorithms tested. The standard version of Solver available in Excel™ does not offer a multi-restart option, although the developer of this solver (Frontline Solver’s) offers more advanced versions which include this option as well as further improvements and additional algorithms.

In this work, six techniques were applied for assisted history-matching purposes. These methods were selected as they were either developed within the research group (GAPS algorithm) or commercially available from reputable vendors that are used extensively in industry (Microsoft® and Palisade®). Although these techniques have proven to be effective in finding optimal solutions, there are many other algorithms available both commercially and in the literature which could also be tested. Testing of further MO GA’s would be of particular interest as they overcome the biggest challenge of SO algorithms which were the primary focus of this work. Testing further techniques is warranted, seeking algorithms which converge faster and/or are potentially more effective in consistently finding the optimal solution.
4.7 Summary

In this work, several algorithms were tested for the purpose of uncertainty analysis and assisted history-matching of flowback data. In previous work, Williams-Kovacs and Clarkson (2013c) applied MC simulation to the same data set, although less iterations were conducted with significantly more input parameters and with wider bounds, bringing the results into question. The GAPS algorithm has also been tested by Kanfar and Clarkson (2016) for history-matching three-phase flowback with a numerical simulator and Ezulike et al. (2016) attempted to use a combination of algorithms to try to decouple parameters in one of their analysis tools, although more rigorous methods could have been applied. Other than these limited studies, uncertainty quantification and assisted history-matching has not been investigated for application to the flowback problem. The main conclusions of this study are as follows:

- MC simulation can effectively be applied for both uncertainty quantification and assisted-history matching, assuming enough trials are conducted to effectively cover the search space. For practical application, this limits the number of uncertain parameters and the distribution range for these parameters.

- As anticipated, application of a gradient-based algorithm was not successful unless a very good initial guess was provided. This is due to the nature of the algorithm limiting its application in the absence of using the multi-restart feature.

- Each of the techniques tested (excluding Excel’s GRG Non-Linear Solver), including both SO and MO techniques, were able to converge to a very similar optimal solution, suggesting that they were likely finding the global optima. There are often problems associated with applying SO algorithms to MO problems due to competing objectives,
although this issue did not appear to arise in the analyzed well. It was demonstrated that each of these techniques provided a significant improvement in history-match quality over a single deterministic analysis, although deterministic history-matching is useful in determining which parameters should be considered uncertain and constraining the range of these uncertain parameters.

- Further testing is warranted to determine the wide-spread applicability of these techniques, and to reduce run time making the application more desirable for industry applications.

- Additional algorithms should be investigated for a larger number of wells to determine which techniques are most applicable to the flowback problem. Specifically, testing additional MO algorithms would be desirable as these algorithms tend to better represent the problem. It is possible that MO algorithms other than the GAPS algorithm could provide better results for flowback analysis.
Chapter Five: Analysis of Stage-by-Stage, Multi-Well and Multi-Layer Flowback from Multi-Fractured Horizontal Wells

5.1 Abstract

A complication in quantitative flowback analysis is that there may be significant communication both between stages and between wells on a given well pad which may or may not continue during long-term production. Further, multiple producing geologic intervals may be contacted by hydraulic fractures, even if there is a permeability barrier between the productive layers (not every permeability barrier is a fracture barrier). The complexities of inter-well/inter-stage communication and multi-layer effects are, however, typically ignored, or not dealt with rigorously, in quantitative flowback analysis. Failure to account for these effects will result in errors in the assessment of hydraulic fracture properties from flowback analysis. The intent of the current chapter is to incorporate these complexities into simple-yet-rigorous analytical techniques.

In order to account for inter-stage/inter-well communication, the “communicating tanks” concept is employed. The method is used to ensure proper allocation and transfer of fluids between stages/wells in the analytical model for flowback analysis. For modeling multi-layer reservoir scenarios, it is assumed that communication occurs only through the hydraulic fractures and that no communication occurs directly between the layers (no cross-flow). This assumption is valid when there is a low permeability layer, such as a shale, between the potentially

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productive layers. If direct communication occurs between the layers in the unstimulated formations, a similar conceptual model as used for multi-well and stage-by-stage flowback can be applied.

The new methods described in this paper are tested against both simulated and field examples. A simulated stage-by-stage case demonstrates that if individual stage/well flowback data is analyzed without accounting for communication or fracture heterogeneity, derived reservoir properties (i.e. fracture half-length) can be in significant error. As a result, future well performance predictions, and attempts to optimize fracture stimulations, will also be in error. Furthermore, it will be shown that a significantly improved history-match can be achieved by allowing communication between wells in a multi-well field case. As with stage-by-stage analysis, not accounting for communication may lead to erroneous results. Finally, accounting for multiple contacted zones can be important in many MFHWs as will also be demonstrated with a field case.

5.2 Introduction

In previous chapters the focus has been on the analysis of commingled data from a single well. This is the simplest situation to model, however many cases have added complexities, such as inter-stage and inter-well communication, particularly during the flowback period, which are important to capture in modeling. There are now methods that can be used to gather stage-by-stage flowback data, which can provide insight into completion heterogeneity.

Another complexity is that unconventional reservoirs tend to be very thick and may have multiple pay zones which can be contacted by the hydraulic fractures. This provides another
modeling complexity. For the most part, such complexities have not gained much interest in the literature, potentially due to their additional complications for modeling.

5.3 Objective

While some of the studies reviewed in Chapter Two have acknowledged the importance of inter-stage and inter-well communication on flowback behavior and analysis results, these effects were first considered in this work. Very recently, Shahamat and Clarkson (2016) developed a multi-phase, multi-well FMB method that accounts for injection and flowback of fracturing fluids, and that method may be applicable to the analysis of flowback data when boundary-dominated flow is observed (for example during fracture depletion). However, that study did not explicitly address inter-stage communication, or the possibility of time-dependent communication between wells. Further, multi-layer effects were not examined.

The primary objective of the current work is to develop an analytical procedure and tools for quantitatively analyzing multi-phase flowback from communicating fracture stages, communicating wells and multi-layer wells. Additional objectives of this work are: 1) to provide motivation for collecting stage-by-stage flowback data; 2) to demonstrate the importance of modeling communication during the flowback period; and 3) to introduce a method for analyzing flowback from multi-layered wells. To date, all work presented in the literature has focused on commingled production from a single-well producing from a single zone. The conceptual model for each of these three scenarios will first be discussed, followed by a description of the analysis procedure. Three case studies will be provided including: 1) a simulated example, which illustrates the importance of collecting stage-by-stage flowback data; 2) a field example, to
demonstrate the importance of considering communication when history-matching flowback data; and 3) a field example from a multi-layer reservoir.

5.4 Theory and Methods

In this section the conceptual model for stage-by-stage, multi-well and multi-layer flowback will be introduced, followed by a discussion of the analysis procedure used for each of these cases. Each of these cases add a layer of complexity on top of assuming a homogeneous circular fracture formation in a single-layer reservoir. Although this base model has proven very useful in many cases, certain cases have additional complexity which must be considered. Three of those complexities will be discussed below.

5.4.1 Conceptual Model of Inter-Well and Inter-Stage Communication During Flowback

Payne (1996) developed a compartmentalized reservoir approach for improving the solution of the MBE in tight gas reservoirs, in which the reservoir is subdivided into a series of compartments (tanks) with each compartment containing one or more producing wells; communication is allowed between the compartments. The problem is illustrated schematically in Fig. 5.1.
Fig. 5.1 – Cross-sectional schematic representation of the compartmentalized reservoir approach with cross-flow from Compartment 1 to Compartment 2. Adapted from Payne (1996).

Adopting the convention that influx is positive from Compartment 1 to Compartment 2, the single-phase linear gas flow rate between compartments can be defined as:

\[
q_{12} = \left( \frac{0.0012k_{A_{com}}}{T_L} \right) [m(\bar{p}_1) - m(\bar{p}_2)]
\]  

(5.1)

Where, \(k\) is permeability (fracture permeability in this application, \(k_f\)), \(A_{com}\) is the cross-sectional area of communication, \(T\) is reservoir temperature, \(L\) is the distance between the center of the two compartments and \(m(\bar{p}_1)\) and \(m(\bar{p}_2)\) are the average pseudopressures of Compartment 1 and Compartments 2 respectively. Eqn. 5.1 can be simplified by defining a communication factor, \(C_{12}\), which is defined as the constant proceeding the delta-pressure term (always positive).

\[
q_{12} = C_{12}[m(\bar{p}_1) - m(\bar{p}_2)]
\]  

(5.2)

A similar equation for cross-flow of single-phase liquid can also be derived.

\[
q_{12} = \left( \frac{0.001127k_{A_{com}}}{\mu B L} \right) [\bar{p}_1 - \bar{p}_2]
\]  

(5.3)

Where, \(\mu\) is fluid viscosity, \(B\) is formation volume factor and \(\bar{p}_1\) and \(\bar{p}_2\) are the average pressures of Compartment 1 and Compartment 2 respectively. Eqn. 5.3 can be used to describe
the single-phase cross-flow of either water or oil and can be simplified into a form similar to Eqn. 5.2. Eqn. 5.3 can be modified for multi-phase liquid (water + oil) communication by writing the communication factor in terms of effective permeability to each phase (dependent on water saturation, $S_w$). For water:

$$q_{w,12} = C_{w,12} [\bar{p}_1 - \bar{p}_2]$$  \hspace{1cm} (5.4)

Where,

$$C_{w,12} = \frac{k_w h_c}{\mu_w B_w} C_{12}$$  \hspace{1cm} (5.5)

$$C_{12} = \frac{0.001127 w_c}{L}$$  \hspace{1cm} (5.6)

In Eqn. 5.5, $\bar{k}_w$ is the average effective permeability of the two compartments to water (function of average water saturation, $\bar{S}_w$), $\bar{\mu}_w$ is the average water viscosity, $\bar{B}_w$ is the average water formation volume factor, $h_c$ is the height of the communication surface. In Eqn. 5.6 $w_c$ is the width of the communication surface. All averages are calculated using the harmonic average definition accounting for all compartments in communication \[ \bar{x} = \frac{\sum_{i=1}^{n} L_i}{\sum_{i=1}^{n} \frac{1}{x_i}} \text{ where } \bar{x}_i = \frac{k_i}{\mu_i} \text{ or } \bar{B}_i \text{ and } i \text{ refers to compartment } i \] where individual compartment parameters are calculated using the average pressure of each compartment. Further, the cross-sectional area is broken into height and width components to allow for explicit estimation of the width of the communication surface when the height is known or can be calculated. Similarly for oil:

$$q_{o,12} = C_{o,12} [\bar{p}_1 - \bar{p}_2]$$  \hspace{1cm} (5.7)

Where,

$$C_{o,12} = \frac{k_o h_c}{\mu_o B_o} C_{12}$$  \hspace{1cm} (5.8)
\[ C_{12} = \frac{0.001127 w_c}{l} \]  

This is a simplistic method to account for changing relative permeability in the communicating fracture network, given that saturation gradients in the fractures are ignored; this may be a deficiency of the current modeling approach, which will be addressed in a future study. In this work, the communicating tank model is used to describe communication between the fracture networks of adjacent stages and/or adjacent wells during flowback (i.e. the compartments discussed above are individual fractures or fracture networks). For this application, it is assumed that all communication occurs within the fractures, as would be expected given the short time period of flowback (i.e. tight matrix is unlikely to provide significant communication – see Discussion). Communication between wells, particularly during flowback, would be expected in many tight oil plays where well spacing may be as small as 300 feet (i.e. 150 foot effective half-lengths would be in communication). This is shown conceptually in Fig. 5.2 for the simplest case in which wells are drilled at the same vertical depth and fractures are assumed to be circular and uniform, although vary in size between the two wells.

**Fig. 5.2** – Cross-sectional schematic representation of compartmentalized reservoir approach for communicating fractures of adjacent wells during flowback.
In Fig. 5.2, $x_e$ is the inter-well spacing (equivalent to $L$ above in Eqn. 5.9), $x_{e,1}$ and $x_{e,2}$ are the distance from the wellbore of Well 1 and the wellbore of Well 2, respectively, to the effective communication plane and $x_{f,1}$ and $x_{f,2}$ are the fracture half-lengths of Well 1 and Well 2 respectively. In Fig. 5.2, $h_c$ can be derived using the geometry of intersecting circles with the following definition:

$$h_c = \frac{1}{x_e} \sqrt{4x_e^2x_{f,1}^2 - \left(x_e^2 - x_{f,2}^2 + x_{f,1}^2\right)^2}$$  \hspace{1cm} (5.10)

Once $C_{12}$ has been estimated from history-matching the flowback of the two communicating wells, $w_c$ can be estimated by rearranging Eqn. 5.9, from which the number of communicating stages can be estimated using the individual fracture width ($w_{f,i}$) assumption:

$$\text{# of Communicating Fractures} = \frac{w_c}{w_{f,i}}$$  \hspace{1cm} (5.11)

The same method can be applied for wells drilled to different vertical depths, as long as the correct wellbore-to-wellbore spacing is used (rather than horizontal spacing). For communicating well cases, the MBE used by Clarkson et al. (2014) can be modified as follows for the two wells.

Before Breakthrough:

$$\overline{p}_{f,1} = p_{f,1} = \frac{(Q_{w,f1}+Q_{w,12})B_{w,1}}{V_{f,1,\text{BBT}}c_{\text{f,1,\text{BBT}}}}$$  \hspace{1cm} (5.12)

$$\overline{p}_{f,2} = p_{f,2} = \frac{(Q_{w,f2}-Q_{w,12})B_{w,2}}{V_{f,2,\text{BBT}}c_{\text{f,2,\text{BBT}}}}$$  \hspace{1cm} (5.13)

After Breakthrough:
\[
\overline{p}_{f,1} = p_{BT,1} - \left[\frac{(Q_{w,f1} - Q_{w,m1} + Q_{w,12})B_{w1} + (Q_{o,f1} - Q_{o,m1} + Q_{o,12})B_{o1}}{V_{f,1,ABT}c_{f,1,ABT}}\right]
\]

\[
\overline{p}_{f,2} = p_{BT,2} - \left[\frac{(Q_{w,f2} - Q_{w,m2} - Q_{w,12})B_{w2} + (Q_{o,f2} - Q_{o,m2} - Q_{o,12})B_{o2}}{V_{f,2,ABT}c_{f,2,ABT}}\right]
\]

(5.14)  (5.15)

Where \(Q_{w,f}\) and \(Q_{o,f}\) are the cumulative water and oil production from the fracture, \(Q_{w,m}\) and \(Q_{o,m}\) are the cumulative water and oil production from the matrix to the fracture, \(Q_{w,12}\) and \(Q_{o,12}\) are the cumulative water and oil transferred from Well 1 to Well 2, \(V_{f,BBT}\) and \(V_{f,ABT}\) are the fracture volumes BBT and ABT, \(B_w\) and \(B_o\) are the water and oil formation volume factors and \(c_t\) is total compressibility.

It is important to note that during flowback, communication and transfer of fluid between wells may begin as soon as the second well is fractured, prior to the start of flowback, and therefore the fracture properties will have changed from their original state by the time the well is put on production. This effect will be completely missed when analyzing wells individually, making accurate fracture characterization difficult. An example pressure profile (created using the developed analytical model) for two communicating wells which are stimulated and brought on flowback at different times is shown below in Fig. 5.3. In the diagram it can be seen that flowback of the first well is initiated before the stimulation of the second well and pressure depletion begins as would be expected for single-well analysis. At approximately one day the second well is stimulated and pressure communication begins, with fluid being transferred from the second well to the first well proportionally to the pressure gradient creating temporary pressure support for the first well. Approximately half a day later, flowback in Well 2 is initiated, causing its pressure to deplete and the pressures of the two wells to begin to converge.
By the end of two days the pressure of the two fracture systems are nearly equivalent and the system would essentially act as a single tank.

![Pressure Profiles For Two Communicating Wells During Flowback](image)

**Fig. 5.3** – Example pressure profile for two communicating wells which are stimulated and brought on flowback at different times.

The approach described above can also be expanded for multiple wells, where a communication factor would be derived for interaction between each of the wells; Eqn. 5.4 and 5.7 can be written more generally for the two phases as:

\[
q_{w,xy} = C_{w,xy}[\bar{p}_x - \bar{p}_y] \quad (5.16)
\]

\[
q_{o,xy} = C_{o,xy}[\bar{p}_x - \bar{p}_y] \quad (5.17)
\]

For example, consider a four well pad, where the four wells are drilled in parallel with largely equal completed length and inter-well spacing. All possible communications are shown in **Fig. 5.4**, although it is possible that not all wells will be *directly* communicating, depending on well spacing, fracture treatment, etc. Note that the analysis becomes more complicated with
each additional well (1 additional history-match parameter for 2 wells, 3 for 3 wells, 6 for 4 wells, etc. according to the formula \( #C_{xy}^\prime s = 0.5(#oftanks)^2 - 0.5(#oftanks) \)).

Fig. 5.4 – Schematic showing all possible communications for a four well pad with equal length and equally spaced wells.

A similar approach can be used to account for communication between individual stages of a single-well, if stage-by-stage flowback data is collected. Consider the simplest case where there are two adjacent stages with different half-lengths in communication, which is shown schematically in Fig. 5.5. \( y_c \) is the stage half-spacing, and therefore \( 2y_c \) is the total stage spacing and \( w_{f,i} \) is the width of the individual stages. For circular fractures, the communication area is defined as \( A_{com} = \pi x_{f,i}^2 \), where \( i \) is the number of the smallest stage in communication (Stage 1 in Fig. 5.5) assuming communication occurs over the entire fracture face. This conceptual model is most applicable to systems with overlapping complex fracture networks (for example overlap between the EFR of the two wells rather than direct communication of the individual fractures when they are considered to be planar – this will be investigated explicitly in a future work).
It is also possible to apply this approach in a case for a multi-well pad with individual stage data gathered on each well. In this case, each fracture has the potential to not only communicate with other fractures within the same well, but also with fractures within the other wells on the pad, making the system highly dynamic. The potential complexity of such communication is demonstrated in Fig. 5.6 for two wells with two stages each.
5.4.2 Conceptual Model For Multi-Layer Flowback

For multi-layered reservoirs, the case where communication only occurs through the hydraulic fractures rather than through the formation is considered herein. Conceptually this is equivalent to having two potentially productive intervals separated by an impermeable layer (or equivalently that the two matrix layers are of low enough permeability that cross-flow through the formation will be inconsequential compared to communication in the fractures, particularly during the short flowback period). This conceptual model is illustrated below for a fracture fully penetrating Productive Layer 1, where the well is landed, and partially penetrating Productive Layer 2:

![Conceptual model for multi-layer scenario in Case Study 2. The fracture fully penetrates Layer 1 but only partially penetrates Layer 2.](image)

Fig. 5.7 – Conceptual model for multi-layer scenario in Case Study 2. The fracture fully penetrates Layer 1 but only partially penetrates Layer 2.
If communication occurs in the formation as well as in the hydraulic fractures (no impermeable layer exists between the productive layers) then a model comparable to the communicating tanks model discussed above for stage-by-stage flowback could be applied. Alternatively, if both layers are low permeability then a transient linear flow equation could be used, although in such cases it is unlikely the cross-flow in the formation will be consequential compared to cross-flow within the significantly higher permeability fractures. This will be discussed further in the Discussion section of the chapter.

5.5 Analysis Procedure

The analysis procedure developed for analyzing stage-by-stage and multi-well flowback data consists of five steps: 1) raw data and diagnostic plots to assess data quality, identify flow-regimes present and evaluate the possibility of communication between individual stages/wells; 2) RTA of individual stages/wells to estimate BBT fracture properties; 3) history-matching of individual wells without communication to obtain an initial estimate of key fracture parameters; 4) incorporation of communication between individual stages/wells to optimize history-matches of all wells; and 5) compare flowback with other data sources to confirm key fracture properties. This procedure is summarized in Fig. 5.8. Note that when introducing communication into the model, it is important to start simple, first introducing the most important communications (between adjacent stages/wells) and then increasing complexity to achieve the desired match. For multi-layer wells, a similar procedure is followed, except in step 3, the flowback data match is attempted using only the primary productive interval, and in step 4, adjacent intervals that may be contacted by the fracture are introduced. Often microseismic, fracture modeling and
temperature logs can be useful when determining whether multiple zones have been contacted, although each method has the potential to provide misleading results.

Fig. 5.8 – Summary of procedure for analyzing stage-by-stage and multi-well flowback data.

5.6 Case Studies

The case studies analyzed in this chapter are summarized in Table 5.1.

<table>
<thead>
<tr>
<th>Case Number</th>
<th>Field or Simulation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Analytical Simulation</td>
<td>Stage-by-stage flowback without communication</td>
</tr>
<tr>
<td>2</td>
<td>Field</td>
<td>Multi-well flowback (multiple flow tests separated by a significant shut-in)</td>
</tr>
<tr>
<td>3</td>
<td>Field</td>
<td>Multi-layer flowback</td>
</tr>
</tbody>
</table>

5.6.1 Case Study 1: Stage-by-Stage Simulated Example Without Communication

During flowback (and on-line production), individual stage production is typically commingled and a total rate and pressure measurement is made at surface for the commingled stream. To demonstrate the motivation for collecting stage-by-stage flowback data, flowback from a 5-stage MFHW was simulated analytically, where 4 of the stages are uniform and the fifth stage (Stage 1) has two times the half-length. Permeability of each of the stages was held constant and all inter-stage communication was ignored for simplicity. Following breakthrough of hydrocarbon, a reduction in effective half-length of 20% for each stage was modeled. The
fracturing fluid was assumed to be water. Flowing pressure for each stage was held constant at 2,000 psia (above the bubble point) throughout the simulation. The configuration for the simulated well is shown below in Fig. 5.9 and key input parameters are summarized in Table 5.2. Fractures are assumed to be bi-wing planar with a circular fracture shape. The primary objectives of the simulated example are to: 1) demonstrate the difficulty in correctly identifying flow-regimes of commingled stage data; and 2) show how analyzing commingled stage data can lead to significant errors in fracture property determination. The data will be analyzed according to the procedure shown in Fig. 5.8. In the field, individual stage contributions can be assigned using tracer data, production logs, fiber-optic monitoring, etc. (see Discussion).

Fig. 5.9 — Schematic of simulated example for stage-by-stage flowback.
Prior to flow-regime identification, production rates of all fluids (water, oil and gas) should be assigned to each individual stage and production rates and flowing pressures should then be plotted against time for each stage to identify breakthrough and any potential communication effects. Other data, including pressure gauge data during stimulation, should also be examined to assist in identifying communication. Following the procedure of Clarkson et al. (2014), flow-

### Table 5.2 — Input Parameters For Case Study 1

<table>
<thead>
<tr>
<th>Fracture Properties</th>
<th>Stage 1</th>
<th>Stage 2-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Fracture Pressure (psia)</td>
<td>5,000</td>
<td>5,000</td>
</tr>
<tr>
<td>Initial Water Saturation (%)</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
<td>31</td>
<td>31</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>Fracture Relative Permeability</td>
<td>m(^n')=n(^m')=1</td>
<td>m(^n')=n(^m')=1</td>
</tr>
<tr>
<td>BBT Half-Length, (x_{BBT}) (ft)</td>
<td>720</td>
<td>360</td>
</tr>
<tr>
<td>ABT Half-Length, (x_{ABT}) (ft)</td>
<td>576</td>
<td>288</td>
</tr>
<tr>
<td>Fracture Compressibility (psi(^{-1}))</td>
<td>5x10(^5)</td>
<td>5x10(^5)</td>
</tr>
</tbody>
</table>

| Number of Hydraulic Fractures | 1 | 4 |
| Individual Hydraulic Fracture Width (ft) | 0.0208 | 0.0208 |
| Total Hydraulic Fracture Width (ft) | 0.0208 | 0.0833 |

<table>
<thead>
<tr>
<th>Reservoir Properties</th>
<th>Stage 1</th>
<th>Stage 2-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Pressure (psia)</td>
<td>2,800</td>
<td>2,800</td>
</tr>
<tr>
<td>Net Pay (ft)</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Matrix Porosity (%)</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Initial Mobile Oil Saturation (%)</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>Initial Mobile Water Saturation (%)</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Matrix Relative Permeability</td>
<td>m(^n')=n(^m')=2</td>
<td>m(^n')=n(^m')=2</td>
</tr>
<tr>
<td>Formation Compressibility (%)</td>
<td>4x10(^6)</td>
<td>4x10(^6)</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.005</td>
<td>0.005</td>
</tr>
<tr>
<td>Reservoir Temperature (°F)</td>
<td>150</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties</th>
<th>Stage 1</th>
<th>Stage 2-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Water Salinity (ppm)</td>
<td>50,000</td>
<td>50,000</td>
</tr>
<tr>
<td>Formation Water Salinity (ppm)</td>
<td>200,000</td>
<td>200,000</td>
</tr>
<tr>
<td>Oil Gravity (°API)</td>
<td>42</td>
<td>42</td>
</tr>
<tr>
<td>Gas-Oil-Ratio (scf/stb)</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>Bubble Point Pressure (psia)</td>
<td>1,997</td>
<td>1,997</td>
</tr>
<tr>
<td>Gas Gravity (air = 1)</td>
<td>0.65</td>
<td>0.65</td>
</tr>
</tbody>
</table>
regime identification is conducted using log-log plots of RNP and RNP’ vs. MBT (both with respect to water). The Fetkovich type-curve is also used to confirm flow-regime identification, and later to confirm fracture property estimates. As discussed by Clarkson et al. (2014), the RNP’ plot is most useful for identifying BBT flow-regimes in flowback data as well as the breakthrough of formation fluids, and therefore will be the focus of this section of the analysis procedure. For this demonstration, the complexities of assessing flow-regimes from the commingled data (highlighting that different stages can be in different flow-regimes at different times during flowback) will be demonstrated. This is particularly important when analyzing flowback data (vs. on-line data) due to the short duration of typical flow tests. **Fig. 5.10** shows the water rate data for each stage, as well as the RNP’ plots for the commingled data and Stage 1 and Stages 2-5 individually. From Fig. 5.10a it can be seen that the stages of different dimensions breakthrough at different times, due to the different fracture pressure responses. The shorter (lower volume) stages deplete in pressure faster than the longer stage and therefore breakthrough occurs earlier in the shorter stages (1.0 vs. 6.5 days – note that all times quoted in this section are MBT and are influenced to some extent by the selected derivative window). Fig. 5.10c plots the RNP’ for the commingled stage data. From this plot, there appears to be a very short period of radial flow within the fractures (0 slope) from 0.02 to 0.04 days of MBT, followed by an extended period of fracture depletions (unit slope) from 0.04 to 1.0 days. At 1.0 day, the first deviation from the unit slope occurs indicating the breakthrough of Stages 2-5. A second deviation occurs at approximately 6.5 days, indicating the breakthrough of Stage 1. From the commingled data, one may then interpret that all stages undergo a short transient radial flow period (0.02 to 0.04 days) followed by a relatively short period of fracture depletion (0.04 to 1.0 days), prior to the breakthrough of formation fluid at ~ 1.0 days. The additional deviation at ~
6.5 days would not likely be apparent from field data due to inherent data noise. Based on this flow-regime identification, modeling of the data will be in error (see below). Fig. 5.10b,d show the RNP’ plots for Stage 1 and Stages 2-5 (individual stage shown), respectively. From these plots it is apparent that the two stage types have radically different flow-regime profiles. From Fig. 5.10c, it is clear that Stage 1 displays a relatively long period of transient radial flow within the fracture (0.02 to 0.15 days) followed by fracture depletion (0.15 to 6.5 days), prior to breakthrough of formation fluid at ~ 6.5 days. This is drastically different than the flow-regimes identified in Fig. 5.10d for Stages 2-5. From this figure, we see a short radial flow period lasting between 0.02 and 0.04 days, followed by a much shorter period of fracture depletion (0.03 to 1.0 days), prior to the breakthrough of formation fluid at ~ 1.0 day.
Fig. 5.10 — Diagnostic plots used to identify flow-regimes associated with flowback data: a) water production rate for each stage and the commingled data (note that stages 2-5 overlay each other); b) RNP’ plot for the commingled data; c) RNP’ plot for stage 1; and d) RNP’ plot for stages 2-5. Synthetic data were generated using an analytical simulator (see Table 1 for inputs). Water data shown in a) is analyzed in plots b) – d). The commingled RNP’ plot illustrates the difficulty in identifying flow-regimes from commingled data, where the stages are in different flow-regimes at different times, as identified on the stage-by-stage plots.

5.6.1.2 Rate-Transient Analysis of BBT Data

RTA of BBT data can be used to obtain estimates of BBT fracture properties (fracture permeability and BBT half-length). In this section, the effective BBT parameters estimated from both commingled and individual stage data will be analyzed by looking at the radial flow plot for proppant pack permeability and FMB for BBT IFFIP (converted to BBT half-length using shape and geometry). The Fetkovich type-curve will also be shown for each case as a confirmation of the parameters estimates from RTA. Flow-regimes are identified from the RNP’ plots shown above in Fig. 5.10 (repeated in Fig. 5.11a, Fig. 5.12a and Fig 5.13a for reference).

1. Commingled data (Fig. 5.11): proppant pack permeability of 1,000 md with a skin of nearly 0 (as input into the simulator) and a BBT IFFIP of 2,800 STB ($x_{f, BBT} = 396$ ft/stage).

2. Stage 1 (Fig. 5.12): fracture permeability of 1,000 md and a skin of nearly 0 and a BBT IFFIP of 1,850 STB ($x_{f, BBT} = 720$ ft/stage).

3. Stage 2-5 (individual stage shown, Fig. 5.13): fracture permeability of 1,000 md and a skin of nearly 0 and a BBT IFFIP of 460 STB/stage ($x_{f, BBT} = 360$ ft/stage).

IFFIP and $x_{f, BBT}$ from each of the individual stage analysis are consistent with the simulator inputs. Using Fig. 5.11 and 5.12 for the individual stages we can estimate the following average parameters: 1) proppant pack permeability of 1,000 md with a skin near 0; and 2) a total BBT
IFFIP of 3,690 STB (Average $x_f_{,BBT} = 432$ ft/stage). Results are summarized in Table 5.3. Comparing proppant pack permeability, we calculate the same value from the commingled data as the same fracture permeability was used for each stage. For BBT IFFIP a value of 2,800 STB ($x_f_{,BBT} = 396$ ft/stage) is estimated from the commingled FMB, which is significantly smaller than the total IFFIP of 3,690 STB ($x_f_{,BBT} = 432$ ft/stage) estimated from the individual analysis; total BBT half-length is under-estimated by 8%. This error could be significantly higher if more of the fractures and their key parameters were heterogeneous. To understand this error consider Fig. 5.11c, from which four distinct regions can be seen (the interpretation for each region comes from Fig. 5.11): 1) normalized cumulative production from 0 to 150 STB (transient radial flow within the fractures); 2) normalized cumulative production from 150 to 1,700 STB (all stages in depletion); 3) normalized cumulative production from 1,700 to 4,300 STB (stages 2-5 have broken through, while stage 1 remains in depletion); and 4) after a normalized cumulative production of 4,300 STB (all stages have broken through). From noisy field data differentiation of region 3 and 4 would likely be impossible, while the RNP’ plot suggests that region 2 is the fracture depletion flow-regime. In this case the apparent depletion flow-regime is dominated by Stages 2-5 being in depletion, while the total depletion volume of Stage 1 is not seen prior to the second deviation, leading to an under-estimation of total BBT IFFIP and therefore $x_f_{,BBT}$.
Fig. 5.11 — Rate-transient analysis of commingled before-breakthrough water flowback data: a) RNP’ plot used for reference to select data to be analyzed with each specialty plot; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots.
Fig. 5.12 — Rate-transient analysis of stage 1 before-breakthrough water flowback data: a) RNP’ plot used to identify flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion data; and d) Fetkovich type-curve plot used to confirm analysis obtained from specialty plots.
5.6.1.3 Analytical Modeling of BBT Water Data and ABT Multi-Phase Data

The objective of the analytical model is to confirm BBT fracture parameters, estimated from RTA, and to estimate ABT fracture parameters. As with the previous section, the results of commingled and individual stage data analysis will be compared. The history-matches for each
of the individual stages and the commingled data are shown below in Fig. 5.14 and results are summarized in Table 5.4. For each case, the BBT fracture parameters are taken from RTA and have not been adjusted in order to match the data using the analytical simulator, and fracture permeability is assumed to be unchanged with breakthrough (as simulated). The commingled data is provided in Fig. 5.14a,b. Stage 1 is shown in Fig. 14c,d and is matched using an ABT half-length of 576 ft/stage and Corey relative permeability exponents of 1 (as simulated). Stages 2-5 are shown in Fig. 5.14e,f (individual stage values shown) and are matched using an ABT half-length of 288 ft/stage and Corey relative permeability exponents of 1 (as simulated). Based on the individual stage analysis, it is then expected that commingled analysis would yield an ABT half-length of 346 ft/stage (1,728 ft total). The “best fit” history-match for the commingled stages is generated using an ABT half-length of 391 ft/stage (1,955 ft total) with a Corey water relative permeability exponent (m) of 2.5 and a Corey oil relative permeability exponent of 1.1. In this case ABT half-length is over-estimated by 12% (which will lead to over-estimated potential reserves). ABT, the deviation in parameters from commingled analysis is less clear than BBT, but can be understood by looking at the history-match parameters. First, it is important to note that different fracture relative permeability curves were required to adequately match the shape of the fractional flow data for the fracture in the commingled case. In this case, a higher value of relative permeability exponent is required for water than oil (simulated to be equal), because upon breakthrough of stages 2-5 in the simulated data, water saturation in the commingled fracture system is under-estimated by the model, since water saturation in Stage 1 is still 100% in the simulation. Having a higher relative permeability exponent to water in the model allows oil to flow more freely out of the fractures, which will cause water saturation to increase closer to the actual simulation value. As a result of the more pessimistic relative
permeability value, ABT half-length is over-estimated to get a total effective flow capacity comparable to what was originally simulated. In this case, no communication effects were simulated and therefore a history-match incorporating communication between the stages is not required.

Fig. 5.14 — History-matching using analytical model: a) commingled production rates; b) commingled cumulative production; a) stage 1 production rates; b) stage 1 cumulative production a) stage 2-5 production
From the simple example discussed above, it is clear that there is significant benefit to collecting stage-by-stage flowback data and analyzing the stages individually. The key benefits include:

1. Improved flow-regime identification – from the above example, it is clear that identifying flow-regimes from commingled data can be difficult, because if there is variability in the fractures generated (generally expected to be the case), the individual stages may be in different flow-regimes at different times, yielding an unclear signature on the key diagnostic plots. This problem will become greater as the number of stages increases (i.e. 12 or more), with variability occurring in multiple parameters. Also, stages will clean-up differently, and may begin contributing at different times, which will further complicate flow-regime identification from commingled data. This problem is potentially more impactful on flowback analysis than long-term production analysis, although having stage-by-stage data is always desirable.

<table>
<thead>
<tr>
<th>Table 5.4 — Case Study 1 History-Matching Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>BBT Fracture Properties</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
</tr>
<tr>
<td>BBT Fracture Fluid-in-Place (STB)</td>
</tr>
<tr>
<td>BBT Half-Length, x_{f,BBT} (ft)</td>
</tr>
<tr>
<td>Total BBT Half-Length, x_{f,BBT} (ft/stage)</td>
</tr>
</tbody>
</table>

| ABT Fracture Properties | Stage 1 | Stage 2-5 | Expected Comm. Value | Comm. Analysis |
| ABT Half-Length per stage, x_{f,ABT} (ft/stage) | 576 | 288 | 346 | 391 |
| Corey Water Exponent - Fracture, n | 1 | 1 | 1 | 2.5 |
| Corey Oil Exponent - Fracture, m | 1 | 1 | 1 | 1.1 |
2. Improved parameter estimation – better parameter estimation is linked to the ability to properly identify flow-regimes in the data. Also, in the above example it was clear that, although a reasonable history-match could be achieved for the commingled data, the parameters may be significantly in error.

3. Understanding completion heterogeneity – by estimating parameters for each individual stage the heterogeneity of completions can be seen clearly and tied back to operations and rock properties to optimize future development.

5.6.2 Case Study 2: Multi-Well Field Example

The flowback analysis procedure and methods discussed above were applied to 2 MFHWs completed in a tight oil reservoir in the WCSB. A total of 8 wells were drilled from the pad in two similar intervals. Wells were spaced laterally at approximately 330 ft, with 165 ft of vertical spacing between the two intervals. Wells were alternated between the two zones, leading to an adjacent inter-well spacing of approximately 370 ft.

During stimulation and flowback data, communication was identified among multiple wells on the pad. For simplicity sake, the focus will be on modeling the primary communication identified between the two wells of interest; remaining errors in the history-matches can be accounted for by secondary communications (discussed briefly below). Two flow tests were conducted for each well, the first of which began approximately two weeks following stimulation and was conducted through flow-through bridge plugs (Flow 1). The second flow test was conducted approximately one month later after the bridge plugs were drilled out (Flow 2). Wellhead pressures and flow rates were monitored at 60 minute intervals throughout the test periods. Ideally, for quantitative analysis, higher frequency data collection is desirable (~ 15-30
minute intervals), although a reasonable quantitative analysis remains possible with hourly data. The initial flow test was analyzed by Williams-Kovacs and Clarkson (2014), while the second flow test was analyzed by Williams-Kovacs et al. (2015). A summary of the stimulation, flow periods and shut-in time between the two flow periods is provided below for each of the two wells.

**Stimulation Overview**

**Well 1:**

- Cased-hole completion
- Hydraulically fractured with hybrid water fracs in 20 stages using plug and perf technology (two perforation clusters per stage)
- Perforation clusters placed with approximately 130 ft spacing (approximately 260 ft stage spacing)
- Approximately 1,560 STB of fluid and 90 T of proppant pumped per stage
- Deep well

**Well 2:**

- Cased-hole completion
- Hydraulically fractured with hybrid water fracs in 30 stages using plug and perf technology (two perforation clusters per stage)
- Perforation clusters placed with approximately 80 ft spacing (approximately 160 ft stage spacing)
• Approximately 2,010 STB of fluid and 90 T of proppant pumped per stage
• Shallow well

Flow Test Overview

Well 1:
• Length of Flow 1: 100 hours (4.2 days)
• Length of shut-in between Flow 1 and 2: 758.5 hours (31.6 days)
• Length of Flow 2: 48 hours (2 days)

Well 2:
• Length of Flow 1: 116 hours (4.8 days)
• Length of shut-in between Flow 1 and 2: 629.5 hours (26.2 days)
• Length of Flow 2: 46 hours (1.9 days)

The purpose of analyzing the first flow test is to demonstrate the impact of communication on modeling. The purpose of analyzing the second flow test is two-fold: 1) to determine whether the two wells are still in communication following an extended shut-in period; and 2) to evaluate whether parameters estimated from Flow 1 can be used to history-match the data from Flow 2. The latter would demonstrate that results from flowback could be used to accurately forecast longer-term production above the bubble point. An overview of the inputs common to the various flowback analysis techniques used for both flow tests of both wells are given in Table 5.5, while the input parameters which vary between the flow tests are provided in Table 5.6.
Note that initial fracture pressure was set to be greater than pressure obtained from a DFIT test for both wells to account for supercharge in the fractures and adjacent formation as a result of the stimulation. This impact is more significant in Well 1, likely due to the shorter shut-in period prior to the first flow test. For this analysis a bi-wing planar fracture geometry with a circular fracture shape was assumed (largely supported by microseismic of off-setting wells).

<table>
<thead>
<tr>
<th>Table 5.5 — Input Parameters for Multi-Well Flowback Analysis Common to Both Flow Tests for Case Study 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Properties</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
</tr>
<tr>
<td>Fracture Compressibility (psi⁻¹)</td>
</tr>
<tr>
<td>Number of Hydraulic Fractures</td>
</tr>
<tr>
<td>Individual Hydraulic Fracture Width (ft)</td>
</tr>
<tr>
<td>Total Hydraulic Fracture Width (ft)</td>
</tr>
<tr>
<td>Reservoir Properties</td>
</tr>
<tr>
<td>Formation Pressure (psia)</td>
</tr>
<tr>
<td>Net Pay (ft)</td>
</tr>
<tr>
<td>Initial Mobile Oil Saturation (%)</td>
</tr>
<tr>
<td>Initial Mobile Water Saturation (%)</td>
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<tr>
<td>Matrix Porosity (%)</td>
</tr>
<tr>
<td>Formation Compressibility (%)</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
</tr>
<tr>
<td>Reservoir Temperature (°F)</td>
</tr>
<tr>
<td>Fluid Properties</td>
</tr>
<tr>
<td>Fracture Water Salinity (ppm)</td>
</tr>
<tr>
<td>Formation Water Salinity (ppm)</td>
</tr>
<tr>
<td>Oil Gravity (°API)</td>
</tr>
<tr>
<td>Gas-Oil-Ratio (scf/stb)</td>
</tr>
<tr>
<td>Bubble Point Pressure (psia)</td>
</tr>
<tr>
<td>Gas Gravity (air = 1)</td>
</tr>
</tbody>
</table>
5.6.2.1 Raw Data and Diagnostic Plots

Following the procedure provided previously, the first step in the analysis is to examine production characteristics, assess potential communication and identify flow-regimes. Individual phase rates, calculated bottomhole flowing pressures (calculated from surface casing pressures using a multi-phase wellbore model) and choke sizes will be shown for the Flow 1 (Fig. 5.15) in order to help identify communication between the two wells. Individual phase rates, calculated bottomhole flowing pressures and gas-oil-ratio (GOR) are shown for both the first and second flow periods in Fig. 5.16.

First considering Flow 1, it can be seen that both wells have only a very short period of single-phase water production (possibly due to the longer shut-in period between stimulation and flowback than the case presented by Clarkson et al. (2014), and therefore BBT flow-regime identification is difficult and will not be shown. Although BBT data is scarce and noisy, the diagnostic plots for these wells are generally consistent with those shown in previous LTO flowback studies (Clarkson et al., 2014) suggesting that the developed analytical model is suitable for this application. For both wells, water rates generally decline throughout the flowback period, while ABT, oil and gas production generally increase after each successive increase in choke size, with a relatively stable GOR at approximately the solution gas level (~

| Table 5.6 — Input Parameters for Multi-Well Flowback Analysis Which Vary from the Two Flow Tests for Case Study 2 |
|--------------------------------------------------|--------|--------|
| Flow Test 1 Properties                          | Well 1 | Well 2 |
| Initial Fracture Pressure (psia)                | 4,500  | 4,000  |
| Initial Water Saturation (%)                    | 100    | 100    |
| Flow Test 2 Properties                          | Well 1 | Well 2 |
| Initial Fracture Pressure (psia)                | > 4,000| 3,500  |
| Initial Water Saturation (%)                    | < 90   | 99     |
1,250 scf/stb). Bottomhole flowing pressures for both wells, calculated using surface data with a multi-phase wellbore model, exhibit a relatively continuous decline throughout the flowback period. At approximately 40 hr, Well 2 is brought on flowback, which causes a significant drop in calculated flowing pressure in Well 1 (without corresponding change in choke size), as well as a reduction in pressure-normalized productivity (particularly for the water phase – not shown). In addition, Well 2 initiated flowback at higher and more stable production levels than expected based on off-setting wells for the given operating conditions (although this is likely also a function of fracture spacing which was down-spaced – increased stage count – and total volume pumped was increased over the majority of wells drilled in the area). The combined effects suggest significant communication between the two wells, which was also noted during stimulation.
Fig. 5.15 — Primary raw data plots used to identify flow behavior and well communication during Flow 1: a) Well 1 water rate and flowing pressure; b) Well 1 hydrocarbon rate, choke size and GOR; c) Well 2 water rate and flowing pressure; and d) Well 1 hydrocarbon rate, choke size and GOR. Minimal single-phase data is seen in both wells at the onset of flowback. Communication is evident in the rate and pressure response of both wells upon the onset of flowback of Well 2. This primary communication was also seen during stimulation.

In Fig. 5.15, time 0 is set to be the start of Flow 1 for Well 1. A summary of the results presented by Williams-Kovacs and Clarkson (2014) for Flow 1 will first be given prior to considering Flow 2 which was first analyzed by Williams-Kovacs and Clarkson (2015).
5.6.2.2 Rate-Transient Analysis of BBT Data

Unlike many tight oil cases, a very short single-phase flow period was observed for both wells during the first flow test (< 5 hours), while multi-phase flow was identified from the onset of the second flow test for both wells, and therefore the diagnostic plots and BBT RTA demonstrated previously are not directly applicable to this case (assume single-phase flow). To derive a first estimate of BBT half-length and fracture permeability for Flow 1, a straight-line was drawn through the first few points on the FMB (Fig. 5.17). This is similar to the method commonly used in industry for estimating contacted gas-in-place during transient flow during on-line production data from tight and shale gas wells (ex. Nobakht and Clarkson, 2011). From this semi-quantitative analysis, the IFFIP was estimated at ~ 5,200 STB for Well 1 and ~ 6,300 STB for Well 2, suggesting a low efficiency of injected (load) fluid compared to the case analyzed in Chapter Four in the same formation, although this number is likely under-estimated as a result of an under-developed fracture depletion signature. Likewise, fracture permeability was estimated at ~ 900 md for Well 1 and ~ 600 md for Well 2 from the x-intercept combined with an estimate of skin. Using the total fracture width and fracture porosity estimates provided
in Table 5.5, combined with the assumption of a circular fracture shape, the BBT fracture half-length is estimated to be 269 ft for Well 1 and 242 ft for Well 2. Due to the small amount of single-phase data in both wells, these parameter estimates are likely in error.

![Flowing Material Balance](image)

**Fig. 5.17** — Flowing material balance to estimate before-breakthrough contacted fracture fluid-in-place: 1) Well 1; and 2) Well 2. Fluid-in-place is estimated at ~ 5,200 STB for Well 1 and ~ 6,300 STB for Well 2. Parameters may be in error due to very short single-phase flow period.

5.6.2.3 Analytical Modeling of BBT Single-Phase Data and ABT Multi-Phase Data

Analytical modeling was then performed for each well individually first, then allowing communication between the two wells, using the methods discussed previously. The first flow test was analyzed, followed by analysis of the second flow test. When history-matching the wells individually without communication, it was not possible to obtain an adequate history-match with a reasonable set of fracture parameters, and therefore the impact of introducing communication into the model will be demonstrated using the same set of history-match parameters for both the individual and communication cases during Flow 1.

5.6.2.3.1 Flow 1 Analytical Modeling
Analytical modeling was performed for each well, allowing for communication between the two wells. The history-matches for Well 1 and Well 2, both with and without communication, are shown below in Fig. 5.18 and Fig. 5.19 respectively. The same set of input parameters were used for both the individual and communication cases to demonstrate the impact of accounting for communication. From the two figures it is obvious that the late-time history-match of Well 1 and the early-time history match of Well 2 are significantly improved by accounting for communication, although the impact on Well 2 is more pronounced. From Fig. 5.18 it can be seen that an improved history-match is achieved for all phases of Well 1, particularly from 0.5 to 3 days. Prior to 0.5 days evidence from stimulation and flowback suggest that Well 1 is directly communicating with a second well on the pad which is providing pressure support, while after day 3 it appears Well 1 is indirectly communicating with a fourth well (potentially via Well 2) reducing fracture pressure in Well 1 (after ~ 4 days the model is unable to replicate the field behavior seen with a rapid decrease in the choke size). From Fig. 5.19 it can be seen that a significantly better history-match is achieved for Well 2, particularly from the initiation of flowback (~ 1.7 days) up until day 3. The history-match between day 3 and 4 remains significantly improved, although the impact of secondary communications becomes evident with all phases beginning to deviate from the model match. The history-matching parameters for both cases are given in Table 5.7. The history-matches for the two wells were modified slightly from those presented by Williams-Kovacs and Clarkson (2014), most significantly, the relative permeability curves for Wells 2 were adjusted, which primarily affects the history-match of this well.
Fig. 5.18 – Analytical history-match for Well 1 during Flow 1 of Case Study 3: a) production rate of all 3 phases without communication; b) cumulative production of all 3 phases without communication; c) production rate of all 3 phases with communication; and d) cumulative production of all 3 phases with communication.
Fig. 5.19 – Analytical history-match for Well 2 during Flow 1 of Case Study 3: a) production rate of all 3 phases without communication; b) cumulative production of all 3 phases with communication; c) production rate of all 3 phases without communication; and d) cumulative production of all 3 phases with communication.

Table 5.7 — Model Input Parameters Used in History-Matching of Flow 1 for Case Study 2

<table>
<thead>
<tr>
<th>Input Parameter</th>
<th>Well 1</th>
<th>Well 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>925</td>
<td>600</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{BBT}$ (ft)</td>
<td>269</td>
<td>227</td>
</tr>
<tr>
<td>ABT Half-Length, $x_{ABT}$ (ft)</td>
<td>197</td>
<td>227</td>
</tr>
<tr>
<td>Breakthrough Pressure (psia)</td>
<td>4,400</td>
<td>3,500</td>
</tr>
<tr>
<td>Fracture Relative Permeability</td>
<td>$n'=2.1, m'=6.2$</td>
<td>$n'=1.1, m'=3.0$</td>
</tr>
<tr>
<td>Matrix Relative Permeability</td>
<td>$n'=2, m'=2$</td>
<td>$n'=2, m'=2$</td>
</tr>
<tr>
<td>Fracture Pressure at End of Flow (psia)</td>
<td>2,600</td>
<td>2,100</td>
</tr>
<tr>
<td>Average Water Saturation at End of Flow, $S_w$ (%)</td>
<td>65%</td>
<td>70%</td>
</tr>
</tbody>
</table>
Note that breakthrough pressure for Well 1 is elevated from the reservoir pressure estimated from DFIT (likely due to elevated pore pressure near the fracture face due to water injection - essentially a mini waterflood), while the breakthrough pressure for Well 2 is comparable to the reservoir pressure estimated from DFIT, likely since this well was shut-in longer between stimulation and flowback, leading to dissipation of pore pressure near the fracture face, and due to communication with Well 1 prior to the initiation of flowback. The commingled history-match was achieved using a $C_{12}$ value of $7 \times 10^{-6}$, which applying Eqn. 5.11 suggests that 17 of the possible 20 stages in Well 1 are in communication. Note that this calculation may be error as it assumes that all fractures are circular and equivalent in dimension. Also, the fracture relative permeability curves are non-linear and slightly different in the two wells for several possible reasons: 1) completion heterogeneity; 2) the assumption of constant fracture permeability for each of the wells; 3) differences in the two completions; 4) commingling of individual stage data; and 5) other causes.

Fig. 5.20a provides the individual fracture pressures and differential fracture pressure for Well 1 and Well 2 (note by definition communication is positive from Well 1 to Well 2). Prior to the initiation of flowback in Well 2 at ~ 1.7 days it can be seen that pressure in the Well 2 fracture system is generally higher than in Well 1, leading to a transfer of fluid from Well 2 to Well 1, although the differential pressure is small and therefore the total fluid transfer is minimal (Fig. 5.20c). After Well 2 is brought on flowback, it is consistently at a lower fracture pressure than Well 1, leading to fluid transfer from Well 1 to Well 2; differential pressure is much higher than prior to 1.7 days, leading to more substantial fluid transfer (Fig. 5.20c). It can also be seen that between 1.7 and 4 days, differential pressure tends to decline as the fracture networks approach equilibrium pressure. Differential pressure then increases significantly after 4 days.
once Well 1 is shut-in. Absolute magnitude of the phase-specific communication factors are then shown in Fig. 5.20b. The magnitude of the communication factor for water declines throughout the flowback period as relative permeability to water in the fractures decreases with water saturation. The communication factor for oil is close to 0 prior to the onset of flowback of Well 2 due to the negligible effective relative permeability to oil in the fractures of Well 2 since flowback is initiated with a brief single-phase water production period (saturation gradients in the fractures are ignored). Because water saturation in the Well 1 fractures remains greater than 70% prior to the onset of flowback in Well 2 and $C_{12,w}$ is higher than the maximum value of $C_{12,o}$ during this period, it is expected that this simplistic approach will not have a significant impact on history-match results in this case. After ~ 1.7 days, the communication factor to oil increases throughout the rest of the flowback period due to the increasing relative permeability to oil as oil saturation in the fractures increases (opposite to water).
Fig. 5.20 — Communication between Well 1 and Well 2: a) differential pressure between fracture networks; b) phase-specific communication factors; and c) fluid transfer rate and cumulative fluid transferred for each phase.

The additional secondary communications discussed above, as well as others that do not significantly impact Well 1 and Well 2, could be rigorously modeled using the same approach for all 8 wells on the pad. Such analysis would require 28 communication factors, some of which would be 0 (for wells not communicating), and therefore this exercise will not be shown in this work.

Flow 1 was recently analyzed by Jia et al. (2017b) using a new hybrid analytical/numerical model developed for analyzing wells in communication. Using this alternate, more rigorous method, the authors derived comparable key fracture parameters to what was found in this case study.
5.6.2.3.2 Flow 2 Analytical Modeling

From Fig. 5.16 it can be seen that the GOR for Well 1 during Flow 2 is greater than 4,000 scf/STB (~3x the solution gas level), while the GOR for Well 2 during Flow 2 is ~1,400 scf/STB (consistent with solution gas level). Based on this observation, it can be concluded that the two wells are no longer in communication by the onset of Flow 2. Further, Well 1 can no longer be modeled using the existing modeling approach which assumes no free gas in the matrix or fractures. Modeling cases with free gas in the matrix and fractures will be addressed in future work. As discussed by Crafton (2008) and Clarkson et al. (2014), phase breakthrough (particularly of gas) typically causes a significant reduction in effective half-length and therefore it is possible that this is the reason for loss of communication between the two wells. Loss of conductivity near the fracture hydraulic fracture tips and in the secondary fractures, which may be propped by water, rather than high concentration proppant as fracture pressure depletes are also possibilities. Despite the loss of communication, history-matching Well 2 during Flow 2 may still be possible without significantly adjusting the parameters estimated above, which will be the focus of the rest of this Case Study.

By comparing Table 5.5 and Table 5.6 it can be seen that the fracture pressure for Well 2 has increased back to the initial reservoir pressure, as the shut-in between the two flow periods was long enough to allow pressure equilibrium to be achieved between the matrix and fractures. It can also be seen that some phase redistribution in the fractures has occurred allowing water saturation in Well 2 to increase back to 99% prior to the second flow. It is likely that this is caused by communication with Well 1 (and possibly other wells on the pad) and possibly
redistribution of fluid between the matrix adjacent to the fractures and the primary fractures during the extended shut-in period.

With the exception of water saturation, no further changes to the model parameters were required to adequately history-match Flow 2 for Well 2 (Fig. 5.21), confirming that the parameters determined during Flow 1 are reasonable and can be used to predict future production above the bubble point. This was the desired outcome of analyzing Flow 2. Note that the extended shut-in period had no apparent impact on well productivity in this case as was demonstrated by Williams-Kovacs and Clarkson (2013b) and Crafton (2008) for shale and tight cases respectively. There is no evidence of communication with any well on the pad during Flow 2 for Well 2.

![Fig. 5.21 – Analytical history-match for Well 2 during Flow 2 of Case Study 3: a) production rate of all 3 phases without communication; and b) cumulative production of all 3 phases without communication.](image)

5.6.3 Case Study 3: Multi-Layer Flowback

Case Study 3 examines a field case for which a reasonable interpretation is that two distinct layers have been contacted by the hydraulic fractures. The two reservoir units are separated by an impermeable layer, leading to no direct cross-flow between the layers, except within the
hydraulic fractures. This scenario could arise in several unconventional plays (tight/shale gas and tight/shale oil) in North America, as well as other regions. The subject well is a MFHW drilled and completed in a tight oil reservoir in the WCSB. The horizontal well was landed in Layer 1 which sits below Layer 2. To protect operator confidentiality, well location, reservoir and completion information have been withheld. A summary of the fracture treatment is presented below:

- Cased-hole completion
- Hydraulically fractured with hybrid water fracs in 25 stages using a cemented liner with sliding sleeve technology
- Stages spaced at approximately 210 ft
- Approximately 320 STB of fluid and 12 T of proppant pumped per stage

Following stimulation, the well was flowed back through a test separator. Fluid production rates and wellhead pressures were collected at hourly intervals throughout the test, which was approximately 200 hours (8.3 days) in length. Inputs common to the different flowback analysis steps are given in **Table 5.8**. Note that it was assumed that the fluid properties for both layers are equivalent. Analysis was conducted assuming the formation of multiple bi-wing planar fractures per stage with a circular fracture shape (or potentially a slightly complex fracture network). In the absence of any off-setting microseismic data, fracture geometry was selected based on a trial and error process to determine which geometry yielded the best history-match while still honoring the capabilities of the formation.
<table>
<thead>
<tr>
<th>Fracture Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Fracture Pressure (psia)</td>
<td>8,000</td>
</tr>
<tr>
<td>Initial Water Saturation (%)</td>
<td>100</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
<td>31</td>
</tr>
<tr>
<td>Fracture Compressibility (psi⁻¹)</td>
<td>1x10⁻⁴</td>
</tr>
<tr>
<td>Number of Hydraulic Fracture Stages</td>
<td>25</td>
</tr>
<tr>
<td>Individual Stage Fracture Width (ft)</td>
<td>0.25</td>
</tr>
<tr>
<td>Total Hydraulic Width (ft)</td>
<td>6.25</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Properties</th>
<th>Layer 1 Value</th>
<th>Layer 2 Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Pressure (psia)</td>
<td>3,850</td>
<td>3,850</td>
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<tr>
<td>Net Pay (ft)</td>
<td>16.4</td>
<td>&gt;20</td>
</tr>
<tr>
<td>Matrix Porosity (%)</td>
<td>6.8</td>
<td>6.9</td>
</tr>
<tr>
<td>Initial Mobile Oil Saturation (%)</td>
<td>84</td>
<td>85</td>
</tr>
<tr>
<td>Initial Mobile Water Saturation (%)</td>
<td>16</td>
<td>15</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.9</td>
<td>0.75</td>
</tr>
<tr>
<td>Formation Compressibility (%)</td>
<td>4x10⁻⁶</td>
<td>4x10⁻⁶</td>
</tr>
<tr>
<td>Reservoir Temperature (°F)</td>
<td>192</td>
<td>192</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Water Salinity (ppm)</td>
<td>50,000</td>
</tr>
<tr>
<td>Formation Water Salinity (ppm)</td>
<td>200,000</td>
</tr>
<tr>
<td>Oil Gravity (°API)</td>
<td>43</td>
</tr>
<tr>
<td>Gas-Oil-Ratio (scf/STB)</td>
<td>800</td>
</tr>
<tr>
<td>Bubble Point Pressure (psia)</td>
<td>2,402</td>
</tr>
<tr>
<td>Gas Gravity (air = 1)</td>
<td>0.894</td>
</tr>
</tbody>
</table>

5.6.3.1 Raw Data and Diagnostic Plots

Production trends and flow-regime diagnostic plots are given in Fig. 5.22. From Fig. 5.22a it can be seen that there is over 1 day of single-phase flow prior to the breakthrough of formation fluids. Upon breakthrough, hydrocarbon rate increases for approximately 4 days before reaching a plateau. A constant GOR occurs throughout the production test, with the exception of the first 0.5 days of hydrocarbon production where a significantly higher GOR is observed. BBT flow-regimes are interpreted from Fig. 5.22b primarily using the RNP’ curves. Early-time data is again noisy, but falls close to a 0-slope prior to establishing a unit slope trend which persists until
breakthrough from the formation is observed. The interpreted BBT flow-regimes are transient radial flow in the fracture, followed by fracture depletion.

![Figure 5.22](image)

Fig. 5.22 – Production data and diagnostic plots associated with flowback data for Case Study 3: a) fluid production rate and flowing pressure data; and b) RNP and RNP’ plot with respect to water.

5.6.3.2 Rate-Transient Analysis of BBT Data

Quantitative RTA (Fig. 5.23), guided by the flow-regime interpretation of Fig. 5.22b (repeated as Fig. 5.23a for simplicity of the reader), was performed for the interpreted transient radial (Fig. 5.23b) and fracture depletion (Fig. 5.23c) flow-regimes to obtain estimates of fracture conductivity and half-length, which were confirmed by applying the Fetkovich type-curve (Fig. 5.23d).
Fig. 5.23 – Rate-transient analysis for Case Study 3: a) water RNP and RNP’ illustrating identified flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) FMB plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots. Deviation from straight-line behavior on the FMB and from the harmonic stem on the Fetkovich type-curve marks the onset of breakthrough.

Parameters estimated from quantitative RTA are provided in Table 5.9.
5.6.3.3 Analytical Modeling of BBT Single-Phase Data and ABT Multi-Phase Data

Preliminary hydraulic fracture modeling performed by the operator suggested that the impermeable layer between Layer 1 and Layer 2 would act as a fracture barrier and therefore analytical modeling (Fig. 5.24) was first conducted assuming contribution only from Layer 1. The flowback data could not be matched using a reasonable set of fracture parameters, with the best match shown in Fig. 5.24a, b. In order to adequately history-match the data, contribution from Layer 2 was required (Fig. 5.24c, d). Because Layer 2 is significantly thicker than Layer 1, partial penetration of Layer 2 was assumed (modeled with a skin effect). BBT parameters were set equal to those estimated from RTA, and breakthrough pressure was set to be greater than the initial reservoir pressure estimate obtained from a pressure build-up test conducted following flowback. Fractional flow theory was also used (not shown) to constrain the relative permeability curves selected for the fractures. Inputs to the simulator, in addition to those shown in Table 5.8, are given in Table 5.10. Note that parameter estimates for Layer 1 were assumed to be equivalent for both the single-layer and multi-layer match.
Fig. 5.24 – Analytical model history-match for Case Study 3: a) single-layer match - production rate of all 3 phases; b) single-layer match - cumulative production of all 3 phases; c) multi-layer match - production rate of all 3 phases; d) multi-layer match - cumulative production of all 3 phases.
Table 5.10 — Model Input Parameters for History-Matching For Case Study 3

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>21</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{BBT}$ (ft)</td>
<td>59</td>
</tr>
<tr>
<td>ABT Half-Length, $x_{ABT}$ (ft)</td>
<td>53</td>
</tr>
<tr>
<td>Breakthrough Pressure (psia)</td>
<td>6,100</td>
</tr>
<tr>
<td>Fracture Relative Permeability</td>
<td>$n=1.0, m=1.1$</td>
</tr>
<tr>
<td>Layer 1 Input Parameters</td>
<td>Parameter Value</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.9</td>
</tr>
<tr>
<td>Matrix Relative Permeability</td>
<td>$n=1.5, n=1.5$</td>
</tr>
<tr>
<td>Layer 2 Input Parameters</td>
<td>Parameter Value</td>
</tr>
<tr>
<td>Contacted Net Pay (ft)</td>
<td>15</td>
</tr>
<tr>
<td>Skin (dimensionless)</td>
<td>0.01</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.75</td>
</tr>
<tr>
<td>Matrix Relative Permeability</td>
<td>$n=1.5, m=1.5$</td>
</tr>
</tbody>
</table>

5.6.3.4 Post-Flowback Build-Up Test Analysis

Following flowback, the well was shut-in for approximately 24 hours (1 day) prior to being flowed for an additional 141 hours (5.9 days). After the second flow period, the well was shut-in and pressures were monitored using downhole recorders for approximately 784 hours (32.7 days). The interpreted RNP and RNP’ plot for the build-up are shown in Fig. 5.25. Interpretation is based on the assumption of contributions from both Layer 1 and Layer 2, where the properties of the two layers have been averaged and the total combined pay estimated from flowback analysis was used. Considering the derivative, early-time data is dominated by wellbore storage (unit slope), followed by a period of linear flow ($\frac{1}{2}$-slope), as would be expected for a hydraulically fractured well. Late in time, the derivative begins to flatten which may be attributed to the onset of radial flow or heterogeneity effects in the reservoir. During the linear flow period there appears to be a slight upward shift around 10 hours, which may be attributed to multiple contributing layers. The average input parameters and calculated
parameters determined from the well-test diagnostic plot are given in Table 5.11. Overall these parameters are in good agreement with parameters estimated from flowback.

Table 5.11 — Input and Calculated Parameters for Post-Flowback Build-up for Case Study 3

<table>
<thead>
<tr>
<th>Input Parameters</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contacted Net Pay (ft)</td>
<td>31.4</td>
</tr>
<tr>
<td>Matrix Porosity (%)</td>
<td>6.87</td>
</tr>
<tr>
<td>Initial Water Saturation (%)</td>
<td>84.5</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.83*</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Calculated Parameters</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Conductivity, $F_c$ (md-ft)</td>
<td>89.4</td>
</tr>
<tr>
<td>Fracture Half-Length (ft)</td>
<td>60.4</td>
</tr>
<tr>
<td>Maximum Matrix Permeability (md)</td>
<td>1.75</td>
</tr>
</tbody>
</table>

*Net pay weighted average from flowback analysis

Fig. 5.25 – Interpreted build-up test diagnostic conducted following flowback for Case Study 3.
5.7 Discussion

In this chapter, the models developed by Clarkson et al. (2014) to analyze multi-phase flowback from MFHW were extended to include communication between stages within a well and/or between adjacent wells and wells producing from multiple zones. For stage-by-stage and multi-well flowback analysis, the methodology applied uses the communicating tank approach introduced by Payne (1996) to account for communication between adjacent production volumes. There are, however, several topics which warrant further discussion: 1) collection of stage-by-stage flowback data; and 2) impact of assumed fracture shape. In the following, these issues are discussed. Multi-layer flowback was also considered, where the layers are only assumed to be in communication through the fractures. It is possible to use the procedure outlined above for stage-by-stage and multi-well flowback to directly model communication between adjacent layers, although it is believed that cross flow between the tight matrix layers is unlikely to have a significant impact as compared to communication through the high permeability fractures.

5.7.1 Collection of Stage-by-Stage Flowback Data

There are two categories of methods used to assist in allocating production back to individual fracture stages: 1) near-wellbore techniques after stimulation; and 2) far-field techniques during stimulation. Each of these categories include several techniques that are fundamentally different and provide drastically different methods for production allocation. Near-wellbore methods typically involve direct measurements of properties which can be used to infer individual stage contributions, while far-field methods typically use indirect measurements to infer stage size/geometry, which can be related to individual stage contributions. In some cases (i.e.
microseismic fracture mapping) these data can also be used to constrain relative dimensions of individual fractures generated during stimulation and used in a similar manner to allocating stage contributions. Some common techniques are briefly summarized in Table 5.12. Data has been compiled from a large number of sources as well as personal experience of the author. From the table it becomes clear that fiber-optic techniques provide the best opportunity for accurately allocating production of each phase to each individual fracture stage. If continuous measurements from fiber-optic techniques are not available, collecting multiple production logs during the flowback period would be desirable to account for changes in individual stage contributions with time. Flowing pressures for each stage can be calculated using a wellbore model from a single surface or downhole pressure measurement by correcting for stage-specific pressure drop along the horizontal wellbore. Alternatively, it is possible to collect individual stage flowing pressures using fiber-optic gauges.

<table>
<thead>
<tr>
<th>Near-Wellbore Techniques</th>
<th>Summary</th>
<th>Primary Advantages</th>
<th>Primary Limitations</th>
</tr>
</thead>
</table>
| Radioactive Tracers      | • Radioactive tracers are added to stimulation fluid and/or proppant prior to pumping  
  • After treatment a gamma ray log is run to measure radioactivity in near-wellbore environment  
  • Gamma ray response is used to help determine placement of fluid and proppant and indirectly allocate production | • Different isotopes can be added to different stages  
  • Relatively low cost | • Measurement at a single point in time  
  • No direct measurement of individual stage contribution  
  • Cannot allocate individual phase contributions  
  • Environmental risks |
| Chemical Tracers         | • Treatment fluids for each stage are tagged with a different chemical tracers prior to pumping  
  • Tracer data is analyzed in produced fluid to allocate production to individual stages | • Different tracers can be used for each stage  
  • No downhole intervention  
  • More environmentally friendly than radioactive tracers  
  • Can use time-lapse data to allocate production with time  
  • Relatively low cost | • No direct measurement of individual stage contribution  
  • Cannot allocate individual phase contributions |
| Temperature Surveys      | • Surveys run after stimulation identify regions that have been had temperature effected by either stimulation or production | • Low cost | • Variable thermal conductivity of formation leads to uncertainty  
  • Requires multiple passes within 24 hr of production |
<table>
<thead>
<tr>
<th>Far-Field Techniques</th>
<th>Summary</th>
<th>Primary Advantages</th>
<th>Primary Limitations</th>
</tr>
</thead>
</table>
| Tiltmeter Mapping    | • Measure hydraulic fracture-induced tilt, or deformation  
|                      | • Map of deformation can be used to estimate fracture geometry of the individual stages  
|                      | • Surface and downhole methods available  
|                      | • Production can be allocated to individual stages based on estimated fracture geometry  
| Microseismic         | • Uses acoustic signals to map the stimulated reservoir  
|                      | • Production can be allocated to individual stages based on relative dimensions from microseismic fracture mapping  
|                      | • Non-intrusive for well being monitored  
|                      | • Provides extensive fracture information beyond allocation of stage data  
|                      | • Requires suitable monitoring well(s)  
|                      | • No direct measurement of individual stage contribution  
|                      | • Cannot allocate individual phase contributions  
|                      | • Quantitative analysis often difficult and open to interpretation  

| Production Logging (Spinner Survey) | • Production can be allocated to individual stages depending on profile  
|                                    | • Measurement at a single point in time  
|                                    | • No direct measurement of individual stage contribution  
|                                    | • Cannot allocate individual phase contributions  
|                                    | • Include multiple sensors (i.e. flow rate, temperature, fluid density, etc.) to measure amount and type of fluid being produced from each stage  
|                                    | • Direct measurement of each stage  
|                                    | • Direct measurement of flow rate is possible  
|                                    | • Multi-phase measurements possible  
|                                    | • Measurement at a single point in time  
|                                    | • Difficult/expensive to run in horizontal wells (particularly open hole)  
|                                    | • Results often questionable in multi-phase flow  

| Downhole Video | • Video camera installed downhole  
|                | • Can visually detect which stages are producing, the fluid that they are producing and the relative magnitude of production between stages  
|                | • Provides visual of actual production within the wellbore  
|                | • Can identify stages which are not producing  
|                | • Multi-phase contributions can be directly detected  
|                | • Only visual data provided (human bias)  
|                | • No direct measurement of individual stage contribution  
|                | • Cannot allocate individual phase contributions  

| Fiber-Optic Based Techniques | • The common techniques: 1) distributed temperature sensing (DTS); 2) distributed acoustic sensing (DAS); and 3) multi-phase flow meters  
|                             | • DTS provides a time-lapse profile of temperature change in the wellbore  
|                             | • DAS uses acoustic measurements to provide individual zone flow rates  
|                             | • Multi-phase flow meters can be installed in each fracture stage to directly measure flow rates of individual phases from each fracture stage  
|                             | • Non-intrusive  
|                             | • Reliable  
|                             | • Direct measurement of each stage  
|                             | • Direct measurement of flow rate is possible  
|                             | • Multi-phase measurements possible  
|                             | • Gathers data continuously with time  
|                             | • High cost  
|                             | • Specialized equipment required  
|                             | • Sensors are fragile (limits some open-hole applications)  
|                             | • Cannot retrieve sensors installed behind casing  

| Production can be allocated to individual stages depending on profile  
| Measurement at a single point in time  
| No direct measurement of individual stage contribution  
| Cannot allocate individual phase contributions  
| Include multiple sensors (i.e. flow rate, temperature, fluid density, etc.) to measure amount and type of fluid being produced from each stage  
| Direct measurement of each stage  
| Direct measurement of flow rate is possible  
| Multi-phase measurements possible  
| Measurement at a single point in time  
| Difficult/expensive to run in horizontal wells (particularly open hole)  
| Results often questionable in multi-phase flow  
| Video camera installed downhole  
| Can visually detect which stages are producing, the fluid that they are producing and the relative magnitude of production between stages  
| Provides visual of actual production within the wellbore  
| Can identify stages which are not producing  
| Multi-phase contributions can be directly detected  
| Only visual data provided (human bias)  
| No direct measurement of individual stage contribution  
| Cannot allocate individual phase contributions  
| The common techniques: 1) distributed temperature sensing (DTS); 2) distributed acoustic sensing (DAS); and 3) multi-phase flow meters  
| DTS provides a time-lapse profile of temperature change in the wellbore  
| DAS uses acoustic measurements to provide individual zone flow rates  
| Multi-phase flow meters can be installed in each fracture stage to directly measure flow rates of individual phases from each fracture stage  
| Non-intrusive  
| Reliable  
| Direct measurement of each stage  
| Direct measurement of flow rate is possible  
| Multi-phase measurements possible  
| Gathers data continuously with time  
| High cost  
| Specialized equipment required  
| Sensors are fragile (limits some open-hole applications)  
| Cannot retrieve sensors installed behind casing  
| Uses acoustic signals to map the stimulated reservoir  
| Production can be allocated to individual stages based on relative dimensions from microseismic fracture mapping  
| Non-intrusive for well being monitored  
| Provides extensive fracture information beyond allocation of stage data  
| Requires suitable monitoring well(s)  
| No direct measurement of individual stage contribution  
| Cannot allocate individual phase contributions  
| Quantitative analysis often difficult and open to interpretation  

245
5.7.2 Impact of Assumed Fracture Geometry

In this work, the focus has been on communication between circular fractures, although alternate fracture shapes can easily be incorporated into the model. Williams-Kovacs and Clarkson (2013a) demonstrated the application of rectangular fractures for a shale gas case and Williams-Kovacs and Clarkson (2013c) showed the impact of elliptical fracture shape for a tight oil case, both for commingled single-well analysis. The application to multi-well analysis is largely the same as what was demonstrated in the previous papers, although when considering stage-by-stage or multi-well flowback analysis the communication plane is also impacted by fracture shape.

First, considering stage-by-stage flowback, the area of the communication plane is dictated by the area of the smallest adjacent fracture (i.e. Stage 1 in Fig. 5.5) assuming the entire fracture face is communicating (may not be true in many cases). In the stage-by-stage application, Eqn. 5.8 and 5.9 can be rewritten, since there is no value in separating $A_{com}$ into its height and width components.

$$C_{0,12} = \frac{k_o}{\mu_o \rho_o} C_{12}$$

$$C_{12} = \frac{0.001127 A_{com}}{L}$$

In this case, knowledge of $A_{com}$ can help constrain fracture plane dimensions or indicate extent of communication over the fracture face (if the entire fracture face is not in communication). For each of the three common fracture shapes (circular, elliptical and rectangular), the area of the communication plane is given by the following formulas assuming the entire fracture face is in communication, where in all cases $i$ refers to the smaller stage of the communicating pair:
Circular:

\[ A_{com} = \pi x_{f,i}^2 \quad (5.20) \]

Elliptical:

\[ A_{com} = \pi x_{f,i} h_{f,i} \quad (5.21) \]

Rectangular

\[ A_{com} = 2x_{f,i} h_{f,i} \quad (5.22) \]

Next, considering the multi-well case, similar geometric formulas of intersecting shapes can be derived to allow an estimate of the number of stages communicating. The case of two intersecting rectangular fracture networks is simple, where \( h_c \) is the height of the fracture network with less height growth (i.e. \( h_c = h_{f,i} \)) for the case where the entire height of the smaller fracture is in communication. In cases where this is not the true, simple geometry can be used to calculate \( h_c \). The case of intersecting ellipses is more complex, but as a demonstration we will look at the simplest case where you have two wells drilled to the same vertical depth with elliptical fracture networks of different sizes. This scenario is shown in Fig. 5.26.
In Fig. 5.26 $h_{f,1}$ and $h_{f,2}$ are the fracture half-heights of well 1 and wells 2 respectively. In the figure, $h_c$ can be derived applying the following procedure.

1. Estimate intersection points from the equations of the two ellipses (in Fig. 5.26 - Well 1:

$$\frac{x^2}{x_{f,1}^2} + \frac{y^2}{h_{f,1}^2} = 1$$

and Well 2:

$$\frac{(x-x_{e,1})^2}{x_{f,2}^2} + \frac{y^2}{h_{f,2}^2} = 1$$):

   a. From algebra, simplify the two equations into a quadratic in $x$: $x^2 \left( \frac{h_{f,1}^2}{x_{f,1}^2} - \frac{h_{f,2}^2}{x_{f,2}^2} \right) +$ $x \left( \frac{2x_{e}h_{f,1}^2}{x_{f,2}^2} \right) - \frac{x_{e}^2h_{f,2}^2}{x_{f,2}^2} = 0$ and solve the quadratic for the $x$-direction coordinates of the two intersection points.

   b. Apply the equation of either fracture network to calculate the $y$-direction coordinate of the intersections.

2. Calculate $h_c$ as the difference in the $y$-direction intersection points (for this particular geometry).
Something similar could also be derived for different combinations of fracture shapes in different orientations (i.e. combination of circular and elliptical fractures, well drilled to different vertical depths, etc.), depending on the complexity of the particular problem.

5.7.3 Handling Direct Communication Between Producing Layer

In Case Study 3 a tight oil well producing from multiple zones, separated by an impermeable layer, was analyzed assuming that cross flow occurred only in the hydraulic fractures. In some cases such a permeability barrier may not exist, or natural fracturing may be prevalent leading to direct communication between the two layers. In such cases, a similar model to the one proposed for handling inter-stage communication could be used. In this case, it is important to understand the lateral extent of the lower permeability layer in order to determine the surface area of communication. Such data can be obtained from geological and geophysical interpretation. In many unconventional plays when the individual producing zones are laterally extensive, the contact area will likely be limited by the ultimate drainage area of the well, which will not be available during flowback, and should be approximated from offsetting production or could be constrained to the SRV assuming that this is where short term production is predominantly coming from. This ultimately could become the most complex case where it is possible to have inter-stage, inter-well and multi-layer communication, introducing additional unknown parameters into the history-matching exercise. For tight rock, a transient transfer term could be used, although it is unlikely that cross flow between the two low permeability layers will be inconsequential compared to direct communication through the hydraulic fractures.
5.8 Summary

In this chapter, an analytical procedure, and associated techniques, was developed for quantitatively analyzing flowback data (rates and pressures) obtained from communicating stages, communicating wells and multiple layers in LTO reservoirs. All previous work has focused on analyzing commingled stage data from a single layer in a single well to estimate bulk fracture properties, ignoring heterogeneity between stages and any communication effects. These techniques are deficient as a result of industry’s push to drill longer laterals, decrease stage/well spacing and pump more aggressive stimulations to access more reserves in tight reservoirs. The base model originally developed by Clarkson et al. (2014) was modified by incorporating the “communicating tanks” approach developed by Payne (1996) to account for communication between adjacent fracture networks and multi-layer effects. The main conclusions of this study are as follows:

- The tools developed in this work can be extended to analyze more complex cases such as stage-by-stage flowback, multi-well flowback and multi-layer flowback.
- There are many problems with analyzing commingled stage data that can be resolved by collecting stage-by-stage flowback data. The primary advantages of these data include: 1) improved flow-regime identification; 2) improved parameter estimation; and 3) understanding completion heterogeneity.
- Individual well history-matching (and therefore parameter estimation) can be improved by introducing communication into the model.
- Inter-well communication during flowback may be a result of water propping of both hydraulic and secondary fractures and may be lost as fracture pressure depletes.
• Analysis of Flow 2 in Case Study 2 suggests that communication between wells may not continue long-term and also suggests that the parameters estimated from flowback can be used to forecast long-term production above the bubble point.
Chapter Six: Additional Case Studies in Light Tight Oil Quantitative Flowback Analysis

6.1 Abstract

As demonstrated in the previous chapters, for quantitative flowback analysis, models have been developed for both oil and gas wells representing a variety of reservoir and operating conditions. In this chapter, the models and procedures are extended to apply to more challenging reservoir/completion scenarios and are used in the analysis of several case studies from western Canada. Each of the case studies demonstrate either the potential value add of the developed techniques, or a unique extension to the basic analysis methods.

The case studies analyzed herein focus on LTO plays. In the first case study, the potential monetary value of conducting quantitative flowback analysis to one operator is considered. In the second case, the well discussed in Chapter Four will be reinterpreted under the assumption that rectangular fractures are created and fracture height is limited to the net pay. In the third case study, the previously-developed version of FLOAT will be expanded to allow for application to LTO wells which have been stimulated with oil-based fracture fluid (not previously considered in the literature). In the final case study, numerical simulation is used to validate the sequence of flow-regimes which are modeled analytically.

6.2 Introduction

As discussed in Chapter Five, more complex flowback scenarios have not been investigated in the literature. There are many real world complexities which have not been addressed, such as

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1 This chapter was taken in part from the following paper: Williams-Kovacs, J.D., Clarkson, C.R. and Zanganeh, B. 2015. Case Studies in Quantitative Flowback Analysis. Paper SPE 175983, presented at the SPE/CSUR Unconventional Resources Conference – Canada held in Calgary, Alberta, 20-22 October.
quantifying the monetary value of conducting quantitative flowback analysis, and analyzing LTO wells stimulated with oil-based hydraulic fracture fluid (which is commonly used in water-sensitive formations). Due to the clay content of many unconventional reservoirs it is often desirable to use an oil-based fracture fluid.

Further, many authors have used numerical simulation as a proof-of-concept for their flowback models. This is an important step for model validation, particularly when long-term production data is not available to be analyzed using more conventional techniques, which would provide a benchmark for the results of different flowback analysis procedures. Ideally, models should be validated with both numerical simulation and by analyzing wells that have enough online production history to adequately estimate key hydraulic fracture properties. The flow-regimes modeled analytically are confirmed using numerical simulation, while comparison with more conventional techniques was demonstrated in Chapter Three and Chapter Five.

### 6.3 Objective

In the literature, all of the methods presented for quantitative flowback analysis have: 1) focused on commingled wells from a single reservoir unit; 2) assume a water-based fracture fluid; and 3) ignored the monetary value of conducting such analysis. For issues 1, real world complexities such as stage-by-stage, multi-well and multi-layer flowback are discussed in Chapter Five, although many complexities still require investigation.

The objective of this chapter is therefore to present a series of tight oil case studies, where the first case study demonstrates the monetary value of conducting quantitative flowback analysis, and the ensuing case studies present practical extensions of the basic models presented in Clarkson et al. (2014). In the second case study, the dataset analyzed in Chapter Four will be re-
analyzed assuming a rectangular fracture geometry where fracture height growth is constrained to the calculated net pay as is assumed in most analytical models which have been applied in the literature. FLOAT will then be expanded to account for oil fracs in oil reservoirs (FLOAT v3), which provides a significant challenge not present with water-based fracs, as only one oil stream is measured which is a combination of both fracture and formation oil. Although most operators sell the cumulative volume of oil-based fluid which is pumped into the well as stimulation fluid, this is often a combination of both fracture and formation oil. The introduction of formation oil to the product stream can easily be observed by the presence of gas production as oil-based fracture fluid does not contain solution gas. Finally, to confirm that the data-driven analytical model developed and applied in this work is physically reasonable, numerical simulation is used to identify flow-regimes during both early-time flowback and long-term production. Whenever possible, flowback results are compared to other data sources to demonstrate the quality of results which can be achieved using quantitative flowback analysis.

6.4 Theory and Methods

In this chapter, the basic conceptual model applied in previous chapters will again be used, and then numerical simulation will be used to confirm the sequence of flow-regimes which have been modeled analytically to confirm the feasibility and accuracy of the proposed model. The conceptual model for the first three case studies is identical to what has been presented previously, although one of the case studies considers an alternate fracture shape which was also derived and discussed in Chapter Three. The conceptual model for the final case study is associated with the numerical simulation setup (discussed below). The correlations for
estimating PVT properties of oil-based fracture fluid will be presented in Appendix 6.1 this section while the numerical model setup will be presented with that case study.

6.5 Analysis Procedure

The analysis procedure used in the case studies in this chapter is comparable to what was discussed in Chapter Two, although two additional steps are conducted in the Case Study 1. The analysis procedure used in this chapter is summarized in Fig. 6.1. In this chapter, less detail will be provided than in the case studies discussed in Chapter Three and Four since the step-by-step procedure was discussed in detail in those case studies. Here, the primary results and observations will be the focus.

![Fig. 6.1 – Summary of procedure for analyzing flowback data and forecasting long-term production using flowback parameter estimates (steps 1-4) and comparing flowback derived parameter estimates with other data sources (step 5).](image)

6.6 Case Studies

The case studies discussed in this paper are summarized in Table 6.1.

<table>
<thead>
<tr>
<th>Table 6.1 — Summary of Case Studies</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Case Number</strong></td>
</tr>
<tr>
<td>1</td>
</tr>
<tr>
<td>2</td>
</tr>
<tr>
<td>3</td>
</tr>
<tr>
<td>4</td>
</tr>
</tbody>
</table>
For each of the field case studies, flowing pressures were measured at the surface and converted to downhole conditions using a wellbore model.

6.6.1 Case Study 1: Monetary Value of Quantitative Flowback Analysis

Case Study 1 examines a field case to demonstrate the monetary value of conducting quantitative flowback analysis. The well investigated is a MFHW drilled and completed in a tight oil reservoir in the WCSB. To protect operator confidentiality, well location, reservoir and completion information has been withheld. A summary of the fracture treatment is provided below:

- Open-hole completion
- Hydraulically fractured with slickwater in 32 stages using ball drop technology (single fracture port per stage)
- Stages spaced at approximately 230 ft
- Approximately 870 STB of fluid and 25 T of proppant pumped per stage

The well was drilled as part of a farm-out agreement and was stimulated with a significantly higher fracture density and pump rate (facilitated by the switch to slickwater) than had previously been used for development in the area. Prior wells drilled and completed with lower fracture density by the operator had been NPV neutral; a decision therefore had to be made on whether to participate at 50% in 4 additional wells completed with the higher fracture density in comparable reservoir to the subject well, or to extend the farm-out based on pay 100% to earn 70% terms. Flowback was the only data available to understand the impact of the new fracture system prior to making the decision.
Following stimulation, several fracture ports were drilled out before flowing the subject well back through a test separator. Fluid productions rates and wellhead pressures were collected at hourly intervals throughout the test, which was approximately 80 hours (3.3 days) in length.

Inputs common to the different flowback analysis steps are given in Table 2.2. Analysis was conducted assuming the formation of a single bi-wing planar fracture at each stage with a circular fracture shape (supported by microseismic data collected for off-setting wells).

<table>
<thead>
<tr>
<th>Table 6.2 — Input Parameters for Case Study 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Properties</td>
</tr>
<tr>
<td>Initial Fracture Pressure (psia)</td>
</tr>
<tr>
<td>Initial Water Saturation (%)</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
</tr>
<tr>
<td>Fracture Compressibility (psiu⁻¹)</td>
</tr>
<tr>
<td>Number of Hydraulic Fracture Stages</td>
</tr>
<tr>
<td>Individual Fracture Width (ft)</td>
</tr>
<tr>
<td>Total Hydraulic Width (ft)</td>
</tr>
<tr>
<td>Reservoir Properties</td>
</tr>
<tr>
<td>Formation Pressure (psia)</td>
</tr>
<tr>
<td>Net Pay (ft)</td>
</tr>
<tr>
<td>Matrix Porosity (%)</td>
</tr>
<tr>
<td>Initial Mobile Oil Saturation (%)</td>
</tr>
<tr>
<td>Initial Mobile Water Saturation (%)</td>
</tr>
<tr>
<td>Formation Compressibility (%)</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
</tr>
<tr>
<td>Reservoir Temperature (°F)</td>
</tr>
<tr>
<td>Fluid Properties</td>
</tr>
<tr>
<td>Fracture Water Salinity (ppm)</td>
</tr>
<tr>
<td>Formation Water Salinity (ppm)</td>
</tr>
<tr>
<td>Oil Gravity (°API)</td>
</tr>
<tr>
<td>Gas-Oil-Ratio (scf/STB)</td>
</tr>
<tr>
<td>Gas Gravity (air = 1)</td>
</tr>
</tbody>
</table>
6.6.1.1 Raw Data and Diagnostic Plots

Water, oil and gas rates as well as bottom-hole flowing pressure and GOR are shown below in Fig. 6.2a, while water RNP and RNP’ are shown in Fig. 6.2b.

![Production data and diagnostic plots](image)

From Fig. 6.2a it is observed that there is over 1 day of single-phase flow prior to the breakthrough of formation fluids. Upon breakthrough, hydrocarbon rate increases for approximately 1 day before reaching a plateau, with a reasonably constant GOR until approximately 3 days, at which point the choke size was increased significantly resulting in a large increase in GOR. Bottomhole flowing pressure is relatively stable ABT, prior to the aforementioned increase in choke size at around 3 days, at which point a rapid decrease in Pwf of ~800 psia is observed, likely causing gas to breakthrough into the fractures.

BBT flow-regimes are interpreted from Fig. 6.2b, which illustrates water RNP and RNP’ plots using MBT as the time function. At early time, radial flow is interpreted to be occurring within the fractures, although confirmation of this flow-regime (zero-slope) is difficult due to data quality. Following this, a unit slope is identified, which is interpreted to be associated with
single-phase fracture depletion – this flow-regime continues until breakthrough of formation fluids.

6.6.1.2 Rate-Transient Analysis of BBT Water Data

Quantitative RTA (Fig. 6.3) was then performed for the interpreted transient radial (Fig. 6.3b) and fracture depletion (Fig. 6.3c) flow-regimes to obtain estimates of fracture conductivity and half-length. Parameter estimates can then be confirmed by applying the Fetkovich type-curve (Fig. 6.3d). Although the data quality is quite poor, each of the analysis techniques yield consistent results. A summary of the parameters estimated from each analysis method is shown below in Table 6.3.
Fig. 6.3 – Rate-transient analysis for Case Study 1: a) water RNP and RNP' illustrating identified flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) flowing material balance plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots.

Table 6.3 — Parameters Solved From Each BBT RTA Technique for Case Study 1

<table>
<thead>
<tr>
<th>Technique</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Radial Flow Plot</td>
<td></td>
</tr>
<tr>
<td>Fracture Conductivity, $F_{cT}$ (md-ft)</td>
<td>600</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>900</td>
</tr>
<tr>
<td>Flowing Material Balance</td>
<td></td>
</tr>
<tr>
<td>Fracture Fluid-In-Place (STB)</td>
<td>16,000</td>
</tr>
<tr>
<td>BBT Half-Length, $x_{BBT}$ (ft)</td>
<td>350</td>
</tr>
<tr>
<td>Fracture Conductivity, $F_{cT}$ (md-ft)</td>
<td>520</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>780</td>
</tr>
<tr>
<td>Fetkovich Type-Curve</td>
<td></td>
</tr>
<tr>
<td>$x/r_{ws}$</td>
<td>~1000</td>
</tr>
<tr>
<td>Fracture Conductivity, $F_{cT}$ (md-ft)</td>
<td>520</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>780</td>
</tr>
</tbody>
</table>
6.6.1.3 Analytical Modeling of BBT Single-Phase Data and ABT Multi-Phase Data

Analytical modeling (Fig. 6.4) was then performed using the parameters determined from BBT RTA as a starting point. Input parameters used for history-matching with the simulator, in addition to what was shown in Table 6.2, are given in Table 6.4. The history-match of water, oil, and gas rates appears reasonable for the first 3 days of the flowback period. BBT parameters were adjusted only slightly from the RTA-derived values, and breakthrough pressure was set to be greater than the initial reservoir pressure estimates obtained from several welltest (flow/build-up) analyses of off-setting wells. Fractional flow theory was also used (not shown) to constrain the relative permeability curves selected for the fractures.

![Analytical model history-match for Case Study 1: a) production rate of all 3 phases; and b) cumulative production of all 3 phases.](image)

Table 6.4 — Model Input Parameters for History-Matching of Case Study 1

<table>
<thead>
<tr>
<th>Input Parameters</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breakthrough Pressure (psia)</td>
<td>4,250</td>
</tr>
<tr>
<td>BBT Half-Length, ( x_{BBT} ) (ft)</td>
<td>372</td>
</tr>
<tr>
<td>ABT Half-Length, ( x_{ABT} ) (ft)</td>
<td>204</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>900</td>
</tr>
<tr>
<td>Fracture Relative Permeability</td>
<td>( n'=1.5, m'=2.5 )</td>
</tr>
<tr>
<td>Fracture Permeability Modulus (psi(^{-1}))</td>
<td>0</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.01</td>
</tr>
</tbody>
</table>
In order to assess the economic viability of the modified stimulation (higher density fracture stages), a numerical simulation was conducted to estimate long-term performance using the key fracture parameters determined from flowback. Relative permeability curves and an estimated flowing pressure profile were supplied by the operator based on off-setting wells, and a 10% initial gas saturation to account for gas breakthrough seen at the end of the flowback period was assumed. The oil and gas production rates predicted by the model are shown below in Fig. 6.5.

![Numerical Simulation of Long-Term Production](image)

**Fig. 6.5 – Numerical simulation of long-term production for Case Study 1 using parameters estimated from quantitative flowback analysis.**

Preliminary economics performed using the rate profiles in Fig. 6.5, and a capital cost of $6MM, along with other economic inputs provided by the farm-out company, suggested an NPV neutral project in line with previous results; therefore the decision was made to extend the farm-out deal rather than participate in the next four wells. As part of a look-back to determine if the right decision was made, 14 months of actual public production data were compared to the numerical simulation forecast (Fig. 6.6). As can be seen, a reasonable forecast for the well, using flowback-derived parameters, was achieved. Furthermore, early production data from the
four follow-up wells suggest similar performance. These results confirm that the correct
decision was made by implementing quantitative flowback analysis, which saved the farm-out
company $12MM of capital that could be reallocated to plays with better economic potential
while still generating a small revenue stream.

This case study clearly demonstrates that even poor quality flowback data can often be
analyzed to get an indication of fracture half-length and conductivity in order to generate a
forecast for long-term online production. This can be very useful for other purposes as well.
Flowback data can also provide information required for completion optimization within a
drilling program, help understand reservoir heterogeneity, etc. much faster than more
conventional techniques.

![Online History-Match](image.png)

Fig. 6.6 – History-match of long-term monthly production data for Case Study 1 using numerical simulation
forecast based on flowback-derived parameters.

### 6.6.2 Case Study 2: Reanalysis of LTO Well Assuming Rectangular Fracture Geometry

Case Study 2 revisits the well analyzed in Chapter Four, with the only difference being that a
rectangular shaped fracture was assumed. The conceptual model, analysis equations and
modeling procedure associated with both circular and rectangular shaped fractures were
discussed in Chapter Two and Three, with the rectangular versions being used in this analysis. Although the microseismic showed significant height growth out of zone, rationalizing the use of a circular fracture shape in Chapter Four, lateral fracture extension remained larger than fracture height. The ratio observed in microseismic was not considered in this re-interpretation as a result of the many issues associated with quantitative microseismic analysis, and therefore height growth was limited to the net pay which is assumed to be a continuous package of reservoir. Making this assumption will allow a direct comparison between our methods and assumptions used extensively in the literature to analyze long-term online production data. For long-term production, restricting fracture height to net pay is a good assumption, because hydrocarbons are primarily being sourced from the net pay. However, unless the pay column is a continuous package confined by two strong fracture barriers, this is likely a poor assumption for quantitative flowback analysis when the fractures have likely grown out of zone or the pay column is not continuous. In this situation, water would flow to the wellbore from a larger gross pay column. In this particular case, petrophysical interpretation suggested a potential fracture barrier above and below the formation of interest, although these formation has been breached in several cases. As a result, the half-length estimated from this analysis (assuming fracture height = net pay) can be assumed to represent a maximum value. Inputs common to the different flowback analysis steps are repeated in Table 6.5. Note that fracture width was doubled, as was done by Clarkson et al. (2016) when analyzing the same data set using the DDA concept, who also made the same assumption about the fractures being confined to the net pay. The rationalization behind this assumption is that a more complex fracture network beyond the resolution of the microseismic was created. Further, it is likely that gross pay contacted by the fractures is greater than net pay (discontinuous pay column or vertical height growth out of zone), which would limit the IFFIP.
All other assumptions were kept the same. Fracture height was held constant both BBT and ABT.
6.6.2.1 Raw Data and Diagnostic Plots

Water, oil and gas rates as well as bottom-hole flowing pressure and GOR are repeated below in Fig. 6.7a, while water RNP and RNP’ are shown in Fig. 6.7b.
Fig. 6.7 – Flowback data: (a) water, oil and gas rate, as well as bottom-hole flowing pressure and GOR; and (b) water RNP and RNP’.

As in Chapter Four, only the first eight days will be analyzed while the flowing pressures remain above the bubble point, and only two phase flow is occurring in the matrix and the fractures. In this case, the noisy data prior to the onset of fracture depletion was assumed to be linear flow. The scatter in the data makes it impossible to accurately identify which transient flow-regime is occurring and therefore it is worthwhile to interpret the data using both fracture shapes.

6.6.2.2 Rate-Transient Analysis of BBT Single-Phase Data and ABT Multi-Phase Data

Quantitative RTA (Fig. 6.8) was then performed for the interpreted transient linear flow period using both the linear superposition plot (Fig. 6.8b) and the square root of time plot (Fig. 6.8c); fracture depletion (Fig. 6.8c) was interpreted using FMB. Linear flow analysis is used to obtain estimates of fracture conductivity and half-length, while the FMB is primarily used to obtain fracture half-length. Parameter estimates can then be confirmed by applying the Wattenbarger type-curve (Fig. 6.8d). A summary of the parameters estimated from each analysis method is shown below in Table 6.6. Due to the significant decrease in fracture height growth
compared to the circular fracture case the estimated fracture half-length is $\sim 70\%$ greater than what was found in Chapter Four. Clarkson et al. (2016) found a fracture half-length comparable to what was shown in Chapter Four, although relative permeability curves and pressure-dependant permeability were not shown in their analysis, and the BBT half-length would be significantly shorter than what is found from the FMB using the same assumptions. Total fracture conductivity is consistent with what was found in Chapter Four because the permeability has been reduced by half and the fracture width has been doubled.
Fig. 6.8 – Rate-transient analysis for Case Study 2: a) water RNP and RNP’ illustrating identified flow-regimes; b) linear flow plot used to analyze single-phase fracture transient data; c) square root of time plot to analyze single-phase transient data; c) FMB plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots.
6.6.2.3 Analytical Modeling of Single-Phase BBT Data and Multi-Phase ABT Data

Analytical modeling (Fig. 6.9) was then performed using the parameters determined from BBT RTA as a starting point. Input parameters used for history-matching with the simulator, in addition to what was shown in Table 6.5, are given in Table 6.7. The history-match of water, oil and gas rates appears reasonable for the analyzed 8 days of flowback. BBT parameters were adjusted only slightly from the RTA-derived values. Breakthrough pressure was set to be 175 psia greater than the value used for the deterministic history-match assuming a circular fracture shape, but 100 psia lower than what was found to be the optimal value for a circular fracture shape in Chapter Four. Fractional flow theory (not shown) was also used to constrain the relative permeability curves selected for the fractures as was shown in Chapter Three. Note that the issue of under-estimating late-time hydrocarbon production, as was the case for the
deterministic history-match assuming a circular fracture shape, is not present assuming a rectangular fracture shape.

![Rate Match](image)

**Fig. 6.9 — Analytical model history-match for Case Study 1: a) production rate of all 3 phases; and b) cumulative production of all 3 phases.**

<table>
<thead>
<tr>
<th>Table 6.7 — Model Input Parameters for History-Match For Case Study 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Input Parameters</strong></td>
</tr>
<tr>
<td>Breakthrough Pressure (psia)</td>
</tr>
<tr>
<td>BBT Half-Length, ( x_{f,BBT} ) (ft)</td>
</tr>
<tr>
<td>ABT Half-Length, ( x_{f,ABT} ) (ft)</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
</tr>
<tr>
<td>Fracture Relative Permeability</td>
</tr>
<tr>
<td>Fracture Permeability Modulus (psi(^{-1}))</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
</tr>
<tr>
<td>Matrix Relative Permeability</td>
</tr>
<tr>
<td>Fracture Dimension Ratio BBT, ( x_{f,BBT}/(h/2) )</td>
</tr>
<tr>
<td>Shape Factor Skin BBT, ( S_{CA,BBT} )</td>
</tr>
<tr>
<td>Fracture Dimension Ratio ABT, ( x_{f,ABT}/(h/2) )</td>
</tr>
<tr>
<td>Shape Factor Skin ABT, ( S_{CA,ABT} )</td>
</tr>
</tbody>
</table>

Note, that a more rigorous hybrid model was developed for analyzing tight oil flowback by Jia et al. (2017c) and was applied to this data set, achieving similar results for fracture permeability and half-length further suggesting that this relatively simple approach can be highly effective. This model is analogous to Jia et al. (2016b) which was discussed previously in which
the matrix is modeled analytically, while the fractures are modeled numerically using the LTFD method, although communication is not considered in this version of the tight oil model as was discussed in the literature review and in Chapter Five.

This case study highlights the uncertainty associated with estimated fracture properties when fracture shape is difficult to constrain. If higher frequency data is obtained, fracture shape could be better constrained by the early-time transient flow-regime observed. Microseismic and accurate fracture modeling may also be useful in assisting in constraining fracture height growth. The interpreted microseismic collected on the well are shown below in Fig. 6.10 and the calibrated fracture modeling is shown in Fig. 6.11.
In this case fracture modeling suggests a fracture height of up to 260 ft, ~ 197 ft worth is propped with a high proppant concentration, although height growth is constrained in the model by a overlying and underlying layers which have been shown to be penetrated by hydraulic fractures in many areas of the formation. Microseismic suggests a hydraulic fracture height of ~ 328 ft from the vertical array, a significant amount of which may be propped, while the
horizontal array shows a fracture height growth of approximately double (the vertical array is thought to be more realistic for estimating fracture height growth). In both cases, this fracture height is significantly larger than what was assumed in this analysis. If fracture height is assumed to be 328 ft, the BBT half-length estimated from the FMB is 452 ft which is comparable to what was found for a circular fracture shape in Chapter Four. It is also important to note that water-propped height and reactivated natural fractures which are too fine to be identified on microseismic may contribute during flowback but not during long-term production. Note that history-matching with a rectangular fracture shape contains an additional step and the shape factor skin must be adjusted whenever half-length is adjusted. This can be constrained to a reasonable range based on the results of the BBT RTA.

6.6.3 Case Study 3: Oil-Based Fracs in LTO Reservoirs

Case Study 3 examines the use of oil fracs in a LTO reservoir. The purpose of this case study is to investigate the complexities of modeling flowback data when an oil-based fracture fluid has been used instead of water-based fracture fluid – previous flowback analyses performed by the authors and in the literature have focused on water-based fluids. The differences between oil- and water-based fracture fluid will be demonstrated using simulations generated with the analytical flowback modeling tool. For this analysis a 20 stage MFHW was assumed.

Oil fracs have been performed in the industry for several decades, typically using a base fluid of diesel, or another highly refined crude oil product. Oil products provide an excellent alternative to water-based fracture fluid in water sensitive formations and a variety of other situations. Due to industry demand, in recent years, service companies have begun to use other products including condensates and uncontaminated crude oils. In many cases the petroleum
liquid produced in a given field can be used as a base fracture fluid in the field, which significantly reduces compatibility issues that can arise by introducing a foreign fluid into the formation.

Analyzing flowback from such wells introduces additional complexities that have not been investigated in the past. The first challenge is to accurately estimate PVT properties for the oil-based fracture fluid. In the literature there are many correlations for calculating properties of live crude oil, although these aren’t applicable for fracture fluids which are comprised of dead oil containing no solution gas. In this work, fracture fluid viscosity is estimated using the dead oil correlation of Beggs and Robinson (1975), although many dead oil viscosity correlations have been published that may provide better results in some cases. Other key PVT properties including compressibility, formation volume factor and density were calculated using the API (2004) standard for temperature and pressure volume correction factors for generalized crude oils, refined products and lubricating oils (collectively referred to as oils in this work). This approach is versatile in that it can be used with any petroleum product (crude oil, condensate, diesel, etc.). The calculations of these PVT properties is discussed in Appendix 6.1. Each of these correlations are somewhat limited in applicability and may not provide accurate estimates of PVT properties for all oil-based fracture systems under all reservoir conditions, and therefore it is suggested that lab data be collected whenever possible.

An additional complexity faced with oil-based fracture fluids is distinguishing fracture oil from formation oil, given that the rate and volume of only a single oil stream is typically recorded during flowback. This will be discussed in greater detail below.

The inputs for the simulation case are provided in Table 6.8. The input parameters are equivalent to those used in the simulation case by Clarkson and Williams-Kovacs (2013b) with
the exception of the fracture fluid; Clarkson and Williams-Kovacs (2013b) considered only water-based fracture fluid.

<table>
<thead>
<tr>
<th>Fracture Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Fracture Pressure (psia)</td>
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</tr>
<tr>
<td>Initial Fracture Oil Saturation (%)</td>
<td>100</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
<td>31</td>
</tr>
<tr>
<td>Fracture Permeability (md)</td>
<td>1.000</td>
</tr>
<tr>
<td>Fracture Relative Permeability</td>
<td>Straight-lines(n=1, m=1)</td>
</tr>
<tr>
<td>Fracture Compressibility (psi(^{-1}))</td>
<td>4x10(^{-5})</td>
</tr>
<tr>
<td>Number of Hydraulic Fracture Stages</td>
<td>20</td>
</tr>
<tr>
<td>Individual Fracture Width (ft)</td>
<td>0.021</td>
</tr>
<tr>
<td>Total Hydraulic Width (ft)</td>
<td>0.42</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breakthrough Pressure (psia)</td>
<td>2,800</td>
</tr>
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<td>Net Pay (ft)</td>
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<tr>
<td>Matrix Porosity (%)</td>
<td>5</td>
</tr>
<tr>
<td>Initial Mobile Oil Saturation (%)</td>
<td>90</td>
</tr>
<tr>
<td>Initial Mobile Water Saturation (%)</td>
<td>10</td>
</tr>
<tr>
<td>Formation Compressibility (%)</td>
<td>4x10(^{-6})</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>0.005</td>
</tr>
<tr>
<td>Reservoir Temperature (°F)</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Oil Salinity (ppm)</td>
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</tr>
<tr>
<td>Formation Water Salinity (ppm)</td>
<td>200,000</td>
</tr>
<tr>
<td>Fracture Oil Gravity (°API)</td>
<td>66</td>
</tr>
<tr>
<td>Formation Oil Gravity (°API)</td>
<td>42</td>
</tr>
<tr>
<td>Gas-Oil-Ratio (scf/STB)</td>
<td>500</td>
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<tr>
<td>Bubble Point Pressure (psia)</td>
<td>2241</td>
</tr>
<tr>
<td>Gas Gravity (air = 1)</td>
<td>0.57</td>
</tr>
</tbody>
</table>

6.6.3.1 Raw Data and Diagnostic Plots

Following the procedure outlined previously (Fig. 6.1), the first step is to analyze production trends to determine when formation fluid breaks through into the fracture. This is more
complicated in this case because, in the field, only total oil and gas is typically measured without differentiating between fracture oil and formation oil. Since a simulated case is analyzed, and the oil streams can be identified, two scenarios will be presented: one in which the oil streams can be differentiated and the other in which only a single oil stream is available (Fig. 6.12).

First, considering the scenario where the oil streams can be differentiated (Fig. 6.12a), the data looks similar to that presented by Clarkson and Williams-Kovacs (2013b), except that study assumed water-based fluid. Breakthrough can easily be identified using the onset of formation hydrocarbon production; GOR is constant at the solution gas level (500 scf/STB) for flow above the bubble point.

Considering the scenario with a single oil stream (Fig. 6.12b), gas production must be used to identify breakthrough of formation fluids (gas is only associated with formation oil). Further, the GOR increases throughout the flowback period as formation oil production increases. Ultimately, once all fracture fluid is produced, GOR should stabilize at the solution gas level assuming flowing pressure is still above the bubble point.

The derivative shown in Fig. 6.12c for the total oil stream looks similar to what has been shown previously for cases with water-based fracture fluid, particularly BBT.
For the remainder of this case study, only the single oil stream scenario will be studied, which better represents the field situation. Once breakthrough has been identified, diagnostic plots can be used to identify BBT flow-regimes, after which quantitative RTA can be performed (Fig. 6.13). For both the diagnostic plot (Fig. 6.13a) and RTA (Fig. 6.13b-d) total oil rate is used. First considering the diagnostic plot, the BBT flow-regimes are equivalent to what was shown in previous water-based fracture fluid cases - a short period of radial flow, followed by a longer period of single-phase fracture depletion. ABT the diagnostic plot signatures will vary slightly from water-based fracture fluid cases as the oil stream now contains both fracture and formation oil.

6.6.3.2 Rate-Transient Analysis of BBT Single-Phase Data and ABT Multi-Phase Data

Quantitative RTA was then completed as before, using the radial flow plot to estimate fracture conductivity, the FMB to estimate IFFIP (and BBT half-length) and the Fetkovich type-curve to confirm the parameter estimates from the straight-line analysis techniques. As
expected, RTA yields the input values for fracture permeability (1,000 md, $F_{cT} = 417$ md-ft) and BBT fracture half-length (500 ft/stage).

![Graphs and plots](image)

Fig. 6.13 – Rate-transient analysis for Case Study 4: a) water RNP and RNP’ illustrating identified flow-regimes; b) radial flow plot used to analyze single-phase fracture transient data; c) FMB plot used to analyze single-phase fracture depletion; and d) Fetkovich type-curve to confirm analysis from specialty plots.

6.6.3.3 Analytical Modeling of BBT Single-Phase Data and ABT Multi-Phase Data

Analytical modeling (Fig. 6.14) was then performed using the parameters determined from BBT RTA as a starting point. As with water fracture cases, the primary history-matching parameters are BBT half-length and fracture permeability, (which are constrained by BBT RTA), ABT half-length, breakthrough pressure, fracture relative permeability, matrix absolute permeability and relative permeability. For oil fracture cases, the plots used in history-matching
include production rates and cumulative production of oil and gas (Fig. 6.14a,b) and GOR (Fig. 6.14c). GOR is used to constrain oil production from the matrix because, as mentioned previously, gas is only associated with formation oil, which will lead to an increasing GOR signature ABT. The shape of the GOR curve will be dependent on breakthrough time and the extent of formation oil production. An additional constraint of formation oil production that could be applied is the use of a mixing model for API gravity in the fracture system, similar to what was presented by Williams-Kovacs and Clarkson (2013c) for produced water salinity, to help distinguish formation oil. Also fracture oil can be traced, which would assist in differentiating between fracture oil and formation oil. As expected, a perfect history-match is achieved using the inputs shown in Table 6.5 along with a BBT half-length of 500 ft/stage (as also calculated from RTA), a breakthrough pressure of 2,800 psia and an ABT half-length of 400 ft/stage (all as modeled).
Although a field case was not available to test this model, it is thought to present a good foundation for quantitatively analyzing flowback for LTO wells stimulated with an oil-based fracture fluid. This could also easily be incorporated into tools developed for analyzing flowback from shale gas wells discussed in Chapter Three.

### 6.6.4 Case Study 4: Confirmation of Flow-Regimes Using Numerical Simulation

Case Study 4 examines a numerical simulation of a single fracture completed in a tight oil reservoir. The primary objective of this case study is to confirm that the sequence of flow-regimes observed in field data, and modeled analytically, can be replicated with a numerical simulator. In this study GEM®, a numerical reservoir simulator by Computer Modeling Group...
Ltd. (CMG), and its coupled geomechanics module, are used to model hydraulic fracture initiation, propagation and dynamic fracture dimensions, non-uniform water leak-off into the formation during treatment and shut-in, and the effect of stress on matrix and fracture properties. The coupling between reservoir fluid flow and geomechanical deformation is described in detail in Tran et al. (2005). Tran et al. (2009) used the modified Barton-Bandis model for evaluation of CO₂ leakage during sequestration due to rock failure and opening of fractures in the cap rock.

The modified Barton-Bandis (GEM User Guide, 2014) model is used in this study for modeling of hydraulic fracture initiation and propagation during high pressure injection of fracturing fluid. In this approach, a dual permeability model consisting of matrix blocks and natural fractures is defined where the fractures are initially inactive. Under certain stress conditions, these fracture blocks are activated and act as hydraulic fracture blocks. A full description of the approach is presented in Zanganeh et al. (2015).

Fig. 6.15 is a plan view schematic of the simplified model. In order to reduce simulation time, only a 2-D single stage hydraulic fracture, and its surrounding matrix, are modeled. It is assumed that the hydraulic fracture can propagate in a single plane perpendicular to the minimum horizontal stress (white line) generating a circular fracture. Water, as the main component of fracturing fluid, is injected at a specified flow rate into the perforation. Fracture length increases during pumping, but does not necessarily reach the outer boundary of the model. Fracture dimensions (length and width) and water distribution around the fracture are a function of input parameters such as injection rate and matrix properties. After a 5 day shut-in, the model is put on production to simulate flowback.
Fig. 6.15 – Plan view schematic of 2-D simulation model. Modified from Zanganeh et al. (2015).

6.6.4.1 Raw Data and Diagnostic Plots

Since BBT flow-regime confirmation is the primary focus of this case study only water rates will be considered. The water rate and flowing pressure, as well as the diagnostic plot for the simulation, are given in Fig 6.16. This simulation includes both flowback and long-term production (the latter of which occurs in a very short period of time, due to the small dimensions of the simulation model). The sequence of flow-regimes seen during flowback is comparable to what has been demonstrated in field data and that is modeled analytically, except, because of the use of a 2D model, the dominant early-time transient flow-regime is transient linear flow in the fractures, rather than transient radial flow. Short-term 3D modeling using a similar approach yielded radial flow in the fracture as the first observable flow-regime, consistent with what has
been observed in field cases. This data could have also been analyzed using the model designed for rectangular shaped fractures applied earlier in this chapter.

![Image of production data and diagnostic plots associated with flowback data for Case Study 5: a) water production rate and flowing pressure data; and b) RNP and RNP' plot with respect to water.](image)

The pressure response associated with the sequence of flow-regimes is shown below in Fig. 6.17, with a description in the caption.

![Image of sequence of flow-regimes observed during flowback + online production for Case Study 5. The sequence of flow-regimes is: (1) start of production; (2) transient linear flow in the fracture; (3) fracture depletion once pressure transient reaches the end of the fracture; (4) coupled flow (fracture depletion + matrix linear); (5) transient linear flow in the formation; and (6) BDF in the formation.](image)
6.7 Summary

In this chapter, several case studies were presented to demonstrate the versatility of the techniques which have been developed by the author for modeling multi-phase flowback from MFHWs completed in tight oil reservoirs. The main conclusions from this chapter are as follows:

- Conducting quantitative flowback analysis can provide immediate monetary value to a company.
- Assumed fracture shape may have a significant impact on estimated fracture half-lengths, especially in formations where fracture barriers are difficult to identify or are not present at all.
- The flowback models presented, which have primarily been applied to water-based fracture fluid cases, can be extended to account for hydrocarbon-based fracture fluids. This is the first time that this has been considered in the literature.
- The flow-regimes modeled analytically in this study can be supported by numerical simulation.

Appendix 6.1 - Oil Fracture PVT Properties

In addition to the major challenge of differentiating fracture oil and formation oil which does not appear in wells which have been stimulated with a water-based fracture, such as those discussed in previous chapters, there is an additional challenge of estimating the fluid properties of fracture oil at downhole conditions. Below the PVT correlations used in this work will be discussed, although as with any correlations they have their limitations and have been primarily derived for the transportation of oil-based products rather than downhole reservoir conditions.
As a result detailed PVT testing on oil-based fracture fluids is suggested for the most accurate interpretation possible, although these correlations will provide a reasonable approximation and allow for a reasonable estimate of key fracture properties.

Dead oil viscosity, $\mu_{OD}$, is calculated using the Beggs and Robinson (1975) correlation. The correlation is shown below:

$$\mu_{OD} = 10^X - 1$$  \hspace{1cm} (6.1.1)

Where,

$$X = yT^{-1.163}$$  \hspace{1cm} (6.1.2)

$$y = 10^Z$$  \hspace{1cm} (6.1.3)

$$Z = 3.0324 - 0.0203y_o$$  \hspace{1cm} (6.1.4)

Other key PVT properties including compressibility, formation volume factor and density are calculated using the API (2004) standard for temperature and pressure volume correction factors for generalized crude oils, refined products and lubricating oils (collectively referred to as oils). Below is a summary of the products covered under this standard.

1. Generalized crude oil: a crude oil is considered to conform to this group if its density falls within the range between approximately -10°API and 100°API. Both crude oils and condensates would fit under this group.

2. Refined Products: refined products are broken down into three sub-categories.

   a. Gasoline: motor gasoline and unfinished gasoline blending stock with a base density range between approximately 50°API and 85°API. This group includes products such as gasoline, unleaded gasoline, catalyst gas, alkylate, naphtha, etc.
b. Jet Fuels: Jet fuels, kerosene and Stoddard solvents with a base density range between approximately 37°API and 50°API. This group includes products such as jet fuel, jet kerosene, kerosene, aviation turbine fuel, Stoddard solvent, etc.

c. Fuel Oils: Diesel oils, heating oils and fuel oils with a base density range between -10°API and 37°API. This group includes products such as fuel oil, furnace oil, diesel fuel, heating fuel, etc.

3. Lubricating oils: a lubricating oil is considered to conform to this standard if its base stock is derived from crude oil fractions by distillation or asphalt precipitation and has an initial boiling point greater than 700°F and densities in the range between approximately -10 to 45° API.

Calculation of PVT properties is a two-step process: 1) convert oil gravity and density from measured conditions to base conditions; and 2) calculate oil compressibility, oil formation volume factor (FVF) and oil gravity and density at reservoir conditions. The workflow (simplified from that presented in the standard) of the two steps is shown below. **Fig. 6.1.1** shows the steps associated with converting from measured conditions to base (atmospheric or standard) conditions and **Fig. 6.1.2** shows the steps associated with converting from base conditions to reservoir conditions.
Fig. 6.1.1 – Steps associated with converting properties of fracture oil from measured conditions to base conditions (step 1). The iterative loop is handled using Newton’s method.
The detailed steps and equations associated with step two are shown given below:

1. Input $\rho_{60}$ from step 1, $T$, $P$ (gauge pressure) & commodity group.

2. Shift the input temperature, $T$ from ITS-90 basis to the IPTS-68 basis $T^*$:

   Calculate $T_{C,90}$ by converting from °F to °C:
   
   $$T_{C,90} = (T_{f,90} - 32) \times \left(\frac{5}{9}\right) \quad (6.1.5)$$

   Calculate scaled temperature value:
   
   $$\tau = \frac{T_{C,90}}{630} \quad (6.1.6)$$

   Calculate the temperature correction:
   
   $$\Delta_t = (a_1(a_2(a_3(a_4(a_5(a_6 + (a_7 + a_8\tau)\tau)\tau)\tau)\tau)\tau)\tau)\tau \quad (6.1.7)$$

   Where, the $a_i$ coefficients are shown below:
<table>
<thead>
<tr>
<th>$i$</th>
<th>$a_i$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-0.148759</td>
</tr>
<tr>
<td>2</td>
<td>-0.267408</td>
</tr>
<tr>
<td>3</td>
<td>-1.080760</td>
</tr>
<tr>
<td>4</td>
<td>1.269056</td>
</tr>
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<td>5</td>
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<td>7.438081</td>
</tr>
<tr>
<td>8</td>
<td>-3.536296</td>
</tr>
</tbody>
</table>

Determine the equivalent IPTS-68 temperature and convert back to °F:

\[ T_{C,68} = T_{C,90} - \Delta_t \]  
\[ T^* = T_{F,68} = T_{C,68} \times \left( \frac{\eta}{5} \right) + 32 \]

(6.1.8)  
(6.1.9)

3. Shift the input $\rho_{60}$ to the IPTS-68 bases $\rho^*$:

\[ \rho^* = \rho_{60} \left\{ 1 + \frac{\exp[A(1+0.8A)]-1}{1+A(1+1.6A)B} \right\} \]  
(6.1.10)

Where,

\[ A = \frac{\delta_{60}}{2} \left[ (\frac{K_0}{\rho_{60}} + K_1) \frac{1}{\rho_{60}} + K_2 \right]; \delta_{60} = 0.01374979547 \]  
(6.1.11)

\[ B = \frac{2K_0+K_1\rho_{60}}{K_0+(K_1+K_2\rho_{60})\rho_{60}} \]  
(6.1.12)

The $K_i$ coefficients used in Eqn. 6.1.11 and 6.1.12 are dependent on the commodity group. The coefficients are given below.

<table>
<thead>
<tr>
<th>Density Range (kg/m$^3$)</th>
<th>$K_0$</th>
<th>$K_1$</th>
<th>$K_2$</th>
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<tbody>
<tr>
<td>Crude Oil (A)</td>
<td></td>
<td></td>
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<tr>
<td>610.6 ≤ $\rho_{60}$ &lt; 1,163.5</td>
<td>341.1</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Refined Products (B)</td>
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<tr>
<td>Fuel Oils</td>
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<tr>
<td>838.3 ≤ $\rho_{60}$ &lt; 1,163.5</td>
<td>103.9</td>
<td>0.2701</td>
<td>0</td>
</tr>
<tr>
<td>Jet Fuels</td>
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<tr>
<td>787.5 ≤ $\rho_{60}$ &lt; 838.3</td>
<td>330.3</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Transition Zone</td>
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<tr>
<td>770.4 ≤ $\rho_{60}$ &lt; 787.5</td>
<td>1489.1</td>
<td>0</td>
<td>-0.0019</td>
</tr>
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<td>Gasolines</td>
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<tr>
<td>610.6 ≤ $\rho_{60}$ &lt; 770.4</td>
<td>192.5</td>
<td>0.2438</td>
<td>0</td>
</tr>
<tr>
<td>Lubricating Oils (D)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>800.9 ≤ $\rho_{60}$ &lt; 1163.5</td>
<td>0</td>
<td>0.3488</td>
<td>0</td>
</tr>
</tbody>
</table>
4. Calculate to the coefficient of thermal expansion at 60°F, $\alpha_{60}$, using the same coefficients given above:

$$\alpha_{60} = \left(\frac{K_0}{\rho^2} + K_1\right)\frac{1}{\rho} + K_2$$  \hspace{1cm} (6.1.13)

5. Calculate the difference between the alternate temperature and the base temperature, $\Delta T$, and use this value to calculate the correction factor due to temperature, $C_{TL}$:

$$\Delta T = T^* - 60.0068749$$  \hspace{1cm} (6.1.14)

$$C_{TL} = \exp\{-\alpha_{60}\Delta T[1 + 0.8\alpha_{60}(\Delta T + \delta_{60})]\}$$  \hspace{1cm} (6.1.15)

6. Calculate the scaled compressibility factor, $F_p$:

$$F_p = \exp \left( -1.9947 + 0.00013427T^* + \frac{793.92+2.326T^*}{\rho^2} \right)$$  \hspace{1cm} (6.1.16)

7. Calculate the correction factor due to pressure:

$$C_{PL} = \frac{1}{1 - 10^{-5}F_p\rho^2}$$  \hspace{1cm} (6.1.17)

8. Calculate the volume correction factor for the combined temperature and pressure effect, $C_{TPL}$:

$$C_{TPL} = C_{TL} C_{PL}$$  \hspace{1cm} (6.1.18)

9. Calculate the density and volume of fracture oil at reservoir conditions:

$$\rho_o = C_{TPL}\rho_{60}$$  \hspace{1cm} (6.1.19)

$$V_{60} = C_{TPL}V_{T,P}$$  \hspace{1cm} (6.1.20)

From the properties calculated in the above procedure, oil compressibility, $c_o$, fracture oil FVF, $B_o$, and oil gravity, $\gamma_o$, can be calculated as follows:

$$c_o = 10^{-5}F_p$$  \hspace{1cm} (6.1.21)

$$B_o = \frac{V_{T,P}}{V_{60}} = \frac{\rho_{60}}{\rho_{T,P}}$$  \hspace{1cm} (6.1.22)
\[ \gamma_0 = \frac{141.5}{\rho_0 / 999.016} - 131.5 \] (6.1.23)
Chapter Seven: Development and Application of a Salinity Model to Compliment Flow Modeling During Flowback of Multi-Fractured Horizontal Wells

7.1 Abstract

This chapter focuses on the development and application of a simple analytical model to analyze salinity data collected during the flowback period. Much like high frequency rate and pressure data, high frequency salinity data is often recorded during the flowback period, although typically at greater time intervals than rate/pressure data (hourly or greater). Generally a rapid increase in produced water salinity is observed during the flowback period when fresh water has been used as the base fracture fluid (Blauch et al., 2009; Gaudlip, et al., 2008; Myers, 2008; Merry et al., 2015). As has been the case with flow modeling of flowback data, investigation into the development of salinity models has occurred in recent years as authors have recognized the wealth of information which can be yielded by analyzing such data. In most cases salinity modeling has been conducted independently of flow modeling (which may limit the interpretation), however an integrated approach will likely be beneficial for interpreting fracture properties, and their interaction with the formation.

In this chapter a simple analytical salinity model is developed to analyze salinity data during the BBT (single-phase) period for a tight siltstone reservoir. To allow for a fully analytical solution, a constant production rate has been assumed, which is mostly consistent with the examined field example. The same basic model could be used with variable production rate using a semi-analytical or numerical solution. A key aspect of this model is the direct integration with flow modeling, with a focus of using salinity modeling to compliment flow modeling and confirmation of the fracture surface area estimated from flow modeling. Discussion of how the

1 This chapter is based on previously unpublished work.
model could be: 1) extended to account for both BBT and ABT data; and 2) used independently of flow modeling if the transport coefficients can be estimated accurately is also provided.

Note that the form of the salinity model may vary (potentially significantly) depending on the play type and is often difficult to develop without extensive lab work. In this chapter, a theoretical model is developed accounting for common mechanisms that may be expected in unconventional siltstone reservoirs (and potentially many shale reservoirs).

7.2 Introduction

As operators continue to look for new methods to characterize hydraulic fractures, particularly early in the well life, researchers are looking to new data sets to provide further insights. One method that has gained some attention is modeling the salinity response of produced water during the flowback period. As mentioned above, the majority of authors have approached flow and salinity modeling individually, which may lead to inconsistent or erroneous results.

Some authors have gone as far as numerically modeling both flow and mass transport of individual ions during the flowback and online production period, although such techniques require complex numerical simulation and are not practical to apply to a significant number of wells.

7.3 Objectives

The objective of the current work is to develop a simple analytical salinity model to match salinity data during the BBT flow period for flowback from a siltstone reservoir. It is assumed
that water rate remains constant during this period to allow for an analytical solution. This assumption is mostly true for the investigated field case.

The primary purpose of the salinity model is to constrain the fracture area and volume estimated from flow modeling. Alternatively, if key transport parameters can be accurately measured in the lab, the developed salinity model could be used as a stand-alone tool to estimate BBT fracture surface area and volume. In reality many of these parameters are not fully understood and can vary greatly depending on the geographic area and formation of interest. As a result, rules of thumb presented in the literature have been used for the key transport parameters which are then tweaked to match the collected salinity data, assuming that contacted fracture area and fracture volume (primary fracture + EFR) can be estimated from flow modeling. An inability to match the data with a reasonable set of parameters would suggest that either the developed model is not applicable to the particular field case or that the fracture surface area derived from flowback is incorrect.

7.4 Sources of Salinity, Conceptual Model and Analytical Model Development

The goal of this exercise is to derive a simplified salinity model which can be applied during the single-phase period (during the shut-in between stimulation and flowback and during before-breakthrough flow). The purpose of the model is to confirm primary fracture area as well as the total volume of the primary fracture and the EFR, where this area and volume have been solved from the flow model by history-matching flowback water salinity as a function of time. In this model salt has been treated as a single component, while in reality it is made up of a variety of ions which may undergo different transport processes. Individual ion matching would be required for a fully comprehensive analysis with a numerical solution, which should be guided
by lab testing. In the absence of any data other than salinity as a function of time for the formation of interest, the model has been developed conceptually to include the processes expected to impact the salinity response in the given siltstone formation. The model is developed assuming the formation of a planar fracture surrounded by an EFR, which is in contact with the unstimulated matrix. The EFR is treated as a single porosity system with enhanced permeability and matrix porosity (as is commonly assumed with EFR flow models) and fracture fluid leakoff is limited primarily to the EFR. Generally speaking water, in the EFR and primary fracture is mobile, while water in the unstimulated matrix is immobile or minimally mobile (constant matrix water saturation throughout the well life). For application of the model it will be assumed that during BBT, single-phase flowback water within the EFR is transferred to the primary fractures at a constant rate that should be less than half of the total water production rate at the well (i.e. greater water production out of the primary fractures which are typically more permeable). This assumption could be relaxed by applying a multi (vs. dual) domain model (ex. Qanbari et al., 2016), although a simple analytical solution would not be possible. It is likely that upon stimulation there is pressure equilibrium between the primary and secondary fractures, with the driving force for flow out of the EFR increasing over time as the pressure in the primary fractures depletes. In the absence of a more detailed flow model and more advanced solution techniques for the mass transfer problem it is difficult to assess the impact of this assumption and should be a focus of future work.

7.4.1 Sources of Salinity

As determined from the literature review presented in Chapter One, there are six mechanisms which have been identified to contribute to the increase of salinity during the flowback period.
1. Diffusion from the matrix to the fracture network.

2. Dissolution of autochthonous and allochthonous salts depending on whether the minerals were formed in situ or migrated and crystalized into place. Alternately, precipitation of salt may reduce fracture salinity.

3. Encroachment of brine from adjacent formations or production of mobile water in the formation of interest.

4. Mobilization or solubilisation of hypersaline connate water.

5. Mixing of low salinity fracture water with high salinity formation water.

6. Cation exchange/leaching from the clay mineral surface.

7. A combination of the above six mechanisms.

7.4.2 Conceptual Model

The conceptual model used in this work is provided in Fig. 7.1. This basic conceptual model can be used for both BBT and ABT flow. Only BBT single-phase flow will be considered in this work; extending the model to account for both BBT and ABT flow is a topic of future work.
Fig. 7.1 – Conceptual model used in the derivation of the salinity model. The fractures are assumed to consist of simple planar fractures surrounded by an enhanced fracture region which is then bound by an unstimulated matrix.

7.4.3 Mathematical Model Development

The mathematical model developed is for a siltstone reservoir, which commonly do not have same extent of complexities as shale reservoirs, as was discussed in the literature review.
7.4.3.1 General Mass Balance on Half of the Primary Fracture

The development of the mathematical model applied in this work begins by conducting a mass balance on the control volume (half of one primary fracture)\(^1\).

\[
\dot{m}_{\text{in}} - \dot{m}_{\text{out}} + \dot{m}_{\text{source}} - \dot{m}_{\text{sink}} = \dot{m}_{\text{accum}} \quad (7.1)
\]

Ignoring significant mass transfer within the high porosity fracture (assumed to be well mixed) and that before flow there is no mass leaving the control volume, Eqn. 7.1 can be simplified to:

\[
\dot{m}_{\text{source}} - \dot{m}_{\text{sink}} = \dot{m}_{\text{accum}} \quad (7.2)
\]

Two potential salt sources are considered: 1) pseudo steady-state diffusion from the matrix to the fractures; and 2) inflow of high salinity fracture fluid which has leaked off into the enhanced fracture region, which may include mobilization of bound water out of the EFR. Two potential sinks are also considered: 1) production of water containing dissolved salt to the well; and 2) precipitation of salt onto the proppant grains. The source terms will be derived in the context of a mass balance on the EFR, which is bounded by the matrix on one side with constant concentration, \(C_m\), and the primary fracture on the other side with variable concentration \(C_{pf}(t)\). It is assumed that the EFR is under pseudo steady-state conditions and therefore can be represented in terms of average parameters. Several authors, including Zimmerman et al. (1993), have shown how a balance equation in terms of average pressure in pressure diffusion cases can be derived based on the transient transport equation and others, including Heinemann and Mittermeir (2011), have shown how such a procedure can be used to derive the general form the Kazemi et al. (1992) shape factor. In the work of Heinemann and Mittermeir (2011) the authors

\(^1\) Note that all derivations in this section assume metric units, while in the field example presented the proper unit conversions are applied as necessary to allow consistency with the remainder of the dissertation.
used a control volume finite difference (CVFD) method which invokes Green’s Divergence theorem to derive the generalized shape factor. A similar method will be used in this chapter in terms of mass transport, with the primary purpose of showing this mass balance being to derive the general form of the shape factor and the transfer function from the EFR to the fractures. For this derivation it is assumed that the EFR acts as a single porosity system at matrix porosity and elevated permeability. It will also be assumed that water in the EFR is mobile during early-time flowback, although because the current flow model assumes planar fractures with a higher than expected width in order to account for fracture complexity, for the solution it will be assumed the inflow rate from the EFR is constant throughout the early flowback period. This assumption could be eliminated if a 3-element (primary fracture, EFR and unstimulated matrix) flow model was used, as suggested by Qanbari et al. (2016). The equation for the EFR can be derived two ways: 1) starting with the 3D advection-diffusion-reaction equation and applying averaging; and 2) applying a simple mass balance on the EFR in terms of average concentration. The second derivation will be saved for Appendix 7.1. Ultimately, the two approaches are equivalent.

7.4.3.1.1 Derivation of the 3D Advection-Diffusion-Reaction Equation and Transfer Functions
For the EFR

First, considering the derivation starting from the 3D advection-diffusion-reaction equation for a single block within the EFR (assuming that the EFR acts as a dual-porosity system), which is surrounded on all sides by fracture, the 1D equation will be derived for simplicity. Generality will be maintained in the matrix component derivation of the EFR which would allow for use under both single and dual-porosity systems. The mass balance on a single block within the EFR can be written as follows:
\[ m_{in} - m_{out} + m_{source} - m_{sink} = m_{accum, block} \]  

(7.3)

One source term exists which is dissolution of salts from bound water, while no sink terms exist (assuming no potential for precipitation within the EFR). Eqn. 7.3 can be simplified as in Eqn. 7.4 and written mathematically as in Eqn. 7.5:

\[ m_{in} - m_{out} + m_{source} = m_{accum, block} \]  

(7.4)

\[ A|\frac{\partial}{\partial x} x + A\partial x r_{d, EFR} = \frac{\partial m_{salt}}{\partial t} \]  

(7.5)

Where, \( J \) is the flux, \( r_{d, EFR} \) and \( m_{salt} \) is the mass of salt in the block of interest. Considering the accumulation term for the fractures:

\[ m_{salt}^{block} = C_{block} V_{w, block} = V_{p, block} S_{w, block} C_{block} = A \partial x \phi_{block} S_{w, block} C_{block} \]  

(7.6)

Where, \( C_{block} \) is the concentration, \( V \) is the volume, \( V_{w, block} \) is the bulk volume, \( V_{p, block} \) is the pore volume, \( \phi_{block} \) is the porosity and \( S_{w, block} \) is the water saturation within the block of interest. Subbing Eqn. 7.6 into Eqn. 7.5:

\[ A|\frac{\partial}{\partial x} x + A\partial x r_{d, EFR} = \frac{\partial (A \partial x \phi_{block} S_{w, block} C_{block})}{\partial t} \]  

(7.7)

Next, define the flux as a combination of advection and diffusion:

\[ Flux = Diffusion + Advection \]  

(7.8)

Mathematically this can be written as:

\[ J = D_{eff, block} \frac{\partial C_{block}}{\partial x} - v_{darcy, block} C_{block} \]  

(7.9)

Where \( D_{eff, block} \) is the effective diffusion coefficient and \( v_{darcy, block} \) is the Darcy velocity. Note that advective flux would only occur after flow. Assuming \( \phi_{block} \neq f(t) \), \( A \neq f(t) \) and \( \partial x \neq f(t) \), Eqn.7.7 can be simplified as:

\[ A|\frac{\partial}{\partial x} x + A\partial x r_{d, block} = A \partial x \phi_{block} \frac{\partial (S_{w, block} C_{block})}{\partial t} \]  

(7.10)
Dividing through by $A\partial x$ and let $\partial x \to 0$ to convert into derivative form.

$$\frac{\partial j}{\partial x} + r_{d,\text{block}} = \Phi_{\text{block}} \frac{\partial (S_{w,\text{block}}C_{\text{block}})}{\partial t} \tag{7.11}$$

Next, substituting for the flux from Eqn. 7.9:

$$\frac{\partial (D_{\text{eff,block}}\frac{\partial C_{\text{block}}}{\partial x} - v_{\text{darcy,block}}C_{\text{block}})}{\partial x} + r_{d,\text{block}} = \Phi_{\text{block}} \frac{\partial (S_{w,\text{block}}C_{\text{block}})}{\partial t} \tag{7.12}$$

The derivative can then be expanded as follows:

$$\frac{\partial (D_{\text{eff,block}}\frac{\partial C_{\text{block}}}{\partial x} - v_{\text{darcy,block}}C_{\text{block}})}{\partial x} + r_{d,\text{block}} = \Phi_{\text{block}} \frac{\partial (S_{w,\text{block}}C_{\text{block}})}{\partial t} \tag{7.13}$$

Considering 3 dimensions, Eqn. 7.13 can be written as follows:

$$\nabla \cdot \left( D_{\text{eff,block}} \nabla C_{\text{block}} - v_{\text{darcy,block}}C_{\text{block}} \right) + r_{d,\text{block}} = \Phi_{\text{block}} \frac{\partial (S_{w,\text{block}}C_{\text{block}})}{\partial t} \tag{7.14}$$

The interflow term between the two domains does not occur in the EFR grid block equation because the interflow is assumed to only occur at the boundaries, rather than throughout the EFR. Eqn. 7.14 is valid for any grid block geometry and can be integrated over the bulk volume of the matrix block, $V_{b,\text{block}}$, with $V_{b,\text{block}}$ cancelling from the denominator on both sides. The averaging integral is shown below 7.15.

$$\bar{g}(t) = \frac{1}{V_{b,\text{block}}} \iiint_{V_{\text{block}}} g \, dV \tag{7.15}$$

Where,

$g = C_{\text{block}}$ or $S_{w,\text{block}}$

Applying the averaging integral to both sides of Eqn. 7.14 and cancelling $V_{b,\text{block}}$ in the denominator:

$$\iiint_{V_{b,\text{block}}} \left[ \nabla \cdot \left( D_{\text{eff,block}} \nabla C_{\text{block}} - v_{\text{darcy,block}}C_{\text{block}} \right) + r_{d,\text{block}} \right] \, dV =$$

$$\iiint_{V_{b,\text{block}}} \Phi_{\text{block}} \frac{\partial (S_{w,\text{block}}C_{\text{block}})}{\partial t} \, dV \tag{7.16}$$
Next, Green’s divergence theorem can be used to re-write the left-hand side of Eqn. 7.14 by converting it from a volume integral to surface integral:

\[
\iiint_{V_{b,\text{block}}} \left[ \nabla \cdot \left( D_{\text{eff,block}} \nabla C_{\text{block}} - v_{\text{darcy,block}} C_{\text{block}} \right) + r_{d,\text{block}} \right] dV = \\
\iint_{A_{\text{block}}} \left[ D_{\text{eff,block}} \frac{\partial C_{\text{block}}}{\partial n} - v_{\text{darcy,block}} C_{\text{block}} \hat{n} \right] dA + V_{b,\text{block}} r_{d,\text{block}}
\]

(7.17)

Where \( \iint_{A_{\text{block}}} \) denotes the integration over the total surface \( A_{\text{block}} \) of \( V_{b,\text{block}} \) and \( \hat{n} \) is the outward pointing unit vector to \( A_{\text{block}} \). The first term on the right-hand side of Eqn. 7.17 can be re-written by splitting up the surface integral into a sum over all subsurfaces \( A_{\text{block},j} \):

\[
\iint_{A_{\text{block}}} \left[ D_{\text{eff,block}} \frac{\partial C_{\text{block}}}{\partial n} - v_{\text{darcy,block}} C_{\text{block}} \hat{n} \right] dA = \sum_{j=1}^{N} \iint_{A_{\text{block},j}} \left[ D_{\text{eff,block},j} \frac{\partial C_{\text{EFR}}}{\partial n} - v_{\text{darcy,block},j} C_{\text{block}} \hat{n} \right] dA
\]

(7.18)

Equation 7.14 can now be written in integral form by equating the right-hand side of Eqn. 7.18 with the right-hand side of Eqn. 7.16:

\[
\sum_{j=1}^{N} \iint_{A_{\text{block},j}} \left[ D_{\text{eff,block},j} \frac{\partial C_{\text{block}}}{\partial n} - v_{\text{darcy,block},j} C_{\text{block}} \hat{n} \right] dA + V_{b,\text{block}} r_{d,\text{block}} =
\]

\[
\iiint_{V_{b,\text{block}}} \phi_{\text{block}} \frac{\partial (s_{w,\text{block}} C_{\text{block}})}{\partial t} dV
\]

(7.19)

Because we want to consider the EFR to be represented by average properties, rather than solving the mass transfer within the matrix blocks, the average of the concentration and saturation within the EFR must be found by applying the averaging integral. By comparing the right-hand side of Eqn. 7.16 with Eqn. 7.15, given that the bulk volume in the denominator was already cancelled in Eqn. 7.16, this can be re-written as follows using average values.

\[
\iiint_{V_{b,\text{block}}} \phi_{\text{block}} \frac{\partial (s_{w,\text{block}} C_{\text{block}})}{\partial t} dV = V_{b,\text{block}} \left[ \phi_{\text{block}} \frac{\partial (s_{w,\text{block}} C_{\text{block}})}{\partial t} \right] =
\]

\[
V_{b,\text{block}} \left[ \phi_{\text{block}} s_{w,\text{block}} \frac{\partial C_{\text{block}}}{\partial t} + \phi_{\text{block}} C_{\text{block}} \frac{\partial s_{w,\text{block}}}{\partial t} \right]
\]

(7.20)
Where, $S_{w,\text{block}}$ is the water saturation in the block of interest. The left-hand side of Eqn. 7.19 can now be equated with the right hand side of Eqn. 7.20, with the resulting equations being divided by $V_{b,\text{block}}$ to yield Eqn. 7.21.

$$
\frac{1}{V_{b,\text{block}}} \sum_{j=1}^{N} \int_{A_{\text{block},j}} \left[ D_{\text{eff,block},j} \frac{\partial C_{\text{block}}}{\partial n} - v_{\text{darcy,block},j} C_{\text{block},j} \right] dA + r_{d,\text{block}} = \\
\phi_{\text{block}} S_{w,\text{block}} \frac{\partial C_{\text{block}}}{\partial t} + \phi_{\text{block}} C_{\text{block}} \frac{\partial S_{w,\text{block}}}{\partial t}
$$

(7.21)

In order to derive a Warren and Root (1963) type coupling term, the term $\frac{\partial C_{\text{block}}}{\partial n}$ can be approximated as follows according to Zimmerman et al. (1996):

$$
\frac{\partial C_{\text{block}}}{\partial n} \approx \frac{(C_f - \bar{C}_{\text{block}})}{w_{\text{block}}}
$$

(7.22)

Where, $\bar{C}_{\text{block}}$ is the average concentration within the block of interest, $w_{\text{block}}$ is the distance from the no-flow boundary normal to the surface $A_{\text{block},j}$ and can be re-written with the index $j$ as $w_{\text{block},j}$. Expanding the left-hand side of Eqn. 7.21, integrating, substituting in for water velocity ($v_{\text{darcy,block},j} = \sum_{j=1}^{N} \frac{q_{w,\text{block},j}}{A_{\text{block},j}}$) assuming an isotropic diffusion coefficient, and making the appropriate cancellations yields Eqn. 7.23:

$$
\frac{1}{V_{b,\text{block}}} \sum_{j=1}^{N} \int_{A_{\text{block},j}} \left( D_{\text{eff,block},j} \frac{\partial C_{\text{block}}}{\partial n} - v_{\text{darcy,block},j} C_{\text{block},j} \right) dA + r_{d,\text{block}} \approx \\
\frac{1}{V_{b,\text{block}}} \sum_{j=1}^{n} A_{\text{block},j} D_{\text{eff,block},j} \left( C_f - \bar{C}_{\text{block}} \right) - \frac{1}{V_{b,\text{block}}} \sum_{j=1}^{n} q_{w,\text{block},j} \bar{C}_{\text{block}} + r_{d,\text{block}}
$$

(7.23)

Where $D_{\text{eff,block},j}$ is the effective diffusion coefficient from the block into the fractures (and can be re-written as $D_{\text{eff,block}|f}$), and $q_{w,\text{block},j}$ is the effective flow rate from the block into the fractures through side $j$ at downhole conditions (and can be re-written as $q_{w,\text{block}|f,j}$). Further $A_{\text{block},j}$ and $w_{\text{block},j}$ can similarly be re-written as $A_{\text{block}|f,j}$ and $w_{\text{block}|f,j}$ respectively. The
notation in Eqn. 7.23 is used to specify transfer from the block domain to the fracture domain.

Equating the right-hand side of Eqn. 7.21 with the right-hand side of Eqn. 7.23:

\[
\frac{1}{V_{b,\text{block}}} \sum_{j=1}^{N} A_{b,\text{block},f,j} D_{eff,b,\text{block},f} (C_f - \bar{C}_{\text{block}}) - \frac{1}{V_{b,\text{block}}} \sum_{j=1}^{n} q_{w,b,\text{block},f,j} \bar{C}_{\text{block}} + r_{d,\text{block}} = \\
\phi_{\text{block}} S_{w,\text{block}} \frac{\partial \bar{C}_{\text{block}}}{\partial t} + \phi_{\text{block}} \alpha_{\text{block}} \frac{\partial S_{w,\text{block}}}{\partial t} 
\]

(7.24)

From the first term on the left-hand side of Eqn. 7.24, the general definition of shape factor, \(\sigma\), initially proposed experimentally by Kazemi et al. (1992), and derived mathematically for pressure diffusion by Heinemman and Mittermeir (2012), can be found:

\[
\sigma = \frac{1}{V_{b,\text{block}}} \sum_{j=1}^{N} A_{b,\text{block},f,j}
\]

(7.25)

The same equation can be applied to the Warren and Root (1963) model, which assumes multiple matrix blocks per fracture block, as was demonstrated by Zimmerman (1996) using a slightly different derivation and assuming that \((1 - \phi_f) \approx 1\). In the Zimmerman approach, they first consider the transfer out of one matrix block and then multiply this value by the number of grid blocks within a representative elemental volume, \(V\), under the assumption that the two continuum (matrix blocks and fractures) occupy the same space. The general form of the shape factor was also derived by Chang (1993) by comparing Warren and Root’s transfer function with Darcy’s Law. For an EFR, represented as a single porosity system with matrix porosity and elevated permeability, and consisting of a single slab with only one-side open to flow and the other side being bound by the matrix where water is immobile, 7.24 can be re-written as follows by replacing the subscript “block” with “EFR”, with the subscript “f” with “pf”:

\[
\frac{A_{EFR,\gamma, pf}}{w_{EFR} V_{b,EFR}} D_{eff,EFR, pf} (C_{pf} - \bar{C}_{EFR}) - \frac{q_{w,EFR}}{V_{b,EFR}} \bar{C}_{EFR} + r_{d,EFR} = \phi_{EFR} S_{w,EFR} \frac{\partial \bar{C}_{EFR}}{\partial t} + \\
\phi_{EFR} \bar{C}_{EFR} \frac{\partial S_{w,EFR}}{\partial t}
\]

(7.26)

305
Substituting in for the shape factor in Eqn. 7.26 yields Eqn. 7.27:

\[
\sigma D_{eff,EFR|pf} (C_{pf} - \bar{C}_{EFR}) = \frac{q_{w,EFR}}{V_{d,EFR}} \bar{C}_{EFR} + r_{d,EFR} = \phi_{EFR} S_{w,EFR} \frac{\partial \bar{C}_{EFR}}{\partial t} + \phi_{EFR} \bar{C}_{EFR} \frac{\partial S_{w,EFR}}{\partial t}
\]

(7.27)

7.4.3.1.2 Effective Diffusion Equation for Mass Transport in Porous Media

The effective diffusion coefficient in porous media can be defined as having a form similar to Eqn. 7.28 (ex. Shackelford and Daniel, 1991).

\[
D_{eff} = \frac{D_o (C) \phi S_w^n}{\tau}
\]

(7.28)

Where, \(D_o\) is the open media diffusion coefficient, \(\phi\) is porosity, \(S_w\) is the water saturation, \(n\) is a constant that is typically set to 1, \(\alpha\) accounts for the increased viscosity near solid surfaces, \(\varepsilon\) accounts for the electrostatic restriction and \(\tau\) is the tortuosity factor which can be defined as \(L/L_e\) where \(L\) is the path length through open median and \(L_e\) is the effective path length through porous media. Although tortuosity can be estimated using Archie’s law for ideal systems or systems in which specialty core analysis has been conducted, the effective path length through porous media is difficult to estimate particularly with unconventional resources. Furthermore, many researchers have suggested that it is difficult to differentiate between the effects of \(\alpha, \gamma, \tau\) and therefore they have been combined into a single impedance (or constriction) factor, \(f\) (ex. Flury and Gimmi, 2002).

Substituting the impedance factor into Eqn. 7.28, the effective diffusion coefficient can be written as follows:

\[
D_{eff} = \phi S_w f D_o (C)
\]

(7.29)
In non-dilute solutions, the effective diffusion coefficient may be an exponential function of diffusant concentration (i.e. Suloff, 2002, Wei and Wuensch, 1976):

$$D_{\text{eff}}(C) = D_o \exp(\beta C) \quad (7.30)$$

Where, $\beta$ is a constant. Ignoring the concentration dependence of the diffusion coefficient, Eqn. 7.29 simplifies to:

$$D_{\text{eff}} = \Phi f S_w D_o \quad (7.31)$$

Note that the effective diffusion coefficient may be time-dependent due to a variety of complexities. This includes things such as non-ideal (and possibly time-dependent) behavior of the impedance factor, concentration-dependent diffusion coefficient, increasing water saturation and development of a more continuous water phase in the matrix immediately surrounding the primary fractures as a result of fracture fluid leakoff/imbibition (impacted by near fracture permeability) and dissolution of salts in the pore space leading to a reduction in tortuosity (or increase in porosity). Further osmotic pressure has been ignored from the model, which may impact the apparent diffusion coefficient if the matrix acts like a semi-permeable membrane allowing water to move down its concentration gradient from the fractures to the matrix. This effect would act to concentrate the water in the fracture system, although it may also reduce effective diffusion rate. This effect is likely to be significantly more important in shales than in other reservoir types. In addition, leaching of salt from clays at the fracture face has been ignored, which again would likely have a greater impact in shales than other reservoir types. The effective diffusion coefficient has been assumed to be constant for the derivation.

7.4.3.1.3 Reaction (Dissolution) Term in the EFR
Next consider the reaction (dissolution) term. It is possible that salt may be precipitated within the EFR, if the EFR results from an existing naturally fractured reservoir, although for the formation of interest it will be assumed that salt is stored in a super-saturated bound layer that covers the grains within the EFR. If the EFR were treated as a true dual porosity system, whether bound water is present within the secondary fractures would be dependent on whether the fractures are natural or induced, although bound water would exist regardless within the matrix block elements. Bound water will not cover the freshly broken matrix and therefore bound water is assumed to only exist within the EFR. It is also possible that in certain situations salt may also be precipitated within either the secondary fractures or matrix blocks within the EFR (ex. Merry et al., 2015), although this is not thought to be likely in the formation of interest. Mass transfer out of a super-saturated bound layer is analogous to a dissolution process where the salt is already stored in a super-saturated bound layer and a concentration gradient forms within the bound layer when it is brought in contact with fresh water, with the maximum concentration existing at the rock surface. Dissolution-type processes can be either classified as transport-controlled or surface reaction-controlled. For this problem it will assumed that salt precipitated onto the fracture surface will follow a transport-controlled dissolution before flow and a surface reaction-controlled dissolution after flow. Further, salt stored in a super-saturated bound layer within the EFR follows a transport-controlled process prior to flow, while some of this bound water may be mobilized following a surface reaction-controlled dissolution mechanism. These assumptions will be explored further throughout the derivation. For a transport-controlled dissolution, the reaction rate was initially defined by Noyes and Whitney (Dokoumetzdis and Macheras, 2006) as:
Where this is a first order reaction, the rate constant \( k_{d,I} \) (dissolution coefficient under transport-controlled conditions) has units of \( t^{-1} \), and \( C_s \) is the solubility limit. Accounting for the fact that we are dealing with porous media, the time derivative in Eqn. 7.32 can be modified as follows:

\[
\tau_{d,EFR} = \frac{\partial C_{EFR}}{\partial t} = k_{d,t,EFR}(C_s - \overline{C_{EFR}}) 
\]

(7.32)

For practical application, \( C_s \) can be replaced by \( C_m \) as matrix concentration would be the maximum possible fracture concentration. Eqn. 7.33 is the form initially presented by Noyes and Whitney. Brunner and Tolloczko defined the transport-controlled rate constant as follows (Dokoumetzdis and Macheras, 2006):

\[
k_{d,t,EFR} = k_1 A_{EFR} 
\]

(7.34)

Where, \( k_1 \) is a rate constant, \( A_{EFR} \) is the internal surface area of the ERF (equivalent to surface area of the matrix pores within the EFR for a single-porosity definition). Nerst and Brunner studied the problem further and incorporated Fick’s first law of diffusion to derive an expression for \( k_1 \) and defined \( k_{d,t,EFR} \) as (Dokoumetzdis and Macheras, 2006):

\[
k_{d,t,EFR} = \frac{DA}{V_d} 
\]

(7.35)

Again Eqn. 7.35 can be modified to account for porous media and the fact that porosity and saturation remain in the time derivative:

\[
k_{d,t,EFR} = \frac{D_{eff,EFR} A_{EFR}}{V_b EFR d_{EFR}} = \frac{D_{eff,EFR} A_{EFR}}{V_b EFR d_{EFR}} 
\]

(7.36)

In fact, Eqn. 7.36 with the rate constant defined as in Eqn. 7.35 can be derived directly from Fick’s first law written in mass flow rate rather than flux. In 7.36 \( D_{eff,EFR} \) is the effective
diffusion coefficient through the water within the EFR respectively, which can be defined as above given 100% water saturation, $A_{EFR}$ is the internal surface area of the EFR and $d_{EFR}$ is the diffusion layer (bound water) thickness for the EFR. Alternatively, Danckwert’s conceptualized the problem slightly differently and introduced surface renewal theory, in which $k_{d,t,EFR}$ is defined as follows (Dokoumetzdis and Macheras, 2006):

$$k_{d,t,EFR} = \frac{\sqrt{\omega DA}}{V}$$

(7.37)

Where, $\omega$ is the rate of surface renewal. The rate constant presented in equation Eqn. 7.36 is most consistent with the observation that salt is often stored in a super-saturated bound layer. For a surface reaction-controlled dissolution (or solubilization or mobilization of a super-saturated bound layer) assuming steady-state at the interface, reaction rate is defined as:

$$r_{d,EFR} = k_{d,r,EFR} \frac{A_{EFR}}{V_{b,EFR}}$$

(7.38)

Where, $k_{d,r,EFR}$ is the rate constant associated with a surface-controlled reaction in the EFR. The rate constant has units of kg/(m²s) and is likely a function of matrix concentration. Further and $V_{b,EFR}$ is the bulk volume of the EFR. It is likely that before flow, as under normal environmental conditions, dissolution will be transport-controlled, while after flow where the rock surface or bound water layer is constantly abraded by high velocity fracturing fluid flowing back to the well the dissolution will likely be surface reaction-controlled. Substituting Eqn. 7.31 into Eqn. 7.27:

$$\sigma \Phi_{EFR} f_{EFR} S_{w,EFR} D_{0,EFR} f \left( C_{p,f} - \frac{C_{EFR}}{S_{w,EFR}} \right) - \frac{q_{w,EFR}}{V_{b,EFR}} f \frac{C_{EFR}}{S_{w,EFR}} + r_{d,EFR} = \Phi_{EFR} \frac{\partial C_{EFR}}{\partial t} + \Phi_{EFR} \frac{\partial S_{w,EFR}}{\partial t}$$

(7.39)
It can now be seen that the PDE in Eqn. 7.13 is converted into an ODE in Eqn. 7.39. From Eqn. 7.39 the rate of mass transfer per unit volume, \( q_{EFR|pf} \), can be defined as:

\[
q_{EFR|pf} = \sigma \Phi_{EFR} f_{EFR} \overline{S_{w,EFR}D_{o,EFR}} f \left( \overline{C_{EFR}} - C_{pf} \right) + \frac{q_{w,EFR|pf}}{V_{b,EFR}} \overline{C_{EFR}}
\]  \( (7.40) \)

To avoid explicitly solving for the average concentration in the EFR, and under the assumption that the matrix acts as an infinite salt source, \( \overline{C_{EFR}} \) will be replaced by \( C_m \), a constant equivalent to matrix concentration, in Eqn. 7.40. The dissolution reaction occurring in the EFR both before and after flow would act to elevate \( \overline{C_{EFR}} \). Mixing due to dispersion associated with leakoff and production would further increase this value towards matrix concentration

\[
q_{EFR|pf} = \sigma \Phi_{EFR} f_{EFR} \overline{S_{w,EFR}D_{o,EFR}} f \left( C_m - C_{pf} \right) + \frac{q_{w,EFR|pf}}{V_{b,EFR}} C_m
\]  \( (7.41) \)

Something similar was done by Kazemi et al. (1992) for pressure diffusion under the assumption that concentration at the center of the matrix block (or equivalently at the boundary of the EFR) is to be used instead of average concentration, where here the concentration at the EFR-matrix interface would be held constant by the matrix acting as an infinite salt source. If concentration in the EFR cannot be assumed to be constant, the mass balance on the EFR would have to be solved explicitly, leading to a Laplace space solution that would require numerical inversion.

7.4.3.1.4 Precipitation Reaction in the Primary Fractures

Next considering the precipitation reaction, assume that salt precipitation follows a first order rate law as shown in Eqn. 7.42. Note that the precipitation could be represented in several ways, including the use of a retardation factor which is often used in the ground water literature.

\[
r_{p,pf} = \frac{\partial (\theta_{pf} S_{w, pf} C_{pf})}{\partial t} = k_{p, pf} C_{pf}
\]  \( (7.42) \)
Where, \( k_{p,pf} \) is the precipitation rate constant in the primary fractures and is a function of the area of the proppant grains on which salt can precipitate. Generality in the rate law will be maintained in the remainder of the derivation.

### 7.4.3.1.5 Completing the Derivation of the Mass Balance of Half of the Primary Fracture

Returning to Eqn. 7.2, this expression can be written mathematically as:

\[
V_{b,pf} \sigma \Phi_{EFR} f_{EFR} \frac{S_{w,EFR} D_{o,EFR}}{V_{b,pf}} \left( C_m - C_f \right) + V_{b,pf} \frac{q_{w,EFR}}{V_{b,pf}} C_m - V_{b,pf} r_{p,pf} - V_{b,pf} \frac{q_{w,w}}{V_{b,pf}} C_f =
\]

\[
\frac{\partial m_{p}^{salt}}{\partial t}
\]

(7.43)

Where \( V_{b,pf} \) is the bulk volume of the primary fractures and \( q_{w,w} \) is the volumetric rate of water being produced at the well at surface conditions. First considering the accumulation term:

\[
m_{p}^{salt} = V_{w,pf} C_{pf} = V_{p,pf} S_{w,pf} C_{pf} = V_{b,pf} \Phi_{pf} S_{w,pf} C_{pf}
\]

(7.44)

Where \( V_{w,pf} \) is the volume of water in the primary fracture, \( V_{p,pf} \) is the pore volume of the primary fractures. Substituting Eqn. 7.44 into Eqn. 7.43:

\[
V_{b,pf} \sigma \Phi_{EFR} f_{EFR} \frac{S_{w,EFR} D_{EFR}}{V_{b,pf}} (C_m - C_{pf}) + V_{b,pf} \frac{q_{w,EFR}}{V_{b,pf}} C_m - V_{b,pf} r_{d,pf} -
\]

\[
V_{b,pf} \frac{q_{w,w}}{V_{b,pf}} C_f = \frac{\partial (V_{b,pf} \Phi_{pf} S_{w,pf} C_{pf})}{\partial t}
\]

(7.45)

Next divide Eqn. 7.44 by \( V_{b,pf} \) and assume that the primary fracture and EFR water saturation is 100% and that \( \Phi_{pf} \neq f(t) \):

\[
\sigma \Phi_{EFR} f_{EFR} D_{EFR} (C_m - C_{pf}) + \frac{q_{w,EFR}}{V_{b,pf}} C_m - r_{p,pf} - \frac{q_{w,w}}{V_{b,pf}} C_{pf} = \Phi_{pf} \frac{\partial C_{pf}}{\partial t}
\]

(7.46)

Eqn. 7.46 is the general transport equation that can be applied to predict fracture water salinity both during the shut-in between the stimulation and the onset of flowback, as well as
during BBT period at the onset of flowback. Eqn. 7.46 can be modified for specific application to the shut-in and single-phase flow periods.

7.4.3.2 Before Flow Transport Equation

Assumptions:

1. Matrix concentration is constant during short-duration flowback, and the EFR is being recharged instantaneously by the surrounding matrix; therefore a mass balance on the matrix as a whole is not required.

2. No production from the well during the shut-in period.

Based on these assumptions Eqn. 7.46 can be written as follows:

$$\sigma \phi_{EFR} f_{EFR} D_{oEFR} |_{pf} (C_m - C_{pf}) - k_{p,pf} C_{pf} = \phi_p \frac{\partial C_{pf}}{\partial t}$$  \hspace{1cm} (7.47)

Eqn. 7.47 can be solved with the following initial condition:

$$C_{pf} (0) = C_{pf_i}$$  \hspace{1cm} (7.48)

7.4.3.3 After Flow Transport Equation

Assumptions:

1. Matrix concentration is constant during short-duration flowback, and the matrix in the area of investigation is being recharged instantaneously by the surrounding matrix; therefore a mass balance on the matrix as a whole is not required.

2. Single-phase production of water from the well proceeds at a constant rate. If rate is not constant, a semi-analytical or numerical solution is required. This assumptions holds for the example that will be shown.
3. Production of water from the EFR to the primary fracture is assumed to occur at a constant rate due to the limitations of the current flow model.

Based on these assumptions Eqn. 7.46 can be written as follows:

\[
\phi_{EFR} f_{EFR} D_{o,EFR|pf} (C_m - C_{pf}) + \frac{q_{w,EFR|pf}}{V_{b,EFR}} C_m - k_{pf} C_{pf} - \frac{q_{w,EFR|pf}}{V_{b,ppf}} C_{pf} = \phi_{pf} \frac{\partial C_{pf}}{\partial t} \tag{7.49}
\]

Equation 7.49 can be solved with the following initial condition (note that time is re-initialized after the onset of flow):

\[
C_{pf}(0) = C_{pf,AF} \tag{7.50}
\]

Eqn. 7.47 and Eqn. 7.49 can then be combined to yield the series of equations which need to be solved to predict the salinity response of produced water during both the shut-in period and early-time single-phase fracture fluid only production:

\[
\phi_{pf} \frac{\partial C_{pf}}{\partial t} = \begin{cases} 
\sigma \phi_{EFR} f_{EFR} D_{o,EFR|pf} (C_m - C_{pf}) - k_{pf} C_{pf} & t \leq t_{flow} \\
\phi_{EFR} f_{EFR} D_{o,EFR|pf} (C_m - C_{pf}) + \frac{q_{w,EFR|pf}}{V_{b,EFR}} C_m - k_{pf} C_{pf} - \frac{q_{w,ppf}}{V_{b,ppf}} C_{pf} & t > t_{flow} \end{cases} \tag{7.51}
\]

The next step is to solve the equations presented in Eqn. 7.41 with the simplifying assumptions discussed above. These assumptions are required to derive a fully-analytical solution.

### 7.4.3.4 Before Flow Solution

Following the assumptions stated previously the EFR is being recharged by the surrounding matrix, and therefore a mass balance for the matrix is not required.

\[
\phi_{pf} \frac{\partial C_{pf}}{\partial t} = \sigma \phi_{EFR} f_{EFR} D_{o,EFR|pf} (C_m - C_{pf}) - k_{pf} C_{pf} \tag{7.52}
\]

Where, \( \sigma \) is not considered a function of time during pseudo steady-state mass transfer.
7.4.3.4.1 Solving the Before Flow Transport Equation

Eqn. 7.52 can be rearranged into the general form for a first order, non-homogenous ODE, which is given by Eqn. 7.53:

\[ y'(t) + p(t)y = q(t) \]  \hspace{1cm} (7.53)

First divide through by \( \Phi_f \):

\[ \frac{\partial C_{pf}}{\partial t} = \sigma \frac{\Phi_{EFR}}{\phi_{pf}} f_{EFR} D_{o,EFR|pf} (C_m - C_{pf}) - \frac{k_{p,pf}}{\phi_{pf}} C_{pf} \]  \hspace{1cm} (7.54)

Next rearrange Eqn. 7.52 into the form of Eqn. 7.51:

\[ \frac{\partial C_{pf}}{\partial t} + \left( \sigma \frac{\Phi_{EFR}}{\phi_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\phi_{pf}} \right) C_f = \sigma \frac{\Phi_{m}}{\phi_{f}} f_{EFR} D_{o,EFR|pf} C_{m} \]  \hspace{1cm} (7.55)

Eqn. 7.55 can be solved using the integrating factor approach, where the integrating factor, \( IF \), is defined as:

\[ IF = \exp(\int p(t) dt) \]  \hspace{1cm} (7.56)

Comparing Eqn. 7.55 and Eqn. 7.53 expressions for \( p(t) \) and \( q(t) \) can be found:

\[ p(t) = \sigma \frac{\Phi_{EFR}}{\phi_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\phi_{pf}} \]  \hspace{1cm} (7.57)

\[ q(t) = \sigma \frac{\Phi_{EFR}}{\phi_{pf}} f_{EFR} D_{o,EFR|pf} C_{m} \]  \hspace{1cm} (7.58)

Calculating the integrating factor:

\[ IF = \exp \left[ \int \left( \sigma \frac{\Phi_{EFR}}{\phi_{f}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\phi_{pf}} \right) dt \right] \]  \hspace{1cm} (7.59)

Evaluating the integral:

\[ IF = \exp \left[ \left( \sigma \frac{\Phi_{EFR}}{\phi_{f}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\phi_{pf}} \right) t \right] \]  \hspace{1cm} (7.60)

The general solution then takes the following form:

\[ y(t) = \frac{\int [IF q(t)] dt + B_1}{IF} \]  \hspace{1cm} (7.61)
Where $B_1$ is a constant. Eqn. 7.59 can be rewritten by substituting in the definition of the integrating factor:

$$y(t) = \exp(-\int p(t)dt) \{ \int [\exp(\int p(t)dt) q(t)]dt + B_1 \} \tag{7.62}$$

Sub Eqn. 7.57 and Eqn. 7.58 into Eqn. 7.62 yields an expression for $C_{pf}(t)$:

$$C_{pf}(t) = \exp \left\{ - \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} + \frac{k_{p pf}}{\varphi_{pf}} \right) t \right\} \left\{ \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m \right) \right\} dt + B_1 \right\} \tag{7.63}$$

Evaluating the integral:

$$C_{pf}(t) = \exp \left\{ - \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} + \frac{k_{p pf}}{\varphi_{pf}} \right) t \right\} \left\{ \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m \right) \right\} dt + B_1 \right\} \tag{7.64}$$

The constant, $B_1$, comes from the initial condition shown in Eqn 7.48:

$$C_{pf}(0) = C_{pf i} = \exp \left\{ - \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} + \frac{k_{p pf}}{\varphi_{pf}} \right) (0) \right\} \left\{ \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m \right) \right\} \left\{ \left( \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m \right) \right\} dt + B_1 \right\} \tag{7.65}$$

Simplifying:

$$C_{pf}(0) = C_{pf i} = \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m + B_1 = \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m + B_1 \tag{7.66}$$

Solving for $B_1$ from the initial conditions:

$$B_1 = C_{pf i} - \frac{\sigma_{EFR}}{\varphi_{pf}} f_{EFR} D_{0,EFR|pf} C_m \tag{7.67}$$
Substituting into Eqn. 7.64 and simplifying:

\[ C_{pf}(t) = \]

\[ \exp \left[ - \left( \frac{\phi_{EFR}}{\phi_{pf}} \int_{EFR} D_{0,EFR} |pf| + \right. \right. \]

\[ \frac{k_{p,pf}}{\phi_{pf}} \left. \right] \left\{ \frac{\sigma_{EFR} f_{EFR} D_{0,EFR} |pf| C_m}{\sigma_{EFR} f_{EFR} D_{0,EFR} |pf| + k_{p,pf}} \right\} \left( \exp \left[ \left( \frac{\phi_{EFR}}{\phi_{pf}} \int_{EFR} D_{0,EFR} |pf| + \frac{k_{p,pf}}{\phi_{pf}} \right) t \right] - 1 \right) + C_{pf} \}

\[(7.68)\]

Eqn. 7.68 is the final solution which can be used to predict salinity response of water in the primary fracture during the shut-in period between stimulation and the onset of flowback.

7.4.3.5 After Flow Solution

After flow it is again assumed that matrix concentration is constant such that a single porosity model is used:

\[ \phi_{EFR} f_{EFR} D_{0,EFR} |pf| \left( C_m - C_{pf} \right) + \frac{q_{w,EFR}|pf|}{V_{b,EFR}} C_m + k_{d,r,pf} \frac{A_f}{V_{b,pf}} \phi_{EFR} - k_{p,pf} C_{pf} - \frac{q_{w,w}}{V_{b,pf}} C_{pf} \]

\[(7.69)\]

7.4.3.5.1 Solving the After Flow Transport Equation

Eqn. 7.69 can be rearranged into the general form for a first order, non-homogeneous ODE as given by Eqn. 7.53. Start by dividing Eqn. 7.69 through by \( \phi_f \):

\[ \frac{\partial C_{pf}}{\partial t} = \sigma \frac{\phi_{EFR}}{\phi_{pf}} f_{EFR} D_{0,EFR} |pf| \left( C_m - C_{pf} \right) + \frac{q_{w,EFR}|pf|}{V_{b,EFR} \phi_{pf}} C_m + k_{d,r,pf} \frac{A_f}{V_{b,pf}} \phi_{EFR} - \frac{k_{p,pf}}{\phi_{pf}} C_{pf} - \]

\[ \frac{q_{w,w}}{V_{b,pf} \phi_{pf}} C_{pf} \]

\[(7.69)\]

Rearranging into the form of Eqn. 7.51:
\[
\frac{\partial C_{pf}}{\partial t} + \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\Phi_{pf}} + \frac{q_{w,w}}{v_{b,pf} \Phi_{pf}} \right) C_{pf} = \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{q_{w,EFR|pf}}{v_{b,EFR} \Phi_{pf}} \right) C_{m} + k_{d,rp,pf} \frac{A_{f}}{v_{b,pf} \Phi_{pf}} \Phi_{EFR} \tag{7.70}
\]

Eqn. 7.70 can be solved using the integrating factor approach, where the integrating factor was defined in Eqn. 7.56. Comparing Eqn. 7.70 and Eqn. 7.53 yields expressions for \(p(t)\) and \(q(t)\):

\[
p(t) = \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\Phi_{pf}} + \frac{q_{w,w}}{v_{b,pf} \Phi_{pf}} \tag{7.71}
\]

\[
q(t) = \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{q_{w,EFR|pf}}{v_{b,EFR} \Phi_{pf}} \right) C_{m} + k_{d,rp,pf} \frac{A_{f}}{v_{b,pf} \Phi_{pf}} \Phi_{EFR} \tag{7.72}
\]

Calculating the integrating factor:

\[
IF = \exp \left[ \int \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\Phi_{pf}} + \frac{q_{w,w}}{v_{b,pf} \Phi_{pf}} C_{pf} \right) dt \right] \tag{7.73}
\]

Evaluating the integral:

\[
IF = \exp \left[ \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\Phi_{pf}} + \frac{q_{w,w}}{v_{b,pf} \Phi_{pf}} \right) t \right] \tag{7.74}
\]

The general solution then takes the form of Eqn. 7.62 where the constant \(B_{f}\) can be replaced with a second constant, \(B_{2}\). Substituting Eqn. 7.71 and Eqn. 7.72 into Eqn. 7.61 we get an expression for \(C_{pf}(t)\):

\[
C_{pf}(t) = \exp \left[ - \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\Phi_{pf}} + \frac{q_{w,w}}{v_{b,pf} \Phi_{pf}} \right) t \right] \left\{ \left( \sigma \frac{\Theta_{EFR}}{\Phi_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{k_{p,pf}}{\Phi_{pf}} + \frac{q_{w,w}}{v_{b,pf} \Phi_{pf}} \right) \left( \sigma \frac{\Theta_{EFR}}{\Theta_{pf}} f_{EFR} D_{o,EFR|pf} + \frac{q_{w,EFR|pf}}{v_{b,EFR} \Phi_{pf}} \right) C_{m} + k_{d,rp,pf} \frac{A_{f}}{v_{b,pf} \Phi_{pf}} \Phi_{EFR} \right\} dt + B_{2} \tag{7.75}
\]

Evaluating the integral:
The constant, $B_2$, comes from the initial condition which was given by Eqn. 7.50:

$$C_{pf}(0) = C_{pf,i,AF} \tag{7.77}$$

Where, $C_{pf,i,AF}$ is the fracture concentration at the end of the shut-in period, with time being re-initialized at the onset of flow:

$$C_{pf}(0) = C_{pf,i,AF} =$$

exp $\left[ \left( \frac{\sigma_{EPR} f_{EPR} D_{o,EFR} p_f}{\phi_{pf}^2} \right)^t \right] \left\{ \left( \frac{\phi_{pf} f_{EPR} D_{o,EFR} p_f}{\phi_{pf}^2} + \frac{q_{w,w} p_f}{v_{b,pf} \phi_{pf}^2} \right)^t \right\} + B_2$ \tag{7.78}

Simplifying:

$$C_{pf}(0) = C_{pf,i,AF} = \left( \frac{\phi_{pf} f_{EPR} D_{o,EFR} p_f}{\phi_{pf}^2} + \frac{q_{w,w} p_f}{v_{b,pf} \phi_{pf}^2} \right)^t \left( \frac{C_m}{\phi_{pf}^2} \right) + B_2 = \left( \frac{\phi_{pf} f_{EPR} D_{o,EFR} p_f}{\phi_{pf}^2} + \frac{q_{w,w} p_f}{v_{b,pf} \phi_{pf}^2} \right)^t \left( \frac{C_m}{\phi_{pf}^2} \right) + B_2$$ \tag{7.79}

Solving for $B_2$, from the initial condition:

$$B_2 = C_{pf,i,AF} - \left( \frac{\phi_{pf} f_{EPR} D_{o,EFR} p_f}{\phi_{pf}^2} + \frac{q_{w,w} p_f}{v_{b,pf} \phi_{pf}^2} \right)^t \left( \frac{C_m}{\phi_{pf}^2} \right) \tag{7.80}$$

Substituting into Eqn. 7.76 and simplifying:
\[ C_{pf}(t) = \exp \left( - \left( \frac{\sigma_{\text{EFRR}}}{\phi_{pf}} f_{EFRR} D_{o, \text{EFRR} | pf} + \frac{k_{p,pf}}{\phi_{pf}} \right) \right) \frac{q_{w,w}}{V_{b,pf} \phi_{pf}} \right) \exp \left( \frac{q_{w,w}}{v_{b,pf} \phi_{pf}} t \right) + 1 + C_{f,Af} \right) \] (7.81)

7.4.3.6 The Final Transport Equation Solution

Combining the Before and After Flow Solutions:

\[ C_{pf}(t) = \begin{cases} \exp \left[ - \left( \frac{\sigma_{\text{EFRR}}}{\phi_{pf}} f_{EFRR} D_{o, \text{EFRR} | pf} + \frac{q_{w,w}}{v_{b,pf} \phi_{pf}} \right) t \right] \exp \left( \frac{q_{w,w}}{v_{b,pf} \phi_{pf}} t \right) + 1 + C_{f,Af} \right) & t \leq t_{\text{flow}} \\ \exp \left[ - \left( \frac{\sigma_{\text{EFRR}}}{\phi_{pf}} f_{EFRR} D_{o, \text{EFRR} | pf} + \frac{q_{w,w}}{v_{b,pf} \phi_{pf}} \right) t \right] \exp \left( \frac{q_{w,w}}{v_{b,pf} \phi_{pf}} t \right) + 1 + C_{f,Af} \right) & t > t_{\text{flow}} \end{cases} \] (7.82)

Salt concentration in kg/m³ is simply converted to salinity in parts per million (ppm) by multiplying by 1000.

Due to the simple analytical nature of the solution, the derived salinity model can be solved in a spreadsheet and has been directly incorporated into the latest version of FLOAT, with FLOAT acting as the flow model used in conjunction with the salinity model. To date the model has not been compared to commercial flow and transport simulators, although this is an important piece of future work to increase confidence in the derived model.
7.5 Analysis Procedure

Ideally the analysis procedure would include a combination of lab studies to constrain some of the key mass transport parameters (i.e. diffusion coefficient) in order to reduce the number of unknowns which are being adjusted to match the data. For the actual application of the model, two different approaches can be used. In the less rigorous approach, only one fracture is considered and the model is initiated at the mid-point of the stimulation. In the more rigorous approach, time 0 is set to the midpoint of the first stage stimulation, and each stage is added at the midpoint of its stimulation time interval, and then the salinity response from each stage is averaged to yield the commingled salinity of the produced water. The longer the stimulation time and waiting period in between stages, the greater the disparity between the approaches. As will be seen in the field case, for a fairly rapid stimulation, there is very little impact on the predicted salinity except at very early times. If stage-by-stage data is collected and analyzed, then the more rigorous approach should be used as the fracture parameters (i.e. fracture area) will be different for each stage. Because there is a lot of heterogeneity in many ultra-tight plays, it is possible that the transport coefficients may be different for each stage, although this would be very difficult to quantify in the lab. One possible approach would be to apply an advanced history-matching technique such as a GA, as was done for flow modeling in Chapter Four.

In the absence of any lab data, values for the key mass transfer parameters can be taken from the literature and tweaked to produce an adequate match. If the salinity data cannot be matched using a reasonable set of mass transfer parameters, then it is likely that the model is either invalid for the well of interest – there may be different mechanisms affecting the salinity response, or the fracture area and volume found from flow modeling are incorrect.
7.6 Field Example

The field example presented in this chapter investigates the same LTO well that was analyzed for flow in Chapter Four. In this application, the primary objective is confirm the fracture surface area and volume as estimated by the flow model. As with flow modeling a circular fracture shape was assumed. Further, it was assumed that the entire fracture surface area contributes salt equally, which is a reasonable assumption in the formation of interest in which there is not a large degree of lithological changes. The main difference in the current analysis is the primary hydraulic fracture was limited to 0.25 in/stage (a value more commonly used for simple bi-wing planar fractures – Valko, 2001), with the remainder of the fracture volume consisting of an EFR. The EFR is assumed to act as a single porosity system, and has matrix porosity - the porosity of the matrix is significantly higher than the porosity of the secondary fractures and therefore the matrix elements control storage while the higher permeability secondary fractures control flow. The total stimulation time is ~ 2 days (~ 3 hours per stage). As a result, the commingled approach was initiated at ~ 1 day (halfway through the stimulation period) and only half of one stage was considered. In the stage-by-stage approach, all stages were considered homogeneous, although each stage was added at the mid-point of the stimulation interval starting at ~ 0.06 days (~ 1.5 hours) and then their contributions averaged to determine the average salinity produced at the well. Although formation fluid breakthrough occurs at ~ 2.2 days, water rate remains approximately constant at ~ 1,400 STB/D (39 STB/D per half-stage) with a saturation greater than 93% for the first 3 days of flowback, and therefore the salinity data from this period will attempt to be matched using the model discussed above. The well was shut-in for ~ 12 days between the end of completion and the onset of flow (~ 13 days from the onset of completion). The input parameters required for the analysis are shown below
in Table 7.1. Note that the formation of interest is not thought to produce significant amounts of water, and therefore formation water salinity is uncertain and was set 50% higher than the highest salinity measurement captured during flowback. This value is in line with what is presented in the literature for other unconventional formations at or near irreducible water saturation.

| Table 7.1 — Input Parameters for Flowback Field Example |
|-----------------------------------------------|----------|
| Fracture Properties                           | Parameter Value |
| Initial Water Saturation (%)                  | 100      |
| Fracture Porosity (%)                         | 31       |
| Number of Hydraulic Fractures                 | 18       |
| Individual Hydraulic Fracture Width (ft)     | 0.0208   |
| Total Hydraulic Fracture Width (ft)           | 0.375    |
| Hydraulic Fracture Surface Area (Ac)          | 14       |
| Reservoir Properties                          | Parameter Value |
| Formation Pressure (psia)                     | 3,700    |
| Matrix (EFR) Porosity (%)                     | 4        |
| EFR Initial Mobile Water saturation (%)       | 100      |
| Reservoir Temperature (°F)                    | 140      |
| Fluid Properties                              | Parameter Value |
| Initial Fracture Water Salinity (ppm)         | 1,000    |
| Formation Water Salinity (ppm)                | 200,000  |

7.6.1 Raw Data

Water rate and salinity data for the first 3 days of flowback are shown below in Fig. 7.2.
As discussed above, water rate is relatively constant over the first 3 days of flowback making the constant rate assumption valid (Fig. 7.2a) and water salinity continually increases throughout the flowback period (Fig. 7.2b). It can also be noted that the first couple of data points fall between 30,000 ppm and 45,000 ppm before the main trend is established starting by ~ 50,000 ppm. As a result, ~ 50,000 ppm is the salinity target for the before flow period. Other mechanisms which have not been modeled may be contributing to this rapid increase in early-time salinity or measurement error may be the cause of these outlier data points.

7.6.2 Salinity History-Match

History-matching water salinity data is a pure history-matching exercise. In the absence of lab data, key mass transfer coefficients which are assumed to be constant throughout the flowback period are given below in Table 7.2.
The diffusion coefficient and EFR constriction factor are consistent with values found in the literature for different forms of porous media. Robinson and Stokes (1959) observed that the diffusion coefficient for chloride salt solutions are within 20%. Balashov et al. (2015) selected a value of $3.8 \times 10^{-9}$ m$^2$/s which has also been used in this work. In the same paper the authors derived a constriction factor which is in the same order of magnitude as the value used in this work. The width of half the EFR for a given stage was set to allow total fracture volume (primary fracture + EFR) to be equal to the IFFIP found using the FMB. Finally, the shape factor was calculated using the fracture dimensions solved from flow modeling.

The profile for water salinity before flow (shut-in period between stimulation and onset of flowback) and the history-match to the first 3 days of flow are shown below in Fig. 7.3a. In Fig. 7.3b, only the salinity match during the three day BBT is shown.

<table>
<thead>
<tr>
<th>Mass Transfer Properties</th>
<th>Parameter Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diffusion Coefficient (m$^2$/s)</td>
<td>$3.28 \times 10^{-9}$</td>
</tr>
<tr>
<td>EFR Constriction Factor (dimensionless)</td>
<td>0.385</td>
</tr>
<tr>
<td>EFR Width Per Half Fracture (ft)</td>
<td>0.08</td>
</tr>
<tr>
<td>EFR Shape Factor (ft$^2$)</td>
<td>162.3</td>
</tr>
</tbody>
</table>
Fig. 7.3 – Water salinity history-match: a) shut-in period and BBT flow; and b) BBT flow only.

From Fig. 7.3 it can be seen that an excellent match is achieved during the desired flow period using both the stage-by-stage and commingled approach with the exception of the first few anomalous data points which may be controlled by mechanism not accounted for in the developed model or could correspond to inaccurate field measurements. The two approaches primarily vary early in time as the stages are executed, with the lines largely converging once all stages have been completed. The key history-match parameters are shown below in Table 7.3.

<table>
<thead>
<tr>
<th>Table 7.3 — Key History-Match Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>History-Match Parameters</td>
</tr>
<tr>
<td>Total Equivalent EFR Flow Rate (STB/D)</td>
</tr>
<tr>
<td>Before Flow Precipitation Rate Constant (s⁻¹)</td>
</tr>
<tr>
<td>After Flow Precipitation Rate Constant (s⁻¹)</td>
</tr>
</tbody>
</table>

Of these values, the only true history-match parameter is the flow rate of water from the EFR into the primary fractures. As discussed previously, this value is not likely static in time, but this assumption has been made to accommodate the current flow model. A flow model that
allows for a primary fracture, an EFR and a matrix, similar to what was proposed by Qanbari et al. (2016) would solve for this parameter in time.

One last thing to confirm is that the matrix has the ability to act as an infinite salt source as has been assumed in the model. The total salt available in bound water in the matrix contacted by the single well analyzed is 126 million kg, assuming a water saturation of 15%. Assuming the entire wellbore, before flow 110,580 kg of salt flow into the primary fractures, while after flow 41,570 kg of salt flow into the fractures and 42,264 kg of salt flow out of the fractures. This results in a net inflow of salt into the primary fractures of 109,886 kg. This suggests that <0.1% of the salt available in the contacted matrix is produced during the first 3 days of flowback, confirming that the assumption of the matrix acting as an infinite salt source is likely valid. Further, 260% of the available salt in the EFR is produced, suggesting that recharge from the matrix is necessary (assumed to be instantaneous).

7.7 Discussion

In this chapter, a simple analytical model was developed to match the salinity profile during the before flow and BBT period of a tight oil field example in order to confirm fracture surface area and volume. This model provides an important validation of the key fracture parameters solved from flow modeling which is the focus of the remainder of this dissertation. Several simplifying assumptions were made. First, it was assumed that water production rate is constant, which was largely true in the field case analyzed. It was also assumed that the inflow rate from the EFR was constant in time, which was required due to the limitations of the current flow model. This model was designed as a starting point for the development of a more advanced tool with additional capabilities. Some of the capabilities which should be included are listed below:
Model advancement to allow for variable production rate at the wellbore. It is rare that BBT flowrate is constant as was seen in the field case analyzed, limiting the application of this simple model. This would require a semi-analytical or numerical solution, such as that of Dong (2010) for contaminant transport in fractured porous media.

Development of a flow model which can predict water inflow rate from the EFR to the primary fracture network BBT. This would eliminate the key history match parameter used here, although would require a numerical solution.

Extension of the model to account for the salinity response both BBT and ABT. This creates additional complexity in the model, as saturation is no longer constant in any of the porosity systems. Such a model would require a numerical solution. It is possible that a commercial flow and transport numerical simulator such as TOUGHREACT™ could be manipulated to handle this problem.

Expansion of the model to allow for multiple-porosity behaviour. This could be as complex as defining the primary fractures as a single porosity system, the EFR as a dual porosity system and the matrix as a single-porosity system. Such a model would require a numerical solution.

Extension of the model for application to oil and gas shales, where mechanisms such as osmotic pressure and clay leaching become important. Extension to such systems introduces a large number of unknowns and should only be applied with adequate lab testing.

Expansion of the model to account for individual ion matching as different salt ions undergo different processes and the ultimate composition of the flowback water is required for recycling and disposal purposes.
• Relaxation of the assumption of perfect mixing within the fractures. Although mixing due to dispersion can be rapid but although it may not be instantaneous as was assumed.
• Investigation of the impact of treating the entire fracture network as a tank which undergoes depletion as compared to the case where depletion occurs in the primary fracture network with inflow from the EFR. Again this would require a more complex flow model.
• Collection of higher frequency salinity data may improve the quality of parameter estimates by providing more consistent data to model. Salinity data is typically only gathered every couple of hours and usually only total salinity is measured, vs. individual ion concentration.

7.8 Summary

In this chapter a simple model was developed to match the salinity of flowback water during the before flow and BBT period. This model has many simplifying assumptions, which means that modification would be required for application to the majority of wells. The main conclusions of this chapter include the following:

• Salinity data can be used to compliment flow data when determining key fracture properties such as surface area and volume.
• Given certain assumptions, a simple fully-analytical model was developed to model the before flow and BBT periods with minimal uncertain parameters.
• If mass transfer parameters can be constrained enough through lab testing or experience in the field, then the salinity model could feasibly be used in its current form in place of flow modeling, although it is ideal to combine the two separate analyses. One of the
biggest challenges would be estimating the flowrate of water from the EFR to the primary fractures without conducting detailed flow modeling.

- The current model could be extended for application to shale gas by including certain shale specific mechanisms such as osmotic pressure and leaching of clay minerals.

Appendix 7.1 – Alternate Derivation of EFR Equation

A mass balance can be written on the EFR as follows:

\[ \dot{m}_{in} - \dot{m}_{out} + \dot{m}_{source} - \dot{m}_{sink} = \dot{m}_{accum} \]  
(7.1.1)

Considering only pseudo steady-state diffusion out of the matrix, Eqn. 7.1.1 can be simplified as follows

\[ \dot{m}_{source} - \dot{m}_{sink} = \dot{m}_{accum} \]  
(7.1.2)

Mathematically this can be written as:

\[ J_{EFR|pf}A_{EFR|pf} + V_{b,EFR}r_{d,EFR} = \frac{\partial m_{salt}^{EFR}}{\partial t} \]  
(7.1.3)

First considering the accumulation term:

\[ m_{salt}^{EFR} = \overline{C}_{EFR}v_{w,EFR} = \overline{C}_{EFR}v_{p,EFR}S_{w,EFR} = \overline{C}_{EFR}v_{b,EFR}\phi_{EFR}S_{w,EFR} \]  
(7.1.4)

Substituting (7.1.4) into (7.1.3):

\[ J_{EFR|pf}A_{EFR|pf} + V_{b,EFR}r_{d,EFR} = \frac{\partial (\overline{C}_{EFR}v_{b,EFR}\phi_{EFR}S_{w,EFR})}{\partial t} \]  
(7.1.5)

Next define the flux as a sum of diffusion and advection:

\[ J_{EFR|pf} = D_{eff,EFR|pf} \frac{(c_f - \overline{C}_{EFR})}{w_{EFR}} - v_{darcy,EFR|pf} \overline{C}_{EFR} = D_{eff,EFR|pf} \frac{(c_f - \overline{C}_{EFR})}{w_{EFR}} - \frac{q_{w,EFR}}{A_{EFR|pf}} \overline{C}_{EFR} \]  
(7.1.6)
Where, \( w_{efr} \) is the characteristic length associated with where the salt is being sourced from in the matrix. For long-term flow, this would be the distance to the no-flow boundary, although during short-term flowback this distance will be much smaller. Note that advective flux would only occur after flow. Next sub Eqn. 7.1.6 into Eqn. 7.1.5 under the assumption that \( A_{EFR} \) is the primary fracture surface area, \( A_{pf} \). \( V_{b,EFR} \neq f(t) \), \( \phi_{EFR} \neq f(t) \) and \( S_{w,EFR} \neq f(t) \). Note that \( S_{w,EFR} \) is the average water saturation in the EFR (leakoff zone).

\[
D_{eff,EFR|pf} \left( \frac{C_f - \overline{C_{EFR}}}{w_{EFR}} \right) A_{pf} - q_{w,EFR|pf} \overline{C_{EFR}} + V_{b,EFR} r_{d,EFR} = V_{b,EFR} \phi_{EFR} \overline{S_{w,EFR}} \frac{\partial \overline{C_{EFR}}}{\partial t} \quad (7.1.7)
\]

Substituting in for the effective diffusion coefficient as defined previously:

\[
\phi_{EFR} \overline{S_{w,EFR}} D_{o,EFR|pf} \left( \frac{C_f - \overline{C_{EFR}}}{w_{EFR}} \right) A_{pf} - q_{w,EFR|pf} \overline{C_{EFR}} + V_{b,EFR} r_{d,EFR} = V_{b,EFR} \phi_{EFR} \overline{S_{w,EFR}} \frac{\partial \overline{C_{EFR}}}{\partial t} \quad (7.1.8)
\]

Next assume 100% water saturation in the EFR and dividing through by \( V_{b,EFR} \):

\[
\phi_{EFR} \overline{S_{w,EFR}} D_{o,EFR|pf} \left( \frac{A_{f}}{V_{b,EFR} w_{EFR}} \right) \left( C_f - \overline{C_{EFR}} \right) - \frac{q_{w,EFR|pf}}{V_{b,EFR}} \overline{C_{EFR}} + r_{d,EFR} = \phi_{EFR} \frac{\partial \overline{C_{EFR}}}{\partial t} \quad (7.1.9)
\]

From Eqn. 7.1.9 the definition of shape factor can be found:

\[
\sigma = \frac{A_f}{V_{b,EFR} w_{EFR}} \quad (7.1.10)
\]

Substituting Eqn. 7.1.10 into Eqn. 7.1.9:

\[
\sigma \phi_{EFR} \overline{S_{w,EFR}} D_{o,EFR|pf} \left( C_f - \overline{C_{EFR}} \right) - \frac{q_{w,EFR|pf}}{V_{b,EFR}} \overline{C_{EFR}} + r_{d,EFR} = \phi_{EFR} \frac{\partial \overline{C_{EFR}}}{\partial t} \quad (7.1.11)
\]

From Eqn. 7.1.11 the rate of mass transfer per unit volume can be defined as:

\[
q_{EFR|pf} = \sigma \phi_{EFR} \overline{S_{w,EFR}} D_{o,EFR|pf} \left( \overline{C_{EFR}} - C_{pf} \right) + \frac{q_{w,EFR|pf}}{V_{b,EFR}} \overline{C_{EFR}} \quad (7.1.12)
\]
To avoid explicitly solving for the average concentration in the EFR and under the assumption that the matrix acts as an infinite salt source, $\bar{C}_{EFR}$ will be replaced by $C_m$, a constant, in Eqn. 7.1.13:

$$q_{EFR|pf} = \sigma \Phi_{EFR} f_{EFR} D_{o,EFR|f} (C_m - C_{pf}) + \frac{q_{w,EFR|pf}}{V_{b,EFR}} C_m$$

(7.1.13)
Chapter Eight: Contributions, Conclusions and Recommendations for Future Work

Unconventional oil and gas has become one of the primary resource classes being exploited in North America, as well as globally. Due to the ultra-low permeability of these reservoirs, MFHWs are used to allow commercial productivity. A reasonable estimate of key fracture properties requires 6-12 months of data using conventional methods, making it difficult to rationalize a change in exploitation strategy and completion style during a drilling program. As a result, operators are looking for new methods to characterize the generated fractures. One technique that has gained popularity in the last five years is quantitative flowback analysis, which was the focus of this dissertation. The papers which contributed to this dissertation were some of the first publications in this growing field of research.

8.1 Contributions and Conclusions

The key findings of this dissertation are summarized below:

1. Hourly (or more frequent) rate and flowing pressure data are collected for almost every MFHW, although this data is rarely used for quantitative or even qualitative purposes. As discussed in the literature review, Kinnon and Williams-Kovacs (2017) conducted a study investigating some common indicators used in industry in attempt to predict long-term well performance, at least qualitatively. In this work, the authors found that there was very little correlation between flowback and online productivity. This was an important finding as companies often gauge future well performance based on things such as peak rate seen on flowback which could lead to poor decision making and ultimately have a financial impact on the business. This dissertation, as well as others, have demonstrated that flowback data can be analyzed quantitatively to estimate key
fracture parameters which can then be used to more accurately forecast long-term productivity. Flowback provides the first rate and pressure data collected on wells making it an excellent candidate for early-time fracture characterization.

2. The techniques developed in this work have been used extensively in industry. Each of the case studies presented in this paper were conducted with a business purpose for an exploration and production (E&P), with emphasis on Case Study 1 in Chapter Six. Another example is a study published by Cugnart et al. (2017) which uses the methods discussed in Chapter Three for analyzing flowback from shale gas wells and also mentions the use of the LTO tool discussed in Chapter Four. The tool is also used by members of the Tight Oil Consortium (TOC) at the University of Calgary which is made up of ~ 12 companies.

3. A similar conceptual model can be used for analyzing shale gas and LTO wells. At the onset of this study Clarkson and Williams-Kovacs (2013a) used a very different conceptual model for shale gas wells than what was used by Clarkson et al. (2014) for LTO cases. As more shale gas cases were studied it was determined that a modification of the conceptual model used for LTO cases with some shale-specific modifications was more appropriate. The key to this approach is coupling of fracture and matrix flow through the use of a MBE.

4. Key fracture parameters can successfully be determined from flowback data using a combination of classic RTA techniques and a pseudo-analytical model which was developed to match the flow-regimes observed in field data. This type of model development is beneficial in many cases as the signatures on key diagnostic plots can provide insight into the mechanisms controlling the process, rather than trying to force-fit
a mathematical model developed from first principals based on a conceptual model which may or may not represent the problem adequately. The majority of work conducted in the literature has used the first principals approach, which in many cases leads to poor history-matches or poor correlation on straight-line plots. This was discussed extensively in the literature review. The sequence of flow-regimes analyzed in this work was also validated using numerical simulation providing further confidence in its wide-spread applicability (although it may not be successful in some cases as with any analysis technique).

5. The results from flowback analysis are typically in very good agreement with those from long-term production. This was demonstrated in both shale gas and LTO field cases in this work, as well as by others, including Cugnart et al. (2017). This suggests that with reasonable data quality, key fracture parameters can be estimated and used to accurately forecast long-term production (or at very least early and mid-time production while the well remains in transient flow, which is the most critical time from a financial perspective).

6. Monte Carlo was successfully applied for two purposes in this work: 1) quantification of the uncertainty in key fracture parameters; and 2) provision of an estimate of the uncertain parameters as an assisted history-matching technique. Although the technique was successful at both, less than 1% of iterations were considered successful, making this an inefficient optimization technique (as would be expected due to its random behaviour). For the limited number of matches, there was very little variability. Two out of five parameters had P10/P90 values of less than 1.1, while the other parameters have values of 1.23, 1.26 and 2.03. This suggests that, although there is significant potential
for uncertainty in quantitative flowback analysis due to the number of parameters being adjusted, a deterministic match appears to provide a relatively unique solution in many cases.

7. Assisted history-matching techniques (including Monte Carlo simulation) can be successfully implemented into the tools developed in this dissertation to find an optimal set of parameters. In the case shown in Chapter Four, all of the techniques yielded very similar results, suggesting a local optimum was being found, and the solution is not biased by the optimization algorithm selected. This result is somewhat surprising as SO algorithms fail in some occasions when MOs exist due to objective conflict and proper weighting selection. This issue was not found in any of the cases investigated. This is critical to industry application where time is not afforded to analyze a well using multiple optimization techniques. There is additional value to industry as deterministic history-matching can be complicated and is often time consuming. By applying an assisted history matching technique, the optimization program does a lot of the labour, assuming a suitable range of key uncertain properties can be determined.

8. The fairly simple structure of FLOAT, which by default assumes a single well drilled laterally into a homogeneous formation, and assumes circular fracture shape and the formation of a single bi-wing planar fracture geometry, allows for modifications to account for a variety of more complex problems. For example, different fracture shapes (i.e. rectangular or elliptical) and geometries (i.e. simple bi-wing planar or complex) can be accounted for. Further the tool can be expanded to account for real-world complexities such as stage-by-stage flowback, multi-well flowback, multi-layer flowback
and oil-based fracture fluid in LTO reservoirs. Each of these extensions were discussed and analyzed in this dissertation.

9. A simple analytical model can be used to history-match BBT salinity data gathered during flowback to confirm fracture surface area to compliment flow modeling. If key parameters such as the average salt diffusion coefficients can be accurately estimated, this could be used as a stand-alone technique to estimate fracture surface area during the BBT period.

8.2 Future Research and Recommendations

Based on the findings of this dissertation, the following recommendations are made for future research on the topic. These recommendations are broken into three categories: 1) data gathering and operations; 2) tool development and analysis; and 3) other.

8.2.1 Flowback Data Gathering and Operations

1. One of the biggest issues in analyzing flowback data is data quality. This was demonstrated by Cugnart et al. (2017), as well in many cases analyzed by the author which were not presented in this dissertation. If quantitative flowback analysis is planned, then extra care should be taken to gather high quality data. Increasing data gathering frequency (i.e. 1 minute or more frequent intervals), particularly early in the flowback period would dramatically increase the probability of seeing a high quality transient flow signature. This can provide important information about fracture shape and also provide greater confidence in key fracture parameter estimates from RTA. Gathering bottomhole pressures would also provide significantly better data. Flowing
pressures are often collected at the surface and converted to bottomhole conditions using a wellbore model. These models tend to be less accurate when dealing with multi-phase flow and could be further impacted by sand production and rapidly changing wellbore conditions. Frequent shut-ins (or any early-time shut-in) can make interpretation difficult as it is difficult to determine initial conditions upon start-up and can impact the derivative signature. The flowback period should be as long as possible. This is often highly dependent on surface operations, although a longer flowback period provides more data to interpret and therefore a more confident estimation in key fracture properties. There have also been several works, including those by Crafton (2008) and Williams-Kovacs and Clarkson (2013b), that have demonstrated that shut-ins, particularly early in the well life, can be damaging to hydraulic fracture properties. The consensus guideline from a group of experts in the field who were consulted on the matter suggested that flowing the wells continuously until the hydrocarbon phase begins to decline is likely optimal for long-term performance.

2. Gather stage-by-stage flowback data. When dealing with commingled data, only an estimate of “average” fracture properties can be determined. As was demonstrated in Chapter Five, this may also lead to erroneous estimates of key fracture properties due to different fractures being in different flow-regimes at different times. It was demonstrated in Chapter Five that even changing one parameter in one stage of a well can have a significant impact on data interpretation. In field applications the extent of completion heterogeneity in multiple parameters is common. The short duration of flowback makes this more crucial than during long-term production, where transient linear flow is typically the only flow-regime which can be observed. Ideally fibre-optic monitoring
would be used, which can provide an estimate of individual phase production and flowing pressure for each stage, although this is also the most expensive option available. Application of any technique which provides information about the extent of production from each stage could significantly improve the interpretation.

3. Conduct laboratory studies on the permeability (conductivity), width, porosity and compressibility of hydraulic fractures in a given formation propped with a certain proppant. This would help constraining fracture permeability, as transient flow within the fractures is often difficult to accurately interpret due to the absence of a clear early transient signature. Such methods can also be used to better understand pressure-dependant permeability in the fractures as fracture pressure is drawn down with production, and could also be used to better understand the pressure-dependant fracture storage (porosity and/or width). Fracture compressibility is another highly uncertain parameter which can have a significant impact on flowback interpretation, particularly fracture half-length and to a lesser extent conductivity. In this work, simple methods such as those developed for naturally fractured reservoirs were used to understand the order of magnitude of fracture compressibility, although lab testing would provide far more accurate information and indicate whether pressure-dependent compressibility should be applied in the model. These results would vary greatly from formation to formation and require a variety of assumptions since so many key parameters are impacted. The Tight Oil Consortium (TOC) research group led by Dr. Christopher Clarkson at the University of Calgary have begun conducting lab tests that would meet this requirement if they are proven successful.
4. A detailed study of the impact of flowback operations on long-term well performance is critical for the industry to optimize long-term production. This was investigated to an extent by Cugnart et al (2017) and numerically by a number of researchers. Numerical studies may be limited due to the assumptions used by numerical simulators and the difficulty of accurately capturing flowback physics. A coupled flow and geomechanical simulator would provide the best representation of field properties. A rigorous field study would require a significant number of wells drilled using a similar completion style in a homogeneous (if possible) reservoir. This can be particularly difficult in unconventional formations as there tends to be a high degree of heterogeneity which could mask the impact of the flowback operations. Assuming the geology allows such a study, only one parameter should be changed at a time, and ideally several wells would be flown back in the same manor. Some of the operations which would be valuable to investigate would be stimulation and flowback sequence, shut-ins at different times during the flowback period (i.e. prior to the onset of hydrocarbon production, while hydrocarbon rate is increasing and once hydrocarbon production has begun to decline), length of soaking period and extent of flowback which should occur prior to soaking, extent of drawdown, importance of removing water from the formation, etc. Note that the results of such a study could vary greatly in different formations.

8.2.2 Flowback Modeling

1. Validate model against numerical simulation. To date numerical simulation has only been used to demonstrate the modeled flow-regimes but could also be used for model validation.

340
2. Couple flow model with a hydraulic fracture model to estimate fracture width as well as half-length. This approach was used by Clarkson et al. (2017). The method could be improved by directly integrating the flow model with the fracture model to more accurately model leak-off during stimulation. An estimate of fracture width is important since the assumed shape, width and porosity control the estimated half-length. For example in the case study shown in Chapter Four, which assumed a circular fracture shape using an individual fracture width of 0.5 in per fracture leads to a half-length of 441 ft, while a width of 0.25 in per fracture leads to a half-length of 663 ft. This corresponds to a ~ 40% longer half-length with the smaller fracture width.

3. Improve the speed and efficiency of current tools. Although these have been developed as research (proof of concept) tools, the growing interest from industry provides motivation for improving model calculation speed due to time constraints often present in industry applications.

4. Test the developed techniques on a significant number of wells from many different plays to understand their widespread applicability and accuracy. During the course of study, many more cases from different formations have been investigated than what was presented in this dissertation. To date, a data set has not been identified which could not be accurately assessed using the methods presented in this dissertation. Regardless, only a small fraction of global unconventional plays have been studied so it is possible that these methods may not be applicable in all scenarios.

5. Investigate the importance of desorbed gas during flowback in different shale plays. This would require laboratory testing to understand desorption pressure and the Langmuir Isotherm, as was conducted in the field case presented in Chapter Three. This would
provide insights into the applicability of the developed model for different shale plays, and also provide information on how the model should be altered for a particular shale play.

6. Extend the methods presented for analyzing shale gas flowback to tight gas situations. An early attempt to model flowback from tight gas reservoirs was conducted by Williams-Kovacs and Clarkson (2013b), although this method was based on the original shale gas model developed by Clarkson and Williams-Kovacs and Clarkson (2013a) and could be vastly improved upon with the insights gathered by investigating significantly more field tight gas cases. The primary modification required for application of the current shale gas model would be developing a MBE which could accurately represent tight gas behavior. Application of the classic gas MBE would work as a good starting point, which could then be altered for the intricacies of flowback such as pressure-dependent fracture volume.

7. Conduct a comprehensive parametric study to determine which parameters have the greatest impact on the flowback history-match, and which parameters should be treated as uncertain in assisted history-matching. As discussed in Chapter Four, the smaller the number of uncertain parameters improves the likelihood of different algorithms locating the absolute minima and therefore finding the optimal combination of key history-matching parameters. This could be assessed using MC simulation in a manner similar to what was shown in Chapter Four, although not limiting the number of uncertain parameters and conducting a significant number of iterations. Depending on the number of parameters with potential uncertainty, this may require millions of iterations and would likely only be practical on a very small number of wells in a given area/formation.
Similar studies in the literature have been carried out on long-term production from
different reservoir types, although it is unlikely that enough iterations have ever been
conducted to accurately assess the importance of accounting for the uncertainty in all
potential parameters due to the time required to conduct this number of iterations.

8. The results of Chapter Four, and other wells assessed using these methods which were
not presented in this dissertation, are quite convincing that a wide variety of different
optimization algorithms could be used to find the absolute minima. Although this has
been the experience to date multiple algorithms should be tested on a significant number
of cases before drawing final conclusions on which algorithm should be used. This
would aid in avoiding the use of an algorithm that may lead to reasonable matches,
although with an unreasonable set of parameters which could lead to poor decision
making. Testing of additional algorithms, particularly MO algorithms, would be
worthwhile to find the best algorithms for use with the flowback problem. MO
algorithms likely have the best potential for accurate results when dealing with MO
problems due to issues with objective conflict. Although accurate results have been
demonstrated using a 1:1 objective weighting, applying different weighting factors when
using SO algorithms would also be worthwhile as selecting an accurate weighting for
different objectives can have a significant impact on results in some cases, particularly as
the number of objectives increases. A good starting point for objective weighting would
be assessing the order of magnitude of the different objectives from the deterministic
history-match, and using the weighting factor to equalize the importance of each
objective. This could be particularly important in the flowback problem; for example, in
the LTO problem, water rates are typically significantly higher than oil rates during
flowback, causing this objective to be significantly larger than the oil objective. For example, in Chapter Four, the water OF was an order of magnitude higher than the oil OF, which could cause the algorithm to focus on matching water rates, leading to a poorer match to hydrocarbon rates.

9. Develop more rigorous methods to account for changes in relative permeability in the communicating fracture networks to improve the saturation-dependant communication factors of each phase. In this work, a simple approximation method, which required no knowledge of saturation gradient within the fractures, was used.

10. Test the multi-well and stage-by-stage analysis techniques on a larger number of field cases to demonstrate the importance of accounting for communication and fracture heterogeneity as well as the applicability of the developed methods.

11. Modify the developed tools to account for secondary communication between wells and stages. This can easily be accounted for within the framework of the developed tools, although as discussed previously, each additional stage or well introduces more unknowns into the problem making a unique history-match more complicated.

12. Rigorously account for cross-flow within the matrix in multi-layer scenarios. As discussed in Chapter Five, the impact of cross-flow between tight formations which are not separated by a permeability barrier is likely minimal in most cases compared to the communication in the primary fractures due to the permeability contrast. Reservoir cross-flow may be important in some cases, however, particularly with prevalent natural fractures or significant creation of a complex fracture network (which can significantly reduce the contrast in permeability between the hydraulic fractures and the “matrix”).
13. Develop rigorous correlations for the PVT properties of hydrocarbon-based fracture fluid specific to reservoir conditions. This would require extensive PVT testing and it is probable that different correlations would be required for different base hydrocarbon fluids – is possible, however, that the same correlations with different constants could be used with different constants as was done in Chapter Six.

14. Develop a more rigorous salinity model that could be applied to both BBT and ABT flow under variable rate conditions. Such a model would require semi-analytical or numerical methods to solve, and would need to offer enough flexibility that it could be manipulated for different formation types with different salinity sources. Extensive lab testing could be conducted to understand the dominant mechanisms in a particular formation and to estimate key transport coefficients. Model accuracy could also be vastly improved by accounting for the individual salt components, rather than treating salt as a single component. This is important as different components undergo different mechanisms under different conditions. It is possible existing commercial software such as TOUGHREACT™ could be manipulated to adequately model this problem.

15. Expand the methods presented in this work for application to more complex fluid systems such as retrograde gas condensate and volatile oil. Reservoirs of these types are currently being exploited extensively in industry and a significant amount of work has been presented in the literature to accurately assess reservoirs of these types using analytical, semi-analytical and numerical methods during long-term production, although there has been minimal work considering flowback data.

16. Develop methods for analyzing flowback of carbonate reservoirs which are typically stimulated with acid fracs. Such reservoirs may present additional complexities over
siliciclastic reservoirs due to the dynamic, time-dependent interaction of acid with the formation as well as the behaviour of fractures which are created by acid interacting with the formation but receive no proppant.

17. Continue to investigate different methods for analyzing flowback data to better capture the physics of the flowback period. This dissertation provided some of the pioneering work on quantitative flowback analysis and developed simple methods that provide reasonable results. Research has already been conducted by the author and his colleagues on application of different methods including a semi-analytical model utilizing the DDA concept as well as hybrid models for naturally fractured or highly complex hydraulic fractures. These works were discussed in the literature review and throughout this dissertation. One significant advantage of these techniques over what was presented in this dissertation is their ability to more rigorously account for complex hydraulic fractures and naturally fractured reservoirs and allow differentiation of contribution of the multiple types of fractures in a single well. Although this benefit is countered by an increase in complexity in model setup and model run time.

8.3 Other Considerations

1. Although there are clear benefits to quantitative analysis of flowback data as a method to provide early-time estimates of key hydraulic fracture properties, there are limitations relating to the inherent assumptions required and presence/quality of data available. As a result, this should not be treated as a stand-alone technique, but instead should be used in association with other early-time techniques (i.e. microseismic, fracture modeling, short-duration post-fracture welltest) and compared with long-term online RTA and reservoir
modeling, when available, to enhance understanding of the reservoir, completion and production characteristics. Using this type of workflow can also assist with decision making and long-term production optimization.


Clarkson, C.R. and Williams-Kovacs, J.D. 2013b. A New Method for Modeling Multi-Phase Flowback of Multi-Fractures Horizontal Tight Oil Wells to Determine Hydraulic Fracture


119894 presented at the SPE Shale Gas Production Conference held in Fort Worth, Texas, 16-18 November.


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Chapter Three

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